NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

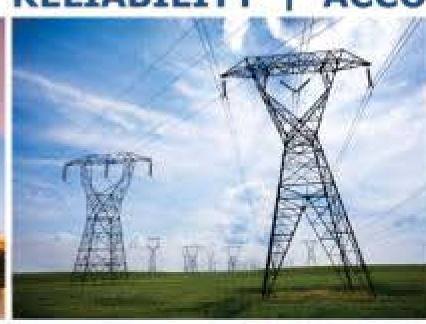
Special Protection Systems (SPS) and Remedial Action Schemes (RAS):

Assessment of Definition, Regional Practices, and Application of Related Standards

Revision 0.1 – April 2013

RELIABILITY | ACCOUNTABILITY



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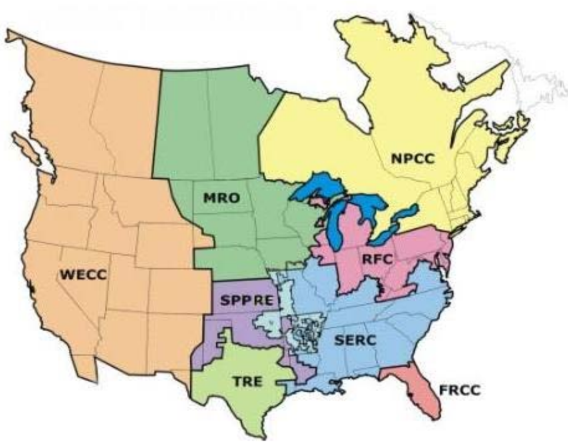
NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to enhance the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a ten-year forecast and winter and summer forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[1]

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into eight Regional areas, as shown on the map and table below. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.



Note: The highlighted area between SPP RE and SERC denotes overlapping Regional area boundaries. For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.

NERC Regional Entities	
FRCC Florida Reliability Coordinating Council	**SERC** SERC Reliability Corporation
MRO Midwest Reliability Organization	**SPP RE** Southwest Power Pool Regional Entity
NPCC Northeast Power Coordinating Council	**TRE** Texas Reliability Entity
RFC ReliabilityFirst Corporation	**WECC** Western Electricity Coordinating Council

[1] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. NERC's reliability standards are also mandatory in Nova Scotia and British Columbia. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

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This technical document was approved by the NERC Planning Committee on March 5, 2013.

Executive Summary

The existing NERC Glossary of Terms definition for a Special Protection System (SPS or, as used in the Western Interconnection, a Remedial Action Scheme or RAS) lacks clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions, leading to inconsistent application of the related NERC Reliability Standards. In addition, three of the related standards (PRC-012-0, PRC-013-0, and PRC-014-0) were identified by FERC in Order No. 693 as fill-in-the-blank standards and consequently are not mandatory and enforceable.

NERC Standards Project 2010-05.2, Phase 2 of Protection Systems: SPS and RAS, will modify the current standards and definitions related to SPS and RAS. The NERC Standards Committee has identified that prior to initiating a project to address these issues, additional research is necessary to clearly define the problem and recommend solutions for consideration. A request for research was submitted by the Standards Committee on January 9, 2012 (see Appendix D). The Planning Committee had already approved a joint effort by the System Analysis and Modeling Subcommittee (SAMS) and System Protection and Control Subcommittee (SPCS) [2] on June 8, 2011 (see Appendix E) which includes issues identified in the request for research. This report addresses all issues identified in the scope of the joint SAMS and SPCS project as well as the Standards Committee request for research; upon approval by the Planning Committee the report should be forwarded to the Standards Committee to support Project 2010-05.2.

This report includes recommendations for a new definition of SPS and revisions to the six SPS-related PRC standards. A strawman definition is provided that eliminates ambiguity in the existing definition and identifies 13 types of schemes that are not SPS, but for which uncertainty has existed in the past based on experience within the Regions. The report also recommends that SPS should be classified based on the type of event to which the SPS responds and the consequence of misoperation. Classification of SPS facilitates standard requirements commensurate with potential reliability risk. Four classifications are proposed.

This report provides recommendations to address FERC concerns with PRC-012-0, PRC-013-0, and PRC-014-0, which assign requirements to Regional Reliability Organizations. Recommendations are made to reassign requirements to specific users, owners, and operators of the bulk power system to remedy this situation.

Project 2010-05.2 should consolidate the requirements pertaining to review, assessment, and documentation of SPS into one standard that includes continent-wide procedures for reviewing new or modified SPS, for assessing existing SPS in annual transmission planning assessments, and for periodic comprehensive SPS assessments. The project also should revise requirements pertaining to analysis and reporting of SPS misoperations in a revision of standard PRC-016-0.1. Due to the significant difference between protection systems and SPS, the subject of SPS misoperations should not be included in a future revision of PRC-004. Given the scope of work and need for drafting team members with different subject matter expertise it may be appropriate to sub-divide Project 2010-05.2 to address review, assessment and documentation of SPS separately from analysis and reporting of misoperations. This report also provides recommendations for Standards Committee consideration that are outside the scope of Project 2010-05.2. These additional recommendations pertain to maintenance and testing and operational aspects of SPS.

[2] The original scope of work involved the SPCS and the predecessor of SAMS, the Transmission Issues Subcommittee (TIS).

Introduction

Problem Statement

The existing NERC Glossary of Terms definition for a Special Protection System (SPS or, as used in the Western Interconnection, a Remedial Action Scheme or RAS) lacks clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions, leading to inconsistent application of the related NERC Reliability Standards. In addition, three of the related standards (PRC-012-0, PRC-013-0, and PRC-014-0) were identified by FERC in Order No. 693 as fill-in-the-blank standards and consequently are not mandatory and enforceable.

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Background

NERC Definitions

The existing NERC *Glossary of Terms* defines an SPS and RAS as:

> *Special Protection System (Remedial Action Scheme)*
>
> An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

In this document, use of the term SPS in general discussions and proposals for future definitions and standards apply to both SPS and RAS. Specific references to existing practices within Regions use the term SPS or RAS as appropriate for that Region.

The NERC *Glossary of Terms* defines a Protection System as:

> *Protection System*

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

Inclusion of the words "protection system" in the term Special Protection System has raised questions whether this is an intentional reference such that SPS are a subset of Protection Systems. Use of protection system (lower case) within the SPS definition identifies that SPS are not Protection Systems. While SPS may include the same types of components as Protection Systems, SPS are not limited to detecting faults or abnormal conditions and tripping affected equipment. SPS may, for example, effect a change to the operating state of power system elements to preserve system stability or to avoid unacceptable voltages or overloads in response to system events. There are many reasons for implementing an SPS; for example, an SPS can be implemented to ensure compliance with the TPL Reliability Standards, to mitigate temporary operating conditions or abnormal configurations (e.g., during construction or maintenance activities), or in instances where system operators would not be able to respond quickly enough to avoid adverse system conditions.

A second area in which the existing SPS definition lacks clarity is the actions that are characteristics of SPS. The actions listed in the definition are broad and may unintentionally include equipment whose purpose is not expressly related to preserving system reliability in response to an event. Inclusion of any system taking "corrective action other than … isolation of faulted components to maintain system reliability" could be deemed to include equipment such as voltage regulators and switching controls for shunt reactive devices. This inclusion would then make these elements subject to single component failure considerations (sometimes referred to as redundancy considerations), coordination, reporting, and maintenance and testing requirements that may be required in the NERC Reliability Standards related to SPS.

This report proposes a revised definition of SPS to address these issues. Development of the proposed definition considered other definitions, common applications, and existing practices regarding classification of SPS.

NERC Reliability Standards

The NERC Reliability Standards contain six standards in the protection and control (PRC) series that specifically pertain to SPS.

- PRC-012-0: Special Protection System Review Procedure
- PRC-013-0: Special Protection System Database
- PRC-014-0: Special Protection System Assessment
- PRC-015-0: Special Protection System Data and Documentation
- PRC-016-0.1: Special Protection System Misoperations
- PRC-017-0: Special Protection System Maintenance and Testing

Three of these standards are not mandatory and enforceable because FERC identified them as fill-in-the-blank standards in Order No. 693, *Mandatory Reliability Standards for the Bulk-Power System*. These standards assign the Regional Reliability Organizations responsibility to establish regional procedures and databases, and to assess and document the operation, coordination, and compliance of SPS. The deference to regional practices, coupled with lack of clarity in the definition of SPS, preclude consistent application of requirements pertaining to SPS. This report provides recommendations that may be implemented through the NERC Reliability Standards Development Process to consolidate the standards and provide greater consistency and clarity regarding requirements.

Chapter 1 – SPS Definition

Considerations for a Revised Definition

Other Definitions in Industry

Several IEEE papers[3] define a similar term to SPS: System Integrity Protection System (SIPS). Adopting the SIPS definition is not appropriate because it is more inclusive than NERC's definition:

> "The SIPS encompasses special protection system (SPS), remedial action schemes (RAS), as well as other system integrity schemes, such as underfrequency (UF), undervoltage (UV), out-of-step (OOS), etc."[4]

NERC applies special consideration to UF and UV load shedding schemes in the Reliability Standards and considers OOS relaying in the context of traditional protection systems. Thus, SIPS is not an appropriate term for use in the Reliability Standards, and a new definition of SPS is more appropriate.

Common Application of SPS in Industry

Most SPS are used to address a range of system issues including stability, voltage, and loading concerns. Less common applications include arresting sub-synchronous resonance and suppressing torsional oscillations. Actions taken by SPS may include (but are not limited to): system reconfiguration, generation rejection or runback, load rejection or shedding, reactive power or braking resistor insertion, and runback or fast ramping of HVdc.

SPS are often deployed because the operational solutions they facilitate are substantially quicker and less expensive to implement than construction of transmission infrastructure. Permanent SPS have been implemented in some cases where the cost associated with system expansion is prohibitive, construction is not possible due to physical constraints, or obtaining permits is not feasible. In other cases temporary SPS have been implemented to maintain system reliability until transmission infrastructure is constructed; or when a reliability risk is temporary (e.g., during equipment outages) and the expense associated with permanent transmission upgrades is not justified.

The deployment of SPS adds complexity to power system operation and planning:

> "Although SPS deployment usually represents a less costly alternative than building new infrastructure, it carries with it unique operational elements among which are: (1) risks of failure on demand and of inadvertent activation; (2) risk of interacting with other SPS in unintended ways; (3) increased management, maintenance, coordination requirements, and analysis complexity."[5]

Subsequent sections of this report consider these three operational elements and provide recommendations regarding how they should be addressed in the NERC Reliability Standards. A summary of the number of schemes identified as SPS or RAS by Region is provided below.

Table 1: Overview of SPS by Region[6]

Region	Total Number	Region	Total Number
FRCC	20	SERC	20
MRO	36	SPP	6
NPCC	117	TRE	24
RFC	47	WECC	192

[3] One noteable reference, Madani, et al, "IEEE PSRC Report on Global Industry Experiences with System Integrity Protection Schemes (SIPS)," IEEE Trans. on Power Delivery, Vol. 25, Oct. 2010.
[4] *Ibid*.
[5] McCalley, et al, "System Protection Schemes: Limitations, Risks, and Management", PSERC Publication 10-19, Dec 2010.
[6] Numbers for 2011 obtained from data reported in the NERC Reliability Metric ALR6-1.

