Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment from August 19, 2010 through September 19, 2010.
2. SC authorized moving the SAR forward to standard development on August 12, 2010.
3. SC authorized initial posting of draft 1 on April 24, 2014.

Description of Current Draft

The Protection System Response to Power Swings Standard Drafting Team (PSRPS SDT) is posting Draft 1 of PRC-026-1 – Relay Performance During Stable Power Swings for a 45-day initial comment period and concurrent/parallel initial ballot in the last ten days of the comment period.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Concurrent/Parallel Initial Ballot	April 2014
45-day Formal Comment Period with Concurrent/Parallel Additional Ballot	July 2014
Final Ballot	September 2014
BOT Adoption	November 2014

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Glossary of Terms Used in Reliability Standards are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Term: None.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Relay Performance During Stable Power Swings**
2. **Number:** **PRC-026-1**
3. **Purpose:** To ensure that load-responsive protective relays do not trip in response to stable power swings during non-Fault conditions.
4. **Applicability:**

4.1. Functional Entities:

4.1.1 Generator Owner that applies load-responsive protective relays at the terminals of the Elements listed in Section 4.2, Facilities.

4.1.2 Planning Coordinator.

4.1.3 Reliability Coordinator.

4.1.4 Transmission Owner that applies load-responsive protective relays at the terminals of the Elements listed in Section 4.2, Facilities.

4.1.5 Transmission Planner.

4.2. Facilities: The following Bulk Electric System (BES) Elements:

4.2.1 Generators.

4.2.2 Transformers.

4.2.3 Transmission lines.

5. **Background:**

This is Phase 3 of a three-phased standard development that is focused on developing a new Reliability Standard, PRC-026-1 – Relay Performance During Stable Power Swings, to address protective relay operations due to stable power swings. The March 18, 2010, FERC Order No. 733, approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In this Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, development of a new Reliability Standard to address generator protective relay loadability, and a new Reliability Standard to address the operation of protective relays due to stable power swings. This project's SAR addresses these directives with a three-phased approach to standard development.

Phase 1 focused on making the specific modifications to PRC-023-1 and was completed in the approved Reliability Standard PRC-023-2, which became mandatory on July 1, 2012.

Phase 2 focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability; PRC-025-1 is currently awaiting regulatory approval.

This Phase 3 of the project focuses on developing a new Reliability Standard, PRC-026-1 – Relay Performance During Stable Power Swings, to address protective relay operations due to stable power swings. This Reliability Standard will establish requirements aimed at preventing protective relays from tripping unnecessarily due to stable power swings by requiring each Transmission Owner and Generator Owner to assess the security of protective relay systems that are susceptible to operation during power swings, and take actions to improve security for stable power swings where such actions would not compromise dependable operation for faults and unstable power swings.

6. Effective Date:

First day of the first full calendar year that is twelve months beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first full calendar year that is twelve months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements and Measures

R1. Each Planning Coordinator, Reliability Coordinator, and Transmission Planner shall, within the first month of each calendar year, identify and provide notification to the respective Generator Owner and Transmission Owner of each Element that meets one or more of the following criteria, if any: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

Criteria:

1. An Element that is located or terminates at a generating plant, where a generating plant stability constraint exists and is addressed by an operating limit or a Special Protection System (SPS) (including line-out conditions).
2. An Element that is associated with a System Operating Limit (SOL) that has been established based on stability constraints identified in system planning or operating studies (including line-out conditions).
3. An Element that has formed the boundary of an island within an angular stability planning simulation where the system Disturbance(s) that caused the islanding condition continues to be a credible event.
4. An Element identified in the most recent Planning Assessment where relay tripping occurred for a power swing during a Disturbance.

M1. Each Planning Coordinator, Reliability Coordinator, and Transmission Planner shall have dated evidence that demonstrates identification and the respective notification of the Element(s), if any, which meet one or more of the criteria in Requirement R1. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

Rationale for R1: The Planning Coordinator, Reliability Coordinator, and Transmission Planner are in positions to identify Elements which meet the criteria, if any. The criterion-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document *Protection System Response to Power Swings*, August 2013, which recommended a focused approach to determine an at-risk Element. Requirements R1, R2, and R3 collectively form an annual assessment. Identification of the Element(s) in the first month of the calendar year allows the remaining time in the calendar year for the relay owners to evaluate Protection Systems (Requirement R3).

R2. Each Generator Owner and Transmission Owner shall, once each calendar year, identify each Element for which it applies a load-responsive protective relay at a terminal of an Element that meets either of the following criteria, if any: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

Criteria:

1. An Element that has tripped since January 1, 2003, due to a power swing during an actual system Disturbance where the Disturbance(s) that caused the trip due to a power swing continues to be credible.
2. An Element that has formed the boundary of an island since January 1, 2003, during an actual system Disturbance where the Disturbance(s) that caused the islanding condition continues to be credible.

M2. Each Generator Owner and Transmission Owner shall have dated evidence that demonstrates identification of the Element(s), if any, which meet either of the criteria in Requirement R2. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

Rationale for R2: The Generator Owner and Transmission Owner are in positions to identify which load-responsive protective relays have tripped due to power swings, if any. The criterion-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document *Protection System Response to Power Swings*, August 2013, which recommended a focused approach to determine an at-risk Element. Requirements R1, R2, and R3 collectively form an annual assessment. The time period in Requirement R2 and R3 allows the relay owners to allocate time during the calendar year to identify the Element(s) and to evaluate Protection Systems based on their particular circumstances.

R3. Each Generator Owner and Transmission Owner shall, once each calendar year, perform one of the following for each Element identified pursuant to Requirement R1 or R2: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

- Demonstrate that the existing Protection System is not expected to trip in response to a stable power swing based on the criterion below.
- Demonstrate that the existing Protection System is not expected to trip in response to a stable power swing because power swing blocking is applied.
- Develop a Corrective Action Plan (CAP) to modify the Protection System so that the Protection System is not expected to trip in response to a stable power swing based on the criterion below or by applying power swing blocking.
- If none of the options above results in dependable fault detection or dependable out-of-step tripping:
    a. obtain agreement from the respective Planning Coordinator, Reliability Coordinator, and Transmission Planner of the Element that the existing Protection System design and settings are acceptable, or
    b. obtain agreement from the respective Planning Coordinator, Reliability Coordinator, and Transmission Planner of the Element that a modification of the Protection System design, settings, or both are acceptable, and develop a CAP for this modification of the Protection System.

