NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Considerations for Power Plant and Transmission System Protection Coordination

Technical Reference Document – Revision 2

System Protection and Control Subcommittee

July 2015

RELIABILITY | ACCOUNTABILITY




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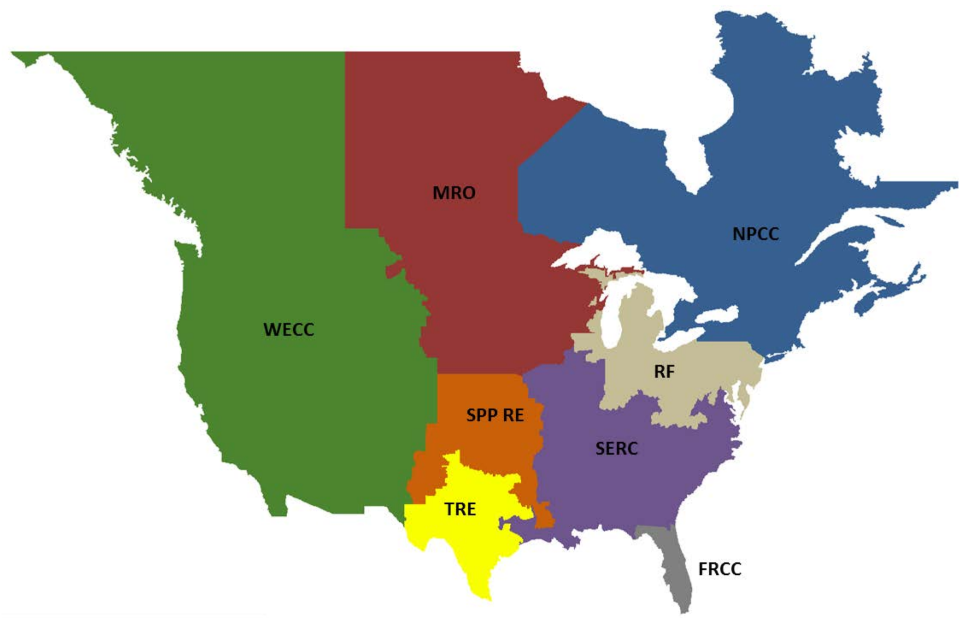
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



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

Disclaimer

The information contained in this technical reference document provides technical guidance for coordinating protection systems and does not impose mandatory requirements subject to compliance. Entities should use this information in conjunction with equipment limitations, manufacturer's recommendations, other industry resources (e.g., IEEE standards), and applicable NERC Reliability Standards. References to and citations from other documents are accurate as of the date of approval of this document. Entities should refer to the latest versions of referenced documents, which may have been revised since approval of this document.

Introduction

The record of generator trips (290 units, about 52,745 MW) during the North American disturbance on August 14, 2003, included 13 types of generation-related protection functions that operated to initiate generator tripping. The NERC Blackout Recommendation Review Task Force (BRRTF) noted, in particular, that overexcitation, undervoltage, loss of excitation, inadvertent energization, overcurrent, and voltage-restrained overcurrent protective functions are sensitive to abnormal voltage and frequency that may be experienced by a cohesive generator group during large power flows. The BRRTF Recommendation TR-22 stated:

> ***"Goal: To reduce the number of unnecessary trips of generators during system disturbances"***

> "NERC should evaluate these protection schemes and their settings for appropriateness including coordination of protection and controls when operating within a coherent generation area (but weakly connected to an interconnection) or within an electrical island. Generators directly connected to the transmission system using a 51V should consider the use of an impedance relay instead."

This report addresses BRRTF recommendation TR-22 by providing guidance for coordinating power plant protection with transmission protection, control systems, and system conditions to minimize unnecessary trips of generation during system disturbances. To provide complete coverage, the report goes beyond the six protective functions referenced in recommendation TR-22 and addresses all protection functions that operated on August 14, 2003. Although information is unavailable that directly addresses which of those generator trips were appropriate for the prevailing bulk power system (BPS) conditions, some of the operations that occurred in the earlier stages contributed to the overall event.

> ***"A reliable electric system requires proper protection and control coordination between power plants and the transmission system."***

The list of protection functions that tripped were: mho-distance (21), voltage-controlled and voltage-restrained overcurrent (51V), volts per hertz (24), undervoltage (27), overvoltage (59), reverse power (32), loss of field (40), negative sequence (46), breaker failure (50BF), inadvertent energizing (50/27), out of step (78), over/underfrequency (81), transformer differential (87T), and a significant number of unknown trips. The number of each type of protective function that tripped generator units during the disturbance is shown in Table 1. This technical reference document concentrates on BPS reliability and resulting performance implications of protection system coordination with power plant protection functions.

Table 1: 2003 Blackout Generation Protection Trips

Function Type	21	24	27	32	40	46	50/27	50 BF	51V	59	78	81	87T	Unknown	Total
Number of Units	8	1	35	8	13	5	7	1	20	26	7	59	4	96	290

For each protective function listed in Table 1, the number of generators on which that protective function operated on August 14, 2003 is presented. There is limited information available that directly addresses which of those protective function operations were appropriate for the prevailing BPS conditions, and which were undesired operations. There is also limited information available as to which protective operations directly tripped generating units and which operated after a turbine trip. However, some undesired generator trips by these protective functions did contribute to expanding the extent of the blackout. This document addresses the coordination between each one of the generator protection functions depicted in Figure 1 and the transmission system protection.

The following protection functions are also discussed in this report to provide guidance on complete coordination to the owners of the transmission system and the generating stations: plant auxiliary undervoltage protection (27), transformer overcurrent (51T), transformer ground overcurrent (51TG), generator neutral overvoltage (59GN), generator differential (87G), and overall unit differential (87U).

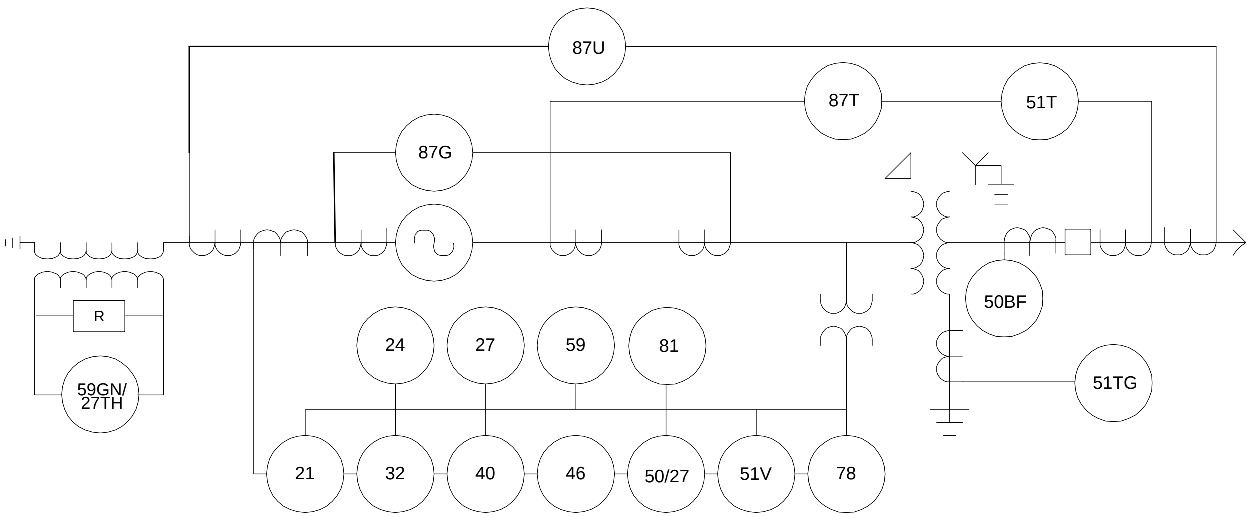


Figure 1: Relay Configuration

The generator trip types that were listed as unknown for the 2003 blackout event are being addressed through the ongoing analysis of subsequent system disturbances for root causes via the NERC Events Analysis program. Other types of generation tripping that have since been identified include lean blowout trips of combustion turbines, power load unbalance actuations during system disturbances, response of nuclear and other types of generator and auxiliary system undervoltage protection to system disturbances, and other unit control actuations.

Goal of this Document

The goal of this reference document is to explore generating plant protection schemes and their settings, and to provide guidance for coordination with transmission protection, control systems, and system conditions to minimize unnecessary trips of generation during system disturbances. The document highlights the need for communication among the Generator Owner, Transmission Owner, and Planning Coordinator.[1] This communication may be especially important when the generator ownership, transmission ownership, and transmission planning functions are not fulfilled by a single, vertically integrated utility.

Scope

This technical reference document is applicable to most generators but concentrates on those connected at 100 kV and above. Where applicable, individual sections of the report provide information when the guidance for a given protective function is based on a certain type of generator or generator connection. This document includes information exchange requirements between Generator Owners and Transmission Owners to facilitate coordination between their protection schemes. This document provides a technical basis to evaluate the

[1] The SPCS recognizes that in some cases the planning studies may involve the Transmission Planner in place of, or in addition to, the Planning Coordinator. Also, unique cases may involve a Distribution Provider that owns a transmission protection system. Some entities perform multiple roles in the NERC Functional Model, so in some cases the Transmission Planner may be the same entity as the Transmission Owner. In this document, use of the term Planning Coordinator is intended to cover all of these cases.

coordination between generator protection and transmission protection systems. The protection coordination discussed in this document applies only to situations where the specific protection functions are present and applied. There are generator protection schemes that do not include some of these functions based on the application or need. This document is not an endorsement of using these functions; good industry guidance such as IEEE Standard (Std.) C37.102, "IEEE Guide to AC Generator Protection," and recommendations from the generator and other equipment manufacturers should take precedence as to which protection functions are applied.

Distributed Generation (DG) facilities connected to distribution systems are outside the scope of this report. Such DG protection requirements and guidance are covered by IEEE Std. 1547–2003, "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems."

Coordination Definition

For purposes of this document and as guidance to the entities, coordination is defined as the following:

> ***Coordination of generation and transmission protection systems (for events external to the plant), means that power plant protection and related control elements must be set and configured to prevent unnecessarily tripping the generator prior to any transmission protection and related control systems acting first, unless the generator is in jeopardy by exceeding its design limits due to operating conditions, generator system faults, or other adverse potentially damaging conditions.***

Multifunction Protective Relays

> ***The application of a protective function to trip a unit should be based on a specific need to protect the turbine generator. If that protection function is not needed, DON'T USE IT!***

Multifunction generator protection systems contain a wide variety of protection functions. There is a strong tendency for users to want to enable and set all these functions. In the past, each separate generator protective function required a separate relay; therefore, the tendency today is to utilize numerous and unnecessary protective functions in many generation applications. It is not appropriate that some of the available protection functions be used in every given application. The decision to enable one of these protective functions should be based on a specific need to protect the turbine generator or a need to provide backup protection functions for the interconnecting power system. If there is no specific protection need for applying a setting, that protection function should not be enabled. On the subject of system backup, an example of protection functions that should not be enabled at the same time are the 21 and 51V. These two protection functions are designed to provide the same protective function for very different applications and purposes and, therefore, should NOT be enabled together. This is explained in the sections covering those protection functions.

Assumed System Stressed Voltage Level

In this report, 0.85 per unit voltage at the system high side of the generator step-up transformer is used as the stressed system voltage condition for an extreme but recoverable system event. This transmission system voltage was observed on August 14, 2003 prior to acceleration of the cascading outages. The duration was sustained for several seconds—longer than the typical time delay associated with transmission and power plant protection systems. Use of 0.85 per unit voltage in this report is consistent with Recommendation 8a, footnote 6 of the NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts (Approved by the Board of Trustees February 10, 2004). Footnote 6 recommends 0.85 per unit voltage as one of the criteria for evaluating transmission line phase distance protection. This voltage subsequently has been incorporated into the transmission relay loadability (PRC-023) and generator relay loadability (PRC-025) standards.

The impetus for writing this technical reference document is to address the recommendations contained within BRRTF, Recommendation TR-22 – Generator Backup Protection Responses in Cohesive Generation Groups, (see Appendix C).

During system disturbances and stressed system conditions, a cohesive generator group can experience lower voltage, underfrequency, and large power flows brought on by large angles across its ties to the interconnection. During the August 14, 2003 system cascade, a number of relaying schemes that intended to trip generators for their own protection operated for the event.

TR-22 recommended that NERC evaluate these protection schemes and their settings for appropriateness, including coordination of protection and controls when operating within a coherent generation area weakly connected to an interconnection or in an electrical island. One example explicitly identified in TR-22 is that "[g]enerators directly connected to the transmission system using a 51V protective function should consider the use of an impedance protective function (21) instead."

Observations on Modeling Practices

A significant element in ensuring reliable and stable operation of the overall electric system is the ability to predict the behavior of generation and transmission acting as a single system. While the transmission system and its system controls are currently well modeled and understood, transmission system protection is not always modeled in dynamic simulations. It is generally assumed in simulations that those protection systems will operate normally and that they are coordinated. Analysis of significant system disturbances between 2007 and 2010 has shown that out of 39 protection system misoperations during those events, 12 were due to miscoordination of generation and transmission protection systems, usually resulting in the unnecessary tripping of generators.

The transient behavior and interaction of generator exciters, governors, and power system stabilizers (generator controls) are commonly modeled in dynamic simulations; however, the behavior and interaction of generator protection and turbine/boiler controls during transient and post-transient conditions normally are not. Consequently, transmission planning and operations engineers may not observe the consequences of those interactions with the rest of the system. The transmission system is judged to be in a safe operating condition if there are no overloads, voltage is acceptable, and all generators remain stable. The validity of this judgment depends on proper modeling and coordination of the protection and control systems. Proper coordination must be provided regardless of ownership of the facilities.

Chapter 1 – Coordination and Data Exchange Summary

Table 2 and its contents provide an executive summary for the protection system function coordination described in each section of this document. The columns provide the following information:

Column 1 — The protective functions that require coordination by the Generator Owner

Column 2 — The corresponding protective functions that require coordination by the Transmission Owner

Column 3 — The system concerns the Transmission Owner and Generator Owner must, as a minimum, jointly address in their protection coordination review

Table 3 provides the specific information to be exchanged that is required from each entity. The table lists protection set points, time delays, and the detailed data required to be exchanged for each specific function between the entities. The columns provide the following information:

Column 1 — The data to be provided by the Generator Owner

Column 2 — The data to be provided by the Transmission Owner

Column 3 — The information to be provided by the Planning Coordinator

A step-by-step procedure is presented for each appropriate protective function to be followed by the Generator Owner and Transmission Owner to complete the coordination process. Each protective function and setting criteria section contains the following basic subsections:

1. Purpose
2. Coordination of Generator and Transmission System
    a. Faults
    b. Loadability
    c. Other Operating Conditions (where applicable)
3. Considerations and Issues
4. Setting Validation for the Coordination
    a. Test Procedure for Validation
    b. Setting Considerations
5. Example
    a. Proper Coordination
    b. Improper Coordination
6. Summary of Detailed Data Required for Coordination of the Protection Function
7. Tables of Protection Coordination Considerations and Data and Information that Must be Exchanged

Table 2: Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Functions**	**System Considerations/Comments**
21 – Phase distance	21 87B 87T 50BF	• Both 21 functions have to coordinate • Trip dependability • Breaker failure time • System swings (out-of-step blocking), • Protective Function Loadability for extreme system conditions that are recoverable • System relay failure • Settings should be used for planning and system studies, either through explicit modeling of the function or through monitoring impedance swings at the relay location in the stability program—and applying engineering judgment.
24 – Volts/Hz	UFLS Program UFLS design is generally the responsibility of the Planning Coordinator.	• Generator V/Hz protection characteristics shall be determined and be recognized in the development of any UFLS program for all required voltage conditions. The Generator Owner (and the Transmission Owner when the GSU transformer is owned by the Transmission Owner) exchange information of V/Hz set points and UFLS set points with the Planning Coordinator. • Coordinate with the V/Hz withstand capability and V/Hz limiter in the excitation control system of the generator. • Coordinate with V/Hz conditions during islanding (high voltage with low-frequency system conditions that may require system mitigation actions). • Regional UFLS program design must be coordinated with these settings. • Islanding issues (high voltage and low frequency) may require planning studies and require reactive element mitigation strategies. • Settings should be used for planning and system studies, either through explicit modeling of the function or through monitoring voltage and frequency performance at the relay location in the stability program—and applying engineering judgment.

Table 2: Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Functions**	**System Considerations/Comments**
27 – Generator Unit Undervoltage Protection **** Should Not Be Set to Trip, Alarm Only**** **If function 27 tripping is used for an unmanned facility** – the settings must coordinate with the stressed system condition of 0.85 per unit voltage and time delays set to allow for clearing of system faults by transmission system protection, including breaker failure times.	21 27 if applicable 87B 87T 50BF Longest time delay for transmission system protection to clear a fault	• Must not trip prematurely for a recoverable extreme system event with low voltage or system fault conditions • UVLS set points and coordination, if applicable • Settings should be used for planning and system studies, either through explicit modeling of the function or through monitoring voltage performance at the relay location in the stability program—and applying engineering judgment. • Must coordinate with transmission line reclosing
27 – Plant Auxiliary Undervoltage **If Tripping is used** – the correct set point and adequate time delay so it does not trip for system faults and recoverable extreme system events	21 27 if applicable 87B 87T 50BF Longest time delay for transmission system protection to clear a fault	• Coordinate the auxiliary bus protection and control when connected directly to the high-voltage system. • Generator Owner to validate the proper operation of auxiliary systems at 85 percent nominal voltage on the high side of the GSU. The preferred undervoltage trip setting is 80 percent. • Settings should be used for planning and system studies, either through explicit modeling of the function or through monitoring voltage performance at the relay location in the stability program—and applying engineering judgment.
27 – Plant High-Voltage system-side undervoltage	21 27 if applicable 87B 87T 50BF Longest time delay for transmission system protection to clear a fault	• Must not trip prematurely for a recoverable extreme system event with low voltage or system fault conditions • UVLS set points and coordination if applicable • Settings should be used for planning and system studies, either through explicit modeling of the function or through monitoring voltage performance at the relay location in the stability program—and applying engineering judgment.

Table 2: Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Functions**	**System Considerations/Comments**
32 – Reverse Power	None	• Some relays can be susceptible to misoperation at high leading reactive power (var) loading.
40 – Loss of Field (LOF)	Settings used for planning and system studies	• Preventing encroachment on reactive capability curve • See details from sections 4.5.1 and A.2.1 of IEEE Std. C37.102–2006. • It is imperative that the LOF function does not operate for stable power swings. The impedance trajectory of most units with a lagging power factor (reactive power into the power system) for stable swings will pass into and back out of the first and second quadrants.
46 – Negative phase sequence overcurrent	21 21G 46 67N 51N Longest time delay of transmission system protection including breaker failure time	• Should be coordinated with system protection for unbalanced system faults • Plant and system operations awareness when experiencing an open pole on the system • Transposition of transmission lines • System studies, when it is required by system condition • Open phase, single-pole tripping • Reclosing • If there is an alarm, Generator Owners must provide I_2 measurements to the Transmission Owner and Planning Coordinator and they must work together to resolve the alarm.
50/27 — Inadvertent energizing	None	• The function 27 must be set at or below 50 percent of the nominal voltage. • Instantaneous overcurrent (function 50) must be set sensitive enough to detect inadvertent energizing (breaker closing). • Timer setting should be adequately long to avoid undesired operations due to transients – at least 2 seconds. • Relay elements (27, 50, and timers) having higher Dropout Ratio (ratio of dropout to pickup of a relay) should be selected to avoid undesired operations.

Table 2: Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Functions**	**System Considerations/Comments**
50BF – Breaker failure on generator interconnection breaker(s)	Protection on line(s) and bus(es) that respond to faults and conditions on the generator side of the interconnection breaker(s)	• Check for single points of failure • Overcurrent (fault detector) and 52a contact considerations • Critical clearing time • Settings should be used for planning and system studies. • Circuit breaker test data (interrupting time)
51T — Phase fault backup overcurrent 51TG — Ground fault backup overcurrent	51 67 51G 51N 67N	• Must have adequate margin over GSU protection and nameplate rating • 51T not recommended, especially when the Transmission Owner uses distance line protection functions • Open-phase, single-pole tripping and reclosing • Generator Owners(s) needs to get Relay Data (functions 51, 67, 67N, etc.) and single-line diagram (including CT and PT arrangement and ratings) from Transmission Owner(s) for function 51T coordination studies
51V — Voltage controlled/restrained	51 67 87B	• 51V not recommended when Transmission Owner uses distance line protection functions • Coordination may be difficult to achieve except on single generators connected to the power system by radial interconnection facilities. • Short-circuit studies for time coordination • Total clearing time • Review voltage setting for extreme system loading conditions • 51V controlled function has only limited system backup protection capability • Settings should be used for planning and system studies, either through explicit modeling of the function or through monitoring voltage and current performance at the relay location in the stability program—and applying engineering judgment.
59 — Overvoltage	59 (when applicable)	• Settings should be used for planning and system studies, either through explicit modeling of the function or through monitoring voltage performance at the relay location in the stability program—and applying engineering judgment.

Table 2: Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Functions**	**System Considerations/Comments**
59GN/27TH — Generator Stator Ground	21N 51N	• Ensure that proper time delay is used such that protection does not trip due to interwinding capacitance issues or instrument secondary grounds, or supervise the 59GN function.
78 — Out of Step	21 (including coordination of out-of-step blocking and tripping) 78 (if applicable)	• System studies are required. • Settings should be used for system studies, either through explicit modeling of the function or through monitoring impedance swings at the relay location in the stability program—and applying engineering judgment.
81U – Underfrequency 81O – Overfrequency	81U 81O Note: UFLS design is generally the responsibility of the Planning Coordinator	• Coordination with system UFLS set points and time delay (typically achieved through compliance with regional frequency standards for generators) • Meet underfrequency and overfrequency requirements. • Auto-restart of distributed generation such as wind generation during overfrequency conditions. • Settings should be used for planning and system studies, either through explicit modeling of the function or through monitoring frequency performance at the relay location in the stability program—and applying engineering judgment.
87G — Generator Differential 87T — Transformer Differential 87U — Overall Differential	None None None	Proper overlap of the overall differential zone and bus differential zone, etc., should be verified.

Table 3: Data to be Exchanged Between Entities		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Function 21 Relay settings (and associated time delays) in the R-X plane in primary ohms at the generator terminals	One-line diagram of the transmission system up to one bus away from the generator high-side bus	Feedback on coordination problems found in system studies

Table 3: Data to be Exchanged Between Entities		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Total clearing times for the generator breakers	Impedance of all transmission elements connected to the generator high-side bus	
	Relay settings on all transmission elements connected to the generator high-side bus	
	Total clearing time for all transmission elements connected to the generator high-side bus	
	Total clearing time for breaker failure for all transmission elements connected to the generator high-side bus	
Function 24 The overexcitation protection characteristics, including time delays and relay location, for the generator and the GSU transformer (if owned by the Generator Owner)	The overexcitation protection characteristics for the GSU transformer (if owned by the Transmission Owner)	Feedback on problems found between overexcitation settings and UFLS programs
Function 27 – Generator Relay settings: Undervoltage set point, if applicable, including time delays, at the generator terminals	Time delay of transmission system protection	Feedback on problems found in coordinating with stressed voltage condition studies and, if applicable, UVLS studies
Function 27 – Plant Auxiliary System Relay settings: Undervoltage set point if applicable, including time delays, at the power plant auxiliary bus	Time delay of transmission system protection	Feedback on problems found in coordinating with stressed voltage condition studies and, if applicable, UVLS studies
Function 27 – High-Voltage System Side Relay settings: Undervoltage set point if applicable, including time delays, at high-side bus	Time delay of transmission system protection	Feedback on problems found in coordinating with stressed voltage condition studies and, if applicable, UVLS studies
Function 32 None	None	None
Function 40 Relay settings: loss-of-field characteristics, including time delays, at the generator terminals Generator reactive capability	The worst-case clearing time for each of the power system elements connected to the transmission bus at which the generator is connected	Impedance trajectory from system-stability studies for the strongest and weakest available system Feedback on problems found in coordination and stability studies

Table 3: Data to be Exchanged Between Entities		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Function 46 Relay settings: negative phase sequence overcurrent protection characteristics, including time delays, at the generator terminals Generator Owners must provide I_2 measurements to the Transmission Owner and Planning Coordinator for resolution if significant unbalance is observed.	The time-to-operate curve for system relays that respond to unbalanced system faults. This would include the 51TG if the GSU is owned by the Transmission Owner	None
Function 50/27 – Inadvertent Energizing Undervoltage setting and current detector settings pickup and time delay	Review method of disconnect and operating procedures	None
Function 50BF – Breaker Failure Times to operate generator protection Breaker failure relaying times	Times to operate, including timers, of transmission system protection Breaker failure relaying times	Provide critical clearing time or confirm total clearing time is less than critical clearing time
Function 51T — Phase fault backup overcurrent relay settings and associated time delays **Function 51TG** — Ground fault backup overcurrent relay settings and associated time delays	One-line diagram of the transmission system up to one bus away from the generator high-side bus	None
Total clearing times for the generator breakers	Impedances of all transmission elements connected to the generator high-side bus	
	Relay settings on all transmission elements connected to the generator high-side bus	
	Total clearing times for all transmission elements connected to the generator high-side bus	
	Total clearing times for breaker failure, for all transmission elements connected to the generator high-side bus	

Table 3: Data to be Exchanged Between Entities		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Function 51V – Voltage Controlled/Restrained Provide settings for pickup and time delay (may need to provide relay manual for proper interpretation of the voltage controlled/restrained function)	Times to operate, including timers, of transmission system protection Breaker failure relaying times	None
Function 59 Relay settings: setting and characteristics, including time-delay setting or inverse-time characteristic, at the generator terminals	Pickup and time-delay information of each 59 function applied for system protection	None
Function 59GN/27TH Provide time-delay setting of the 59GN/27TH	Provide worst-case clearing time for phase-to-ground or phase-to-phase-to-ground close-in faults, including the breaker failure time.	None
Function 78 Relay settings, time delays, and characteristics for out-of-step tripping Generator characteristics for use in stability studies	Provide relay settings, time delays, and characteristics for the out-of-step tripping and blocking, if used. Breaker failure tripping schemes	Identify potential for a generator out-of-step condition resulting from a transmission system fault. Feedback on coordination problems found in stability studies
Function 81U/81O Relay settings and time delays	None	Feedback on problems found between underfrequency settings and UFLS programs
Function 87G — Generator Differential	None	None
Function 87T — Transformer Differential	None	None
Function 87U — Overall Differential	None	None

Chapter 2 – Discussion of Specific Protection Functions

This report does not prescribe practices to Generator Owners and Transmission Owners, but is intended to provide useful information and guidance for self-examination of their protection schemes as well data exchange and coordination. It is envisioned that this self-examination and coordination process will significantly reduce the number of nuisance trips in future events. These suggested processes should be simple and easy to perform for generator protection application reviews. The following are general data and information requirements that should be exchanged by the Generator Owners and Transmission Owners for a complete review of all protection functions. Note that all data and information may not be required for a review of each individual protection function. Note also that unique situations may exist in which the Transmission Owners owns protective relays within the generating plant, or the Generator Owner owns protective relays that protect transmission system elements. In these unique situations one entity may be responsible for coordination, but the principles in this reference document are still applicable.

Coordinating several of the protection functions requires that the Generator Owner and Transmission Owner have knowledge of the system conditions expected to occur during extreme system events. This document includes data exchange requirements between the Generator Owner, Transmission Owner, and the Planning Coordinator to facilitate exchange of this information. While this document refers specifically to the Planning Coordinator, the system studies may be performed by the Transmission Planner. Some entities perform multiple roles in the NERC Functional Model, so in some cases the Transmission Planner may be the same entity as the Transmission Owner. In this document, use of the term Planning Coordinator is intended to cover all of these cases.

Generator Owner Data and Information Requirements

In addition to the protective function settings the Generator Owner should provide additional general and specific application information as requested, including the following, where applicable:

- Relay scheme descriptions
- Generator off nominal frequency operating limits
- CT and VT/CCVT configurations
- Main transformer connection configuration
- Main transformer tap position(s) and impedance (positive and zero sequence) and neutral grounding impedances
- High-voltage transmission line impedances (positive and zero sequence) and mutual coupled impedances (zero sequence)
- Generator impedances (saturated and unsaturated reactances that include direct and quadrature axes, negative- and zero-sequence impedances, and their associated time constants)
- Documentation for each of the protective functions listed above, including whether each function trips or alarms, and the type of trip initiated (e.g., turbine, generator, field) for functions that trip

Transmission Owner Data and Information Requirements

In addition to the protective function settings, the Transmission Owner should provide additional information as requested, including the following, where applicable:

- Relay scheme descriptions
- CT and VT/CCVT configurations

- Any transformer connection configuration with transformer tap position(s) and impedance (positive and zero sequence) and neutral grounding impedances
- High-voltage transmission line impedances (positive and zero sequence) and mutual coupled impedances (zero sequence)
- Documentation showing the function of all protective functions listed above
- Results of fault study or short-circuit model
- Communication-aided schemes

This information is required to gain a complete understanding of the protection schemes in place for all involved entities and, if necessary, allow the Planning Coordinator to include the plant protection in models for system studies.

Phase Distance Protection (Function 21)

Purpose of Generator Function 21 — Phase Distance Protection

Phase distance protection measures impedance derived from the quotient of generator terminal voltage divided by generator stator current. When it is applied, its function is to provide backup protection for system multiphase faults that have not been cleared by transmission system circuit breakers via their protective relays. Note that function 51V (Section 3.10) is another method of providing backup for system faults, and it is never appropriate to enable both function 51V and function 21. Section 4.6.1.1 of IEEE Std. C37.102–2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***<u>that is not cleared by the transmission line breakers.</u>*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay.* *<u>Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and</u>* ***<u>normal loading conditions.</u>*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear [reference omitted]. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine-generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment blinders can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay should coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus*** *[reference omitted].*
>
> *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer [impedance]). This setting should be checked for*

coordination with the Zone-1 element on the shortest line off of the bus. The normal Zone-2 time-delay criteria would be used to set the delay for this element.

Alternatively, Zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting.

In addition to the purposes described for generator protection in IEEE Std. C37.102–2006, the impact of the impedance function on the performance of the power system as a whole needs to be considered. Protecting the generator must be balanced with protecting the reliability of the power system. If the generator impedance function is set to operate when the generator is not at risk thermally or from a stability perspective, it can trip, leaving other generators to shoulder its share of the system load. If multiple generators' impedance functions are set similarly and trip, the remaining generators may become at risk for damage. This is especially of concern in stressed or extreme contingency conditions. Sequential tripping of generators under such conditions can lead to cascading tripping of system elements, potentially leading to a system blackout. In addition, coordinating the generator and transmission system protection reduces the number of unnecessary generator trips and associated equipment stress and lost operating revenue.

There are two common approaches to setting function 21 as applied to the protection of generators. One approach is to set the function focus on thermal protection of the generator for a transmission fault that is not cleared by transmission relays, and the other approach is to set it with a longer reach to provide backup for transmission protection system failures (e.g. 120 percent of the longest line connected to the generating station bus, including the effects of infeed from other lines and sources).

The first approach often leads to setting the function at about 150 percent to 200 percent of the generator MVA rating at its rated power factor. This approach is focused on protecting the generator, although some level of backup protection is provided for the transmission system as could be needed for transmission line relay failure. The setting of 150 percent to 200 percent of rated MVA at the rated power factor is intended to provide a secure setting, but it is still necessary to evaluate the setting to ensure it will not operate for system loading during extreme system conditions.

In the second approach, two zones of impedance functions are often used. Zone 1 and zone 2 are time delayed. Zone 1 is set to detect faults on the high side of the generator step-up transformer and the high-voltage bus. Zone 1 must be set not to overreach the transmission line zone 1 functions with margin. Zone 1 is a backup function and must be time delayed. Its time delay is set longer than the primary relaying time (zone 1 transmission line distance protection (function 21), generator differential (function 87G), transformer differential (function 87T), overall differential (function 87U), bus differential (function 87B)) plus circuit breaker failure time (function 50BF) and a reasonable margin. The generator zone 2 is set to detect a fault on the longest line (with infeed). Zone 2's time delay is set longer than the longest time delay of all transmission line protection times for all zones in which it can detect a fault, including breaker failure time and a reasonable margin.

For the reliability of the overall power system, backup protection should be provided for transmission protection system failure. Depending on the protection philosophies of the Generator Owner and Transmission Owner and any agreements between them, one or both of these entities may provide this protection.

It is necessary to evaluate the zone 2 (extended reach) setting to ensure it will not operate for system loading during extreme system conditions. During extreme system contingencies, it is likely that the power system generators may swing with respect to each other. Often these swings dampen and the system returns to a steady state. It is essential that functions that can respond to stable swings do not trip the generator unnecessarily. The

21 impedance function is such a function. This loadability evaluation is in addition to checking the coordination with transmission system protection for system faults as stated above.

Annex A.2.3 of the IEEE Std. C37.102–2006 provides a setting example for the impedance function. Although annexes are not a part of the guide, they do provide useful explanations. In IEEE Std. C37.102–2006, Annex A describes settings calculations for generator relays using a particular example. For the impedance function that is used to detect system relay failures, called zone 2 in the annex, it states the following settings rules:

Set zone 2 to the [smallest] of the three following criteria:

a. *120% of longest line (with in-feed). If the unit is connected to a breaker and a half bus, this would be the length of the adjacent line.*

b. *50% to 66.7% of load impedance (200% to 150% of the generator capability curve) at the rated power factor angle.*

c. *80% to 90% of load impedance (125% to 111% of the generator capability curve) at the maximum torque angle.*

As with both PRC-023 and PRC-025, the loadability standards for transmission lines and generators, this technical reference document defines a stressed system condition as a bus voltage of 0.85 per unit at the high-voltage side of the generator step-up (GSU) transformer. This is not a worst-case voltage but a voltage that was observed in the August 14, 2003 blackout at many buses before the cascading portion of the blackout. It was in a time frame during which automatic action to return the power system to within limits was quite possible. In contrast to loadability requirements for transmission system relays in PRC-023 for which the 0.85 per unit voltage is treated as a quasi-steady-state condition, evaluation of generator relay loadability must include the generating unit dynamic response to this stressed voltage condition.

In a stressed system condition, it is likely that the generator exciter may be undergoing some level of field forcing. In this document, two operating conditions are examined: (1) when the unit is at rated active power out in MW with a level of reactive power output in Mvar of 150 percent times rated MW (some level of field forcing), and (2) when the unit is at its declared low active power operating limit (e.g., 40 percent of rated load) with a level of reactive power output in Mvar of 175 percent times rated MW (some additional level of field forcing). Both conditions are evaluated with the generator step-up transformer high-side voltage at 0.85 per unit. These dynamic load levels were chosen based on observed unit loading values during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit responses to similar system conditions. These load operating points are believed to be conservatively high levels of reactive power out of the generator with a 0.85 per unit high-side voltage based on these observations.

Coordination of Generator and Transmission Systems

The relay settings as determined by the Generator Owner require affirmation by the Transmission Owner for fault detection and time coordination. The relay setting must also be tested to ensure that it will not respond incorrectly for system loading during extreme system conditions when the generator is not at risk of thermal damage. For the purposes of validating loadability, two separate methods are proposed and discussed. The first method is a conservative but simple test that evaluates loadability against two operating points. These operating points were selected based on observed unit loading values during the August 14, 2003 blackout as well as other subsequent system events, and on simulations evaluating a wide range of operating conditions, including both fault and steady-state conditions. These load operating points are believed to be a conservatively high level of reactive power out of the generator with a 0.85 per unit high-side voltage, such that a relay set to be secure for these conservative operating points will be secure for the wide range of conditions that may challenge the apparent impedance characteristic of the phase distance protection. The second method allows for more extensive evaluation of the worst-case expected operating points for a specific generator that may be applied when the conservative but simple test restricts application of the desired relay setting.