Classification of SPS Types

Three regions classify SPS according to various criteria, including the type of event the SPS is designed to address as well as the ability of the SPS to impact on a local versus wide-area reliability. The following information describes how NPCC, WECC and TRE classify SPS. Please note that examples of regional practices are provided for illustration throughout this document, but are not necessarily best practices or applicable to all Regions. Also in this context, what constitutes local versus wide-area varies among Regions and is not based on the NERC glossary term Wide Area, which is specific to calculation of Interconnection Reliability Operating Limits (IROL).[7]

NPCC

Type I – A Special Protection System which recognizes or anticipates abnormal system conditions resulting from design and operating criteria contingencies, and whose misoperation or failure to operate would have a significant adverse impact outside of the local area. The corrective action taken by the Special Protection System along with the actions taken by other protection systems are intended to return power system parameters to a stable and recoverable state.

Type II – A Special Protection System which recognizes or anticipates abnormal system conditions resulting from extreme contingencies or other extreme causes, and whose misoperation or failure to operate would have a significant adverse impact outside of the local area.

Type III – A Special Protection System whose misoperation or failure to operate results in no significant adverse impact outside the local area.

The following terms are also defined by NPCC to assess the impact of the SPS for their classification:

Significant adverse impact – With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from faults or disturbances, shall be deemed as having significant adverse impact:

a. system instability;
b. unacceptable system dynamic response or equipment tripping;
c. voltage levels in violation of applicable emergency limits;
d. loadings on transmission facilities in violation of applicable emergency limits;
e. unacceptable loss of load.

Local area – An electrically confined or radial portion of the system. The geographic size and number of system elements contained will vary based on system characteristics. A local area may be relatively large geographically with relatively few buses in a sparse system, or be relatively small geographically with a relatively large number of buses in a densely networked system.

WECC

Local Area Protection Scheme (LAPS): A Remedial Action Scheme (RAS) whose failure to operate would NOT result in any of the following:

- Violations of TPL-(001 thru 004)-WECC-1-CR – System Performance Criteria,
- Maximum load loss ≥ 300 MW,
- Maximum generation loss ≥ 1000 MW.

[7] The NERC Glossary defines Wide Area as “The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.”

Wide Area Protection Scheme (WAPS): A Remedial Action Scheme (RAS) whose failure to operate WOULD result in any of the following:

- Violations of TPL-(001 thru 004)-WECC-1-CR – System Performance Criteria,
- Maximum load loss ≥ 300 MW,
- Maximum generation loss ≥ 1000 MW.

Safety Net: A type of Remedial Action Scheme designed to remediate TPL-004-0 (System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)), or other extreme events.

TRE:

(a) A "Type 1 SPS" is any SPS that has wide-area impact and specifically includes any SPS that:

 (i) Is designed to alter generation output or otherwise constrain generation or imports over DC Ties; or

 (ii) Is designed to open 345 kV transmission lines or other lines that interconnect Transmission Service Providers (TSPs) and impact transfer limits.

(b) A "Type 2 SPS" is any SPS that has only local-area impact and involves only the facilities of the owner-TSP.

These three regional classifications can be roughly mapped:

- NPCC Type I = WECC WAPS = TRE Type 1
- NPCC Type III = WECC LAPS = TRE Type 2
- NPCC Type II = WECC Safety Net

SPS classification differentiates the reliability risk associated with SPS and provides a means to establish more or less stringent requirements consistent with the reliability risk. For example, it may be appropriate to establish less stringent requirements pertaining to monitoring or single component failure of SPS that present a lower reliability risk. A recommendation for classification of SPS is included with the proposed definition and subsequent discussion of standard requirements includes recommendations where different requirements based on classification are deemed appropriate.

Common Exclusions from the SPS Definition in Industry

Exclusions provide a means to assure that specific protection or control systems are not unintentionally included as SPS. The NERC glossary definition of SPS states that "An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS)."

Even with the exclusions in the NERC definition, other commonly applied protection and control systems meet the general language in the SPS definition. Considerable effort has been expended by industry discussing what systems are SPS. NPCC and SERC have documented examples of exclusions to the SPS definition in their regional guidelines. NPCC explicitly excludes "Automatic underfrequency load shedding; Automatic undervoltage load shedding and manual or automatic locally controlled shunt devices."[8] SERC's SPS guideline calls out specific exclusions as follows:

a. UFLS and/or UVLS,
b. Fault conditions that must be isolated including bus breakup / backup / breaker failure protection,
c. Relays that protect for specific equipment damage (such as overload, overcurrent, hotspot, reclose blocking, etc.),
d. Out of step relaying,
e. Capacitor bank / reactor controls,

[8] NPCC *Glossary of Terms Used by Directories*

f. Load Tap Changer (LTC) controls,

g. Automated actions that could be performed by an operator in a reasonable amount of time, including alternate source schemes, and

h. Scheme that trips generation to prevent islanding

A recommended list of protection and control systems that should be excluded from classification as SPS is included with the proposed definition.

Exclusion for Operator Aides

SAMS and SPCS considered a number of factors in discussing this subject including:

1) whether the actions are required to be completed with such urgency that it would be difficult for an operator to react and execute in the necessary time, and

2) whether the required actions are of such complexity or across such a large area that it would be difficult for an operator to perform the actions in the necessary time.

It is difficult to address these questions with concise and measurable terms, making it difficult to explicitly exclude them in the definition without introducing ambiguous terms counter to the objective of providing needed clarity in the SPS definition. Whether its existence is based upon convenience or not, any automated system with the potential to impact bulk power system reliability should be defined and expressed to the appropriate authority (e.g., Planning Coordinator, Reliability Coordinator) for the purposes of system modeling and coordination studies, to ensure that these systems are properly coordinated with other protection and control systems, and to ensure that inadvertent operations do not result in adverse system impacts.

On these bases, SAMS and SPCS decided not to provide an exclusion for schemes based on a general criterion as to whether the scheme automates actions that an operator could perform in a reasonable amount of time or schemes installed for operator convenience. However, SAMS and SPCS do recommend exclusions for specific applications that meet these criteria such as automatic sequences that are initiated manually by an operator. Furthermore, any scheme that is not installed "to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of two or more elements removed, an extreme event, or Cascading" would be excluded by definition, regardless of whether it is installed to assist an operator.

Voltage Threshold

All elements, at any voltage level, of an SPS intended to remediate performance issues on the bulk electric system (BES), or of an SPS that acts upon BES elements, should be subject to the NERC requirements.

Proposed Definition

The proposed definition clarifies the areas that have been interpreted differently between individual entities and within Regions, in some cases leading to differing regional definitions of SPS. The proposed definition provides a framework for differentiating among SPS with differing levels of reliability risk and will support the drafting of new or revised SPS standards.

Special Protection System (SPS)

A scheme designed to detect predetermined system conditions and automatically take corrective actions, other than the isolation of faulted elements, to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of: two or more elements removed, an extreme event, or Cascading.

Subject to the exclusions below, such schemes are designed to maintain system stability, acceptable system voltages, acceptable power flows, or to address other reliability concerns. They may execute actions that include but are not limited to: changes in MW and Mvar output, tripping of generators and other sources, load curtailment or tripping, or system reconfiguration.

The following schemes do not constitute an SPS in and of themselves:

a) Underfrequency or undervoltage load shedding

b) Locally sensing devices applied on an element to protect it against equipment damage for non-fault conditions by tripping or modifying the operation of that element, such as, but not limited to, generator loss-of-field or transformer top-oil temperature

c) Autoreclosing schemes

d) Locally sensed and locally operated series and shunt reactive devices, FACTS devices, phase-shifting transformers, variable frequency transformers, generation excitation systems, and tap-changing transformers

e) Schemes that prevent high line voltage by automatically switching the affected line

f) Schemes that automatically de-energize a line for non-fault operation when one end of the line is open

g) Out-of-step relaying

h) Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)

i) Protection schemes that operate local breakers other than those on the faulted circuit to facilitate fault clearing, such as, but not limited to, opening a circuit breaker to remove infeed so protection at a remote terminal can detect a fault or to reduce fault duty

j) Automatic sequences that proceed when manually initiated solely by an operator

k) Sub-synchronous resonance (SSR) protection schemes

l) Modulation of HVdc or SVC via supplementary controls such as angle damping or frequency damping applied to damp local or inter-area oscillations

m) A Protection System that includes multiple elements within its zone of protection, or that isolates more than the faulted element because an interrupting device is not provided between the faulted element and one or more other elements

SPS are categorized into four distinct types. These types may be subject to different requirements within the NERC Reliability Standards.

- Type PS (planning-significant): A scheme designed to meet system performance requirements identified in the NERC Reliability Standards, where failure or inadvertent operation of the scheme can have a significant impact on the BES.
- Type PL (planning-limited): A scheme designed to meet system performance requirements identified in the NERC Reliability Standards, where failure or inadvertent operation of the scheme can have only a limited impact on the BES.
- Type ES (extreme-significant): A scheme designed to limit the impact of two or more elements removed, an extreme event, or Cascading, where failure or inadvertent operation of the scheme can have a significant impact on the BES.
- Type EL (extreme-limited): A scheme designed to limit the impact of two or more elements removed, an extreme event, or Cascading, where failure or inadvertent operation of the scheme can have only a limited impact on the BES.

An SPS is classified as having a significant impact on the BES if failure or inadvertent operation of the scheme results in any of the following:

- Non-Consequential Load Loss ≥ 300 MW

- Aggregate resource loss (tripping or runback of generation or HVdc) > the largest Real Power resource within the interconnection[9]
- Loss of synchronism between two or more portions of the system each including more than one generating plant
- Negatively damped oscillations

If none of these criteria are met, the SPS is classified as having a limited impact on the BES.

Definition of Significant and Limited Impact

The parameters used to define the bright line between "significant" and "limited" impacts are proposed to consider only the electrical scale of the event. Defining the bright line in this way eliminates the difficulty in distinguishing the geographic impact of an SPS as either "wide" or "local."

NERC Standard EOP-004-1, DOE Form OE-417 Electric Emergency Incident and Disturbance Report, establishes the criteria by which an event is categorized as a Disturbance and requires a disturbance report. In terms of SPS, the proposed criteria for significant impact mirrors EOP-004-1 by including a non-consequential load loss value of 300 MW.

NERC Reliability Standards require consideration of loss of any generating unit; therefore, generating unit loss would not impact reliability of the bulk power system unless the combined capacity loss exceeds the largest unit within the interconnection. The generation loss level was selected as a loss greater than the largest unit within an interconnection on this basis.

Tripping multiple generating units exceeding the capacity of the largest unit within an 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 identify system performance indicative of the potential for instability, uncontrolled separation, or cascading outages, without requiring detailed analyses to confirm the extent to which instability, uncontrolled separation, or cascading outages may occur. These indicators, combined with the loss of load criterion, are proposed to identify the potential reliability risk associated with failure of a SPS. Subsequent sections of this report recommend requirements for assessment and design of SPS based on whether the potential reliability risk associated with the SPS are significant versus limited impacts.

The proposed thresholds differentiate between significant and limited impact. While it should be clear there is no upper threshold on what constitutes a significant impact, there also is no lower threshold proposed as to what constitutes limited impact. Whether a scheme is an SPS is determined by the definition; significant and limited impact are used only to classify SPS. For example, if a scheme is installed to meet system performance requirements identified in the NERC Reliability Standards then it is an SPS regardless of its potential impact. A failure of the SPS would result in a violation of a NERC Reliability Standard. Thus, excluding a scheme with impact below a certain threshold would undermine the reliability objective of the standard requirement the scheme is installed to address.

[9] I.e., Eastern, Western, ERCOT, or Quebec Interconnection.

Chapter 2 – Design and Maintenance Requirements

Under the proposed definition, SPS are implemented to preserve acceptable system performance, and as such may be critical to power system reliability and therefore subject to single component failure considerations, and maintenance and testing requirements outlined in the PRC standards.

General Design Considerations

Aside from the single component failure, and maintenance and testing considerations outlined below, Disturbance Monitoring Equipment should be provided in the design of an SPS to permit analysis of the SPS performance following an event. Also, as with other automated systems, the design of an SPS should facilitate its maintenance and testing.