Criterion:

A distance relay impedance characteristic, used for tripping, that is completely contained within the lens characteristic formed in the impedance (R-X) plane that connects the endpoints of the total system impedance by varying the sending end and receiving end voltages from 0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance where:

1. The system separation angle is:
    - At least 120 degrees where power swing blocking is not applied, or
    - An angle less than 120 degrees as agreed upon by the Planning Coordinator, Reliability Coordinator, and Transmission Planner where power swing blocking is not applied.
2. All generation is in service and all transmission Elements are in their normal operating state.
3. Sub-transient reactance is used for all machines.

M3. Each Generator Owner and Transmission Owner shall have dated evidence that demonstrates one of the options was performed according to Requirement R3. Evidence may include, but is not limited to, the following documentation: apparent impedance characteristic plots, email, design drawings, facsimiles, R-X plots, software output, records, reports, transmittals, lists, settings sheets, or spreadsheets.

Rationale for R3: Performing one of the options in Requirement R3 assures that the reliability goal of this standard will be met. The first option ensures that the Generator Owner and Transmission Owner protective relays are secure from tripping in response to stable power swings having a system separation angle of up to 120 degrees. The second option allows the Generator Owner and Transmission Owner to exclude protective relays that have power swing blocking applied. The third option allows the Generator Owner and Transmission Owner, where possible, to modify the Protection System to meet the criterion or apply power swing blocking. The fourth option allows the Generator Owner and Transmission Owner to maintain a balance between Protection System security and dependability for cases where tripping on stable power swings may be necessary to maintain the ability to trip for unstable power swings or faults; however, agreement is required by others to ensure that tripping for a stable power swing is acceptable. Protection System modifications may be necessary to achieve acceptable performance. A time period of once each calendar year allows time to evaluate the Protection System, develop a CAP, or obtain necessary agreement.

R4. Each Generator Owner and Transmission Owner shall implement each CAP developed pursuant to Requirement R3, and update each CAP if actions or timetables change, until all actions are complete. *[Violation Risk Factor: Medium][Time Horizon: Operations Planning, Long-Term Planning]*

M4. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates implementation of each CAP according to Requirement R4, including updates to actions or timetables. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

Rationale for R4: Implementation of the CAP must accomplish all identified actions to be complete to achieve the desired reliability goal. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting changes and completion of activities provides measurable progress and confirmation of completion.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner, Planning Coordinator, Reliability Coordinator, Transmission Owner, and Transmission Planner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator, Reliability Coordinator, and Transmission Planner shall retain evidence of Requirements R1, Measures M1 for three calendar years.
- The Generator Owner and Transmission Owner shall retain evidence of Requirements R2 and R3, Measures M2 and M3 for three calendar years.
- The Generator Owner and Transmission Owner shall retain evidence of Requirements R4, Measures M4 for 12 calendar months following completion of each CAP.

If a Generator Owner, Planning Coordinator, Reliability Coordinator, Transmission Owner, or Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Long-term Planning	Medium	The responsible entity identified an Element and provided notification in accordance with Requirement R1, but was less than or equal to 30 calendar days late.	The responsible entity identified an Element and provided notification in accordance with Requirement R1, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified an Element and provided notification in accordance with Requirement R1, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The responsible entity identified an Element and provided notification in accordance with Requirement R1, but was more than 90 calendar days late. OR The responsible entity failed to identify an Element or to provide notification in accordance with Requirement R1.
R2	Operations Planning, Long-term Planning	Medium	The responsible entity identified Element in accordance with Requirement R2, but was less than or equal to 30 calendar days late.	The responsible entity identified Element in accordance with Requirement R2, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified Element in accordance with Requirement R2, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The responsible entity identified Element in accordance with Requirement R2, but was more than 90 calendar days late. OR

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The responsible entity failed to identify an Element in accordance with Requirement R2.
R3	Operations Planning, Long-term Planning	Medium	The responsible entity performed one of the options in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity performed one of the options in accordance with Requirement R3, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The responsible entity performed one of the options in accordance with Requirement R3, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The responsible entity performed one of the options in accordance with Requirement R3, but was more than 90 calendar days late. OR The responsible entity failed to perform one of the options in accordance with Requirement R3.
R4	Operations Planning, Long-term Planning	Medium	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

IEEE Power System Relaying Committee WG D6. *Power Swing and Out-of-Step Considerations on Transmission Lines*. July 2005.

Kundar, Prabha. *Power System Stability and Control*. 1994. Palo Alto: EPRI, McGraw Hill, Inc.

NERC System Protection and Control Subcommittee. *Protection System Response to Power Swings*. August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf.

Reimert, Donald. *Protective Relaying for Power Generation Systems*. 2006. Boca Raton: CRC Press.

Guidelines and Technical Basis

Introduction

The NERC System Protection and Control Subcommittee technical document, *Protection System Response to Power Swings*, August 2013[1] ("PSRPS Report" or "report") was specifically prepared to support the development of this NERC Reliability Standard. The report provided a historical perspective on power swings as early as 1965 up through the approval of the report by the NERC Planning Committee. The report also addresses reliability issues regarding trade-offs between security and dependability of protection systems, considerations for this NERC Reliability Standard, and a collection of technical information about power swing characteristics and varying issues with practical applications and approaches to power swings. Of these topics, the PSRPS Report suggests an approach for this NERC Reliability Standard ("standard" or "PRC-026-1") which is consistent with addressing two of the three regulatory directives in the FERC Order No. 733. The first directive concerns the need for "…protective relay systems that differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement."[2] Second, is "…to develop a Reliability Standard addressing undesirable relay operation due to stable power swings."[3] The third directive "…to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings"[4] was considered during development of the standard.

The development of this NERC Reliability Standard implements the majority of the approach suggested by the PSRPS Report. These guidelines include a narrative of any deviation in the report's approach.

Burden to Entities

The PSRPS Report provides a technical basis and approach for focusing on Protection Systems which are susceptible to power swings while achieving the reliability objective. The approach reduces the number of relays for which the requirements would apply by first identifying the Bulk Electric System (BES) Element(s) that need to be evaluated. The first step uses criteria to identify a BES Element on which a Protection System is expected to be challenged by power swings. Of those BES Elements, the second step is to identify the Element(s) that apply a load-responsive protective relay. Rather than requiring the Transmission Planner to perform simulations to obtain information for each identified Element(s), the Generator Owner and Transmission Owner will reduce the need for simulation by comparing the load-responsive protective relay characteristic to a specific criterion.

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[1] NERC System Protection and Control Subcommittee technical document, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

[2] Transmission Relay Loadability Reliability Standard, Order No. 733, P.150 FERC ¶ 61,221 (2010).

[3] Ibid. P.153.

[4] Ibid. P.162.