Method 1: As stated above, the first method is a conservative but simple test that is applied to validate generator relay loadability. This method may be applied for any application of the phase distance backup function, although it may be most useful when this function is applied to provide generator backup thermal protection. With this method, the relay reach is compared against the loadability requirement by calculation or graphically by plotting the relay characteristic on an impedance plot and checking against the apparent impedance operating points as specified above. These operating points are calculated with stator current based on (1) rated MW and a Mvar value of 150 percent times rated MW output (e.g., 768 MW + j1152 Mvar), and (2) a declared low active power operating point such as 40 percent of rated MW and a Mvar value of 175 percent times rated MW output (e.g., 307 MW + j1344 Mvar). In both cases, the generator terminal voltage is calculated based on the stressed system condition of 0.85 per unit voltage on the high side of the generator step-up transformer.

Method 2: The second method may be applied when the test in Method 1 restricts application of the desired relay setting. This method allows for more extensive evaluation of the worst-case expected operating points based on characteristics of the specific generator. These operating points may be determined from dynamic modeling of the apparent impedance trajectory during simulated events. The stressed system condition used is similar to Method 1, but the evaluation is conducted using a dynamic model simulation with the voltage at the high side reduced to 0.85 per unit prior to field-forcing to simulate the response of the unit to depressed transmission system voltage. This process provides a more accurate and comprehensive representation of the field forcing, active and reactive power output, and the resulting apparent impedance trajectory during the event.

Faults

Proper impedance function performance during faults is demonstrated in the examples subsection below. In the examples, it is assumed that transmission line relay failure has occurred and the fault is at the far end of the protected line. The examples present solutions that can be used to permit tripping for the fault while not tripping for non-fault conditions when the generator is not at risk.

Loadability

IEEE Std. C37.102–2006 presents a range of likely acceptable settings for the impedance function of 150 –200 percent of the generator MVA rating at rated power factor as settings that will not operate for normal generator outputs. This setting can be re-stated in terms of ohms as 0.66–0.50 per unit ohms on the machine base. The methods in this document go beyond these requirements by examining generator output under stressed conditions. Most exciters have a field-forcing function (see Appendix A, Reference 2 in IEEE Std. 421.1–2007, "Standard Definitions for Excitation Systems for Synchronous Machines") that enables the exciter to operate beyond its full load output. These outputs can last 10 seconds or more before controls reduce the exciter field currents to rated output.

Section 4.2.1 of IEEE Std. C37.102–2006 states (emphasis added):

> *The field winding may operate continuously at a current equal to or less than that required producing rated-kVA at rated power factor and voltage. For power factors less than rated, the generator output must be reduced to keep the field current within these limits. The capability curves as defined in IEEE Std. 67–1990 are determined on this basis.*
>
> *Under abnormal conditions, such as short circuits and other system disturbances,* ***it is permissible to exceed these limits for a short time. IEEE Std. C50.13–2005****, lists the short-time thermal capability for cylindrical-rotor machines. In this standard, the field winding short time thermal capability is given in terms of permissible field current as a function of time as noted follows:"*

Time (seconds)	*10*	*30*	*60*	*120*
Field current (percent)	*209*	*146*	*125*	*113*

A generator impedance function has a time delay much less than 10 seconds. Time coordination with any excitation control that activates to lower field current is not likely. The 10-second limit is 209 percent of rated field current at full load (Amperes Field Full Load (AFFL)). AFFL is typically approximately 250 percent of Ampere Field Air Gap (AFAG). AFAG is the 1.0 per unit (unity) field current per industry standards. Levels of field current higher than AFFL, as specified by the exciter manufacturer, are possible during field forcing.

The recommended basis for the loadability test during stressed systems are two operating conditions: (1) when the unit is at rated active power out in MW with a level of reactive power output in Mvar of 150 percent times rated MW (some level of field forcing), and (2) when the unit is at its declared low active power operating limit (e.g., 40 percent of rated load) with a level of reactive power output in Mvar of 175 percent times rated MW (some additional level of field forcing). Both conditions are evaluated with the generator step-up transformer high-side voltage at 0.85 per unit. In reference to the discussion above, these values of stator current will result in a level of field current that is greater than AFFL, but less than the maximum 10-second value of 209 percent of AFFL. Typical values are on the order of 3.5 per unit to 4.5 per unit (350 percent to 450 percent of AFAG corresponds to 140 percent to 180 percent of AFFL).

The recommended loadability is to prevent protective functions applied for fault detection from operating during achievable loading conditions. This recommendation is not intended to preclude application of protective functions applied to detect generator overloads, such as described in IEEE Std. C37.102–2006. These protective functions are designed to coordinate with the generator short-time capability by utilizing an extremely inverse characteristic. Typical settings allow the protection system to operate no faster than 7 seconds at 218 percent of full load current (e.g., rated armature current) and prevent operation below 115 percent of full load current. Similarly, protective functions may be applied to detect transformer overloads when designed to coordinate with the transformer thermal capability and to allow an operator 15 minutes or more to respond to overload conditions.

Coordination with Breaker Failure

The 21 function will detect transmission system faults. These faults normally will be cleared by the transmission system relays. Should a circuit breaker fail at the time it is called upon to interrupt the fault, breaker failure relaying will initiate time-delayed backup clearing by tripping all circuit breakers adjacent to the failed breaker. The 21 relay time delay must be set to coordinate with the breaker failure clearing times with a reasonable margin. This requirement is necessary for all transmission protection zones (protected elements) within which the 21 function can detect a fault. For example, a 21 function set to detect faults on the bus connected to the high side of the GSU will also detect some faults that occur on transmission lines connected to that bus. Time coordination is needed should the transmission line fault and its breaker fail.

The following example addresses coordination of the 21 function with transmission line and breaker failure protection.

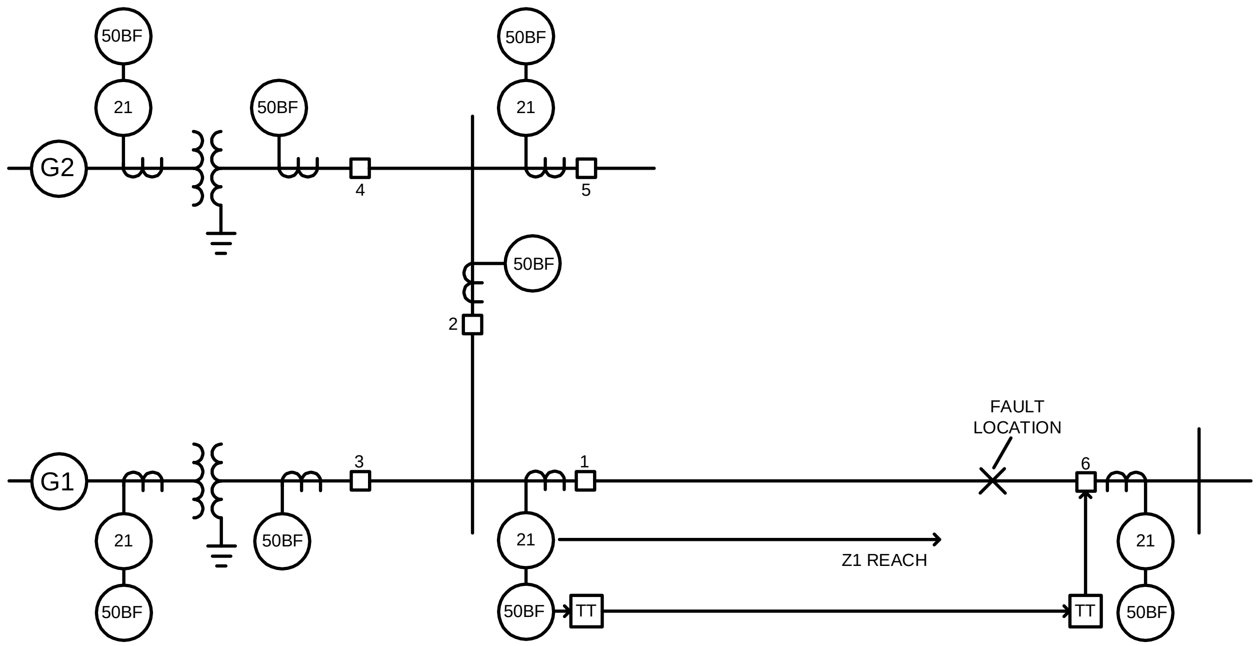


Figure 2: Breaker Failure Coordination

As noted above, the phase distance protection may be set to detect faults on the generator step-up transformer high-side bus or may be set to detect faults on the transmission lines exiting the generating station subject to generator relay loadability limitations. In the former case, the phase distance protection must coordinate with the zone 1 protection on the lines exiting the station since the phase distance protection will overreach the high-side bus. In the latter case, the phase distance protection must coordinate with the longest clearing time for a fault in the protection zone it overreaches. This may be the zone 1 protection or zone 2 protection depending on relay reach and infeed present at the high-side bus, and also on whether high-speed communication-assisted protection is applied on the lines exiting the station.

Consider the system in Figure 2 in which the phase distance protection on generators G1 and G2 is set to detect faults on the transmission lines exiting the station, but overreaches the zone 1 reach of the transmission line relays. To prevent misoperation for a fault on the line beyond breaker 1, the time delay of the G2 phase distance relay must be set longer than the total clearing time for a failure of breaker 1 to clear the fault and the resultant tripping time of breaker 2. This time will be the summation of the breaker 1 line relaying for a zone 2 operation, breaker failure time delay for breaker 1, breaker failure lockout (device 86BF) time, and breaker 2 clearing time, plus a reasonable margin. Similarly, the phase distance protection on generator G1 must be set to coordinate for a line fault beyond breaker 5 with a failure of breaker 5 to clear the fault.

Considerations and Issues

From a trip dependability perspective (e.g., relay failure protection), it may be desirable to set the impedance function to detect faults in another zone of protection. For some system configurations, however, the impedance function may not be able to detect these faults due to the effect of infeed from other fault current sources. In these cases, other means for providing relay failure protection for the zone is required. Unbalanced system faults are detected by negative sequence functions, which are immune to operating on balanced load. Coordination for three-phase faults is the most challenging because of the need not to trip for load and because the generator reactance increases with time from subtransient to transient and then approaches synchronous reactance. The generator fault current decreases in time based on its associated reactances and time constants. (Please see reference 18 for further detail.) For a transmission system three-phase fault, the generator overfrequency protection and overspeed protection may operate in response to unit acceleration resulting from the three-phase fault before any thermal damage can occur. These functions provide this protection in addition to their primary function.

The impedance function must not operate for stable system swings. When the impedance function is set to provide remote backup, the function becomes increasingly susceptible to tripping for stable swings as the apparent impedance setting of the function increases. The best way to evaluate susceptibility to tripping is with a stability study. The study typically is performed by the Planning Coordinator with input from the Generator Owner, since the Planning Coordinator possesses the analysis expertise and the system models necessary to perform the study. The Generator Owner should provide the Planning Coordinator with the impedance function setting and the basis for the setting. For the critical stable swing, the swing loci of apparent impedances should not enter the relay characteristic. Adjustment of time delay is not sufficient to ensure coordination for stable swings. Should the swing penetrate the relay characteristic, the function should be reset, or other control or logic implemented, to ensure the function will not operate for stable swings.

For unstable swings, the phase distance function should not be used to trip, as the angle at which the breaker opens cannot be controlled with a 21 function. The voltage across the breaker can reach dangerous values if the breaker is opened when the angle is near 180 degrees. Under these conditions, a 78 (out-of-step) tripping function should be used to trip such that the breaker opening can be controlled to occur at a safe angle using blinder settings of the 78 function.

Coordination Procedure

At all times the generation protection settings must coordinate with the response times of the overexcitation limiter (OEL) and V/Hz limiter on the excitation control system of the generator.

Step 1 – Generator Owner and Transmission Owner agree on the reach and time-delay settings for the system and generator protection 21 functions.

Step 2 – Generator Owner verifies that the generator 21 functions are coordinated with OEL functions of the excitation system to meet the loadability requirements. This is especially important when the excitation system of the machine is replaced.

Step 3 – Generator Owner and Transmission Owner review any setting changes deemed necessary as a result of step 2.

Depending on the results of step 2, this may be an iterative process and may require additional changes to the transmission system protection.

Loadability Requirements when the Protection is set to Provide Generator Thermal Backup Protection

The phase distance function typically is set in the range of 50–66.7 percent of load impedance (200 percent to 150 percent of the generator capability curve) at the rated power factor angle when applied for machine-only coverage. The following items must be evaluated to ensure security for stressed conditions.

- This setting, including a reasonable margin, should not exceed the two apparent load impedances that are calculated from the generator terminal voltage and stator current. Two operating conditions are examined and used to calculate the apparent load impedances: (1) when the unit is at rated active power out in MW with a level of reactive power output in Mvar of 150 percent times rated MW (some level of field forcing), and (2) when the unit is at its declared low active power operating limit (e.g., 40 percent of rated load) with a level of reactive power output in Mvar of 175 percent times rated MW (some additional level of field forcing). Both conditions are evaluated with the generator step-up transformer high-side voltage at 0.85 per unit.

- In cases where coordination cannot be obtained for these conservative assumptions, a more extensive evaluation of the worst-case expected operating point may be performed based on characteristics of the specific generator. These operating points may be determined by dynamic modeling of the apparent impedance trajectories during simulated events.

Loadability Requirements when the Protection is set to Provide Generator Trip Dependability

The phase distance function typically is set to reach 120 percent of the longest line (with infeed) when applied for relay failure backup coverage. The following items must be evaluated to ensure security for stressed conditions:

- This setting, including a reasonable margin, should not exceed the two apparent load impedances that are calculated from the generator terminal voltage and stator current or by dynamic model simulations. When the protection is set for relay failure backup, it is unlikely that the setting will meet the conservative calculated Method 1 operating points, specifically (1) when the unit is at rated active power out in MW with a level of reactive power output in Mvar of 150 percent times rated MW (some level of field forcing), and (2) when the unit is at its declared low active power operating limit point (e.g., 40 percent of rated load) with a level of reactive power output in Mvar of 175 percent times rated MW (some additional level of field forcing). Both conditions are evaluated with the generator step-up transformer high-side voltage at 0.85 per unit.
- In cases where coordination cannot be obtained for these conservative assumptions, a more extensive evaluation of the worst-case expected operating load points may be performed based on characteristics of the specific generator. These operating points may be determined by dynamic modeling of the apparent impedance trajectories during simulated events.
- During extreme system contingencies, it is likely that the power system generators may swing with respect to each other. It is essential that functions that can respond to stable swings do not trip the generator unnecessarily. The 21 impedance function is such a function.
- Infeed effects in many cases will limit use of this function to providing backup protection for the high-side bus.

Examples

Proper Coordination

In this example, the impedance function is required to protect the generator and provide transmission line relay failure backup protection. The example is based on a 904 MVA generator connected to a 345 kV system by three transmission lines (see Figure 3).

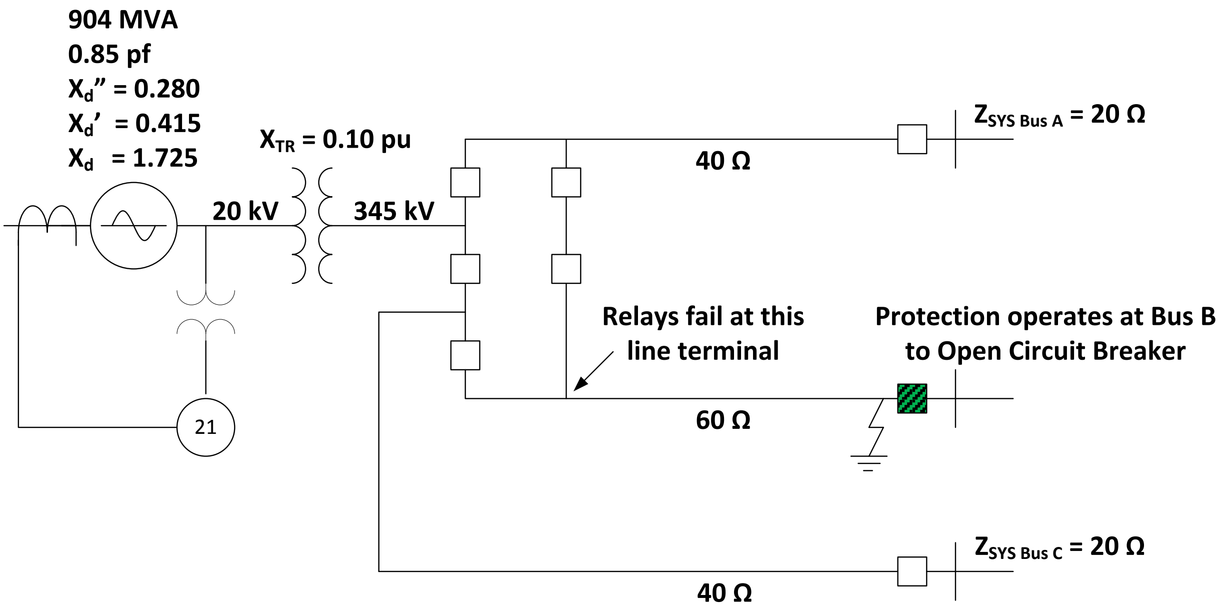


Figure 3: 904 MVA Generator Connected to a 345 kV System by Three Lines

System Faults – Generator Thermal Backup Protection

Figure 4 demonstrates time and reach coordination of the function 21 with transmission line relays when the function 21 is set to 150–200 percent of the machine at rated power factor to provide generator thermal backup protection for system faults.

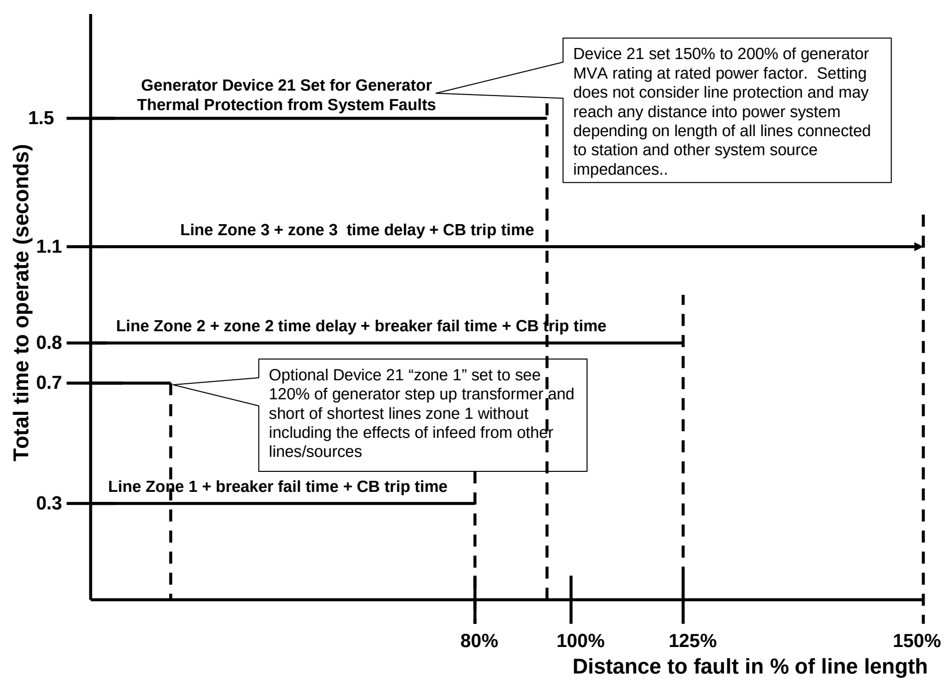


Figure 4: Time Coordination Graph for Generator Thermal Backup Protection

System Faults – Generator Trip Dependability

Figure 5 demonstrates time and reach coordination of the function 21 with transmission line relays when the function 21 is set to detect faults, with infeed, at the end of the longest transmission line connected to the station high-voltage bus.

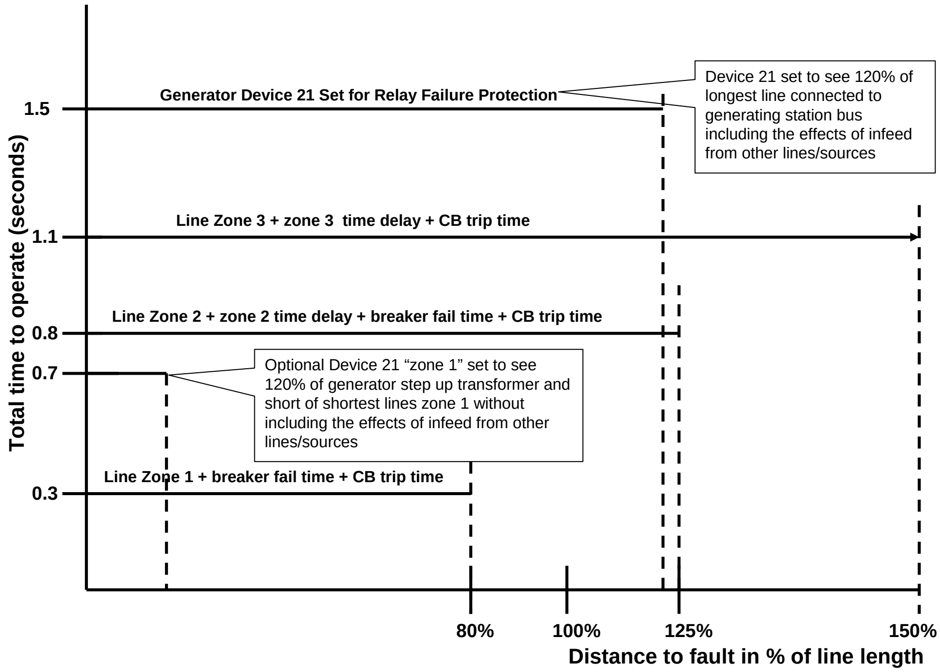


Figure 5: Coordination Graph for Generator Trip Dependability

Loadability – Generator Thermal Backup Protection

Figure 6 shows the apparent impedances calculated for a 904 MVA, 0.85 power factor generator for two operating points based on the generator stator current and terminal voltage associated with (1) rated MW output and a level of Mvar of 150 percent times rated MW (768 MW + j1152 Mvar), and (2) based on the unit operating at its declared low active power operating limit point (e.g., 40 percent of rated load) with a level of reactive power output in Mvar of 175 percent times rated MW (some additional level of field forcing). Both conditions are evaluated at the stressed system condition of 0.85 per unit voltage on the high side of the generator step-up transformer. The apparent impedances are plotted against a relay setting at 200 percent of the machine's full rated MVA (0.5 per unit impedance) at rated power factor with a maximum torque angle of 85°. For this example, these apparent impedances do not coordinate with the 200 percent setting. For this application, it is not imperative that the reach at the rated power factor angle is in the range 0.50–0.66 per unit; this reach is used as a guideline for ensuring the generator phase distance protection setting is secure, rather than ensuring trip dependability.

A modified relay characteristic also is plotted with a revised relay setting at 298 percent of the machine's full rated MVA (0.3358 per unit impedance) at rated power factor with a maximum torque angle of 85°. The apparent impedance does coordinate, with margin, with the revised setting with an 85° maximum torque angle.

A typical time-delay setting for this element would be similar to the zone 3 remote backup element time delay used for transmission relays. This provides time coordination between the generator phase distance backup protection and the protection systems on the transmission lines connected to the generator step-up transformer high-side bus, including breaker failure. In this example, a 1.5-second setting is selected. (See Example 1 in Appendix E for further details.)

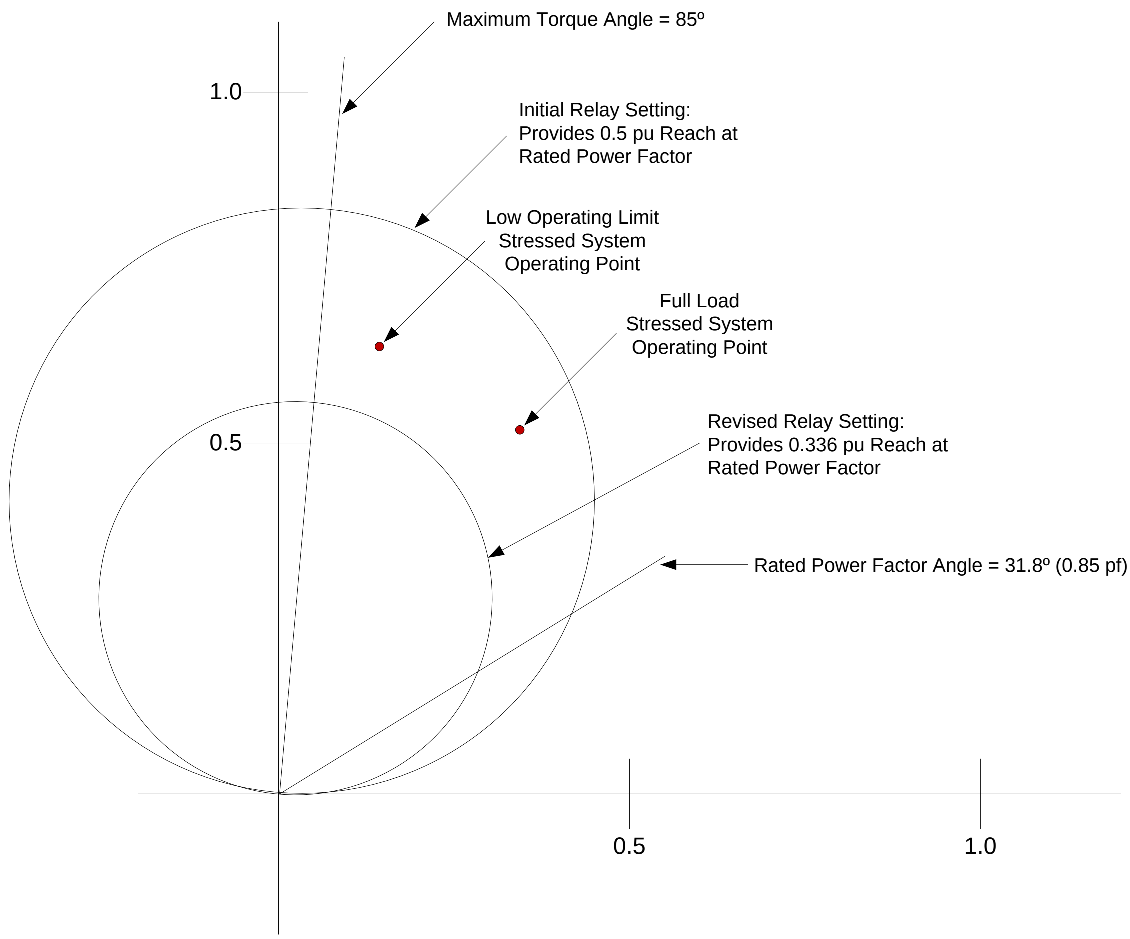


Figure 6: Calculated Apparent Impedance versus Two Phase Distance Settings Based on 200% and 298% of Rated Generator MVA at Rated Power Factor

Loadability – Generator Trip Dependability

Figure 7 shows the two apparent impedances simulated for the same 904 MVA generator for the stressed system condition of 0.85 per unit voltage on the high side of the generator step-up transformer prior to field forcing. For comparison, the calculated apparent impedances are plotted for the operating points using Method 1 and derived by simulations using Method 2. In this example, the worst-case expected operating points based on characteristics of the specific generator derived using Method 2 are less stringent than the conservative but simple test that evaluates loadability against the two operating points calculated in Method 1. The zone 2 function utilizes blinders to meet the loadability requirement derived in Method 2 with sufficient reach to provide system relay failure backup coverage. A zone 1 function is added to provide more complete coverage for generator protection and to provide faster backup clearing for generator step-up transformer and high-side bus faults. Time-delay settings for these two zones would be coordinated as shown above in Figure 5. In this example, a 0.5-second timer setting is selected for zone 1, and a 1.5-second timer setting is selected for zone 2. (See Example 2 in Appendix E for further details.)

Note that the modification applied in the example above for the relay set to provide generator thermal backup protection (i.e., reducing the reach) cannot be applied to the zone 2 function because pulling back the reach to meet the loadability requirement will result in a setting that does not provide the desired trip dependability backup protection. In this example, blinders are applied to the zone 2 function to meet the relay loadability requirement based on the apparent impedance points obtained by simulation using Method 2.

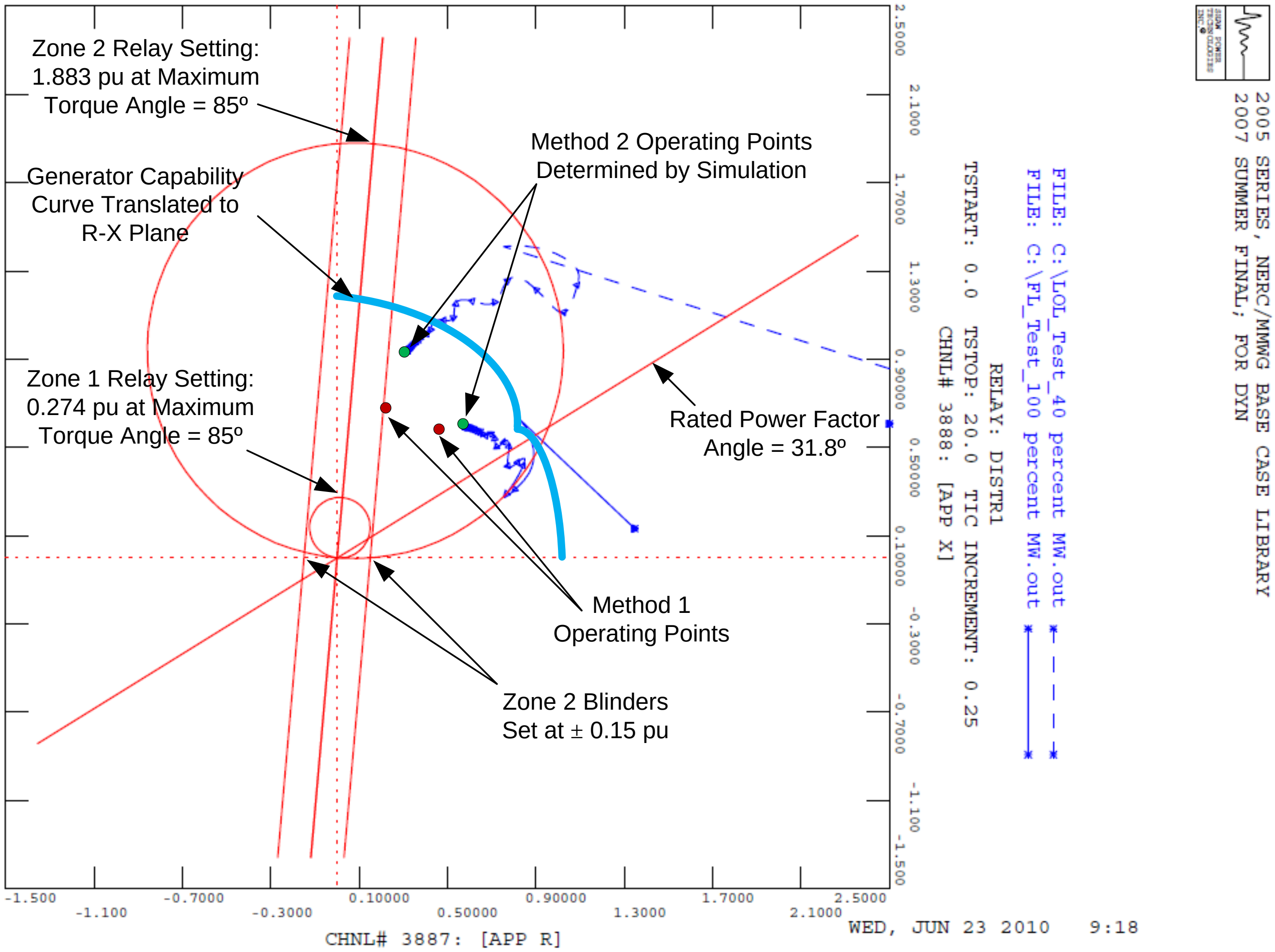


Figure 7: Simulated Apparent Impedance Plotted against Zone 1 and Zone 2 Functions with Blinder

It is important to note that even though the zone 2 setting with blinders provides security for the two operating points used to assess relay loadability, the setting still encroaches on the generator capability curve. Figure 7 includes the generator capability curve in the R-X plane overlaid on the phase distance protection settings and operating points derived in this example. In this figure, the area above the generator capability curve represents the region in which the generator is operating within its capability. This figure illustrates that under certain operating conditions, the generator apparent impedance may enter inside the blinders of the zone 2 operating characteristic. This condition would occur with the generator operating at a low active power (MW) level and high reactive power (Mvar) level. In this particular example, the apparent impedance would enter this region of the R-X plane when operating below the generator low operating limit. Thus, for this particular example, the risk of tripping the generator is limited to unit start-up and shutdown while the generator is ramping up or down below its low operating limit. Nonetheless, the generator is at risk of tripping unless the Generator Operator is aware of this potential and operation of the unit is limited to avoid the portion of the generator capability curve that is encroached on by the zone 2 setting.

The only way to ensure full security for the phase distance protection is to pull the reach back to be inside the generator capability curve. The reach must be pulled back even within the steady-state capability curve in order to provide security for generator dynamic response during field forcing, as illustrated by inclusion of the operating points derived by Method 2. In the limiting case, if the generator may be operated as a synchronous condenser (i.e., the low operating limit is 0 MW), the only alternative is to pull back the zone 2 relay reach. Figure 8 provides an alternate solution in which the zone 2 reach is pulled back to ensure security for all steady-state operating conditions and to meet the relay loadability requirements for the operating points derived through Method 2. In this example, the zone 2 reach is reduced to 0.814 per unit, compared to the desired reach of 1.883 per unit.

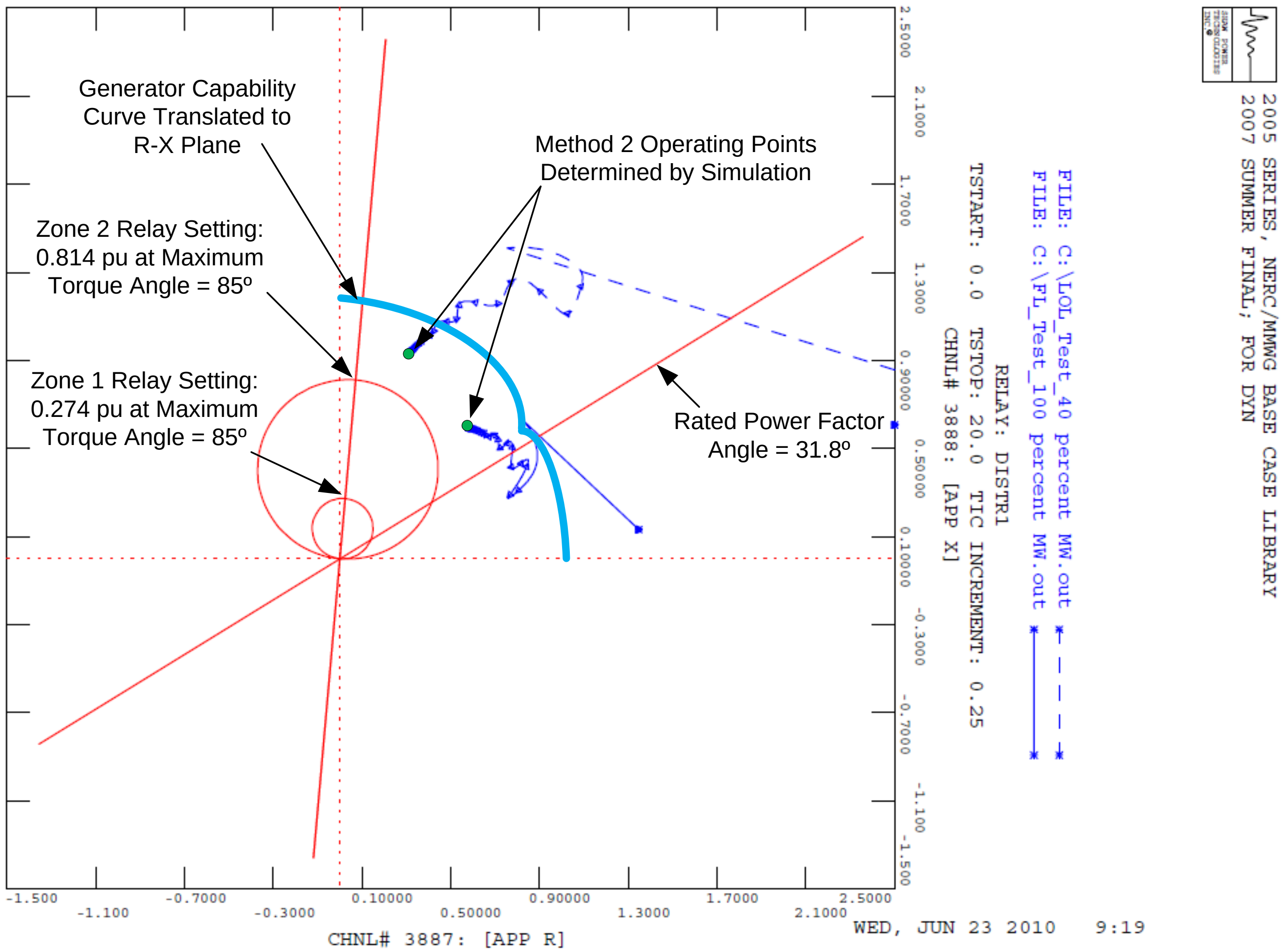


Figure 8: Simulated Apparent Impedance Plotted against Zone 1 and Zone 2 Functions set to Coordinate with the Generator Reactive Capability Curve and Dynamic Reactive Capability During Field Forcing

Methods to Increase Loadability

Tools to increase relay loadability presented in the SPCS transmission line relay loadability documents, and repeated in Figure 9, may provide some benefit. However, it is important to note that these methods are applied in the figure at transmission load angles on the order of 30 degrees. The methods may provide greater benefit at transmission load angles than for generator load angles, which, during field forcing, may be on the order of 45 to 60 degrees.

Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed system condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as reactive power support capability (field forcing). For this reason, adding blinders or reshaping the characteristic provides greater security than enabling load encroachment. The effectiveness of using the offset zone 2 mho characteristic will vary depending on the relationship between the zone 1 reach, the zone 2 offset, and the apparent impedance angle used for assessing loadability. The offset zone 2 can be effective when applied as shown in Figure 9; however, the offset zone 2 provides less security if the zone 1 and zone 2 settings are selected so that the operating point during field forcing is near the point at which the zone 1 and zone 2 characteristics cross, creating a notching effect similar to the load encroachment technique.

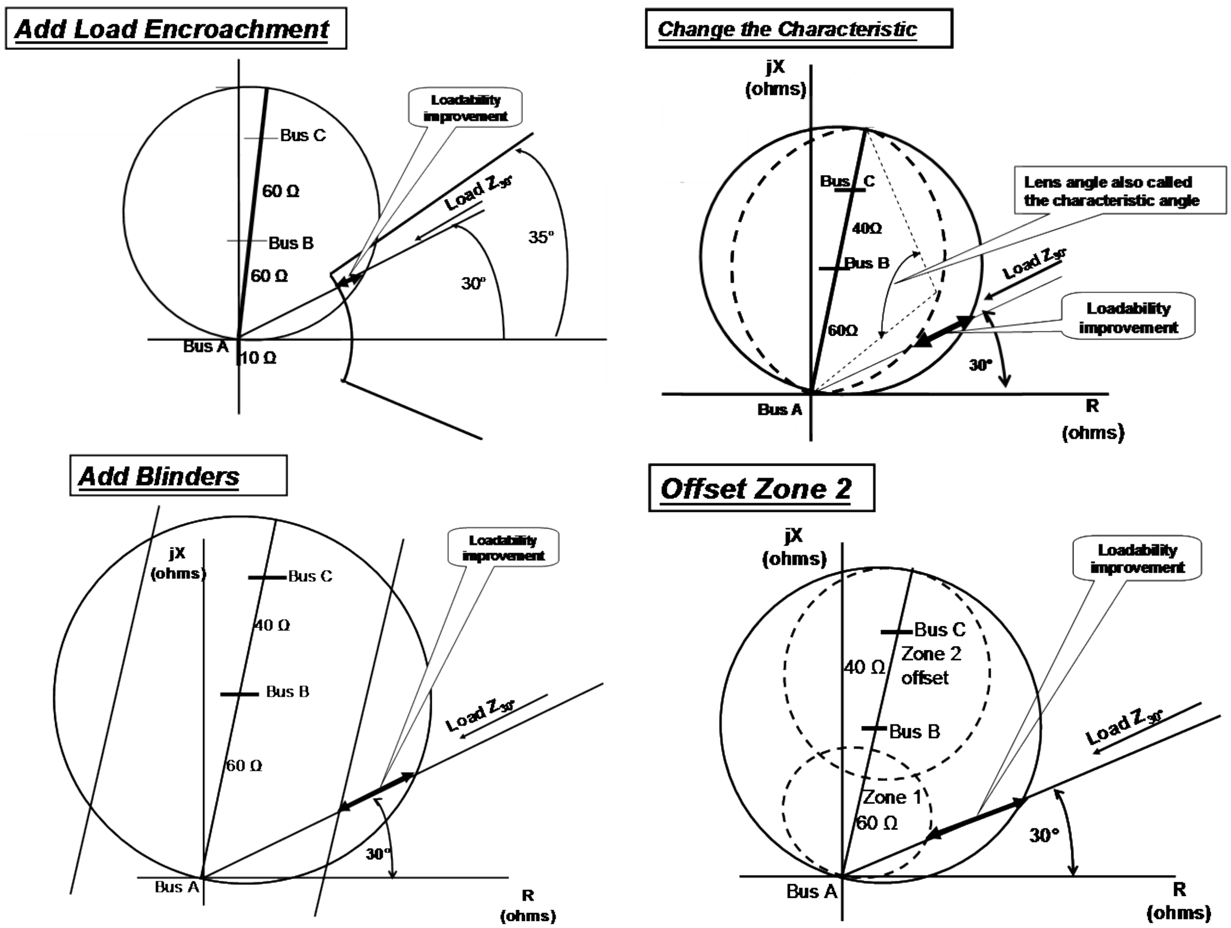


Figure 9: Methods to Increase Loadability

Summary of Protection Function Required for Coordination

Table 2: Excerpt — Function 21 Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Functions**	**System Concerns**
21 – Phase distance	21 87B 87T 50BF	• Both 21 functions have to coordinate • Trip dependability • Breaker failure time • System swings (out-of-step blocking), • Protective Function Loadability for extreme system conditions that are recoverable • System relay failure • Settings should be used for planning and system studies, either through explicit modeling of the function or through monitoring impedance swings at the relay location in the

Table 2: Excerpt — Function 21 Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Functions**	**System Concerns**
		stability program—and applying engineering judgment.

Summary of Protection Function Data and Information Exchange Required for Coordination

The following table presents the data and information that need to be exchanged between entities to validate and document appropriate coordination as demonstrated in the above examples. The protection coordination may be iterative and require multiple exchanges of these data before coordination is achieved.

Table 3: Excerpt — Function 21 Data to be Exchanged Between Entities		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Relay settings (and associated time delays) in the R-X plane in primary ohms at the generator terminals	One-line diagram of the transmission system up to one bus away from the generator high-side bus	Feedback on coordination problems found in system studies
Total clearing times for the generator breakers	Impedance of all transmission elements connected to the generator high-side bus	
	Relay settings on all transmission elements connected to the generator high-side bus	
	Total clearing time for all transmission elements connected to the generator high-side bus	
	Total clearing time for breaker failure for all transmission elements connected to the generator high-side bus	

Overexcitation or V/Hz Protection (Function 24)

Purpose of the Generator Function 24 — Overexcitation Protection

Overexcitation protection uses a measure of the ratio of generator terminal voltage to frequency. Section 4.5.4 of IEEE Std. C37.102–2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows:

> *Overexcitation of a generator or any transformers connected to the generator terminals will occur whenever the ratio of the voltage to frequency (V/Hz) applied to the terminals of the equipment exceeds 105% (generator base) for a generator; and 105% (transformer base) at full load, 0.8 pf or 110% at no load at the secondary terminals for a transformer. The secondary is defined to be the output terminals of the transformer. When these volts/hertz (V/Hz) ratios are exceeded, saturation of the magnetic core of the generator or connected transformers may occur, and stray flux may be induced in nonlaminated components that are not designed to carry flux. Excessive flux may also cause excessive eddy currents in the generator laminations that result in excessive*

voltages between laminations. This may cause severe overheating in the generator or transformer and eventual breakdown in insulation. The field current in the generator could also be excessive.

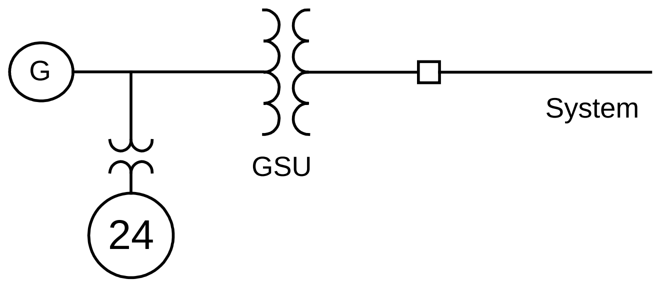


Figure 10: Generator Overexcitation Protection

Coordination of Generator and Transmission System

Faults
There are no coordination issues for system faults for this function.

Loadability
There are no coordination issues related to loadability for this function.

Other Operating Conditions
Coordination between generating plant overexcitation protection and the transmission system is necessary for off-nominal frequency events during which system frequency declines low enough to initiate operation of the UFLS program. In most interconnections, frequency can decline low enough to initiate UFLS operation only during an islanding condition. However, adequate frequency decline may occur to initiate UFLS operation as a result of tripping generators and tie lines on smaller interconnections or on weakly connected portions of interconnections.

Coordination is necessary to ensure that the UFLS program can operate to restore a balance between generation and load to recover and stabilize frequency at a sustainable operating condition. Without coordination, generation may trip by operation of overexcitation protection to exacerbate the imbalance between load and generation, resulting in tripping of more load than necessary or, in the worst case, resulting in system collapse if the resulting imbalance exceeds the design basis of the UFLS program. The need for coordination may not be readily apparent since the relays respond to different quantities and are deployed remotely from each other (as shown in Figure 11); however, the coordination is necessary for reliability of the overall power system. It is important to note that the coordination is not a relay-to-relay coordination in the traditional sense; rather, it is a coordination between the generator and transformer withstand characteristics, the overexcitation protection, and the UFLS program and transmission system design.

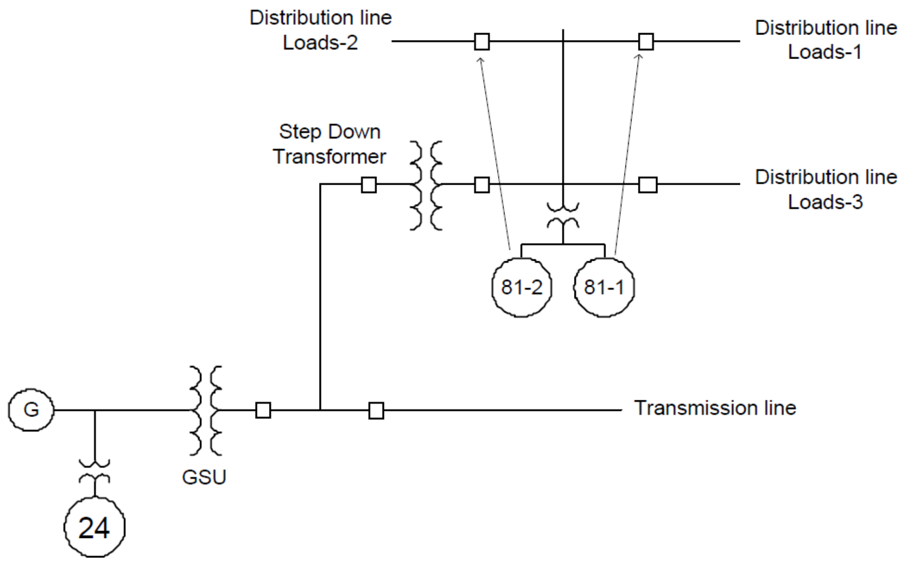


Figure 11: Example Location of UFLS Program Relays and Generator Function 24

Considerations and Issues

Overexcitation withstand limit characteristics of generators and transformers should be obtained from the equipment manufacturer whenever possible.

During an event that initiates UFLS operation, excitation levels typically remain within equipment capability, provided that system voltage can be controlled within normal operating ranges. However, abnormal system voltage during UFLS events is not uncommon, particularly when such events occur during heavy load conditions. Following UFLS operation, the transfer of active power to loads is reduced, resulting in lower reactive power losses and high system voltage. Under such conditions, restoring a balance between load and generation to recover system frequency may be insufficient to control excitation to acceptable levels. Additional coordination may be required to remove reactive compensation (e.g., shunt capacitor banks) or to connect shunt reactors.

Coordination Procedure

The following data and information exchange steps should be taken by the Generator Owner and Planning Coordinator. Note that in cases where the generator step-up transformer is owned by the Transmission Owner, the Transmission Owner would have the same responsibility as the Generator Owner.

Step 1 – Generator Owner to provide settings, time delays, and protection characteristics to the Planning Coordinator for both the generator and generator step-up transformer.

Step 2 – The Generator Owner and Planning Coordinator confirm that the protection settings coordinate and allow the UFLS program to operate first.

Step 3 – The Planning Coordinator performs studies to verify this if necessary.

Setting Procedure

a. Plot the V/Hz withstand capability curves of the generator step-up transformer and generator similar to the ones shown in Figure 12.

b. Plot the overexcitation (V/Hz) protection characteristic on the same graph.

c. Check proper coordination between the relay characteristic time curves and timing settings of excitation control limiter(s). The limiters in the excitation control system limiter should act first. The settings for the protective function must be set so that the function will only operate if the excitation is greater than the limiter setting but before the capability of the protected equipment is reached. Short time excursions beyond the overexcitation limit should not cause the protection systems to trip the generator, because the overexcitation limiter time-delay setting is used to prevent tripping during these conditions. Protection system tripping times are generally long enough that coordination with exciter response is not a problem.

d. If UFLS is used on the system connected to the generator (shown in Figure 11), then the UFLS program and the overexcitation settings should be coordinated such that UFLS is given a chance to act before overexcitation protection trips the unit. The overexcitation protection should be set with an adequate margin above the withstand capability to ensure equipment protection while providing as much operating range as possible for design of the UFLS program.

Coordination between the overexcitation protection and the UFLS program design can be validated only through a stability study. The study should either monitor excitation at all buses at which overexcitation protection is utilized for comparison against tripping characteristics, or the overexcitation protection should be modeled in the study. With either approach, a determination that coordination exists should be based on observing that no generators would trip by overexcitation protection. In a limited number of cases, conditions may exist that coordination cannot be achieved for every generating unit. In such cases, coordination may be deemed acceptable if tripping does not cascade and is limited to a small amount of generation (as a percentage of the load in the affected portion of the system). Protection models should be added to system models for any units for which coordination cannot be obtained. In any case, stability studies should have sufficient margins, and a sufficient number of scenarios should be simulated to provide confidence in the determination.

Examples

Figure 12 shows a setting example for overexcitation protection using definite time and inverse time overexcitation (V/Hz) functions.

Generator and transformer manufacturers should be consulted for the information on overexcitation withstand capability. An example withstand curve shown in Figure 12 is given in Tables 4 and 5.

Table 4: Example V/Hz Withstand Capability of GSU Transformer

Time (Min.)	**40**	**30**	**20**	**10**	**6**	**2**	**1**	**0.5**	**0.3**
V/Hz (%)	106.4	106.9	107.4	108.4	109.3	112.1	114.3	118.0	123.5

Table 5: Example V/Hz Withstand Capability of Generator

Time (Min.)	**33**	**25**	**20**	**15**	**10**	**5**	**2**	**1**	**0.5**	**0.2**
V/Hz (%)	110	111	111.5	112.5	113.5	115.5	118.0	120.0	122.0	125.0

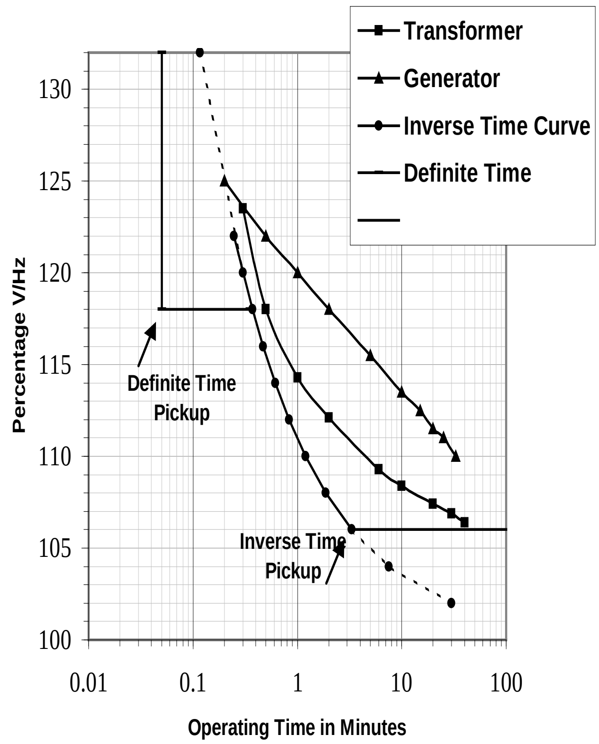


Figure 12: Setting Example with Inverse and Definite Time V/Hz Relays

Proper Coordination

As noted above, the overexcitation protection is set to coordinate with the generator and generator step-up transformer withstand capability and the excitation control limiters. Proper coordination between the overexcitation setting and the generator or transformer withstand characteristic can be demonstrated on a plot of excitation versus time. Settings for the overexcitation protection that may result in conditions for which the overexcitation protection may operate, such as high voltage and underfrequency conditions in UFLS assessments, should be considered in planning studies. Coordination between the UFLS program design and overexcitation protection cannot be demonstrated in this traditional manner; a transient stability study is necessary to demonstrate this coordination (see the Overfrequency and Underfrequency Protection section for further information). A transient stability study is necessary due to the time-varying nature of the voltage and frequency, which may vary significantly prior to and following UFLS operation and between different locations within the system. To ensure coordination, the UFLS program and overexcitation protection should be evaluated for all expected recoverable events. This includes conditions where high voltage and low frequency occur that may require mitigation actions such as tripping capacitor banks. UFLS design parameters (threshold settings, block size, time delays, etc.) and resultant voltage-frequency relationships should be checked against the overexcitation function setting characteristics. If tripping a generator by overexcitation protection is unavoidable, the overexcitation protection for that generator should be accounted for in the system models used for planning and operational studies.

Summary of Protection Functions Required for Coordination

Table 2 Excerpt: Function 24 Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Functions**	**System Concerns**
24 – Volts/Hz	UFLS Program UFLS design is generally the responsibility of the Planning Coordinator.	• Generator V/Hz protection characteristics shall be determined and be recognized in the development of any UFLS program for all required voltage conditions. The Generator Owner (and the Transmission Owner when the GSU transformer is owned by the Transmission Owner) exchange information of V/Hz set points and UFLS set points with the Planning Coordinator. • Coordinate with the V/Hz withstand capability and V/Hz limiter in the excitation control system of the generator. • Coordinate with V/Hz conditions during islanding (high voltage with low-frequency system conditions that may require system mitigation actions). • Regional UFLS program design must be coordinated with these settings. • Islanding issues (high voltage and low frequency) may require planning studies and require reactive element mitigation strategies. • Settings should be used for planning and system studies, either through explicit modeling of the function or through monitoring voltage and frequency performance at the relay location in the stability program—and applying engineering judgment.

Summary of Protection Function Data and Information Exchange Required for Coordination

The following table presents the data and information that need to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above examples. Whenever a miscoordination between the overexcitation setting of a generator and the UFLS program cannot be resolved, it may be necessary to redesign the UFLS program to compensate for the loss of that generation in order to be fully coordinated.

Table 3 Excerpt: Function 24 Data to be Exchanged Between Entities		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
The overexcitation protection characteristics, including time delays and relay location, for the generator and the GSU transformer (if owned by the Generator Owner)	The overexcitation protection characteristics for the GSU transformer (if owned by the Transmission Owner)	Feedback on problems found between overexcitation settings and UFLS programs

Undervoltage Protection (Function 27)

Generator Unit Undervoltage Protection

Purpose of Generator Function 27 — Undervoltage Protection

Undervoltage protection uses a measure of generator terminal voltage. Section 4.5.7 of IEEE Std. C37.102–2006, “Guide for AC Generator Protection,” describes the purpose of this protection as follows:

> *Generators are usually designed to operate continuously at a minimum voltage of 95% of its rated voltage, while delivering rated power at rated frequency. Operating a generator with terminal voltage lower than 95% of its rated voltage may result in undesirable effects such as reduction in stability limit, import of excessive reactive power from the grid to which it is connected, and malfunctioning of voltage sensitive devices and equipment.*
>
> *The undervoltage relay is generally connected to alarm and not trip the unit, so that the operator can take appropriate action to remedy the undervoltage condition (if possible).*

IEEE Std. C37.102–2006 does not recommend use of the 27 function for tripping, but only to alert operators to take necessary actions.

For the generating unit, undervoltage protection that trips the unit is rarely applied to generators. It is frequently used to provide supervision for other protection function or schemes, such as loss-of-field relay (40), distance relay (21), inadvertent energizing relay (50/27), out-of-step relay (78), etc., where the abnormality to be detected leads directly or indirectly to an undervoltage condition. (See corresponding sections pertaining to these functions.)

Undervoltage alarms as experienced by hydro, fossil, combustion, and nuclear units are an indicator of possible abnormal operating conditions such as excitation problems and thermal issues within the unit. Other alarms from Resistance Temperature Detectors (RTDs) and hydrogen pressure are better indicators of thermal concerns. Manufacturers recommend operator action up to and including reduction in unit output rather than a unit trip. Tripping units on undervoltage is not recommended by the IEEE Std. C37.102–2006 guide on generator protection. Rather, C37.102-2006 recommends an alarm to alert the operator to the abnormal conditions that require operator intervention. Each type of unit—hydro, fossil, nuclear, combustion, and renewable—have different abnormal operating issues relating to system undervoltage.

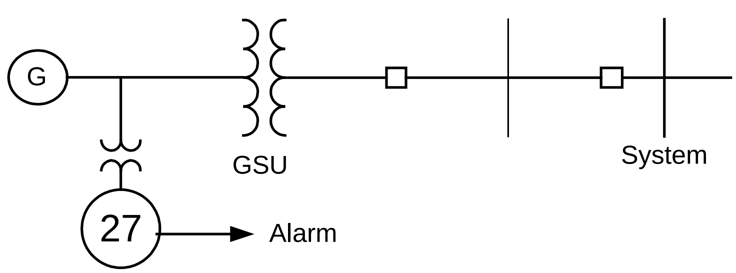


Figure 13: Typical Unit Generator Undervoltage Scheme

Coordination of Generator and Transmission System

An undervoltage function is used for detecting a predetermined low-voltage level and alarming or supervising other functions, such as loss of field (40), distance (21), inadvertent energizing (50/27), out of step (78), etc.

In a few occasions, such as unmanned plants, the 27 function may be used to trip the generator (when on-line). The 27 function to trip is applied as a surrogate for machine thermal current protection and detection of other abnormal conditions detrimental to the generator where an operator is not available to take appropriate action to mitigate the problem.

Faults

There are several considerations for use of the 27 function:

- There are coordination issues regarding system faults.
- The undervoltage function should never trip for any transmission system fault condition.
- The Transmission Owner needs to provide the longest clearing time and reclosing times for faults on transmission system elements connected to the high-side bus.
- This coordination should be validated by both the Generator Owner and Transmission Owner.

Alarm Only — Preferred Method

- Follow IEEE Std. C37.012–2005, "IEEE Application Guide for Capacitance Current Switching for AC High-Voltage Circuit Breakers"—set 27 function for alarm only.
- Have written procedure for operators to follow when the 27 undervoltage alarm occurs.

  NOTE: If the MVA output range of the generator is proportionately reduced with voltage, then an alarm initiated by the 27 function is sufficient, because the unit is being operated within its thermal capability limits.

Tripping for Faults (not recommended, except as noted above)

- Utilize the 27 undervoltage function for tripping with a maximum setting of 0.9 pu for pickup and with a minimum time delay of 10 seconds.
- All planning and operational studies should model this undervoltage tripping of the generator to properly reflect its performance under transient or abnormal steady-state conditions.

  NOTE: It is highly recommended to use more direct temperature and thermal detection methods, such as RTDs, thermocouples, and cooling medium temperature measurements, versus an undervoltage protection function to protect the generator.

Loadability

As noted above, the preferred method is to alarm only with the undervoltage function. If the undervoltage function is used to trip the unit, the additional coordination issues must be addressed by the Transmission and Generator Owners.

1. The Transmission and Generator Owners exchange and utilize the information below to analyze the coordination of the undervoltage protection.
   a. Set point and time delay should be given to the Transmission Owner.
2. This coordination should be validated by both the Generator Owner and Transmission Owner.

Considerations and Issues

The loss of generating units due to tripping of the undervoltage functions or operator action during a system fault or a recoverable extreme system event must be avoided. A recoverable extreme system event is defined as a transmission system voltage of 0.85 per unit at the high side of the generator transformer.

If undervoltage tripping is used for the generator and an Undervoltage Load Shedding (UVLS) program is used on the system connected to the generator, the UVLS set points and time delays must be coordinated with the generator undervoltage trips. In this case, the generator set points should be modeled in system studies to verify coordination. A simple relay-to-relay setting coordination is inadequate due to differences in voltage between the generator terminals and transmission or distribution buses where the UVLS protection is implemented.

Coordination Procedure

Step 1 – The Generator Owner determines the proper undervoltage trip set point for his machine. This should be based on the manufacturer's recommendation or protection application circumstances for the generating station.

Step 2 – The Transmission Owner determines the local or remote backup clearing times for all transmission elements connected to the high-side bus.

Step 3 – The Generator Owner and Transmission Owner collaboratively analyze the settings to determine if they are coordinated. The time delay of the undervoltage function trip must be longer than the greater of the local or remote backup clearing times for all transmission elements connected to the high-side bus, but not less than 10 seconds.

Alarm Only — Preferred Method
IEEE Std. C37.102–2006 does not recommend use of the 27 function for tripping, but only to alarm to alert operators to take necessary actions.

Undervoltage function (27) calculation:

V_{27} = 90% of $V_{nominal}$ = 0.9 x 120 V = 108 V with a 10-second time delay to prevent nuisance alarms (per IEEE Std. C37.102–2006).

Tripping Used (Not Recommended)
CAUTION: If the Generator Owner uses the 27 function for tripping, the following conditions must be met at a minimum: Time delay of the undervoltage function trip must be longer than the greater of the local or remote backup clearing times for all transmission elements connected to the high-side bus, but not less than 10 seconds.

Undervoltage function (27) calculation:

V_{27} = 87% of $V_{nominal}$ = 0.87 x 120 V = 104 V with a coordinated time delay

Note: An 87 percent set point was chosen because the power plant is not capable of continued operation at this voltage level, and it allows for a reasonable margin for extreme system contingencies.

Examples

Proper Coordination
If the undervoltage function is set to trip the generator, a threshold setting below 90 percent voltage at the generator terminals and an adequate time delay is necessary to allow system recovery above this level.

Improper Coordination

If the undervoltage function is set to trip the generator, a threshold setting higher than 90 percent voltage at the generator terminals and/or an inadequate time delay.

There is no improper coordination for an alarm-only function.

Summary of Protection Functions Required for Coordination

Table 2 Excerpt: Function 27 (Gen. Prot.) Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Functions**	**System Concerns**
27 – Generator Unit Undervoltage Protection **** Should Not Be Set to Trip, Alarm Only**** **If function 27 tripping is used for an unmanned facility** – the settings must coordinate with the stressed system condition of 0.85 per unit voltage and time delays set to allow for clearing of system faults by transmission system protection, including breaker failure times.	21 27 if applicable 87B 87T 50BF Longest time delay for transmission system protection to clear a fault	• Must not trip prematurely for a recoverable extreme system event with low voltage or system fault conditions • UVLS set points and coordination, if applicable • Settings should be used for planning and system studies, either through explicit modeling of the function or through monitoring voltage performance at the relay location in the stability program—and applying engineering judgment. • Must coordinate with transmission line reclosing

Summary of Protection Function Data and Information Exchange Required for Coordination

The following table presents the data and information that need to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above examples.

Table 3 Excerpt: Function 27 (Gen. Prot.) Data to be Exchanged Between Entities		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Relay settings: Undervoltage set point, if applicable, including time delays, at the generator terminals	Time delay of transmission system protection	Feedback on problems found in coordinating with stressed voltage condition studies and, if applicable, UVLS studies

Generating Plant Auxiliary Power Supply Systems Undervoltage Protection

Purpose of the Generator Auxiliary System Function 27 — Undervoltage Protection

This undervoltage protection uses a measure of auxiliary system voltage.

When the voltage levels of the auxiliary system reach the undervoltage set point, this protection initiates alarming, automatic transfer to alternative power supply (if available with transfer capability), starting of emergency generator(s), or, if necessary, tripping.

This function is used to transfer loads to the backup auxiliary power supply as well as to protect auxiliary system equipment from severe undervoltage conditions that would have serious consequences, such as auxiliary motors stalling or voltage collapse for the generating unit(s).

This function also protects the integrity of the power supply to safety-related buses applied to support the reactor of nuclear power plants. In these applications, two undervoltage thresholds are utilized: the first undervoltage level (function 27SB1) initiates auxiliary load transfers to an alternative power supply, and the second undervoltage level (function 27SB2) initiates a unit trip. (See the Nuclear Power Plants — Undervoltage Protection and Control Requirements for Class 1E Safety-Related Auxiliaries Design Guidelines and Preferred Power Supply section for further details.)

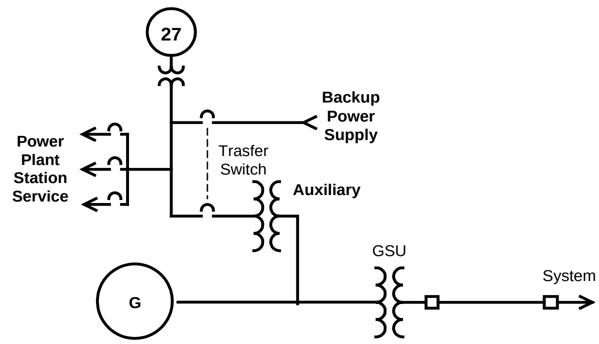


Figure 14: Generating Plant Auxiliary Power System Undervoltage Protection Scheme

Coordination of Generator and Transmission System

Faults

Coordination issues can exist regarding system faults when this function is used to trip the generator. This protection should not react to any transmission system faults. When applying the function 27 undervoltage protection for plant auxiliaries, it should be recognized that it is common for transmission line faults that occur near a power plant to momentarily result in a depressed voltage condition. Transmission system faults are momentary events on the electric system that are generally cleared in a few cycles but may occasionally last a few seconds. These faults will momentarily depress the transmission voltage such that the transmission/plant substation voltage drops to almost zero for a power plant substation bus fault. Or, if a transmission line fault occurs at some distance from the power plant, the voltage at the plant substation bus would be higher. Generation equipment undervoltage settings should permit ride-through capability for such momentary voltage excursions during fault clearing on the transmission system.

Loadability

Step 1 – If the undervoltage function is used to trip the auxiliaries system (which would lead to tripping the generator), the Transmission and Generator Owners exchange and utilize the information below to analyze the coordination of the undervoltage protection.

a. The set point and time delay should be given to the Transmission Owner.

b. The Transmission Owner needs to provide the longest clearing time and reclosing times for faults on transmission system elements connected to the high-side bus.

Step 2 – Check to see that the auxiliary system trip level will not preclude the unit from riding through a recoverable extreme system event defined as:

a. A transmission system voltage of 0.85 per unit at the high side of a system-connected auxiliary transformer.

b. A transmission system voltage of 0.85 per unit at the high side of a generator step-up transformer for generator-connected auxiliary systems.

Step 3 – For nuclear units, coordination between the Transmission Owner and the Generator Owner of the nuclear power generating unit(s) is required for Preferred Power Supply and Nuclear Plant Interface Requirements (NPIRs). Please also see the section titled Nuclear Power Plants — Undervoltage Protection and Control Requirements for Class 1E Safety-Related Auxiliaries Design Guidelines and Preferred Power Supply in this document for further details.

Considerations and Issues

- Auxiliary power supply system — auxiliary motors with 80–85 percent motor terminal voltage create approximately 64–72 percent motor torque. Motor torque is approximately equal to the supplied motor terminal voltage squared in per unit or percent of rated motor voltage. Lack of adequate voltage can cause auxiliary motors to cascade into a voltage collapse and a stall condition, as well as the possibility of contactors dropping out. In some applications, the motor-rated terminal voltage is less than system nominal to allow for inherent system voltage drops (e.g., 4,000 volts on a 4,160 volt bus). This needs to be taken into consideration when evaluating the motor capability based on reduced voltages. Additionally, adjustable speed drive motors should be reviewed to ensure they will perform satisfactorily for system faults and depressed voltage conditions.
- The loss of nuclear units during system disturbances is of great concern, especially for system voltages above 85 percent of rated system voltage. Some units start tripping auxiliaries at voltages from 90 percent to 95 percent. These undervoltage settings were determined by engineering studies supporting the nuclear plant and safe shutdown during the nuclear licensing procedure. As such, they are not likely to be changed. Therefore, Transmission Owners, Transmission Operators, Planning Coordinators, and Reliability Coordinators should recognize the undervoltage sensitivity of those units to tripping during voltage perturbations.
- The Generator Owner should consider auxiliary motor contactor low-voltage drop-out points when reviewing undervoltage protection on the plant auxiliary systems.

Coordination Procedure

Setting Procedure

Step 1 – Verify that the setting is set to prevent operation for voltage greater than or equal to 85 percent of nominal voltage at the high side of a system-connected auxiliary transformer or at the high side of the generator step-up transformer for generator-connected auxiliary systems.

Step 2 – Verify that the timer setting is set long enough to prevent operation for a transient condition on the order of two to three seconds or more.

Step 3 – Some nuclear power plants use an undervoltage function, commonly set around 90 percent, on the safety-related bus based on their design basis to support safe shutdown of the reactor.

Setting Considerations

- Undervoltage protection should not trip for a recoverable transmission system event; that is, a system voltage of 85 percent nominal during the event.
- Undervoltage function calculation for a safety-related bus in a nuclear power plant needs to be completed based on IEEE Std. 741–2007, “IEEE Standard Criteria for the Protection of Class 1E Power Systems and Equipment in Nuclear Power Generating Station”; see the Purpose of the Generator Auxiliary System Function 27 — Undervoltage Protection section of this document for further details.

- NRC design basis studies are required to determine the undervoltage level set points (IEEE Std. 741–2007 and IEEE Std. 765–2006, "IEEE Standard for Preferred Power Supply (PPS) for Nuclear Power Generating Stations"); see the Purpose of the Generator Auxiliary System Function 27 — Undervoltage Protection section of this document for further details.
- IEEE Std. C37.96–2012, "IEEE Guide for AC Motor Protection," suggests an undervoltage setting of 80 percent voltage, with a two-to-three-second time delay.
- Motor applications that cause voltage drops during starting that approach 80 percent may require a lower setting. This consideration should be applied based on the specific application.
- In some cases, undervoltage protection is not applied for auxiliary systems.
- Undervoltage protection may be connected to trip the appropriate contactor or circuit breaker where operation will not trip load that is essential to operation of the power plant.
- Overcurrent protection provides protection for thermal concerns associated with operating motors at reduced voltage.