SPS Single Component Failure Requirements

Requirement R1.3 in PRC-012-0 requires SPS owners to demonstrate an SPS is designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in NERC Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0. This requirement should be retained in future standards such that Types PS and PL SPS are required to be designed so that power system performance meets the performance requirements of TPL-001-0, TPL-002-0, or TPL-003-0, in the event of a single component failure. The design of Type PS and PL SPS can provide the required performance through any of the methods outlined below, or a combination of these methods:

1. Arming more load or generation than necessary to meet the intended results. Thus the failure of the scheme to drop a portion of load or generation would not be an issue. In this context it is necessary to arm the tripping of more load delivery points or generating units rather than simply arming more MW of load or generation. When this option is used, studies of the SPS design must demonstrate that tripping the total armed amount of load or generation will not cause other adverse impacts to reliability.

2. Providing redundancy of SPS components listed below.
   - Any single ac current source and/or related input to the SPS. Separate secondary windings of a free-standing current transformer (CT) or multiple CTs on a common bushing should be considered an acceptable level of redundancy.
   - Any single ac voltage source and/or related input to the SPS. Separate secondary windings of a common capacitance coupled voltage transformer (CCVT), voltage transformer (VT), or similar device should be considered an acceptable level of redundancy.
   - Any single device used to measure electrical quantities used by the SPS.
   - Any single communication channel and/or any single piece of related communication equipment used by the SPS.
   - Any single computer or programmable logic device used to analyze information and provide SPS operational output.
   - Any single element of the dc control circuitry that is used for the SPS, including breaker closing circuits.
   - Any single auxiliary relay or auxiliary device used by the SPS.
   - Any single breaker trip coil for any breaker operated by the SPS.
   - Any single station battery or single charger, or other single dc source, where central monitoring is not provided for both low voltage and battery open conditions.

3. Using remote or time delayed actions such as breaker failure protection[10] or alternative automatic actions to back up failures of single components (e.g., an independent scheme that trips an element if an overload exists for longer than the time necessary for the SPS to take action). The backup operation would still need to provide mitigation to meet the necessary result in the required timeframe.

4. For Type PL SPS, manual backup operation may be used to address the failure of a single SPS component if studies are provided to show that implemented procedures will be effective in providing the required response when a SPS failure occurs. The implemented procedures will include alarm response and manual operation time requirements to provide the backup functions.

Some SPS utilize an Energy Management System (EMS) system for transmitting signals or calculating information necessary for SPS operation such as the amount of load or generation to trip. Loss of the EMS system must be considered when assessing the impact of a single component failure. For example, when the EMS is used to transmit a signal, a separate communication path must be available. When a non-redundant EMS provides a calculated value to two otherwise independent systems, a backup calculation or default value must be provided to the SPS in the event of an EMS failure.

Types ES and EL SPS are designed to provide system protection against extreme events. The events that Types ES and EL SPS are intended to address have a lower probability of occurrence and the TPL standards do not require mitigation for these events. Dependability of SPS operation is therefore not critical for these events and, consistent with the existing standards, these SPS should not be required to perform their protection functions even with a single component failure. Design requirements for Type ES SPS should emphasize security; however, in some cases Type ES SPS are installed to address an event with consequences so significant (e.g., system separation or collapse of an interconnection) that consideration should be given to both dependability and security. In consideration that the addition of redundancy in some cases might make the SPS less secure, such cases may warrant implementation of a voting scheme[11].

Maintenance and Testing

The Project 2007-17, Protection System Maintenance and Testing, drafting team revised PRC-005 to include maintenance and testing requirements for SPS contained in PRC-017-0.[12] All of the existing requirements in PRC-017-0 that are based on a reliability objective are mapped to PRC-005-2. However, this report identifies two subjects that are not covered in either the existing standard or the proposed standard:

- Complex SPS require different procedures than those used for maintenance of protection systems.
- Maintenance of non-protection system components used in SPS is not addressed in any existing NERC Reliability Standards.

These subjects should be addressed in a future revision of PRC-005 or development of a separate standard.

[10] In this context it is not intended that breaker failure protection must be redundant; rather, that breaker failure protection may be relied on to meet the design requirements (e.g., if an SPS required tripping a breaker with a single trip coil).
[11] A voting scheme achieves both dependable and secure operation by requiring, for example, two out of three schemes to detect the condition prior to initiating action.
[12] PRC-005-2 was adopted by the NERC Board of Trustees on November 7, 2012

Chapter 3 – Study and Documentation Requirements

Review and Approval of New or Modified SPS

Requirement R1 in PRC-012-0 requires each Regional Reliability Organization to have a documented review procedure to ensure that SPS comply with regional criteria and NERC Reliability Standards. However, the potential for SPS interaction and for SPS operation or misoperation to have inter-regional impacts suggests that a uniform procedure for reviewing SPS is important to ensure bulk power system reliability. This report recommends fundamental aspects that should be included in a continent-wide SPS review procedure and included in the revised reliability standards pertaining to SPS. The review process should be conducted by an entity or entities with the widest possible view of system reliability, and must be a user, owner, or operator of the bulk power system. To assure that both planning and operating views are evaluated before a new or modified SPS is placed in service, responsibility for reviewing and approving implementation of SPS should be assigned to the Reliability Coordinator and Planning Coordinator. Ideally these reviews should be performed on a regional or interconnection-wide basis. If in the future an entity is registered as the Reliability Assurer for each Region, the responsibility for performing these reviews, or alternately for coordinating these reviews, should be assigned to the Reliability Assurer.

A continent-wide review process should be established in a revised reliability standard that includes the following aspects:

- The SPS owner[13] should be required to obtain approval from its Reliability Coordinator and its Planning Coordinator in whose area the SPS is installed[14] prior to placing a new or modified SPS in service.
- An entity proposing a new or modified SPS should be required to file an application with its Reliability Coordinator and Planning Coordinator that includes the following information:
  - A document outlining the details of the SPS as specified below in the section titled, Data Submittals by Entities that Own SPS.
  - Studies that demonstrate the operation, coordination, and effectiveness of the SPS, including the impacts of correct operation, a failure to operate, and inadvertent operation. The study report should include the following:[15]
    - Entity conducting the SPS study
    - Study completion date
    - Study years
    - System conditions
    - Contingencies analyzed
    - Demonstration that the SPS meets criteria discussed in the Design Considerations chapter of this report
    - Discussion of coordination of the SPS with other SPS, UFLS, UVLS, and protection systems
- The Reliability Coordinator and Planning Coordinator should be required to provide copies of the application and supporting information to Transmission Planners, Transmission Operators, and Balancing Authorities within their area, and to adjacent Reliability Coordinators and Planning Coordinators.
- Entities receiving the application should be allowed to provide comments to the Reliability Coordinator and Planning Coordinator.

[13] In cases where more than one entity owns an SPS, the standards should designate that a designated "reporting entity" be responsible for transmitting data to the Reliability Coordinator and Planning Coordinator, while all owners retain responsibility for other requirements such as maintenance and testing.

[14] In cases where an SPS has components installed in or takes action in more than one Reliability Coordinator area or Planning Coordinator area, all affected Reliability Coordinators and Planning Coordinators should have approval authority.

[15] The same documentation requirements should apply to Periodic Comprehensive Assessments of SPS Coordination.

- When deciding whether to approve an SPS, the Reliability Coordinator and the Planning Coordinator in whose area the SPS is to be installed or modified should be required to consider supporting information provided with the application; comments from Transmission Planners, Transmission Operators, and Balancing Authorities and other Reliability Coordinators and Planning Coordinators; and any supplemental information provided by the SPS owner.
- The basis of the Reliability Coordinator and Planning Coordinator approval should be limited to whether all required information has been submitted and the studies are sufficient to support that all performance requirements are met.

Assessment of Existing SPS

Study of SPS in Annual Transmission Planning Assessments

Requirement R1 in PRC-014-0 specifically addresses assessment of the operation, coordination, and effectiveness of all SPS and assigns this responsibility to the Regional Reliability Organization. Reliability standards must assign responsibility to owners, operators, and users of the bulk power system. For assessments of SPS, it is important to identify an entity with the necessary expertise in system studies and a wide-area view to facilitate coordination of SPS across the system. Instead of assigning this responsibility to the Regional Reliability Organization or the Regional Entity, the assessment responsibility should be assigned to the Planning Coordinator and Transmission Planner for SPS within their specific area.

Annually, the Planning Coordinator and Transmission Planner should review the operation, coordination, and effectiveness of the SPS, including the impacts of correct operation, a failure to operate, and inadvertent operation. If system changes have occurred which can affect the operation of the SPS, annual studies should include system conditions and contingencies modeled in the study supporting the application for installation of or modifications to an SPS.

Any issues identified should be documented and submitted to the Reliability Coordinator and the SPS owner. The Reliability Coordinator and Planning Coordinator should be required to determine, in consultation with the SPS owner, whether a corrective action plan is required, and if so, whether the SPS can remain in-service or must be removed from service until a corrective action plan is implemented. If a corrective action plan is required, the SPS owner should be required to submit an application for a modified SPS as described above in the section titled Review and Approval of New or Modified SPS.

Periodic Comprehensive Assessments of SPS Coordination

Comprehensive assessment should occur every five years, or sooner, if significant changes are made to system topology or operating characteristics that may impact the coordination among SPS and between SPS and UFLS, UVLS, and other protection systems. Responsibility for the comprehensive assessment should be assigned to the Reliability Coordinator to achieve the wide-area review necessary for a comprehensive assessment. Planning Coordinators, Transmission Planners, Transmission Operators, Balancing Authorities, and adjacent Reliability Coordinators should be required to provide support to the Reliability Coordinator when requested to do so. As part of the periodic review the Reliability Coordinator should be required to request the Planning Coordinator and Transmission Planner to assess and document whether the SPS is still necessary, serves its intended purpose, meets criteria discussed in the Design Considerations chapter of this report, coordinates with other SPS, UFLS, UVLS, and protection systems, and does not have unintended adverse consequences on reliability.

The Reliability Coordinator should be required to provide its periodic assessment to Planning Coordinators, Transmission Planners, Transmission Operators, and Balancing Authorities in its area, and to adjacent Reliability Coordinators, and should be required to consider comments provided by these entities. Any issues identified with an SPS should be documented and submitted to the SPS owner. If any concerns are identified, the Reliability Coordinator and the Planning Coordinator in whose area the SPS is installed should determine, in consultation with the SPS owner, whether a corrective action plan is required, and if so, whether the SPS can remain in-service or must be removed from service until a corrective action plan is implemented. If a corrective action plan is required, the SPS owner should be required to submit an application for a modified SPS as described above in the section titled Review and Approval of New or Modified SPS.

Documentation Requirements

Data Submittals by Entities that Own SPS

Reliability standard PRC-015-0 establishes requirements for SPS owners to provide data for existing and proposed SPS as specified in reliability standard PRC-013-0 Requirement R1. PRC-013-0 establishes the data provided shall include the following:

- Design Objectives — Contingencies and system conditions for which the SPS was designed
- Operation — The actions taken by the SPS in response to Disturbance conditions
- Modeling — Information on detection logic or relay settings that control operation of the SPS

This requirement should be carried forward to the revised standards for the SPS owner to provide detailed information regarding the conditions of SPS operation. However, this requirement should be modified to ensure that communication of this information is clear and understandable to all entities that require the information to plan and operate the bulk power system (e.g., Planning Coordinators, Transmission Planners, Reliability Coordinators, Transmission Operators, and Balancing Authorities). Additional specificity should be added to this list of data to assure that sufficient information is provided for entities to understand and model SPS operation.