Applicability

The standard is applicable to the Generator Owner, Planning Coordinator, Reliability Coordinator, Transmission Owner, and Transmission Planner entities. More specifically, the Generator Owner and Transmission Owner entities are applicable when applying load-responsive protective relays at the terminals of the applicable BES Elements. All the entities have a responsibility to identify the Elements which meet specific criteria. The standard is applicable to the following BES Elements: generators, transmission lines, and transformers. The Distribution Provider was considered for inclusion in the standard; however, it is not subject to the standard because this entity by functional registration would not own generators, transmission lines, or transformers other than load serving.

Requirement R1

In the first month of each calendar year this requirement initiates the identification of the Elements that meet specific criteria known by the Planning Coordinator, Reliability Coordinator, and the Transmission Planner.

Because the dynamic studies performed by the Planning Coordinator and the Transmission Planner vary by region, it is important for both of these entities to have a reliability requirement to identify such Elements. The Reliability Coordinator is also included because of its wide-area awareness of the BES and its unique potential to identify Elements susceptible to tripping due to power swings.

The first criterion involves Elements that are located at or terminate at a generating plant where an existing stability constraint has been established and is managed by either a specific operating limit or a Special Protection System (SPS). For example, assume a generating plant contains two 500 MW generating units, one connected to a 345 kV bus and one connected to a 230 kV bus. Assume a single transformer connects the 345 kV bus to the 230 kV bus, and that the plant is connected to the rest of the BES through a single 345 kV transmission circuit and two 230 kV circuits. Assume a stability constraint exists that limits the output of the plant to 700 MW for an outage of the 345 kV transmission line, and that a SPS exists to run back the output of the generating plant to 700 MW for a loss of the 345 kV transmission line. For this hypothetical example, both generating units would be included as Elements meeting the criterion. Furthermore, the generator step-up (GSU) transformers, the generator interconnection, the 345-230 kV power transformer, and the two 230 kV transmission circuits would be identified as Elements meeting the criterion. The 345 kV transmission circuit would not be identified as meeting the criterion since the event that triggered the stability constraint is a loss of the 345 kV transmission circuit.

The second criterion involves Elements that have an established System Operating Limit (SOL) based on a stability limit or issue driven by one or more specific events. For example, if two long parallel 500 kV transmission lines have a combined SOL of 1,200 MW, and this limit is based on angular instability resulting from a fault and subsequent loss of one of the two circuits, then both circuits would be identified as an Element meeting the criterion.

The third criterion involves the Element that has formed the boundary of an island within an angular stability planning simulation. While the island may form due to various transmission circuits tripping for a combination of reasons, such as stable and unstable power swings, faults, and excessive loading, the criterion requires that all lines that tripped in simulation to form the island be identified as meeting the criterion.

The last criterion allows the Planning Coordinator and Transmission Planner to include any other Elements revealed in Planning Assessments.

Requirement R2

The approach of Requirement R2 requires the Generator Owner and Transmission Owner to identify Elements once each calendar year that meet the focused criteria specific to these entities. The only Elements that are in scope are Elements that meet the criteria and apply a load-responsive protective relay at the terminal of the Element. Using the criteria focuses the reliability concern on the Element that is at-risk.

The first criterion involves Elements that have tripped for actual power swings, regardless of whether the power swing was stable or unstable. In order to ensure previous trips due to power swings are considered, the entity must consider Disturbances since January 1, 2003 in order to capture the August 14, 2003 Blackout.[5] In consideration that BES topologies change, the Requirement includes a provision to exclude the Element where a historical Disturbance is no longer credible; meaning the Disturbance is no longer capable of occurring in the future due to actual changes to the BES.

The second criterion involves the formation of an island based on an actual Disturbance. While the island may form due to various transmission circuits tripping for a combination of reasons, such as power swings (stable or unstable), faults, or excessive loading, the criterion requires that all lines that tripped to form the island be identified as meeting the criterion. This criterion also has an exception similar to the first criterion. Any event that caused an actual island to form since August 1, 2003 that is no longer credible due to actual changes to the BES is not required be used to identify Elements as meeting the criterion.

For example, assume eight lines connect an area containing generation and load to the rest of the BES, and five of the lines terminate on a single straight bus. Assume a forced outage of the straight bus in the past caused an island by tripping open the five lines connecting to the straight bus, and subsequently causing the other three lines into the area to trip on power swings or excessive loading. If the BES is reconfigured such that the five lines into the straight bus are now divided between two different substations, a single Disturbance that caused the five lines to open is no longer a credible event; therefore, these Elements should not be identified as meeting the criterion based on this particular event. If any other event remains credible for the Element, then it would be identified under the criterion.

Requirement R3

The purpose of Requirement R3 is to provide alternatives for a Generator Owner or Transmission Owner to demonstrate that Protection Systems on identified Elements are not susceptible to tripping in response to power swings meeting specified conditions. It also provides alternatives for

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[5] http://www.nerc.com/pa/rrm/ea/pages/blackout-august-2003.aspx

the Generator Owner or Transmission Owner to obtain agreement from its Planning Coordinator, Reliability Coordinator, and Transmission Planner that an existing or modified Protection System is acceptable when providing security for the specified conditions would compromise dependable tripping for faults or unstable power swings.

The first option in Requirement R3 allows the Generator Owner or Transmission Owner to evaluate Elements identified in Requirements R1 or R2 to determine if load-responsive protective relays at the terminals of each identified Element are susceptible to tripping in response to a stable power swing. Specific criteria and system conditions are provided to analyze the characteristic of the load-responsive protective relays of each Element.

The second option in Requirement R3 allows the Generator Owner or Transmission Owner to exclude protective relays if they are blocked from tripping by power swing blocking (PSB). If PSB is applied, it is expected that the relays were set in consultation with the Transmission Planner to verify maximum slip rates, so that proper PSB settings can be applied. It is expected that Elements utilizing PSB relays have been evaluated for susceptibility to tripping in response to stable power swings, and thus can be excluded.

The third option in Requirement R3 allows the Generator Owner or Transmission Owner to modify its Protection System to achieve the desired goal of reducing the likelihood of tripping on a stable power swing. The Generator Owner or Transmission Owner may achieve this goal by meeting the criterion used in the first option or by applying power swing blocking. Modifications to the Protection System could include revising settings or logic, or replacing the Protection System. A Corrective Action Plan (CAP) is employed to allow an entity the flexibility to identify the actions and timetable to make the necessary adjustments. A CAP allows for outage scheduling, time for design, procurement, and installation of new relaying or the application of new settings. The amount of detail regarding the listing of the actions required to make the necessary changes to the Protection System is left to the discretion and management of the entity.