For further information on function 27 issues, see Sections 4.5.7 and A.2.13 of IEEE Std. C37.102–2006 and Section 7.2.4 of IEEE Std. C37.96–2012.

NOTE: Caution should be used in setting function 27 for auxiliary tripping when variable speed drives are used.

Examples

Proper Coordination

- Undervoltage function (27) calculation:

  V_{27} = 80% of $V_{nominal}$ = 0.8 x 120 V = 96 V and a time delay of two to three seconds

- Avoid the loss of generating unit due to tripping of the auxiliary system elements during a recoverable extreme system event. A recoverable extreme system event is defined as a transmission system voltage at the high side of the generator transformer of 0.85 per unit.
- A time delay of two to three seconds should allow system protection to act first to remove the adverse/fault condition.

Improper Coordination

Improper coordination would result from a threshold setting higher than 90 percent voltage at the auxiliary system bus and/or an inadequate time delay.

Summary of Protection Functions Required for Coordination

Table 2 Excerpt: Function 27 (Plant Aux.) Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Functions**	**System Concerns**
27 – Plant Auxiliary Undervoltage **If Tripping is used** – the correct set point and adequate time delay so it does not trip for system faults and recoverable extreme system events	21 27 if applicable 87B 87T 50BF Longest time delay for transmission system protection to clear a fault	• Coordinate the auxiliary bus protection and control when connected directly to the high-voltage system. • Generator Owner to validate the proper operation of auxiliary systems at 85 percent nominal voltage on the high side of the GSU. The preferred undervoltage trip setting is 80 percent. • Settings should be used for planning and system studies, either through explicit modeling of the function or through monitoring voltage performance at the relay location in the stability program—and applying engineering judgment.

Summary of Protection Function Data and Information Exchange Required for Coordination

The following table presents the data and information that need to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above examples.

Table 3 Excerpt: Function 27 (Plant Aux.) Data to be Exchanged Between Entities		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Relay settings: Undervoltage set point if applicable, including time delays, at the power plant auxiliary bus	Time delay of transmission system protection	Feedback on problems found in coordinating with stressed voltage condition studies and, if applicable, UVLS studies

Undervoltage Relays (Function 27) Applied at the Point of Common Coupling

IEEE Std. 1547–2003, "Standard for Interconnecting Distributed Resources with Electric Power Systems," prescribes undervoltage protection at the point of common coupling (PCC) (i.e., the point of interconnection). The purpose of this function is to trip the distributed resource on undervoltage if the distributed resource is islanded from the interconnected distribution system along with local load or is measuring a prolonged system fault. **IEEE Std. 1547–2003 applies to generators of less than 10 MW that are connected to the distribution system.**

Owners of some large generators connected to the transmission system have added this function at the point of common coupling. It is possible that some interconnection agreements include this protection as a requirement. IEEE Std. 1547–2003 does not apply to the transmission system connection of generators as addressed in this technical reference document. Anti-islanding protection is not recommended, because the isolation of the generator from the transmission system will not isolate the generator on system load, nor will there likely be an undervoltage if the islanded generator is not isolated with load that is greater than generation. Any isolation will be detected by overspeed and overfrequency protection functions. An undervoltage function connected to the high-voltage side of the generator step-up at a generating station should not be used unless it serves an alarm function. If an undervoltage function is used, it should be connected to the voltage transformers on the terminal of the generator in alarm mode. See also Section 3.3.1.

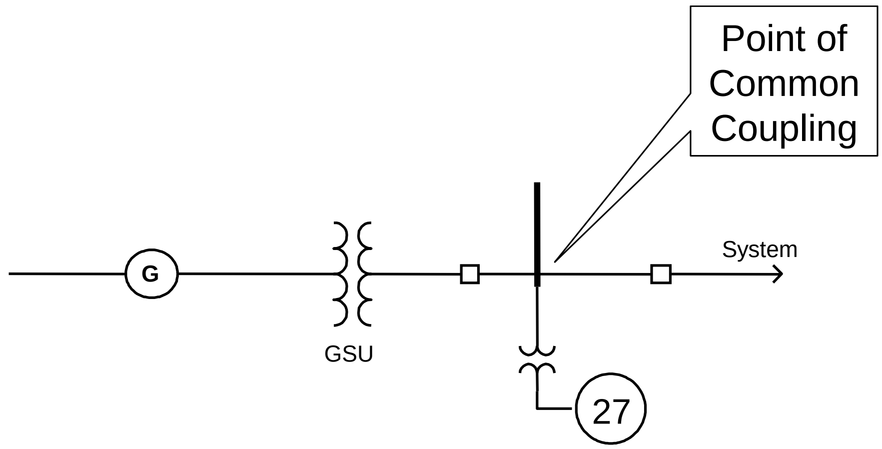


Figure 15: Undervoltage Relay Applied at the Point of Common Coupling

Purpose of the Function 27 at Point of Common Coupling

The purpose of these functions is to alert the Generator Operator that an undervoltage on the transmission system is occurring and that the operator should be on a heightened state of awareness, matching this alarm with others that may be occurring within the plant. See the Generator Unit Undervoltage Protection section of this document.

Coordination of Generator and Transmission System

If a UVLS protection is deployed in the vicinity of the generator, the Generator Operator should be cognizant of the UVLS program and its settings within the system connected to the generator. The Generator Operator should be aware of all studies that demonstrate the need for UVLS and should be trained on the impact of transmission undervoltage on plant operation.

Faults

Undervoltage functions sensing transmission voltages can alarm for system faults. Undervoltage functions may alarm for phase-ground faults and multiphase faults. The generator operator should, upon alarm, focus attention on in-plant alarms, especially per generator-manufacturer-recommended plant alarm conditions.

Loadability

PCC undervoltage functions should alarm for stressed system conditions. This means that these functions should alarm for 0.85 per unit system voltage or less. System studies may be performed to quantify and qualify the likely nature of the system undervoltage function alarms to assert based on the severity of stressed system conditions. Since this function should only alarm, it should be immune to loadability tripping.

Considerations and Issues

There should be no loss of generation due to system undervoltage alarms or operator action during a system fault or a recoverable extreme system event. A recoverable extreme system event is defined as a transmission system voltage at the high side of the generator transformer of 0.85 per unit. UVLS studies should include undervoltage alarm set points so that the Transmission Owner can alert and provide operator training input with regard to the studied changing voltages that can occur as UVLS is performing the system return to planned voltage levels.

Coordination Procedure

Step 1 – Generator Owner to provide settings, time delays, and protection output alarm functions to the Transmission Owner and Planning Coordinator for both the generator and generator step-up transformer.

Step 2 – The Transmission Owner and Planning Coordinator confirm that any UVLS actions are conveyed to the Generator Owner.

Step 3 – The Generator Owner conveys and confirms operator action steps with the Transmission Owner and Planning Coordinator for their concurrence based on a joint understanding of system study results.

Setting Considerations

If an alarm is used by Generator Owners, then:

Undervoltage function (27) calculation:

V_{27} = 85% of $V_{nominal}$ = 0.85 x 120 V = 102 V with a coordinated time delay

Note: An 85 percent set point was chosen to allow for a reasonable margin for extreme system contingencies.

Examples

In this example, a stressed system condition is occurring. The Generator Operator observes the condition and measures the PCC voltage. The Generator Operator contacts the Transmission Operator requesting information and conveys the plant PCC voltage value to the Transmission Operator. As per joint training (including simulation training), the Generator Operator conveys plant status to the Transmission Operator and both agree on the next step in plant operations based on all alarm and status information both inside the plant and within the transmission system.

Proper Coordination

PCC undervoltage function is applied to alarm only. Both Generator Owner and Transmission Owner share system and plant alarm, change in equipment status, and next-step activities using three-way communication and operational planning studied results.

Improper Coordination

There is no improper coordination for an alarm-only function.

Summary of Protection Functions Required for Coordination

Table 2 Excerpt: Function 27 (Plant HV System Side) Protection Coordination Considerations

Generator Protection Function	Transmission System Protection Functions	System Concerns
27 – Plant High-Voltage system-side undervoltage	21 27 if applicable 87B 87T 50BF Longest time delay for transmission system protection to clear a fault	• Must not trip prematurely for a recoverable extreme system event with low voltage or system fault conditions • UVLS set points and coordination if applicable • Settings should be used for planning and system studies, either through explicit modeling of the function or through monitoring voltage performance at the relay location in the stability program—and applying engineering judgment.

Summary of Protection Function Data and Information Exchange Required for Coordination

The following table presents the data and information that need to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above examples.

Table 3 Excerpt: Function 27 (Plant HV System Side) Data to be Exchanged Between Entities		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Relay settings: Undervoltage set point if applicable, including time delays, at high-side bus	Time delay of transmission system protection	Feedback on problems found in coordinating with stressed voltage condition studies and, if applicable, UVLS studies

Nuclear Power Plants — Undervoltage Protection and Control Requirements for Class 1E Safety-Related Auxiliaries Design Guidelines and Preferred Power Supply (PPS)

The base standards for these nuclear requirements are NERC Reliability Standard NUC-001 — Nuclear Plant Interface Coordination; IEEE Std. 741–2007; and IEEE Std. 765–2006.

NERC Reliability Standard NUC-001 requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring safe nuclear plant operation and shutdown.

Section B of NERC Standard NUC-001 describes requirements R1–R9, which are necessary to meet the intent of the interface between the nuclear generating plant and the other entities.

Additionally, the IEEE Nuclear Committee guidelines for protection and control action during degraded voltage conditions for Class 1E systems is found in Appendix A of IEEE Std. 741–2007, Illustration of Concepts Associated with Degraded Voltage Protection.

The guidelines for the types of transmission system studies and data requirements to ensure voltage adequacy of preferred power supply based on the nuclear power generating stations' design basis are in Appendix B of IEEE Std. 765–2006. The Transmission Owner must perform the transmission system studies that demonstrate and validate the PPS performance and that it meets the post-event voltage requirements for the design basis of the plant. This must be valid for all reasonably expected system conditions; otherwise, alternatives need to be investigated (0.85 per unit transmission system voltage as an example for a recoverable extreme system event).

A strong communications tie between the nuclear plant owner and the Transmission Owner is critical.

The following information needs to be exchanged and agreed to by both parties:

a. Input data for models
b. Modeling methods
c. Design and licensing bases
d. Interpretation of study results

The minimum required steady-state post-event grid voltage is based on the nuclear unit maintaining acceptable requirements and possible continued operation.

A recognition and notification process for unacceptable PPS voltages at the nuclear plant substations must be in place from the Transmission Owner to the nuclear plant operations.

Please refer to NERC Reliability Standard NUC-001, IEEE Std. 741–2007, and IEEE Std. 765–2006 for further details.

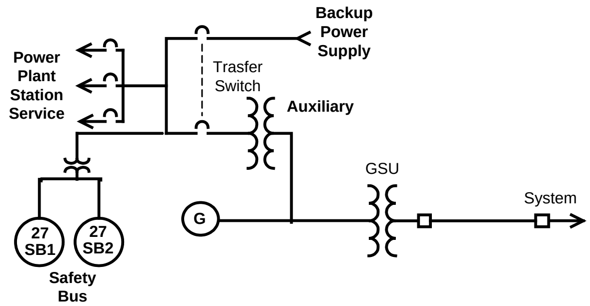


Figure 16: Nuclear Power Plant Auxiliary System Power Supply

Once the criteria and plan are established between the Generator Owner of the nuclear plant and Transmission Owner, the Planning Coordinator must incorporate this strategy into any analysis of recoverable extreme system events, including if the analysis deems that the nuclear generating unit is tripped during the event. The Planning Coordinator must then demonstrate the ability of the system to survive without the benefit of the nuclear generating unit.

Comparison of Stressed Transmission System Voltage Impact on Combustion Turbine Plants with Auxiliaries Directly Fed from the Transmission System versus Fed from the Generator Bus via a Unit Auxiliary Transformer

With their substantial addition to the electric grid in recent years, combustion turbine generating units are becoming a more significant part of the total generation. Due to cost reduction in designs to maintain competiveness, some of these plants were designed with transmission-fed auxiliary system supply transformers in lieu of a unit auxiliary transformer fed from the generator bus. For these systems, the auxiliary loads do not derive a direct benefit of field forcing (voltage boost) during system-degraded voltage events. This field forcing can represent a significant amount of voltage for a brief period in time. The generator, depending on its MVA size as compared to the size and stiffness of the system, can provide a voltage boost of a few percent or more on the generator bus above the system voltage on the transmission high side. This was demonstrated in the section titled Phase Distance Protection for the System Backup Protection with Generator Terminal Voltages above the System Voltage. A few percent higher voltage can prove valuable during these types of extreme reduced-voltage events and may make the difference for continued operation of the auxiliary system and, thus, the generating unit(s).

To illustrate this condition, a hypothetical combustion turbine generating unit will be used to show the difference between the two designs (system-fed and generator-fed auxiliary systems). A number of other factors can impact whether the auxiliary system can survive during these extreme system events reduced voltage events and are identified below. IEEE Std. 666-2007, “IEEE Design Guide for Electric Power Service Systems for Generating Stations,” provides detailed information and guidance pertaining to these topics on auxiliary systems.

Some of the factors that have an impact are:

1. Motor-rated voltage (e.g., 4,000 volt motors applied on 4,160 volt nominal system).
2. Motor-rated torque capability at rated voltage. Some motors have rated torque capability at a reduced voltage to provide margin.
3. Utilization of no-load taps on the transformer.

Utilization of these techniques can help optimize the auxiliary system performance during stressed system voltage events.

If a conservative five percent voltage drop is assumed for an auxiliary system to the motor terminals, for the following two examples:

- Unit auxiliary transformer-fed auxiliary system — Degraded system voltage is 0.85 per unit and generator voltage is at 0.87 per unit due to field forcing; a 0.05 per unit voltage drop yields a 0.82 per unit voltage at the motor terminals. If the trip setting is at 0.80 per unit, the motors will not be tripped.
- Transmission system transformer-fed auxiliary system — Degraded system voltage is 0.85 per unit and transformer voltage is at 0.85 per unit; a 0.05 per unit voltage drop yields a 0.80 per unit voltage at the motor terminals. If the trip setting is at 0.80 per unit, the motors will be tripped.

Figures 17 and 18 show the differences between the two supplies discussed in this section.

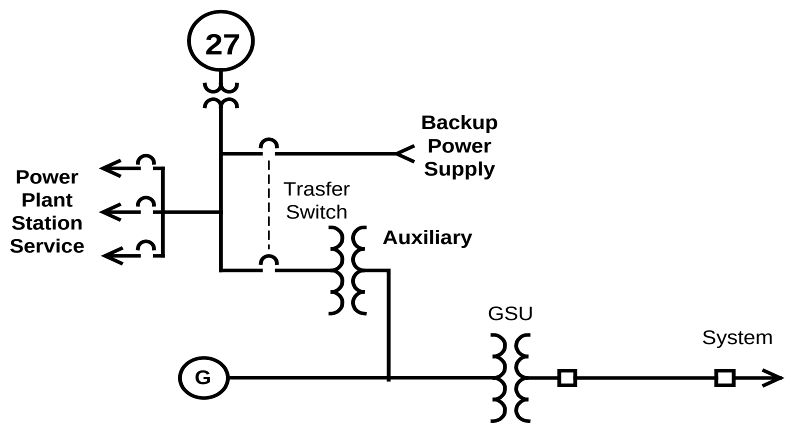


Figure 17: Unit Auxiliary Transformer Supplied Scheme

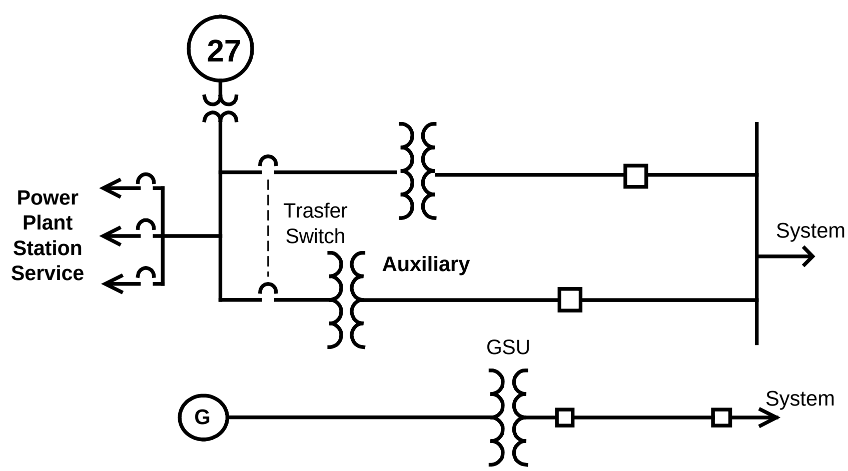


Figure 18: Transmission System Transformer Supplied Scheme

Design and application changes, such as sourcing off the generator bus or other methods less impacted by the transmission system, should be given consideration to benefit the reliability of the auxiliary system voltage during stressed system conditions. See IEEE Std. 666-2007 for more background. **The fact that units with auxiliaries fed**

from the system (not the generator bus) could trip on undervoltage during system events must be recognized in system studies.

Reverse Power Protection (Function 32)

Purpose of Generator Function 32 — Anti-Motoring Protection

Reverse power protection uses a measure of reverse power derived from the real component of generator voltage times generator stator current times √3. Section 4.5.5 of IEEE Std. C37.102–2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows:

> *Motoring of a generator occurs when the energy supply to the prime mover is cut off while the generator is still online. When this occurs, the generator will act as a synchronous motor and drive the prime mover. While this condition is defined as generator motoring, the primary concern is the protection of the prime mover that may be damaged during a motoring condition.*
>
> *In sequential tripping schemes for steam turbine generators, a deliberate motoring period is included in the control logic to prevent potential over-speeding of the unit (see also 7.2.3.4). While some of the devices used in the control logic for sequential tripping schemes are the same as those used in antimotoring protection, the two functions should not be confused. Antimotoring protection should provide backup protection for this control logic as well as for other possible motoring conditions that would not be detected by the sequential tripping control logic (such as inadvertent closure of governor valves or high system frequency conditions).*
>
> *Intentional motoring conditions may be permitted on both gas turbine and hydro applications, where the process is used to accelerate the rotor during starting conditions or the installation is operated in a pump/storage mode.*

Reverse power protection is applied to prevent mechanical damage (on turbine blades, shafts, gear boxes, etc.) in the event of failure of the prime mover.

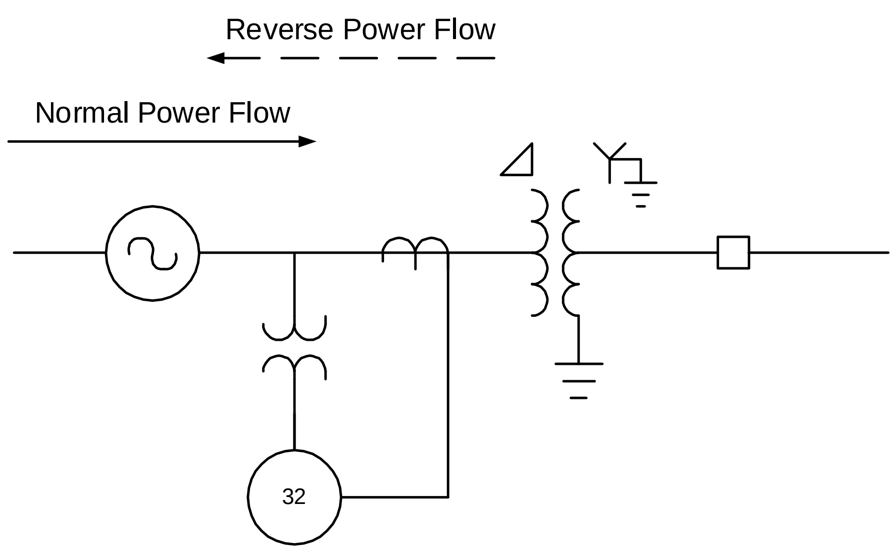


Figure 19: Reverse Power Flow Detection

Coordination of Generator and Transmission System

Faults
There are no coordination issues for system faults for this function.

Loadability
In general, there are no loadability issues with this function.

Considerations and Issues
The reverse power condition is undesired for generators. The power drawn by the generator during motoring is equal to the mechanical losses, and they can be very low for large steam units (below 0.5 percent in some cases). Therefore, a reverse power function typically is set very sensitive to prevent mechanical damage on turbine blades, shafts, gear boxes, etc.

When setting this function, it is important to note that some relays can be susceptible to tripping during conditions when the unit is operated underexcited (leading) with high reactive power (var) loading. In particular, this can occur when the active power (MW) loading is low, such as when a unit is initially synchronizing to the grid.

The following must be considered:

- The time-delay setting: a typical setting is 10 to 30 seconds or longer, depending on the unit.
- The time-delay should be set long enough that the unit will not trip for a system-transient condition or power swing condition where a momentary reverse power is possible for a short duration.

Further discussion is given in Section A.2.9 of IEEE Std. C37.102–2006.

Coordination Procedure
Refer to IEEE Std. C37.102–2006 for function 32 setting recommendations.

Examples
In general, there are no coordination issues with this function.

Summary of Protection Functions Required for Coordination

Table 2 Excerpt: Function 32 Protection Coordination Consideration

Generator Protection Function	Transmission System Protection Functions	System Concerns
32 – Reverse Power	None	• Some relays can be susceptible to misoperation at high leading reactive power (var) loading.

Summary of Protection Function Data and Information Exchange Required for Coordination

Table 3 Excerpt: Function 32 Data to be Exchanged Between Entities

Generator Owner	Transmission Owner	Planning Coordinator
None	None	None

Loss-of-Field Protection (LOF) — Function 40

Purpose of the Generator Function 40 — Loss-of-Field Protection

Loss-of-field protection uses a measure of impedance derived from the quotient of generator terminal voltage divided by generator stator current. Section 4.5.1 of IEEE Std. C37.102–2006 describes the purpose of this protection as follows:

> *The source of excitation for a generator may be completely or partially removed through such incidents as accidental tripping of a field breaker, field open circuit, field short circuit (flashover of the slip rings), voltage regulation system failure, or the loss of supply to the excitation system. Whatever the cause, a loss of excitation may present serious operating conditions for both the generator and the system.*

The guide also includes the following passages specific to combustion gas and steam turbine (round rotor) generators:

> *When a generator loses its excitation, it will overspeed and operate as an induction generator. It will continue to supply some power to the system, and it will receive its excitation from the system in the form of vars."*
>
> *"In general, the severest condition for both the generator and the system is when a generator loses excitation while operating at full load. For this condition, the stator currents may be in excess of 2.0 pu, and since the generator has lost synchronism, there may be high levels of current induced in the rotor. These high current levels may cause damaging overheating of the stator windings. In addition, since the loss-of-field condition corresponds to operation at very low excitation, overheating of the end portions of the stator core may result. No general statements may be made with regard to the permissible time a generator may operate without field, and the generator manufacturers should be consulted for guidance.*
>
> *With regard to effects on the system, the var drain from the system may depress system voltages and thereby affect the performance of generators in the same station, or elsewhere on the system. In addition, the increased reactive flow across the system may cause voltage reduction and/or tripping of transmission lines and thereby adversely affect system stability.*

A loss-of-field condition may result in both the loss of reactive power support from a generator and the creation of a substantial reactive power drain from the system. On large generators, this condition can contribute to or trigger a wide-area system voltage collapse.

Protection from a loss-of-field condition of the generator is provided to prevent machine damage due to large stator currents and to prevent large reactive drain from the system resulting in voltage collapse and tripping of transmission lines.

When the excitation (field) is reduced or lost, the terminal voltage begins to decrease and the stator current increases, resulting in a decrease in impedance (Z=V/I) viewed from the generator terminals. Also, the power factor changes from lagging to leading. The impedance moves into the fourth quadrant from first quadrant due to the reactive power flow from the system into the generator. For detecting this impedance change, there are two basic relaying schemes as shown in Figures 20 (dual offset mho characteristics type) and 22 (dual offset mho characteristics with directional element).

The loss-of-field function can misoperate during system disturbances and power swing conditions if they are not set properly, considering coordination with generator parameters and system conditions. This is especially true if only a single offset mho characteristic is used with a short time delay or no time delay.

The purpose of this section is to describe the coordination issues with the setting of loss-of-field relaying and certain system conditions that can cause inadvertent tripping of the unit. The field current in the generator could also be excessive.

Figure 20 shows the problems associated when the swing results in a stable operating point outside the excitation capabilities of the machine, resulting in a necessary trip of the loss-of-field function.

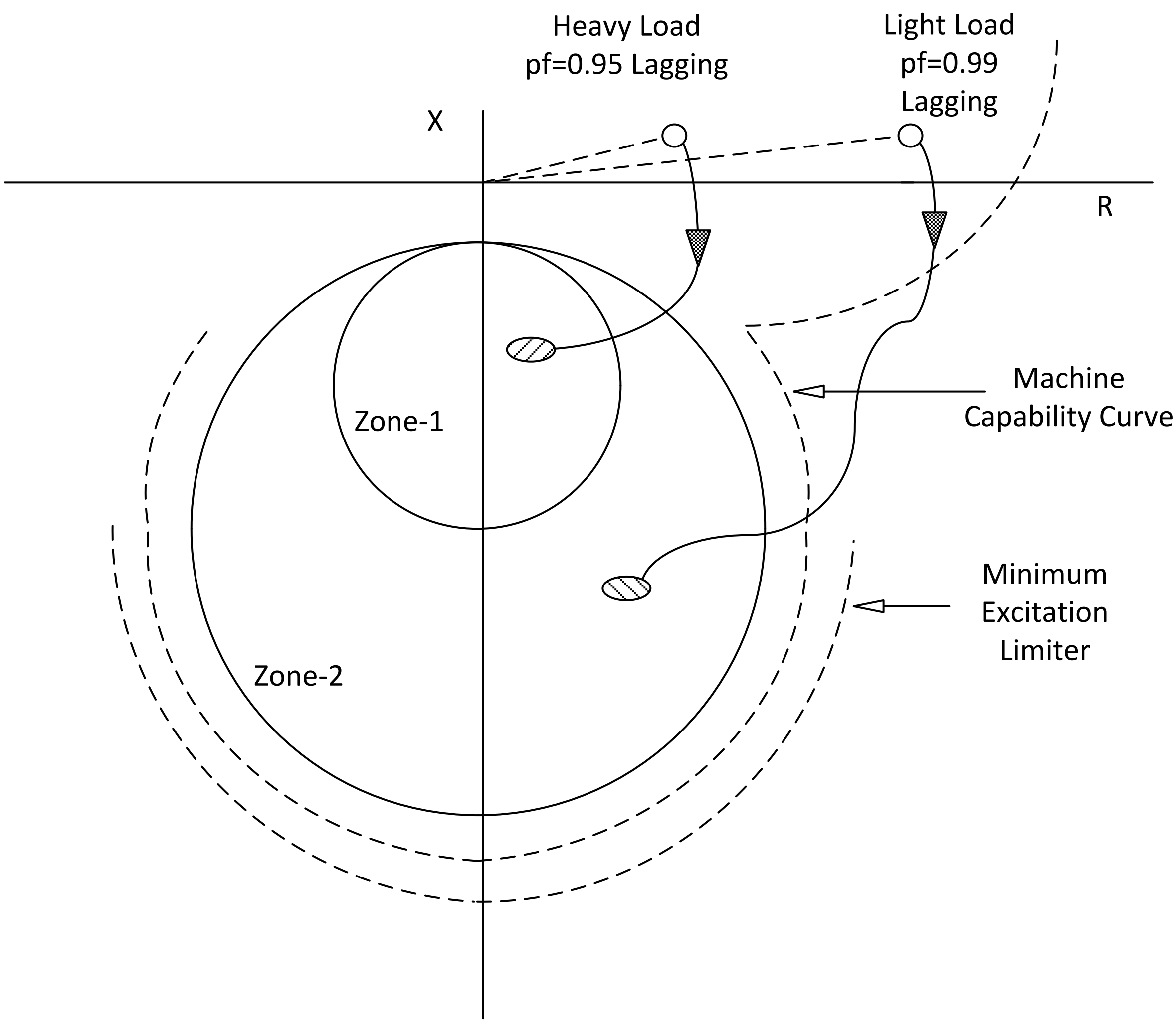


Figure 20: (1) Locus of Swing Impedance during Light and Heavy Loads for Loss of Field, and (2) Relationship between Minimum Excitation Limiter (MEL) or Underexcitation Limiter (UEL)

Coordination of Generator and Transmission System

Faults

Step 1 – The Transmission Owner provides the Planning Coordinator with the worst-case clearing time for each of the power system elements connected to the transmission bus at which the generator is connected.

Step 2 – The Planning Coordinator determines the stability impedance trajectory for the above conditions.

Step 3 – The Planning Coordinator provides these plots to the Generator Owner. The Generator Owner utilizes these plots to demonstrate that these impedance trajectories coordinate with the time-delay setting of the loss-of-field function to prevent misoperations by having adequate time delay.

System-stability studies are used to evaluate the generator and system responses to power system faults. The Generator Owner must share information on settings with the Planning Coordinator to facilitate studies to confirm whether the loss-of-field function may operate for external fault conditions not related to a loss-of-field condition. The loss-of-field function may operate for an unstable power swing. While tripping for this condition may be acceptable, out-of-step protection provides more dependable tripping.

Loadability

Step 1 – The Generator Owner confirms that the loss-of-field function setting coordinates with the generator's reactive capability and the excitation system capability to ensure that the loss-of-field function does not restrict operation of the generating unit.

Step 2 – A light load system study is completed in which the generator is taking in vars. A sufficient number of operating conditions and system contingencies are evaluated to identify the worst-case operating condition for coordination with the loss-of-field function setting. The output of this study is provided to the Generator Owner to evaluate whether the worst-case operating load condition(s) lie outside the loss-of-field characteristic.

Step 3 – For any case where the operating load point lies within a properly set loss-of-field characteristic, a mutually agreed upon solution must be applied (i.e., shunt reactor, turning off capacitor banks in the area, etc.). Where the solution requires real-time action by an operator, the solution is incorporated into a system operating procedure.

Coordination between Generator Owners, Transmission Owners, and Planning Coordinators is necessary to prevent loadability considerations from restricting system operations. This is typically not a problem when the generator is supplying vars, because the loss-of-field characteristics are set to operate in the third and fourth quadrants. However, when the generator is taking in vars due to light-load and line-charging conditions or failure of a transmission capacitor bank to open due to control failures, loss-of-field functions can operate if the apparent impedance enters the relay characteristic in the fourth quadrant.

Considerations and Issues

There are two hazards to be concerned with when operating a generator underexcited. The first concern is the generator capability curve (GCC) limit. Operation of the generator beyond the underexcited operating limit of the GCC can result in damage to the unit. The primary protection for this is the underexcitation limiter (UEL) control on the excitation system. Loss-of-field functions should be properly coordinated with the GCC and UEL.

The other concern is the steady-state stability limit (SSSL). If the unit is operated with too little excitation, it can go out of step. The loss-of-field function settings should also properly coordinate with the SSSL.

Other considerations include operation of the generator as a synchronous condenser and the generator absorbing reactive power from connected long transmission lines (line charging) or large transmission capacitor banks near the generating plant. Procedures such as closing the remote end of the transmission first before reclosing the generator terminal of the line would minimize the effects of line charging causing misoperation of the loss-of-field function.

The Generator Owner should provide the setting information for the loss-of-field function to the Transmission Owner and the Planning Coordinator. The impedance trajectory of most units with a lagging power factor (vars into the power system) for stable swings will pass into and back out of the first and second quadrants. It is imperative that the loss-of-field function does not operate for stable power swings.

The loss-of-field function settings must be provided to the Planning Coordinator by the Generator Owner so that the Planning Coordinator can determine if any stable swings encroach long enough in the loss-of-field function trip zone to cause an inadvertent trip. The Planning Coordinator has the responsibility to periodically verify that power system modifications do not result in stable swings entering the trip zone(s) of the loss-of-field function, causing an inadvertent trip. If permanent modifications to the power system cause the stable swing impedance trajectory to enter the loss-of-field characteristic, then the Planning Coordinator must notify the Generator Owner that new loss-of-field function settings are required. The Planning Coordinator should provide the new stable swing impedance trajectory so that the new loss-of-field settings will accommodate stable swings with adequate time delay. The new settings must be provided to the Planning Coordinator from the Generator Owner for future periodic monitoring.

In a limited number of cases, conditions may exist in which coordination cannot be achieved for every generating unit. In such cases, coordination may be deemed acceptable if tripping does not cascade and is limited to a small amount of generation (as a percentage of the load in the affected portion of the system). Protection models must be added to system models for any units for which coordination cannot be obtained.

Coordination Considerations

- The coordination requirements with generator controls are such that the loss-of-field function must not operate before the UEL limit (with a margin) is reached. It is also important to determine if the UEL in the excitation control allows the quick change of reactive power (see Figure 20) beyond the limit. If it does, then the setting should have an adequate margin between the UEL and the loss-of-field setting to prevent unnecessary operation of the loss-of-field function during this condition. The other concern is the SSSL, particularly when the automatic voltage regulator (AVR) of the unit is operating in manual mode. If the unit is operated with too little excitation, it can go out of step. Therefore, the unit should be tripped before a steady-state stability limit is reached.
- Some relay characteristics change with variation in frequency (this is especially true for electromechanical and static relays). These characteristic changes during power swing conditions (where the frequency can vary considerably from nominal values) can cause unnecessary tripping of the generator by the loss-of-field function. These characteristic changes need to be considered while setting the function for hydro units, because hydro units can safely operate at speeds greater than 110 percent of nominal while separated from the power system. At frequencies above 60 Hz, the angle of maximum torque for some loss-of-field functions will shift farther into the fourth quadrant, and the circle diameter may increase by 200 percent to 300 percent. With this characteristic change and the shift, it is possible for the function to operate on the increased line-charging current caused by the temporary overspeed and overvoltage condition. Unnecessary operation of the loss-of-field relay schemes for this condition may be prevented by supervising the schemes with either an undervoltage function or an overfrequency function. The overfrequency function would be set to pick up at 110 percent of rated frequency. It would be connected to block tripping when it is picked up and to permit tripping when it resets. An undervoltage function would be set to pick up between 0.8 and 0.9 per unit of generator-rated voltage and is used with the impedance functions to detect a complete loss-of-field condition where the system is not able to provide sufficient reactive power to the generator. Typically, a 0.25-to-1.0-second time delay is used with this function.

- The protection scheme may use a single-zone offset mho characteristic or a dual-zone offset mho characteristic. Dual-zone offset mho characteristics are preferred, especially for steam and combustion turbine units where X_d typically is very large.
- The loss-of-field scheme should be provided with an adequate time delay for providing security against operation during stable power swings.
- The relay timers should have a fast reset ratio for secure operation.
- The loss-of-field setting should consider two system scenarios: the strongest available system (all transmission facilities in service and all generation on), and the weakest credible system (maximum transmission constraints and minimum generation dispatch). Special considerations for loss-of-field settings may be necessary for blackstart operation of the unit.

Example

Proper Coordination

The following describes how the typical loss-of-field function should be set. These settings should be reflected in transmission system planning and operational planning analyses.

Typical loss-of-field relay setting calculation for a two-zone offset mho characteristic:

Step 1 – Calculate the base impedance = 17.56Ω/per unit

$$Z_{base} = \frac{20{,}000V/VTR\sqrt{3}}{14{,}202A/CTR} = \frac{20{,}000/166.67}{14{,}202/3600} = \frac{69.28}{3.945} = 17.56\Omega/\text{per unit}$$

Step 2 – Convert X'_d and X_d in per unit to Ohms:

$$X'_d = (0.20577\,pu)(17.56\Omega/pu) = 3.61\ \Omega$$
$$X_d = (1.1888\,pu)(17.56\Omega/pu) = 20.88\ \Omega$$

Step 3 – Function settings:

Offset = (50%) (X'_d) = (0.5) (3.61 Ω) = 1.8 Ω
Z1 = 1 pu = 17.6 Ω
Z2 = X_d = 20.88 Ω

Step 4 – Plot various characteristics as shown in Figure 20.