Since SPS design and complexity vary considerably, a brief description of the action taken when certain system conditions are detected generally does not provide a sufficient level of detail. Conversely, logic and control wiring diagrams may provide too much detail that is not readily understood except by the SPS owner's protection and control engineers. To achieve an appropriate level of detail that provides a common understanding by the SPS owner and other entities, the SPS owner should work with the Transmission Planner to develop a document outlining the details of the SPS operation specifically tailored to the needs and knowledge level of the entities that require this information to plan and operate the bulk power system. The document should include the following:

- SPS name
- SPS owner
- Expected in-service date
- Whether the SPS is intended to be permanent or temporary
- SPS classification (per revised definition), and documentation or explanation of how the SPS mitigates the planning or extreme event and why the impact is significant or limited
- Logic diagram, flow chart, or truth table documenting the scheme logic and illustrating how functional operation is accomplished
- Whether the SPS logic is:
  - Event-based [16]
  - Parameter-based [17]
  - A combination of event-based and parameter-based
- System performance criteria violation necessitating the SPS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery)

[16] Event-based schemes directly detect outages and/or fault events and initiate actions such as generator/load tripping to fully or partially mitigate the event impact. This open-loop type of control is commonly used for preventing system instabilities when necessary remedial actions need to be applied as quickly as possible.

[17] Parameter-based schemes measure variables for which a significant change confirms the occurrence of a critical event. This is also a form of open-loop control but with indirect event detection. The indirect method is mainly used to detect remote switching of breakers (e.g., at the opposite end of a line) and significant sudden changes which can cause instabilities, but may not be readily detected directly. To provide timely remedial action execution, the measured variables may include power, angles, etc., and/or their derivatives.

- Parameters and equipment status monitored as inputs to the SPS (e.g., voltage, current or power flow, breaker position) and specific monitoring points and locations
- Under what conditions the SPS is armed (e.g., always armed, armed for certain system conditions, actuation thresholds)
- Whether arming is accomplished automatically or manually, if required
- Arming criteria – analog quantities and/or equipment status monitored to determine existence of the system condition for which SPS is armed (e.g., generation/load patterns, reactive power reserves, facility loading)
- Action taken – for example: transmission facilities switched in or out; generators tripped, runback, or started; load dropped; tap setting changed (phase-shifting transformer); controller set-point changed (AVR, SVC, HVdc converter); turbine fast valving or generator excitation forcing; braking resistor insertion
- Time to operate, including intentional time delays (e.g., timer settings) and inherent delays (e.g., relay operating time)
- Information with sufficient detail necessary to model the SPS.

SPS Database

PRC-013-0, Requirement R1 requires the Regional Reliability Organization to maintain an SPS database, including data on design objectives, operation, and modeling of each SPS. Similar to the other requirements presently assigned to the Regional Reliability Organization, this requirement should be assigned to a user, owner, or operator of the bulk power system. To minimize the number of databases and facilitate sharing of information with entities that require SPS data to plan and operate the bulk power system, this requirement should be assigned to the Planning Coordinator. The Planning Coordinator should be required to provide its database to NERC for the purpose maintaining a continent-wide data base[18] that NERC would make available to Reliability Coordinators, Transmission Operators, Balancing Authorities, Planning Coordinators, and Transmission Planners that require this data. The database should contain information for each SPS as described above in the section titled, Data Submittals by Entities that Own SPS.

[18] The requirement in a NERC Reliability Standard would be applicable to the Planning Coordinator; the responsibility for NERC to maintain a continent-wide database should be addressed outside the standard.

Chapter 4 – Operational Requirements

Due to their unique nature, SPS may have special operational considerations, with potentially differing requirements among the proposed types for monitoring, notification of status, and the response time required to address SPS failure. Furthermore, consideration should be given to the documentation of procedures for operator interaction with SPS, and how operators should respond to SPS failures.

One entity should be assigned primary responsibility for monitoring, coordination, and control of an SPS. Depending on the complexity, this responsible party may be a Reliability Coordinator, Balancing Authority, or Transmission Operator. Complex SPS may have multiple owners or affected entities, including different functional entities and the chain of notification and control should be clearly established.

Monitoring of Status

Existing NERC Reliability Standard IRO-005-3.1a, Requirement R1.1 requires Reliability Coordinators to monitor SPS. Similarly PRC-001-1, Requirement R6 requires Balancing Authorities and Transmission Operators to monitor SPS. The SPS standards should establish the level of monitoring capability that must be provided by the SPS owner. Classification of the SPS will dictate its design criteria and may lend itself to different levels of monitoring.

All SPS should be monitored by SCADA/EMS with real-time status communicated to EMS that minimally includes whether the scheme is in-service or out-of-service, and the current operational state of the scheme. For SPS that are armed manually the arming status may be the same as whether the SPS is in-service or out-of-service. For SPS that are armed automatically these two states are independent because an SPS that has been placed in-service may be armed or unarmed based on whether the automatic arming criteria have been met. In cases where the classification of the SPS requires redundancy, the minimal status indications should be provided for each system. The minimum status is sufficient for operational purposes; however, where possible it may be useful to provide additional information regarding partial failures or the status of critical components to allow the SPS owner to more efficiently troubleshoot a reported failure. Whether this capability exists will depend in part on the design and vintage of equipment used in the SPS. While all schemes should be required to provide the minimum level of monitoring, new schemes should be designed with the objective of providing monitoring similar to what is provided for microprocessor-based protection systems.

Similarly, the SCADA/EMS presentation to the operator would need to indicate the criticality of the scheme (e.g., through the use of audible alarms and a high priority in the alarm queue). The operator would be expected to know how to respond depending on the nature of the issue detected, as some partial SPS failures might not result in a complete failure of the scheme.

In cases where SPS cross ownership and operational boundaries, it is important that all entities involved with the SPS are provided with an appropriate level of monitoring.

Notification of Status

Since the owner and operator of an SPS or component are often different organizations, and because SPS may cross entity boundaries, it is important that the SPS status is communicated appropriately between entities. Existing NERC Reliability Standards already require some level of notification of SPS status by Reliability Coordinators, Balancing Authorities and Transmission Operators.[19] Furthermore, SPS owners (e.g., Transmission Owner, Generator Owner) should be responsible for communicating scheme or component issues to the operating organizations (e.g., Transmission Operator, Generator Operator), who should then be responsible for communicating the issues to the involved Reliability Coordinator, Balancing Authority, and other Transmission Operators or Generator Operators that might rely on the SPS (for example, in setting operating limits).

The required timing associated with such notification will depend on the type of scheme; for example, the misoperation of a Type PS or ES scheme would require rapid notification to all interested parties. In general, the more critical a scheme is to the reliability of the system, the then more important its notification and response; however, it is also important that some

[19] See, for example, IRO-005-3.1a Requirement R9 and PRC-001-1, Requirement R6.

level notification be made for all schemes, due to the complex nature of SPS and their interaction with each other, to allow entities to understand the reliability impact of a neighboring entity's SPS failure or misoperation.

Response to Failures

As with many of the other issues, the response time required to address SPS failure is tightly coupled to the potential impact of the SPS as well as the operating conditions at the time of failure. For example, if the SPS is intended to address an event with a significant impact such as an IROL, then any corrective action in response to a misoperation would need to be taken in 30 minutes or less, consistent with the T_V[20] associated with the IROL. On the other hand, depending on the operating conditions, a particular scheme's unavailability may not result in an adverse impact to reliability. Actions taken following an SPS failure should consider whether the failure affects dependability or security of the SPS and the potential impact to reliability.

Generally speaking, the SPS failure modes are known and the necessary corrective actions are documented (e.g., contingency plans) so that the system can be placed in a safe operating state. In any case, a full or partial failure of an SPS requires that the system performance level provided by having the SPS in service is met, or a more conservative and safe operating condition would need to be achieved, in a timeframe appropriate for the nature of the SPS and operating conditions. When one system of a redundant SPS fails, the action taken by the operator may depend on the system conditions the SPS is installed to address and the operating conditions at the time of the failure. For example, an operator may respond to failure of one system by operating to higher equipment ratings when an SPS is installed to address thermal loading violations. However, the operator may not be able to rely on the remaining system of a redundant SPS when the SPS is installed to prevent instability, system separation, or cascading outages, in which case the operator must reduce transfers or take other actions to secure the system.

Operational Documentation

Operational documentation is necessary to provide the operator with enough information to understand all aspects of the scheme and is used to provide knowledge transfer as staff changes occur. Overall documentation requirements are identified in the section on Study and Documentation Requirements; however, the operator does not require all information provided by the SPS owner for the database maintained by the Planning Coordinator. The operational documentation is sometimes called a "description of operations" and provides the operation actions for the following areas:

- General Description – This provides an overview of the purpose of the scheme including the monitoring, set points and actions of the scheme. The operator and other stake holders can use this information to understand the need for the scheme.
- Operation – This will provide the specific information concerning, arming, alarming, and actions taken by this scheme including the monitoring points of the scheme. The operator can use this information to provide triage and plan a course of action concerning restoration of the electric system. This information should provide an understanding of what has operated, why these elements have been impacted, and possible mitigations or restoration activities.
- Failures, Alarms, Targeting – This information will provide the operator and first responders with descriptions of alarms and targets and the actions needed when the scheme is rendered unusable either during maintenance or because of a failure. The instructions will guide the operator on how to respond to component failures that partially impair the scheme or those failures that might disable entire scheme.

Regulatory agencies provide oversight of these schemes and require owners of these schemes to provide descriptions and operational information. NERC PRC-015 requires owners to provide description of schemes and the Study and Documentation Requirements section of this report proposes specific documentation requirements for inclusion in a revised standard. In addition to NERC, some Regional Entities also require SPS owners to provide the Region with additional information concerning the operations of the schemes. Some regional regulatory agencies also require the owners to verify that they have taken certain actions after a misoperation or a failure of these schemes.

[20] Specifically, T_V is discussed in NERC Reliability Standard IRO-009-1, Requirement R2.

Chapter 5 – Analysis of SPS Operations

Operations of SPS provide an opportunity to assess their performance in actual operating power systems, as opposed to assessing the impact through a preconceived set of system studies. Analysis of SPS operations is presently addressed in PRC-012-0 and PRC-016-0.1, which establish requirements for Regional Reliability Organizations and SPS owners respectively. PRC-012-0 requires that each Regional Reliability Organization establish a regional definition of an SPS misoperation (R1.6), as well as requirements for analysis and documentation of corrective action plans for all SPS misoperations (R1.7). PRC-016-0.1 requires that SPS owners analyze their SPS operations and maintain a record of all misoperations in accordance with their regional SPS review procedure (R1) and that SPS owners take corrective actions to avoid future misoperations (R2).

PRC-012-0 is one of the standards identified in FERC Order No. 693 as a fill-in-the-blank standard and this standard therefore is not mandatory and enforceable. SAMS and SPCS have not identified any rationale for having regional definitions of an SPS misoperation or regional processes for analyzing SPS operations. Establishment of a continent-wide definition and review process will facilitate meaningful metrics for assessing the impact of SPS misoperations on bulk power system reliability. Rather than revising PRC-012-0 to assign responsibility for developing regional definitions and review processes to a user, owner, or operator of the bulk power system, this report recommends that one continent-wide definition and review process should be established through the NERC Reliability Standard Development Process, and that criteria be established for SPS owners to follow a continent-wide review process in place of the existing requirements in PRC-016-0.1.