The fourth option in Requirement R3 allows the Generator Owner or Transmission Owner for the situation where making the Protection System secure for stable power swings, either through modified settings or replacement, will either significantly decrease the dependability for tripping for faults within its zone of protection or for tripping for out-of-step conditions. To ensure the risks due to tripping for stable power swings are balanced against the risk due to the reduction in dependability, and that reasonable effort to find viable Protection System modifications has been made, the applicable Generator Owner and Transmission Owner must obtain agreement from the Planning Coordinator, Reliability Coordinator, and Transmission Planner that tripping for a stable power swing is acceptable. The entities may agree that the existing or modified Protection System design and settings are acceptable. This option allows for cases where the existing Protection System design and settings are not acceptable, but modifications that do not meet the criterion in the first option result in an acceptable balance between dependability and security. In these cases, a CAP is employed to allow an entity the flexibility to identify the actions and timetable to make the necessary adjustments. A CAP allows for outage scheduling, time for design, procurement, and installation of new relaying or the application of new settings. The amount of detail regarding the listing of the actions required to make the necessary changes to the Protection System is left to the discretion and management of the entity.

Application to Transmission Owners

The criterion describes a lens characteristic formed in the impedance (R-X) plane that connects the endpoints of the total system impedance together by varying the sending and receiving end system voltages from 0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance (Figures 1 and 2). The total system impedance is determined by summing the sending end source impedance, the line impedance in parallel with the Thévinen equivalent transfer impedance, and the receiving end source impedance (Figure 3). This total system source impedance is minimized to create a conservative, worst-case condition by including all transmission Elements that represent a "normal" system configuration with generation set at the value reported to the Transmission Planner. Further, sub-transient generator reactances are used since they are smaller than the transient or synchronous reactances, and result in a smaller source impedance and smaller separation angle in the graphical analysis (Figures 4 and 5).

The source impedances can be obtained by a number of different methods using commercially available short circuit calculation tools.[6] Most short circuit tools have a network reduction feature that allows the user to select the local and remote terminal buses to retain. The first method reduces the system to one that contains two buses, an equivalent generator at each bus (representing the source impedance at the sending and receiving ends), and two parallel lines; one being the line impedance of the protected line with relays being analyzed, the other being the transfer impedance representing all other combinations of lines that connect the two buses together (Figure 3). Another conservative method is to open both ends of the line in question, and apply a three-phase bolted fault at each bus. The resulting source impedance at each end will be less than or equal to the actual source impedance calculated by the network reduction method. Either method can be used to develop the system source impedances at both ends.

The first two bullets of criterion 1, identify the system separation angles to be used to identify the shape and size of the power swing stability boundary used to test load-responsive impedance relay elements. Both bullets test impedance relay elements that are not supervised by power swing blocking. The first bullet evaluates a system separation angle of at least 120 degrees that is held constant while varying the sending and receiving end source voltages from 0 to 1.0 per unit, thus creating a power swing stability boundary shaped like a lens about the system impedance. This lens characteristic is compared to the tripping portion of the distance relay characteristic, that is, the portion that is not supervised by load encroachment logic, or some other form of supervision that restricts the distance element from tripping for heavy, balanced load conditions. If the impedance characteristics are completely contained within the lens characteristic, the Element passes the evaluation (Figures 6 and 7). A system separation angle of 120 degrees was chosen for the evaluation where PSB is not applied because it is generally accepted in the industry that recovery for a swing beyond this angle is unlikely to occur.[7]

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[6] Appendix in *Out-Of-Step Protection Fundamentals and Advancements*, by Demetrios A. Tziouvaras and Daqing Hou, available at https://www.selinc.com (April 17, 2014).

[7] "The critical angle for maintaining stability will vary depending on the contingency and the system condition at the time the contingency occurs; however, the likelihood of recovering from a swing that exceeds 120 degrees is marginal and 120 degrees is generally accepted as an appropriate basis for setting out-of-step protection. Given the importance of separating unstable systems, defining 120 degrees as the critical angle is appropriate to achieve a

The second bullet evaluates impedance relay elements at a system separation angle of less than 120 degrees, similar to the first criterion bullet described above. The angle evaluated must be agreed upon by the Planning Coordinator, Reliability Coordinator, and Transmission Planner, and tripping of the distance elements for stable power swings should not occur at this angle, as shown by system planning or operating studies.

