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.
4. Draft 1 of PRC-026-1 was posted for a 45-day formal comment period from April 25 – June 9, 2014 and an initial ballot in the last ten days of the comment period from May 30 – June 9, 2014.

Description of Current Draft

The Protection System Response to Power Swings Standard Drafting Team (PSRPS SDT) is posting Draft ~~1~~2 of PRC-026-1 – Relay Performance During Stable Power Swings for a 45-day ~~initial~~additional comment period and concurrent/parallel ~~initial~~additonal 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~~August 2014
Final Ballot	~~September~~October 2014
~~BOT~~NERC Board of Trustees 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~~rationale 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~~are expected to 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 as described in PRC-026-1 – Attachment A 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**~~**4.1.3** Transmission Owner that applies load-responsive protective relays as described in PRC-026-1 – Attachment A 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~~the third phase of a three-phased standard development project that ~~is~~ focused on developing ~~a~~this 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~~was approved by FERC on July 17, 2014.

~~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~~This Phase 3 of the project establishes requirements aimed at preventing protective relays from tripping unnecessarily due to stable power swings by requiring ~~each Transmission Owner and Generator Owner~~the identification of Elements on which a power swing may affect Protection System operation, and to develop requirements to assess the security of load-responsive protective ~~relay systems that are susceptible to operation during power swings, and take actions~~relays to tripping in response to a stable power swing. Last, to require entities to implement Corrective Action Plans, where necessary, to improve security of security of load-responsive protective relays for stable power swings ~~where such actions would~~so they are expected to not ~~compromise~~trip in response to stable power swings during non-Fault conditions while maintaining dependable ~~operation for faults and unstable power swings~~fault detection and dependable out-of-step tripping.

6. Effective Date:

Requirements R1-R3, R5, and R6

First day of the first full calendar year that is ~~twelve~~12 months ~~beyond~~after the date that ~~this~~the standard is approved by an applicable ~~regulatory authorities, or~~governmental authority or as otherwise provided for in ~~those jurisdictions~~a jurisdiction where ~~regulatory~~ approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard ~~becomes~~shall become effective on the first day of the first full calendar year that is ~~twelve~~12 months ~~beyond~~after the date ~~this~~the standard is ~~approved~~adopted by the NERC Board of Trustees~~,~~ or as otherwise ~~made~~provided for in that jurisdiction.

Requirement R4

First day of the first full calendar year that is 36 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective ~~pursuant to the laws applicable to such ERO governmental authorities~~on the first day of the first full calendar year that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Planning Coordinator~~, Reliability Coordinator, and Transmission Planner~~ shall, ~~within the first month of~~at least once each calendar year, identify each Element in its area that meets one or more of the following criteria 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,~~ Generator(s) where ~~a generating plant~~an angular stability constraint exists ~~and~~that is addressed by an operating limit or a ~~Special Protection System (SPS) (including line-out conditions~~Remedial Action Scheme (RAS) and those Elements terminating at the transmission switching station associated with the generator(s).
2. An Element that is ~~associated with~~ monitored as part of a System Operating Limit (SOL) that has been established based on angular stability constraints identified in system planning or operating studies~~ (including line-out conditions).~~.
3. An Element that ~~has formed~~forms the boundary of an island due to angular instability within ~~an angular stability planning simulation where the system Disturbance(s) that caused the islanding condition continues to be a credible event~~the most recent underfrequency load shedding (UFLS) assessment.
4. An Element identified in the most recent Planning Assessment where relay tripping ~~occurred for a~~occurs due to a stable or unstable power swing during a ~~Disturbance~~simulated disturbance.
5. An Element reported by the Generator Owner or Transmission Owner pursuant to Requirement R2 or Requirement R3, unless the Planning Coordinator determines the Element is no longer susceptible to power swings.

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,~~ has a wide-area view and ~~Transmission Planner are~~is in ~~positions~~the position 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~~,~~ ("PSRPS Report"),[1] which ~~recommended~~recommends 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~~within 30 calendar ~~year, identify each Element for which it applies a load-responsive protective relay at a terminal of~~days of identifying an Element that meets either of the following criteria, ~~if any~~provide notification of the Element to its Planning Coordinator: *[Violation Risk Factor: Medium] [Time Horizon: ~~Operations Planning,~~ Long-term Planning]*

Criteria:

1. An Element that ~~has tripped since January 1, 2003,~~trips due to a stable or unstable power swing during an actual system Disturbance ~~where the Disturbance(s) that caused the trip~~ due to ~~a power swing continues to be credible~~the operation of its load-responsive protective relays.
2. An Element that ~~has formed~~forms 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~~due to the operation of its load-responsive protective relays.

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.

[1] 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)

Rationale for R2: The ~~Generator Owner and~~ Transmission Owner ~~are~~is in ~~positions~~the position to identify ~~which~~the load-responsive protective relays that have tripped due to power swings, if any. The ~~criterion-based approach~~criteria 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~~PSRPS Report. A time ~~period in Requirement R2 and R3 allows~~to complete a review of 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~~tripping is not addressed here as other NERC Reliability Standards address the review of Protection System operations.

R3. Each Generator Owner ~~and Transmission Owner~~ shall, ~~once each~~within 30 calendar ~~year, perform one~~days of identifying an Element that meets the following ~~for each~~criterion, provide notification of the Element ~~identified pursuant~~ to ~~Requirement R1 or R2~~its Planning Coordinator: *[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.~~

~~1. All generation is in service and all transmission Elements are in their normal operating state.~~

~~2. Sub-transient reactance is used for all machines.~~

1. An Element that trips due to a stable or unstable power swing during an actual system Disturbance due to the operation of its load-responsive protective relays.

M3. Each Generator Owner shall have dated evidence that demonstrates identification of the Element(s), if any, which the criterion in Requirement R3. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

Rationale for R3: The Generator Owner is in the position to identify the load-responsive protective relays that have tripped due to power swings, if any. The criterion is consistent with the PSRPS Report. A requirement or time to complete a review of the relay tripping is not addressed here as other NERC Reliability Standards address the review of Protection System operations.

R4. Each Generator Owner and Transmission Owner shall, within 12 full calendar months of receiving notification of an Element pursuant to Requirement R1 or within 12 full calendar months of identifying an Element pursuant to Requirement R2 or R3, evaluate each identified Element's load-responsive protective relay(s) based on the PRC-026-1 – Attachment B Criteria where the evaluation has not been performed in the last three calendar years. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

~~M3.~~M4. Each Generator Owner and Transmission Owner shall have dated evidence that demonstrates ~~one of~~ the ~~options~~evaluation was performed according to Requirement ~~R3~~R4. 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.~~**Rationale for R4:** Performing the evaluation in Requirement R4 is the first step in ensuring that the reliability goal of this standard will be met. The PRC-026-1 – Attachment B, Criteria provides a basis for determining if the relays are expected to not trip for a stable power swing. See the Guidelines and Technical Basis for a detailed explanation of the evaluation.

~~**R4.**~~**R5.** Each Generator Owner and Transmission Owner shall ~~implement each CAP developed~~, within 60 calendar days of an evaluation that identifies load-responsive protective relays that do not meet the PRC-026-1 – Attachment B Criteria pursuant to Requirement ~~R3,~~R4, develop a Corrective Action Plan (CAP) to modify the Protection System to meet the PRC-026-1 – Attachment B Criteria while maintaining dependable fault detection and ~~update each CAP~~ dependable out-of-step tripping (if ~~actions or timetables change, until all actions are complete.~~out-of-step tripping is applied at the terminal of the Element). *[Violation Risk Factor: Medium~~][~~] [Time Horizon: Operations Planning~~, Long-Term Planning]~~]*

~~**M4.**~~**M5.** The Generator Owner and Transmission Owner shall have dated evidence that demonstrates ~~implementation~~the development of ~~each~~a CAP ~~according to~~in accordance with Requirement ~~R4, including updates to actions or timetables~~R5. 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.~~**Rationale for R5:** To meet the reliability purpose of the standard, a CAP is necessary to modify the entity's Protection System to meet PRC-026-1 – Attachment B so that protective relays are expected to not trip in response to stable power swings. The phrase, "while maintaining dependable fault detection and dependable out-of-step tripping" in Requirement R5 describes that the entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

R6. Each Generator Owner and Transmission Owner shall implement each CAP developed pursuant to Requirement R5, and update each CAP if actions or timetables change until all actions are complete. *[Violation Risk Factor: Medium][Time Horizon: Long-Term Planning]*

M6. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates implementation of each CAP according to Requirement R6, 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 R6: 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~~Owner 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~~Requirement R1~~, Measures M1~~ for a minimum of three calendar years following the completion of each Requirement.
- The Transmission Owner shall retain evidence of Requirement R2 for a minimum of three calendar years following the completion of each Requirement.
- The Generator Owner shall retain evidence of Requirement R3 for a minimum of three calendar years following the completion of each Requirement.
- The Generator Owner and Transmission Owner shall retain evidence of ~~Requirements R2 and R3, Measures M2 and M3~~Requirement R4 for ~~three~~a minimum of 36 calendar ~~years~~months following completion of each evaluation.
- The Generator Owner and Transmission Owner shall retain evidence of Requirements ~~R4, Measures M4 for~~R5 and R6, including any supporting analysis per Requirements R1, R2, R3, and R4, for a minimum of 12 calendar months following completion of each CAP.

If a Generator Owner, Planning Coordinator, ~~Reliability Coordinator, Transmission Owner,~~ or Transmission ~~Planner~~Owner 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~~Planning Coordinator 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~~Planning Coordinator 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~~Planning Coordinator 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~~Planning Coordinator identified an Element and provided notification in accordance with Requirement R1, but was more than 90 calendar days late. OR The ~~responsible entity~~Planning Coordinator failed to identify an Element ~~or~~in accordance with Requirement R1. OR The Planning Coordinator failed to provide notification in accordance with Requirement R1.
R2	~~Operations Planning,~~	Medium	The ~~responsible entity~~Transmission	The ~~responsible entity~~Transmission	The ~~responsible entity~~Transmission	The ~~responsible entity~~Transmission

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Long-term Planning		Owner identified an Element and provided notification in accordance with Requirement R2, but was less than or equal to ~~30~~10 calendar days late.	Owner identified an Element and provided notification in accordance with Requirement R2, but was more than ~~30~~10 calendar days and less than or equal to ~~60~~20 calendar days late.	Owner identified an Element and provided notification in accordance with Requirement R2, but was more than ~~60~~20 calendar days and less than or equal to ~~90~~30 calendar days late.	Owner identified an Element and provided notification in accordance with Requirement R2, but was more than ~~90~~30 calendar days late. OR The ~~responsible entity~~Transmission Owner failed to identify an Element in accordance with Requirement R2. OR The Transmission Owner failed to provide notification in accordance with Requirement R2.
R3	~~Operations Planning,~~ Long-term Planning	Medium	The ~~responsible entity performed one of the options~~Generator Owner identified an Element and provided notification in accordance with	The ~~responsible entity performed one of the options~~Generator Owner identified an Element and provided notification	The ~~responsible entity performed one of the options~~Generator Owner identified an Element and provided notification	The ~~responsible entity performed one of the options~~Generator Owner identified an Element and provided notification

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Requirement R3, but was less than or equal to ~~30~~10 calendar days late.	in accordance with Requirement R3, but was more than ~~30~~10 calendar days and less than or equal to ~~60~~20 calendar days late.	in accordance with Requirement R3, but was more than ~~60~~20 calendar days and less than or equal to ~~90~~30 calendar days late.	in accordance with Requirement R3, but was more than ~~90~~30 calendar days late. OR The ~~responsible entity~~Generator Owner failed to ~~perform one of the options~~identify an Element in accordance with Requirement R3. OR The Generator Owner failed to provide notification in accordance with Requirement R3.
R4	Operations Planning~~, Long-term Planning~~	~~Medium~~High	The ~~responsible entity implemented, but failed to update a CAP, when actions~~Generator Owner or ~~timetables changed,~~Transmission Owner evaluated each	~~N/A~~The Generator Owner or Transmission Owner evaluated each identified Element's load-responsive protective relay(s) in accordance with	~~N/A~~The Generator Owner or Transmission Owner evaluated each identified Element's load-responsive protective relay(s) in accordance with	The ~~responsible entity~~Generator Owner or Transmission Owner evaluated each identified Element's load-responsive protective relay(s) in

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			identified Element's load-responsive protective relay(s) in accordance with Requirement R4, but was less than or equal to 30 calendar days late.	Requirement R4, but was more than 30 calendar days and less than or equal to 60 calendar days late.	Requirement R4, but was more than 60 calendar days and less than or equal to 90 calendar days late.	accordance with Requirement R4, but was more than 90 calendar days late. OR The Generator Owner or Transmission Owner failed to ~~implement a CAP~~evaluate each identified Element's load-responsive protective relay(s) in accordance with Requirement R4.
R5	Long-term Planning	Medium	The Generator Owner or Transmission Owner developed a CAP in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days.	The Generator Owner or Transmission Owner developed a CAP in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days.	The Generator Owner or Transmission Owner developed a CAP in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days.	The Generator Owner or Transmission Owner developed a CAP in accordance with Requirement R5, but in more than 90 calendar days. OR The Generator Owner or Transmission Owner

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						failed to develop a CAP in accordance with Requirement R5.
R6	Long-term Planning	Medium	The Generator Owner or Transmission Owner implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The Generator Owner or Transmission Owner failed to implement a CAP in accordance with Requirement R6.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Applied Protective Relaying, Westinghouse Electric Corporation, 1979.

Burdy, John, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

IEEE Power System Relaying Committee WG D6~~.~~, *Power Swing and Out-of-Step Considerations on Transmission Lines*~~.~~, July 2005: http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf~~.~~.

Kimbark Edward Wilson, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

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~~

PRC-026-1 – Attachment A

This standard includes any protective functions which could trip instantaneously or with a time delay of less than 15 cycles, on load current (i.e., "load-responsive") including, but not limited to:

- Phase distance
- Phase overcurrent
- Out-of-step tripping
- Loss-of-field

The following protection functions are excluded from requirements of this standard:

- Relay elements supervised by power swing blocking
- Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Elements that are only enabled during a loss of communications
- Thermal emulation relays which are used in conjunction with dynamic Facility Ratings
- Relay elements associated with dc lines
- Relay elements associated with dc converter transformers
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard
- Relay elements associated with switch-onto-fault schemes
- Reverse power relay on the generator
- Generator relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes)
- Current differential relay, pilot wire relay, and phase comparison relay
- Voltage-restrained or voltage-controlled overcurrent relays

PRC-026-1 – Attachment B

Criteria A:

An impedance-based relay characteristic, used for tripping, that is completely contained within the portion of the lens characteristic formed in the impedance (R-X) plane that connects the endpoints of the total system impedance (with the parallel transfer impedance removed) bounded by varying the sending- and receiving-end voltages from 0.7 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance where:

2. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates the expected maximum stable separation angle is less than 120 degrees.
3. All generation is in service and all transmission Elements are in their normal operating state when calculating the system impedance.
4. Saturated (transient or sub-transient) reactance is used for all machines.

Rationale for Attachment B (Criteria A): The PRC-026-1, Attachment B, Criteria A provides a basis for determining if the relays are expected to not trip for a stable power swing having a system separation angle of up to 120 degrees with the sending-end and receiving-end voltages varying from 0.7 to 1.0 per unit (See Guidelines and Technical Basis).

Criteria B:

The pickup of an overcurrent relay element used for tripping, that is above the calculated current value (with the parallel transfer impedance removed) for the conditions below:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.
4. Both the sending and receiving voltages at 1.05 per unit.

Rationale for Attachment B (Criteria B): The PRC-026-1, Attachment B, Criteria B provides a basis for determining if the relays are expected to not trip for a stable power swing having a system separation angle of up to 120 degrees with the sending and receiving voltages at 1.05 per unit (See Guidelines and Technical Basis).

Guidelines and Technical Basis

Introduction

The NERC System Protection and Control Subcommittee technical document, *Protection System Response to Power Swings*, August 2013[2] ("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~~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."[3] Second, is "…to develop a Reliability Standard addressing undesirable relay operation due to stable power swings."[4] 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"[5] 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.~~standard implements the majority of the approach suggested by the report. However, it is noted that the Reliability Coordinator and Transmission Planner have not been included in the standard's Applicability (as suggested by the PSRPS Report). This is so that a single entity, the Planning Coordinator, may be the single source for identifying Elements according to Requirement R1. A single source will insure that multiple entities will not identify Elements in duplicate, nor will one entity fail to provide an Element because it believes the Element is being provided by another entity. The Planning Coordinator has, or has access to, the wide-area model and can correctly identify the Elements that may be susceptible to a stable power swing.

The phrase, "while maintaining dependable fault detection and dependable out-of-step tripping" in Requirement R1, describes that the Generator Owner and Transmission Owner is to comply

[2] 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)

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

[4] Ibid. P.153.

[5] Ibid. P.162.

with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the Generator Owner and Transmission Owner consider both the requirements within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

Power Swings

The IEEE Power System Relaying Committee WG D6 developed a technical document called *Power Swing and Out-of-Step Considerations on Transmission Lines* (July 2005) that provides background on power swings. The following are general definitions from that document:[6]

> Power Swing: a variation in three phase power flow which occurs when the generator rotor angles are advancing or retarding relative to each other in response to changes in load magnitude and direction, line switching, loss of generation, faults, and other system disturbances.
>
> Pole Slip: a condition whereby a generator, or group of generators, terminal voltage angles (or phases) go past 180 degrees with respect to the rest of the connected power system.
>
> Stable Power Swing: a power swing is considered stable if the generators do not slip poles and the system reaches a new state of equilibrium, i.e. an acceptable operating condition.
>
> Unstable Power Swing: a power swing that will result in a generator or group of generators experiencing pole slipping for which some corrective action must be taken.
>
> Out-of-Step Condition: Same as an unstable power swing.
>
> Electrical System Center or Voltage Zero: it is the point or points in the system where the voltage becomes zero during an unstable power swing.

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~~that the ~~requirements~~PRC-026-1 Requirements would apply to 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~~evaluate each load-responsive protective relay that is applied

[6] http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

on each identified Element. 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~~criteria found in PRC-026-1 – Attachment B.

Applicability

The standard is applicable to the Generator Owner, Planning Coordinator, ~~Reliability Coordinator, Transmission Owner,~~ and Transmission ~~Planner~~Owner 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.

Load-responsive protective relays include any protective functions which could trip with or without time delay, on load current.

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 Planning Coordinator has a wide-area view and is in the positon to identify what, if any, Elements meet the criteria. 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),[7] which recommends a focused approach to determine an at-risk Element. Identification of Elements comes from the annual Planning Assessments pursuant to the transmission planning (i.e., "TPL") and other NERC Reliability Standards, and the standard is not requiring any other assessments to be performed by the Planning Coordinator. The required annual notification to the respective Generator Owner and Transmission Owner is

[7] http://www.nerc.com/comm/PC/System%20Protection%20 and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

sufficient because it is expected that the Planning Coordinator will make its notifications following the completion of its annual Planning Assessments.

Criterion 1

The first criterion involves ~~Elements that are located at or terminate at a~~ generator(s) where an angular stability constraint exists which is addressed by an operating limit or a Remedial Action Scheme (RAS) and those Elements terminating at the transmission switching station associated with the generator(s). For example, a scheme to remove generation for specific conditions is implemented for a four-unit 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~~ (1,100 MW). Two of the units are 500 MW each; one is connected to the 345 kV system and one is connected to the 230 kV system. The Transmission Owner has two 230 kV transmission lines and one 345 kV transmission line all terminating at the generating facility as well as a 345/230 kV autotransformer. The remaining 100 MW consists of two 50 MW combustion turbine (CT) units connected to four 66 kV transmission lines. The 66 kV transmission is not electrically joined to the 345 kV and 230 kV transmission lines at the plant ~~contains two 500 MW generating units, one connected to a 345 kV bus and one connected to~~ site and is not 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~~ part of the operating limit or RAS. A stability constraint limits the output of the portion of the plant affected by the RAS to 700 MW for an outage of the 345 kV transmission line~~, and that a SPS exists to run back the output~~. The RAS trips one of the ~~generating plant to 700~~500 MW units to maintain stability for a loss of the 345 kV transmission line~~.~~ when the total output from both 500 MW units is above 700 MW. For this ~~hypothetical~~ example, both 500 MW generating units ~~would be included as Elements meeting the criterion. Furthermore,~~and the associated 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~~this criterion. The 345/230 kV autotransformer, the 345 kV transmission ~~circuit~~line, and the two 230 kV transmission lines would also be identified as Elements meeting this criterion. The 50 MW combustion turbines and 66 kV transmission lines 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~~pursuant Criterion 1 because these Elements are not subject to an operating limit or RAS and do not terminate at the transmission switching station associated with the generators that are subject to the operating limit and RAS.

Criterion 2

The second criterion involves Elements that ~~have~~ are monitored due to an established System Operating Limit (SOL) based on ~~a~~an angular stability limit ~~or issue driven by one or more specific events~~regardless of the outage conditions that result in the enforcement of the SOL. 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~~lines, then both ~~circuits~~lines would be identified as an Element meeting the criterion.

Criterion 3

The third criterion involves the Element that ~~has formed~~forms the boundary of an island due to angular instability within an ~~angular stability planning simulation.~~underfrequency load shedding (UFLS) assessment. While the island may form due to various transmission ~~circuits~~lines 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 due to "angular instability" 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.[8] 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~~

Criterion 4

The fourth criterion involves Elements identified in the most recent Planning Assessment where relay tripping occurs due to a stable or unstable power swing during a simulated disturbance. The intent is for the Planning Coordinator to include any Element(s) where relay tripping was

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

observed during simulations performed for the most recent Planning Assessment associated with the transmission planning TPL-001-4 Reliability Standard. Note that relay tripping must be assessed within Planning Assessments per TPL-001-4, R4, Part 4.3.1.3, which indicates that analysis shall include the "Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models." Identifying such Elements according to criterion 4 and notifying the respective Generator Owner and Transmission Owner will require that the owners of any load-responsive protective relay applied at the terminals of the identified Element evaluate the relay's susceptibility to tripping in response a stable power swing.

Planning Coordinators have discretion to determine whether observed tripping for a power swing in its Planning Assessments occurs for valid contingencies and system conditions. The Planning Coordinator will address tripping that is observed in transient analyses on an individual basis; therefore, the Planning Coordinator is responsible for identifying the Elements based only on simulation results that are determined to be valid.

Due to the nature of how a Planning Assessment is performed, there may be cases where a previously identified Element is not identified in the most recent Planning Assessment. If so, this is acceptable because the Generator Owner and Transmission Owner would have taken action upon the initial notification of the previously identified Element. When an Element is not identified in later Planning Assessments, the risk would have already been assessed under Requirement R4 and mitigated according to Requirements R5 and R6 when appropriate. According to Requirement R4, the Generator Owner and Transmission Owner are only required to re-evaluate each load-responsive protective relay for an identified Element where the evaluation has not been performed in the last three calendar years.

Criterion 5

The fifth criterion involves Elements that have actually tripped due to a stable or unstable power swing as reported by the Generator Owner and Transmission Owner. The Planning Coordinator will continue to identify each reported Element until the Planning Coordinator determines that the Element is expected to not trip in response to power swings due to BES configuration changes. For example, eight lines interconnecting areas containing both generation and load to the rest of the BES, and five of the lines terminate on a single straight bus~~. Assume a~~ as shown in Figure 1. A forced outage of the straight bus in the past caused an island to form 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~~the Planning Coordinator may determine that the changes eliminated susceptibility to power swings as shown in Figure 2. If so, the Planning Coordinator is no longer required to identify these Elements previously reported by either the Transmission Owner pursuant to Requirement R2 or Generator Owner pursuant to Requirement R3.

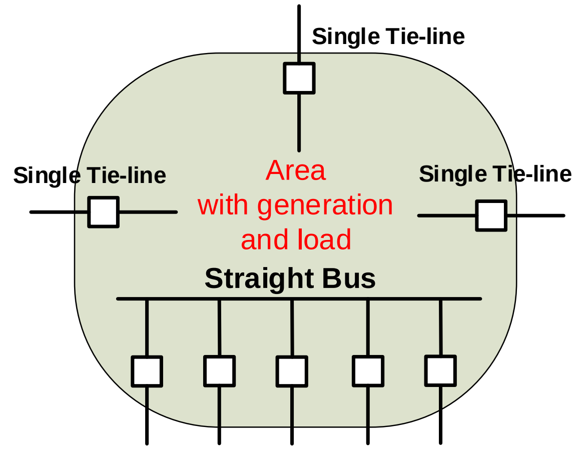


Figure 1. Criterion five example of an area with generation and load that experienced a power swing.

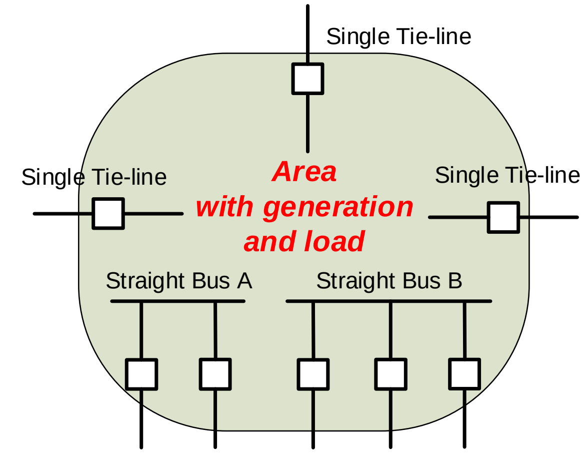


Figure 2. Criterion five example of an area with generation and load that was later reconfigured and determined to no longer be susceptible to power swings.

Although Requirement R1 requires the Planning Coordinator to notify the respective Generator Owner and Transmission Owner of any Elements meeting the one or more of the five criteria, it does not preclude the Planning Coordinator from providing additional information, such as apparent impedance characteristics, in advance or upon request, that may be useful in evaluating protective relays. Generator Owners and Transmission Owners are able to complete protective relay evaluations and perform the required actions without additional information. The standard does not included any requirement for the entities to provide information that is already being shared or exchanged between entities for operating needs. While a requirement has not been included for the exchange of information, entities must recognize that relay performance needs to be measured against the most current information.

Requirement R2

The approach of Requirement R2 requires the Transmission Owner to identify Elements that meet the focused criteria. Only the Elements that meet the criteria and apply a load-responsive protective relay at the terminal of the Element are in scope. Using the criteria focuses the reliability concern on the Element that is at-risk to power swings.

The first criterion involves Elements that have tripped due to a power swing during an actual system Disturbance, regardless of whether the power swing was stable or unstable. Elements that have tripped by unstable power swings are included in this requirement because they were not identified in Requirement R1 and this forms a basis for evaluating the load responsive relay operation for stable power swings. After this standard becomes effective, if it is determined in an outage investigation that an Element tripped because of a power swing condition (either stable or unstable), this standard will become applicable to the Element. An example of an identified Element is an Element tripped by a distance relay element (i.e., a relay with a time delay of less than 15 cycles) during a power swing condition. Another example that would identify an Element is where out-of-step (OOS) tripping is applied on the Element, and if a legitimate OOS trip occurred as expected during a power swing event.

The second criterion involves the formation of an island based on an actual system Disturbance. While the island may form due to several transmission lines tripping for a combination of reasons, such as power swings (stable or unstable), faults, or excessive loading, the criterion requires that all Elements that tripped to form the island be identified as meeting this criterion. For example, the Disturbance may have been initiated by one line faulting with a second line being out of service. The outage of those two lines then initiated a swing condition between the "island" and the rest of the system across the remaining ties causing the remaining ties to open. A second case might be that the island could have formed by a fault on one of the other ties with a line out of service with the swing going across the first and second lines mentioned above resulting in those lines opening due to the swing. Therefore, the inclusion of all the Elements that formed the boundary of the island are included as Elements to be reported to the Planning Coordinator.

The owner of the load-responsive protective relay that tripped for either criterion is required to identify the Element and notify its Planning Coordinator. Notifying the Planning Coordinator of the Element ensures that the planner is aware of an Element that is susceptible to a power swing or formed an island. The Planning Coordinator will continue to notify the respective entities of the identified Element under Requirement R1, Criterion 5 unless the Planning Coordinator determines the Element is no longer susceptible to power swings.

Requirement R3

~~The purpose of~~ Requirement R3 is similar to ~~provide alternatives for a~~Requirement R2, Criterion 1 and requires the Generator Owner ~~or Transmission Owner~~ to ~~demonstrate~~identify any Element that trips due to a power swing condition (stable or unstable) in an actual event. This standard does not focus on the review of Protection Systems ~~on identified Elements are not~~ because they are covered by other NERC Reliability Standards. When a review of the Generator Owner's Protection System reveals that tripping occurred due to a power swing, it is required to identify the Element and to notify its Planning Coordinator. Notifying the Planning Coordinator of the Element ensures that the planner is aware of an Element that was susceptible to ~~tripping in response to~~ a power swing. The Planning Coordinator will continue to notify entities of the identified Element under Requirement R1 unless the Planning Coordinator determines the Element is no longer susceptible to power swings ~~meeting~~ .

Requirement R4

Requirement R4 requires the Generator Owner and Transmission Owner to evaluate its load-responsive protective relays applied at all of the terminals of an identified Element to ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions. A method is provided within the standard to support consistent evaluation by Generator Owners and Transmission Owners based on specified conditions. ~~It also provides alternatives for the~~ Once a 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~~ is notified of Elements pursuant to Requirement R1, or once a Generator Owner or Transmission Owner identifies an Element pursuant to Requirement R2 or R3, it has 12 full calendar months to evaluate each Element's load-responsive protective relays based on the PRC-026-1 – Attachment B, Criteria A and B if the evaluation hasn't been performed in the last three calendar years.

Information Common to Both Generation and Transmission Elements

The PRC-026-1 – Attachment A lists the load-responsive protective relays that are subject to this standard. Generator Owners and Transmission Owners may own load–responsive protective relays (i.e. distance relays) that directly affect generation or transmission BES Elements and will require analysis as a result of Elements being identified by Requirements R1, R2 or R3. For example, distance relays owned by the Transmission Owner may be installed at the high-voltage side of the generator step-up (GSU) transformer (directional toward the generator) providing backup to generation protection. Generator Owners may have distance relays applied for back-up transmission protection or back-up protection for the GSU transformer. The Generator Owner may have relays installed at the generator terminals or the high-voltage side of the GSU transformer.

Exclusion of Time Based Load-Responsive Protective Relays

The purpose of the standard is "To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions." Load-responsive protective relays with high-speed tripping pose the highest risk of operating during a power swing. Because of this, high-speed tripping is included in the standard and others (Zone 2 and 3) with a time a delay of 15 cycles or greater are excluded. The time delay used for ~~the specified conditions~~exclusion on some load-responsive protective relays is recommended based on 1) the minimum time delay these relays are set in practice, and 2) the maximum expected time that load-responsive protective relays would ~~compromise dependable tripping~~ be exposed to the stable swing based on a swing rate.

In order to establish a time delay that strikes a line between a high-risk load-responsive protective relay and one that has a time delay for ~~faults or unstable power swings~~tripping, a sample of swing rates were calculated based on a stable power swing entering and leaving the impedance characteristic as shown in Table 1. For a relay impedance characteristic that has the swing entering and leaving beginning at 90 degrees with a termination at 120 before exiting the zone, calculation of the timer must be greater than the time the stable swing is inside the relay operate zone.