SPS Misoperation Definition

Establishing a definition of an SPS misoperation must account for the many different aspects affecting whether operation of an SPS achieves its desired effect on power system performance. In addition to aspects traditionally considered in assessing protection system misoperations such as failure to operate and unnecessary operation, analysis of an SPS operation also must consider whether the action was properly initiated and whether the initiated action achieved the desired power system performance. This report proposes that a tiered definition be used to assess which aspects of an SPS operation are reportable for metric purposes, which require analysis and reporting to the Reliability Coordinator and Planning Coordinator, and which require a corrective action plan. The following definition is recommended for an SPS misoperation.

SPS Misoperation

A SPS Misoperation includes any operation that exhibits one or more of the following attributes:

a. Failure to Operate – Any failure of a SPS to perform its intended function within the designed time when system conditions intended to trigger the SPS occur.

b. Unnecessary Operation – Any operation of a SPS that occurs without the occurrence of the intended system trigger condition(s).

c. Unintended System Response – Any unintended adverse system response to the SPS operation.

d. Failure to Mitigate – Any failure of the SPS to mitigate the power system conditions for which it is intended.

The SPS review process should include requirements based on the SPS misoperation definition as follows:

- The SPS owner must provide analysis of all misoperations to its Reliability Coordinator and Planning Coordinator.
- The SPS owner must develop and implement a corrective action plan for all SPS misoperations.
- Reporting for reliability metric purposes should be limited to SPS misoperations that exhibit attributes (a) or (b) of the proposed definition, but should be addressed outside PRC-016-1, in a manner similar to the process under development for reporting protection system misoperations in Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

SPS Operation Review Process

The review process should be included in a revised version of PRC-016 and PRC-012-0 should be retired upon approval of a continent-wide definition and revised PRC-016. The SPS operation review process should require that SPS owners analyze all SPS operations in sufficient detail to determine whether or not the response of the power system to the SPS operation is appropriate to meeting the purpose of the SPS. This requirement should be applied uniformly to all SPS types. The time required to review each SPS operation will vary with the complexity of the SPS.

The analysis of each operation should include:

- The power system conditions which triggered the SPS.
- A determination of whether or not the SPS responded as designed.
- An analysis of the power system response to the SPS operation.
- An analysis of the effectiveness of the SPS in mitigating power system issues it was designed to address. This analysis should identify whether or not those issues existed or were likely to occur at the time of the SPS operation.
- Any unintended or adverse power system response to the SPS operation.

For each SPS operation, the analysis should identify the power system conditions which existed at the time of the SPS operation. These conditions should be analyzed to determine whether or not the SPS operation was appropriate. This part of the analysis is to determine both whether or not the SPS operated as designed, and whether or not the conditions the SPS is intended to mitigate were present at the time of SPS operation.

Some SPS use a proxy to determine the possible existence of a system problem. For example, the opening of a generator outlet may cause an overload remote from the generator. An SPS could monitor the status of the outlet and run back generation to avoid the possible overload, rather than monitoring the loading on the potentially impacted element. The analysis should determine whether the SPS responded to the loss of outlet, and whether the overload actually would have occurred without SPS operation.

The analysis should also examine the response of the system to the SPS operation. This part of the analysis is to determine whether or not the SPS is effective in its intended mitigation, and if it has unforeseen adverse or unnecessary impacts on the power system.

As noted with the proposed definition above, the reporting requirements for each SPS misoperation should vary based on the attributes of the misoperation. The following discussion proposes reporting requirements and provides rationale for the type of SPS misoperation to which each should apply.

1. The SPS owner should be required to provide analysis of the misoperation to its Reliability Coordinator and Planning Coordinator for all SPS misoperations. The report should be provided to the Reliability Coordinator and the Planning Coordinator because such misoperations may require a reevaluation of the SPS under the review process proposed in the Study and Documentation Requirements section. The report should include the corrective action to assist the Reliability Coordinator and Planning Coordinator in confirming whether the SPS requires reevaluation.

2. The SPS owner should be required to develop and implement a corrective action plan for all SPS misoperations. Reporting details of the corrective action plan should be limited to purposes supporting reliability. As noted above, the report to the Reliability Coordinator and Planning Coordinator should include corrective actions. If an SPS must be removed from service or its operation is modified pending implementation of the corrective action plan, the status must be reported to the Reliability Coordinator, Transmission Operator, or Balancing Authority.

3. The SPS owner should be required to report for reliability metric purposes any SPS misoperation that involves a failure to operate or unnecessary operation. These attributes are analogous to protection system misoperations that must be reported and involve a failure of the SPS to operate per its installed design. The mechanism for

requiring reporting for reliability metric purposes should be similar to the process for reporting protection system misoperations under development in Project 2010-05.1: Protection Systems: Phase 1 (Misoperations).

4. The SPS owner should not be required to report or develop corrective action plans for other failures associated with an SPS that are not associated with an SPS operation or failure to operate, such as:
   - Failure to Arm – Any failure of a SPS to automatically arm itself for system conditions that are intended to result in the SPS being automatically armed;
   - Unnecessary Arming – Any automatic arming of a SPS that occurs without the occurrence of the intended arming system condition(s); and
   - Failure to Reset – Any failure of a SPS to automatically reset following a return of normal system conditions, if the system design requires automatic reset.

These types of failures can be corrected by the SPS owner without involving the Reliability Coordinator and the Planning Coordinator, and are analogous to a protection system owner identifying a failed power supply on a relay. If the failure has not resulted in a misoperation then reporting and corrective action plans are not required. It should be noted however, that operational requirements apply and if an SPS must be removed from service the status must be reported to the Reliability Coordinator, Transmission Operator, or Balancing Authority.

Chapter 6 – Recommendations

Definition

The existing SPS definition in the NERC glossary lacks clarity and specificity necessary for consistent identification and classification of SPS. The following strawman definition is proposed.

Special Protection System

A scheme designed to detect predetermined system conditions and automatically take corrective actions, other than the isolation of faulted elements, to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of: two or more elements removed, an extreme event, or Cascading.

Subject to the exclusions below, such schemes are designed to maintain system stability, acceptable system voltages, acceptable power flows, or to address other reliability concerns. They may execute actions that include but are not limited to: changes in MW and Mvar output, tripping of generators and other sources, load curtailment or tripping, or system reconfiguration.

The following schemes do not constitute an SPS in and of themselves:

a) Underfrequency or undervoltage load shedding

b) Locally sensing devices applied on an element to protect it against equipment damage for non-fault conditions by tripping or modifying the operation of that element, such as, but not limited to, generator loss-of-field or transformer top-oil temperature

c) Autoreclosing schemes

d) Locally sensed and locally operated series and shunt reactive devices, FACTS devices, phase-shifting transformers, variable frequency transformers, generation excitation systems, and tap-changing transformers

e) Schemes that prevent high line voltage by automatically switching the affected line

f) Schemes that automatically de-energize a line for non-fault operation when one end of the line is open

g) Out-of-step relaying

h) Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)

i) Protection schemes that operate local breakers other than those on the faulted circuit to facilitate fault clearing, such as, but not limited to, opening a circuit breaker to remove infeed so protection at a remote terminal can detect a fault or to reduce fault duty

j) Automatic sequences that proceed when manually initiated solely by an operator

k) Sub-synchronous resonance (SSR) protection schemes

l) Modulation of HVdc or SVC via supplementary controls such as angle damping or frequency damping applied to damp local or inter-area oscillations

m) A Protection System that includes multiple elements within its zone of protection, or that isolates more than the faulted element because an interrupting device is not provided between the faulted element and one or more other elements

Classification

SPS should be classified based on the type of event to which the SPS responds and the consequence of misoperation. Classification of SPS facilitates standard requirements commensurate with potential reliability risk. Four classifications are proposed:

- Type PS: planning – significant,
- Type PL: planning – limited,
- Type ES: extreme – significant, and
- Type EL: extreme – limited.

The planning classification applies to schemes designed to meet system performance requirements identified in the NERC Reliability Standards, while the extreme classification applies to schemes designed to limit the impact of two or more elements removed, an extreme event, or Cascading.

The significant classification applies to a scheme for which a failure to operate or inadvertent operation of the scheme can result in non-consequential load loss greater than or equal to 300 MW, aggregate resource loss (tripping or runback of generation or HVdc) greater than the largest Real Power resource within the interconnection, loss of synchronism between two portions of the system, or negatively damped oscillations. The limited classification applies to a scheme for which a failure to operate or inadvertent operation would not result in a significant impact.

Applicability to Functional Model Entities

Three of the existing SPS-related reliability standards (PRC-012-0, PRC-013-0, and PRC-014-0) assign requirements to the Regional Reliability Organization. These standards are not mandatory and enforceable because FERC identified them as fill-in-the-blank standards in Order No. 693. This report recommends that requirements be reassigned to users, owners, and operators of the bulk power system in accordance with the NERC Functional Model. The following recommendations are included in the report:

- Review of new or modified SPS – assign to Reliability Coordinators and Planning Coordinators.
- SPS database maintenance – assign to Planning Coordinators; have Planning Coordinators submit databases to NERC for maintenance of a continent-wide database.
- Assessment of existing SPS – assign Planning Coordinators and Transmission Planners responsibility to include SPS assessments in annual transmission planning assessments; assign Reliability Coordinators responsibility to coordinate a periodic assessment of SPS design and coordination.

Revisions to Reliability Standards

Figure 1 provides a high-level overview of recommendations related to the six PRC standards that apply to SPS. Recommendations include consolidating the six existing standards into three standards.

- Combine all requirements pertaining to review, assessment, and documentation of SPS (presently in PRC-012-0, PRC-013-0, PRC-014-0, and PRC-015-0) in one new standard, PRC-012-1. The requirement in PRC-012-0 for regional procedures for reviewing SPS misoperations is superseded by recommendations for revisions to PRC-016-0.1. The requirement in PRC-012-0 for regional maintenance and testing requirements is superseded by PRC-005-2.
- Requirements pertaining to analysis and reporting of SPS misoperations should be revised in a new standard, PRC-016-1. Due to the significant difference between protection systems and SPS, the subject of SPS misoperations should not be included in a future revision of PRC-004.
- Requirements pertaining to maintenance and testing of SPS already have been translated to PRC-005-2 by the Project 2007-17 Protection System Maintenance & Testing drafting team.

Additional detail is provided in Table 2 in Appendix C – Mapping of Requirements from Existing Standards. This table summarizes the recommendations for how each requirement in the existing six SPS-related standards should be mapped to revised standards. The more significant recommendations are summarized below.