Step 5 – Set the time delays for zone 1 and zone 2 functions.

Typical time-delay settings are:

Zone 1: 0.1 sec

Zone 2: 0.5 sec

System stability studies should be conducted to see if the above time delays are sufficient to prevent inadvertent tripping during stable power swings.

Figure 22 illustrates an alternate scheme where one of the offset mho relays is set with a positive offset. Figure 22 also shows an example case of an apparent impedance trajectory during a stable swing as a result of fault clearing. Response of the loss-of-field relay during these types of swing characteristics needs to be studied.

Step 6 – Set the undervoltage supervision (if appropriate):

V = 85% of $V_{nominal}$ = 0.85 x 120V =102 V

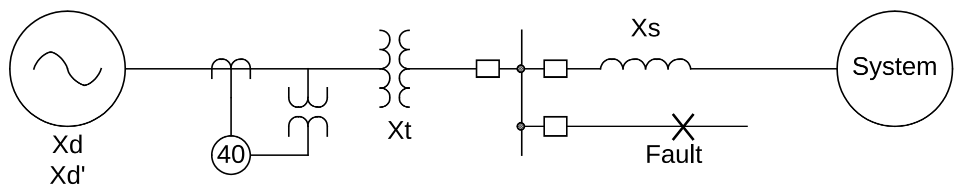


Figure 21: Simplified System Configuration of Function 40 Relay and Fault Locations

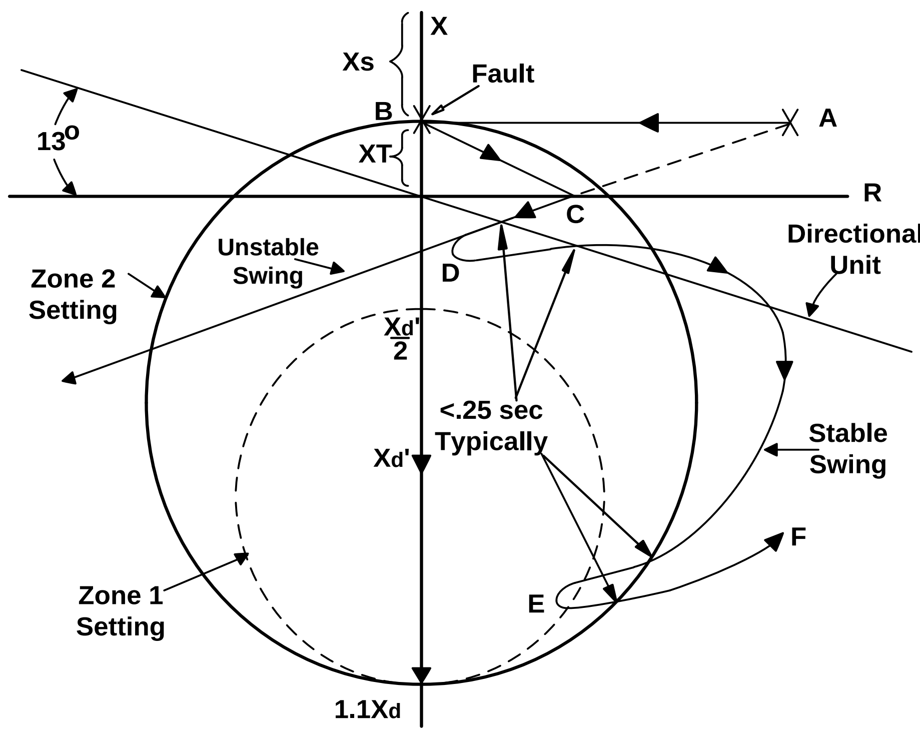


Figure 22: "Two-Zone Offset MHO with Directional Element" Loss-of-Field Relay Charactersitic

Figure 22 Notes:

- *A – 0.9 lagging power factor 1.0 per unit load impedance*
- *B – Three-phase fault location*
- *C – Apparent impedance immediately after fault is cleared*
- *A-B-C-D-E-F – Locus of swing impedance for lagging 0.9 power factor with fault clearing at critical switching time*

Figure 22 shows a stable swing incursion into the zone 1 of the loss-of-field function. This would result in an undesirable operation of the loss-of-field function if the zone 1 time delay is not sufficient.

When a dual-offset mho characteristic is used for loss-of-field protection, it should be carefully studied for security to prevent operation for stable swings when the generation is connected to a weak transmission system.

For further details and discussion regarding interaction of this protective function, the excitation system controls, and limiters, please refer to Reference 8 (see Appendix A), *Coordination of Generator Protection with Generator Excitation Control and Generator Capability*.

Summary of Protection Functions Required for Coordination

Table 2 Excerpt: Function 40 Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Functions**	**System Concerns**
40 – Loss of Field (LOF)	Settings used for planning and system studies	• Preventing encroachment on reactive capability curve • See details from sections 4.5.1 and A.2.1 of IEEE Std. C37.102–2006. • It is imperative that the LOF function does not operate for stable power swings. The impedance trajectory of most units with a lagging power factor (reactive power into the power system) for stable swings will pass into and back out of the first and second quadrants.

Summary of Protection Function Data and Information Exchange Required for Coordination

The following table presents the data and information that need to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above example.

Table 3 Excerpt: Function 40 Data to be Exchanged Between Entities		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Relay settings: loss-of-field characteristics, including time delays, at the generator terminals Generator reactive capability	The worst-case clearing time for each of the power system elements connected to the transmission bus at which the generator is connected	Impedance trajectory from system-stability studies for the strongest and weakest available system Feedback on problems found in coordination and stability studies

Negative Phase Sequence or Unbalanced Overcurrent Protection (Function 46)

Purpose of the Generator Function 46 — Negative Phase Sequence Overcurrent Protection

Negative sequence overcurrent protection uses a measure of negative sequence current produced by the unbalanced conditions of the system to which the generator is connected. Section 4.5.2 of IEEE Std. C37.102–2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows:

There are a number of system conditions that may cause unbalanced three-phase currents in a generator. The most common causes are system asymmetries (untransposed lines), unbalanced loads, unbalanced system faults, and open phases. These system conditions produce negative-phase-sequence components of current that induce a double-frequency current in the surface of the rotor, the retaining rings, the slot wedges, and to a smaller degree, in the field winding. These rotor currents may cause high and possibly dangerous temperatures in a very short time.

The ability of a generator to accommodate unbalanced currents is specified by IEEE Std. C50.12, IEEE Std. C50.13, and IEC 60034-1 in terms of negative-sequence current (I_2). This guide specifies the continuous I_2 capability of a generator and the short time capability of a generator, specified in terms $I_2^2t = K$, as shown in Figure 4-39 (curve drawn using data from IEEE Std. C50.13.)

The negative-sequence component of current is similar to the positive-sequence system except the resulting reaction field rotates in the opposite direction to the dc field system. Hence, a flux is produced that cuts the rotor at twice the rotational velocity, thereby inducing double-frequency currents in the field system and in the rotor body. The resulting eddy currents can be very large and cause severe heating of the rotor.

Negative-sequence overcurrent protection often includes two settings: one very sensitive setting that alarms for operator action, and a less-sensitive setting that results in tripping.

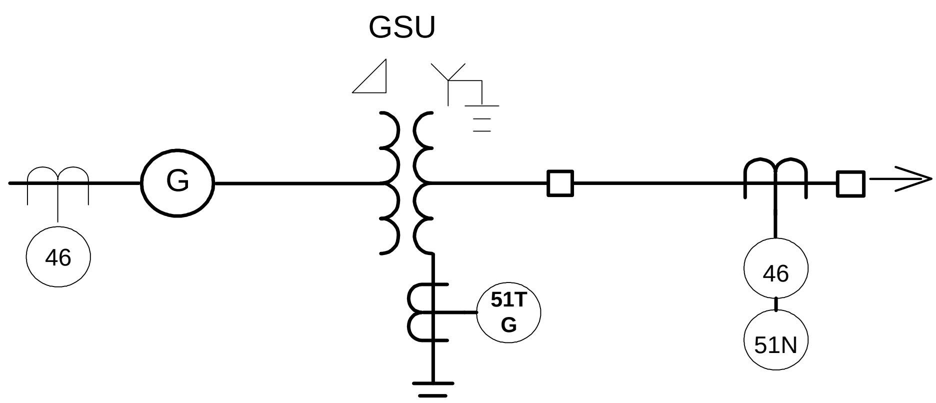


Figure 23: Negative Phase Sequence Protection Coordination

Coordination of Generator and Transmission System

Faults

Step 1 – The Transmission Owner determines the longest clearing time (including breaker failure time) for phase-to-phase and phase-to-ground faults.

Step 2 – The Transmission Owner and Generator Owner verify that the generator negative-sequence function time delay is properly coordinated with appropriate margin with the time delays determined in Step 1.

The transmission system design and operation of protection must take into consideration generator negative-sequence concerns and capabilities.

Areas that need to be addressed by both the Transmission Owner and Generator Owner are as follows:

- Single-pole tripping (or other open-phase conditions such as single-phase disconnect switch operation) on the transmission system will cause high short-term negative-sequence currents until balanced operation is restored.
- Unbalanced faults will result in negative sequence currents until the fault is cleared.
- Open phases such as a pole on a circuit breaker.

Loadability

At maximum generator output, there should be no negative sequence alarm.

Considerations and Issues

For further discussion of negative-sequence current protection, see Section A.2.8 of IEEE Std. C37.102–2006.

The negative-sequence protection function needs to be coordinated with all transmission system unbalanced fault protection.

- If there is an alarm, both the Transmission Owner and Generator Owner must work together to resolve it.
- Untransposed transmission lines can result in negative-sequence current circulation on the transmission system, which can be reflected into generators and cause negative-sequence overcurrent operation.

Coordination Procedure

The following areas should be examined to provide proper protection against excessive negative-sequence current effects: short-time unbalanced current factor (K), and continuous negative-sequence current level (%).

Refer to IEEE Std. C37.102–2006, clause 4.5.2, and IEEE Std. C50.12–2005, "IEEE Standard for Salient-Pole 50 Hz and 60 Hz Synchronous Generators and Generator/Motors for Hydraulic Turbine Applications Rated 5 MVA and Above," clause 4.1.6.1.

Example

Proper Coordination

The generator negative-sequence protection when set according to IEEE Std. C37.102-2006 will generally coordinate with system protection for unbalanced fault conditions due to the set point time delay. Even at 100 percent negative-sequence current, it will take seconds for the protection to trip the generator. The Generator Owner and Transmission Owner need to discuss the magnitude of negative-sequence current resulting from open phases, untransposed lines, and other operational unbalances exhibited by the transmission system, and ensure that the generator negative-sequence function will not trip the generator for negative-sequence currents that are less than the allowable continuous negative-sequence current ratings of the machine.

Generator nameplate:

- Continuous negative-sequence capability of the generator: 10%
- The K factor ($I_2^2 t = K$): 30

Relay Settings:

Inverse Time Function

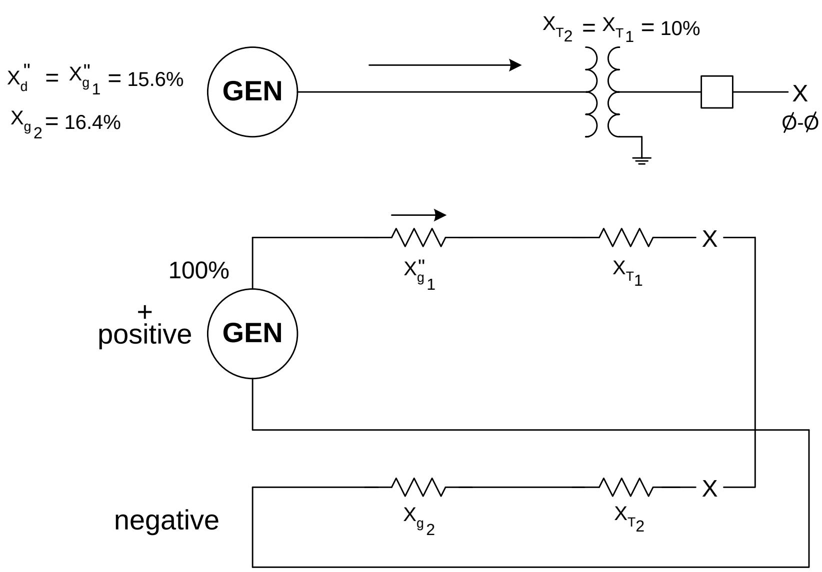
- Pickup for the inverse time function ($I_2^2 t = K$) - 29
- K = 29

Set definite time function for alarm.

- Pickup = 5%
- Time delay = 30 seconds

Time Delay Coordination

As an example, the following generator configuration is used to verify coordination for a phase-to-phase fault at the high side of the generator step-up transformer. This fault location yields the highest negative-sequence current and, thus, the shortest operating time.



$$I_1 = I_2 = \frac{100}{X_{g1} + 2X_T + X_{g2}} = \frac{100}{15.6 + 20 + 16.4} = 1.92 \text{ pu}$$

Figure 24: Sequence Diagram of a Phase-to-Phase Fault

The time delay of the inverse time function for 1.92 per unit negative-sequence current is:

$t = K/I_2^2 = 29/1.92^2 = 7.866$ sec.

This time delay is much longer than any transmission line phase-to-phase fault protection time delay, including the breaker failure time.

Improper Coordination

Coordination is not a concern, because proper setting of the time delays associated with negative-sequence functions will inherently coordinate with system protection due to the wide disparity in time constants between the two protection systems.

Summary of Protection Functions Required for Coordination

Table 2 Excerpt: Function 46 Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Functions**	**System Concerns**
46 – Negative phase sequence overcurrent	21 21G 46 67N 51N Longest time delay of transmission system protection including breaker failure time	• Should be coordinated with system protection for unbalanced system faults • Plant and system operations awareness when experiencing an open pole on the system • Transposition of transmission lines • System studies, when it is required by system condition • Open phase, single-pole tripping • Reclosing • If there is an alarm, Generator Owners must provide I_2 measurements to the Transmission Owner and Planning Coordinator and they must work together to resolve the alarm.

Summary of Protection Function Data and Information Exchange Required for Coordination

The following table presents the data and information that need to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above example.

Table 3 Excerpt: Function 46 Data to be Exchanged Between Entities		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Relay settings: negative phase sequence overcurrent protection characteristics, including time delays, at the generator terminals Generator Owners must provide I_2 measurements to the Transmission Owner and Planning Coordinator for resolution if significant unbalance is observed.	The time-to-operate curve for system relays that respond to unbalanced system faults. This would include the 51TG if the GSU is owned by the Transmission Owner	None

Inadvertent Energizing Protection (Function 50/27)

Purpose of the Generator Function 50/27 — Inadvertent Energizing Protection

Inadvertent Energizing Protection uses a measure of both generator terminal voltage and generator stator current to detect this condition. Section 5.4 of IEEE Std. C37.102–2006 describes the purpose of this protection as follows:

Inadvertent or accidental energizing of off-line generators has occurred often enough to warrant installation of dedicated protection to detect this condition. Operating errors, breaker head flashovers (see 4.7.1), control circuit malfunctions, or a combination of these causes has resulted in generators being accidentally energized while off-line.

The problem is particularly prevalent on large generators that are commonly connected through a disconnect switch to either a ring bus or breaker-and-a-half bus configuration. These bus configurations allow the high-voltage generator breakers to be returned to service as bus breakers, to close a ring bus or breaker-and-a-half bay when the machine is off-line. The generator, under this condition, is isolated from the power system through only the high-voltage disconnect switch. While interlocks are commonly used to prevent accidental closure of this disconnect switch, a number of generators have been damaged or completely destroyed when interlocks were inadvertently bypassed or failed and the switch accidentally closed.

When a generator on turning gear is energized from the power system (three-phase source), it will accelerate like an induction motor. The generator terminal voltage and the current are a function of the generator, transformer, and system impedances. Depending on the system, this current may be as high as 3 pu to 4 pu and as low as 1 pu to 2 pu of the machine rating. While the machine is accelerating, high currents induced into the rotor may cause significant damage in only a matter of seconds.

If the generator is accidentally back fed from the station auxiliary transformer, the current may be as low as 0.1 pu to 0.2 pu. While this is of concern and has occurred, there have not been reports of extensive generator damage from this type of energization; however, auxiliary transformers have failed.

When a generator is off-line on turning gear and is inadvertently energized from the power system, it will develop an inrush current (similar to an induction motor start) that can be as high as 300 percent to 400 percent of the generator nameplate (rating). This inrush current subjects the turbine shaft and blades to large forces and potentially damages the stator windings due to the excessive slip frequency currents and subsequent rapid overheating. The impedance of the transformer and the stiffness of the system dictate the level of inrush current.

This protection is required when the unit is off-line and may or may not be armed when the unit is in service and connected to the system.

A significant number of large machines have been severely damaged and, in some cases, completely destroyed due to inadvertent energizing.

Figure 25 shows a typical inadvertent energizing protection scheme.

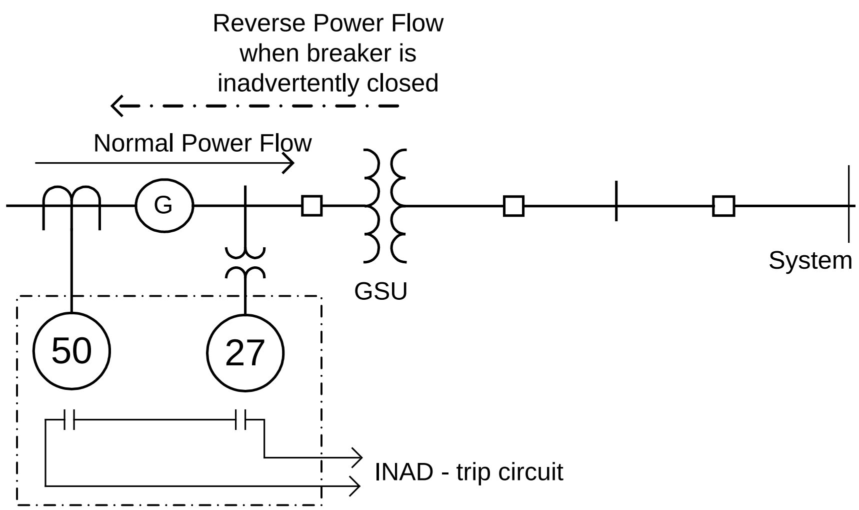


Figure 25: Inadvertent Energizing (INAD) Protection Scheme

Coordination of Generator and Transmission System

Faults

Generator Owner verifies the voltage supervision pickup is 50 percent or less, as recommended by IEEE Std. C37.102–2006.

- It is highly desirable to remove the inadvertent energizing protection from service when the unit is synchronized to the system or, at a minimum, be provided with appropriate secure supervision to ensure that this function does not operate for synchronized generators during system disturbances with reduced voltages.
- The inadvertent energizing protection must be in service when the generator is out of service and should operate with as short a time delay as possible.
- If this function is not disarmed while the unit is in service, then in addition to ensuring an undervoltage set point of less than 50 percent nominal, the timer setting should be long enough to avoid undesired operations (two seconds or greater), which for some applications may conflict with the protection objective.

In the August 14, 2003 disturbance, system voltage was depressed significantly. During that event, seven units using inadvertent energizing schemes operated on synchronized generators due to depressed voltage and unnecessarily removed those units from the system. It is believed that these units had the undervoltage supervision set higher than the recommended set point (i.e., the supervision was not set less than 50 percent of nominal voltage).

Loadability

There are no loadability concerns with this protection function.

Considerations and Issues

The undervoltage (27) supervision function must be set at 50 percent of the nominal voltage level or lower. The setting should be developed based on the specific application and engineering analysis.

Coordination Procedure

Test Procedure for Validation

Check that the function 27 is set lower than 50 percent of the nominal voltage level or lower based on the specific application and engineering analysis.

Setting Considerations

- The function 27 must be set lower than 50 percent of the nominal voltage level or lower to avoid undesired operations.
- Instantaneous overcurrent (function 50) must be set sensitive enough to detect inadvertent energizing (breaker closing).

Example

Proper Coordination

Undervoltage supervision settings of less than 50 percent of nominal voltage, or lower, and more than two seconds of time delay will reduce the possibility of undesired tripping. Note: Inadvertent energizing schemes will be initiated when a condition exists with (1) overcurrent (undesired unit energizing), and (2) undervoltage (unit being off-line) with a delay time. Note that the time delay on the undervoltage supervision does not delay tripping; rather, it delays arming of the scheme.

Improper Coordination

Use of undervoltage supervision settings of greater than 50 percent of nominal voltage, or use of time delays of less than two seconds will greatly increase the possibility of undesired tripping.

Summary of Protection Functions Required for Coordination

Table 2 Excerpt: Function 50/27 (Inadvertent Energization) Protection Coordination Considerations

Generator Protection Function	Transmission System Protection Functions	System Concerns
50/27 — Inadvertent energizing	None	• The function 27 must be set at or below 50 percent of the nominal voltage. • Instantaneous overcurrent (function 50) must be set sensitive enough to detect inadvertent energizing (breaker closing). • Timer setting should be adequately long to avoid undesired operations due to transients – at least 2 seconds. • Relay elements (27, 50, and timers) having higher Dropout Ratio (ratio of dropout to pickup of a relay) should be selected to avoid undesired operations.

Summary of Protection Function Data and Information Exchange Required for Coordination

The following table presents the data and information that need to be exchanged between the entities to validate and document appropriate coordination.

Table 3 Excerpt: Function 50/27 (Inadvertent Energization) Data to be Exchanged Between Entities		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Undervoltage setting and current detector settings pickup and time delay	Review method of disconnect and operating procedures	None

Breaker Failure Protection (Function 50BF)

Purpose of the Generator Function 50BF — Breaker Failure Protection

Breaker failure protection uses a measure of breaker current and/or breaker position to detect this condition. Section 4.7 of IEEE Std. C37.102–2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *Functional diagrams of two typical generator zone breaker failure schemes are shown in Figure 4-52a and Figure 4-52b [of the IEEE Guide]. Like all such schemes, when the protective relays detect an internal fault or an abnormal operating condition, they will attempt to trip the generator and at the same time initiate the breaker-failure timer.*
>
> *If a breaker does not clear the fault or abnormal condition in a specified time, the timer will trip the necessary breakers to remove the generator from the system. As shown in Figure 4-52a, the breaker-failure timer is initiated by the combination of a protective relay and either a current detector (CD) or a breaker "a" switch, which indicates that the breaker has failed to open. Figure 4-52b shows a variation of this scheme that times out and then permits the CD to trip if current continues to flow. The reset time of the CD need not enter into the setting of the BF timer. The breaker "a" switch is used since there are faults and/or abnormal operating conditions such as stator or bus ground faults, overexcitation (V/Hz), excessive negative sequence, excessive underfrequency, reverse power flow, etc., that may not produce sufficient current to operate the CDs. If each pole of the breaker operates independently, breaker "a" switches from all three poles should be paralleled and connected into the logic circuit.*

Breaker failure protection must be provided for large generators such that the generator is isolated in the event its breakers fail to open subsequent to receiving a signal to trip. The current input to the breaker failure relay should be supplied from a CT that measures current through the circuit breaker.

When a generator unit breaker fails, it is required to initiate the tripping of backup breaker(s) for isolation of the failed breaker. Figures 26 and 27 describe breaker failure relaying as it relates to generator and transmission line breaker failures.

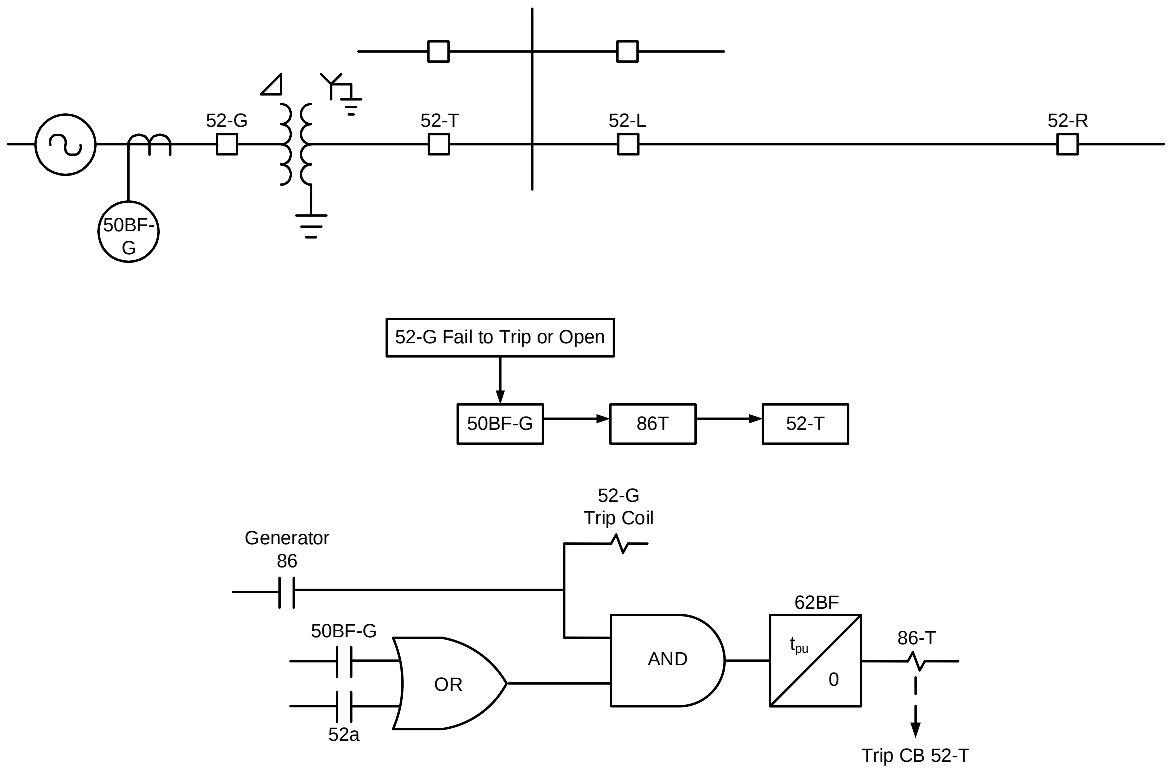


Figure 26: Unit Breaker Failure Logic Diagram

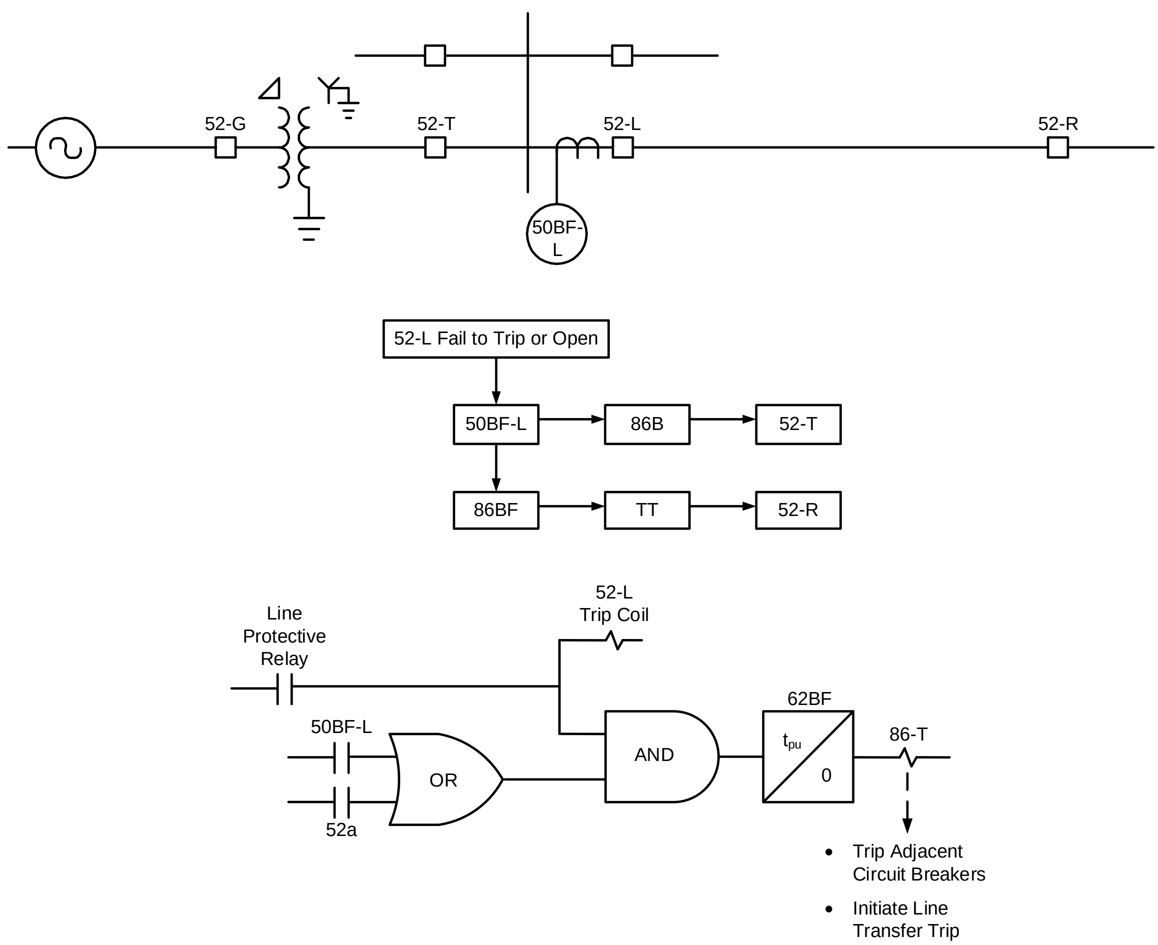


Figure 27: Line Breaker Failure Logic Diagram

Coordination of Generator and Transmission System

Faults

The following coordination issues must be addressed:

> The Transmission Owner and Generator Owner must, for each set of relay coordination, verify that breaker failure time is accounted for properly.

For example:

- All generator unit backup relaying schemes are required to coordinate with protective relays on the next zone of protection, including breaker failure relaying time.
- For obtaining the security and reliability of power system stability, the Generator Owner and Transmission Owner are required to coordinate, plan, design, and test the scheme.
- There must be design coordination to ensure that appropriate backup breakers are tripped for breaker failure operation.

Loadability

There are no loadability issues to be addressed.

Considerations and Issues

All upstream (next-level) protection settings and systems must be considered when evaluating the performance of breaker failure functions associated with generators. Total clearing time (which includes breaker failure time) of each breaker in the generation station substation should coordinate with the critical clearing times associated with unit stability.

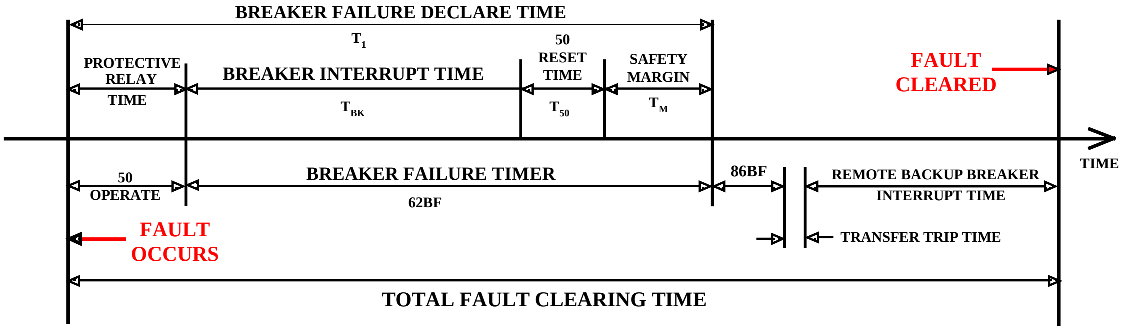


Figure 28: Example of Breaker Failure Timing Chart[2]

The following is an example of the breaker failure timer settings (62BF) of a breaker failure scheme for typical three-cycle breakers:

Three-Cycle Breaker — Breaker Failure Timer = Breaker Interrupting Time + 50 Reset Time + Safety Margin

62BF = TBK + T50 + TM = 3.0 + 1.55 + 5.0 = 9.55 cycles, or 159 milliseconds

[2] This chart is excerpted from the IEEE Std. C37.119–2005 "Guide for Breaker Failure Protection of Power Circuit Breakers."

Coordination Procedure

Setting Considerations

- Total clearing time (which includes breaker failure time) of each breaker in the generation station substation should coordinate with the critical clearing times associated with unit stability. See IEEE Std. C37.119–2005, "IEEE Guide for Breaker Failure Protection of Power Circuit Breakers," for a well-designed breaker failure scheme.
- Clearing time issues are addressed further in Sections 4.7 and A.2.11 of IEEE Std. C37.102–2006.
- Refer to Section 3.1 for coordination of upstream protective function 21 with the breaker failure scheme.

Summary of Protection Functions Required for Coordination

Table 2 Excerpt: Function 50BF Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Functions**	**System Concerns**
50BF – Breaker failure on generator interconnection breaker(s)	Protection on line(s) and bus(es) that respond to faults and conditions on the generator side of the interconnection breaker(s)	• Check for single points of failure • Overcurrent (fault detector) and 52a contact considerations • Critical clearing time • Settings should be used for planning and system studies. • Circuit breaker test data (interrupting time)

Summary of Protection Function Data and Information Exchange Required for Coordination

The following table presents the data and information that need to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above examples.

Table 3 Excerpt: Function 50BF Data to be Exchanged Between Entities		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Times to operate of generator protection Breaker failure relaying times	Times to operate, including timers, of transmission system protection Breaker failure relaying times	Provide critical clearing time or confirm total clearing time is less than critical clearing time

Generator Step-Up Phase Overcurrent (Function 51T) and Ground Overcurrent (Function 51TG) Protection

Purpose of the Generator Step-Up Function 51T — Backup Phase and Function 51TG – Backup Ground Overcurrent

Generator Step-Up Backup Phase Overcurrent Protection — Function 51T

Neither IEEE Std. C37.91–2008, IEEE Guide for Protecting Power Transformers," nor IEEE Std C37.102–2006 supports the use of a phase overcurrent function for backup protection for faults in both the generator step-up and generator, or for system faults. This applies regardless of whether the phase overcurrent protection applied is a discrete relay or an overcurrent function in a multifunction protective relay, such as overcurrent phase functions associated with restraint inputs on microprocessor differential relays.

Section 4.6.1.2 of IEEE Std. C37.102–2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows:

> *In general, a simple time-overcurrent relay cannot be properly set to provide adequate backup protection. The pickup setting of this type of relay would normally have to be set from 1.5 to 2 times the maximum generator rated full-load current in order to prevent unnecessary tripping of the generator during some emergency overload condition. The settings should be reviewed to ensure that the relay will not operate during a system emergency, where the generator terminal voltage will be depressed and the rotor currents will be higher.*

With this pickup setting and with time delays exceeding 0.5 s, the simple time-overcurrent relay may never operate since the generator fault current may have decayed below relay pickup. After 0.5 s or more, generator fault current will be determined by machine synchronous reactance, and the current magnitude could be well below generator rated full-load current, which would be below the relay setting.

Figure 29 shows a multifunction transformer differential relay with the phase overcurrent function associated with the high-side generator step-up restraint enabled. However, these functions could be discrete relays also. As quoted above, IEEE Std. C37.102–2006 indicates that 51T function pickup must be set from 1.5 to 2.0 of the generator-rated full-load current. Based on information concerning field forcing found in Section 3.1, this document requires that pickup for the 51T must be at least 2.0 times the generator full-load rating. If the 51T function is applied for phase overcurrent protection for the generator step-up transformer phase overcurrent protection, it must be applied with caution due to coordination issues that are associated with fault-sensing requirements in the 0.5-second-or-longer time frame. However, the 51T function can be applied to provide transformer through-fault current winding protection per IEEE Std. C37.91-2008, Annex A and the Coordination Procedures subsection below. The 51T time dial should be set as high as possible just below the transformer thermal damage curve (approximate through-fault damage current capability is 2 seconds) so that it will be relatively slow and relatively easy to coordinate with worst-case transmission protection (51T should always operate slower than transmission protection). Although generator fault current magnitude may decay below generator-rated full-load current (and thus be below the relay setting), this condition does not pose a threat to the generator.