~~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.~~

Eq. (1)

$$Zone\ time > 2 \times \left(\frac{(120° - Angle\ of\ entry\ into\ the\ relay\ characteristic)}{Slip\ Rate}\right)$$

Table 1. Swing Rates	
Zone Timer (Cycles)	Slip Rate (Hz)
10	1.00
15	0.67
20	0.50
30	0.33

With a minimum zone timer of 15 cycles, the corresponding slip of the system is 0.67 Hz. This represents an approximation of a slow slip rate during a system Disturbance. This value corresponds to the typical minimum time delay used for zone 2 distance relays in transmission line protection. Longer time delays allow for slower slip rates.

Application to Transmission ~~*Owners*~~Elements

~~The criterion describes~~The criteria in PRC-026-1 – Attachment B describe 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 0.7 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance (with the parallel transfer impedance removed—see Figures ~~1 and 2~~3 through 5). The total system impedance is derived from a two-bus equivalent network and is determined by summing the sending-end source impedance, the line impedance ~~in parallel with~~(excluding the ~~Thévinen~~Thévenin equivalent transfer impedance~~,~~), and the receiving-end source impedance ~~(Figure 3). This~~ as shown in Figures 6 and 7. The goal in establishing the total system ~~source~~ impedance is ~~minimized~~ to ~~create~~represent a conservative~~, worst-case condition by including all transmission Elements that represent a~~ condition that will maximize the security of the relay against various system conditions. The smallest total system impedance represents a condition where the size of the lens characteristic in the R-X plane is smallest and is a conservative operating point from the standpoint of ensuring a load responsive relay will not trip given a predetermined angular displacement between the sending- and receiving-end voltages. The smallest total system impedance results when all generation is in service and all transmission elements are modeled in their "normal" system configuration ~~with generation set at the value reported to the Transmission Planner. Further,~~ (PRC-026-1 – Attachment B, Criteria A). The parallel transfer impedance is removed to represent a likely condition where parallel elements may be lost during the disturbance, and the loss of these elements magnifies the sensitivity of the load-responsive relays on the parallel line by removing the "infeed effect" (i.e., the apparent impedance sensed by the relay is decreased as a result of the loss of the transfer impedance, thus making the relay more likely to trip for a stable power swing).

The sending- and receiving-end source voltages are varied from 0.7 to 1.0 per unit to form a portion of a lens characteristic instead of varying the voltages from 0 to 1.0 per unit, which would form a full-lens characteristic. The ratio of these two voltages is used in the calculation of the portion of the lens, and result in a ratio range from 0.7 to 1.43.

Eq. (2) $$\frac{E_S}{E_R} = \frac{0.7}{1.0} = 0.7$$ Eq. (3): $$\frac{E_R}{E_S} = \frac{1.0}{0.7} = 1.43$$

The internal generator voltage during severe power swings or transmission system fault conditions will be greater than zero, due to voltage regulator support. The voltage ratio of 0.7 to 1.43 is chosen to be more conservative than the PRC-023 and PRC-025 NERC Reliability Standards, where a lower bound voltage of 0.85 per unit voltage is used. A plus and minus 15% internal generator voltage range was chosen as a conservative voltage range for calculation of the voltage ratio that would determine the end points of the portion of the lens. For example, the voltage ratio using these voltages would result in a ratio range from 0.739 to 1.353.

Eq. (4) $$\frac{E_S}{E_R} = \frac{0.85}{1.15} = 0.739$$ Eq. (5): $$\frac{E_R}{E_S} = \frac{1.15}{0.85} = 1.353$$

The lower ratio is rounded down to 0.7 to be more conservative, allowing a voltage range of 0.7 to 1.0 per unit to be used for the calculation of the lens end points.[9]

When the parallel transfer impedance is included in the model, the split in current through the parallel transfer impedance path results in actual measured relay impedances that are larger than those measured when the parallel transfer impedance is removed (i.e., infeed effect), which would make it more likely for an impedance relay element to be completely contained within the applicable portion of the lens characteristic in Figure 11. If the transfer impedance is included in the lens evaluation, a distance relay element could be deemed as meeting PRC-026-1 – Attachment B and, in fact would be secure, assuming all elements were in their normal state. In this case, it could trip for a stable power swing during an actual event if the system was weakened (i.e., a higher transfer impedance) by the loss of a subset of lines that make up the parallel transfer impedance. This could happen because those parallel lines tripped on unstable swings, contained the initiating fault, and/or were lost due to operation of breaker failure or remote back-up protection schemes in Figure 10.

Either the saturated transient or sub-transient direct axis reactance values may be used for machines in the evaluation because they are smaller than un-saturated reactance values. Since, sub-transient saturated generator reactances are ~~used since they are~~ smaller than the transient or synchronous ~~reactances, and~~ reactance, they result in a smaller source impedance and a smaller ~~separation angle~~lens characteristic in the graphical analysis ~~(Figures 4 and 5~~as shown in Figures

[9] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004, Section 6 (The Cascade Stage of the Blackout), p. 94 under "Why the Generators Tripped Off," states, "Some generator undervoltage relays were set to trip at or above 90% voltage. However, a motor stalls out at about 70% voltage and a motor starter contactor drops out around 75%, so if there is a compelling need to protect the turbine from the system the under-voltage trigger point should be no higher than 80%."

8 and 9. Since power swings occur in a time frame where generator transient reactances will be prevalent, it is acceptable to use saturated transient reactances instead of saturated sub-transient reactance values. Some short-circuit models may not include transient reactance values, so in this case, the use of sub-transient is acceptable because it also produces more conservative results than transient reactances. For this reason, either value is acceptable when determining the system source impedances (PRC-026-1 – Attachment B, Criteria A and B, No. 3).

Saturated reactance values are also the values used in short-circuit programs that produce the system impedance mentioned above. Planning and stability software generally use the un-saturated reactance values. Generator models used in transient stability analyses recognize that the extent of the saturation effect depends upon both rotor (field) and stator currents. Accordingly, they derive the effective saturated parameters of the machine at each instant by internal calculation from the specified (constant) unsaturated values of machine reactances and the instantaneous internal flux level. The specific assumptions regarding which inductances are affected by saturation, and the relative effect of that saturation, are different for the various generator models used. Thus, unsaturated values of all machine reactances are used in setting up planning and stability software data, and the appropriate set of open-circuit magnetization curve data is provided for each machine.

The source or system equivalent impedances can be obtained by a number of different methods using commercially available short-circuit calculation tools.[10] 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 ~~(~~in Figure ~~3).~~6. 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.

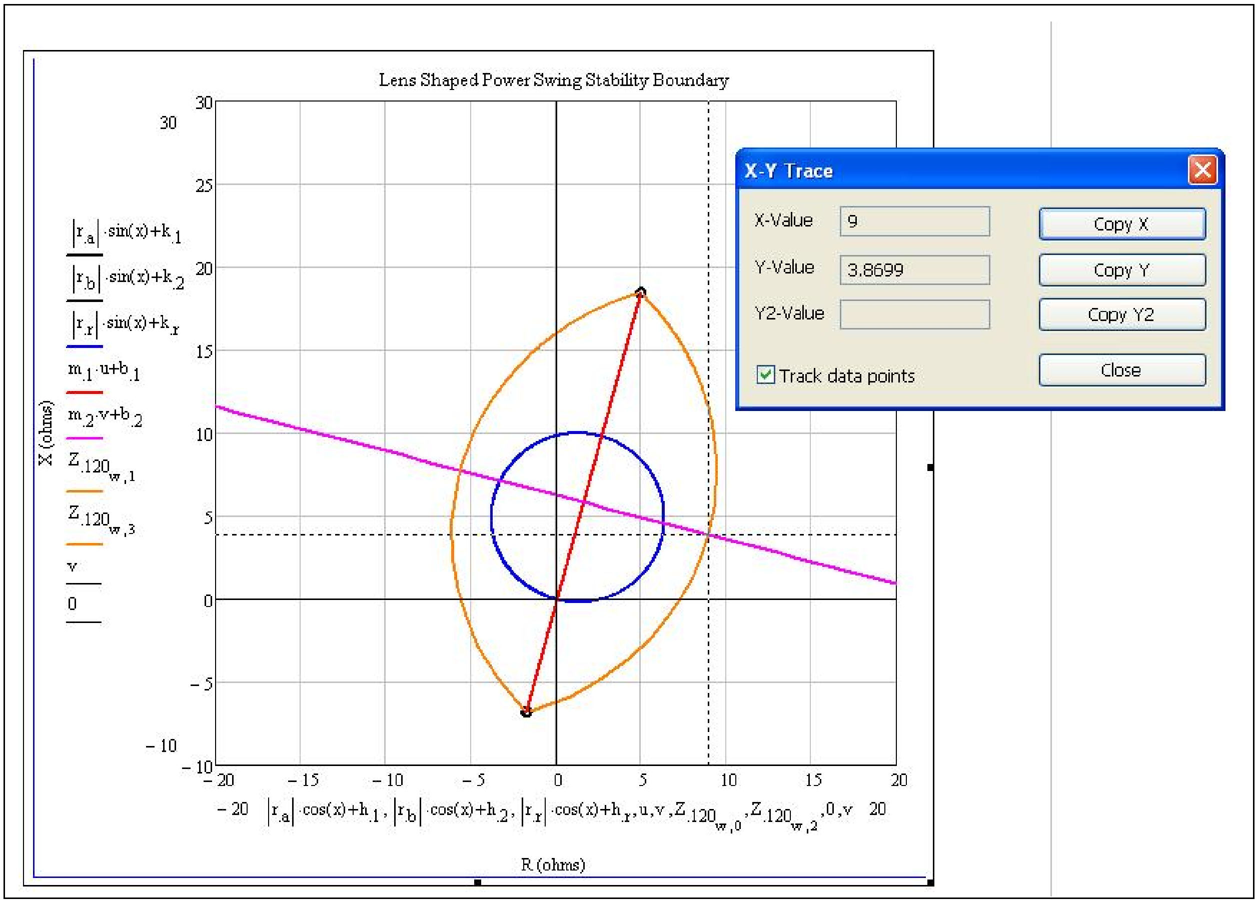
The ~~first~~ two bullets of ~~criterion~~PRC-026-1 – Attachment B, Criteria A, No. 1, identify the system separation angles to ~~be used to~~ identify the ~~shape and~~ size of the power swing stability boundary to be used to test load-responsive impedance relay elements. Both bullets test impedance relay elements that are not supervised by power swing blocking. The first bullet of PRC-026-1 – Attachment B, Criteria A, No. 1 evaluates a system separation angle of at least 120 degrees that is held constant while varying the sending- and receiving-end source voltages from 0.7 to 1.0 per unit, thus creating a power swing stability boundary shaped like a portion of a lens about the total system impedance in Figure 3. This portion of a 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~~, blinders, or some other form of supervision as shown in Figure 12

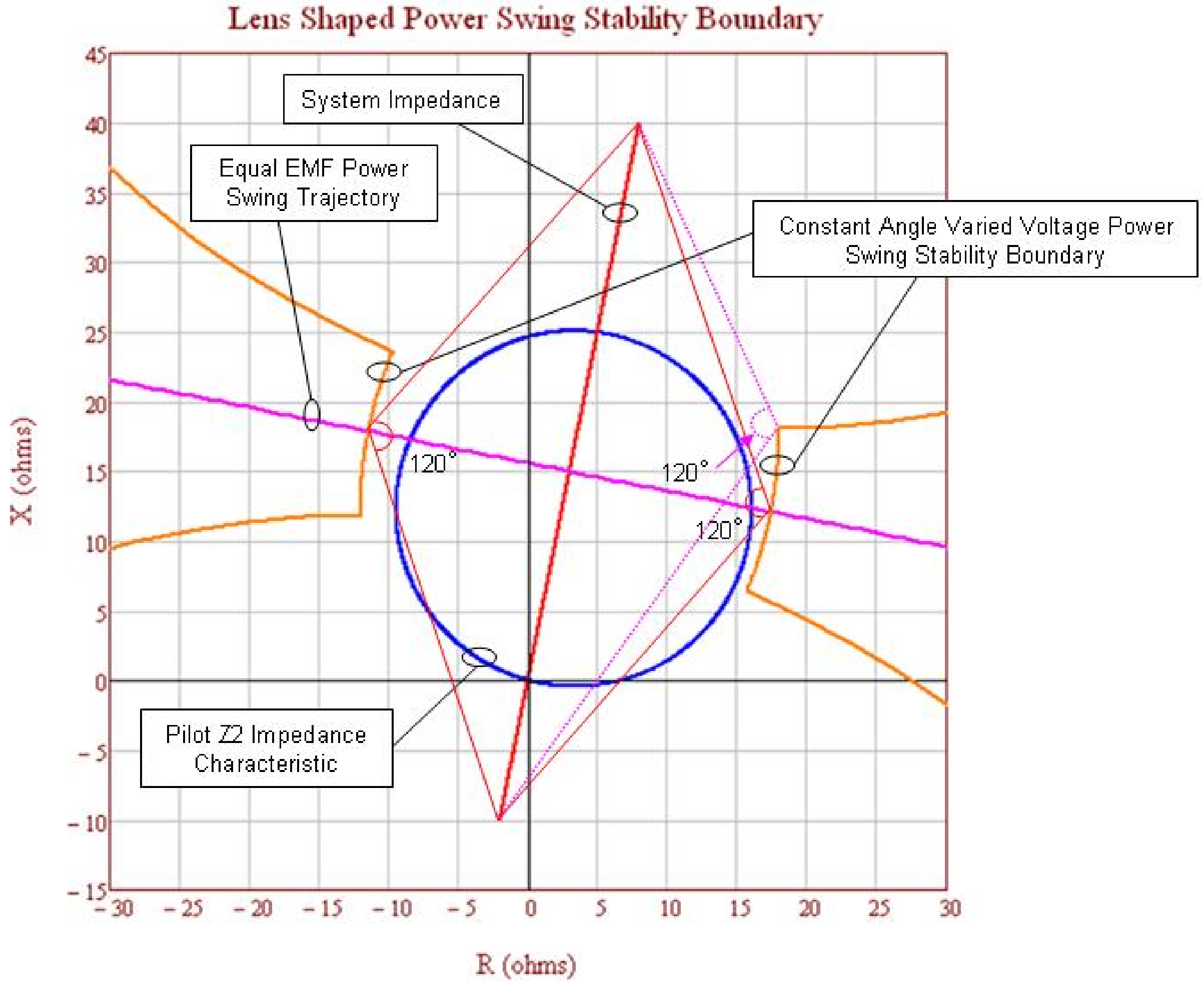
[10] Demetrios A. Tziouvaras and Daqing Hou, Appendix in *Out-Of-Step Protection Fundamentals and Advancements*, ~~by Demetrios A. Tziouvaras and Daqing Hou, available at (~~April 17, 2014: https://www.selinc.com~~)~~.

that restricts the distance element from tripping for heavy, balanced load conditions. ~~If~~If the tripping portion of the impedance characteristics are completely contained within the portion of a lens characteristic, the Element ~~passes the evaluation (Figures 6 and 7).~~meets Criteria A in PRC-026-1 – Attachment B. 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.[11]

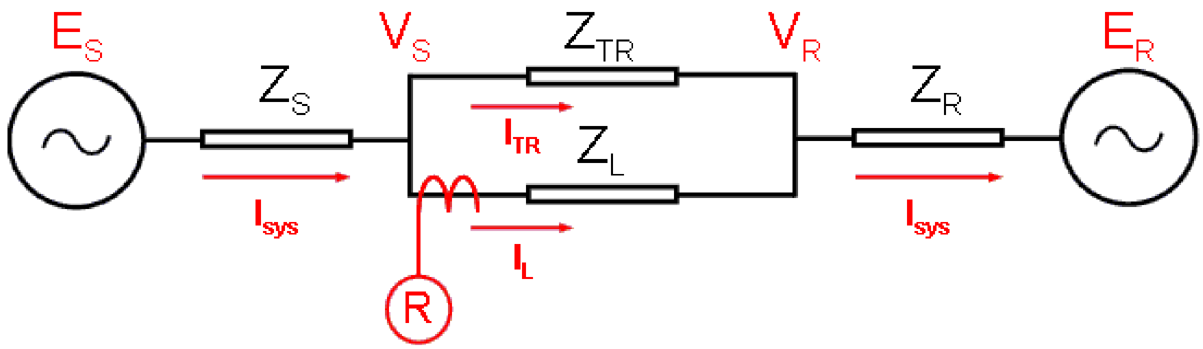
The second bullet of PRC-026-1 – Attachment B, Criteria A, No. 1 evaluates impedance relay elements at a system separation angle of less than 120 degrees, similar to the first ~~criterion~~ bullet described above. ~~The~~An angle ~~evaluated must~~less than 120 degrees may be ~~agreed upon by~~used if a documented stability analysis demonstrates that the ~~Planning Coordinator, Reliability Coordinator, and Transmission Planner, and tripping of the distance elements for stable~~ power ~~swings should not occur~~swing becomes unstable at ~~this angle, as shown by~~a system ~~planning or operating studies~~separation angle of less than 120 degrees.

[11] "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 proper balance between dependable tripping for unstable power swings and secure operation for stable power swings." 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~~PSRPS Report at p. 28.~~), p. 28.


Lens Shaped Power Swing Stability Boundary
X (ohms)
R (ohms)
X-Y Trace
X-Value 9
Y-Value 3.8699
Y2-Value
Copy X
Copy Y
Copy Y2
Track data points
Close



~~**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.~~**Figure 3.** The portion of the lens characteristic that is formed in the impedance (R-X) plane. The pilot zone 2 relay is completely contained within the portion of the lens (e.g., it does not intersect any portion of the partial lens), therefore it complies with PRC-026-1 – Attachment B, Criteria A, No. 1.



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

$Z_r = 2.848 + 11.244j$ ohms

$Z_l = 2.18105 + 7.18651j$ ohms

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

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

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

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

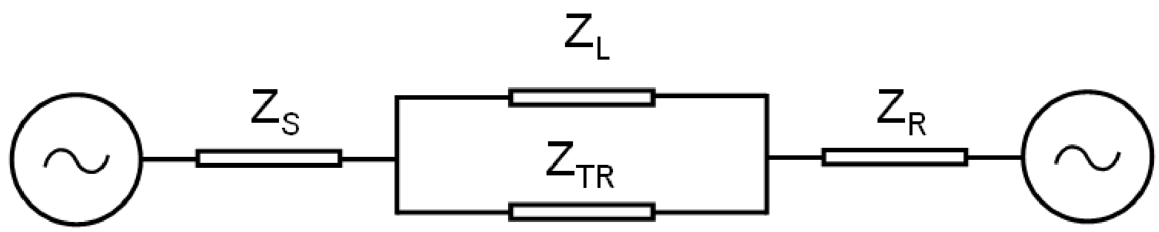
$$R_o := |Z_{s1}|\cdot \cos\left[\frac{\pi}{2} - (A_{s1} + Z_{Tang1})\right] - \operatorname{Re}(Z_s) \qquad R_o = 8.94754 \qquad R_{o\_pri} := R_o\cdot \frac{PTR}{CTR}$$

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

$R_{o\_pri} = 8.94754$ ohms

$X_{o\_pri} = 3.88384$ ohms

Figure ~~2. Mathematical calculations for~~**4.** System impedance as seen by relay R~~-X coordinate plot in Figure 1~~.



$$Z_{Total} = Z_S + \frac{Z_L \cdot Z_{TR}}{Z_L + Z_{TR}} + Z_R$$

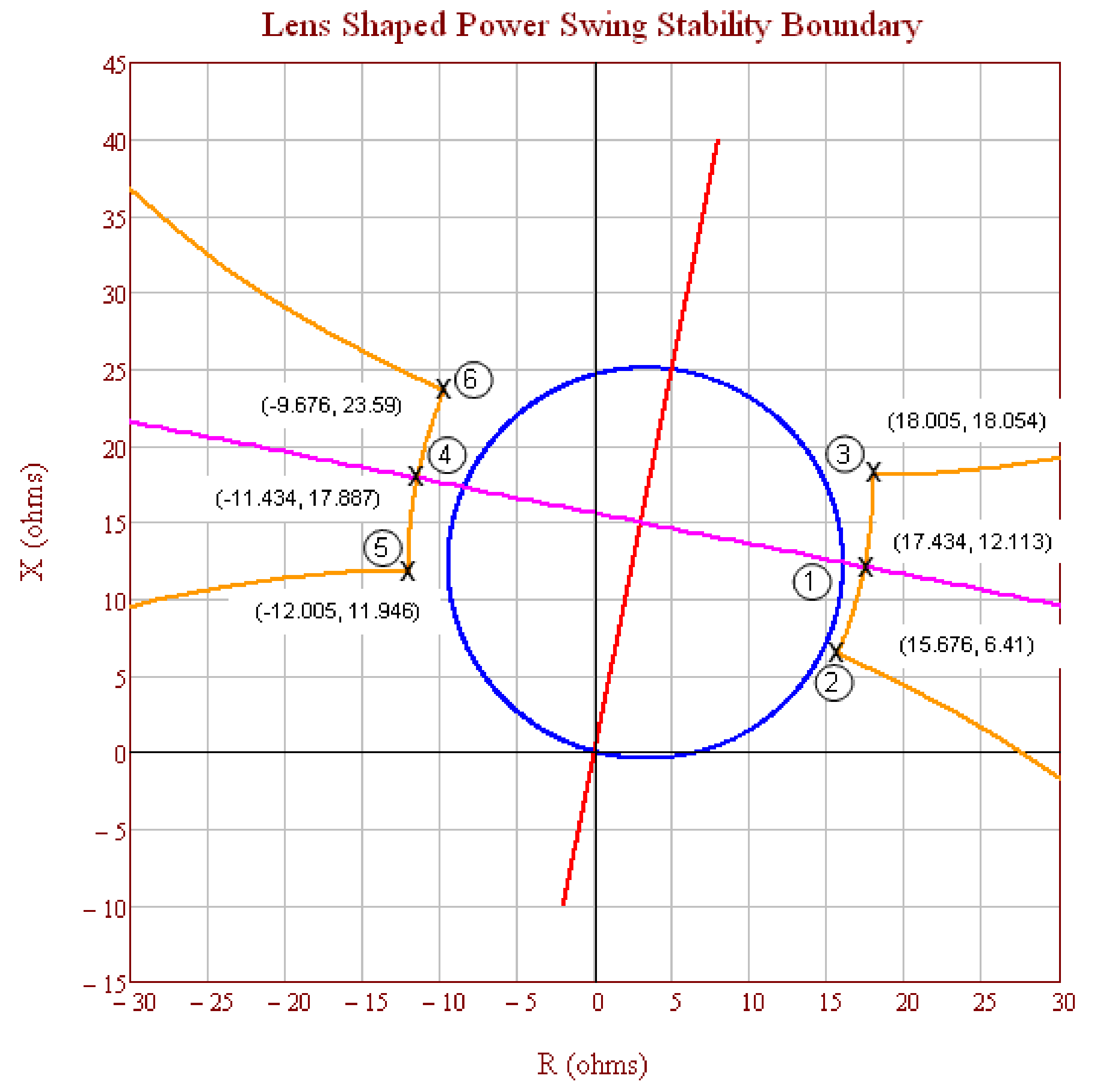


Figure ~~**3.** Calculation of total system impedance given sending end source impedance Z_S, receiving end source impedance Z_R, line impedance Z_L, and~~ **5.** Lens characteristic with the transfer impedance ~~Z_{TR}~~included and contains specific points identified for the calculations.

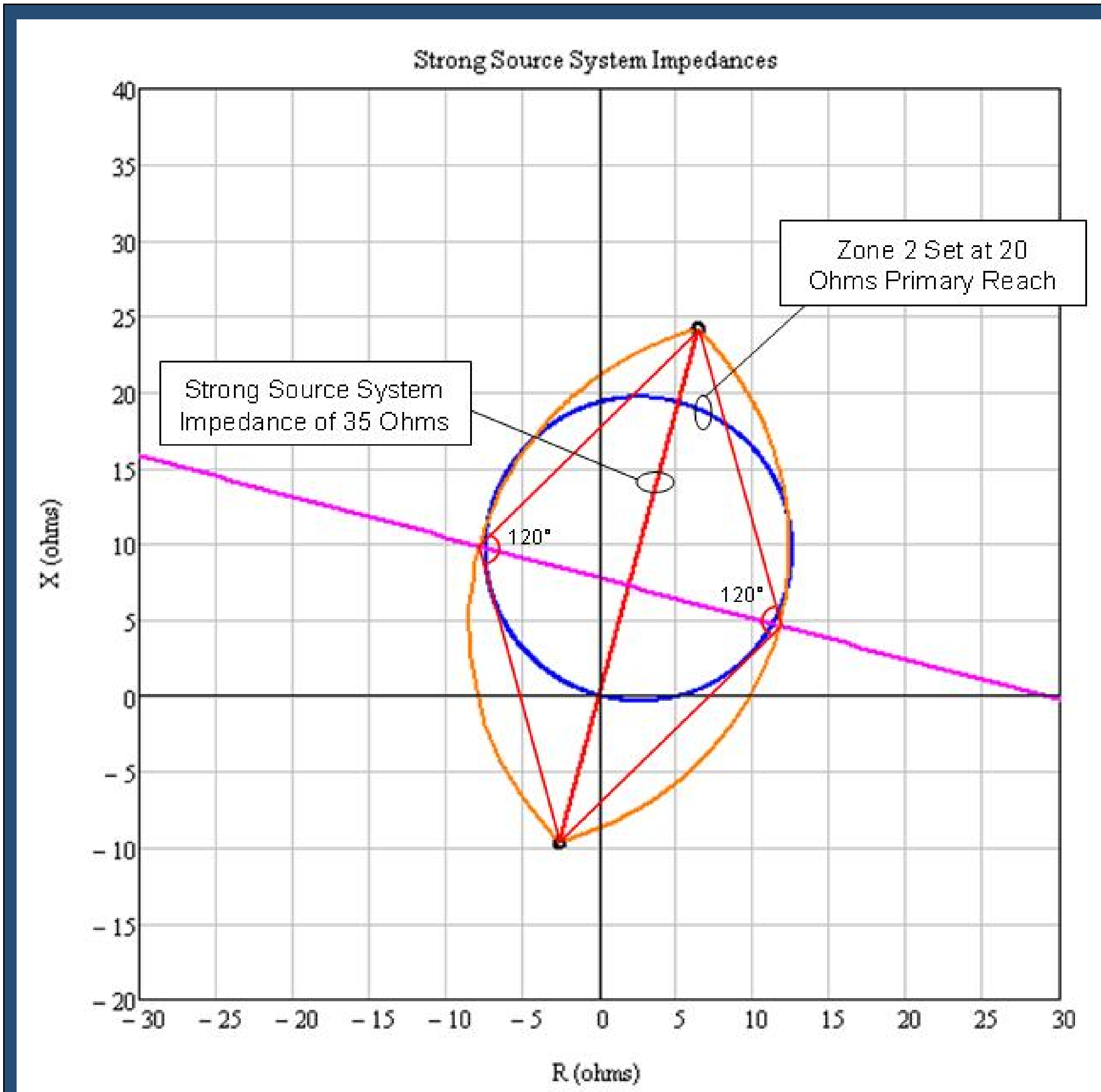


Table 2. Example Calculation (Lens Point 1)

~~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.~~This example is for calculating the impedance the first point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending voltage (E_S) leading the receiving voltage (E_R) by 120 degrees. See Figures 4 and 5.