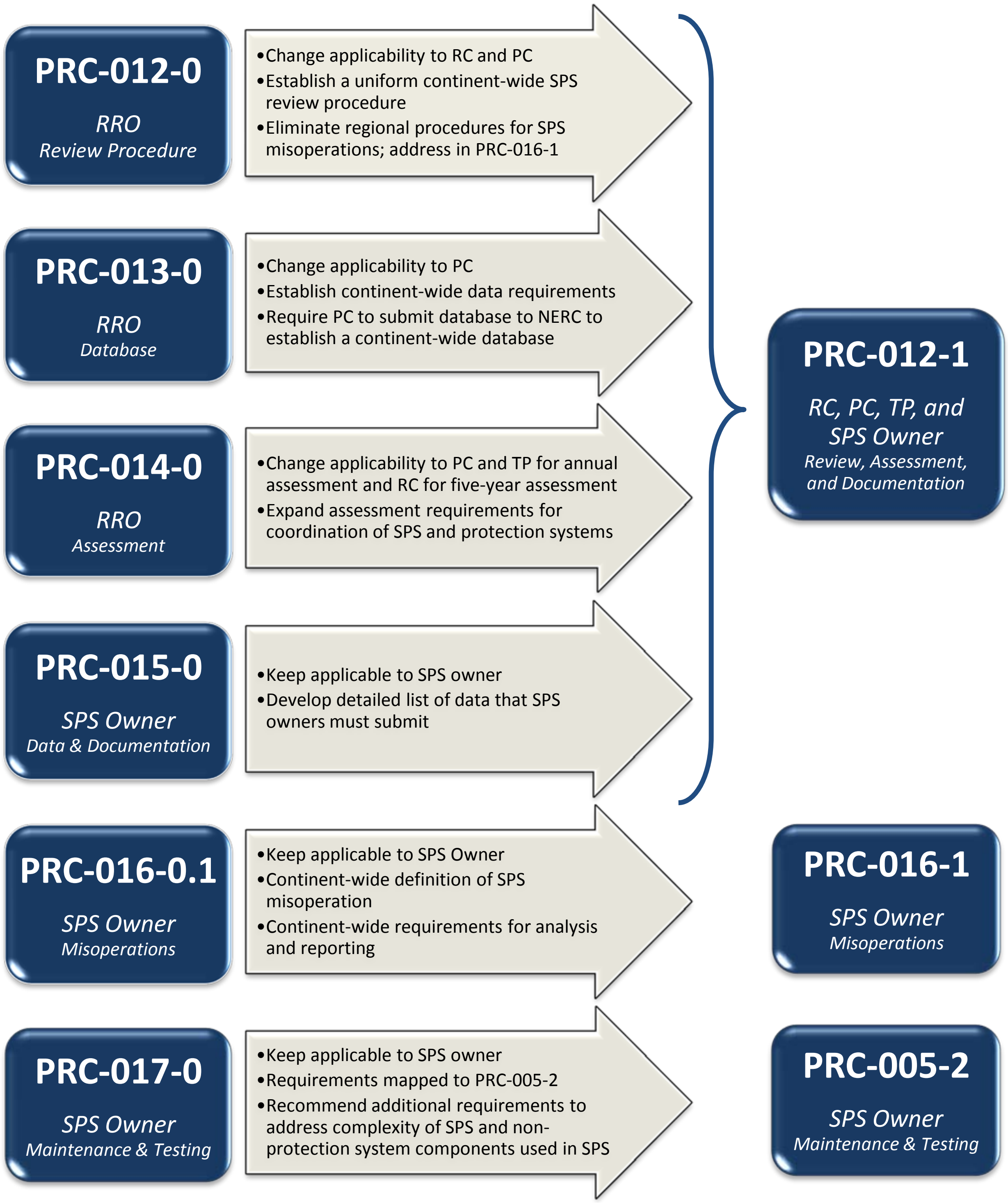

Figure 1 – Recommended Mapping of Existing PRC Standards

Standard PRC-012-1 – SPS Review, Assessment, and Documentation

- SPS owners should be required to design Type PL and Type PS SPS so that a single SPS component failure does not prevent the interconnected transmission system from meeting the performance requirements defined in NERC Reliability Standards TPL-001-0, TPL-002-0, or TPL-003-0.
- Existing requirements for regional procedures for reviewing new or modified SPS should be replaced with a continent-wide procedure assigned to Reliability Coordinators and Planning Coordinators to assure a wide-area view of both planning and operational aspects of SPS.
- Annual transmission planning assessments should include an assessment by the Planning Coordinator and Transmission Planner to review the operation, coordination, and effectiveness of SPS, including the effect of correct operation, a failure to operate, and inadvertent operations.
- Periodic comprehensive assessments (every five years or less) of SPS should be performed by the Reliability Coordinator, with support as requested from other entities, to assess whether SPS are still necessary, serves their intended purpose, meet relevant design criteria, coordinate with other SPS, UFLS, UVLS, and protection systems, and do not have unintended adverse consequences on reliability.
- Detailed continent-wide requirements for data submittals should be established for SPS owners proposing new or modified SPS. Detailed recommendations are included in this report.
- Planning Coordinators should be assigned responsibility for maintaining databases containing all information submitted by SPS owners. Planning Coordinators should be required to submit their databases to NERC so that NERC can maintain and make available a continent-wide SPS database.

Standard PRC-016-1 – SPS Misoperations

- PRC-016-1 should include a continent-wide definition of SPS misoperation based on the strawman definition proposed in this report.
- PRC-016-1 should include a continent-wide process for analysis of SPS operations and reporting SPS misoperations, including requirements for SPS owners to develop corrective action plans and provide analysis of SPS misoperations to Reliability Coordinators and Planning Coordinators.
- Reporting SPS operation and misoperation data for reliability metric purposes should be addressed outside PRC-016-1, in a manner similar to the process under development for reporting protection system misoperations in Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

Standard PRC-005-2 – Protection System Maintenance and Testing

- Maintenance and testing requirements for SPS should be expanded in the NERC Reliability Standards to address the complexity of testing SPS and the maintenance of non-protection system components used in SPS. These subjects should be addressed in a future revision of PRC-005 or development of a separate standard.

Recommendations to Be Included in Other Standards

This report discusses some aspects of SPS that are not addressed in the six SPS-related PRC standards. Recommendations should be incorporated in appropriate NERC Reliability Standards.

- SPS owners should be required to provide disturbance monitoring equipment to permit analysis of SPS performance following an event.
- Operating entities should be required to provide operators with documentation of procedures for operator interaction with SPS, and how operators should respond to SPS failures.
- All SPS should be monitored by SCADA/EMS with real-time status communicated that minimally includes whether the scheme is in-service, out-of-service, and the current operational state of the scheme.
- One entity should be assigned responsibility for monitoring, coordination, and control of an SPS.

Appendix A – Modeling and Simulation Considerations

The addition of two stable control systems does not necessarily result in a stable composite control system; the same is true for SPS. Although the SPS may not be directly linked in their actions, their composite actions and effect on the electric system for commonly-sensed system conditions or perturbations can often behave as a single control system. Therefore, it is imperative that they be evaluated for their potential to interact with each other, particularly during a system disturbance. The composite interaction of multiple SPS, or of SPS with UFLS, UVLS, or other protection systems could result in system instability or cascading.

Because of the complexity of some schemes, modeling them in system simulation is currently performed most often by monitoring their trigger conditions and manually mimicking their intended actions such as changing system configuration, switching reactive devices, and adjusting or tripping generation. Such manual manipulations in powerflow and dynamics studies are only effective when studying a single SPS unless an iterative process is used. Even then, manual manipulation may not be effective and may not be possible in studying the simultaneous actions of multiple SPS that could potentially interact with each other. The difficulty is most significant when considering the potential interaction of parameter-based SPS, since interaction with event-based SPS would occur only if the initial event and SPS operation caused a second event to occur.

It is sometimes possible to simulate the behavior of a single SPS through simulation tools such as user-defined scripts using vendor-provided or open-source programming capability, or standard relay models in the typical modeling and simulation software packages. However, doing so for the myriad of SPS that may exist, even in a portion of an interconnection, is cumbersome. Furthermore, simulating multiple SPS in real-time operations tools (e.g., EMS) for real-time contingency analysis is extremely difficult and often requires new and innovative algorithm and software development. In addition, models used in real-time systems are often abridged or reduced equivalents and may not permit accurate representation of a particular SPS's functions. All of these issues are extremely problematic given the sheer number of SPS in North American interconnections.

To assure SPS will function in a coordinated fashion may require that they be modeled and studied from their design inception in the planning horizon, through pre-seasonal system studies that determine transfer capabilities, and in the operating horizon from day-ahead planning through the real-time contingency analysis that system operators depend on for guidance. Present analysis methods are limited by the capability of the software tools and management of the SPS, and in some cases protection system, data. The industry should put emphasis on future developments in these areas.

General Considerations for Simulations

This section puts forth a number of factors, limitations, objectives, and overall guiding principles that a standard drafting team should consider in development of a new SPS standard with respect to the requirements for modeling and simulation, including data and process requirements necessary to support accurate and meaningful studies of SPS by Transmission Planners.

This report assumes that the modeling and simulation activities to be addressed are those performed for the planning horizon by Transmission Planning personnel. It is assumed that studies are performed using commercial off-the-shelf software packages and using databases derived from the interconnection-wide series of powerflow and dynamics cases. Studies using EMS based tools (e.g., study tools built into state estimators, real-time contingency analysis software, etc.) for real-time operations are not within the scope of this appendix.

It is important however, that the Transmission Planner share the results of planning horizon studies with operations personnel such that the impacts of SPS are effectively understood for the operating horizon also. This can be accomplished in a number of ways. Where operations support staff have similar study tools, sharing of the powerflow/dynamics cases, models, simulation scripts and similar data would enable them to evaluate SPS operation (or misoperation) for the operating horizon. Providing alarm or action limits for observable parameters (i.e., those that could be monitored in the operating environment) related to SPS operation would be another possibility. In this case, the parameters may be a direct indication or a proxy value that is indicative of the system condition of concern. Regardless of the process employed, the overriding consideration is that study results are adequately translated into actionable intelligence that is available to and understood by the system operator. While this is not intended to create a recommendation for a specific SPS standard requirement, how this would ultimately be accomplished should be kept in mind as SPS standards are developed and implemented.

As a general rule, SPS are conceived by transmission planning engineers and implemented by protection and control engineers. To some extent, the engineers in these two groups are concerned with different aspects of SPS operation and use different terminology to describe SPS (and other system) functions. For example, a transmission planner may consider a protection system component failure to be a contingency while a protection engineer may consider this to be a design consideration. Transmission planning engineers conceive an SPS as a solution to system-level problems. Their focus is on the "big picture" functional operation of the SPS for specific system level conditions. Protection and control engineers implement an SPS via detailed design using various sensors, relays, etc. Their focus is on efficiently implementing the functional requirements as they understand them to be. It is imperative that the planning engineers effectively communicate the requirements of the SPS to protection engineers and monitor the design and implementation of the scheme to ensure that the SPS is implemented and functions as prescribed by the planner.

The planning and protection engineers should also consult with the operations personnel to ensure that possible system-level events which might result in unintended SPS operation are considered. Involving operations personnel at each stage of the design process will help ensure that the range of operating conditions likely to be encountered in the real world (including outages), as well as practical operating considerations, are also adequately considered in the SPS design and implementation.

An explicit requirement should exist to represent the salient features of SPS operation in a form that can be readily shared with, understood by, and used in simulations by other Transmission Planners. Simulation of SPS in powerflow or dynamic studies may involve a combination of using standard relay models, various monitoring features, and scripts or program code to adequately simulate the functioning of the SPS. These may include user-defined scripts using vendor-provided or open-source programming capability, or standard relay models in the typical modeling and simulation software packages (either executed during solution-run time or as user-written dynamic models), etc. Transmission Planners generally have their own individual preferences as to how to reflect these functions when performing simulations. Additionally, different Transmission Planning organizations have different levels of expertise in developing scenarios to reflect actual system operation and performing simulations based on those scenarios. Therefore, it is important that the modeling information to be used by other Transmission Planning engineers as input (including run scripts) in simulations be simple, understandable and well documented. Any scripts or models provided need to be "open source" in nature and well-documented to enable independent verification. The use of user models, FORTRAN object code, compiled scripts, and similar which make it difficult for the receiving Transmission Planner to review and understand how the SPS model functions must be avoided.

In addition to providing the relay models, program code/script, and similar input as part of the database, a summary document should be provided explaining the SPS. The information shared must include a summary and guidance document which includes the following, as applicable.

- An overview explanation of the basic functioning of the SPS, describing when and how it operates
- A listing of the setpoints applicable to the SPS (e.g., relay trip settings, etc.)
- A summary overview of how the SPS is being simulated via relay models, simulation scripts that may be provided
- Specific bus numbers, branch identifiers, machine identifiers, etc. should be referenced to help the Transmission Planner receiving this information understand how the SPS is being simulated

SPS modeling information should be readily available as part of the interconnection-wide modeling processes, but not an integral part of an interconnection-wide case year database. Specific recommendations are included in the chapter on study and documentation requirements.