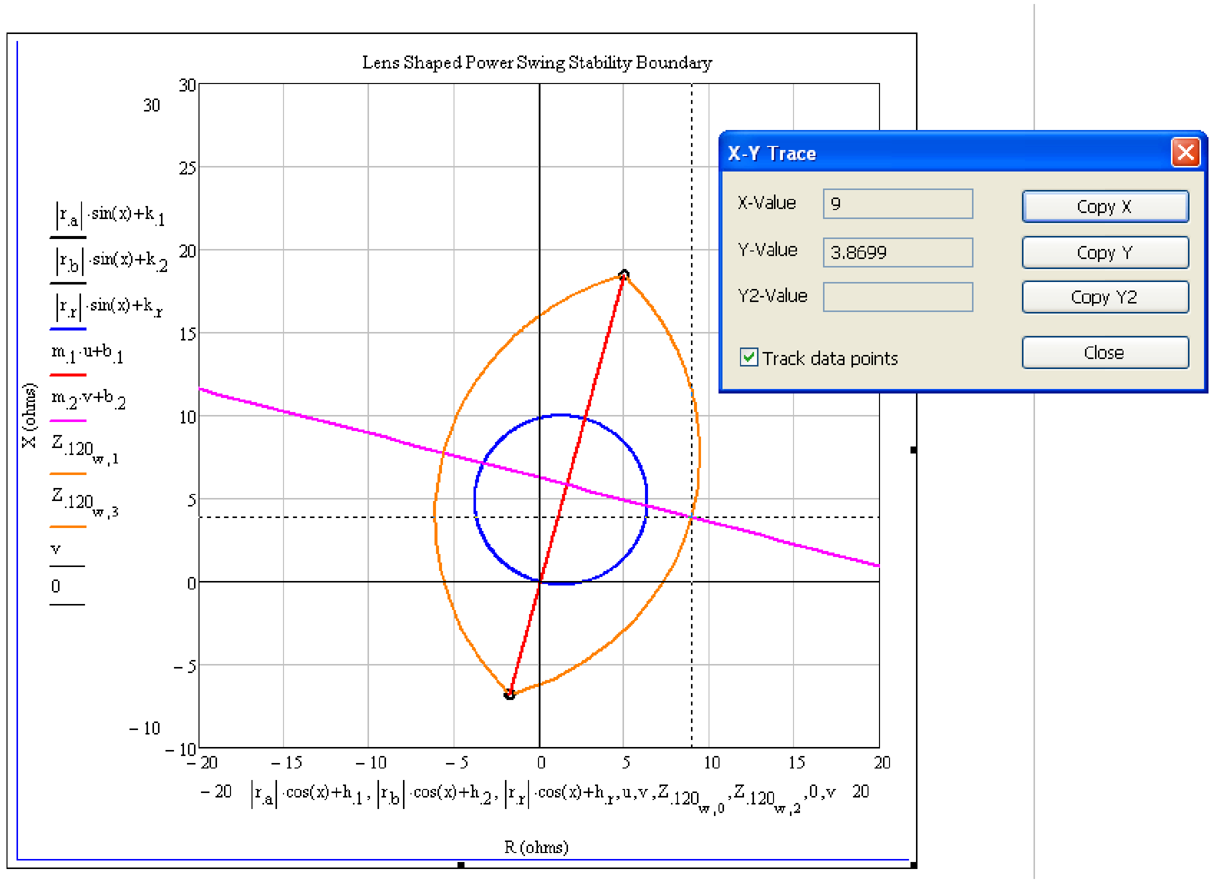


Figure 1. Graphical output showing the plotted R-X coordinates of the calculated lens characteristic (orange plot) with a constant angle of 120 degrees and varying source voltages. The equal EMF ($V_S = V_R$, where $N = V_S / V_R = 1$) coordinate is shown.

proper balance between dependable tripping for unstable power swings and secure operation for stable power swings." PSRPS Report at p. 28.

$Z_s = 1.691 + 6.783j$ ohms $\quad A_o = 120\,deg$ Calculated Angle

$Z_r = 2.848 + 11.244j$ ohms

$Z_1 = 2.18105 + 7.18651j$ ohms

$$N_a := \frac{|E_S|}{|E_R|} \qquad N_a = 1 \qquad N_b := \frac{|E_R|}{|E_S|} \qquad N_b = 1$$

$$Z_T := Z_s + Z_r + Z_1 \qquad Z_T = 6.72005 + 25.21351j$$

$$Z_{r1} := \sqrt{\frac{Z_T^{\,2}}{1 + N_a^{\,2} - 2 \cdot N_a \cdot \cos(A_o)}} \qquad |Z_{r1}| = 15.06519 \qquad Z_{s1} := N_a \cdot Z_{r1} \qquad |Z_{s1}| = 15.06519$$

$$A_{s1} := \operatorname{asin}\left(\frac{|Z_{r1}| \cdot \sin(A_o)}{|Z_T|}\right) \qquad A_{s1} = 30 \cdot deg \qquad Z_{Tang1} := \left(90 - \frac{\arg(Z_T)}{deg}\right) \cdot deg \qquad Z_{Tang1} = 0.26047$$

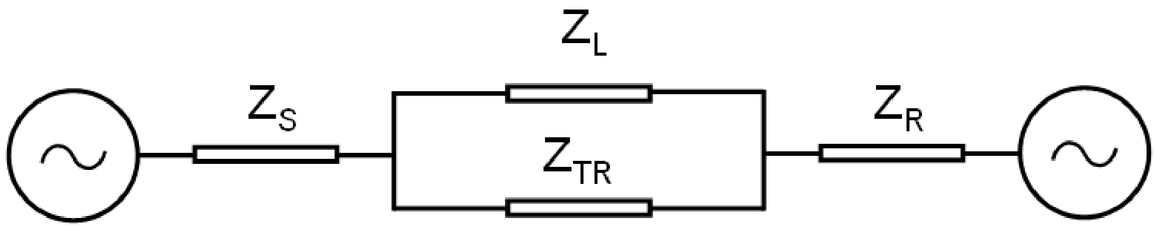
$$R_o := |Z_{s1}| \cdot \cos\left[\frac{\pi}{2} - (A_{s1} + Z_{Tang1})\right] - \operatorname{Re}(Z_s) \qquad R_o = 8.94754 \qquad R_{o\_pri} := R_o \cdot \frac{PTR}{CTR}$$

$$X_o := |Z_{s1}| \cdot \sin\left[\frac{\pi}{2} - (A_{s1} + Z_{Tang1})\right] - \operatorname{Im}(Z_s) \qquad X_o = 3.88384 \qquad X_{o\_pri} := X_o \cdot \frac{PTR}{CTR}$$

$R_{o\_pri} = 8.94754$ ohms

$X_{o\_pri} = 3.88384$ ohms

Figure 2. Mathematical calculations for R-X coordinate plot in Figure 1.



$$Z_{\mathbf{Total}} = Z_{\mathbf{S}} + \frac{Z_{\mathbf{L}} \cdot Z_{\mathbf{TR}}}{Z_{\mathbf{L}} + Z_{\mathbf{TR}}} + Z_{\mathbf{R}}$$

Figure 3. Calculation of total system impedance given sending-end source impedance Z_S, receiving-end source impedance Z_R, line impedance Z_L, and transfer impedance Z_{TR}.