Eq. (6)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}}$

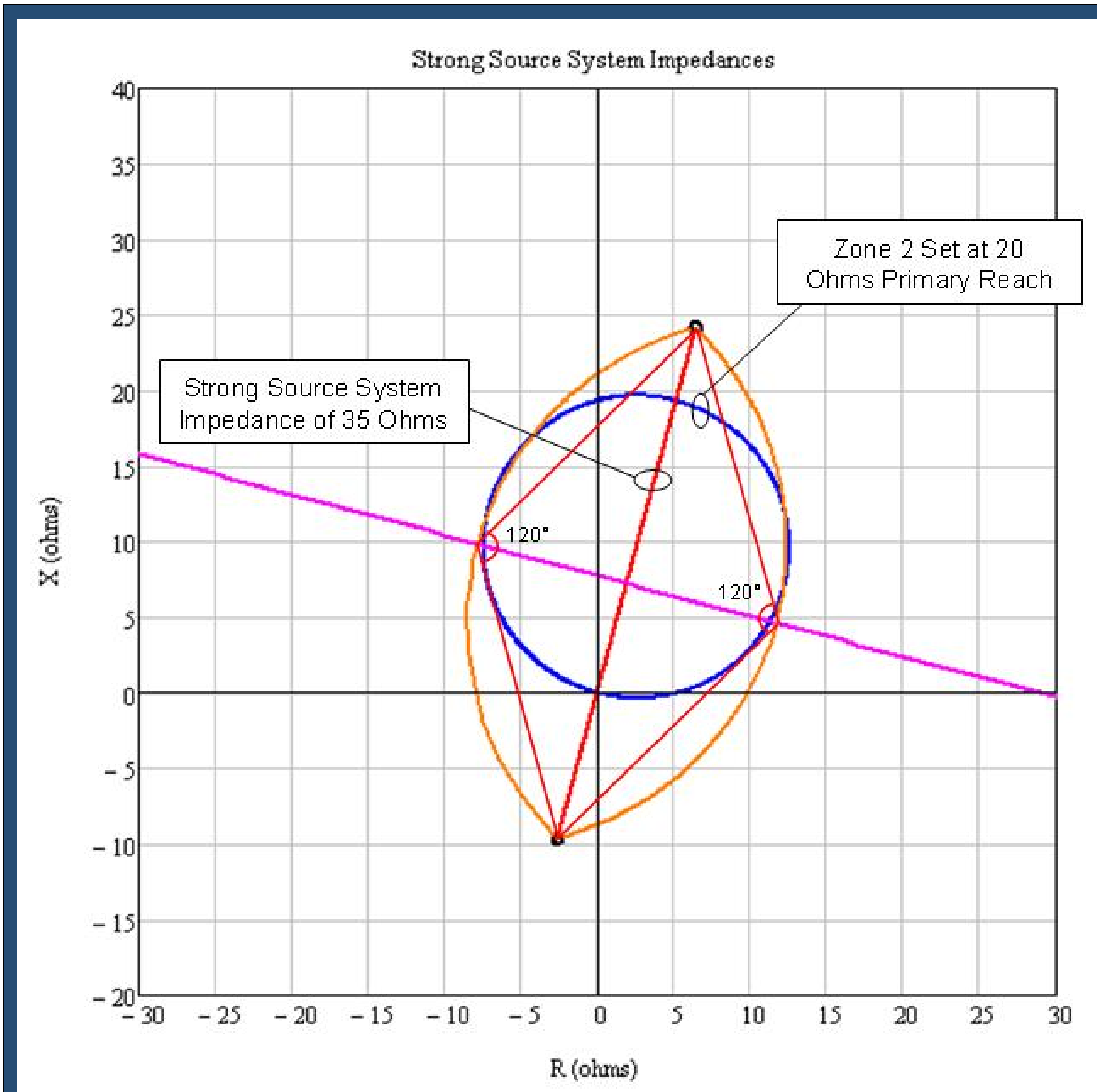


Table 2. Example Calculation (Lens Point 1)

	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}}$
	$E_S = 132{,}791\angle 120°\ V$
Eq. (7)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$

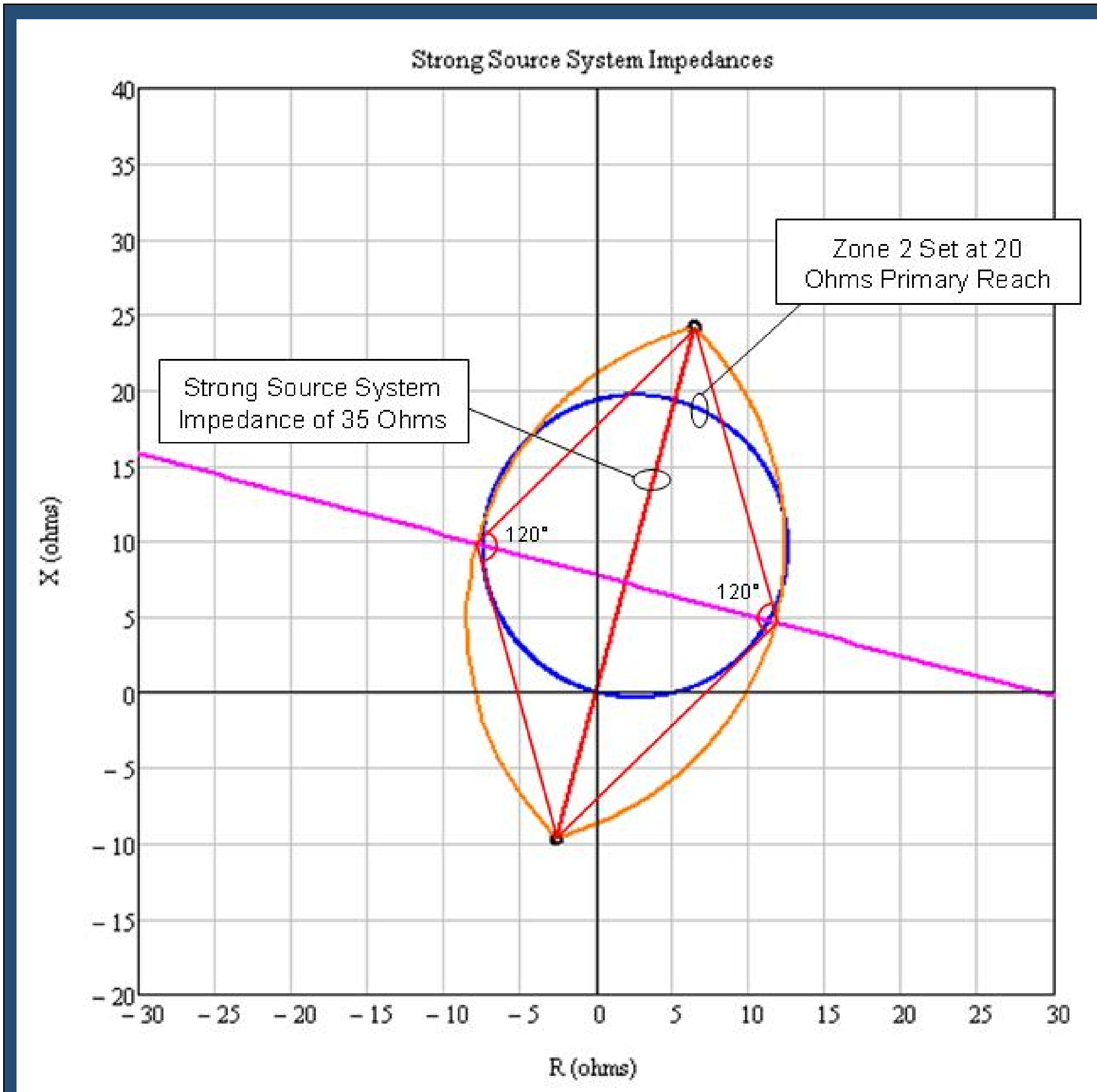


Table 2. Example Calculation (Lens Point 1)

	$E_R = 132{,}791\angle 0°\ V$		
Given positive sequence impedance data (The transfer impedance Z_{TR} is set to infinity).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		

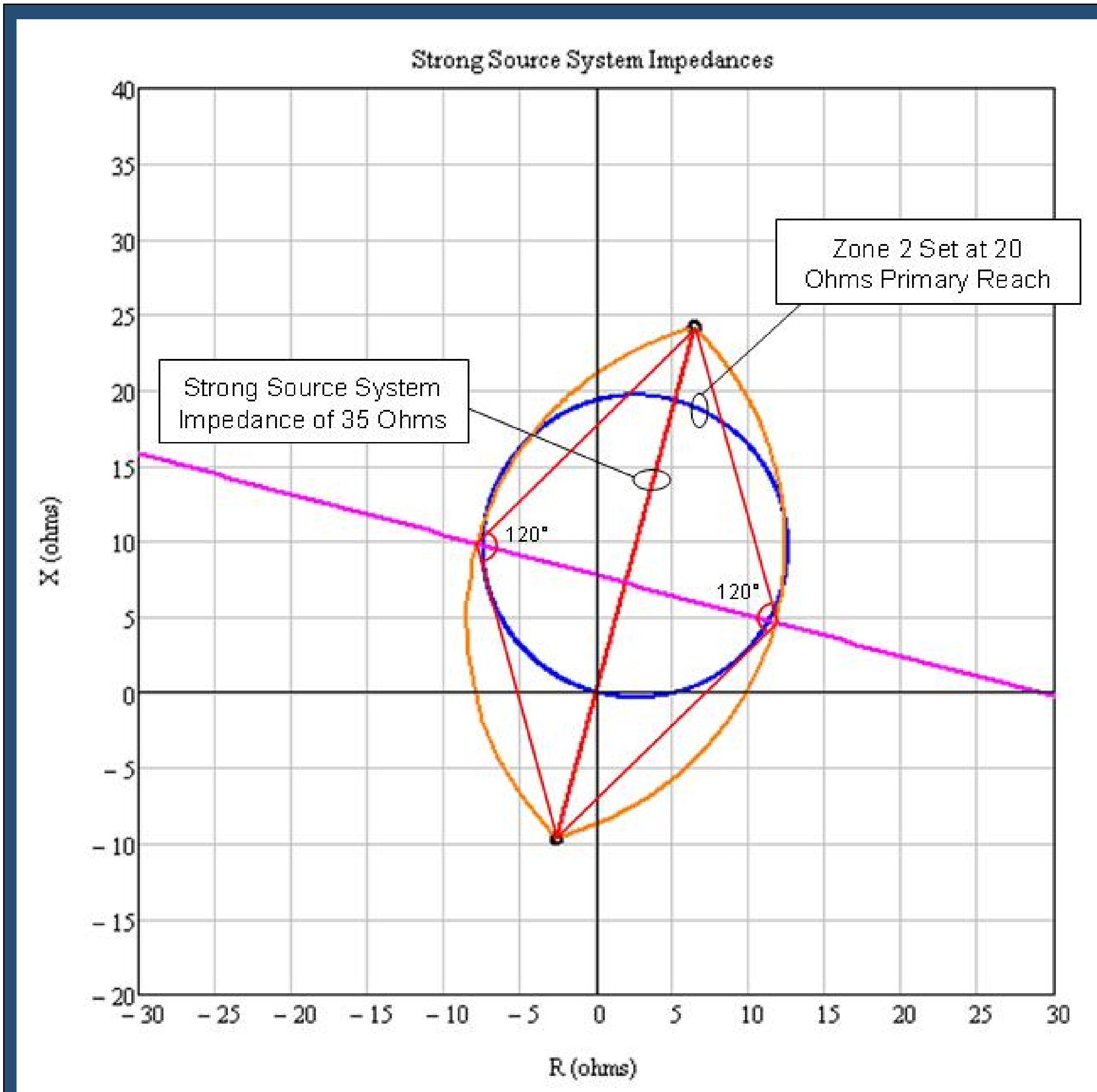


Table 2. Example Calculation (Lens Point 1)

Total impedance between generators.	
Eq. (8)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$
	$Z_{total} = \dfrac{\left((4 + j20)\,\Omega \times (4 + j20)^{10}\,\Omega\right)}{\left((4 + j20)\,\Omega + (4 + j20)^{10}\,\Omega\right)}$
	$Z_{total} = 4 + j20\,\Omega$

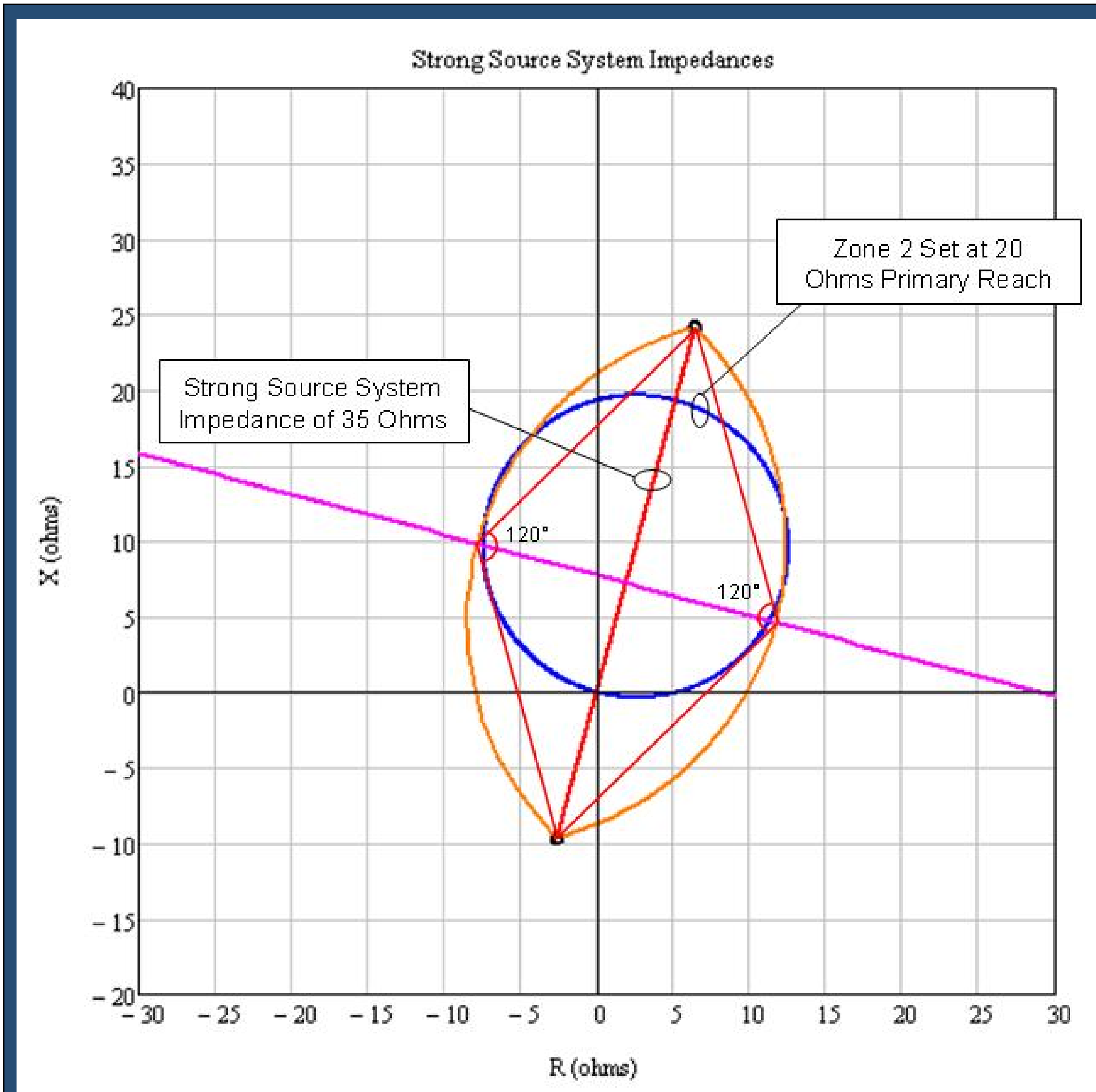


Table 2. Example Calculation (Lens Point 1)

Total system impedance.	
Eq. (9)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10)\,\Omega + (4 + j20)\,\Omega + (4 + j20)\,\Omega$
	$Z_{sys} = 10 + j50\,\Omega$

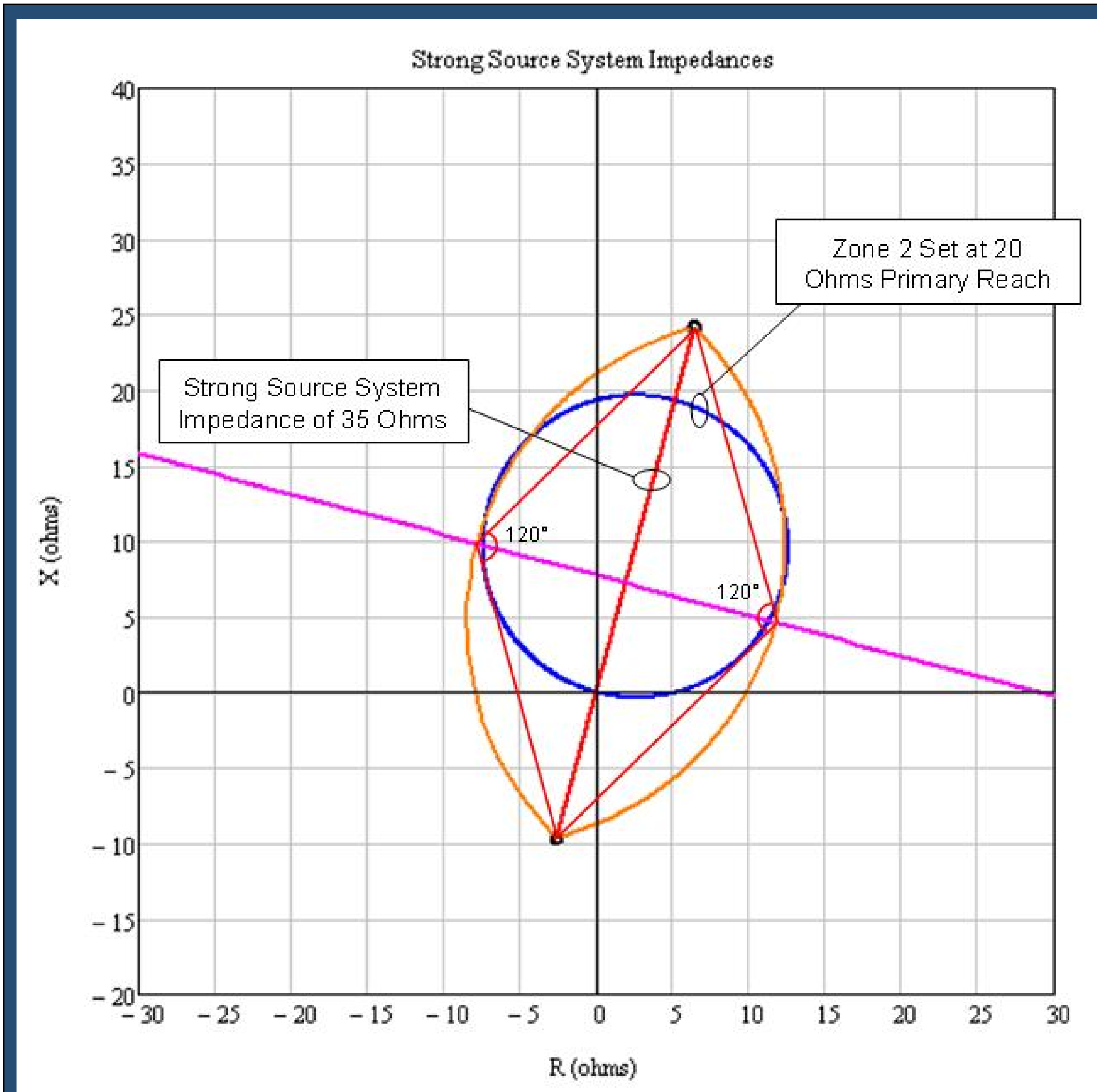


Table 2. Example Calculation (Lens Point 1)

Total system current from sending source.	
Eq. (10)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \dfrac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$
	$I_{sys} = 4{,}511\angle 71.3°\ A$

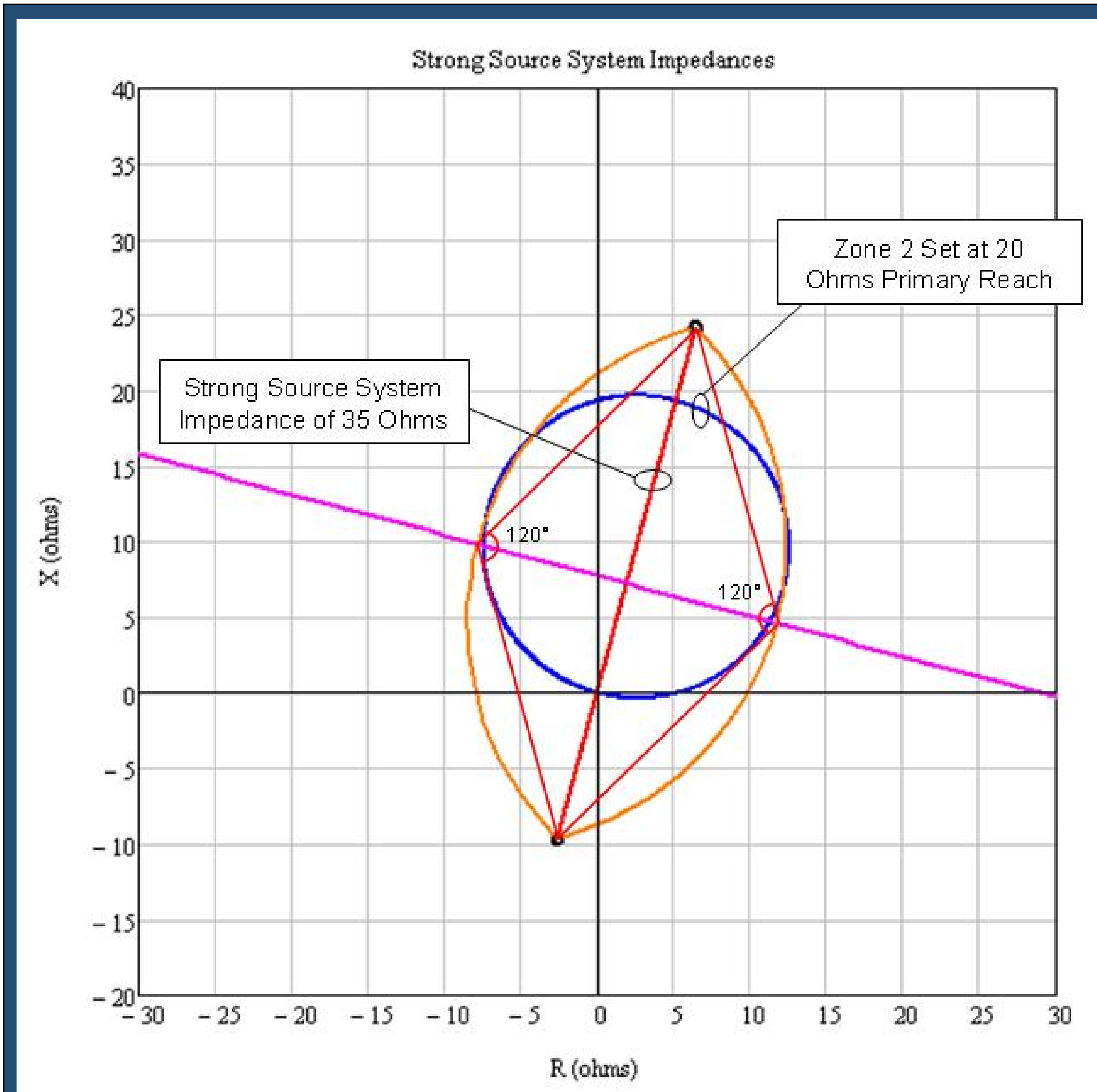


Table 2. Example Calculation (Lens Point 1)

The current as measured by the relay on Z_L is only the current flowing through that line as determined by using the current divider equation.	
Eq. (11)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 4{,}511\angle 71.3°\,A \times \frac{(4 + j20)^{10}\,\Omega}{(4 + j20)\,\Omega + (4 + j20)^{10}\,\Omega}$
	$I_L = 4{,}511\angle 71.3°\,A$

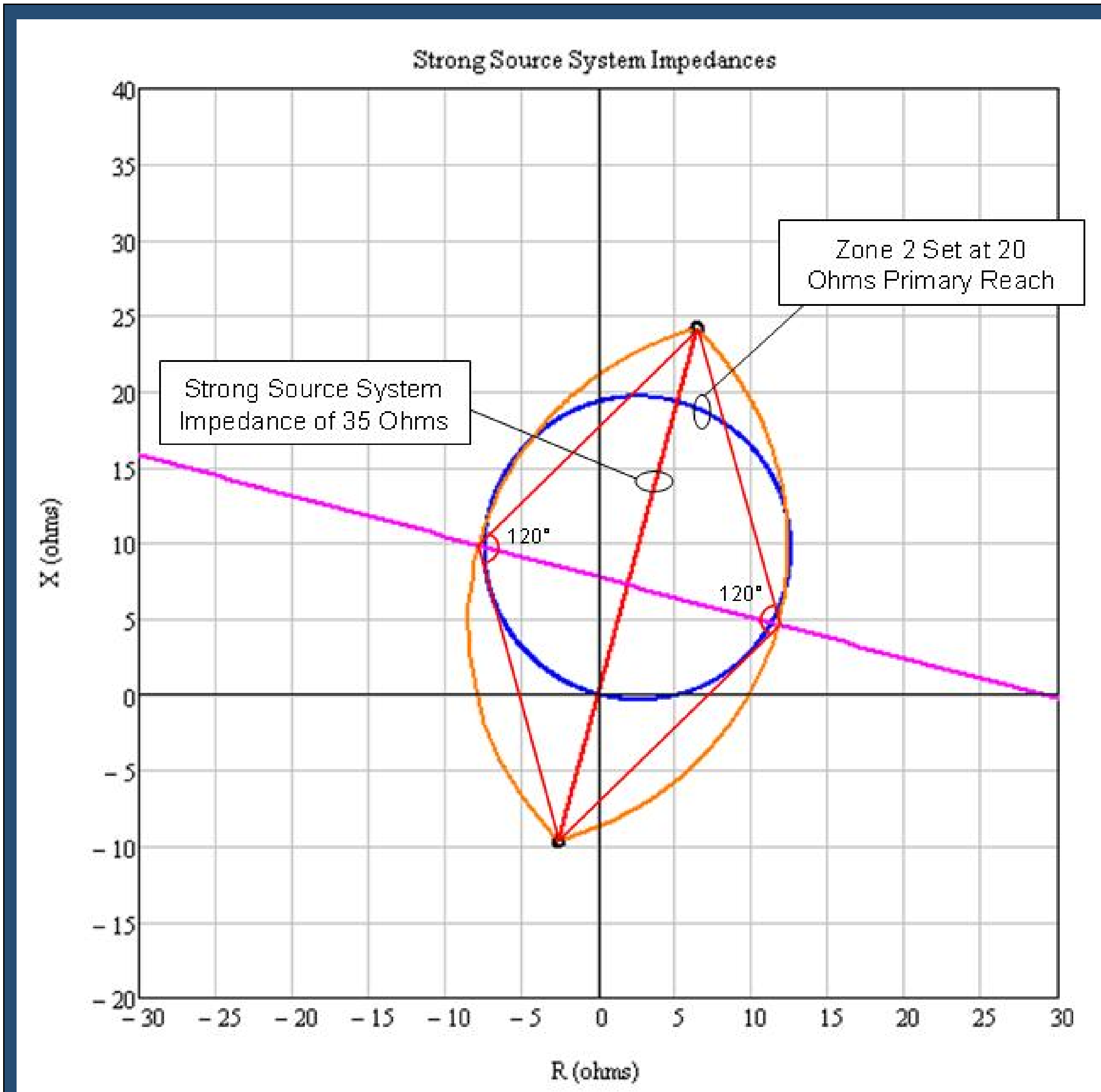


Table 2. Example Calculation (Lens Point 1)

The voltage as measured by the relay on Z_L is the voltage drop from the sending source through the sending source impedance.	
Eq. (12)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10)\ \Omega \times 4{,}511\angle 71.3°\ A]$
	$V_S = 95{,}757\angle 106.1°\ V$

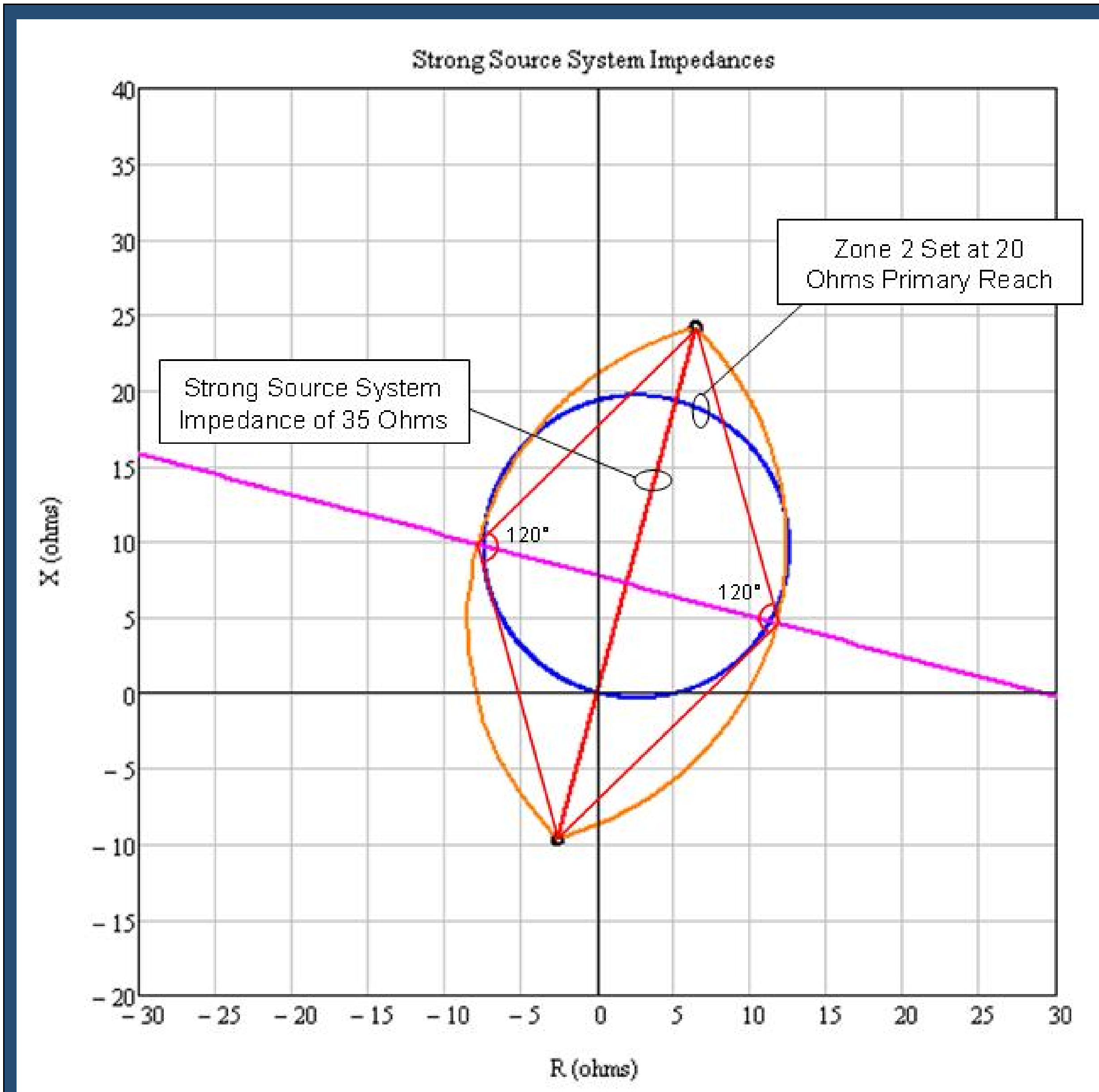


Table 2. Example Calculation (Lens Point 1)

The impedance seen by the relay on Z_L.	
Eq. (13)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1°\ V}{4{,}511\angle 71.3°\ A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

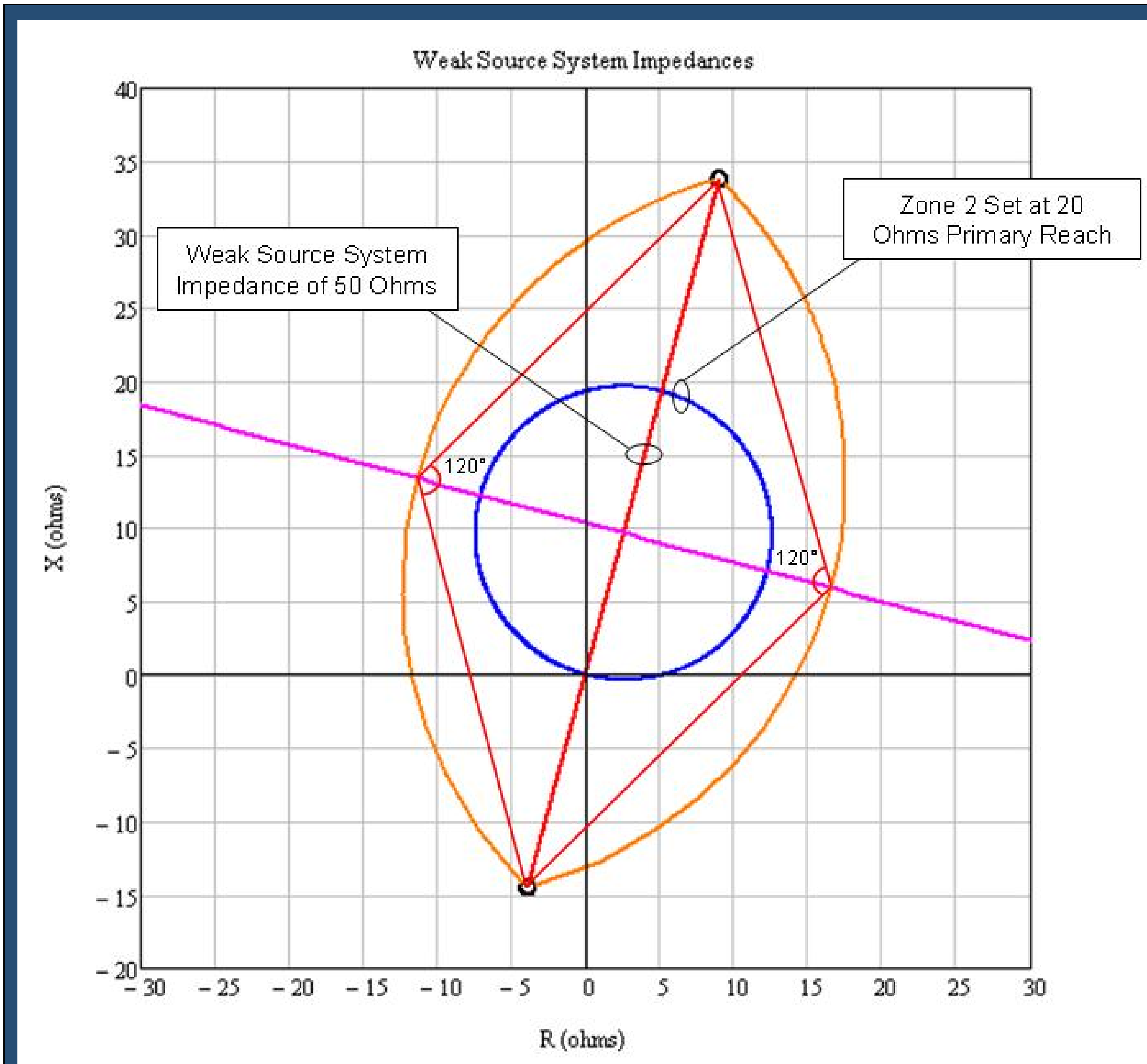


Table 3. Example Calculation (Lens Point 2)

~~**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.~~This example is for calculating the impedance second point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending voltage (E_S) at 70% of the receiving voltage (E_R) and leading the receiving voltage by 120 degrees. See Figures 4 and 5.