Because of the special nature of SPS, it is not practical or even possible to include them in the interconnection-wide load flow and/or dynamic database case years in the classic sense (e.g., such as one would include a generator or FACTS device model). Additionally, it is simply not necessary to model all SPS for all simulations. The reality is that an SPS in the Northeast will likely have very little impact on the results of simulations focused on the Southeast. Therefore, including all SPS in all simulations places an unreasonable burden on Transmission Planners. However, due consideration should be given to the interaction of a given SPS with other SPS. Note that geographical distance alone may not be sufficient justification not to consider the interaction of several SPS.

However, it is important that information about all SPS be available for use, as deemed appropriate by the Transmission Planners whose systems may be affected by the SPS operation (or misoperation). It is also important the relevant parameter-based SPS be modeled concurrently in simulations to appropriately evaluate potential interactions among the SPS.

Therefore, the data management process for providing SPS information for simulations purposes should include the following considerations.

- Sufficiently detailed SPS information and documentation as described above can be managed as part of the interconnection-wide powerflow and dynamic case creation process.
- Providing the models and simulation scripts alone is not sufficient. A functional description to assist the Transmission Planner in understanding how these modeling/simulation elements work to emulate the SPS function is necessary in order for the Transmission Planner to properly simulate and interpret the results of simulations involving the SPS.
- The SPS information may reside separately from the interconnection-wide powerflow and dynamic cases, but a clear association to each case must be evident.
- Each Transmission Planner will be able to select the SPS that are relevant to the simulation they are performing. Engineering judgment, with a documented reason, for excluding SPS from simulations is acceptable.
- Where included, the impact of multiple SPS and their interaction should be reasonably accounted for in the simulation activities.

It is envisioned that Transmission Planners will generally include only those SPS that, in their judgment, are relative to the simulations being performed and/or could potentially interact with other SPS being included in these simulations. However, it would be prudent to have some big picture check for unintended SPS interaction. Therefore, a joint, interconnection-wide study or assessment should be periodically performed to evaluate potential interactions among SPS across the entire interconnection. Such a study or assessment should include modeling and simulation of all of the SPS throughout the interconnection. A periodicity of five years for this joint study is suggested as an appropriate time frame.

Use of SPS Simulations in Transmission Planning Studies

SPS are used as alternatives to transmission infrastructure to support reliable system operation for identified concerns. As such, these schemes must be analyzed in transmission planning analyses just as any other transmission system addition would be, with a focus on:

- Operation as expected for the design case of concern
- Understanding the potential for operation beyond the original design intent
- Determining if there is a potential for failure to operate to rectify the design case of concern.

In system planning, the types of studies which are typically performed to determine system performance are powerflow and dynamic simulations and analyses. SPS need to be modeled in both of these types of studies.

Powerflow (i.e., steady-state) SPS modeling techniques which could be employed include:

- Explicit modeling of the SPS monitoring and consequent actions with scripting and programming automatically called during powerflow processing
- Explicit modeling of the actuation of the SPS in contingencies which are expected to cause the SPS to actuate
- Contingencies are included in the analysis with and without the SPS actuated
- Monitoring of system performance to determine if system conditions would actuate an SPS

  - The monitoring occurs for all contingencies examined
  - Any result indicating potential actuation of an SPS is rerun with the SPS actuated

Dynamic (i.e., stability) SPS modeling techniques which could be employed include:

- Explicit modeling of the SPS in the dynamic simulation with a model that includes the monitoring and consequent actions during the dynamic simulations
- Explicit modeling of the actuation of the SPS in contingencies which are expected to cause the SPS to actuate
- The dynamic/stability contingencies are included in the analysis with and without the SPS actuated
- Monitoring of SPS trigger elements (voltage, current, flow and/or frequency on system elements or element status) to determine if actuation of an SPS would have actuated
  - Rerun the simulation with the SPS actuated if the monitored results indicate potential actuation of the SPS

The SPS modeling techniques used in system planning should be based upon modeling information provided by the SPS owner which clearly describes what the SPS senses and the consequent actions taken when its triggering needs are met.

The need for accurate modeling information can be demonstrated with an example. In the example, two SPS exist in an area. One SPS trips a large generating plant for loss of a transmission circuit due to first swing stability concerns. This SPS acts within cycles of the initiating line loss. The second SPS inserts a series reactor into a transmission circuit to limit flow and eliminate an overload on the circuit. The second SPS acts within seconds (5 seconds for this example) of the overload condition occurring.

Steady state studies of the area where these SPS exist would examine the representative cases (sets of system conditions) and contingency sets for the study in question. If the power flow software allowed, a post-solution program could be run to test if the actuating circumstances for each SPS were met; if so, the contingent solution would be rerun and tested again for any other SPS which would actuate. If the power flow software did not have this flexibility, the engineer could include an SPS actuation for those contingencies expected to trigger the SPS and run that expanded contingency list; the results could be examined with attention paid to the loading for the circuit protected by the second SPS. Any contingencies which caused an overload on the triggering circuit could be rerun with the SPS actuated.

Since both SPS act within the dynamic simulation timeframe, the SPS should be modeled or monitored in stability simulations. Dynamic models could exist for both SPS. Should the flow on the SPS-triggering line exceed the flow actuation setpoint for the required time duration, the dynamic simulation would capture the impact of the reactor insertion and the SPS actuation. If the SPS were not explicitly modeled, their trigger values could be monitored (i.e., the status or flow on the line for the first SPS and the flow on the potentially overloaded circuit for the second SPS). The monitored data channels would be examined after each simulation to determine if the simulation needed to be rerun while modeling the appropriate SPS actions.

The goal for modeling SPS in studies is to confirm that they will operate to correct the intended system concerns as necessary to preserve acceptable system performance. In addition, the analyses provide understanding for system planning and operations on when and how the use of the SPS may change over time. This information may be critical for system operations staff to maintain reliable system operation.

Appendix B – Operational Considerations

This information is a high level list of important issues and concerns if performing SPS analyses in real-time operations.

Real-time SPS Evaluation

Current system conditions must be identified before evaluating whether an SPS would perform its function and achieve its desired outcome. Results of security analysis should be required to indicate whether an SPS should be armed (if armed manually) and whether an SPS will operate for a given contingency. Security analysis should model operation of the SPS in addition to the initiating contingency when the SPS is armed.

SPS evaluation often cannot be done with SCADA input alone. Some non-SCADA input may be needed; for example, limits from off-line studies are converted into inputs available in the Energy Management System (EMS). The inputs that support SPS evaluation and operation need to be codified in operating guides and presented on operator displays for ease of use and operation. Custom code and displays are generally required to aggregate all needed information for usage by engineers and operators in real time.

The impact of SPS operation on facilities external to the SPS owner/operator needs to be jointly considered and communicated to external entities and appropriately accounted for in EMS. Furthermore, the effects of external contingencies on the SPS triggers should be accounted for within EMS and known to operators.

SPS evaluation typically involves the testing of a limited set of relevant contingencies, requiring the use Real-Time Contingency Analysis (RTCA). In some cases, a dc solution to identify thermal issues is adequate; in other cases, a full ac solution is required (e.g., where triggers are voltage dependent).

Some EMS are not robust enough to compute ac solutions in EMS/RTCA. Depending on the classification of an SPS (e.g., significant), an EMS/RTCA with such limited capability would be insufficient to evaluate the impact of the SPS. In such cases it is necessary to establish other means, such as supplemental off-line tools or delegation of this analysis to an entity that has this capability, to study the operational impacts of the SPS.

If the EMS/RTCA does not reach a solved state, then the SPS cannot be evaluated. For example, some EMS/RTCA will fail to solve or fail to converge upon the creation of islands in the model. In these cases, SPS modeling may require custom software solutions.

Multiple Decision-Making Capability

When evaluating SPS in EMS/RTCA, intermediate steps must be modeled and intermediate states must be evaluated. It should be assumed that an SPS may suffer a full or partial failure and that system conditions will change as the SPS operates. Adverse conditions may arise during intermediate steps that lead to undesired outcomes or put the system into an unplanned operating state.

The post-contingency, pre-SPS-operation state must be known to assess system conditions before the SPS action can be evaluated. For example, the loss of a large nuclear station automatically activates a large emergency core cooling load. This new system state would require a re-solution to check post-contingent node voltage (i.e., with the load connected) before consideration of SPS activation and results can occur. This requires that several stages and intermediate actions be modeled in the evolution of the final system topology to ensure that the system can reach the desired end-state.

Information Management

Each SPS may have its own set of arming and activation triggers. Examples include equipment status, line loading and voltage. These triggers may be complex, and could affect the alarming capability required of EMS.

Changes to EMS models may require long lead times before an SPS can be implemented; for example, changes to models often require pushing through multiple staged software environments. Entities should use software designs that are flexible to accommodate timely changes to SPS models that might not be tied to the network model database release schedule. When implementing an SPS before the EMS model can be updated, it is necessary to establish other means, such as supplemental off-line tools or delegation of this analysis to an entity that has this capability, to study the operational impacts of the SPS.

Modeling Simplicity and Usability

Complex SPS schemes require due diligence to maintain and support. Entities should be required to develop and document an efficient approach to SPS control. An entity's strategy should allow for concurrent and/or consecutive SPS actions.

Appendix C – Mapping of Requirements from Existing Standards

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-012-0	R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include:	PRC-012-1 should define a continent-wide SPS review procedure conducted by the Reliability Coordinator and Planning Coordinator.	See Review and Approval of New or Modified SPS on pp. 16-17.
PRC-012-0	R1.1. Description of the process for submitting a proposed SPS for Regional Reliability Organization review.	PRC-012-1 should define a continent-wide SPS review procedure conducted by the Reliability Coordinator and Planning Coordinator.	See Review and Approval of New or Modified SPS on pp. 16-17.
PRC-012-0	R1.2. Requirements to provide data that describes design, operation, and modeling of an SPS.	PRC-012-1 should define continent-wide requirements for SPS owners to provide data that is clear and understandable to all entities that require this information to plan and operate the bulk power system.	See Data Submittals by Entities that Own SPS on pp. 18-19.
PRC-012-0	R1.3. Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.	PRC-012-1 should require that all Type PS and PL SPS are designed so system performance requirements are met in the event of a single component failure within the SPS.	See SPS Single Component Failure Requirements on p. 14-15

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-012-0	R1.4. Requirements to demonstrate that the inadvertent operation of an SPS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed, and not exceed TPL-003-0.	PRC-012-1 should require that an entity proposing a new or modified SPS should be required to submit studies that demonstrate the operation, coordination, and effectiveness of the SPS, including the impacts of a correct operation, a failure to operate, and inadvertent operation.	See Review and Approval of New or Modified SPS on p. 16.
PRC-012-0	R1.5. Requirements to demonstrate the proposed SPS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures.	PRC-012-1 should require that an entity proposing a new or modified SPS should be required to submit studies that demonstrate the operation, coordination, and effectiveness of the SPS, including the impacts of a correct operation, a failure to operate, and inadvertent operation.	See Review and Approval of New or Modified SPS on p. 16.
PRC-012-0	R1.6. Regional Reliability Organization definition of misoperation.	A continent-wide definition of an SPS misoperation should be established.	See SPS Misoperation Definition on p. 22.
PRC-012-0	R1.7. Requirements for analysis and documentation of corrective action plans for all SPS misoperations.	Do not carry forward to revised standards.	The need for this requirement is eliminated by establishing continent-wide requirements in PRC-016-1. See SPS Operation Review Process on pp. 23-24.
PRC-012-0	R1.8. Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure.	Do not carry forward to revised standards.	The need for this requirement is eliminated by establishing a continent-wide review procedure within PRC-012-1. See Review and Approval of New or Modified SPS on pp. 16-17.
PRC-012-0	R1.9. Determination, as appropriate, of maintenance and testing requirements.	Do not carry forward to revised standards.	The need for this requirement is eliminated by establishing continent-wide maintenance and testing requirements within PRC-005-2.