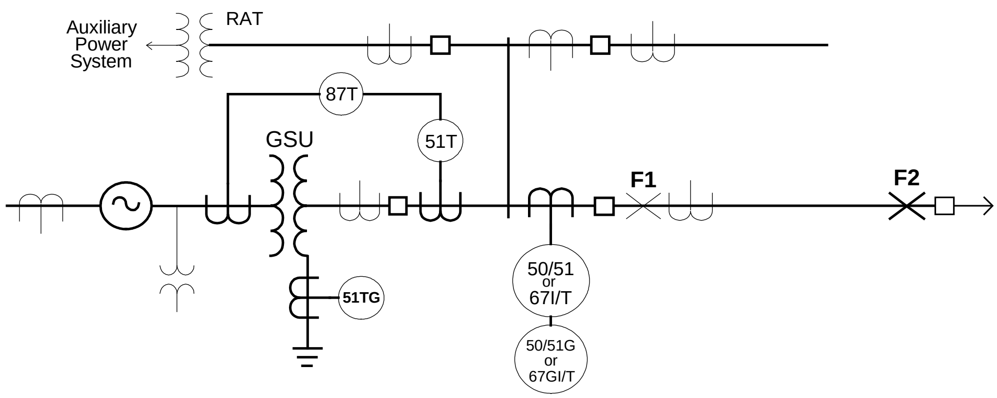


Figure 29: Phase and Ground Backup Overcurrent Relays on Generator Step-Up Transformer

Generator Step-Up Transformer Backup Ground Overcurrent Protection — Function 51TG

The ground overcurrent function 51TG, as shown in Figure 29, is used to provide generator and generator step-up ground backup overcurrent protection for uncleared system ground faults. The ground backup overcurrent function 51TG is connected to detect the ground current provided by the generator step-up transformer when connected as a ground source. It has no loading requirements, so it can be set for fault considerations. However, it should accommodate the worst-case system imbalance anticipated at the generator step-up transformer. From a time/overcurrent perspective, the 51TG needs to coordinate with the longest clearing time of the transmission ground protection systems as required by its application and the generator step-up transformer damage curve.

Generator Step-Up Transformer and Transmission System Coordination for Overcurrent Functions

Faults

Use of a generator step-up transformer phase overcurrent function (51T) for backup protection is strongly discouraged. This document has two sections that describe relay functions that are better designed for this function: the Phase Distance Protection (Function 21) section and the Voltage-Controlled or Voltage-Restrained Overcurrent Protection (Function 51V) section. These sections describe the use and application of phase-distance and voltage-supervised overcurrent relaying to provide the best phase backup protection that can be coordinated between the protective relaying of a Generator Owner and Transmission Owner. However, for completeness, the issues required to utilize the 51T backup overcurrent protection function will be covered in this section. When used, the 51T function and associated settings need to consider the following:

- The 51T must be set to pick up for the worst-case fault on the transmission system based on the application. See the loadability section for complete requirements to determine 51T pickup.
- The 51T must have sufficient time delay with adequate margin to coordinate with the worst-case clearing time of the transmission protection with breaker failure clearing times included.
- The 51T must be set such that the generator has the ability to produce the fault current long enough to complete the overcurrent backup function.
- The 51T must meet the loadability requirements outlined in the loadability subsection below.

The 51TG is used to back up uncleared system faults and must meet the following considerations for fault coordination:

- The 51TG must be set to pick up for the worst-case fault on the transmission system based on the application. The pickup value for the 51TG must also be capable of accommodating the greatest system imbalance with margin anticipated at the generator step-up transformer.
- The 51TG must have sufficient time delay with adequate margin to coordinate with the worst-case clearing time of the transmission protection with breaker failure clearing times included.

The 51TG backup overcurrent provides backup and time-delayed protection for ground faults when primary relaying or equipment does not operate properly. Relay failure and stuck breaker are two examples when the 51TG might be able to provide protection of the generator step-up transformer. Great care must be used in determining the sensitivity (pickup value) and selectivity (time-to-operate value) in order to complete the backup function without causing any misoperation.

Loadability

The 51T function has the following loadability requirement:

- The 51T must have as a minimum setting equal to 200 percent of the generator MVA rating at rated power factor.

The above requirement allows a generator to remain online through extreme operating system events by allowing a generator to utilize its full capability of field forcing.

The recommended loadability is to prevent protective functions applied for fault detection from operating during achievable loading conditions. This recommendation is not intended to preclude application of protective functions applied to detect generator overloads, such as described in IEEE Std. C37.102–2006. These protective functions are designed to coordinate with the generator short-time capability by utilizing an extremely inverse characteristic. Typical settings allow the protection to operate no faster than 7 seconds at 218 percent of full load current (e.g., rated armature current), and prevent operation below 115 percent of full load current. Similarly, protective functions may be applied to detect transformer overloads when designed to coordinate with the transformer thermal capability and to allow an operator 15 minutes or more to respond to overload conditions.

Note: Any 51 function utilized from the generator or generator step-up transformer multifunction protective relays must meet the above loadability requirement.

Considerations and Issues for Utilizing 51T and 51TG

As noted above concerning the 51T function, other protective functions are available to provide this backup protection while providing better coordination with the transmission and generator protections.

The 51TG backup overcurrent provides backup and time-delayed protection for ground faults when primary relaying or equipment does not operate properly. Relay failures and/or stuck breakers are examples of when the 51TG might be able to provide protection for the generator step-up transformer. The value of 51TG is that it covers a potential once-in-a-lifetime event where protective relaying and breaker failure relaying are unable to clear a transmission line fault. Great care must be used in determining the sensitivity (pickup value) and selectivity (time-to-operate value) to complete the backup function without causing any misoperation.

Device 51TG should be set to detect and operate for non-cleared transmission bus and line faults based on its application design requirements. When its application is for a generating station and system configuration that are simple (see Figure 29), it is generally not difficult to obtain reasonable relay settings for the 51TG function.

Refer to IEEE Std. C37.102–2006, Section 4.6 and Subsections 4.6.1–4.6.4 for recommendations on setting the 21, 51V, and 51TG functions, and refer to the references in IEEE Std. C37.102–2006 that discourage the use of the 51T. The performance of these functions during fault conditions must be coordinated with the system fault protection to ensure that the sensitivity and timing of the relaying results in tripping of the proper system elements, while permitting the generator to stay on-line during system-stressed conditions. Once the coordination is determined between the Generator Owner and Transmission Owner for the 51T function, the Generator Owner must evaluate coordination between the 51T function and the generator step-up transformer and generator protection for the fault current available from the system to ensure complete coordination. Short-circuit studies are required to determine fault values for which the overcurrent functions must operate and coordinate.

Coordination Procedure

Coordination of Function 51T

Function 51T must be set to the following requirements:

- The 51T must have a minimum current pickup of twice the generator MVA rating at the rated power factor.
- The 51T must operate slower with margin than the slowest transmission protection system that it must coordinate with based on protection design, including breaker failure time.
- The 51T must sense the required fault based on the transmission protection design with the fault current available from the generator in the time frame in which it is set to operate.
- The Generator Owner must determine that the setting for the 51T that coordinates with the transmission protection will also coordinate with the generator protection systems for the fault current available from the transmission system.

Coordination of Function 51TG

Function 51TG must be set to the following requirements:

- The 51TG must have a current pickup with margin greater than the largest non-fault system imbalance anticipated based on system design.

- The 51TG must operate slower with margin than the slowest transmission protection system that it must coordinate with based on protection design, including breaker failure time.

Example

Proper Coordination

For the system shown in Figure 30 below, coordination of the generation and transmission protection is described with the following assumptions: It will be assumed for the system shown that the transmission protection systems are overcurrent non-redundant schemes. It is also assumed that the line with fault locations F1 and F2 presented the worst-case coordination requirements for the generator backup protection. Also, the line used for a reserve auxiliary transformer (RAT) for the unit is out of service during normal operation. The line shown without a breaker termination at the remote terminal supplies a nearby load with no fault contribution. Current transformer ratio for the HV side generator step-up transformer and the line protection are 3Y-2000/5A (CTR = 400:1), multiratio CTs. The generator loadability requirement will be twice the unit MVA rating, which is equal to twice the generator step-up transformer rating.

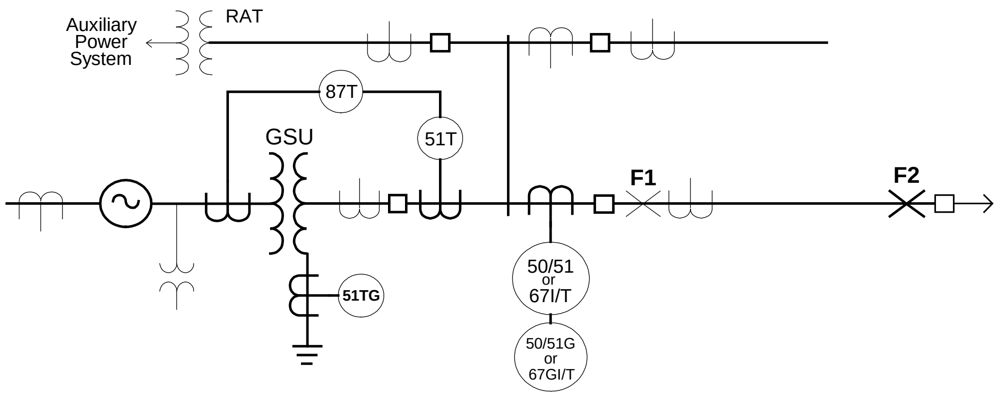


Figure 30: Phase and Ground Backup Overcurrent Relays on Generator Step-Up Transformer

Settings for Function 51T:

Step 1 – Rated current = $\dfrac{425MVA}{138kV\sqrt{3}}$ = 1,778 A, primary = (1,778 A/400) = 4.445 A, secondary

Step 2 – Select a relay characteristic curve. [Note: Curve is typically chosen to match the curve used by the Transmission Owner; e.g., a very inverse curve.]

Step 3 – Tap setting of 51T = 2 X I rated = (4.445A) X (2) = 8.89 A; choose Tap = 9.0 A

Step 4 – From short-circuit studies; obtain the 3ϕ through-fault current for the fault located on the generator bus shown as F1 in the diagram. $I_{3\phi}$=11,587 A, primary through-fault current on generator step-up transformer. Relay current = 11,587 A, primary/400 = 28.96 A, secondary

Step 5 – Multiple = Relay current/Tap = 28.96 A/9.0 A = 3.21; choose a time dial that results in an operating time equal to approximately 30 cycles more than the slowest transmission overcurrent setting. The time-delay setting with margin will result in a time setting in the 60–90 cycles range. The 30-cycles margin will accommodate breaker failure clearing timers up to 20 cycles with margin.

Step 6 – Ensure coordination with all appropriate transmission system protection functions. If the overcurrent function will be used to back up the line protective relays, then the minimum end line contribution from the generator has to be approximately 4,500 Amps or higher in the appropriate time range. Otherwise, the 51T will fail to operate as a backup protective function for the reasons stated throughout this section, resulting in the need to choose an overcurrent function with appropriate supervision to provide the overcurrent backup protection function. The 4,500 Amps number was determined by taking the 51T function pickup (400 x 9.0) x a margin of 1.25 as a minimum. This would be represented as F2 in Figure 30.

Step 7 – The Generator Owner takes the information concerning the 51T function in the plot and determines that it will coordinate with the other generator protection for the available transmission system fault current for generator step-up transformers and generator faults.

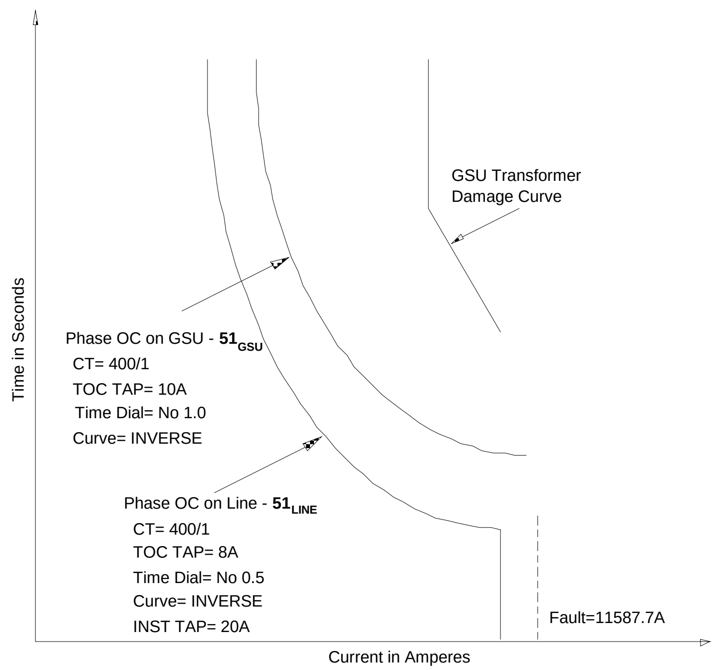


Figure 31: Function 51T Generator Step-Up Transformer and 51 LINE (G or N) Overcurrent Relay Coordination Curves

Setting for the 51TG

Assumption: Current transformer ratio for the neutral CT on the generator step-up transformer is 1-600/5 A (CTR = 120:1), multiratio.

Step 1 – Obtain $3I_0$ current from short-circuit studies for fault location F2 (the primary minimum fault current provided from the neutral of the generator step-up transformer that must be detected by 51TG). F2 = 1930 Amps primary.

Step 2 – Select a relay characteristic curve. [Note: Curve is typically chosen to match the curve used by the Transmission Owner; e.g. a very inverse curve.]

Step 3 – Tap Setting of 51TG [Note: Tap is typically selected based on available minimum short-circuit current (F2) and current transformer ratio on the neutral of generator step-up transformer

(120:1) such that two or higher times pickup is available for the fault that represents the minimum ground current that the 51TG is required to detect (provide backup protection for a fault at F2) while being set above the worst-case system imbalance.]. 51TG tap setting = (F2)/(2.0 margin *CTR) = 1930 A/(2.0 * 120) = 8.04, choose 8.0 tap.

Step 4 – From short-circuit studies obtain the $3I_0$ through-fault current for the fault located on the generator bus shown as F1 in the diagram. $3I_0$ = 7,556 A, primary from the neutral of generator step-up transformer. Relay current = 7,556 A/120 = 62.96 A, secondary

Step 5 – Multiple = Relay current/Tap = 62.96 A/8 A = 7.87; choose a time dial that provides an operating time approximately 30 cycles or more than the slowest transmission overcurrent setting. The time-delay setting with margin will result in a time setting in the 60–90 cycles range. The 30-cycle margin will accommodate breaker failure clearing timers up to 20 cycles with margin.

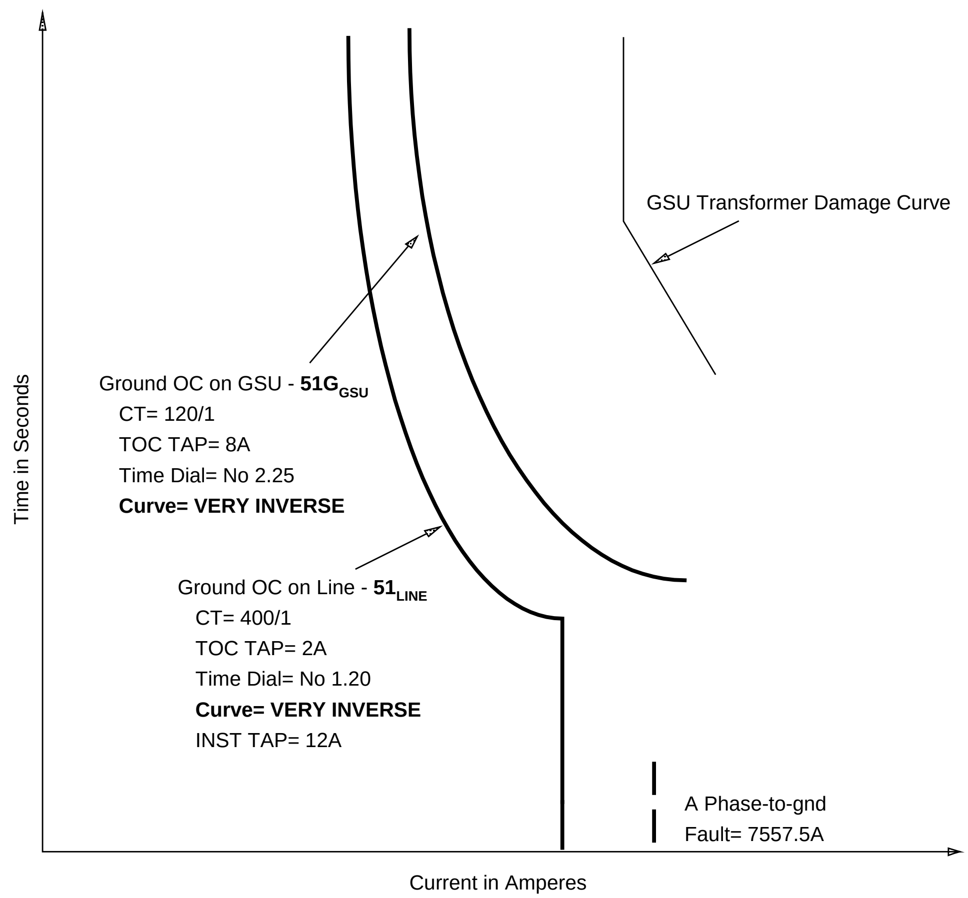


Figure 32: Function 51TG Overcurrent Relay Characteristic Curve

Improper Coordination

The miscoordination between the $51G_{LINE}$ (or $51N_{LINE}$) and the $51G_{GSU}$ is due to the selection of dissimilar curves for one-on-one coordination as was required in the above example. $51G_{LINE}$ is a very inverse curve, and the $51G_{GSU}$ is an inverse curve. Use similar curves to fix the miscoordination.

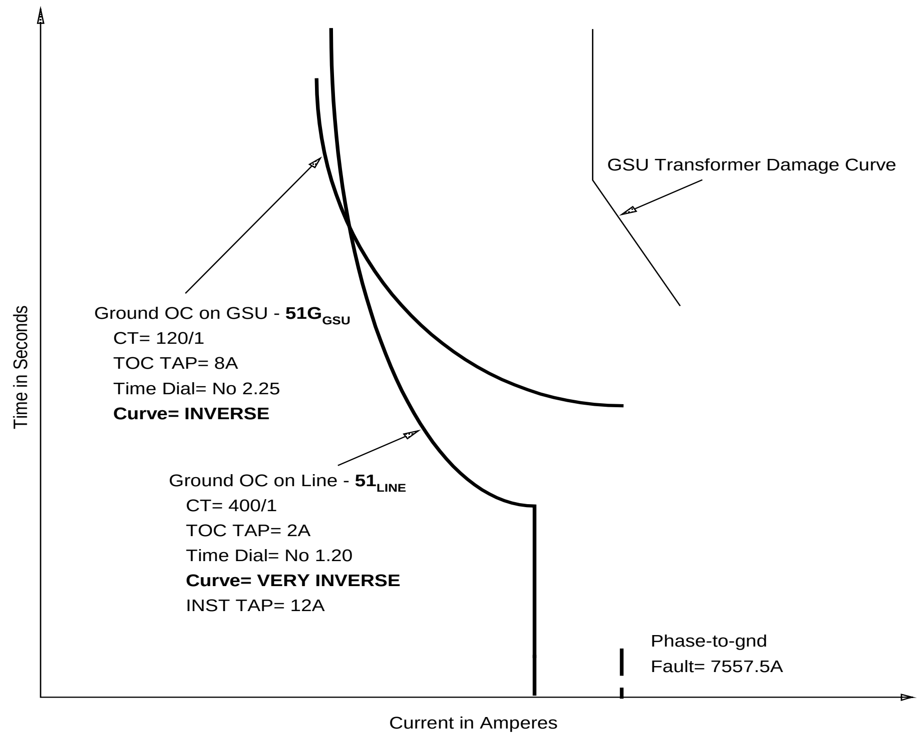


Figure 33: Miscoordination of 51G$_{LINE}$ and 51G$_{GSU}$ Settings

Summary of Protection Functions Required for Coordination

Table 2 Excerpt: Functions 51T/51TG Protection Coordination Data Exchange Requirements		
Generator Protection Function	**Transmission System Protection Functions**	**System Concerns**
51T — Phase fault backup overcurrent 51TG — Ground fault backup overcurrent	51 67 51G 51N 67N	• Must have adequate margin over GSU protection and nameplate rating • 51T not recommended, especially when the Transmission Owner uses distance line protection functions • Open-phase, single-pole tripping and reclosing • Generator Owners(s) needs to get Relay Data (functions 51, 67, 67N, etc.) and single-line diagram (including CT and PT arrangement and ratings) from Transmission Owner(s) for function 51T coordination studies

Summary of Protection Function Data and Information Exchange Required for Coordination

The following table presents the data and information that need to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above example.

Table 3 Excerpt: Functions 51T/51TG Data to be Exchanged Between Entities		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Function 51T — Phase fault backup overcurrent relay settings and associated time delays **Function 51TG** — Ground fault backup overcurrent relay settings and associated time delays	One-line diagram of the transmission system up to one bus away from the generator high-side bus	None
Total clearing times for the generator breakers	Impedances of all transmission elements connected to the generator high-side bus	
	Relay settings on all transmission elements connected to the generator high-side bus	
	Total clearing times for all transmission elements connected to the generator high-side bus	
	Total clearing times for breaker failure, for all transmission elements connected to the generator high-side bus	

If the voltage-controlled or voltage-restrained overcurrent function is used in place of the 51T, see the Voltage-Controlled or Voltage-Restrained Overcurrent Protection (Function 51V) section of this document for proper utilization and coordination.

If a distance function is used in place of the 51T, see the Phase Distance Protection (Function 21) section of this document for proper utilization and coordination.

Voltage-Controlled or Voltage-Restrained Overcurrent Protection (Function 51V)

Purpose of the Generator Function 51V — Voltage-Controlled or Voltage-Restrained Overcurrent Protection

Voltage-controlled and voltage-restrained overcurrent protection uses a measure of generator terminal voltage and generator stator current. Its function is to provide backup protection for system faults when the power system to which the generator is connected is protected by time-current coordinated protections. In practice, however, coordination of the 51V function may be difficult to achieve except on single generators connected to the power system by radial interconnection facilities. Note that the 21 phase distance function is another method of providing backup for system faults, and it is never appropriate to enable both function 21 and function 51V. The 21 function should be used when the generator protection must be coordinated with phase distance protection applied on the transmission system, or when proper coordination and dependable tripping cannot be achieved due to the challenges described in this section. Section 4.6.1.2 of IEEE Std. C37.102–2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows:

> *The type of overcurrent device generally used for system phase fault backup protection is either a voltage-restrained or voltage-controlled time-overcurrent relay. Both types of relays are designed to restrain operation under emergency overload conditions and still provide adequate sensitivity for the detection of faults.*
>
> *In the voltage-restrained relay, the current pickup varies as a function of the voltage applied to [the] relay. In one type of relay with zero voltage restraint, the current pickup is 25% of the pickup setting with 100% voltage restraint. On units that have a short, short-circuit time constant, the 51V voltage-restrained overcurrent relay should be used.*
>
> *In the voltage-controlled relay, a sensitive low pickup time-overcurrent relay is torque controlled by a voltage relay. At normal and emergency operating voltage levels, the voltage relay is picked up and the relay is restrained from operating. Under fault conditions, the voltage relay will drop out, thereby permitting operation of the sensitive time-overcurrent relay. If applied properly, the overcurrent pickup level in both types of relays will be below the generator fault current level as determined by synchronous reactance.*
>
> *The 51V voltage element setting should be calculated such that under extreme emergency conditions (the lowest expected system voltage), the 51V relay will not trip. However, during faults, within the protection zone of the relay, the relay will be enabled (51VC), or sensitized (51VR), to trip with the expected fault current level.*
>
> *To provide system phase fault backup, three voltage-restrained or voltage-controlled time-overcurrent relays are connected to receive currents and voltages in the same manner as the distance relays illustrated in Figure 4-49 and Figure 4-50 [of IEEE Standard C37.102-2006]. In some small and medium size machine applications a single 51V relay is used, if a negative-sequence overcurrent [function] is included. The two together provide phase backup protection for all types of external faults.*

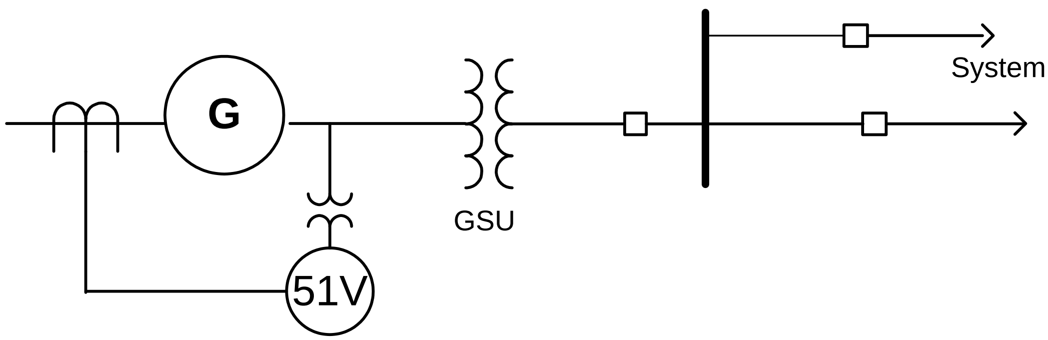


Figure 34: Application of 51V System Backup Relays – Unit Generator Transformer Arrangement

Coordination of Generator and Transmission System

Faults

The Generator Owner and Transmission Owner need to exchange the following data:

Generator Owner

- Unit ratings, subtransient, transient, and synchronous reactance and time constants and GSU transformer impedance (based on the tap setting)
- Station one-line diagrams
- 51V-C or 51V-R relay type, CT ratio, VT ratio
- Relay settings and setting criteria
- Coordination curve for a three-phase fault on the high side of the GSU, based on generator subtransient reactance
- Coordination curve for a three-phase fault at the end of the highest impedance line leaving the generator station, based on all sources in and generators modeled using transient reactance

Transmission Owner

- Relay setting criteria
- Fault study values of current and voltage for three-phase faults at the high side of the GSU transformer and at the end of the highest impedance line leaving the generator station, including voltages at the generator terminals
- Relay types and operating times for three-phase faults up to one bus away from the generator high-voltage bus

51V-C Setting Considerations

Under fault conditions, the voltage function will drop out, thereby permitting operation of the sensitive time-overcurrent function. The overcurrent pickup level will be below the generator fault current level as determined by synchronous reactance. It is possible that the overcurrent pickup level for the voltage controlled function, 51V-C, may be below load current.

The voltage function must be set such that it will not drop out below extreme system contingencies. The 51V-C must be coordinated with the longest clearing time, including breaker failure, for any of the transmission protection schemes (functions 21, 51, 67, and 87B when the bus protection has an inverse time delay) within the protected reach of the 51V-C function. A time margin of 0.5 seconds is typically considered adequate.

51V-R Setting Considerations

Under fault conditions, the depressed voltage will make the time-overcurrent function more sensitive. The overcurrent pickup level must be set with a margin above the generator full-load current.

The 51V-R must be coordinated with the longest clearing time, including breaker failure, for any of the transmission protection schemes (functions 21, 51, 67, and 87B with the bus protection as inverse time delay) within the protected reach of the 51V-R function. A time margin of 0.5 seconds is typically considered adequate.

Loadability

- For the 51V-C function, the voltage function must prevent operation for all system loading conditions as the overcurrent function will be set less than the generator full-load current. The voltage function setting should be calculated such that under extreme emergency conditions (the lowest expected system voltage), the 51V function will not trip. A voltage setting of 0.75 per unit or less is acceptable.
- For the 51V-R function, the voltage function will not prevent operation for system loading conditions. The overcurrent function must be set above generator full-load current. IEEE Std. C37.102–2006 recommends the overcurrent function to be set 150 percent above full load current.
- Coordinate with stator thermal capability curve (IEEE Std. C50.13–2005).
- Note that 51V functions are subject to misoperation for blown fuses that result in loss of the voltage control or voltage restraint.

Considerations and Issues

The bolded portions above from IEEE Std. C37.102–2006 capture the salient points of the application of the 51V function.

For trip dependability within the protected zone, the current portion of the function must be set using fault currents obtained by modeling the generator reactance as its synchronous reactance. This means that to set the current portion of the function to detect faults within the protected zone, the minimum pickup of the current function will be less than maximum machine load current. In the below example taken from IEEE Std. C37.102–2006 Appendix A, the current function of the 51V-C function is set to 50 percent of the full load rating of the machine. The protected zone can be defined as:

> The generator step-up transformer, the high-voltage bus, and a portion of a faulted transmission line which has not been isolated by primary system relaying for a prolonged multiphase fault.

The 51V function should not operate unless the transmission protection fails. As such, the time delay chosen should provide ample margin to ensure coordination with the transmission protection. However, the delay must not exceed the generator short-time thermal capability as defined by IEEE Std. C50.13-2005 or the transformer through-fault-protection curve as per IEEE Std. C37.91–2008 Annex A.

The undervoltage function is the security aspect of the 51V-C function. IEEE Std. C37.102–2006 states:

> *The 51V voltage element setting should be calculated such that under extreme emergency conditions (the lowest expected system voltage), the 51V relay will not trip.*

In IEEE Std. C37.102–2006 (see Appendix A reference), the undervoltage setting for the example is 75 percent of rated voltage, which is considered acceptable to avoid generator tripping during extreme emergency conditions.

The transmission system is usually protected with phase distance (impedance) relays. Time coordination is attained between distance relays using definite time settings. The 51V functions have varying time delays based on their time versus current time to operate curves. Time coordinating a 51V and a 21 lends to longer clearing times at lower currents. The 51V functions are often used effectively on generators connected to a distribution system where distribution feeders are protected with time-inverse characteristic relays. **For these reasons, it is recommended that an impedance function be used rather than a 51V function for generators connected to the transmission system.**

The voltage function of the 51V-C is set 0.75 per unit voltage or less to avoid operation for extreme system contingencies. A fault study must be performed to ensure that this setting has a reasonable margin for the faults that are to be cleared by the 51V. Backup clearing of system faults is not totally dependent on a 51V function (or 21 function). Clearing of unbalanced multiphase faults can be achieved by the negative-sequence function. Clearing of three-phase faults may occur by the operation of overfrequency and overspeed tripping functions, but this should not be relied on. The 51V function provides minimal transmission system backup protection for relay failure. It must not be relied upon to operate to complete an isolation of a system fault when a circuit breaker fails to operate as it does not have enough sensitivity. The 51V has a very slow operating time for multiphase faults. This may lead to local system instability resulting in the tripping of generators in the area. An impedance function would be recommended in its place to avoid instability as stated in IEEE Std. C37.102–2006. Voltage functions must be set less than extreme system contingency voltages or the voltage-controlled function will trip under load. The voltage-restrained function time to operate is variable dependent on voltage. For generators connected to the transmission system utilizing distance protection functions, the 21 function is recommended over the 51V function. It is not necessary to have both functions enabled in a multifunction relay. The 21 function protection coverage will vary with infeed conditions, but its operating time is clearly defined and therefore will coordinate better with transmission system distance protection functions.

It also is necessary to consider the fault voltage at the generator terminals when confirming dependable operation of the 51V function. Typically, a generator excitation system is capable of delivering ceiling voltage of 1.5 to 2.0 times the rated exciter voltage required for full load operation. The excitation boost is a benefit for the overcurrent element of either type of 51 V function; however, if there is impedance between the generator and the fault, the increased field current will also significantly increase the generator terminal voltage. The effect will be to desensitize the voltage-restrained relay, or possibly prevent the dropout of the undervoltage element of the voltage-controlled relay. Consequently, setting calculations are not only required to determine the minimum fault current conditions, but also to establish maximum fault voltage conditions. Higher fault voltage will appear if the fault is an arcing fault or is a fault far from the transformer terminals. The 51V function operates for phase-to-phase and three-phase faults, so the limiting case for maximum fault system voltage should be considered phase-to-phase faults rather than three-phase faults. When a voltage-controlled function is applied, the undervoltage element should be set above the maximum fault voltage (calculated with the automatic voltage regulator at full boost and the generator fully loaded prior to the fault) with margin. If it is not possible to achieve both security for stressed operating conditions and dependable operation for faults, application of an impedance function may be necessary in place of the 51V function.

Special Considerations for Older Generators with Low Power Factors and Rotating Exciters

Older low power factor machines that have slower-responding rotating exciters present an additional susceptibility to tripping for the following reasons:

- The relatively low power factor (0.80 to 0.85) results in very high reactive current components in response to the exciter trying to support the system voltage.

- The slower response of the rotating exciters in both increasing and decreasing field current in those instances results in a longer time that the 51V function will be picked up, which increases the chances for tripping by the 51V.
- If it is impractical to mitigate this susceptibility, Transmission Owners, Transmission Operators, Planning Coordinators, and Reliability Coordinators should recognize this generator tripping susceptibility in their system studies.

Special Considerations for Applications Associated with Self-Excited Units

These systems take in excitation power from the generator terminals using power potential transformers (PPTs). Faults cause a reduction in terminal voltage which, in turn, reduces the available excitation voltage. If the resulting excitation is insufficient to support the fault current, the excitation will collapse, and fault current will decay to near zero. The greater the impedance between the fault and the generator terminals, the higher the terminal voltage and the more likely the system is to sustain fault current. A complete collapse of excitation will occur for a three-phase fault at the generator terminals. Phase-to-phase faults and phase-to-ground faults will retain some voltage on the unfaulted phases, but this voltage is generally not sufficient to maintain fault current at a level suitable for overcurrent tripping.

If 51V functions are applied to a self-excited system, performance of relays should be verified against the fault current decrement curve; alternatively, a power current transformer (PCT) could be included to boost excitation during fault conditions. The supplemental excitation provided by the PCT should be sufficient to maintain fault current at a level that will facilitate overcurrent tripping. Without the PCT, fault clearing for a primary protection failure will be dependent upon the relay operating per its time-current characteristic before the fault current collapses.

Coordination Procedure

Test Procedure for Validation

Voltage-Controlled Overcurrent Function (51VC)

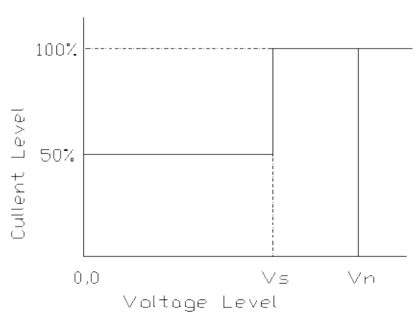


Figure 35: Voltage-Controlled Overcurrent Relay (51VC)

In the voltage-controlled function, a sensitive low pickup time-overcurrent function is torque-controlled by a voltage function. At normal and emergency operating voltage levels, the voltage function is picked up and the relay is restrained from operating. Under fault conditions, the voltage function will drop out, thereby permitting operation of the sensitive time-overcurrent function.

- The overcurrent pickup is usually set at 50 percent of generator full-load current as determined by maximum real power out and exciter at maximum field forcing.

- The undervoltage function should be set to drop out (enable overcurrent function) at 0.75 per unit generator terminal voltage or less.
- The overcurrent function should not start timing until the undervoltage function drops out.
- Time coordination should be provided for all faults on the high side of the generator step-up transformer, including breaker failure time and an agreed upon a reasonable margin. Time coordination must also include the time overcurrent protection for all elements connected to the generator high-side bus for which the 51V function will operate.
- The Generator Owner’s required margin is typically 0.5 seconds over 51 and 67 and instantaneous protection for transmission system fault(s).