Eq. (14)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}} \times 70\%$

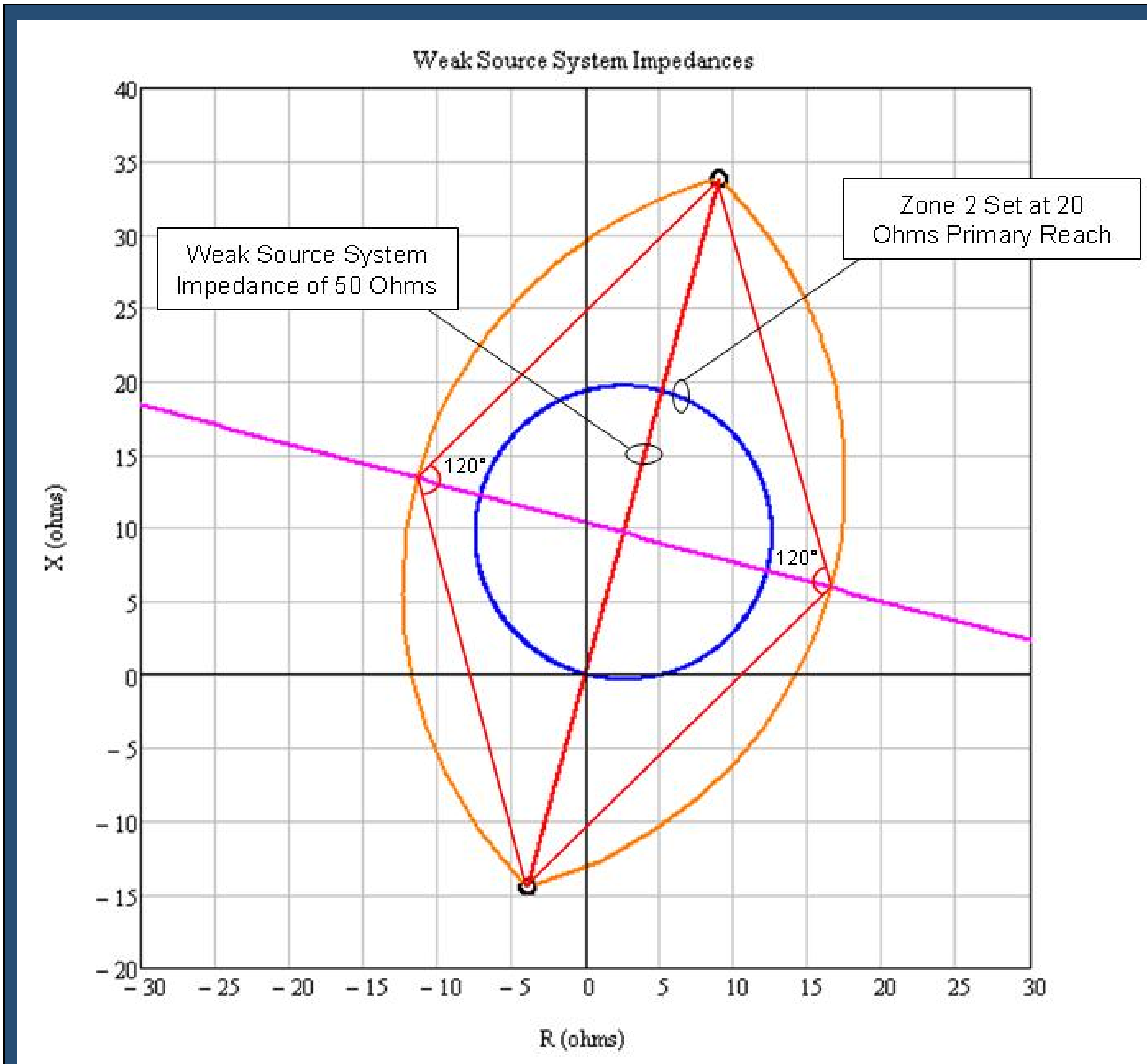


Table 3. Example Calculation (Lens Point 2)

	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 0.70$
	$E_S = 92{,}953.7\angle 120°\ V$
Eq. (15)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$
	$E_R = 132{,}791\angle 0°\ V$

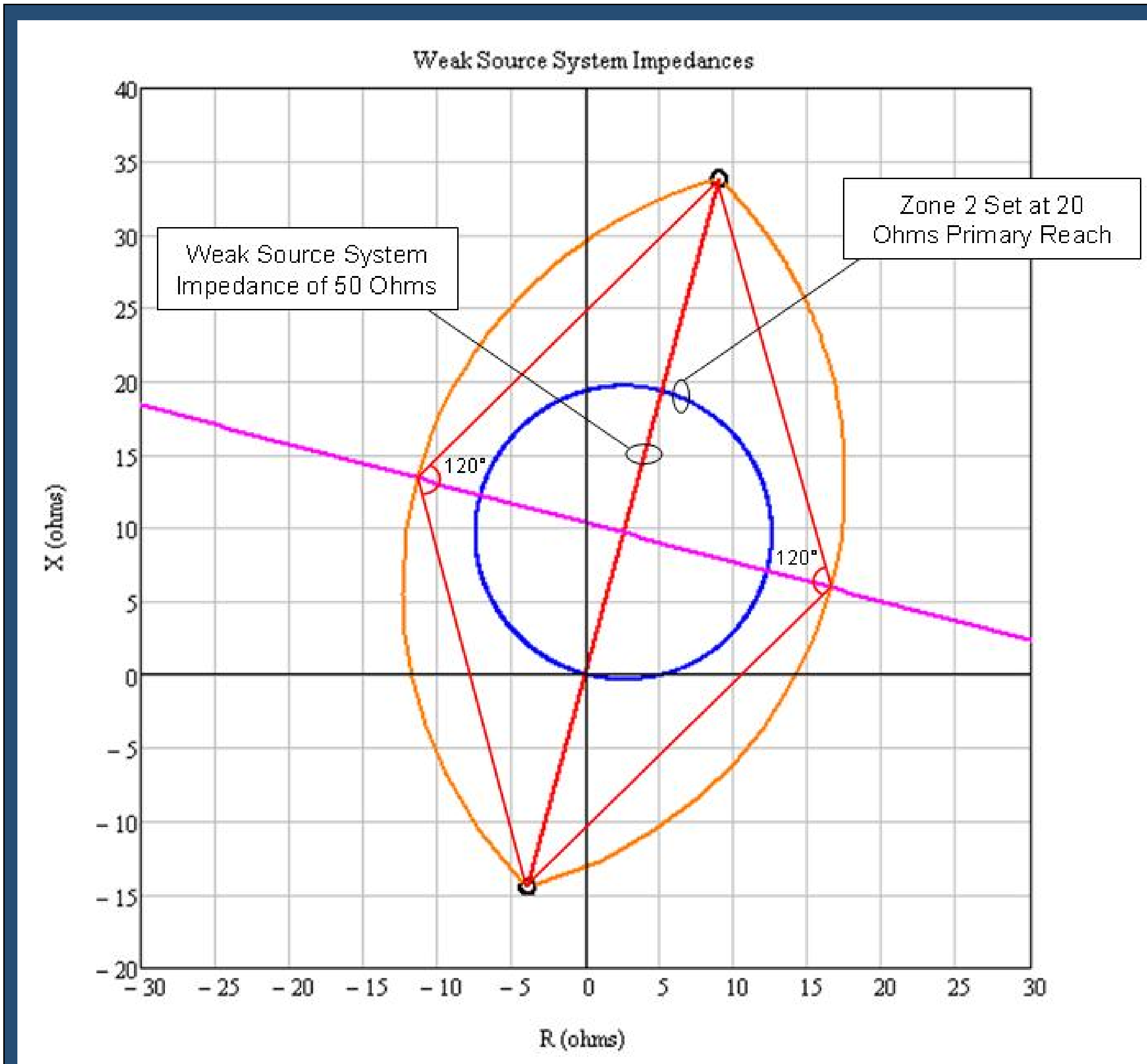


Table 3. Example Calculation (Lens Point 2)

Given positive sequence impedance data (The transfer impedance Z_{TR} is set to infinity).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between generators.			
Eq. (16)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{((4 + j20)\ \Omega \times (4 + j20)^{10}\ \Omega)}{((4 + j20)\ \Omega + (4 + j20)^{10}\ \Omega)}$		

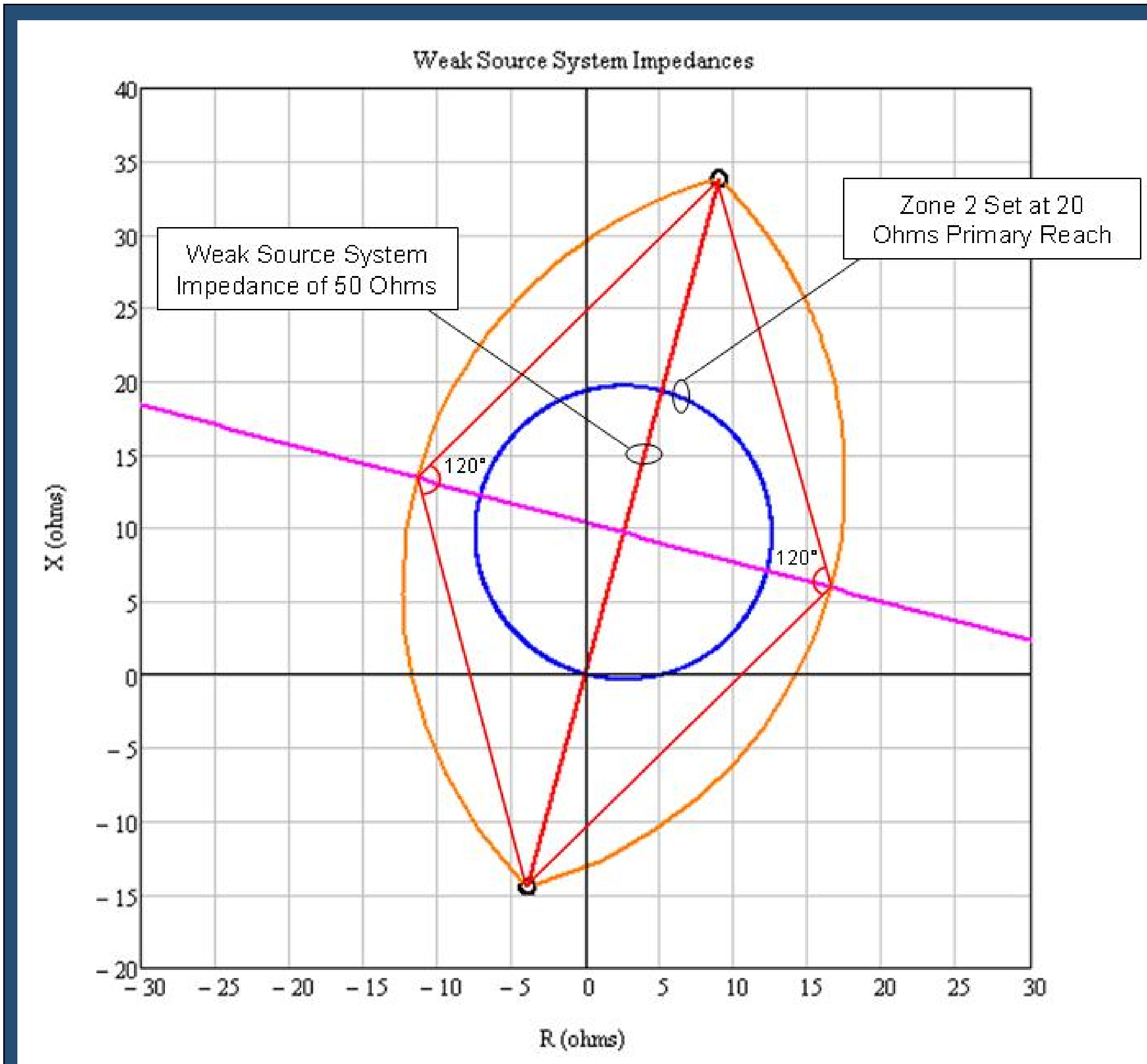


Table 3. Example Calculation (Lens Point 2)

	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (17)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$
	$Z_{sys} = 10 + j50\ \Omega$

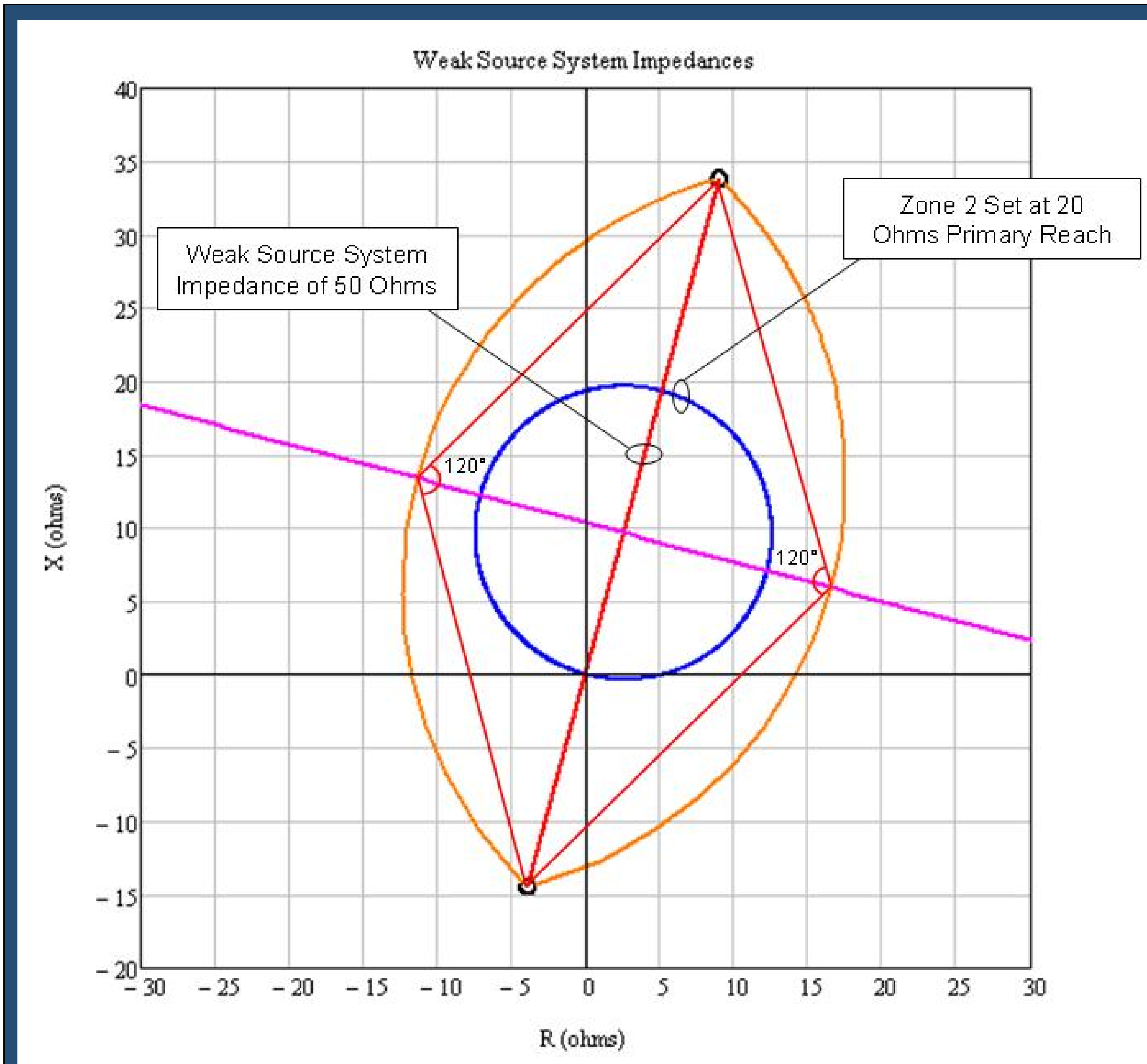


Table 3. Example Calculation (Lens Point 2)	
Total system current from sending source.	
Eq. (18)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \dfrac{92{,}953.7\angle 120°\,V - 132{,}791\angle 0°\,V}{(10 + j50)\,\Omega}$
	$I_{sys} = 3{,}854\angle 77°\,A$

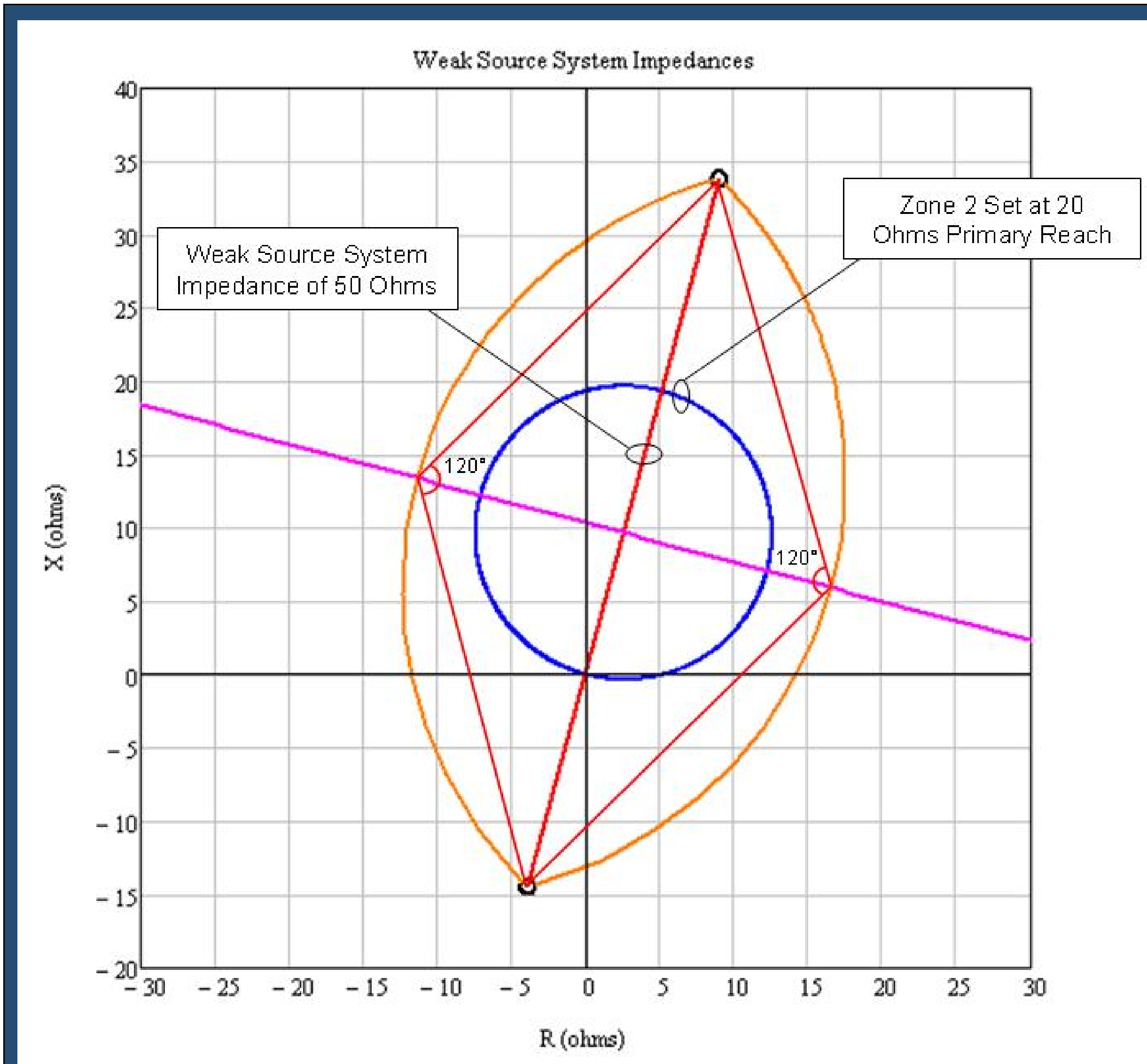


Table 3. Example Calculation (Lens Point 2)

The current as measured by the relay on ZL is only the current flowing through that line as determined by using the current divider equation.	
Eq. (19)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 77°\ A \times \dfrac{(4 + j20)^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20)^{10}\ \Omega}$
	$I_L = 3{,}854\angle 77°\ A$

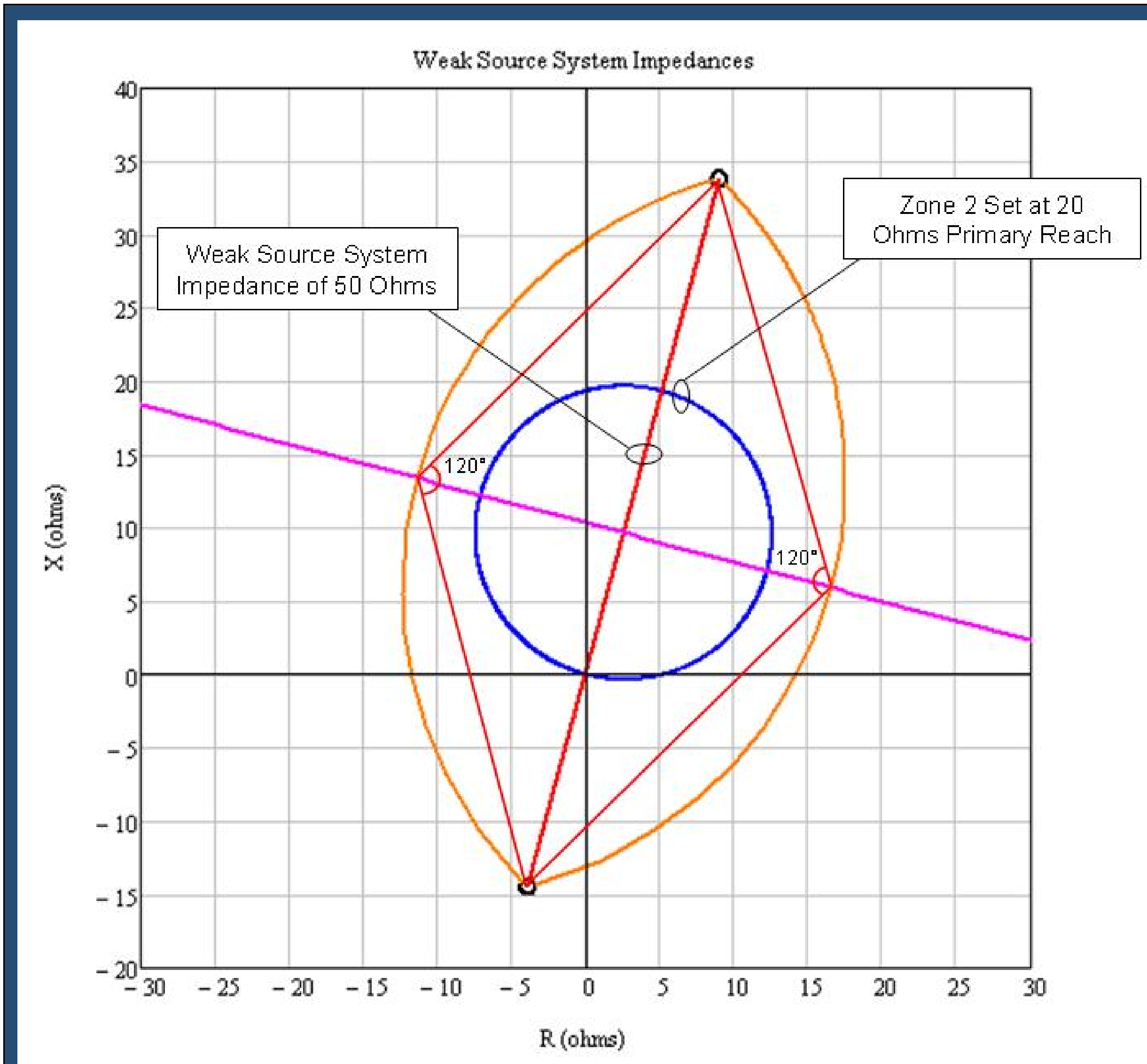


Table 3. Example Calculation (Lens Point 2)

The voltage as measured by the relay on Z_L is the voltage drop from the sending source through the sending source impedance.	
Eq. (20)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 92{,}953\angle 120°\ V - [(2 + j10\ )\Omega \times 3{,}854\angle 77°\ A]$
	$V_S = 65{,}271\angle 99°\ V$
The impedance seen by the relay on Z_L.	
Eq. (21)	$Z_{L-Relay} = \frac{V_S}{I_L}$

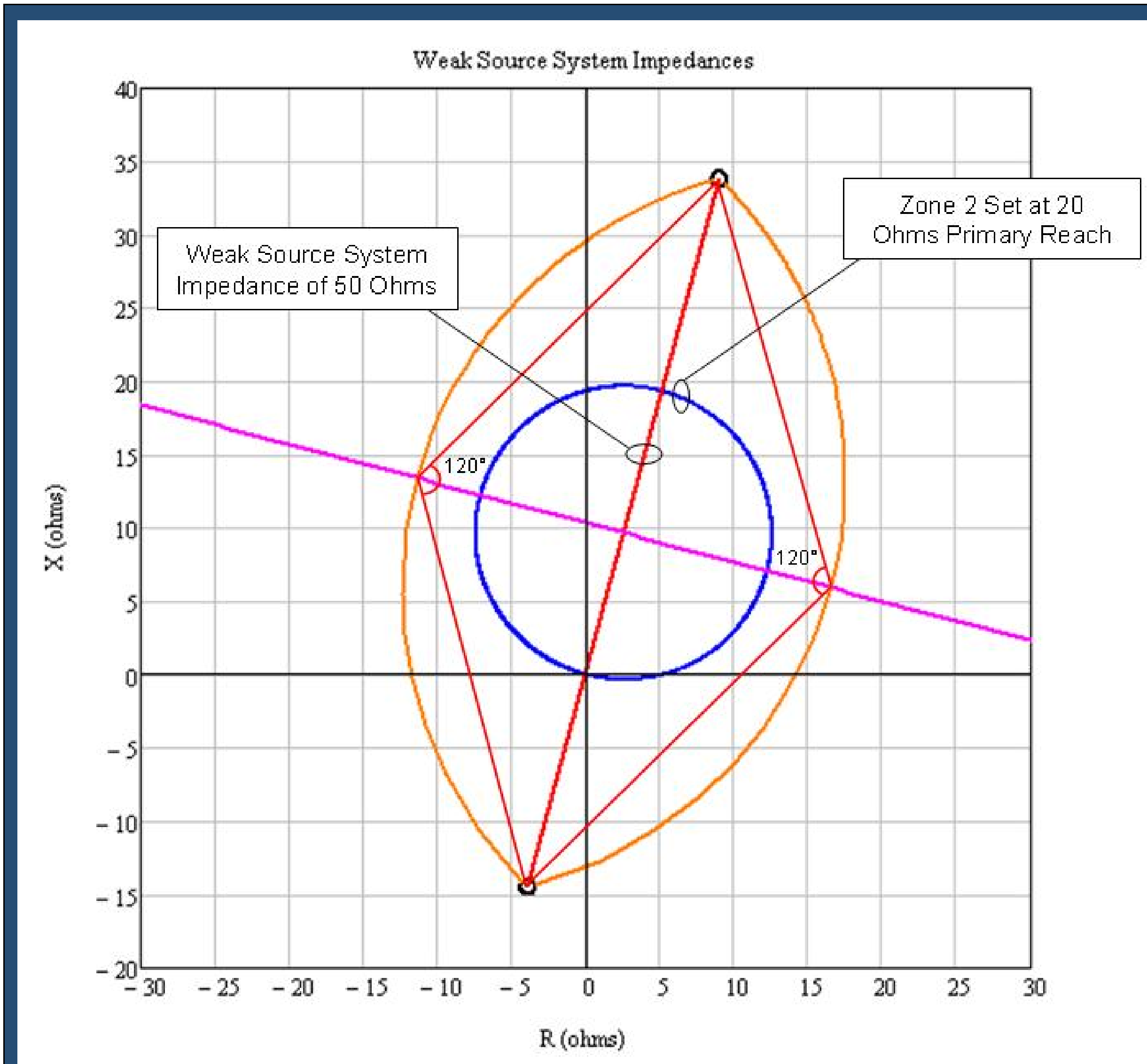
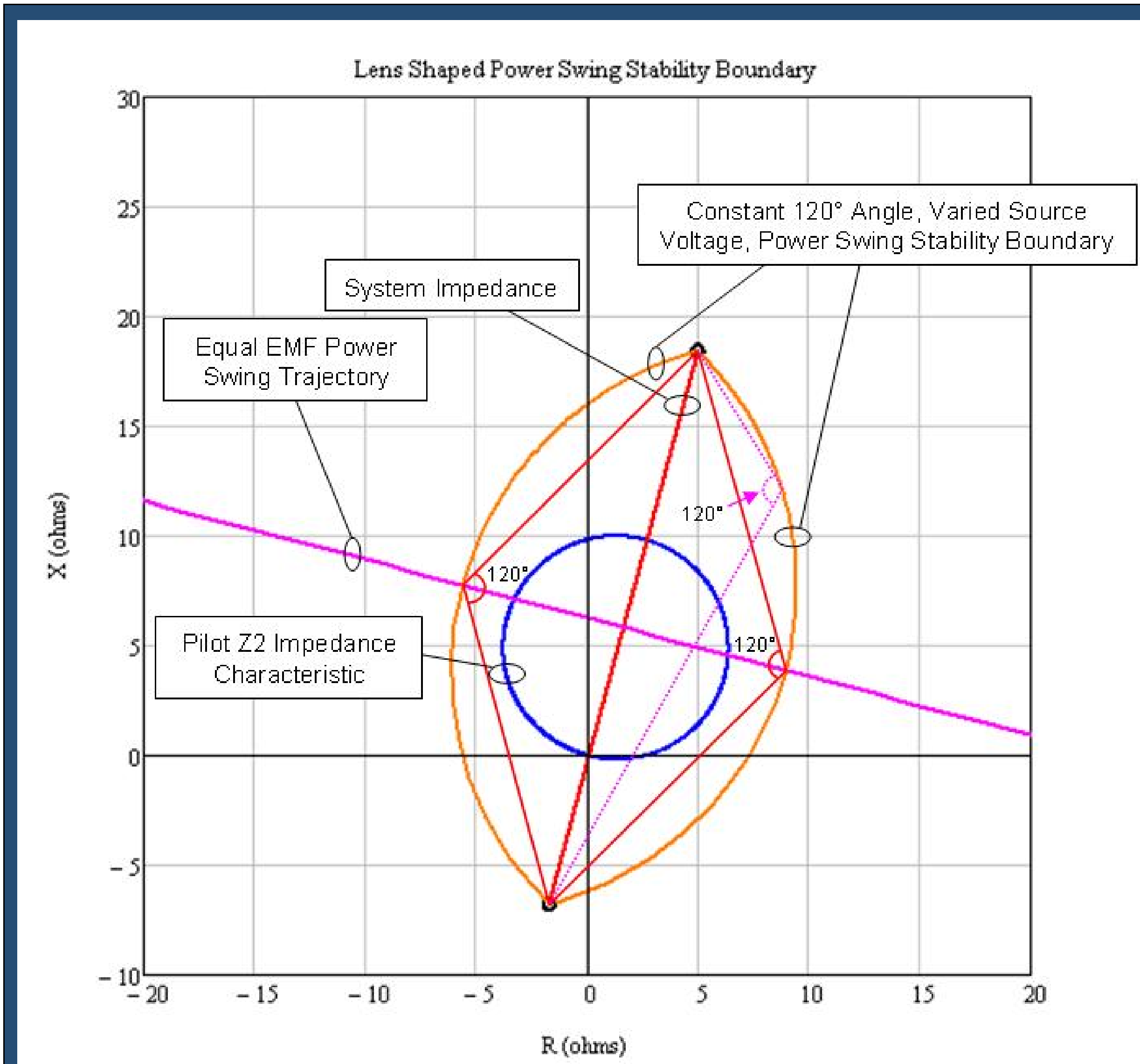


Table 3. Example Calculation (Lens Point 2)

	$Z_{L-Relay} = \dfrac{65{,}271\angle 99°\ V}{3{,}854\angle 77°\ A}$
	$Z_{L-Relay} = 15.676 + j6.41\ \Omega$



~~Table 4. Example Calculation (Lens Point 3)~~

~~**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.~~This example is for calculating the impedance third point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving voltage (E_R) at 70% of the sending voltage (E_S) and the sending voltage leading the receiving voltage by 120 degrees. See Figures 4 and 5.