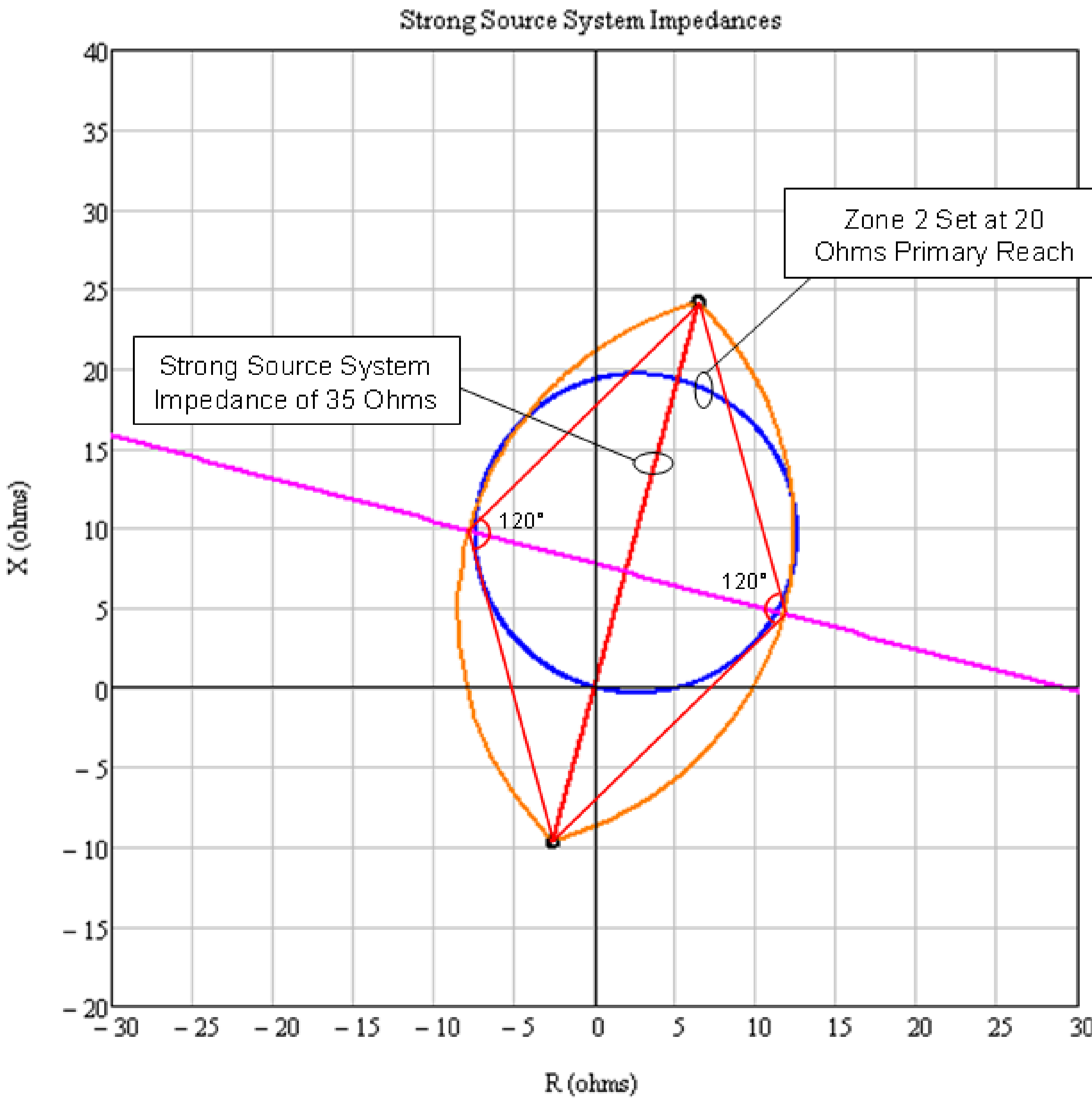


Figure 4. A strong-source system with a line impedance of Z_{Line} = 16 ohms is shown. This represents a heavily-loaded system, using a maximum generation profile and using generator sub-transient reactance. The zone 2 mho circle (set at 125% of Z_{Line}) extends into the power swing stability boundary (orange lens characteristic). Using the strongest source system is more conservative because it shrinks the power swing stability boundary, bringing it closer to the mho circle.

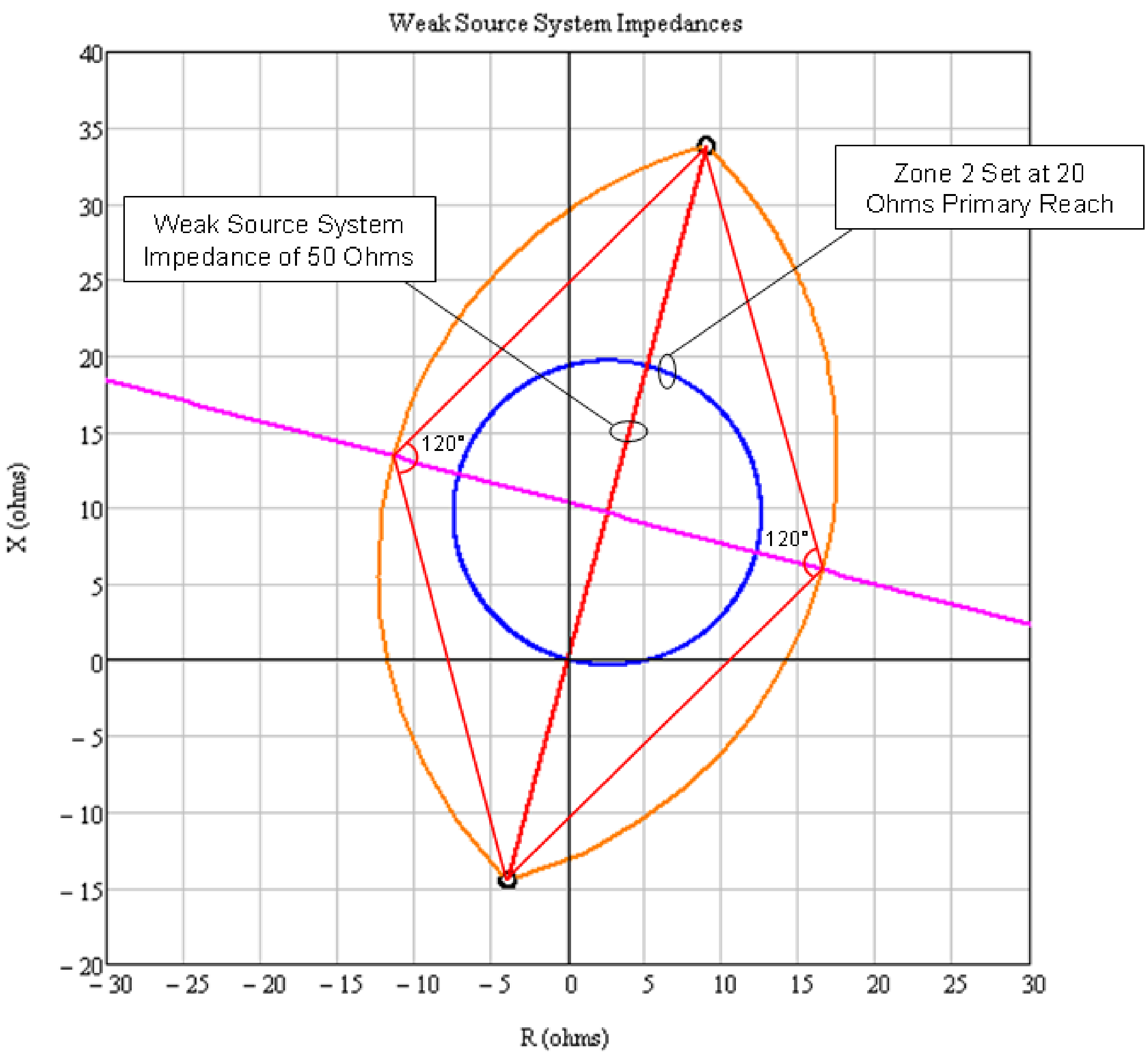


Figure 5. A weak-source system with a line impedance of Z_{Line} = 16 ohms is shown. This represents a lightly-loaded system, using a minimum generation profile and/or using generator transient reactance instead of using generator sub-transient reactance. The zone 2 mho circle (set at 125% of Z_{Line}) does not extend into the power swing stability boundary (orange lens characteristic). Using a weaker source system expands the power swing stability boundary away from the mho circle.