Voltage-Restrained Overcurrent Function (51VR)

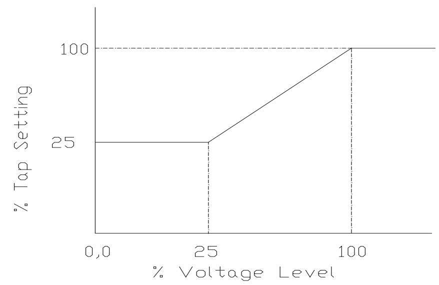


Figure 36: Voltage Restrained OC Relay (51VR)

The characteristic of a voltage-restrained overcurrent function allows for a variable minimum pickup of the overcurrent function as determined by the generator terminal voltage. As shown in Figure 36, at 100 percent generator terminal voltage, the overcurrent function will pick up at 100 percent of its pickup setting. The minimum pickup of the overcurrent function decreases linearly with voltage until 25 percent or less when the minimum pickup of the overcurrent function is 25 percent of its minimum pickup setting.

The 100 percent voltage level setting (see Figure 36) for the voltage restraint must be at 0.75 per unit terminal voltage or less. The relay voltage margin for trip dependability should be determined and agreed upon for a fault on the high side terminal of the generator step-up transformer.

Time coordination for all faults on the high side of the generator step-up transformer must include breaker failure time and agreed upon margin. Time coordination must also include the time overcurrent protection for all elements connected to the generator high-side bus for which the 51V function will operate.

Setting Considerations

- For the 51V-C function, the voltage function must prevent operation for all system loading conditions as the overcurrent function will be set less than the generator full-load current. The voltage function setting should be calculated such that under extreme emergency conditions (the lowest-expected system voltage), the 51V function will not trip. A voltage setting of 0.75 per unit or less is acceptable.
- For the 51V-R function, the voltage function will not prevent operation for system loading conditions. The overcurrent function must be set above generator full-load current. IEEE Std. C37.102–2006 recommends the overcurrent function to be set at 150 percent above full-load current.
- If the relay engineer is concerned with whether the relay will provide backup protection in the entire assumed zone of protection, it is necessary to compare the dynamic curve (as defined in IEEE Std. C37.112-1996) to the fault decrement curve; however, this concern can be eliminated by using an impedance function.
- For either function, infeed effects in many cases will limit use of these functions to provide backup protection for faults beyond the high-side bus.

Examples

Proper Coordination (From IEEE Std. C37.102–2006 Appendix A: Sample Calculations for Settings of Generator Protection Functions):

Voltage-Controlled Overcurrent Function (51V-C)

- $I_{Rate} = \dfrac{492MVA}{20kV\sqrt{3}}$ = 14,202 A, primary = 3.945 A, secondary
- Current pickup = 50% of I_{Rate} = (0.5) (3.945 A) = 1.97 A ==> Use 2.0 A tap
- Undervoltage function pickup Vs = 75% of V_{Rate} = (0.75) (120 V) = 90 V
- Select a relay characteristic curve shape (inverse, very inverse, etc.).
- Coordination must be attained for a fault on the high side of the generator step-up transformer cleared in high-speed time + breaker failure time. Time coordination must also include the time overcurrent protection for all elements connected to the generator high-side bus for which the 51V function will operate. All coordination must include a reasonable margin, for example 0.5 seconds.

Voltage-Restrained Overcurrent Function (51V-R)

- Current pickup = 150% of I_{Rate} = (1.5) (3.945 A) (Note that at 25 percent voltage restraint, this function will pick up at 25 percent of 150 percent or 0.375 pu on the machine base when using a voltage-restrained overcurrent function with a characteristic as shown above.)
- Select a relay characteristic curve shape (inverse, very inverse, etc.).
- Coordination must be attained for a fault on the high side of the generator step-up transformer cleared in high-speed time + breaker failure time. Time coordination must also include the time overcurrent protection for all elements connected to the generator high-side bus for which the 51V function will operate. All coordination must include a reasonable margin, for example 0.5 seconds.

Proper Coordination

In the following example, a 51V-R protection is applied on the generator shown in Figure 37.

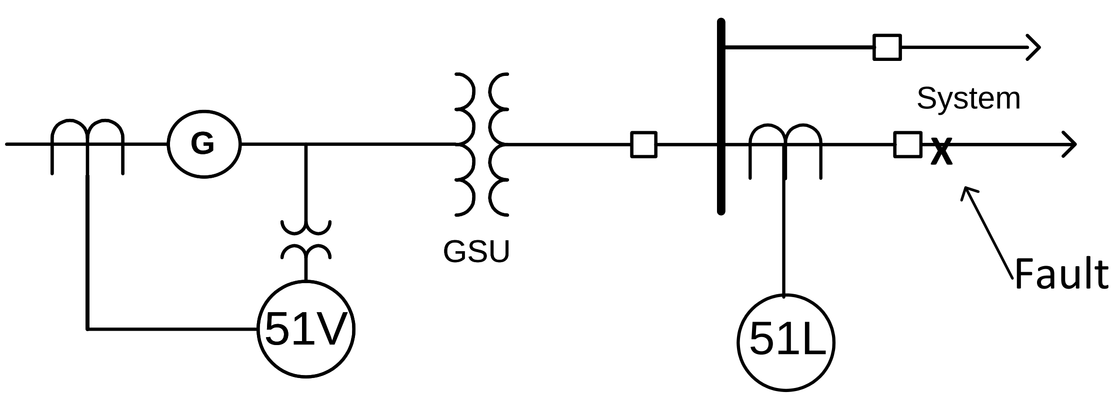


Figure 37: System One-Line for Setting Example

Figure 38 depicts coordination between the 51V-R function and the Transmission or Distribution Owner's line overcurrent relays, including margin for breaker failure clearing time. The characteristic (e.g., definite, inverse, very inverse, etc.) chosen for the time overcurrent function of the 51V is selected to coordinate with the Transmission or Distribution Owner's relays. The relay in this example is set to provide a 0.5-second coordination margin for a close-in fault. The 51V-R characteristic is coordinated with the 51 line protection and the generator withstand curve.

The 51V-R characteristic is shown as a cross-hatched area representing the variability in pickup for the time dial setting selected as a function of the restraining voltage. The left boundary of the shaded region is the time-current curve associated with voltage less than or equal to 25 percent; i.e., the fastest possible operating time that must be coordinated with the line protection. The right boundary is the time-current curve associated with full voltage restraint; i.e., the slowest possible operating time that must be coordinated with the generator physical capability.

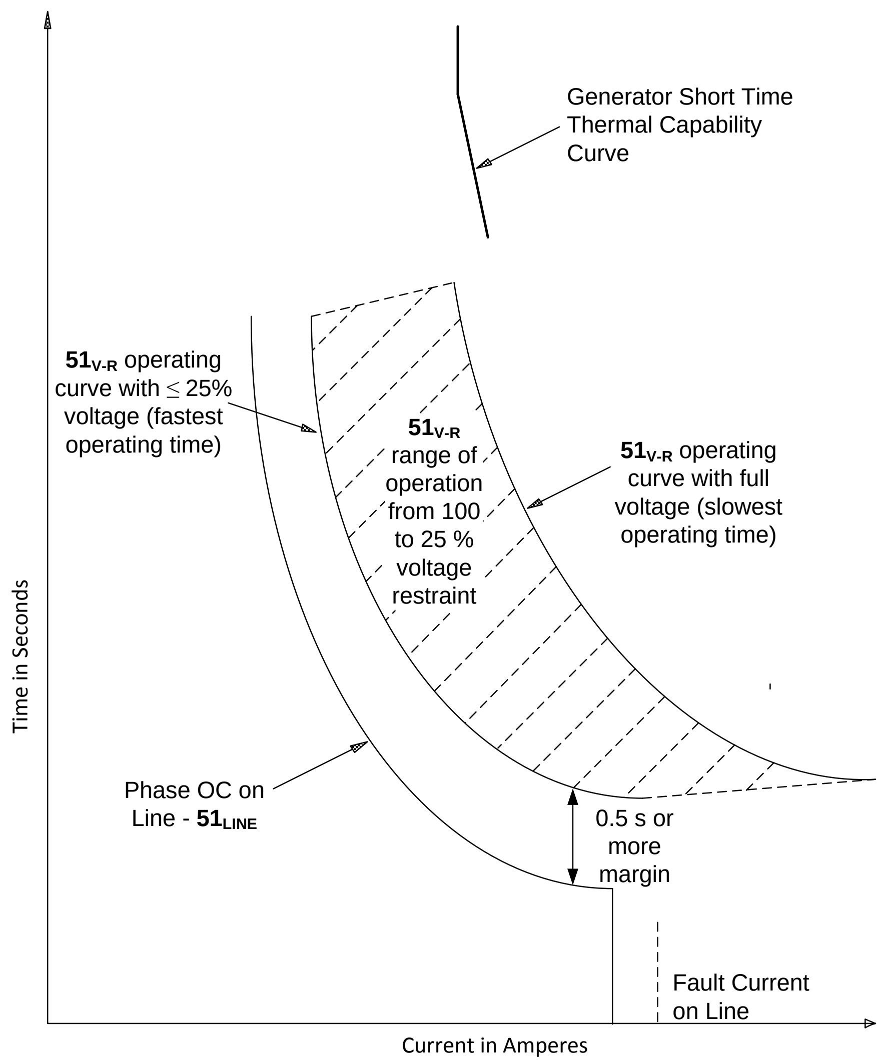


Figure 38: Proper Coordination

Improper Coordination

An example of improper time-current coordination is provided in the section titled Generator Step-up Phase Overcurrent (Function 51T) and Ground Overcurrent (Function 51TG) Protection and Figure 33.

Summary of Protection Functions Required for Coordination

Table 2 Excerpt: Function 51V Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Functions**	**System Concerns**
51V — Voltage controlled/restrained	51 67 87B	• 51V not recommended when Transmission Owner uses distance line protection functions • Coordination may be difficult to achieve except on single generators connected to the power system by radial interconnection facilities. • Short-circuit studies for time coordination • Total clearing time • Review voltage setting for extreme system loading conditions • 51V controlled function has only limited system backup protection capability • Settings should be used for planning and system studies, either through explicit modeling of the function or through monitoring voltage and current performance at the relay location in the stability program—and applying engineering judgment.

Summary of Protection Function Data and Information Exchange Required for Coordination

The following table presents the data and information that need to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above examples.

Table 3 Excerpt: Function 51V Data to be Exchanged Between Entities		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Provide settings for pickup and time delay (may need to provide relay manual for proper interpretation of the voltage controlled/restrained function)	Times to operate, including timers, of transmission system protection Breaker failure relaying times	None

Overvoltage Protection (Function 59)

Purpose of the Generator Function 59 — Overvoltage Protection

Overvoltage protection uses the measurement of generator terminal voltage. Section 4.5.6 of the IEEE Std. C37.102–2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows:

> *Generator overvoltage may occur without necessarily exceeding the V/Hz limits of the machine. In general, this is a problem associated with hydrogenerators, where upon load rejection, the overspeed may exceed 200% of normal. Under this condition on a V/Hz basis, the overexcitation may not be excessive but the sustained voltage magnitude may be above permissible limits. Generator V/Hz relays will not detect this overvoltage condition and hence a separate overvoltage*

protection is required. In general, this is not a problem with steam and gas turbine generators because of the rapid response of the speed-control system and voltage regulators.”

“Protection for generator overvoltage is provided with a frequency-compensated (or frequency-insensitive) overvoltage relay. The relay should have both an instantaneous unit and a time-delay unit with an inverse time characteristic. The instantaneous unit is generally set to pick up at 130% to 150% voltage while the inverse time unit is set to pick up at about 110% of normal voltage. Two definite time delay relays can also be applied.

Overvoltage protection is used for preventing an insulation breakdown from a sustained overvoltage. The generator insulation system is capable of operating at 105 percent of overvoltage continuously.

A sustained overvoltage condition beyond 105 percent normally should not occur for a generator with a healthy voltage regulator, but it may be caused by the following contingencies: (1) defective automatic voltage regulator (AVR) operation, (2) manual operation without the voltage regulator in service, and (3) sudden load loss.

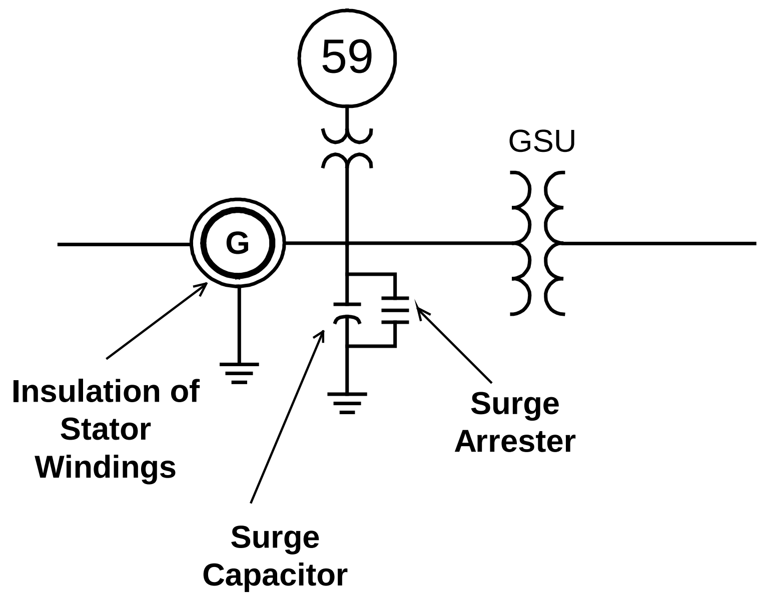


Figure 39: Overvoltage Relay with Surge Devices Shown Connected to the Stator Windings

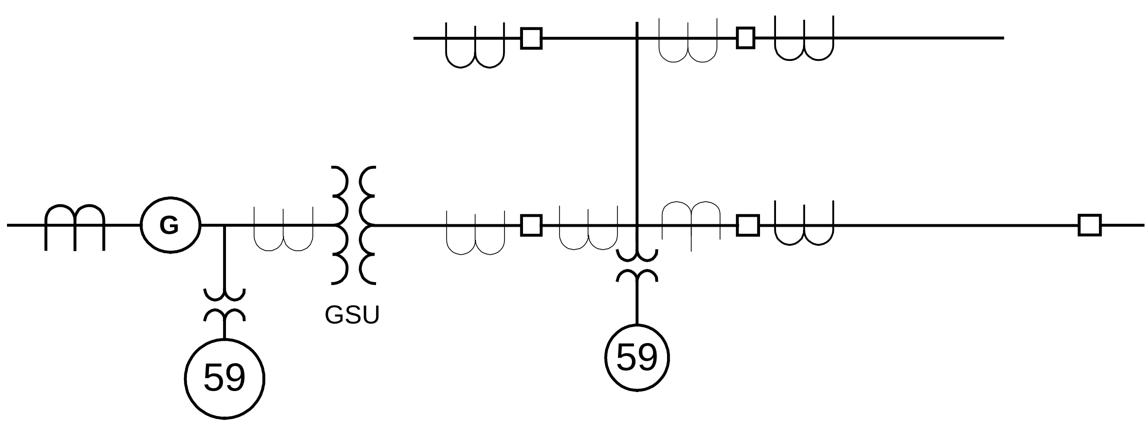


Figure 40: Location of Overvoltage Relays Requiring Coordination

Coordination of Generator and Transmission System

Faults

There are no coordination requirements with the transmission protective relays for system faults given the high-voltage set point and long delay—tens of seconds or longer. Additionally, most system fault conditions would cause a reduction in voltage.

Function 59 protection is mainly provided for the generator stator winding insulation. Surge arrestors protect the stator from overvoltages caused by lightning, impulses, and inrush. See the settings example below.

Loadability

If a long-time setting of 1.1 per unit nominal voltage with significant time delay (as an example, 10 seconds or longer) is used to trip, coordination with recoverable extreme system events with overvoltage should be considered. This suggests that, for credible contingencies where overvoltage may occur, shunt reactors near the generator should be placed in service, and/or capacitor banks near the generator should be removed from service prior to the 10-second trip limit on the generator.

Considerations and Issues

When the generator voltage regulator keeps the generator terminal voltage within 105 percent of nominal, there is no system coordination issue. However, the Planning Coordinator needs to understand the performance of both the voltage regulator and the 59 overvoltage function settings to study extended-time overvoltage system conditions.

Coordination Procedure

Setting Considerations

- Two types of relays (or functions) are commonly used on a generator protection: instantaneous (function 59I) and time delay (function 59T).
- “Generators shall operate successfully at rated kilovolts-amperes (kVA), frequency, and power factor at any voltage not more than five percent above or below rated voltage…” (Clauses 4.1.5 of IEEE Std. C50.12–2005 and 4.1.7 of IEEE Std. C50.13–2005).
- “Generators shall be thermally capable of continuous operation within the confines of their reactive capability curves over the ranges of ±5% in voltage and ±2% in frequency.” (Clauses 4.1.5 of IEEE Std. C50.12–2005 and 4.1.7 of IEEE Std. C50.13–2005).

Example

Proper Coordination

The following is an example of setting the 59T and 59I function time delays:

Step 1 – $V_{Nominal}$ = (20,000 V) (120/20,000) = 120 V

Step 2 – 59T = 105% of 110% of $V_{Nominal}$ = 1.05x 1.10 x 120V = 139 V (1.155 pu), with a time delay of 10 seconds or longer.

Step 3 – 59I = 105% of 130% of $V_{Nominal}$ = 1.05 x 1.30 x 120 V = 184 V (= 1.365 pu)

Figure 41 is a typical load rejection response curve of a voltage regulator for an example of a hydro turbine generator. The regulator causes the generator to operate back to near-nominal voltage in about two seconds, well before any action by the overvoltage protection.

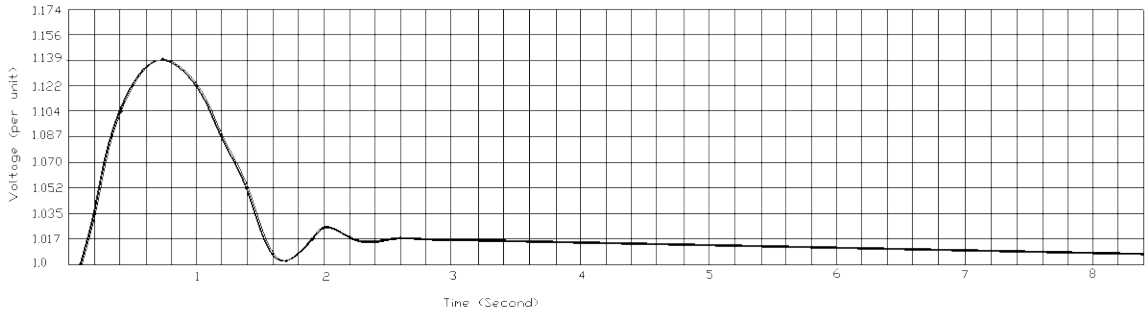


Figure 41: Typical Example Load Rejection Data for Voltage Regulator Response Time

Summary of Protection Functions Required for Coordination

Table 2 Excerpt: Function 59 Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Functions**	**System Concerns**
59 — Overvoltage	59 (when applicable)	• Settings should be used for planning and system studies, either through explicit modeling of the function or through monitoring voltage performance at the relay location in the stability program—and applying engineering judgment.

Summary of Protection Function Data and Information Exchange Required for Coordination

Table 3 Excerpt: Function 59 Data to be Exchanged Between Entities		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Relay settings: setting and characteristics, including time-delay setting or inverse-time characteristic, at the generator terminals	Pickup and time-delay information of each 59 function applied for system protection	None

Stator Ground Protection (Function 59GN/27TH)

Purpose of the Generator Function 59GN/27TH — Stator Ground Relay

Stator ground fault protection uses a measurement of zero-sequence generator neutral voltage to detect generator system ground faults. Section 4.3.3 of IEEE Std. C37.102–2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows:

> *Protective schemes that are designed to detect three-phase and phase-to-phase stator faults are not intended to provide protection for phase-to-ground faults in the generator zone. The degree*

of ground fault protection provided by these schemes is directly related to how the generator is grounded and, therefore, to the magnitude of the ground fault current available. The maximum phase-to-ground fault current available at the generator terminals may vary from three-phase fault current levels or higher to almost zero. In addition, the magnitude of stator ground fault current decreases almost linearly as the fault location moves from the stator terminals toward the neutral of the generator. For a ground fault near the neutral of a wye-connected generator, the available phase-to-ground fault current becomes small regardless of the grounding method.

As noted in the preceding sub-clause, differential relaying will not provide ground fault protection on high impedance-grounded machines where primary fault current levels are limited to 3 A to 25 A. Differential relaying schemes may detect some stator phase-to-ground faults depending upon how the generator is grounded. Figure 4-18 illustrates the approximate relationship between available ground fault current and the percent of the stator winding protected by a current-differential scheme. When the ground fault current level is limited below generator rated load current, a large portion of the generator may be unprotected.

The guide also includes the following observations in Section 4.3.1:

Generator faults are considered to be serious since they may cause severe and costly damage to insulation, windings, and the core; they may also produce severe mechanical torsional shock to shafts and couplings. Moreover, fault currents in a generator do not cease to flow when the generator is tripped from the system and the field disconnected. Fault current may continue to flow for many seconds because of trapped flux within the machine, thereby increasing the amount of fault damage.

High-impedance grounding is standard for unit generators and is used in industrial systems. The discussion here centers on the common high-resistance grounding, where the fault current is limited to about 3 A to 25 A primary. This limits iron burning in the generator to avoid costly repairs.

The stator ground function 59GN is intended to detect a ground fault on the stator windings of a generator connected to a delta-connected winding on the generator step-up transformer. With typical settings, the stator ground function is capable of detecting faults to within 2 to 5 percent of the stator neutral. This function is susceptible to operating for faults on the secondary of wye-grounded/wye-grounded voltage transformers connected at the generator terminals and for ground faults on the high side of the generator step-up transformer due to zero-sequence voltage induced through the capacitive coupling between the windings of the generator step-up transformer. The stator ground function is set with a time delay to coordinate with the voltage transformer fuses and transmission system ground fault protection.

The stator ground fault protection is supplemented by a second protective function to provide coverage for faults near the neutral of the generator. Many of these schemes sense third harmonic voltage at the generator neutral or the generator terminals. A third harmonic undervoltage function is a common method that monitors a decrease in the third harmonic voltage in the neutral connection that will occur during a stator phase-to-ground fault. The third harmonic undervoltage function is not susceptible to operation due to coupled voltage through the generator step-up transformer capacitance if the high-side of the generator step-up transformer is grounded. However, this function may be supervised to prevent operation below a minimum power level because, at low power levels, an adequate third harmonic will not be present.

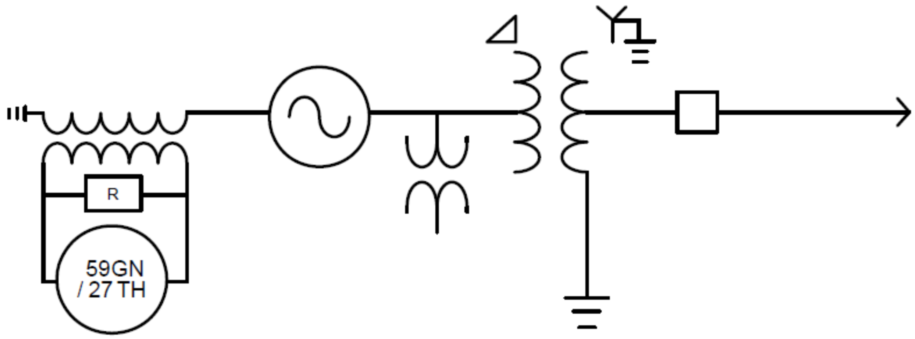


Figure 42: Stator Ground Protection

Coordination of Generator and Transmission System

Faults

Step 1 – Transmission Owner determines worst-case clearing time for close-in phase-to-phase-to-ground or phase-to-ground faults on the system with breaker failure and total clearing times accounted for.

Step 2 – Generator Owner must ensure that the timer on the 59GN is longer than worst case provided above by the Transmission Owner with appropriate margin.

The performance of these functions during fault conditions must be coordinated with the system fault protection to ensure that the overall sensitivity and timing of the relaying results in tripping of the proper system elements. Proper time delay is used such that protection does not trip due to interwinding capacitance issues or instrument secondary grounds.

Loadability

There are no loadability issues with this protection function.

Considerations and Issues

The 59GN function is intended to detect a phase-to-ground fault on the stator windings of a generator connected to a delta-connected winding on the generator step-up transformer.

Coordination Procedure and Considerations

Time-delay settings for the 59GN/27TH function must be coordinated with the worst-case clearing time for phase-to-ground or phase-to-phase-to-ground close-in faults, including the breaker failure time. This is done to avoid tripping this function for system ground or unbalanced faults. Even when high-impedance grounding is provided to limit fault current for stator phase-to-ground faults, the arcing energy associated with the low levels of fault current may be sufficient to cause severe welding of laminations in a very short time. Generator Owners may utilize variations of the stator ground voltage function to reduce the operating time, may take measures to limit the stator ground fault current, or both.

Example

The time delay for any 59GN function that is set sensitive enough to detect single line-to-ground faults on the high side of the generator step-up transformer is set longer than the longest clearing time of the transmission protection, and the 59GN is set to coordinate with fuse protection if wye-grounded/wye-grounded voltage transformers are applied at the terminals of the generator. There are no coordination issues for the 27TH function.

Summary of Protection Functions Required for Coordination

Table 2 Excerpt: Functions 59GN/27TH Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Functions**	**System Concerns**
59GN/27TH — Generator Stator Ground	21N 51N	• Ensure that proper time delay is used such that protection does not trip due to interwinding capacitance issues or instrument secondary grounds, or supervise the 59GN function.

Summary of Protection Function Data and Information Exchange Required for Coordination

Table 3 Excerpt: Functions 59GN/27TH Data to be Exchanged Between Entities		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Provide time-delay setting of the 59GN/27TH	Provide worst-case clearing time for phase-to-ground or phase-to-phase-to-ground close-in faults, including the breaker failure time.	None

Out-of-Step or Loss-of-Synchronism Protection (Function 78)

Purpose of the Generator Function 78 — Loss of Synchronism Protection

The application of an out-of-step protective function to protect the turbine generator should be based on detailed stability studies and analysis.

Out-of-step relaying is generally required for larger machines connected to EHV systems. Stability studies may be performed to confirm the need for out-of-step relaying for these applications, or for smaller machines connected at lower voltages.

Out-of-step protection uses a measure of apparent impedance derived from the quotient of generator terminal voltage divided by generator stator current. Section 4.5.3.1 of the IEEE Std. C37.102–2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows:

The protection normally applied in the generator zone, such as differential relaying, time-delay system backup, etc., will not detect loss of synchronism. The loss-of-excitation relay may provide some degree of protection but cannot be relied on to detect generator loss of synchronism under all system conditions. Therefore, if during a loss of synchronism the electrical center is located in the region from the high-voltage terminals of the GSU transformer down into the generator; separate out-of-step relaying should be provided to protect the machine. This is generally required for larger machines that are connected to EHV systems. On large machines the swing travels through either the generator or the main transformer.

This protection may also be required even if the electrical center is out in the system and the system relaying is slow or cannot detect a loss of synchronism. Transmission line pilot-wire relaying, current-differential relaying, or phase comparison relaying will not detect a loss of synchronism. For generators connected to lower voltage systems, overcurrent relaying may not be sensitive enough to operate on loss of synchronism.

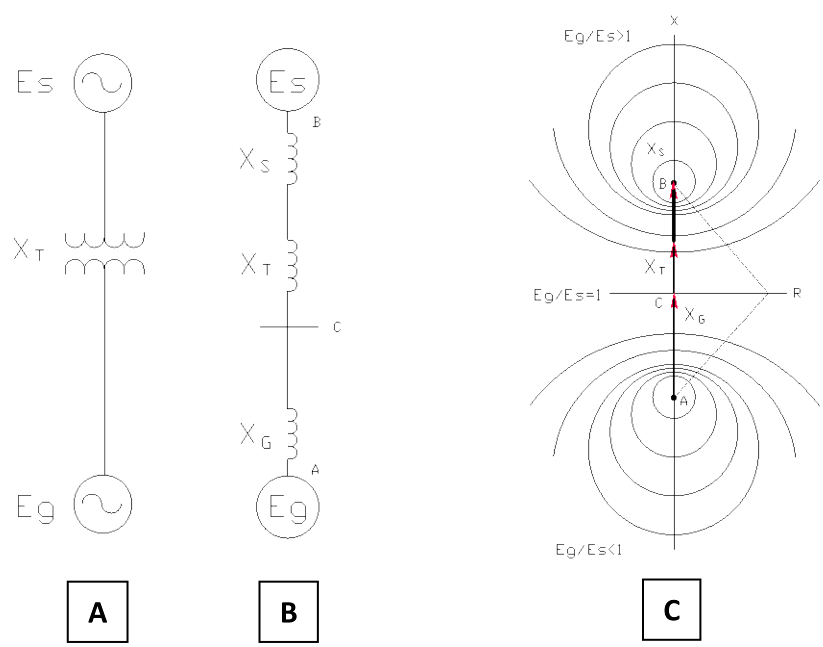


Figure 43: Loci of Swing by E_g / E_s

Figure 43 A and B illustrate a simple representation of two systems: E_s (the power system) and E_g (a generator), connected through a generator step-up transformer.

Figure 43 C shows typical power swing loci, which are dependent on the ratio of E_g/E_s. When E_g is less than E_s, which may occur when the generator is underexcited, the power swing loci will appear electrically "closer" to the generator than the power system. Due to the variability of the apparent impedance trajectory, it is desirable to base out-of-step protection settings on transient stability simulations.

The point at which the apparent impedance swing crosses the impedance line between the generator and the system is referred to as the electrical center of the swing and represents the point at which zero voltage occurs when the generator and the system are 180 degrees out of phase. During pole slipping, the voltage magnitude between the generator and the system reaches two per unit when the angle difference reaches 180 degrees, which can result in high currents that cause mechanical forces in the generator stator windings and undesired transient shaft torques. It is possible for the resulting torques to be of sufficient magnitude to cause the shaft to snap or damage turbine blades.

Figure 44 shows an example of relay CT and VT connections for the out-of-step function. Other configurations may be used, depending on out-of-step strategies.

An out-of-step condition can also cause excessive overheating and shorting at the ends of the stator core. Out-of-step (pole-slip) operation can cause damaging transient forces in the windings of the generator step-up transformer as well.

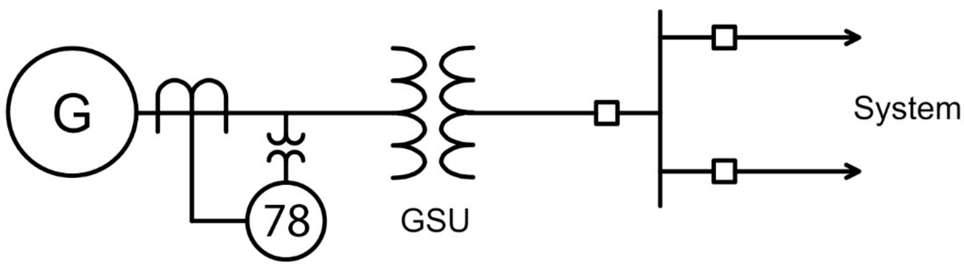


Figure 44: Generator Out-of-Step Relay Connection

Coordination of Generator and Transmission System

Faults

There are no coordination issues for system faults for this function, although the apparent impedance swings for which out-of-step protection must be set often occur as the result of system faults.

Issues associated with obtaining proper response to power swings are often more complex than those affecting the coordination of protection systems clearing faults. Faults must be cleared and, in general, the fewer components removed from service, the better. Swings present additional complexities, including the concept that stable swings do not require tripping. For swings whose system centers pass near generator locations, proper response may depend on strategic decisions made prior to the disturbance.

Consider Figure 44, where a single generator is connected to the larger system through two transmission lines. If during an unstable swing, the swing center passes through each line impedance, impedance relays may operate and trip both lines. If it is desirable to trip the generator and retain the lines for this condition, then out-of-step blocking needs to detect the swing and block the impedance relays on each line. In addition, the out-of-step condition needs to be identified, and the generator needs to be tripped. One way to do this would be to apply out-of-step blocking to the line impedance elements, and select an out-of-step tripping scheme to respond to unstable swings whose centers pass through either the line impedances, or the series impedance of the generator and its GSU. The tripping scheme would trip only the generator. The scheme shown in Figure 45 would work, provided that the mho element be expanded to include both the GSU and the larger of the two line impedances. Since dependable tripping is required, redundant tripping schemes may be desirable.

These are not typical “coordination” issues, and the situation would get increasingly complex as additional lines and generators are added to the location. In addition to out-of-step blocking and tripping, remedial action schemes may be used to implement the desired strategy.

Loadability

There are no coordination issues related to loadability for this function.

Other Operating Conditions

- A generator may slip out of synchronism with the power system for a number of reasons. The primary causes are: long duration of a low-impedance fault on the power system, generator operation at a high load angle close to its stability limit, or partial or complete loss of excitation.
- To properly apply this protection function, stability studies must be performed involving coordination between the Planning Coordinator, Transmission Owner, and Generator Owner. The stability studies, which usually are conducted by the Planning Coordinator, evaluate a variety of system contingencies and operating conditions. Typically, this involves simulation of local three-phase faults (similar to the simulations in Appendix F) for various line-out conditions, transfer levels, and system load levels. The extent of the studies necessary will depend, in part, on the characteristics of the system to which the generator is connected. The protection function application must be reviewed as system conditions change.
- Studies must be used to verify that the out-of-step protection operates only for unstable conditions and that it does not operate for load conditions or stable swing conditions. The critical conditions for setting the function are the marginal condition that represents the unstable swing that is closest to a stable condition, and the fastest swing (typically resulting from the most severe system condition).
- Typically, the out-of-step settings are developed by calculating initial settings for blinders, time delay, etc. using a graphical approach. The settings are then refined as necessary based on transient stability simulations to ensure dependable tripping for unstable swings and secure operation for stable swings. This process requires an exchange of information between the Transmission Owner, the Generator Owner, and the Planning Coordinator.

Considerations and Issues

Stability studies must be performed to validate that the out-of-step protection will provide dependable operation for unstable swings and will not trip for stable system conditions and stable swings.

Setting Procedure

The out-of-step protection characteristic using a single blinder scheme is shown in Figure 45.

The mho supervisory characteristic restricts the operation area to swings that pass through or near the generator and its step-up transformer. Faults that occur between blinders A and B will cause both characteristics to pick up; thus, no tripping will be initiated. For operation of the blinder scheme, there must be a time differential between operation of the two blinders such that the swing originates outside the mho characteristic and progresses from one blinder to the other, typically over a period of a few cycles.

The settings of this 78 function can be carried out with the procedure presented here. Figure 45 helps to illustrate the impedance settings.

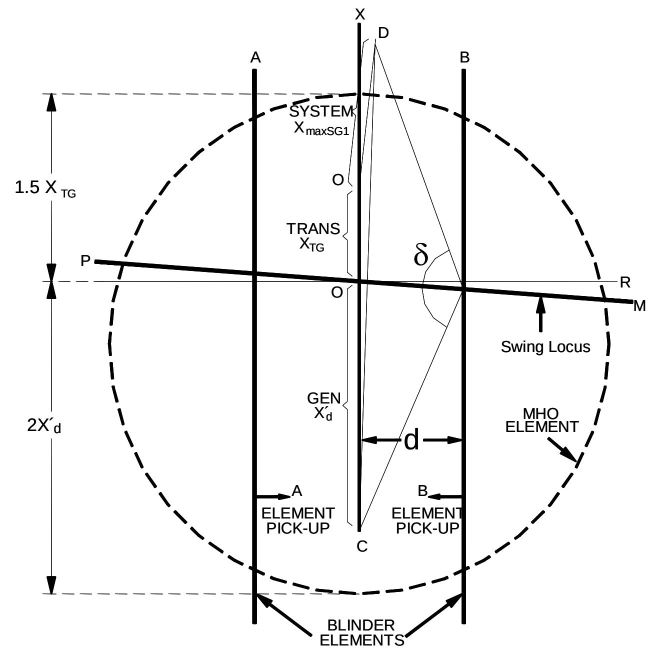


Figure 45: Out-of-Step Protection Characteristic Using a Single Blinder Scheme

1. Model the overall system and carry out transient stability simulations for representative operating conditions. The modeling of the generators should include the voltage regulator, generator governor, and power system stabilizer, if in service.
2. Determine values of generator transient reactance (X'_d), unit transformer reactance (X_{TG}), and system impedance under maximum generation (X_{maxSG1}).
3. Set the mho unit to limit the reach to 1.5 times the transformer impedance in the system direction. In the generator direction, the reach is typically set at twice the generator transient reactance. Therefore, the diameter of the mho characteristic is $2\,X'_d + 1.5\,X_{TG}$.
4. Determine the critical angle δ between the generator and the system by means of transient stability simulations. This is the angle corresponding to fault clearing just greater than the critical clearing time.
5. Determine the blinder distance d, which is calculated with the following expression:

$$d = \left(\left(\frac{X'_d + X_{TG} + X_{\max SG1}}{2}\right) x \tan(90 - \delta / 2)\right)$$

6. Determine the time for the impedance trajectory to travel from the position corresponding to the critical angle δ to that corresponding to 180°. This time is obtained from the rotor angle versus time curve, which is generated by the transient stability study for the transmission fault when the system experiences the first slip.