Eq. (22)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}}$
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}}$

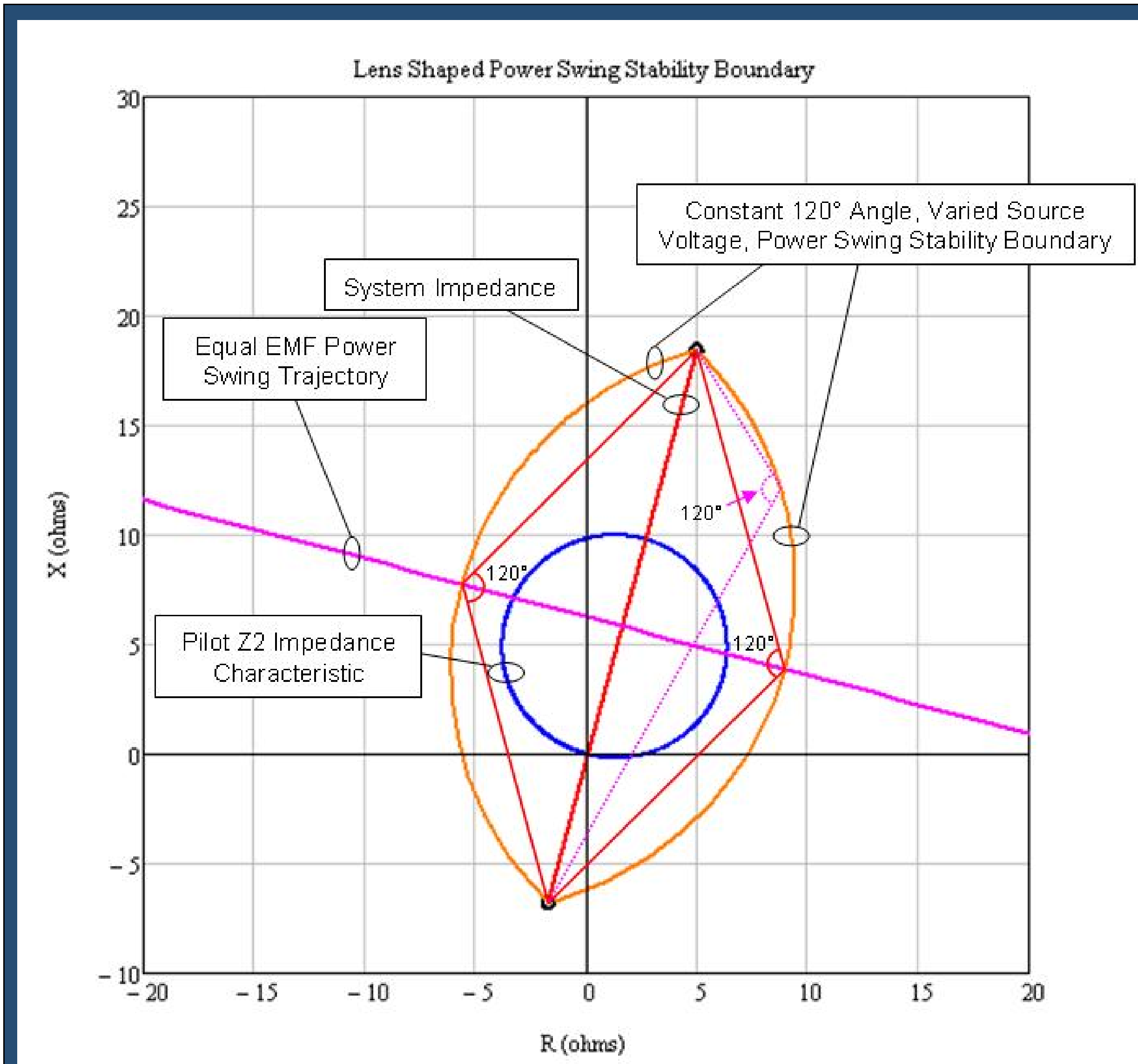


Table 4. Example Calculation (Lens Point 3)

	$E_S = 132{,}791\angle 120°\ V$		
Eq. (23)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Given positive sequence impedance data (The transfer impedance Z_{TR} is set to infinity).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$

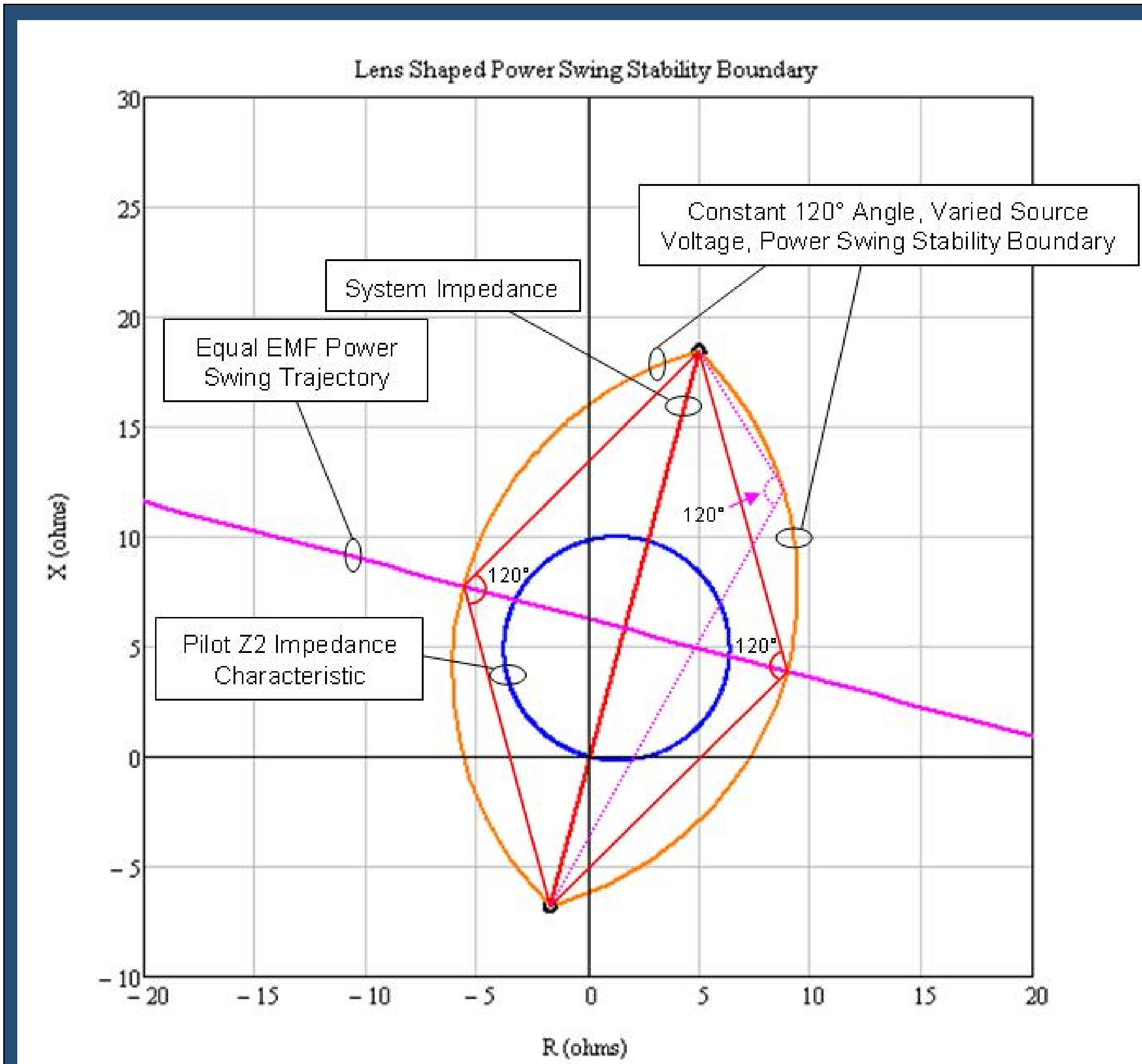


Table 4. Example Calculation (Lens Point 3)

Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$
Total impedance between generators.	
Eq. (24)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20)^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20)^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$

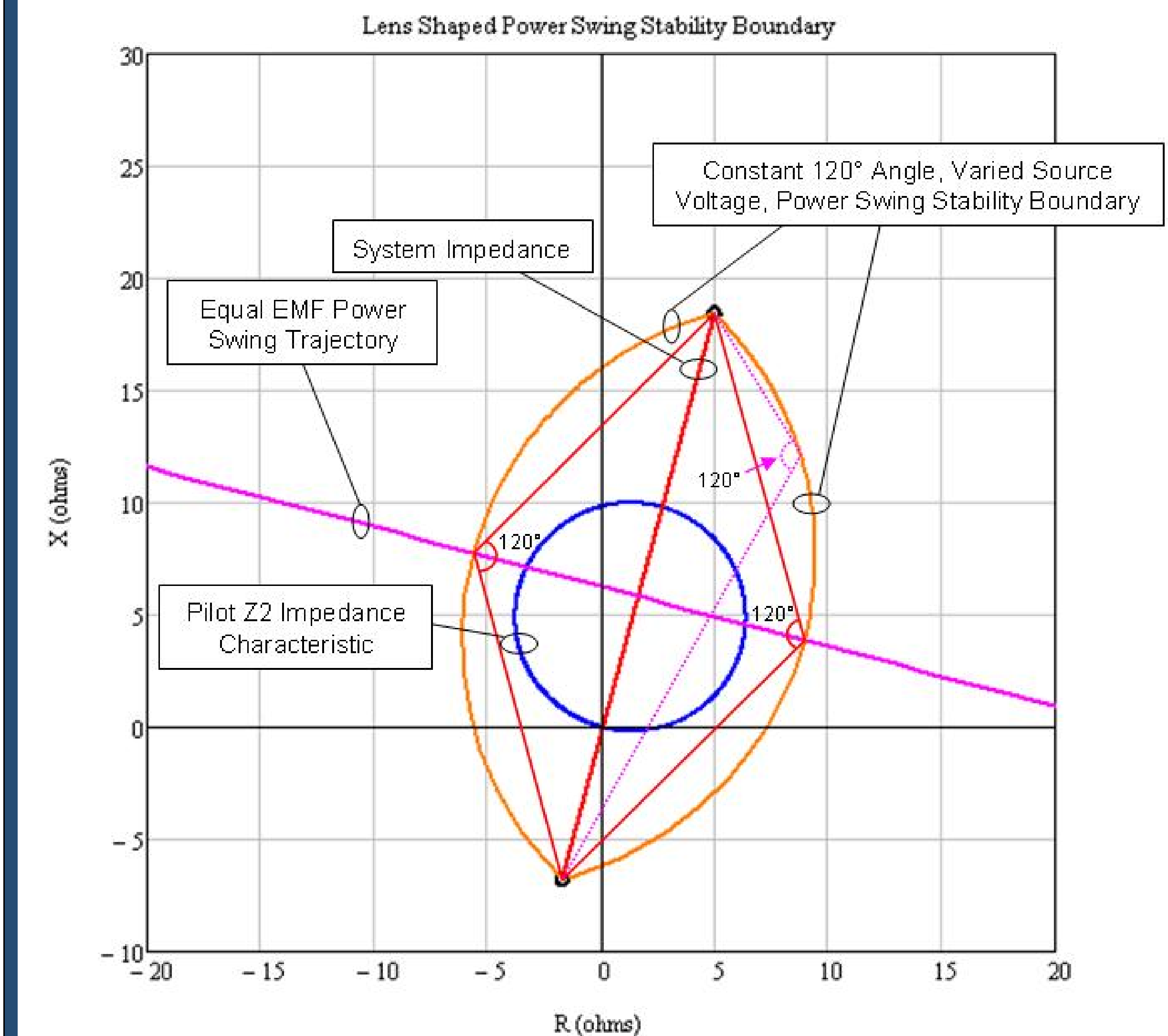


Table 4. Example Calculation (Lens Point 3)

Total system impedance.	
Eq. (25)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending source.	
Eq. (26)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$

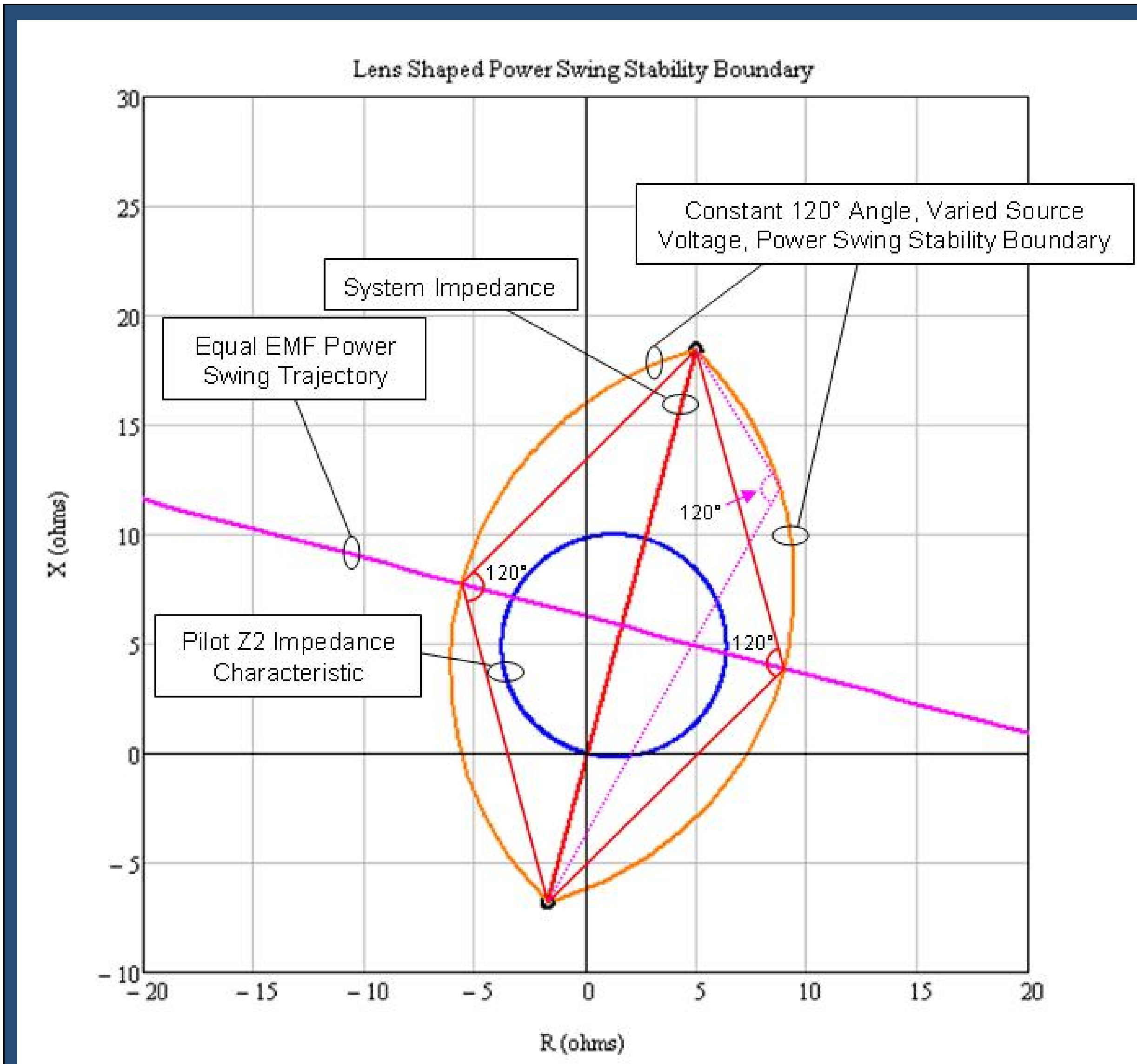


Table 4. Example Calculation (Lens Point 3)

	$I_{sys} = \dfrac{132{,}791\angle 120°\ V - 92{,}953.7\angle 0°\ V}{(10 + j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 65.5°\ A$
The current as measured by the relay on ZL is only the current flowing through that line as determined by using the current divider equation.	
Eq. (27)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 65.5°\ A \times \dfrac{(4 + j20)^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20)^{10}\ \Omega}$

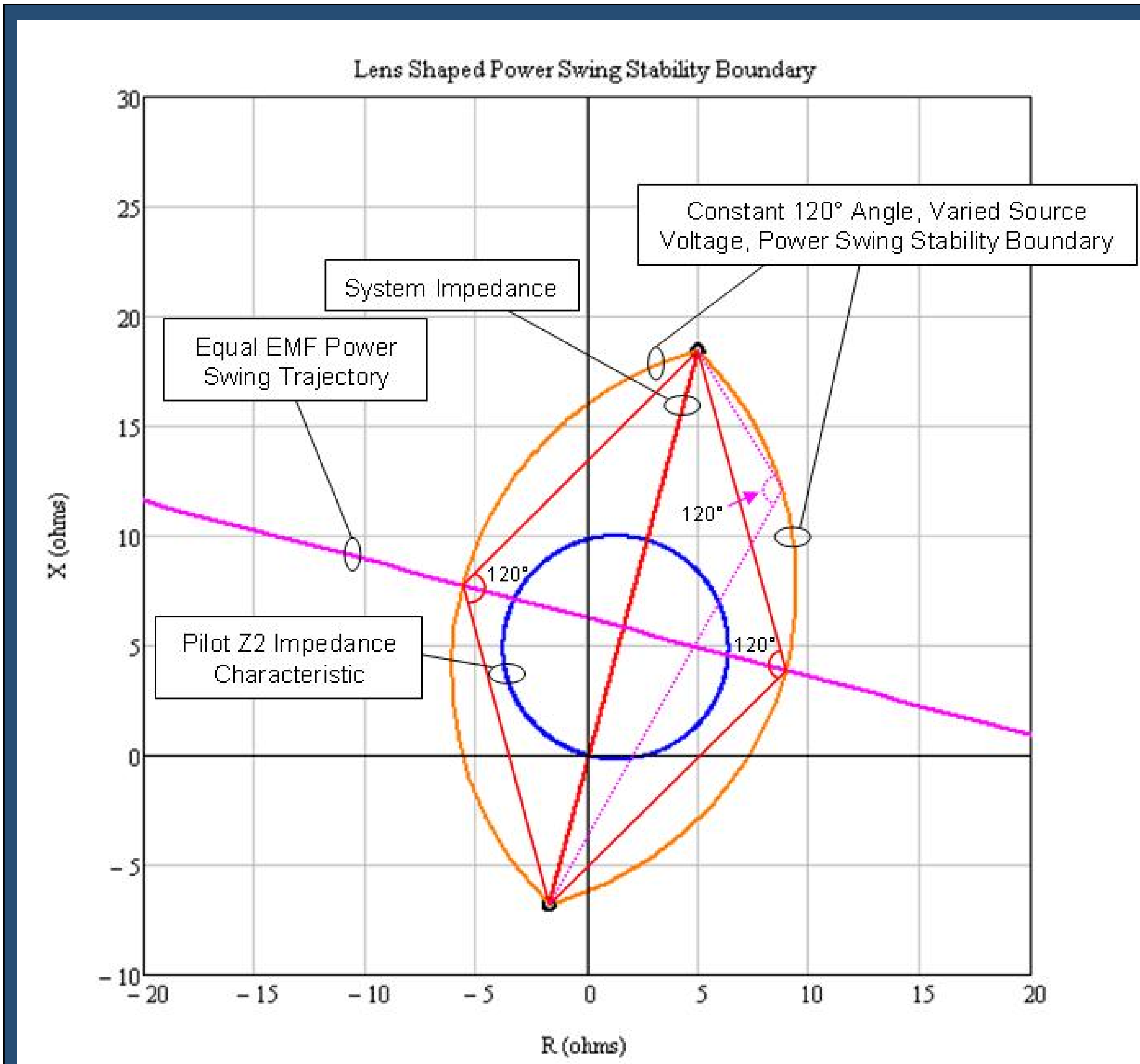


Table 4. Example Calculation (Lens Point 3)

	$I_L = 3{,}854\angle 65.5°\ A$
The voltage as measured by the relay on Z_L is the voltage drop from the sending source through the sending source impedance.	
Eq. (28)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10)\ \Omega \times 3{,}854\angle 65.5°\ A]$
	$V_S = 98{,}265\angle 110.6°\ V$

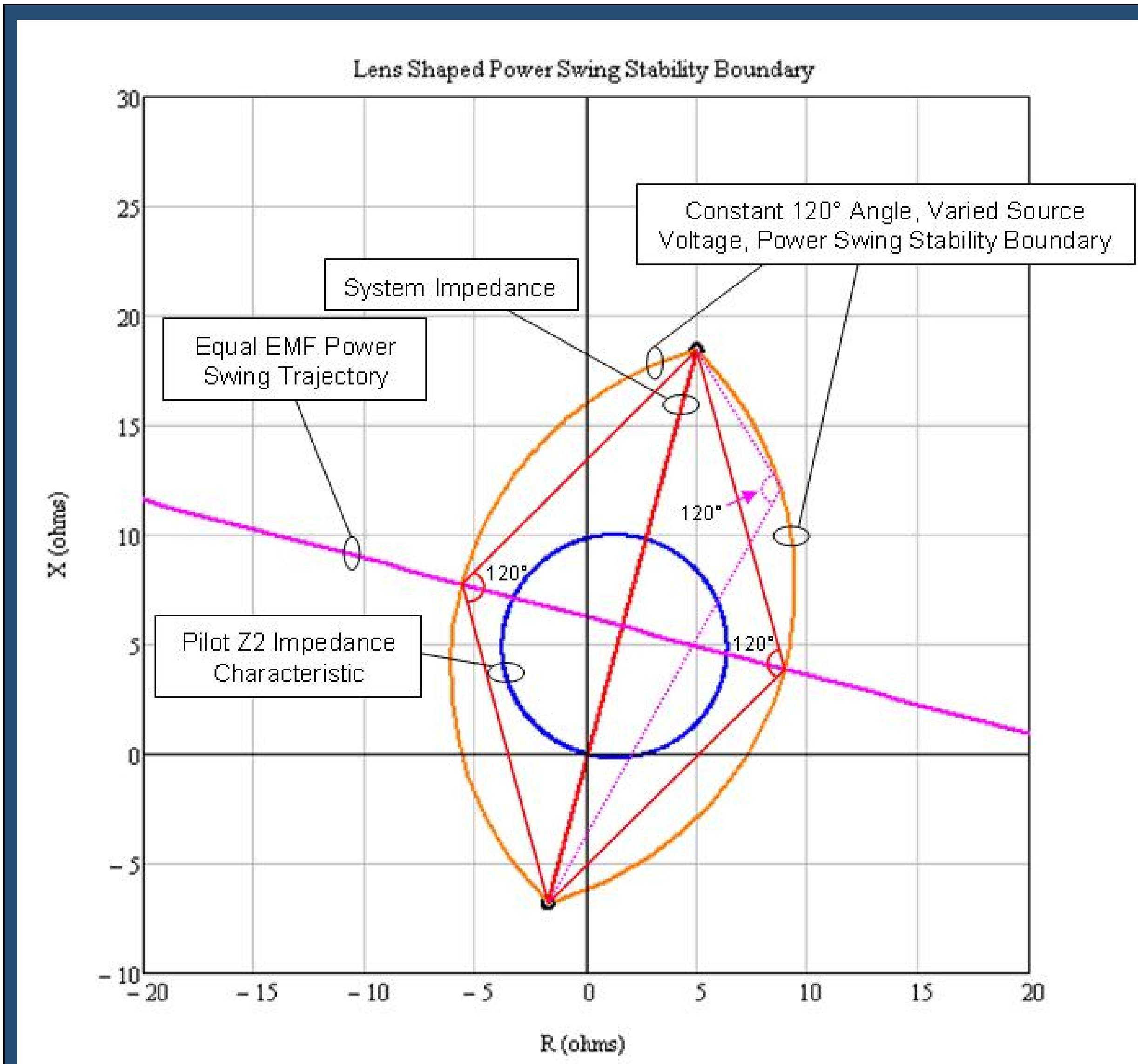


Table 4. Example Calculation (Lens Point 3)

The impedance seen by the relay on Z_L.	
Eq. (29)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle 110.6°\ V}{3{,}854\angle 65.5°\ A}$
	$Z_{L-Relay} = 18.005 + j18.054\ \Omega$

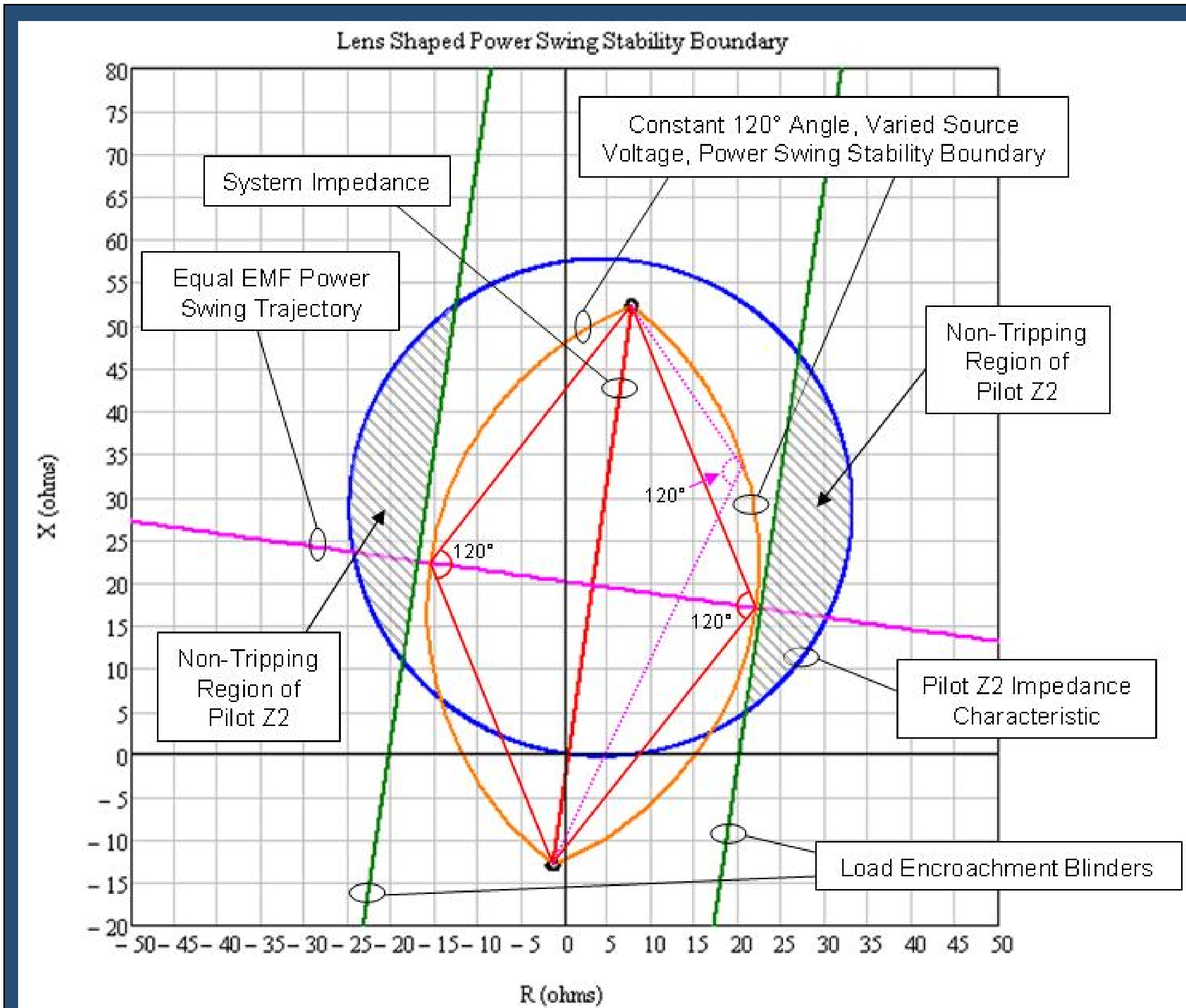


Table 5. Example Calculation (Lens Point 4)

~~**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.~~This example is for calculating the impedance fourth point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending voltage (ES) leading the receiving voltage (ER) by 240 degrees. See Figures 4 and 5.