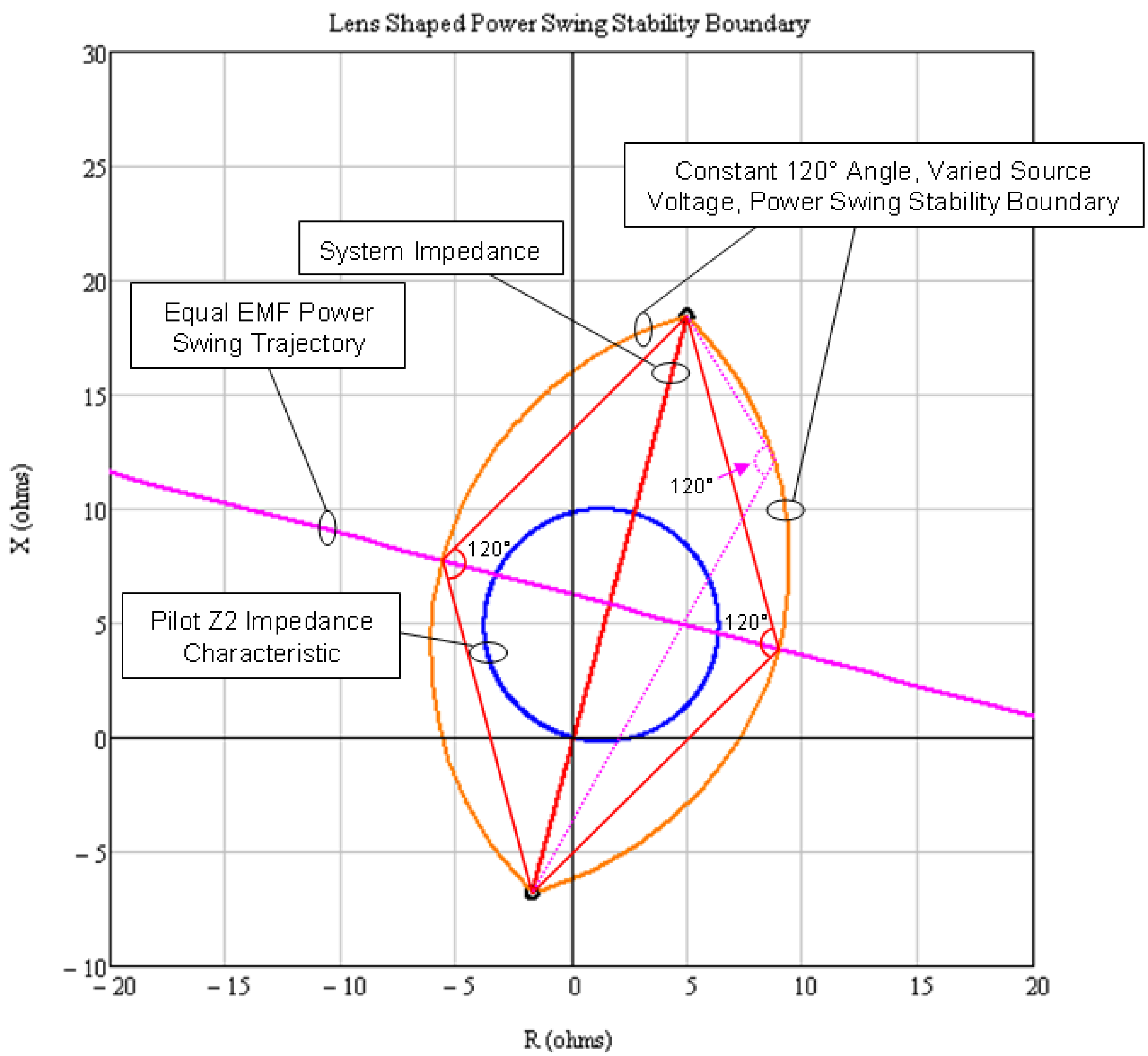


Figure 6. The pilot zone 2 element (blue) is completely contained within the power swing stability boundary (orange). This Element passes the Requirement R3 evaluation.