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-012-0	R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its SPS review procedure on request (within 30 calendar days).	Do not carry forward to revised standards.	Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information.
PRC-013-0	R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with an SPS installed shall maintain an SPS database. The database shall include the following types of information:	PRC-012-1 should require that each Planning Coordinator maintain a database, and provide the database to NERC for the purpose of maintaining a continent-wide database.	See SPS Database on p. 19.
PRC-013-0	R1.1. Design Objectives — Contingencies and system conditions for which the SPS was designed,	This information is included in a comprehensive list of data requirements to be provided by the SPS owner and maintained in a database by the Planning Coordinator.	See Data Submittals by Entities that Own SPS on pp. 18-19 and SPS Database on p. 19.
PRC-013-0	R1.2. Operation — The actions taken by the SPS in response to Disturbance conditions, and	This information is included in a comprehensive list of data requirements to be provided by the SPS owner and maintained in a database by the Planning Coordinator.	See Data Submittals by Entities that Own SPS on pp. 18-19 and SPS Database on p. 19.
PRC-013-0	R1.3. Modeling — Information on detection logic or relay settings that control operation of the SPS.	This information is included in a comprehensive list of data requirements to be provided by the SPS owner and maintained in a database by the Planning Coordinator.	See Data Submittals by Entities that Own SPS on pp. 18-19 and SPS Database on p. 19.

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-013-0	R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).	Do not carry forward to revised standards.	Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information.
PRC-014-0	R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all SPSs installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.	PRC-012-1 should require the Planning Coordinator and Transmission Planner to assess SPS in annual transmission planning assessments and require the Reliability Coordinator to conduct a periodic review every five years, or sooner if significant changes are made to the system topology or operating characteristics that may impact the coordination among SPS and between SPS and UFLS, UVLS, and other protection systems.	See Periodic Comprehensive Assessments of SPS Coordination on p. 17.
PRC-014-0	R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all SPSs installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).	Do not carry forward to revised standards.	Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information.
PRC-014-0	R3. The documentation of the Regional Reliability Organization's SPS assessment shall include the following elements:	PRC-012-1 should require the Reliability Coordinator to document its periodic assessments. The documentation should include the same elements required in a study supporting approval of a new or modified SPS.	See Review and Approval of New or Modified SPS on pp. 16-17 and Assessment of Existing SPS on p. 17.
PRC-014-0	R3.1. Identification of group conducting the assessment and the date the assessment was performed.	This list of elements includes: • Entity conducting the study • Study completion date	See Review and Approval of New or Modified SPS on pp. 16-17.

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-014-0	R3.2. Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.	This list of elements includes: • Study years • System conditions • Contingencies analyzed • Study completion date	See Review and Approval of New or Modified SPS on pp. 16-17.
PRC-014-0	R3.3. Identification of SPSs that were found not to comply with NERC standards and Regional Reliability Organization criteria.	PRC-012-1 should require the Planning Coordinator and Transmission Planner document and submit any issues identified in the annual assessment to the Reliability Coordinator. PRC-012-1 should require the Reliability Coordinator to document and submit any issues identified in the periodic assessment to the SPS owner.	See Assessment of Existing SPS on p. 17.
PRC-014-0	R3.4. Discussion of any coordination problems found between a SPS and other protection and control systems.	PRC-012-1 should require the Reliability Coordinator to request the Planning Coordinator and Transmission Planner to assess and document whether the SPS is still necessary, serves its intended purpose, meets performance criteria, coordinates with other SPS, UFLS, UVLS, and protection systems, and does not have unintended adverse consequences on reliability.	See Periodic Comprehensive Assessments of SPS Coordination on p. 17.
PRC-014-0	R3.5. Provide corrective action plans for non-compliant SPSs.	PRC-012-1 should require that if issues are identified in an annual or periodic assessment, the Reliability Coordinator and Planning Coordinator determine, in consultation with the SPS owner, whether a corrective action plan is required, and if so, whether the SPS can remain in service until a corrective action plan is implemented. If a corrective action plan is required, PRC-012-1 should require the SPS owner to submit an application for a new or modified SPS.	See Assessment of Existing SPS on p. 17.

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-015-0	R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall maintain a list of and provide data for existing and proposed SPSs as specified in Reliability Standard PRC-013-0_R1.	PRC-012-1 should define continent-wide requirements for SPS owners to provide data that is clear and understandable to all entities that require this information to plan and operate the bulk power system.	See Data Submittals by Entities that Own SPS on pp. 18-19.
PRC-015-0	R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service.	Do not carry forward to revised standards. PRC-012-1 should have a requirement for the SPS owner to file an application for approval of an SPS, which assures that the SPS is reviewed in accordance with the continent-wide review procedure prior to being placed in service.	See Review and Approval of New or Modified SPS on pp. 16-17.
PRC-015-0	R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of Studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).	Do not carry forward to revised standards.	Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information.
PRC-016-0.1	R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall analyze its SPS operations and maintain a record of all misoperations in accordance with the Regional SPS review procedure specified in Reliability Standard PRC-012-0_R1.	PRC-016-1 should establish a continent-wide process for analyzing and reporting SPS misoperations.	See SPS Operation Review Process on pp. 23-24.

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-016-0.1	R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall take corrective actions to avoid future misoperations.	PRC-016-1 should establish a requirement that the SPS owner should be required to develop and implement a corrective action plan for SPS misoperations.	See SPS Operation Review Process on pp. 23-24.
PRC-016-0.1	R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).	Do not carry forward to revised standards.	Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information.
PRC-017-0[21]	R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in place. The program(s) shall include:	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, R1.
PRC-017-0	R1.1. SPS identification shall include but is not limited to:	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, Tables 1-1 – 1-5, and Table 2.
PRC-017-0	R1.1.1. Relays.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, Table 1-1.
PRC-017-0	R1.1.2. Instrument transformers.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, Table 1-3.
PRC-017-0	R1.1.3. Communications systems, where appropriate.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, Table 1-2.

[21] Mapping for requirements in PRC-017-0 are adapted from the mapping document developed by the Project 2007-17 Protection System Maintenance & Testing drafting team.

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-017-0	R1.1.4. Batteries.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, Table 1-4.
PRC-017-0	R1.2. Documentation of maintenance and testing intervals and their basis.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, R1 and R2.
PRC-017-0	R1.3. Summary of testing procedure.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, R1, Tables 1-1 – 1-5, and Table 2.
PRC-017-0	R1.4. Schedule for system testing.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, R1 and R2.
PRC-017-0	R1.5. Schedule for system maintenance.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, R1 and R2
PRC-017-0	R1.6. Date last tested/maintained.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, R3 and associated Measures, R4 and associated Measure, and Data Retention.
PRC-017-0	R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).	Addressed by Project 2007-17, Protection System Maintenance and Testing; this requirement is not carried forward to the revised standard.	Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information.

Appendix D – Standards Committee Request for Research; January 9, 2011

Request for Research

Project 2010-05.2

Phase 2 of Protection Systems: SPS and RAS

Introduction

NERC's Standards Committee has tentatively identified this project for initiation in late 2012. Prior to then, there is a need for additional research and scoping of the project to determine:

- What is the problem that this project will try to solve?
- Is the development of a standard the appropriate manner to solve that problem, or should alternative approaches be used?
- If a standard is appropriate, what is the recommended solution to the problem?

Results based standards projects use the approach of defining the needs, goals, and objectives for the project. For this project, we would like your assistance in this effort. Below is a draft problem statement for your consideration.

Need (Problem)

Special Protection Systems (SPS) and Remedial Action Schemes (RAS) can misoperate and negatively impact the reliability of the BES.

Does the need above correctly document the concern described in the attached draft SAR?

Do you agree that this is a problem that needs to be addressed?

Is a standard the appropriate vehicle to address this problem, or should an alternative approach be used? If an alternative, is recommended, what would that alternative be?

If development of a standard is appropriate, then please consider the following Goal

Goal (Solution)

Require the analysis, reporting, and correction of Misoperations of SPS and RAS.

Request

Please provide the Standards Committee with the following information:

- An updated Need/Problem (or a statement of concurrence with the draft presented here)
- A statement indicating whether or not you believe this problem is one which needs to be addressed
- If you agree the problem needs to be addressed, a suggestion for how to address the problem
- If you suggest a standard be developed to address the problem, then please provide
  - An updated goal (or a statement of concurrence with the draft presented here)
  - A set of objectives in support of that goal
  - If you have any suggested changes to the attached draft SAR, please propose them
  - If you have specific recommendations for requirements language or additional information, please include them

Thank you in advance for your assistance.

Appendix E – Scope of Work Approved by the Planning Committee; June 8, 2011

Assessment of Special Protection System Standards and Regional Practices

Proposal:

The SPCS proposes to conduct an assessment of the SPS-related PRC standards and definition of SPS, conduct an assessment of existing regional practices summarizing commonality and differences, and to document its findings in a report to the Planning Committee that can serve as a reference document for a standard drafting team that ultimately will be assigned to review these standards. If deemed appropriate, the report could be used to support a Compliance Application Notice (CAN) to address part of this issue until a revised definition and standard(s) are developed. The SPCS further proposes this activity should be a joint effort with the Transmission Issues Subcommittee (TIS).

Rationale:

- The SPCS scope calls for providing subject matter expertise for NERC Standards related to protection systems and controls, and the SPCS work plan includes an assignment to review all existing PRC-series Reliability Standards, to advise the Planning Committee of its assessment, and to develop Standards Authorization Requests, as appropriate, to address any perceived deficiencies.
- The SPCS has reviewed all PRC standards except the group of SPS standards. The SPCS had started assessment of these standards, but the assessment was deferred due to other priority work such as the Power Plant and Transmission System Protection Coordination technical reference document.
- The SPCS has reviewed its work plan and determined that this is the next logical project for the SPCS. Work on the Transmission System Phase Backup Protection reliability guideline is wrapping up at this time and the SPCS can make the SPS review one of two priority activities for this year (the other is the document addressing operation of protection systems in response to power swings).
- The SPCS believes that a thorough review of SPS-related PRC standards would benefit from the expertise of TIS and the SPCS recommends a joint SPCS/TIS effort coordinated by the SPCS. This proposal has been reviewed with and is supported by TIS.
- The SPCS proposes to conduct an assessment of the standards and definition of SPS, and conduct an assessment of existing regional practices summarizing commonality and differences among the various regional practices.
- The SPCS believes that differences among regional practices must be resolved through a formal process; a consensus opinion of what constitutes an SPCS would lack standing unless it is vetted through a stakeholder process. The SPCS proposes to document its findings in a report that can serve as a reference document for a standard drafting team that ultimately will be assigned to review these standards. If deemed appropriate, the report could be used to support a CAN to address part of this issue until a revised standard(s) is developed.
- The scope of work for such a review is significant and direction should come through the NERC Planning Committee as the body to which SPCS and TIS report.
- The SPCS believes that an appropriate time frame for completing this report would be to submit a draft to the Planning Committee at its March 2012 meeting. The SPCS and TIS believe this schedule is appropriate to support a thorough review.

Approved by the NERC Planning Committee
June 8, 2011

Appendix F – System Analysis and Modeling Subcommittee Roster

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Appendix I – Revision History

Revision History		
Version	**Date**	**Modification(s)**
0	March 5, 2013	Initial Document
0.1	April 18, 2013	Appendix A – Correction to remove trade names and replace with generic language in the section, General Considerations for Simulation