Eq. (30)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$
	$E_S = \frac{230{,}000\angle 240°\, V}{\sqrt{3}}$
	$E_S = 132{,}791\angle 240°\, V$

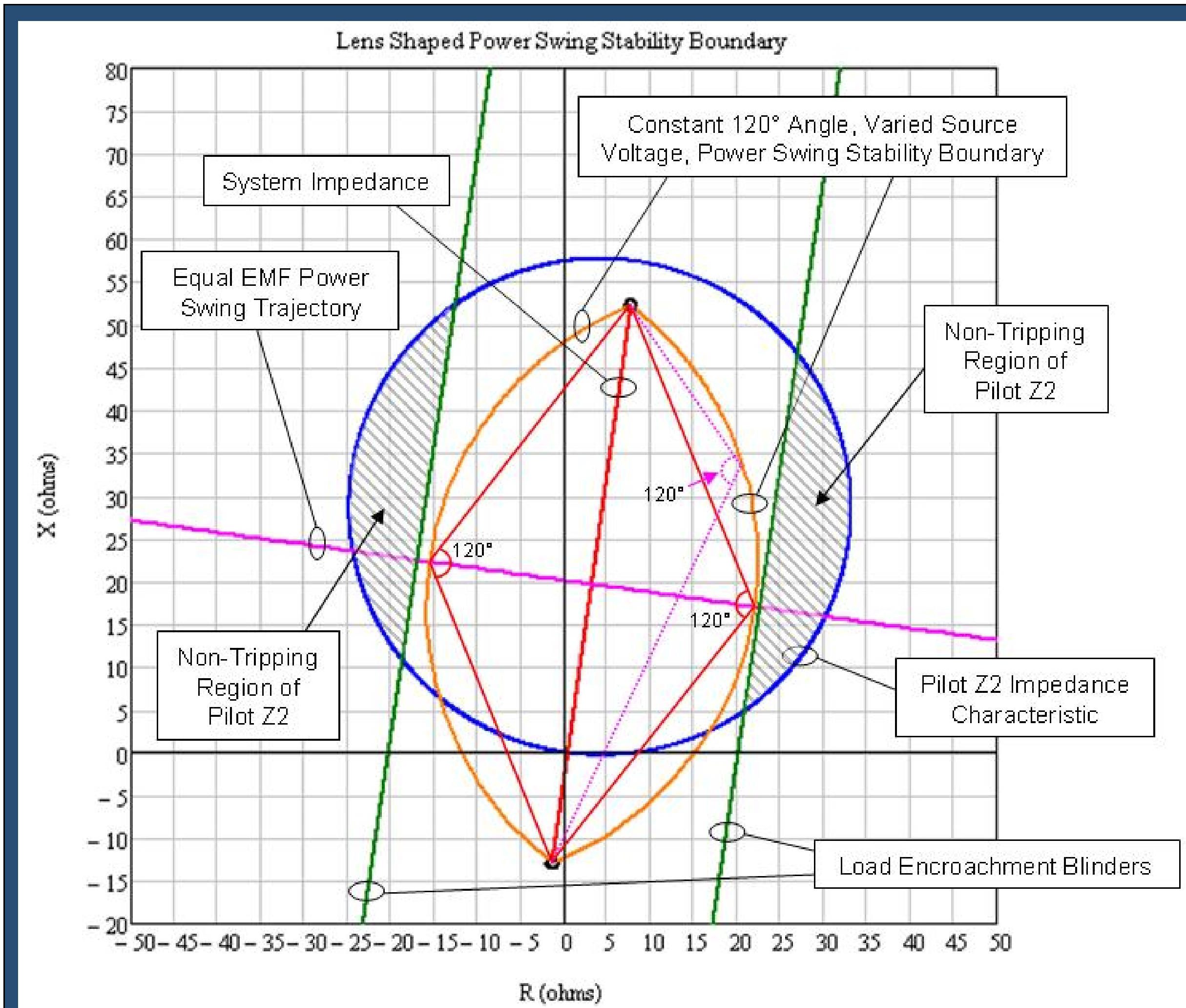


Table 5. Example Calculation (Lens Point 4)

Eq. (31)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given positive sequence impedance data (The transfer impedance Z_{TR} is set to infinity).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		

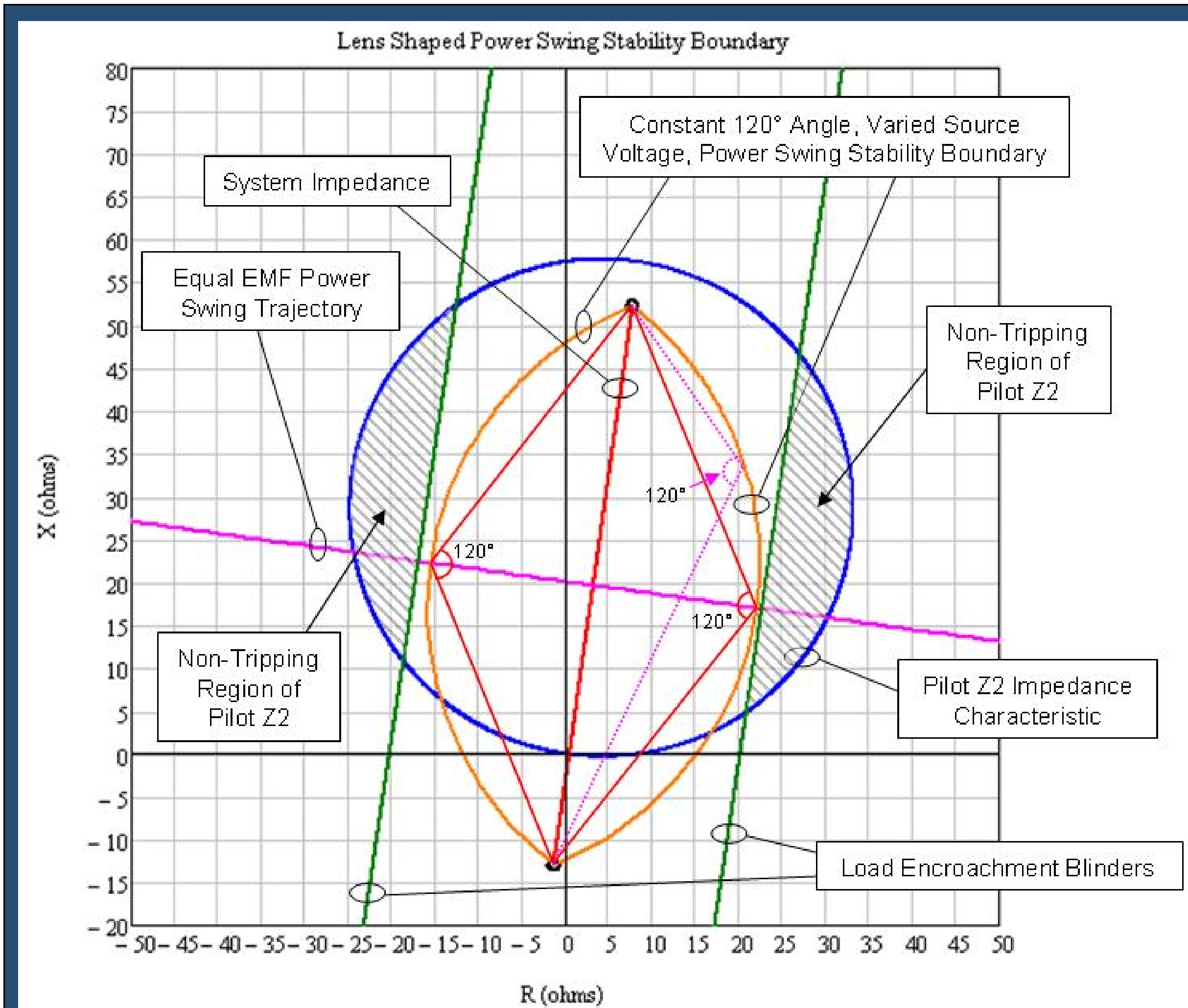


Table 5. Example Calculation (Lens Point 4)

Total impedance between generators.	
Eq. (32)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20)^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20)^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (33)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$

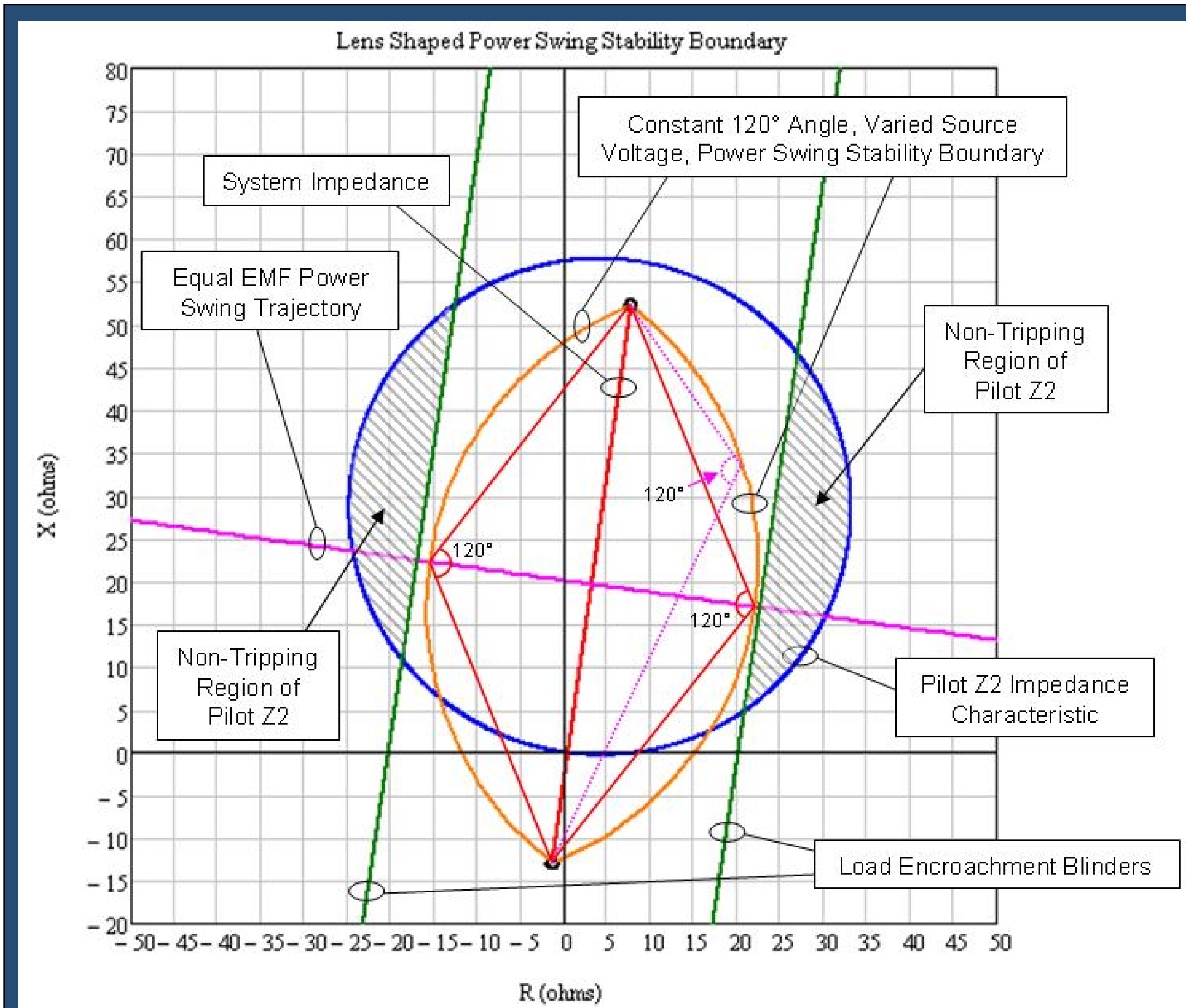


Table 5. Example Calculation (Lens Point 4)

	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending source.	
Eq. (34)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \dfrac{132{,}791\angle 240°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$
	$I_{sys} = 4{,}510\angle 131.3°\ A$

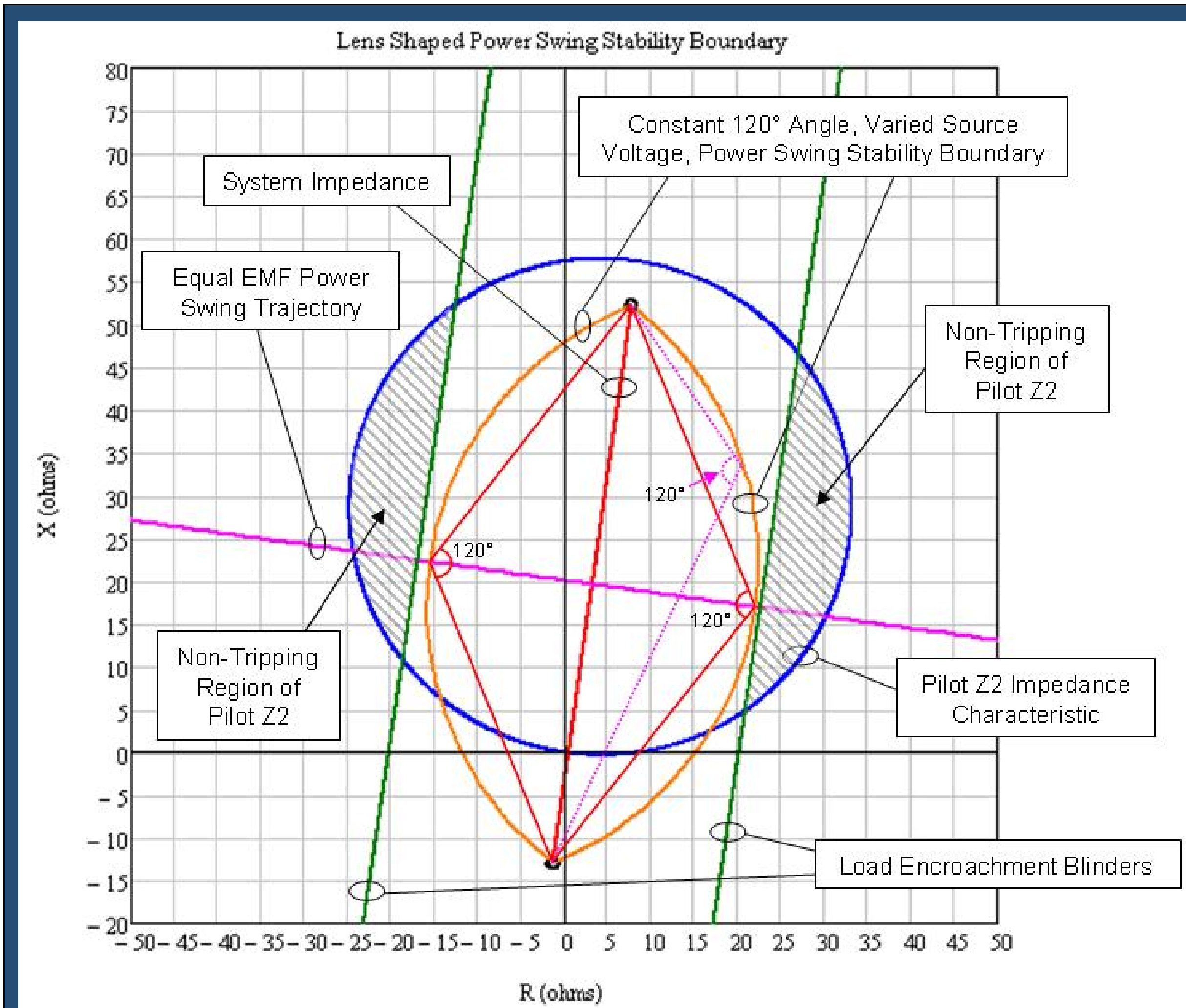


Table 5. Example Calculation (Lens Point 4)

The current as measured by the relay on ZL is only the current flowing through that line as determined by using the current divider equation.	
Eq. (35)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 4{,}510\angle 131.1°\ A \times \frac{(4 + j20)^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20)^{10}\ \Omega}$
	$I_L = 4{,}510\angle 131.1°\ A$
The voltage as measured by the relay on Z_L is the voltage drop from the sending source through the sending source impedance.	
Eq. (36)	$V_S = E_S - (Z_S \times I_L)$

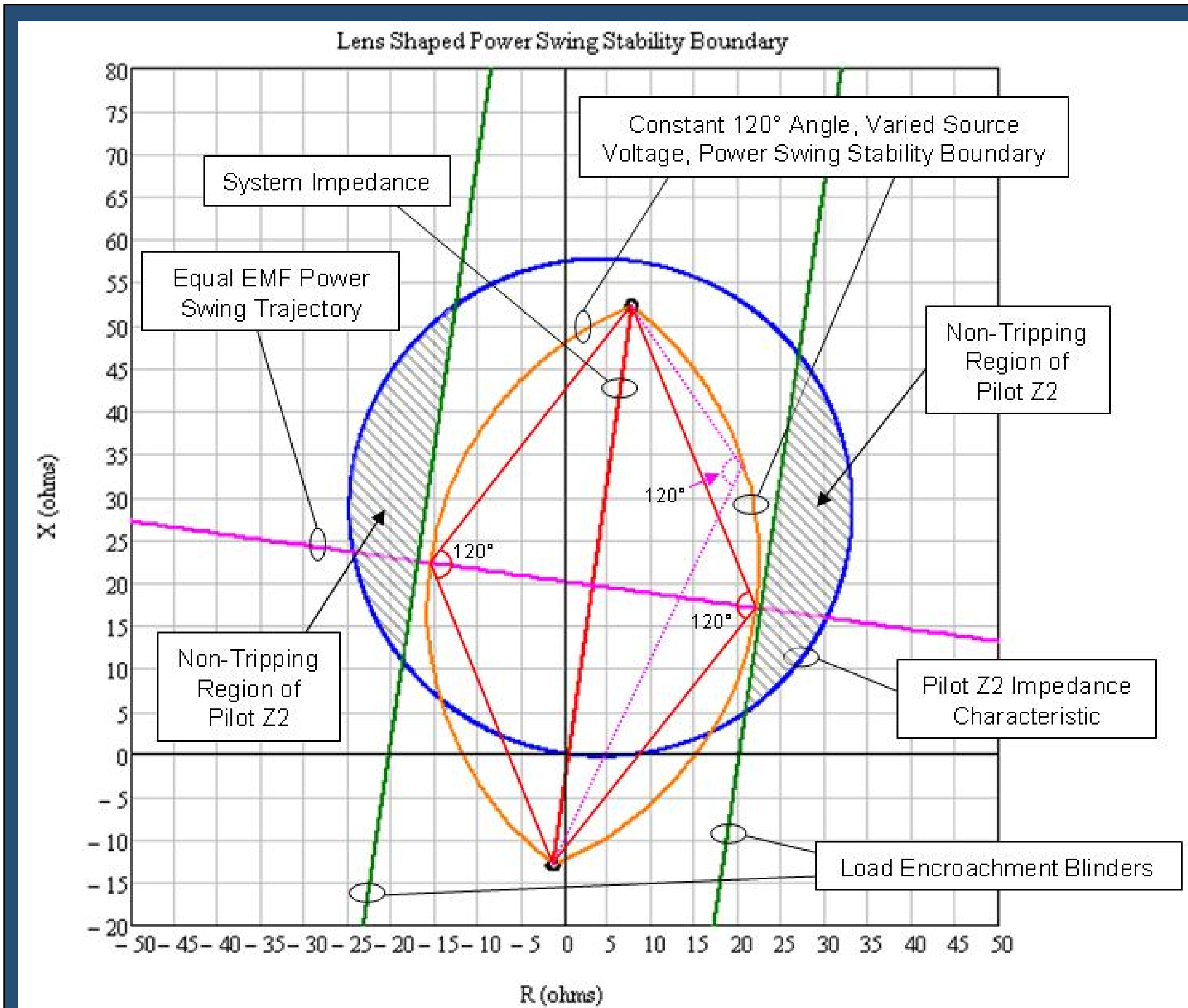


Table 5. Example Calculation (Lens Point 4)	
	$V_S = 132{,}791\angle 240°\ V - [(2 + j10\ )\ \Omega \times 4{,}510\angle 131.1°\ A]$
	$V_S = 95{,}756\angle -106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (37)	$Z_{L-Relay} = \dfrac{V_S}{I_L}$
	$Z_{L-Relay} = \dfrac{95{,}756\angle -106.1°\ V}{4{,}510\angle 131.1°\ A}$
	$Z_{L-Relay} = -11.434 + j17.887\ \Omega$

~~***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~~

Table 6. Example Calculation (Lens Point 5)			
This example is for calculating the impedance fifth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending voltage (E_S) at 70% of the receiving voltage (E_R) and leading the receiving voltage by 240 degrees. See Figures 4 and 5.			
Eq. (38)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}} \times 70\%$		
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 240°\ V$		
Eq. (39)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given positive sequence impedance data (The transfer impedance Z_{TR} is set to infinity).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between generators.			
Eq. (40)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20)^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20)^{10}\ \Omega\right)}$		

Table 6. Example Calculation (Lens Point 5)	
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (41)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10\ \Omega) + (4 + j20\ \Omega) + (4 + j20\ \Omega)$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending source.	
Eq. (42)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 240°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$
	$I_{sys} = 3{,}854\angle 125.5°\ A$
The current as measured by the relay on Z_L is only the current flowing through that line as determined by using the current divider equation.	
Eq. (43)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 125.5°\ A \times \frac{(4 + j20)^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20)^{10}\ \Omega}$
	$I_L = 3{,}854\angle 125.5°\ A$
The voltage as measured by the relay on Z_L is the voltage drop from the sending source through the sending source impedance.	
Eq. (44)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 92{,}953.7\angle 240°\ V - [(2 + j10\ )\ \Omega \times 3{,}854\angle 125.5°\ A]$
	$V_S = 65{,}270.5\angle - 99.4°\ V$
The impedance seen by the relay on Z_L.	
Eq. (45)	$Z_{L-Relay} = \frac{V_S}{I_L}$

Table 6. Example Calculation (Lens Point 5)	
	$Z_{L-Relay} = \frac{65{,}270.5\angle -99.4°\ V}{3{,}854\angle 125.5°\ A}$
	$Z_{L-Relay} = -12.005 + j11.946\ \Omega$

Table 7. Example Calculation (Lens Point 6)			
This example is for calculating the impedance sixth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving voltage (E_R) at 70% of the sending voltage (E_S) and the sending voltage leading the receiving voltage by 240 degrees. See Figures 4 and 5.			
Eq. (46)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (47)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Given positive sequence impedance data (The transfer impedance Z_{TR} is set to infinity).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between generators.			
Eq. (48)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		

Table 7. Example Calculation (Lens Point 6)	
	$Z_{total} = \frac{((4 + j20)\,\Omega \times (4 + j20)^{10}\,\Omega)}{((4 + j20)\,\Omega + (4 + j20)^{10}\,\Omega)}$
	$Z_{total} = 4 + j20\,\Omega$
Total system impedance.	
Eq. (49)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10)\,\Omega + (4 + j20)\,\Omega + (4 + j20)\,\Omega$
	$Z_{sys} = 10 + j50\,\Omega$
Total system current from sending source.	
Eq. (50)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{132{,}791\angle 240°\,V - 92{,}953.7\angle 0°\,V}{10 + j50\,\Omega}$
	$I_{sys} = 3{,}854\angle 137.1°\,A$
The current as measured by the relay on Z_L is only the current flowing through that line as determined by using the current divider equation.	
Eq. (51)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 137.1°\,A \times \frac{(4 + j20)^{10}\,\Omega}{(4 + j20)\,\Omega + (4 + j20)^{10}\,\Omega}$
	$I_L = 3{,}854\angle 137.1°\,A$
The voltage as measured by the relay on Z_L is the voltage drop from the sending source through the sending source impedance.	
Eq. (52)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240°\,V - [(2 + j10\,)\Omega \times 3{,}854\angle 137.1°\,A]$
	$V_S = 98{,}265\angle - 110.6°\,V$

Table 7. Example Calculation (Lens Point 6)	
The impedance seen by the relay on Z_L.	
Eq. (53)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle -110.6°\ V}{3{,}854\angle 137.1°\ A}$
	$Z_{L-Relay} = -9.676 + j23.59\ \Omega$

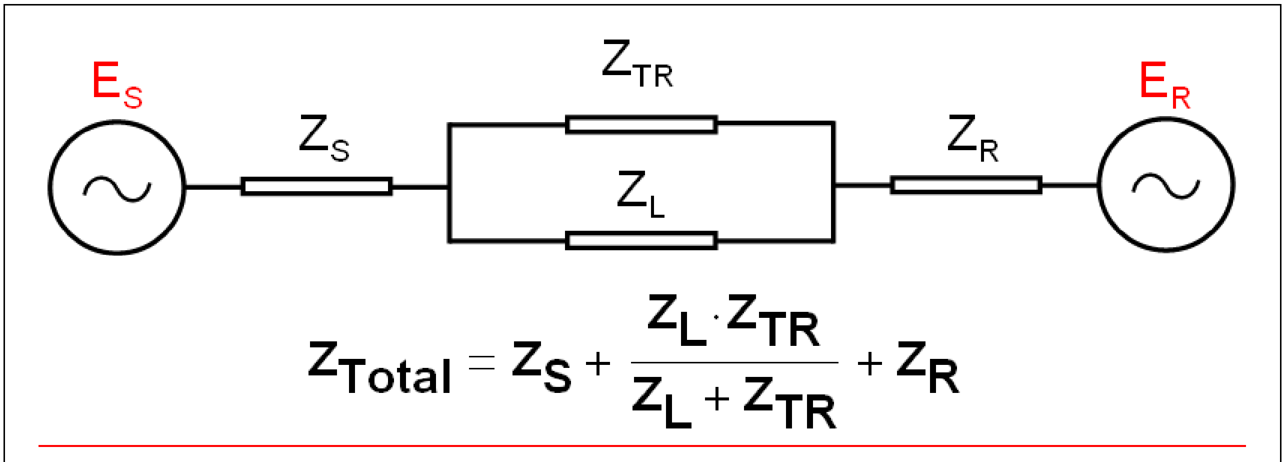


Figure 6. Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, line impedance Z_L, and transfer impedance Z_{TR}.

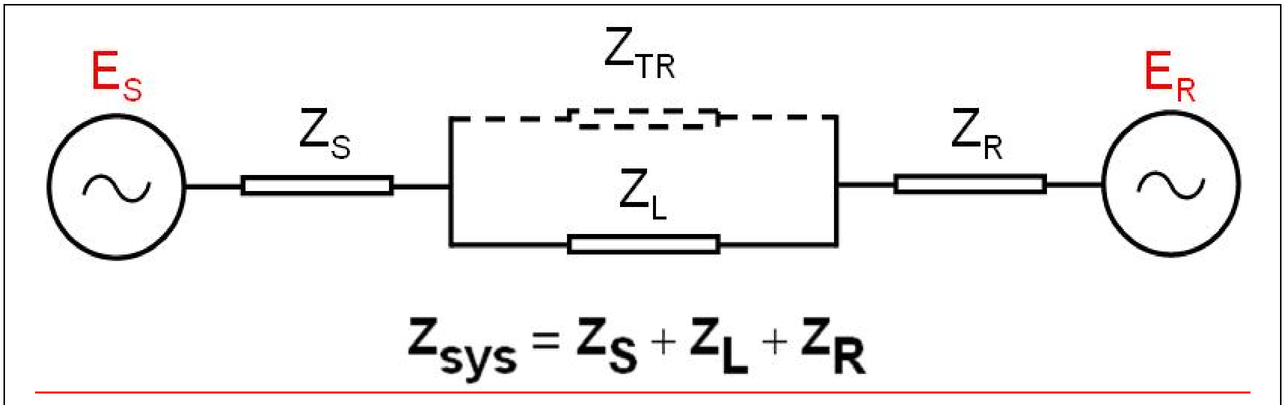


Figure 7. Reduced two bus system with sending-end source impedance Z_S, receiving-end source

impedance Z_R, line impedance Z_L, and transfer impedance Z_{TR} removed.

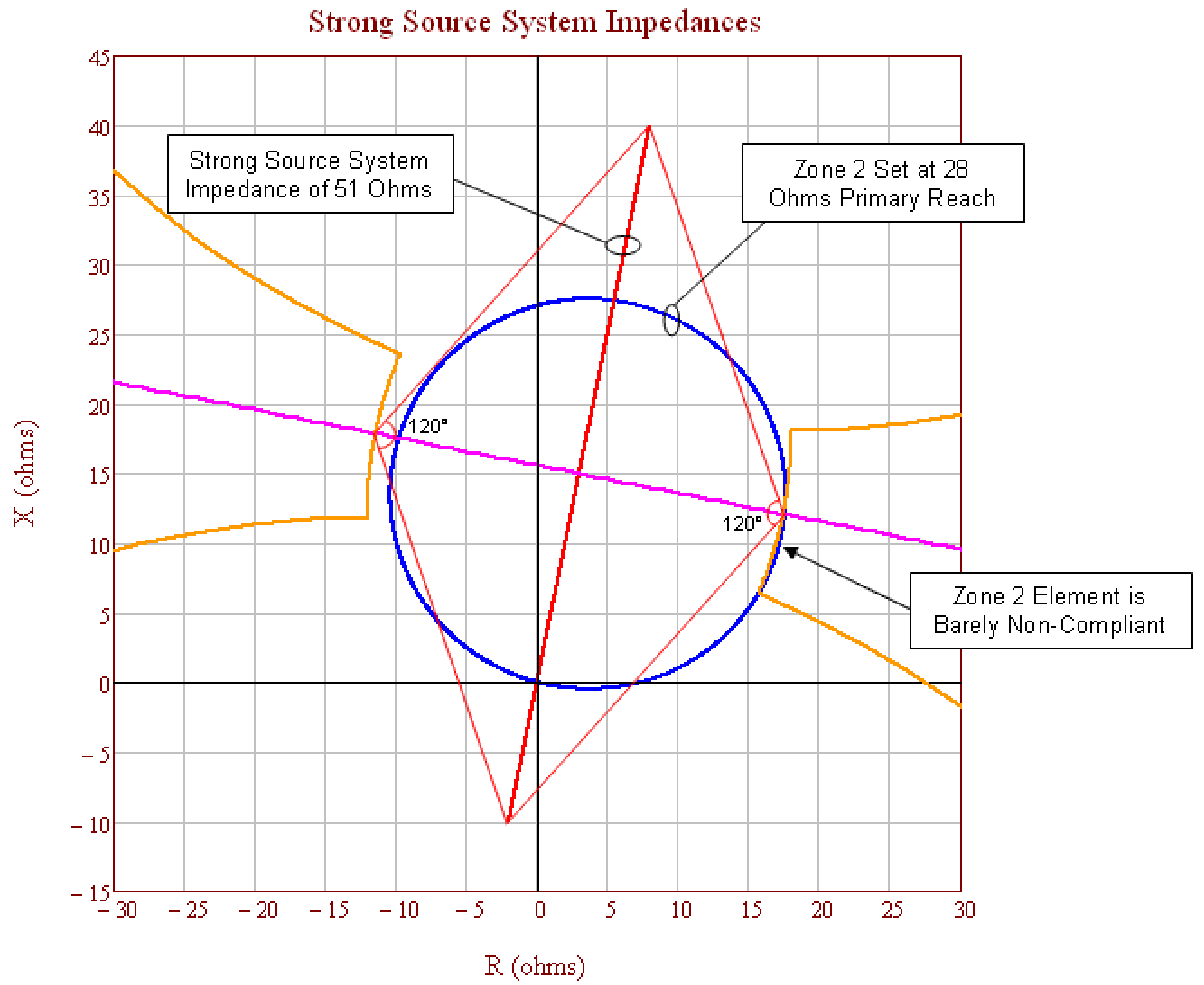


Figure 8. A strong-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This relay element (i.e., the blue circle) does not meet the PRC-026-1 – Attachment B, Criteria A because it is not completely contained within the power swing stability boundary (i.e., the orange lens characteristic).