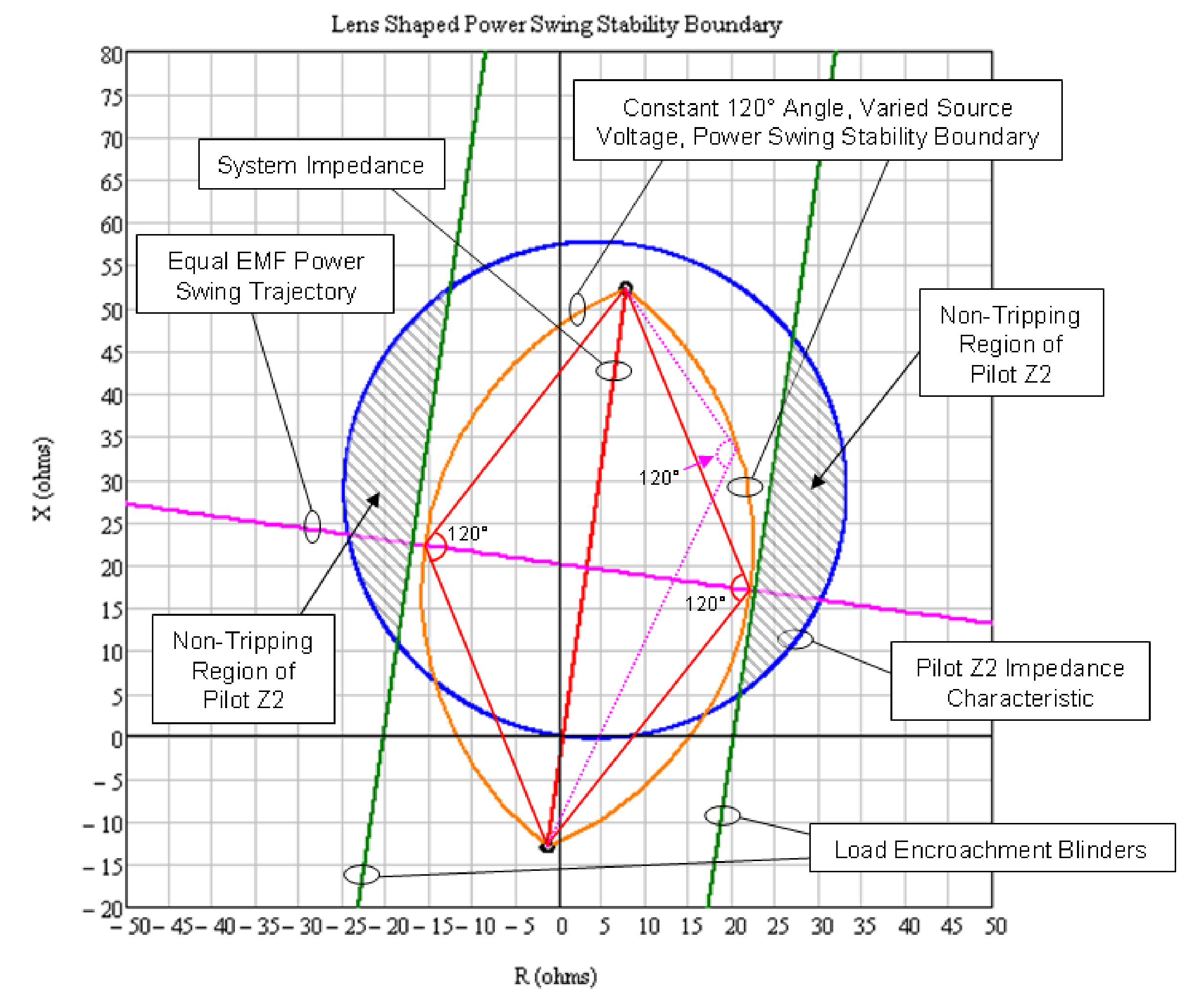


Figure 7. The tripping portion (not blocked by load encroachment) of the pilot zone 2 element (blue) is not completely contained within the power swing stability boundary (orange). This Element does not pass the Requirement R3 evaluation.

Application to Generator Owners

Generators have a variety of load responsive protection relays that protect the generator from abnormal operation and are subject to incorrect operation caused by stable power swings. They include protective relays that operate on current or an impedance function. Specific relays are time overcurrent, voltage controlled/restrained overcurrent, loss of field, and distance relays.

Impedance Type Relays

The determination of the apparent impedance at the generator terminals is complex, especially for cases where there are multiple generators connected to a high-voltage bus. There are various quantities that are interdependent as the disturbance progresses through the time domain whether it is a stable or unstable power swing. These variances include changes in machine internal voltage, speed governor action, voltage regulator action, the reaction of other local generators, and the reaction of other interconnected transmission Elements. A transient stability program is used to determine the apparent impedance for best results, especially for relays that are used for transmission line backup protection. Distance and out-of-step relays that are subject to power swings are connected at generator terminals and/or on the high-voltage side of the generator step-up (GSU) transformer. The loss of field relay(s) is connected at the generator terminals.

The electrical center will be in the transmission system for cases where the generator is connected through a weak transmission system (high external system source impedance). Other cases where the generator is connected through a strong transmission system, the electrical center will be inside the unit connected zone. In either case, impedance relays connected at the generator terminals or at the high-voltage side of the GSU may be subject to operation in response to stable power swings. Impedance relays used to back-up transmission protection usually have a time delay trip and are coordinated with local transmission line distance relay protection. Out-of-step relaying subject to a stable power swing may not operate correctly if the settings are not properly applied. If it is anticipated that the electrical center will be in the unit connected zone or the apparent impedance would challenge the relay operation, the Transmission Planner must perform transient stability studies to validate the existence of a power swing condition that a generator may experience. The Generator Owner uses the apparent impedance plot in a time domain to verify correct settings.

The simplified method used in the Application to Transmission Owners section is also used here to provide a helpful understanding of a stable power swing on load-responsive protective relays for those cases where the generator is connected to the transmission system and there are no infeed effects to be considered. For cases where infeed affects the apparent impedance (multiple unit connected generators connected to a transmission switchyard), the Generator Owner will provide the unit and relay data to the Transmission Planner for analysis. The quantities used to determine the apparent impedance characteristics are the generator unsaturated generator X''_d, GSU impedance, transmission line impedance, and the system equivalent. A voltage range of 0.65 to 1.5 should be considered to cover the delay of internal voltage for generators under manual or automatic voltage control.

Requirement R4

This requirement ensures that any Corrective Action Plan (CAP) developed in the previous requirement is implemented through completion. Having such a requirement allows the entity's work toward making protection scheme adjustments measurable given the variability of the timetables of each CAP.

To achieve the stated purpose of this standard, which is to ensure that relays do not operate in response to stable power swings during non-fault conditions, the responsible entity is required to implement and complete a CAP that addresses the relays that are at risk of tripping during a stable power swing for the applicable Elements on the BES. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the risk of the relays unnecessarily tripping during stable power swings, thereby improving reliability and reducing risk to the BES.

The following are examples of actions taken to complete CAPs for a relay responding to a stable power swing where a setting change was determined to be acceptable (without diminishing the ability of the relay to protect for faults within its zone of protection).

> **Example R4a:** Actions: Settings were issued on 6/02/2014 to reduce the zone 3 reach of the KD-10 relay from 30 ohms to 25 ohms so that the relay characteristic is completely contained within the lens characteristic identified by the criterion. The settings were applied to the relay on 6/25/2014. CAP completed on 06/25/2014.

> **Example R4b:** Actions: Settings were issued on 6/02/2014 to enable out-of-step blocking on the SEL-321 relay to prevent tripping in response to stable power swings. The setting changes were applied to the relay on 6/25/2014. CAP completed on 06/25/2014.

The following is an example of actions taken to complete a CAP for a relay responding to a stable power swing that required the addition of an out-of-step blocking relay.

> **Example R4c:** Actions: A project for the addition of an out-of-step blocking relay (KS) to supervise the zone 3 (KD-10) relay was initiated on 6/5/2014 to prevent tripping in response to stable power swings. The relay installation was completed on 9/25/2014. CAP completed on 9/25/2014.

The following is an example of actions taken to complete a CAP with a timetable that required updating for the replacement of the relay.

> **Example R4d:** Actions: A project for the replacement of the KD-10 relays at both terminals of line X with GE L90 relays was initiated on 6/5/2014 to prevent tripping in response to stable power swings. The completion of the project was postponed due to line outage rescheduling from 11/15/2014 to 3/15/2015. Following the timetable change, the KD-10 relay replacement was completed on 3/18/2015. CAP completed on 3/18/2015.

The CAP is complete when all the documented actions to resolve the specific problem (i.e., unnecessary tripping during stable power swings) are completed.