The figure above represents a heavily loaded system using a maximum generation profile. The zone 2 mho circle (set at 137% of Z_L) extends into the power swing stability boundary (i.e., the orange partial 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. This figure also graphically represents the effect of a system strengthening over time and this is the reason for re-evaluation if the relay has not been evaluated in the last three calendar years. Figure 9 below depicts a relay that meets the, PRC-026-1 – Attachment B, Criteria A. Figure 8 depicts the same relay with the same setting three years later, where each source has strengthened by about 10% and now the same zone 2 element does not meet Criteria A.

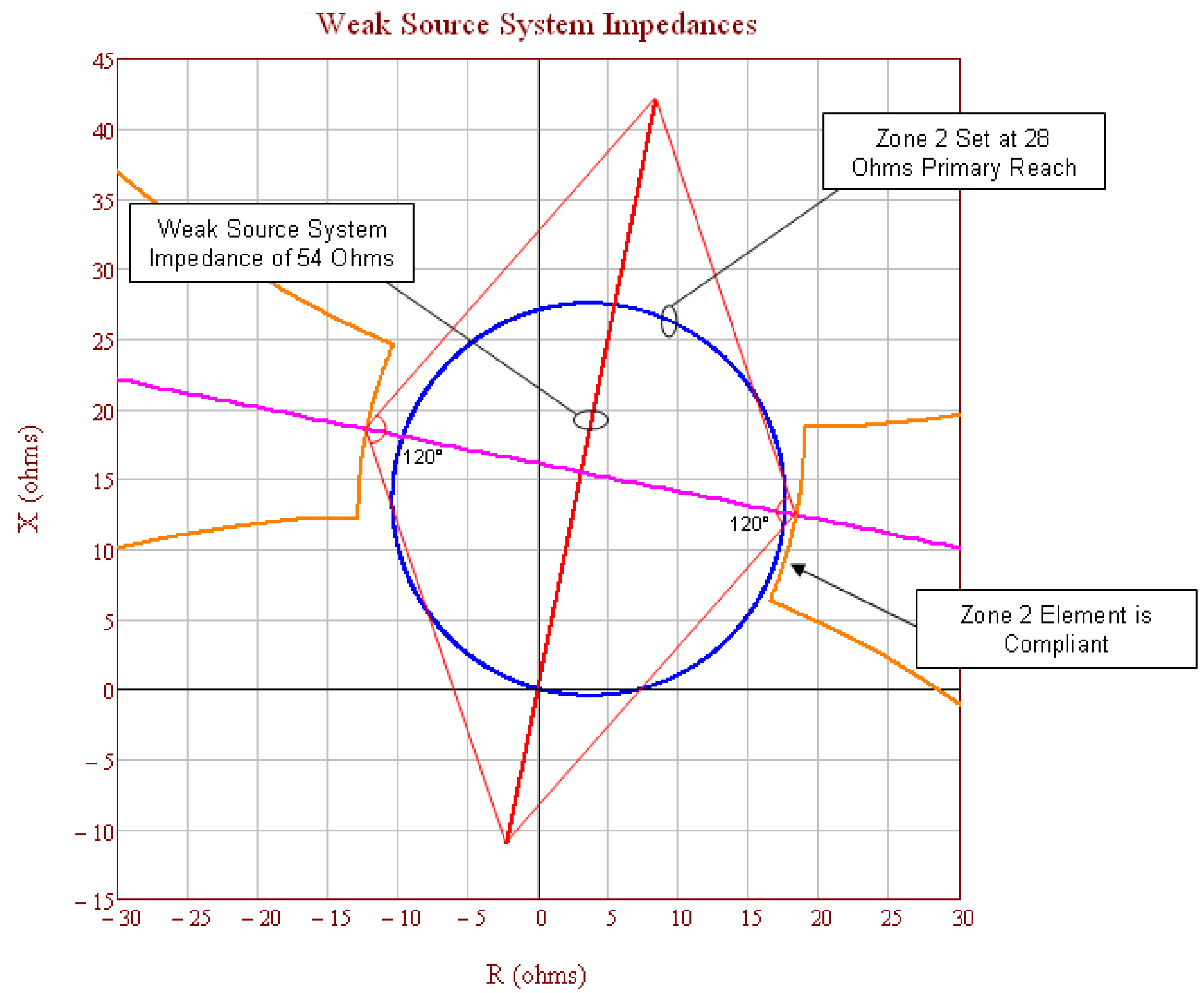


Figure 9. A weak-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This zone 2 element (i.e., the blue circle) meets the PRC-026-1 – Attachment B, Criteria A because it is completely contained within the power swing stability boundary (i.e., the orange lens characteristic).

The figure above represents a lightly loaded system, using a minimum generation profile. The zone 2 mho circle (set at 137% of Z_L) does not extend into the power swing stability boundary (i.e., the orange lens characteristic). Using a weaker source system expands the power swing stability boundary away from the mho circle.

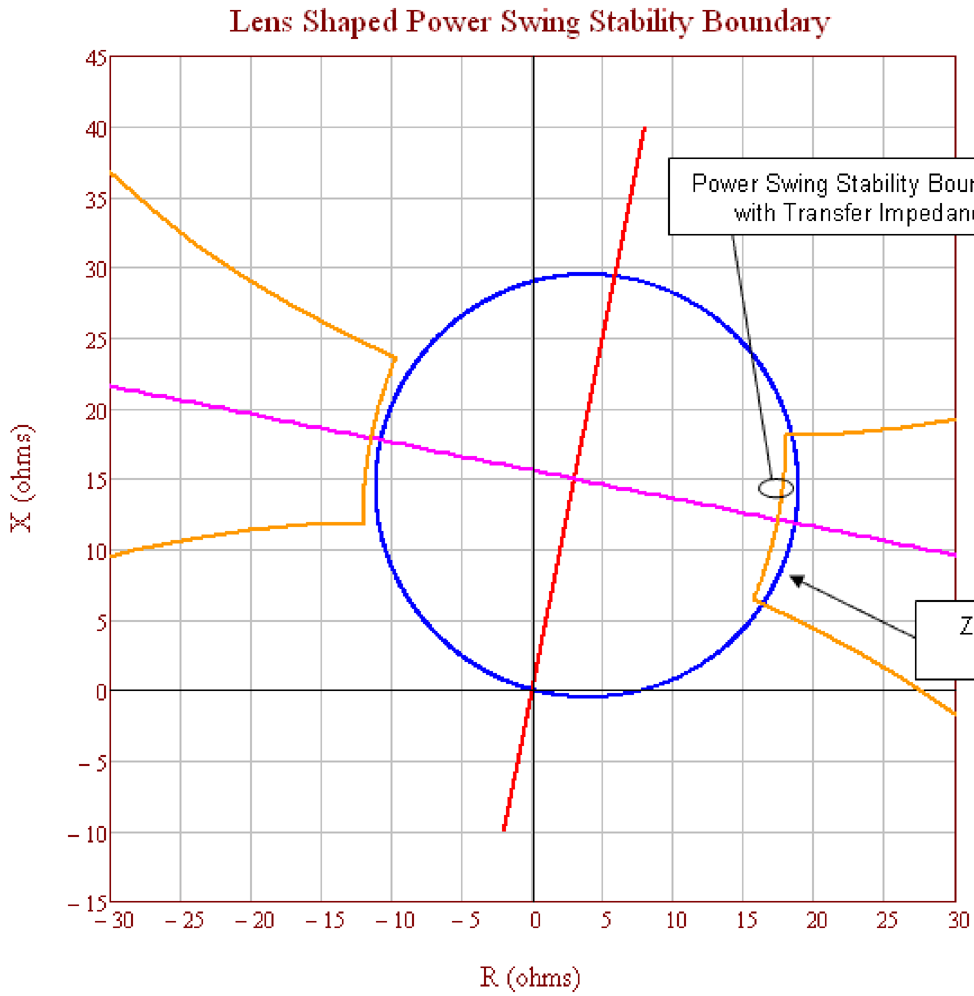


Figure 10. This is an example of a power swing stability boundary (i.e., the orange lens characteristic) with the transfer impedance removed. This relay zone 2 element (i.e., the blue circle) does not meet PRC-026-1 – Attachment B, Criteria A because it is not completely contained within the power swing stability boundary.

Table 8. Example Calculation (Transfer Impedance Removed)	
Calculations for the point at 120 degrees with equal source impedances. The total system current equals the line current. See Figure 10.	
Eq. (54)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$

Table 8. Example Calculation (Transfer Impedance Removed)			
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (55)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between generators.			
Eq. (56)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{((4 + j20)\ \Omega \times (4 + j20)^{10}\ \Omega)}{((4 + j20)\ \Omega + (4 + j20)^{10}\ \Omega)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (57)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending source.			
Eq. (58)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		

Table 8. Example Calculation (Transfer Impedance Removed)	
The current as measured by the relay on Z_L is only the current flowing through that line as determined by using the current divider equation.	
Eq. (59)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 4{,}511\angle 71.3°\ A \times \frac{(4 + j20)^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20)^{10}\ \Omega}$
	$I_L = 4{,}511\angle 71.3°\ A$
The voltage as measured by the relay on Z_L is the voltage drop from the sending source through the sending source impedance.	
Eq. (60)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10\ \Omega) \times 4{,}511\angle 71.3°\ A]$
	$V_S = 95{,}757\angle 106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (61)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1°\ V}{4{,}511\angle 71.3°\ A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

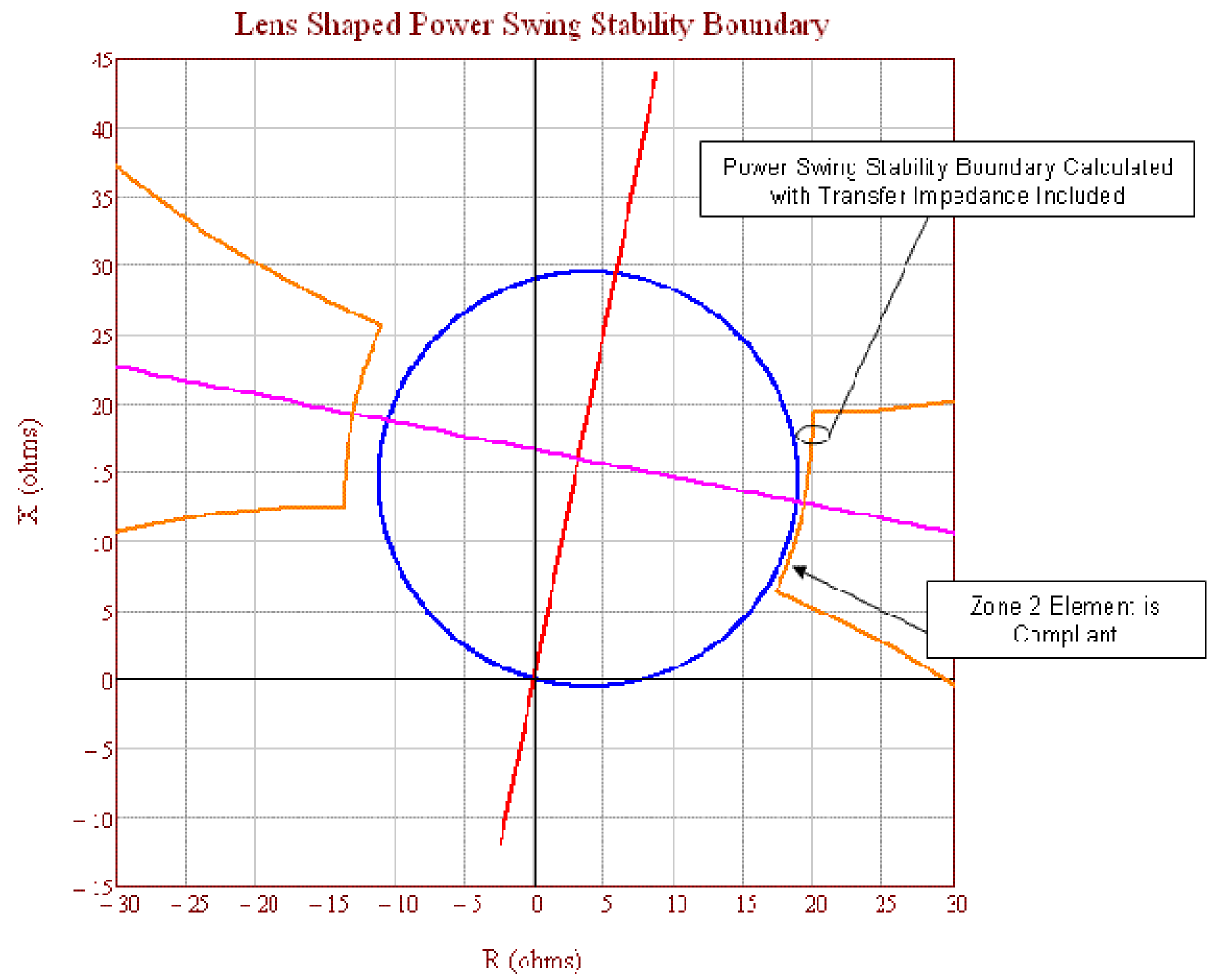


Figure 11. This is an example of a power swing stability boundary (i.e., the orange lens characteristic) with the transfer impedance included. The zone 2 element (i.e., the blue circle) meets the PRC-026-1 – Attachment B, Criteria A because it is completely contained within the power swing stability boundary.

In the figure above, the transfer impedance is 5 times the line impedance. The lens characteristic has expanded out beyond the zone 2 element due to the infeed effect from the parallel current through the transfer impedance, thus allowing the zone 2 element to meet PRC-026-1 – Attachment B, Criteria A.

Table 9. Example Calculation (Transfer Impedance Included)			
Calculations for the point at 120 degrees with equal source impedances. The total system current does not equal the line current. See Figure 11.			
Eq. (62)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (63)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 5$		
	$Z_{TR} = (4 + j20)\ \Omega \times 5$		
	$Z_{TR} = 20 + j100\ \Omega$		
Total impedance between generators.			
Eq. (64)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{(4 + j20)\ \Omega \times (20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$		
	$Z_{total} = 3.333 + j16.667\ \Omega$		
Total system impedance.			
Eq. (65)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (3.333 + j16.667)\ \Omega + (4 + j20)\ \Omega$		

Table 9. Example Calculation (Transfer Impedance Included)	
	$Z_{sys} = 9.333 + j46.667\ \Omega$
Total system current from sending source.	
Eq. (66)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \dfrac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{9.333 + j46.667\ \Omega}$
	$I_{sys} = 4{,}832\angle 71.3°\ A$
The current as measured by the relay on Z_L is only the current flowing through that line as determined by using the current divider equation.	
Eq. (67)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 4{,}832\angle 71.3°\ A \times \dfrac{(20 + j100)\ \Omega}{(9.333 + j46.667)\ \Omega + (20 + j100)\ \Omega}$
	$I_L = 4{,}027.4\angle 71.3°\ A$
The voltage as measured by the relay on Z_L is the voltage drop from the sending source through the sending source impedance.	
Eq. (68)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10\ \Omega) \times 4{,}027\angle 71.3°\ A]$
	$V_S = 93{,}417\angle 104.7°\ V$
The impedance seen by the relay on Z_L.	
Eq. (69)	$Z_{L-Relay} = \dfrac{V_S}{I_L}$
	$Z_{L-Relay} = \dfrac{93{,}417\angle 104.7°\ V}{4{,}027\angle 71.3°\ A}$
	$Z_{L-Relay} = 19.366 + j12.767\ \Omega$

Table 10. Percent Increase of a Lens Due To Parallel Transfer Impedance.	
The following demonstrates the percent size increase of the lens characteristic for Z_{TR} in multiples of Z_L with the transfer impedance included.	
Z_{TR} in multiples of Z_L	Percent increase of lens with equal EMF sources (Infinite source as reference)
Infinite	N/A
1000	0.05%
100	0.46%
10	4.63%
5	9.27%
2	23.26%
1	46.76%
0.5	94.14%
0.25	189.56%

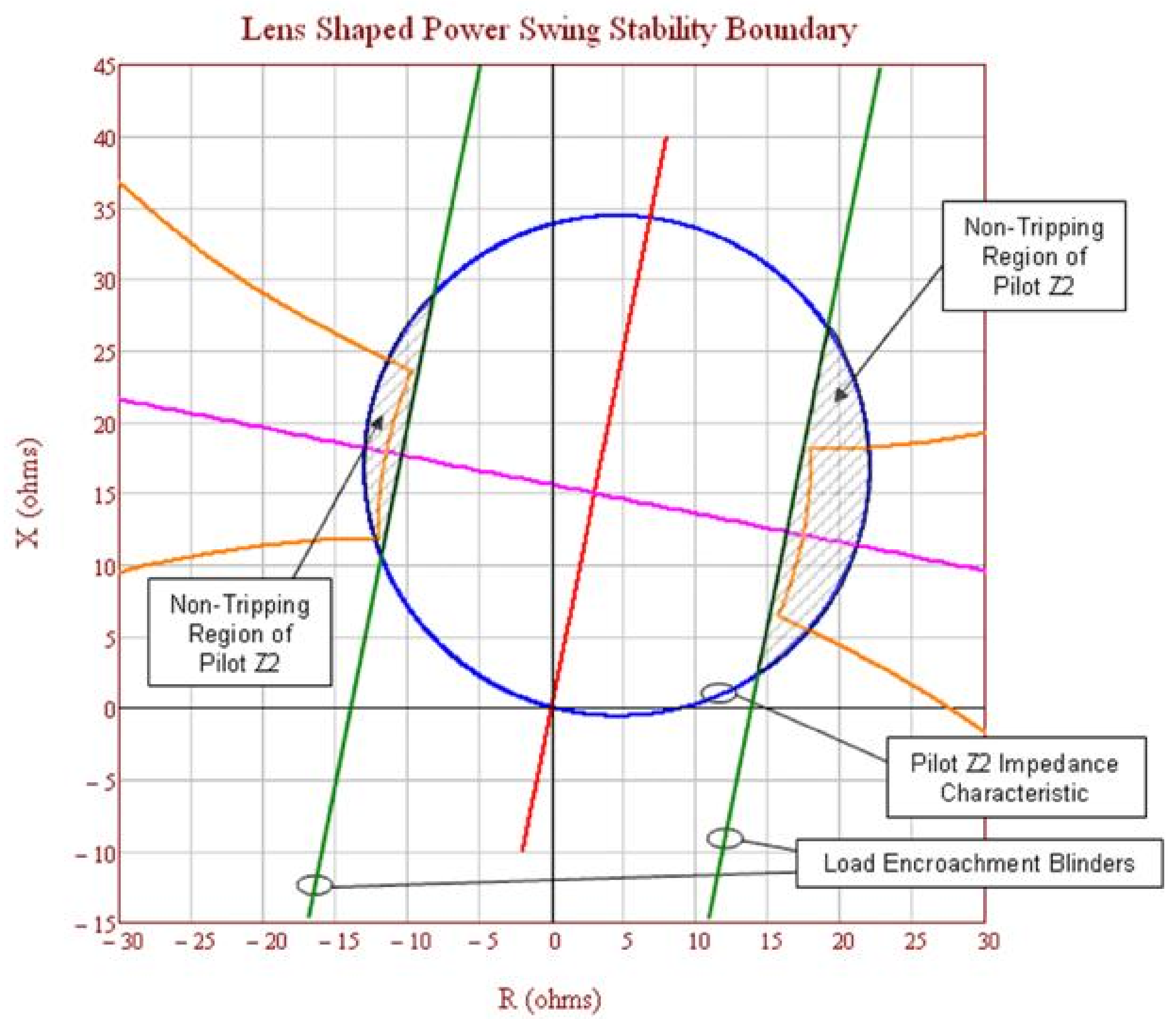


Figure 12. The tripping portion not blocked by load encroachment (i.e., the parallel green lines) of the pilot zone 2 element (i.e., the blue circle) is completely contained within the power swing stability boundary (i.e., the orange lens characteristic). Therefore, the zone 2 element meets the PRC-026-1 – Attachment B, Criteria A.

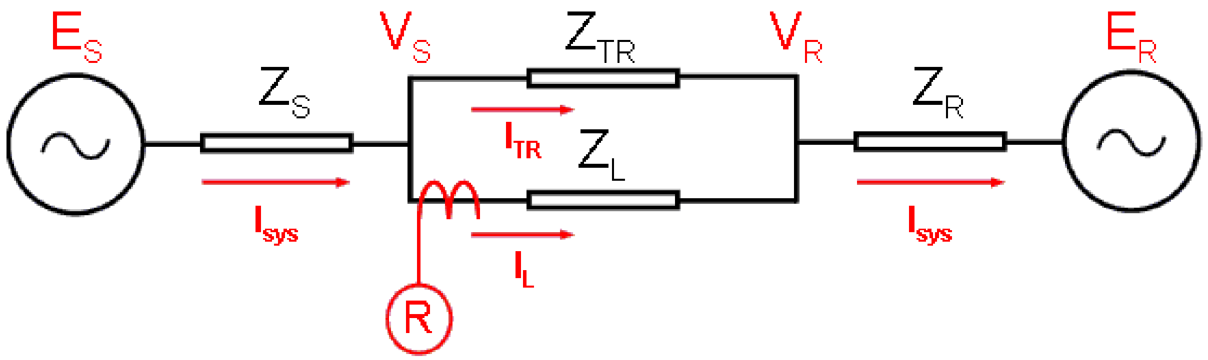


Figure 13: The infeed diagram shows the impedance in front of the relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.

Table 11. Calculations (System Apparent Impedance in the forward direction)				
The following equations are provided for calculating the apparent impedance back to the E_R source voltage as seen by relay R. Infeed equations from V_S to source E_R where $E_R = 0$. See Figure 13.				
Eq. (70)	$I_L = \frac{V_S - V_R}{Z_L}$			
Eq. (71)	$I_{sys} = \frac{V_R - E_R}{Z_R}$			
Eq. (72)	$I_{sys} = I_L + I_{TR}$			
Eq. (73)	$I_{sys} = \frac{V_R}{Z_R}$	Since $E_R = 0$	Rearranged:	$V_R = I_{sys} \times Z_R$
Eq. (74)	$I_L = \frac{V_S - I_{sys} \times Z_R}{Z_L}$			
Eq. (75)	$I_L = \frac{V_S - [(I_L + I_{TR}) \times Z_R]}{Z_L}$			
Eq. (76)	$V_S = (I_L \times Z_L) + (I_L \times Z_R) + (I_{TR} \times Z_R)$			
Eq. (77)	$Z_{Relay} = \frac{V_S}{I_L} = Z_L + Z_R + \frac{I_{TR} \times Z_R}{I_L} = Z_L + Z_R \times \left(1 + \frac{I_{TR}}{I_L}\right)$			

Table 11. Calculations (System Apparent Impedance in the forward direction)	
Eq. (78)	$I_{TR} = I_{sys} \times \dfrac{Z_L}{Z_L + Z_{TR}}$
Eq. (79)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$
Eq. (80)	$\dfrac{I_{TR}}{I_L} = \dfrac{Z_L}{Z_{TR}}$
The infeed equations shows the impedance in front of the relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.	
Eq. (81)	$Z_{Relay} = Z_L + Z_R \times \left(1 + \dfrac{Z_L}{Z_{TR}}\right)$

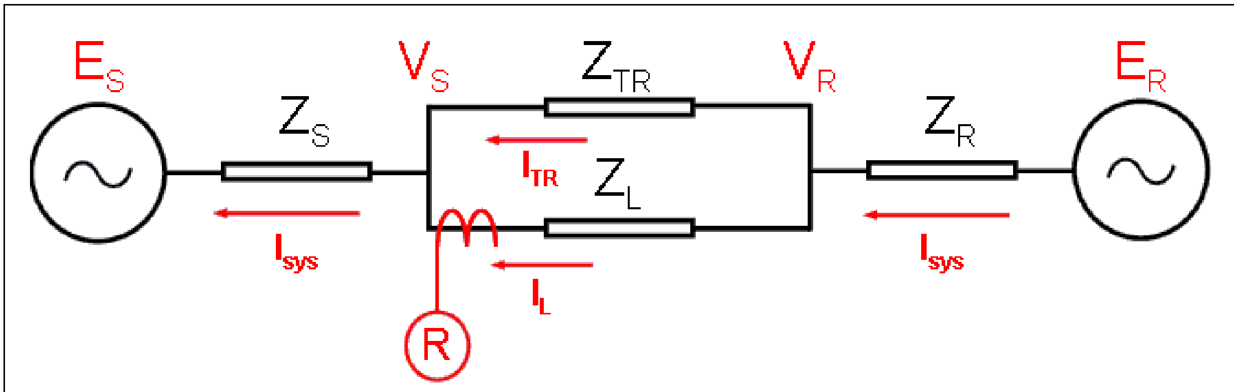


Figure 14: The infeed diagram shows the impedance behind relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.

Table 12. Calculations (System Apparent Impedance in the reverse direction)	
The following equations are provided for calculating the apparent impedance back to the E_S source voltage as seen by relay R. Infeed equations from V_R back to source E_S where $E_S = 0$. See Figure 14.	
Eq. (82)	$I_L = \dfrac{V_R - V_S}{Z_L}$

Table 12. Calculations (System Apparent Impedance in the reverse direction)				
Eq. (83)	$I_{sys} = \frac{V_S - E_S}{Z_S}$			
Eq. (84)	$I_{sys} = I_L + I_{TR}$			
Eq. (85)	$I_{sys} = \frac{V_S}{Z_S}$	Since $E_s = 0$	Rearranged:	$V_S = I_{sys} \times Z_S$
Eq. (86)	$I_L = \frac{V_R - I_{sys} \times Z_S}{Z_L}$			
Eq. (87)	$I_L = \frac{V_R - [(I_L + I_{TR}) \times Z_S]}{Z_L}$			
Eq. (88)	$V_R = (I_L \times Z_L) + (I_L \times Z_S) + (I_{TR} \times Z_{RS})$			
Eq. (89)	$Z_{Relay} = \frac{V_R}{I_L} = Z_L + Z_S + \frac{I_{TR} \times Z_S}{I_L} = Z_L + Z_S \times \left(1 + \frac{I_{TR}}{I_L}\right)$			
Eq. (90)	$I_{TR} = I_{sys} \times \frac{Z_L}{Z_L + Z_{TR}}$			
Eq. (91)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$			
Eq. (92)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$			
The infeed equations shows the impedance behind relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.				
Eq. (93)	$Z_{Relay} = Z_L + Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	As seen by relay R at the receiving-end of the line.		
Eq. (94)	$Z_{Relay} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	Subtract Z_L for relay R impedance as seen at sending-end of the line.		

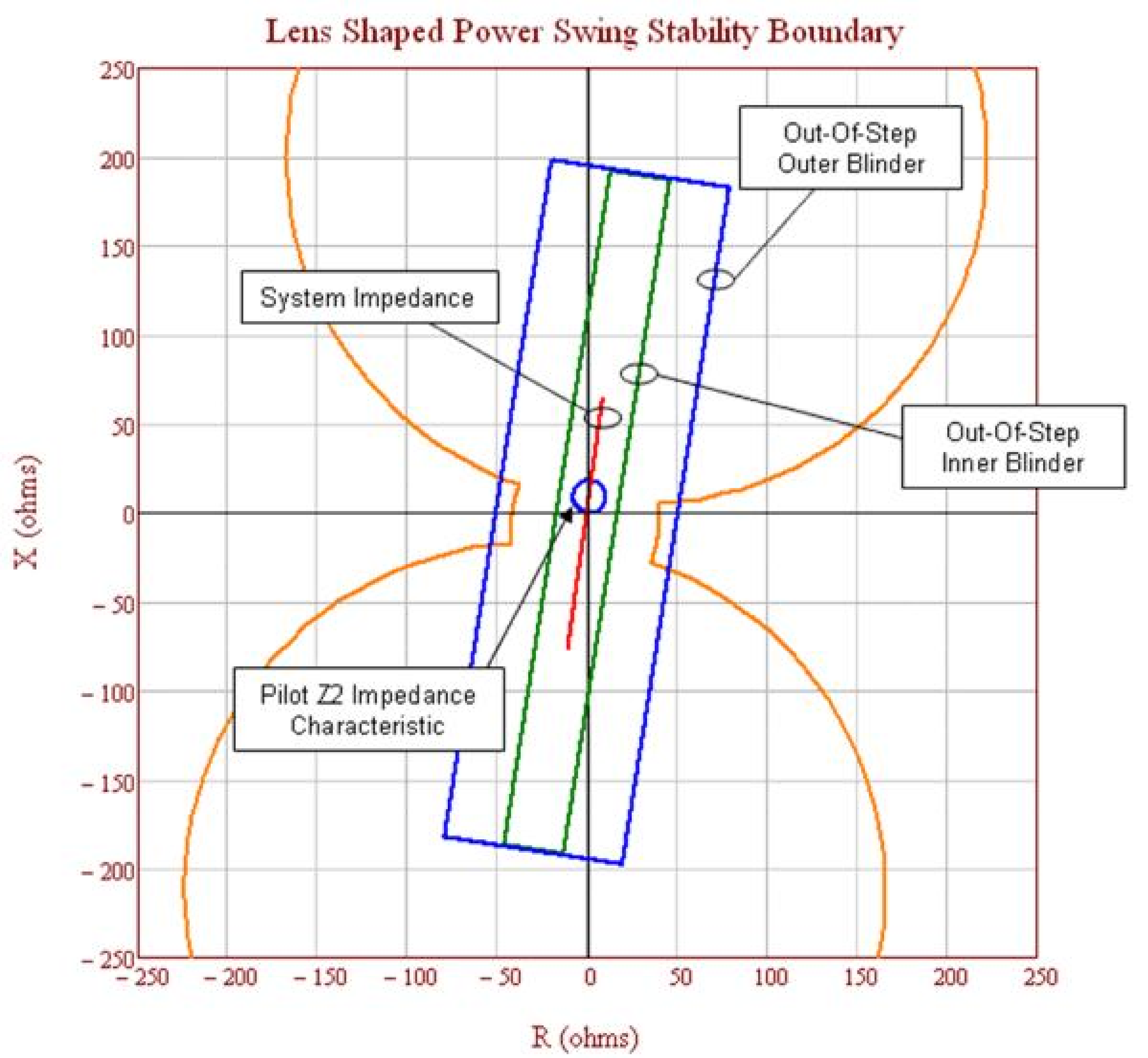


Figure 15. Out-of-step trip (OST) inner blinder (i.e., the parallel green lines) meets the PRC-026-1 – Attachment B, Criteria A because the inner OST blinder initiates tripping either On-The-Way-In or On-The-Way-Out. Since the inner blinder is completely contained within the portion of the power swing stability boundary (i.e., the orange lens characteristic), the zone 2 element (i.e., the blue circle) meets the PRC-026-1 – Attachment B, Criteria A.

Table 13. Example Calculation (Voltage Ratios)			
These calculations are based on the loss of synchronism characteristics for the cases of N < 1 and N > 1 as found in the *Application of Out-of-Step Blocking and Tripping Relays*, GER-3180, p. 12, Figure 3.[12] The GE illustration shows the formulae used to calculate the radius and center of the circles that make up the ends of the portion of the lens.			
Voltage ratio equations, source impedance equation with infeed formulae applied, and circle equations.			
Given:	$E_S = 0.7$	$E_R = 1.0$	
Eq. (95)	$N_a = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{0.7}{1.0} = 0.7$		
Eq. (96)	$N_b = \frac{\lvert E_R \rvert}{\lvert E_S \rvert} = \frac{1.0}{0.7} = 1.43$		
The total system impedance as seen by the relay with infeed formulae applied.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
	$Z_{TR} = (4 + j20)^{10}\ \Omega$		
Eq. (97)	$Z_{sys} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right) + \left[Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right]$		
	$Z_{sys} = 10 + j50\ \Omega$		
The calculated coordinates of the lower circle center.			
Eq. (98)	$Z_{C1} = -\left[Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] - \left[\frac{N_a^2 \times Z_{sys}}{1 - N_a^2}\right]$		
	$Z_{C1} = -\left[(2 + j10)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20)^{10}\ \Omega}\right)\right] - \left[\frac{0.7^2 \times (10 + j50)\ \Omega}{1 - 0.7^2}\right]$		
	$Z_{C1} = -11.608 - j58.039\ \Omega$		

[12] http://store.gedigitalenergy.com/faq/Documents/Alps/GER-3180.pdf

Table 13. Example Calculation (Voltage Ratios)	
The calculated radius of the lower circle.	
Eq. (99)	$r_a = \left[\frac{N_a \times Z_{sys}}{1 - N_a^2}\right]$
	$r_a = \left[\frac{0.7 \times (10 + j50)\ \Omega}{1 - 0.7^2}\right]$
	$r_a = 69.987\ \Omega$
The calculated coordinates of the upper circle center.	
Eq. (100)	$Z_{C2} = Z_L + \left[Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] + \left[\frac{Z_{sys}}{N_b^2 - 1}\right]$
	$Z_{C2} = -\left[(4 + j20)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20)^{10}\ \Omega}\right)\right] + \left[\frac{(10 + j50)\ \Omega}{1.43^2 - 1}\right]$
	$Z_{C2} = 17.608 + j88.039\ \Omega$
The calculated radius of the upper circle.	
Eq. (101)	$r_b = \left[\frac{N_b \times Z_{sys}}{N_b^2 - 1}\right]$
	$r_b = \left[\frac{1.43 \times (10 + j50)\ \Omega}{1.43^2 - 1}\right]$
	$r_b = 69.987\ \Omega$

Application Specific to Criteria B

The PRC-026-1 – Attachment B, Criteria B evaluates overcurrent elements used for tripping. The same criteria as PRC-026-1 – Attachment B, Criteria A is used except for an additional criteria (No. 4) that calculates a current magnitude based upon generator terminal voltages of 1.05 per unit. The formula used to calculate the current is as follows:

Table 14. Example Calculation (Overcurrent)			
This example is for a 230 kV line terminal with a directional instantaneous phase overcurrent element set to 50 amps secondary times a CT ratio of 160:1 that equals 8000 amps on the primary. The following calculation is where V_S equals the base line-to-ground sending-end generator source voltage times 1.05 at an angle of 120 degrees, V_R equals the base line-to-ground receiving-end generator terminal voltage times 1.05 at an angle of 0 degrees, and Z_{sys} equals the sum of the sending-end, line, and receiving-end source impedances in ohms.			
Eq. (102)	$V_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}} \times 1.05$		
	$V_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 1.05$		
	$V_S = 139{,}430\angle 120°\ V$		
Receiving-end generator terminal voltage.			
Eq. (103)	$V_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}} \times 1.05$		
	$V_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 1.05$		
	$V_R = 139{,}430\angle 0°\ V$		
The total impedance of the system (Z_{sys}) equals the sum of the sending-end source impedance (Z_S), the impedance of the line (Z_L), and receiving-end impedance (Z_R) in ohms.			
Given:	$Z_S = 3 + j26\ \Omega$	$Z_L = 1.3 + j8.7\ \Omega$	$Z_R = 0.3 + j7.3\ \Omega$
Eq. (104)	$Z_{sys} = Z_S + Z_L + Z_R$		
	$Z_{sys} = (3 + j26)\ \Omega + (1.3 + j8.7)\ \Omega + (0.3 + j7.3)\ \Omega$		
	$Z_{sys} = 4.6 + j42\ \Omega$		
Total system current from sending source.			
Eq. (105)	$I_{sys} = \dfrac{(V_S - V_R)}{Z_{sys}}$		
	$I_{sys} = \dfrac{(139{,}430\angle 120°\ V - 139{,}430\angle 0°\ V)}{(4.6 + j42)\ \Omega}$		

Table 14. Example Calculation (Overcurrent)	
	$I_{sys} = 5{,}715.82\angle 66.25°\ A$
This example is for a 230 kV line terminal with a directional instantaneous phase overcurrent element set to 50 amps-secondary times a CT ratio of 160:1 that equals 8,000 amps-primary. Here, the phase instantaneous setting of 8,000 amps is greater than the calculated system current of 5,716 amps, therefore it is compliant with PRC-026-1 – Attachment B, Criteria B.	

Application to Generation Elements

As with Transmission Elements, the determination of the apparent impedance seen at ~~the generator terminals~~an Element located at, or near, a generation Facility is complex~~, especially~~ for ~~cases where there are multiple generators connected~~power swings due 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.~~quantities. These variances ~~include~~in quantities are caused by 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~~ as the event progresses through the time domain. Though transient stability ~~program is~~simulations may be used to determine the apparent impedance for ~~best results, especially~~verifying load-responsive relay settings,[13,14] Requirement R4, PRC-026-1 – Attachment B, Criteria A and B provides a simplified method for ~~relays that are used for transmission line backup protection. Distance and out-of-step relays that are subject~~evaluating the load-responsive protective relay's susceptibility to tripping in response to a stable 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~~swing without requiring stability simulations.

~~The~~In general, 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~~could be inside the unit connected zone.[15] In either case, ~~impedance~~load-responsive protective relays connected at the generator terminals or at the high-voltage side of the generator step-up (GSU) transformer may be ~~subject to operation in response to stable~~challenged by power swings~~. Impedance relays used to back-up transmission protection usually have~~ as determined by the Planning Coordinator in Requirement R1 or 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~~

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[13] Donald Reimert, *Protective Relaying for Power Generation Systems*, Boca Raton, FL, CRC Press, 2006.

[14] Prabha Kundar, *Power System Stability and Control*, EPRI, McGraw Hill, Inc., 1994.

[15] Ibid, Kundar.

~~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~~event documented by an actual Disturbance in Requirement R2 and R3.

~~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~~

Load-responsive protective relays such as time over-current, voltage controlled time-overcurrent or voltage-restrained time-overcurrent relays are excluded from this standard since they are set based on equipment permissible overload capability. Their operating time is much greater than 15 cycles for the current levels observed during a power swing.

Instantaneous overcurrent and definite-time overcurrent relays with a time delay of less than 15 cycles are included and are required to be evaluated.

The generator loss-of-field protective function is provided by impedance relay(s) connected at the generator terminals. The settings are applied to protect the generator from a partial or complete loss of excitation under all generator loading conditions and, at the same time, be immune to tripping on stable power swings. It is more likely that the relay would operate during a power swing when the automatic voltage regulator (AVR) is in manual mode rather than when in automatic mode.[16] Figure 16 illustrates in the R-X plot, the loss-of-field relays typically include up to three zones of protection.

[16] John Burdy, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

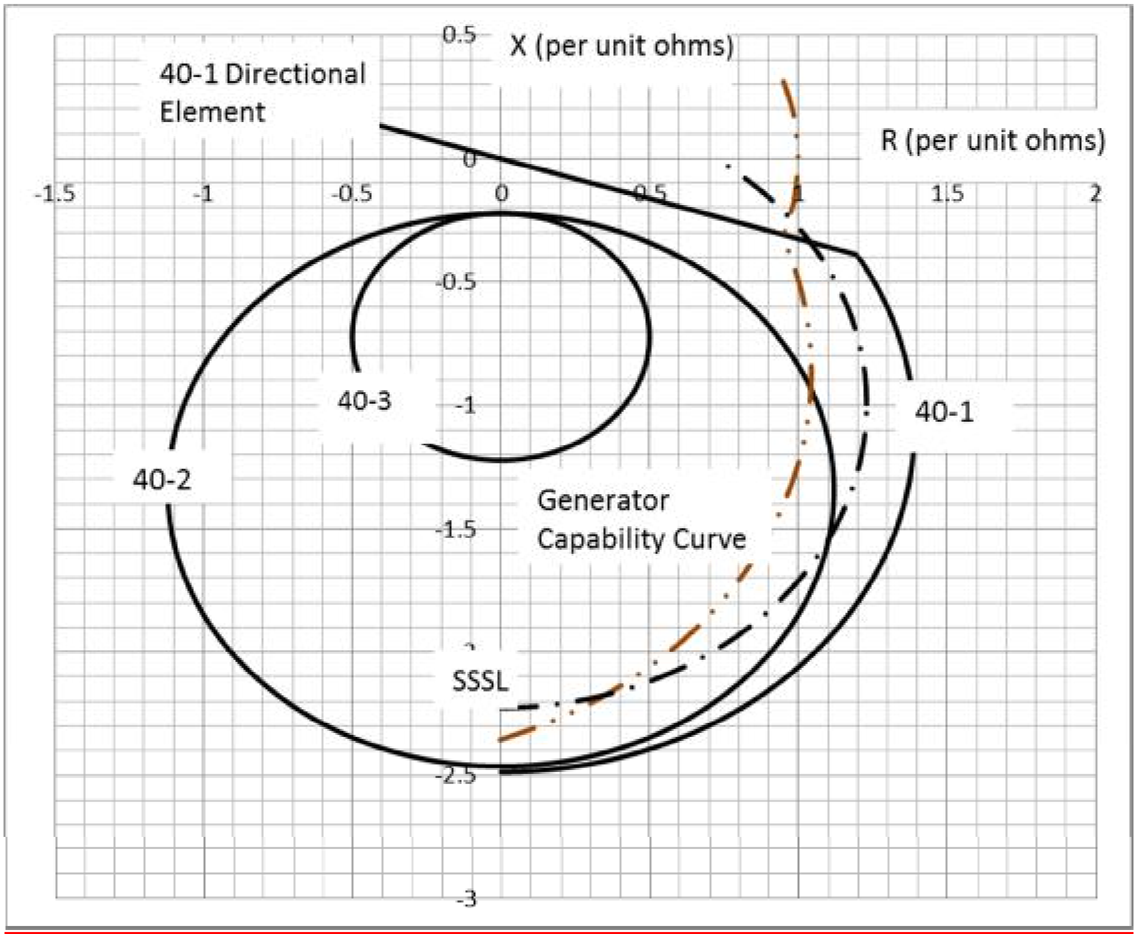

Figure 16. An R-X graph of typical impedance settings for loss-of-field relays.

Loss-of-field characteristic 40-1 has a wider impedance characteristic (positive offset) than characteristic 40-2 or characteristic 40-3 and provides additional generator protection for a partial loss of field or a loss of field under low load (less than 10% of rated). The tripping logic of this protection scheme is established by a directional contact, a voltage setpoint, and a time delay. The voltage and time delay add security to the relay operation for stable power swings. Characteristic 40-3 is less sensitive to power swings than characteristic 40-2 and is set outside the generator capability curve in the leading direction. Regardless of the relay impedance setting, PRC-019 requires that the "in-service limiters operate before Protection Systems to avoid unnecessary trip" and "in-service Protection System devices are set to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits." Time delays for tripping associated with loss-of-field relays[17,18]

[17] Ibid, Burdy.

[18] *Applied Protective Relaying*, Westinghouse Electric Corporation, 1979.

have a range from 15 cycles for characteristic 40-2 to 60 cycles for characteristic 40-1 to minimize tripping during stable power swings. In the standard, 15 cycles establishes a threshold for applicability; however, it is the responsibility of the Generator Owner to establish settings that provide security against stable power swings and, at the same time, dependable protection for the generator.

The simple two-machine system circuit (method also used in Transmission Element section) is used to analyze the effect of a power swing at a generator facility for load-responsive relays pursuant to Requirement R4. In this section, the calculation method is used for calculating the impedance seen by the relay connected at a point in the circuit.[19] The electrical quantities used to determine the apparent impedance plot using this method are generator saturated transient reactance (X'_d), GSU transformer impedance (X_{GSU}), transmission line impedance (Z_L), and the system equivalent (Z_e) at the point of interconnection. All impedance values are known to the Generator Owner except for the system equivalent. The system equivalent is available from the Transmission Owner. The sending- and receiving-end source voltages are varied from 0.7 to 1.0 per unit to form a portion of a lens characteristic instead of varying the voltages from 0 to 1.0 per unit which would form a full lens characteristic. The voltage range of 0.7 – 1.0 results in a ratio range from 0.7 to 1.43.This ratio range is used in determining the portion of the lens. A system separation angle of 120 degrees is also used in each load-responsive protective relay evaluation.

Below is an example calculation of the apparent impedance locus method based on Figures 18 and 19.[20] In this example, the generator is connected to the 345 kV transmission system through the GSU transformer and has the ratings listed. The load-responsive protective relay responsibilities below are divided between the Generator Owner and Transmission Owner.

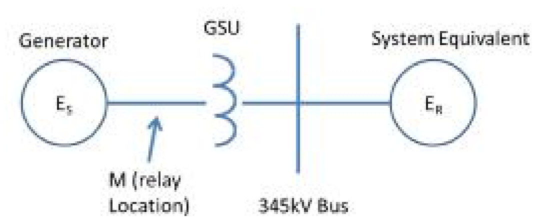	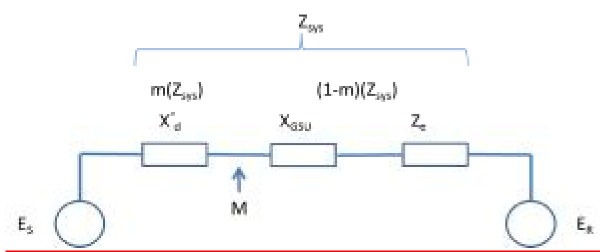
Figure 17. Simple one-line diagram of the system to be evaluated.	**Figure 18.** Simple system equivalent impedance diagram to be evaluated.[21]

[19] Edward Wilson Kimbark, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

[20] Ibid, Kimbark.

[21] Ibid, Kimbark.

Table15. Example Data (Generator)	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA)	940 MVA
Sub-transient reactance (940MVA base – per unit)	$X''d = 0.3845$
Generator rated voltage (Line-to-Line)	$20\ kV$
Generator step-up (GSU) transformer rating	$880\ MVA$
GSU transformer reactance (880 MVA base)	$X_{GSU} = 16.05\%$
System Equivalent (100 MVA base)	$Z_e = 0.00723\angle 86°$ ohms
Generator Owner Load-Responsive Protective Relays	
40-1	Positive Offset Impedance
	Offset = 0.294 per unit ohms
	Diameter = 0.294 per unit ohms
40-2	Negative Offset Impedance
	Offset = 0.22 per unit ohms
	Diameter = 2.24 per unit ohms
40-3	Negative Offset Impedance
	Offset = 0.22 per unit ohms
	Diameter = 1.00 per unit ohms
21-1	Diameter = 0.643 per unit ohms
	MTA = 85°
50	I (pickup) = 5.0 per unit
Transmission Owned Load-Responsive Protective Relays	
21-2	Diameter = 0.55 per unit ohms
	MTA = 85°

Calculations shown for a 120 degree angle and $E_S/E_R = 1$. The equation for calculating Z_R is:[22]

Eq. (106) $$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$$

Where m is the relay location as a function of the total impedance (real number less than 1)

E_S and E_R is the sending- and receiving-end voltages

Z_{sys} is the total system impedance

Z_R is the complex impedance at the relay location and plotted on an R-X diagram

All of the above are constants (940 MVA base) while the angle δ is varied. Table 16 below contains calculations for a generator using the data listed in Table 15.

Table16. Example Calculations (Generator)			
Given:	$X_d^{"} = j0.3845\ \Omega$	$X_{GSU} = j0.171\ \Omega$	$Z_e = 0.06796\ \Omega$
Eq. (107)	$Z_{sys} = X_d^{"} + X_{GSU} + Z_e$		
	$Z_{sys} = j0.3845\ \Omega + j0.171\ \Omega + 0.06796\ \Omega$		
	$Z_{sys} = 0.6239\ \angle 90°\ \Omega$		
Eq. (108)	$m = \frac{X_d^{"}}{Z_{sys}} = \frac{0.3845}{0.6239} = 0.61633$		
Eq. (109)	$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$		
	$Z_R = \left(\frac{(1-0.61633)\times(1\angle 120°) + (0.61633)(1\angle 0°)}{1\angle 120° - 1\angle 0°}\right) \times (0.6234\angle 90°)\ \Omega$		
	$Z_R = \left(\frac{0.4244 + j0.3323}{-1.5 + j\ 0.866}\right) \times (0.6234\angle 90°)\ \Omega$		
	$Z_R = (0.3112\angle -111.94°) \times (0.6234\angle 90°)\ \Omega$		
	$Z_R = 0.194\angle -21.94°\ \Omega$		

[22] Ibid, Kimbark.

Table16. Example Calculations (Generator)	
	$Z_R = -0.18 - j0.073\ \Omega$

Table 17 lists the swing impedance values at other angles and at E_S/E_R = 1, 1.43, and 0.7. The impedance values are plotted on an R-X graph with the center being at the generator terminals for use in evaluating impedance relay settings.

Table 17: Sample calculations for a swing impedance chart for varying voltages at the sending- and receiving-end.

Angle (δ) (Degrees)	E_S/E_R=1 Z_R Magnitude (PU Ohms)	E_S/E_R=1 Z_R Angle (Degrees)	E_S/E_R=1.43 Z_R Magnitude (PU Ohms)	E_S/E_R=1.43 Z_R Angle (Degrees)	E_S/E_R=0.7 Z_R Magnitude (PU Ohms)	E_S/E_R=0.7 Z_R Angle (Degrees)
90	0.320	-13.1	0.296	6.3	0.344	-31.5
120	0.194	-21.9	0.173	-0.4	0.227	-40.1
150	0.111	-41.0	0.082	-10.3	0.154	-58.4
210	0.111	-25.9	0.082	190.3	0.154	238.4
240	0.111	221.0	0.173	180.4	0.225	220.1
270	0.320	193.1	0.296	173.7	0.344	211.5

Requirement R4 Generator Examples

Distance Relay Application

Based on PRC-026-1 – Attachment B, Criteria A, the distance relay (21-1) (owned by the generation entity) characteristic is in the region where a stable power swing would not occur as shown in Figure 19. There is no further obligation to the owner in this standard for this load-responsive protective relay.

The distance relay (21-2) (owned by the transmission entity) is connected at the high-voltage side of the GSU transformer and its impedance characteristic is in the region where a stable power swing could occur causing the relay to operate. In this example, if the intentional time delay of this relay is less than 15 cycles, the Transmission Owner is required to create a CAP (Requirement R5) to meet PRC-026 – Attachment B, Criteria B. Some of the options include, but are not limited to, changing the relay setting (i.e. impedance reach, angle, time delay), modify the scheme (i.e. add power swing blocking), or replace the Protection System. Note that the relay may be excluded from this standard if it has an intentional time delay equal to or greater than 15 cycles.

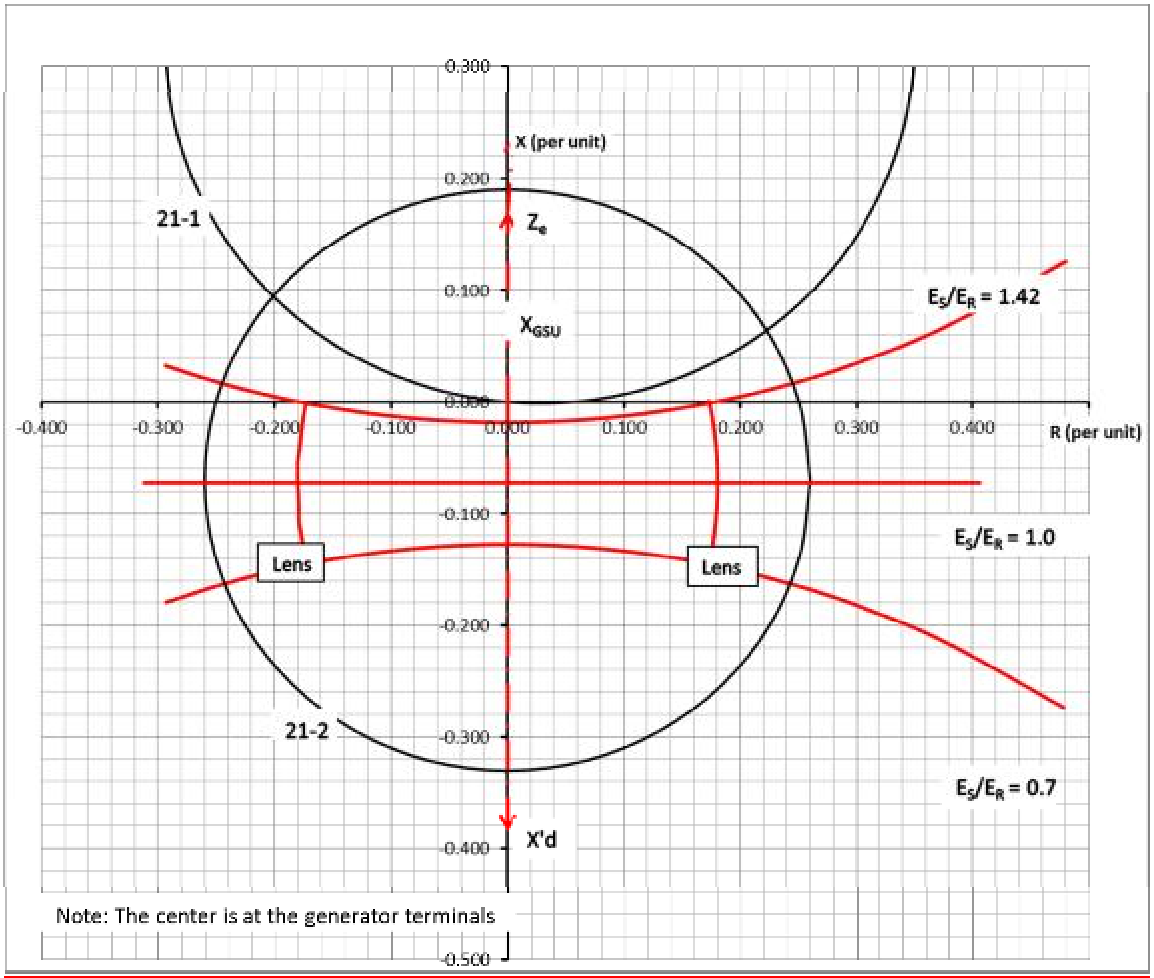

Figure 19. Swing impedance graph for impedance relays at a generating facility.

Loss-of-Field Relay Application

In Figure 20, the R-X diagram shows the loss-of-field relay (40-1 and 40-2) characteristics are in the region where a stable power swing can cause a relay operation. Protective relay 40-1 would be excluded if it has an intentional time delay equal to or greater than 15 cycles. Similarly, 40-2 would be excluded if its intentional time delay is equal to or greater than 15 cycles. For example, if 40-1 has a time delay of 1 second and 40-2 has a time delay of 0.25 seconds, they are excluded and there is no further obligation to the owner in this standard for these relays. The loss-of-field relay characteristic 40-3 is outside the region where a stable power swing can cause a relay operation. In this case, the owner may select high speed tripping on operation of the 40-3 impedance element.

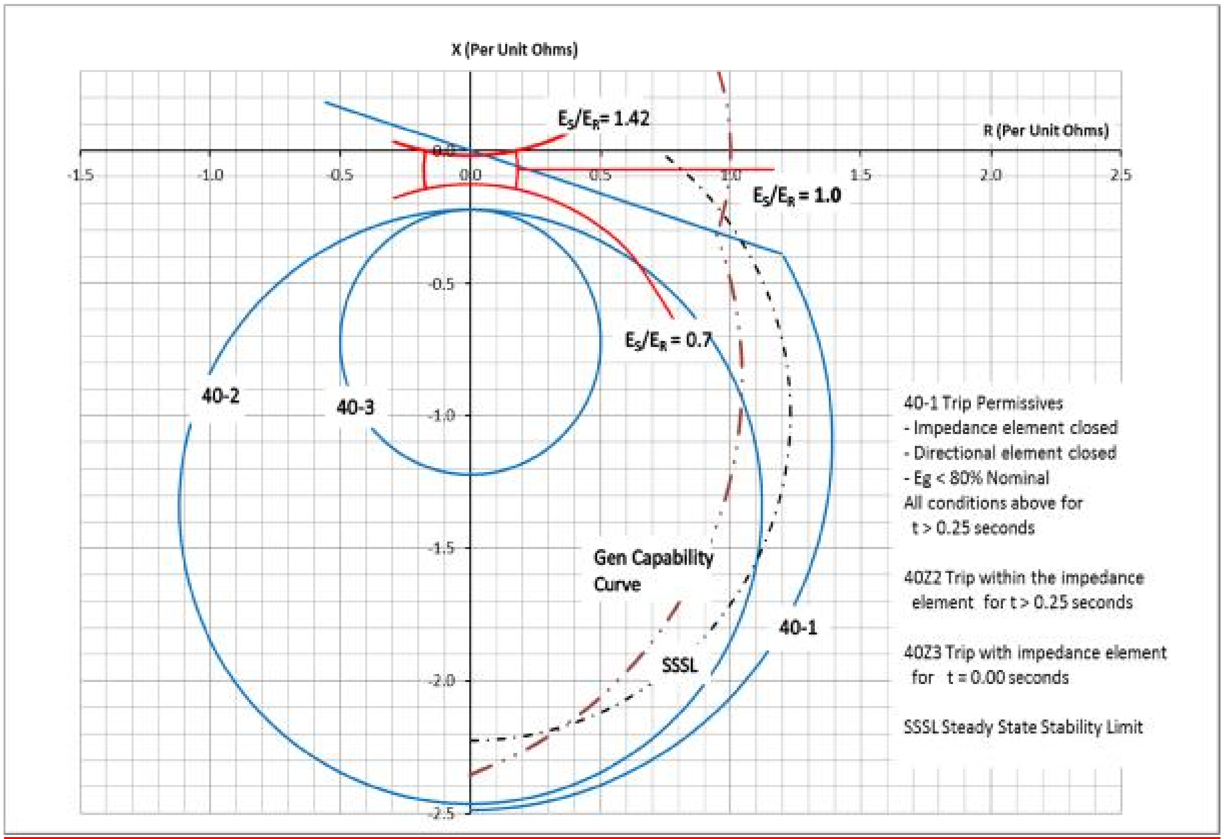

Figure 20: Stable power swing R-X graph for loss-of-field relays.

Instantaneous Overcurrent Relay

In similar fashion to the transmission overcurrent example calculation in Table 14, the instantaneous overcurrent relay minimum setting is established by PRC-026-1 – Attachment B, Criteria B. The solution is found by:

Eq. (110) $$I_{sys} = \frac{E_S - E_R}{Z_{\mathrm{sys}}}$$

As stated in the relay settings in Table 15, the relay is installed on the high-voltage side of the GSU transformer with a pickup of 5.0 per unit current. The maximum allowable current is calculated below.

$$I_{sys} = \frac{(1.05\angle 120° - 1.05\angle 0°)}{0.6234\angle 90°}\ A$$

$$I_{sys} = \frac{1.775\angle 150°\ V}{0.6234\angle 90°\ \Omega} A$$

$$I_{sys} = 2.84\ \angle 60°\ A$$

The phase instantaneous setting of 5.0 per unit amps is greater than the calculated system current of 2.84 per unit amps; therefore it is compliant with PRC-026-1 – Attachment B, Criteria B.

Requirement R5

This requirement ensures that all actions associated with any Corrective Action Plan (CAP) developed in the previous requirement ~~is implemented through completion. Having such a~~are completed. The requirement ~~allows~~also permits the ~~entity's work toward making protection scheme adjustments measurable given~~entity to modify a CAP as necessary, while in the ~~variability~~process of fulfilling the ~~timetables~~purpose of ~~each CAP~~the standard.

To achieve the stated purpose of this standard, which is to ensure that relays ~~do~~are expected to not ~~operate~~trip 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~~ Fault conditions, the applicable ~~Elements on~~ entity is required to develop and complete a CAP that reduces the risk of relays tripping during a stable power swing that may occur on any applicable Element of the BES. Protection System owners are required~~ in~~, during the implementation of a CAP, to update it when ~~actions~~any action or timetable ~~change,~~changes until the CAP is 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~~that could be exposed to a stable power swing ~~where~~and 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~~R5a:** Actions: Settings were issued on 6/02/~~2014~~2015 to reduce the zone ~~3~~2 reach of the ~~KD-10 relay~~impedance relay used in the permissive overreaching transfer trip (POTT) scheme 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~~2015. CAP completed on 06/25/~~2014~~2015.

> **Example ~~R4b~~R5b:** Actions: Settings were issued on 6/02/~~2014~~2015 to enable out-of-step blocking on the ~~SEL-321~~existing microprocessor-based relay to prevent tripping in response to stable power swings. The setting changes were applied to the relay on 6/25/~~2014~~2015. CAP completed on 06/25/~~2014~~2015.

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~~electromechanical power swing blocking relay.

> **Example ~~R4c~~R5c:** Actions: A project for the addition of an ~~out-of-step~~electromechanical power swing blocking relay ~~(KS)~~ to supervise the zone ~~3 (KD-10)~~2 impedance relay was initiated on 6/5/~~2014~~2015 to prevent tripping in response to stable power swings. The relay installation was completed on 9/25/~~2014~~2015. CAP completed on 9/25/~~2014~~2015.

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~~R5d:** Actions: A project for the replacement of the ~~KD-10~~impedance relays at both terminals of line X with ~~GE L90~~line current differential relays was initiated on 6/5/~~2014~~2015 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~~2015 to 3/15/~~2015~~2016. Following the timetable change, the ~~KD-10~~impedance relay replacement was completed on 3/18/~~2015~~2016. CAP completed on 3/18/~~2015~~2016.

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

Requirement R6

To achieve the stated purpose of this standard, which is to ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions, the applicable entity is required to fully implement any CAP developed pursuant to Requirement R5 that modifies the Protection System to meet PRC-026-1 – Attachment B, Criteria A and B. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until all actions are complete. Accomplishing this objective is intended to reduce the occurrence of Protection System tripping during a stable power swing, thereby improving reliability and minimizing risk to the BES.