7. The time delay of the 78 function should be set equal to the value obtained from the transient stability study in step 6. This value is equal to half the time for the apparent impedance to travel between the two blinders and provides adequate margin to permit tripping for faster swings while providing security against operation for fault conditions.

A setting example is provided in Section 3.13.5.1.1 that provides a step-by-step procedure. A stability study example is provided in Appendix F that illustrates the process for refining the time-delay setting and critical angle δ from the calculated initial settings developed using a graphical approach.

Setting Considerations

Generators Connected to a Single Transmission Line
For a generator directly connected to a transmission line, a determination is made whether existing clearing times on the adjacent transmission lines are adequate to ensure stability of the generation. In some cases, relaying (for example, an existing stepped distance scheme) may have to be replaced with a communication-assisted scheme to improve the clearing speed and to ensure stability. Faults and clearing times on the line to which the generator is connected are of no consequence in terms of impacting the stability of the generator, because for a fault on the transmission line, the generation will be disconnected from the system.

Check List

- The direct axis transient reactance (X_d’) used in the setting calculation should be on the generator base.
- The generator step-up transformer reactance (Xt) used in the setting calculation should be on the generator base.
- The reverse reach (toward the system) should be greater than the generator step-up transformer reactance (Xt).
- A proper angular separation δ between the generator and the system should be used to set the blinders (as determined by a transient stability study).
- A power system stability study should be performed for the relay time-delay setting.

Setting Example

Several types of out-of-step algorithms and relay characteristics exist, and details for developing settings are specific to the particular relay used. The following example illustrates the setting details associated with one particular relay type and provides an overview of the process used to ensure proper coordination.

Example of Calculation for MHO Element and Blinder Settings
The following data is used to illustrate the setting calculations for the out-of-step (78) function:

Generator

492 MVA (MVAG), 20 kV, 14202 A, 0.77 pf

Direct axis transient reactance ($X_d^{'}$) = 0.20577 pu

VT ratio = 20000/120 = 166.67 and CT ratio = 18000/5 = 3600

Unit transformer

425 MVA (MVAT), 145 kV/19 kV, Y-ground/Δ

Leakage reactance X_T = 0.1111 pu on 425 MVA base.

Power system

Positive sequence impedance during maximum generation on 100 MVA (MVAS) and 138 kV base:

$Z_{\max S1}$ = 0.000511 + j0.010033 pu

To calculate the setting, we will convert all data to the generator base.

The generator step-up transformer reactance on the generator base is given by:

$$X_{TG} = \frac{MVA_G}{MVA_T} \frac{kV_T^2}{kV_G^2} X_T = 0.11607 \text{ pu}$$

Since the system base voltage is different from the transformer base voltage, it is necessary to first convert the system impedance values to the transformer base, then to the generator base. The resulting calculated system impedance is:

$Z_{\max SG1}$ = 0.002055 + j0.040352 pu

The setting calculations will be simplified if the voltage, current, and impedances are converted to relay quantities (CT and VT secondary) as follows:

The generator VT primary base voltage line to ground is:

20,000/√3 = 11547 V

The base voltage for the relay (or generator VT secondary) is:

$V_{LN\_B\_relay}$ = VT primary voltage/VT ratio = 11547/166.6 = 69.28 V

The generator CT primary line base current is 14202.8 A. Thus, the base current for the relay (or CT secondary) is given by:

I_{B_relay} = CT primary current/CT ratio = 14202.8/3600 = 3.945 A

The base impedance based on the relay secondary quantities is given by:

$$Z_{B\_relay} = \frac{V_{LN\_B\_relay}}{I_{B\_relay}} = 69.28 \text{ V}/3.95 \text{ A} = 17.56\ \Omega$$

Converting all reactances to CT and VT secondary quantities gives:

X'_d = 0.20577 x 17.56 Ω = 3.613 Ω = 0.11607 x 17.56 Ω = 2.04 Ω

$X_{\max SG1}$ = 0.04035 x 17.56 Ω = 0.7086 Ω

The impedance angle of the mho unit β = 90˚

The blinder distance (d) = (($X_d^{'}$ + X_{TG} + $X_{\max SG1}$)/2) x tan (90-(δ/2)), where δ is the angular separation between the generator and the system at which the relay determines instability. If a stability study is not available, this angle is typically set at 120˚.

When using the critical angle obtained in Appendix F, δ = 140°, then the blinder distance d = 1.16 Ω.

The diameter of the mho unit is (2 x $X_d^{'}$ + 1.5 x X_{TG}) = 10.3 Ω and the impedance angle of the mho unit is 90˚. The resulting out-of-step relay characteristic is shown in Figure 46.

The time delay for the out-of-step function based on the simulation results in Appendix F can be set as 250 ms.

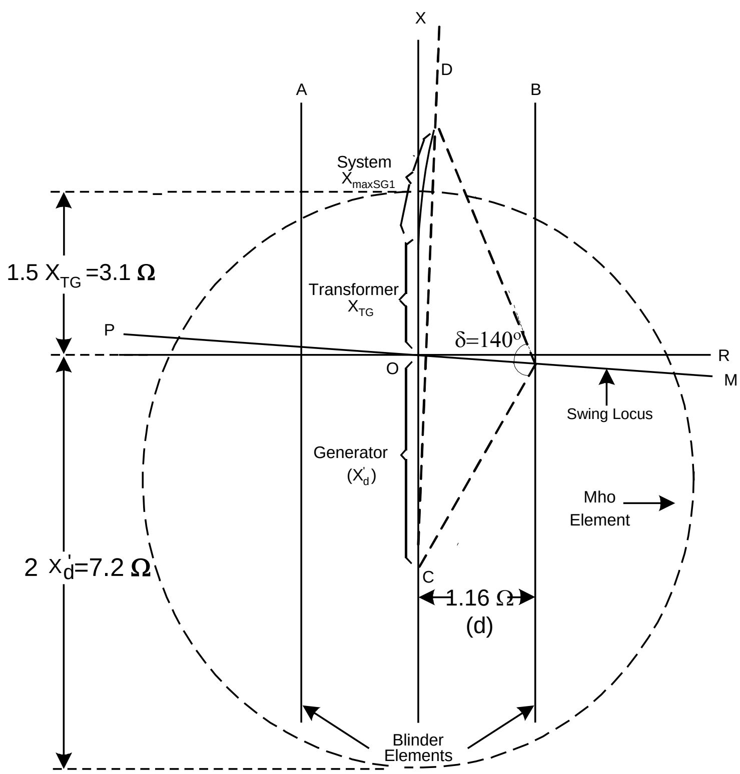


Figure 46: Out-of-Step Relay Settings

Example of Studies Required for Proper Scheme Settings

- These initial settings are modeled in transient stability simulations to verify secure operation for stable swings and dependable operation for unstable swings.
- The limiting transmission fault identified by the Planning Coordinator should be simulated with the fault clearing equal to the critical clearing time to ensure secure operation. The swing for this fault represents the farthest the apparent impedance should swing toward the out-of-step relay characteristic during a stable swing.

- The limiting transmission fault identified by the Planning Coordinator should be simulated with the fault clearing time just enough greater than the critical clearing time to result in the generator slipping out of step. The swing for this fault represents the slowest unstable swing.
- The more severe transmission faults should be simulated to verify dependable operation. The swings for these faults represent faster unstable swings that must be differentiated from a change in apparent impedance associated with application of a fault.
- The timing of the trip output from the relay should be verified for the unstable swings to ensure that the circuit breaker is not opened when the generator is 180 degrees out of phase with the transmission system.

If the above simulations do not result in both secure and dependable operation, the relay characteristic and trip timer settings should be adjusted to obtain the desired operation. The simulations listed above represent a minimal set of simulations. The degree of confidence in the relay settings is improved by running more simulations that may be based on other contingencies and sensitivity to parameters such as fault type, fault impedance, system load level, breaker failure, line outages, and pre-fault generator loading.

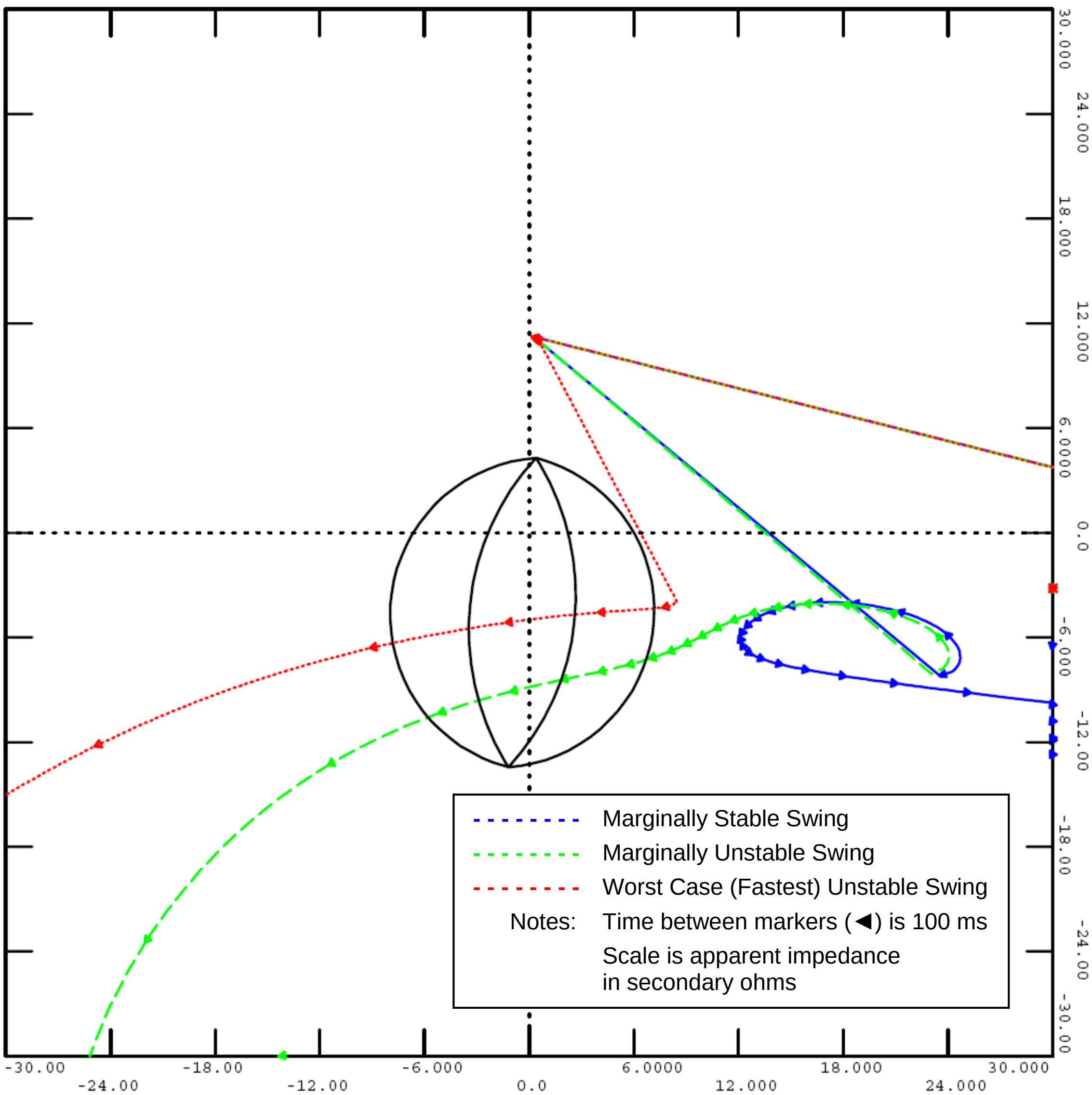


Figure 47: Sample Apparent Impedance Swings

Sample apparent impedance swings are presented in Figure 47 for a dual-lens characteristic out-of-step function. In this figure, the time interval between markers is 100 ms (6 cycles) such that the faster swings have greater distance between markers. The three traces represent marginally stable and unstable swings for fault clearing at and just beyond the critical clearing time, and a trace for the worst credible contingency representing the fastest unstable swing.

Summary of Protection Functions Required for Coordination

Table 2 Excerpt: Function 78 Protection Coordination Considerations

Generator Protection Function	Transmission System Protection Functions	System Concerns
78 — Out of Step	21 (including coordination of out-of-step blocking and tripping) 78 (if applicable)	• System studies are required. • Settings should be used for system studies, either through explicit modeling of the function or through monitoring impedance swings at the relay location in the stability program—and applying engineering judgment.

Summary of Protection Function Data and Information Exchange Required for Out-of-Step Settings

The following table presents the data and information that need to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above examples.

Table 3 Excerpt: Function 78 Data to be Exchanged Between Entities

Generator Owner	Transmission Owner	Planning Coordinator
Relay settings, time delays, and characteristics for out-of-step tripping	Provide relay settings, time delays, and characteristics for the out-of-step tripping and blocking, if used.	Identify potential for a generator out-of-step condition resulting from a transmission system fault.
Generator characteristics for use in stability studies	Breaker failure tripping schemes	Feedback on coordination problems found in stability studies

Overfrequency and Underfrequency Protection (Function 81)

Purpose of the Generator Function 81 — Overfrequency and Underfrequency Protection

Overfrequency and underfrequency protection uses the measurement of voltage frequency to detect overfrequency and underfrequency conditions. Section 4.5.8 of IEEE Std. C37.102–2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows:

> *The operation of generators at abnormal frequencies (either overfrequency or underfrequency) can result from load rejection or mismatch between system loading and generation. Full- or partial-load rejection may be caused by clearing of system faults or by overshedding of load during a major system disturbance. Load rejection will cause the generator to overspeed and operate at some frequency above normal. In general, the overfrequency condition does not pose serious problems since operator and/or control action may be used to quickly restore generator speed and frequency to normal without the need for tripping the generator.*

Mismatch between load and generation may be caused by a variety of system disturbances and/or operating conditions. However, of primary concern is the system disturbance caused by a major loss of generation that produces system separation and severe overloading on the remaining system generators. Under this condition, the system frequency will decay and the generators may be subjected to prolonged operation at reduced frequency. While load shedding schemes are designed to arrest the frequency decay and to restore frequency to normal during such disturbances, it is possible that undershedding of load may occur. This may cause an extremely slow return of frequency to normal or the bottoming out of system frequency at some level below normal. In either case, there exists the possibility of operation at reduced frequency for sufficient time to damage steam or gas turbine generators. In general, underfrequency operation of a turbine generator is more critical than overfrequency operation since the operator does not have the option of control action. Therefore, it is usually recommended that some form of underfrequency protection be provided for steam and gas turbine generators.

Overfrequency and underfrequency conditions occur as a result of a mismatch between load and generation. Typical levels of overfrequency and underfrequency resulting from tripping of generation or load, or sudden increases in load, do not pose a threat to equipment and are corrected through Automatic Generation Control (AGC) or operator action. Serious abnormal underfrequency and overfrequency conditions may occur as a result of conditions on the power system that result in a significant mismatch between load and generation. The amount by which frequency deviates from nominal is a function of the percentage mismatch; thus, the most significant frequency deviations typically occur when a portion of the system becomes isolated from the rest of the interconnection.

The governor controlling the prime mover normally limits overfrequency conditions below the operating thresholds of the generator frequency protection. The governor may also be capable of limiting underfrequency conditions depending on the operating mode and pre-disturbance output level of the generator. The overfrequency and underfrequency protective functions primarily provide protection for the prime mover (turbine, etc.) rather than electrical protection for the generator itself. It is important to note when applying these protective functions that damage due to off-nominal frequency operation tends to be cumulative.

Steam turbine blades are designed and tuned for efficient operation at rated frequency of rotation. Operation with load at different frequencies can result in blade resonance and fatigue damage in the long blades in the turbine low-pressure unit. Transiently passing through a low frequency is not a problem; it is when a low frequency is sustained at a particular point that there could be a problem for a given turbine.

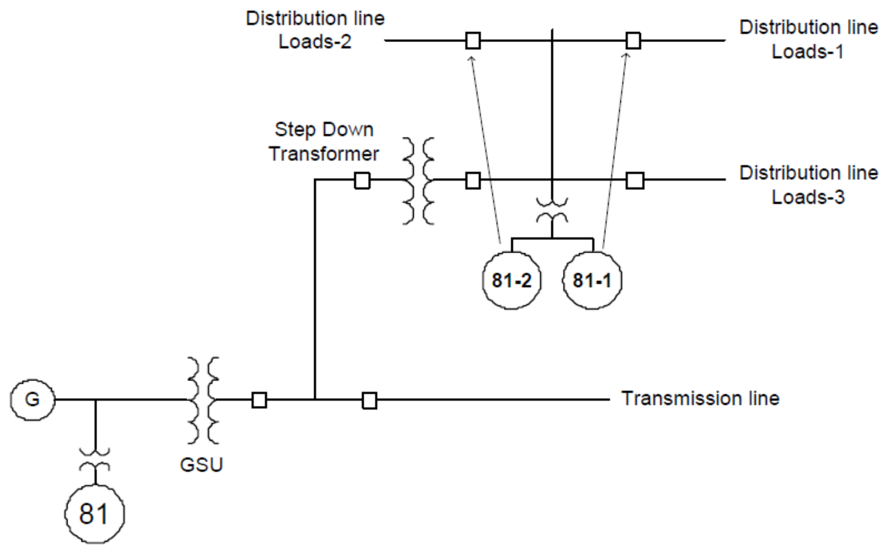


Figure 48: Typical Location of Generator Frequency Relays and Load Shedding Relays Requiring Coordination

Coordination of Generator and Transmission System

Faults
There are no coordination issues for system faults for this function.

Loadability
There are no coordination issues related to loadability for this function.

Other Operating Conditions
Coordination between generating plant overfrequency and underfrequency protection and the transmission system is necessary for off-nominal frequency events during which system frequency declines low enough to initiate operation of the underfrequency load shedding (UFLS) program. In most interconnections, frequency can decline low enough to initiate UFLS operation only during an island condition. However, adequate frequency decline may occur to initiate UFLS operation as a result of tripping generators or tie lines on smaller interconnections or on weakly connected portions of interconnections.

Coordination is necessary to ensure that the UFLS program can operate to restore a balance between generation and load to recover and stabilize frequency at a sustainable operating condition. Without coordination, generation may trip by operation of underfrequency protection to exacerbate the unbalance between load and generation, resulting in tripping of more load than necessary or, in the worst case, resulting in system collapse if the resulting imbalance exceeds the design basis of the UFLS program. Coordination also is necessary to ensure that overfrequency protection does not operate if frequency temporarily overshoots 60 Hz subsequent to UFLS operation and prior to frequency stabilizing at a sustainable operating condition. It is important to note that the coordination is not a relay-to-relay coordination in the traditional sense; rather, it is coordination between the generator prime mover capabilities, the overfrequency and underfrequency protection, and the UFLS program and transmission system design.

A UFLS program that is designed properly and operates for a condition within its design parameters (typically for a generation deficiency of up to 25–30 percent of load) will recover frequency to nearly 60 Hz. For conditions that exceed the design parameters of the UFLS program, or for cases in which the amount of load shed is nearly equal to the initial generation deficiency, it is possible that frequency recovery will “stall” and settle at a lower-than-normal frequency. If it is necessary to apply underfrequency protection, turbine limits that account for both frequency and time at frequency must be obtained from the turbine manufacturer in order to properly set protection functions. The UFLS program always should be allowed to take action well before tripping a generating unit for turbine protection. If this is not possible, most regions require accounting for unit tripping in UFLS design assessments and require UFLS program modifications such as arming additional “compensating” load shedding equal to the capacity of the unit.

Considerations and Issues

Turbine limits must be obtained from the turbine manufacturer in order to properly set the overfrequency and underfrequency protection functions. The limits typically are expressed as the cumulative amount of time that the turbine can operate at off-nominal frequencies. As noted in IEEE Std. C37.102–2006, “Guide for AC Generator Protection,” generators that are designed to accommodate IEC-60034-3 (Rotating electrical machines – Part 3: Specific requirements for synchronous generators driven by steam turbines or combustion gas turbines) are required to deliver continuously rated output at the rated power factor over the ranges of ±5% in voltage and ±2% in frequency, as shown by the shaded area in Figure 49 (Figure 4-48 in IEEE Std. C37.102–2006).

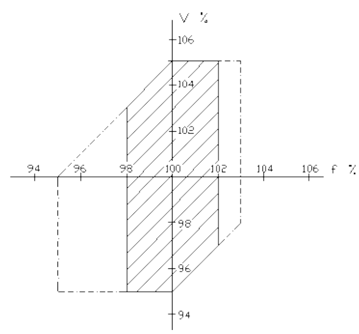


Figure 49: Generator Operation Ranges

While this characteristic defines limits for continuous operation, frequency operational limits in the form of time-frequency characteristics are necessary to coordinate overfrequency and underfrequency protection with the turbine and generator capability. A typical underfrequency generator capability curve is included in Figure 50.

Details for setting the protection functions are provided in Section 4.5.8 of IEEE Std. C37.102–2006. Generator off-nominal frequency protection and governor settings should be coordinated to ensure that the protection does not trip the unit for a condition from which the governor could restore the unit to an acceptable operating condition.

In order to provide reliable, coordinated protection, the overfrequency and underfrequency protection functions must have adequate pickup setting range (usually 55–65 Hz) and adequate time delay to coordinate with the UFLS program. It also is important to have an adequate operating range in terms of system frequency for the protection. Most relays are designed to operate in a range of 40–70 Hz, which is adequate. It is important to understand the protection function limitations as some relays are blocked automatically if the system frequency or voltage is outside the range of relay specifications, while other relays remain in service but are subject to misoperations.

Proper load shedding on the power system is crucial to minimizing the impacts of underfrequency and overfrequency issues on steam and gas turbine generators. Reduced-frequency operation may cause thermal damage and turbine blade resonance and fatigue in the long blades in the turbine low-pressure steam or gas turbine generators.

The generator underfrequency protection settings must be recognized in the development or evaluation of any UFLS system. Underfrequency tripping of generators should not occur before completion of the underfrequency load shedding, as defined by regional requirements. Properly planned UFLS programs, validated by system studies, are critical to the reliability of the transmission system. Selection of generation underfrequency performance specifications and protection settings for new generators should be matched to the existing regional UFLS programs. Further details are provided in IEEE Std. C37.106, "Guide for Abnormal Frequency Protection for Power Generating Plants."

Coordination Procedure

Step 1 – Planning Coordinator provides the regional underfrequency load shedding and generator off-nominal frequency protection setting criteria.

Step 2 – Generator Owner obtains equipment limits from the manufacturer.

Step 3 – Generator Owner and Planning Coordinator verify that the generator off-nominal frequency protection is set to coordinate with the regional UFLS program design and generator off-nominal frequency protection setting criteria.

Step 4 – If coordination cannot be achieved without compromising protection of the generating unit, the Planning Coordinator performs studies to assess the impact on the UFLS program design and identify modifications, if necessary, to accommodate the generator protection setting while ensuring the UFLS program continues to meet its design objectives.

Setting Validation for Coordination

Step 1 – Plot the generator and turbine capabilities on a graph of frequency versus time, similar to the graph shown in Figure 50.

Step 2 – Plot the applicable NERC and regional requirements for setting overfrequency and underfrequency protection on generating units on the same graph. These requirements are coordinated with the UFLS program design and provide some margin between the performance characteristics to which the regional UFLS program is designed and the frequency-time requirements for setting generator protection. Note that the generator protection is not coordinated directly with the UFLS relay settings because, subsequent to the UFLS program operating to shed load, a time delay will exist before frequency decline is arrested and recovery begins. This time delay, as well as the rate at which frequency recovers, is a function of the physical characteristics of the system including types of load, generating unit inertia, and governing response.

Step 3 – Plot the protection settings on the same graph. Note that for some plant designs, critical station service load may be supplied from a motor-generator (M-G) set. When an overfrequency or underfrequency protection is located on the load side of the M-G set, the protection function trip setting must be adjusted to account for any frequency difference between the system and the load.

Step 4 – Verify whether the protection function settings coordinate with the generator and turbine capability and the regional requirements. If coordination cannot be achieved, set the protection based on the generator and turbine capability and follow the applicable processes to report the relay setting so the generator protection can be modeled by the Planning Coordinator in system studies.

Example

Proper Coordination

Figure 50 illustrates an example of how generator protection settings are coordinated with the turbine capability and the underfrequency protection setting limits for generating units. The figure shows the underfrequency and overfrequency capability of a hypothetical generating unit and the relay setting limits for the Eastern Interconnection as provided in NERC Reliability Standard PRC-024-1 – Generator Frequency and Voltage Protective Relay Settings.

The generator underfrequency and overfrequency protection limit curves are established to allow the system to recover from disturbances without tripping generation, which could exacerbate the disturbance and lead to a collapse of the system or an isolated portion of the system. The generator underfrequency protection settings must be set above the green curve, which defines the turbine capability provided by the manufacturer, and on or below the red curve, which defines the applicable generator underfrequency protection setting limits. In this example, the protection is set with an instantaneous trip threshold at 57.7 Hz and a time-delayed threshold setting at 58.5 Hz with a definite time delay of 60 seconds. Both settings coordinate in this example.

For reference, the figure also includes hypothetical UFLS set points. In this example, load is shed in five stages. The UFLS set points are determined through transient stability studies to ensure that frequency decline is arrested and frequency recovers to an acceptable level. NERC Reliability Standard PRC-006-1 defines the acceptable frequency limits, which fall within the generator protection limit curves with margin applied.

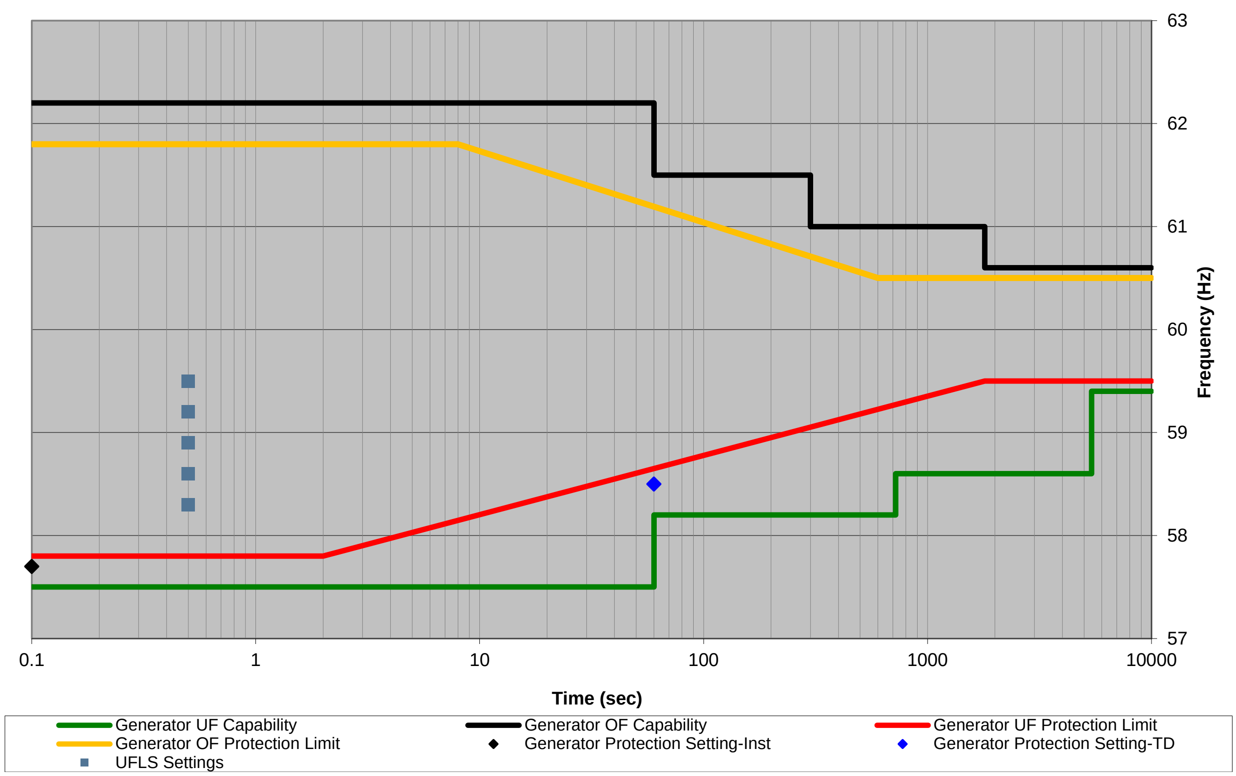


Figure 50: Generator Underfrequency Protection Coordination Example

Summary of Protection Functions Required for Coordination

Table 2 Excerpt: Functions 81U/81O Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Functions**	**System Concerns**
81U – Underfrequency 81O – Overfrequency	81U 81O Note: UFLS design is generally the responsibility of the Planning Coordinator	• Coordination with system UFLS set points and time delay (typically achieved through compliance with regional frequency standards for generators) • Meet underfrequency and overfrequency requirements. • Auto-restart of distributed generation such as wind generation during overfrequency conditions. • Settings should be used for planning and system studies, either through explicit modeling of the function or through monitoring frequency performance at the relay location in the stability program—and applying engineering judgment.

Summary of Protection Function Data and Information Exchange Required for Coordination

The following table presents the data and information that need to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above examples. Whenever a miscoordination between the underfrequency setting of a generator and the UFLS program cannot be resolved, the UFLS program may have to be redesigned to compensate for the loss of that generation in order to be fully coordinated.

Table 3 Excerpt: Functions 81U/81O Data to be Exchanged Between Entities		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Relay settings and time delays	None	Feedback on problems found between underfrequency settings and UFLS programs

Generator Differential (Function 87G), Transformer Differential (Function 87T), and Overall Differential (Function 87U) Protection

Purpose

Function 87G — Generator Differential Protection

Generator differential protection (function 87G) is used for phase-fault protection of generator stator windings. Differential relaying will detect three-phase faults, phase-to-phase faults, phase-to-phase-to-ground faults, and some phase-to-ground faults depending upon how the generator is grounded. Section 4.3.2 of IEEE Std. C37.102–2006, “Guide for AC Generator Protection,” describes the purpose of this protection as follows:

> *Some form of high-speed differential relaying is generally used for phase fault protection of generator stator windings. Differential relaying will detect three-phase faults, phase-to-phase*

faults, double-phase-to-ground faults, and some single-phase-to-ground faults, depending upon how the generator is grounded.

Differential relaying will not detect turn-to-turn faults in the same phase since there is no difference in the current entering and leaving the phase winding. Where applicable, separate turn fault protection may be provided with the split-phase relaying scheme. This scheme will be discussed subsequently.

Differential relaying will not detect stator ground faults on high-impedance grounded generators. The high impedance normally limits the fault current to levels considerably below the practical sensitivity of the differential relaying.

Three types of high-speed differential relays are used for stator phase fault detection: percentage differential, high-impedance differential, and self-balancing differential.

Function 87T — Transformer Differential Protection

Transformer differential protection (function 87T) is used solely for protection of the generator step-up transformer.

Function 87U — Overall Differential Protection

Overall differential protection may be applied on the unit generator-transformer arrangement with or without a low-voltage generator unit breaker. An example without a generator unit breaker is shown in Figure 51. The advantage of this scheme is to provide redundant generator and generator step-up transformer differential protection.

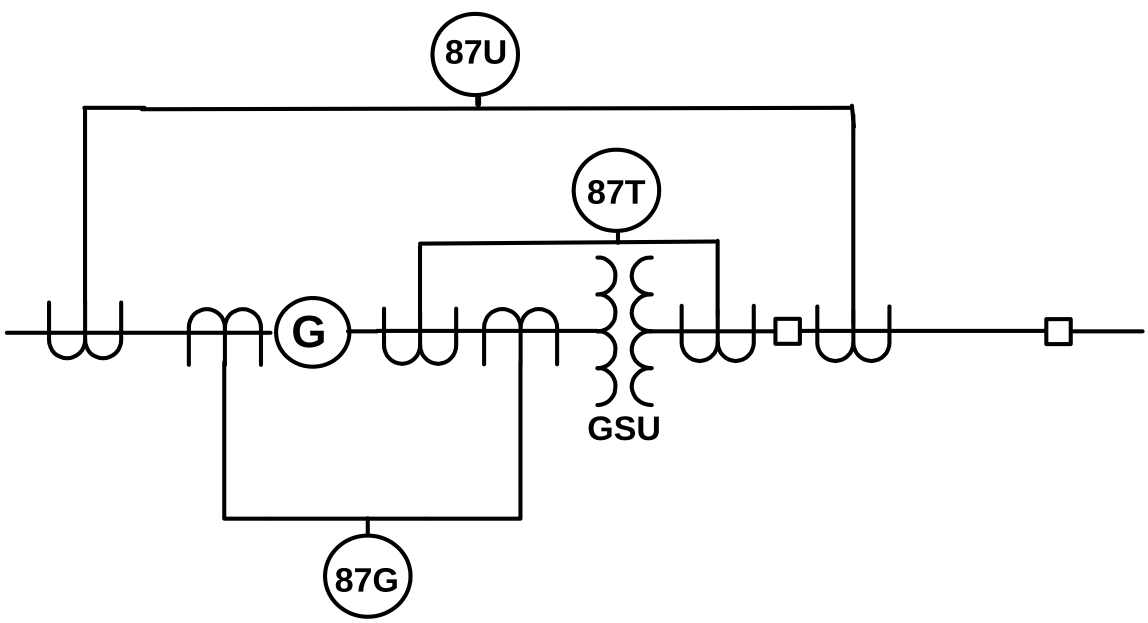


Figure 51: Overall Differential, Transformer Differential, and Generator Differential Relays without Unit Circuit Breaker

Coordination of Generator and Transmission System

Faults

There are no fault considerations for this protective function.

Loadability
There are no loadability issues with this protection function.

Considerations and Issues
The Transmission Owner and Generator Owner should verify proper overlap of differential zones.

Coordination Procedure and Considerations
The setting procedure for the 87G generator differential protection is discussed in IEEE Std. C37.102–2006, Section 4.3, Stator Fault Protection. The 87U overall unit differential protection is discussed in IEEE Std. C37.91–2008, "IEEE Guide for Protective Relay Application to Power Transformers," Section 14.1. The 87T generator step-up transformer differential protection is discussed in IEEE Std. C37.91–2008, Appendix C.1.

Example

Proper Coordination
No coordination required.

Improper Coordination
No coordination required.

Summary of Protection Functions Required for Coordination

Table 2 Excerpt: Functions 87T/87G/87U Protection Coordination Data Exchange Requirements		
Generator Protection Function	**Transmission System Protection Functions**	**System Concerns**
87G — Generator Differential	None	Proper overlap of the overall differential zone and bus differential zone, etc., should be verified.
87T — Transformer Differential	None	
87U — Overall Differential	None	

Summary of Protection Function Data and Information Exchange Required for Coordination
No coordination required.

Table 3 Excerpt — Functions 87T/87G/87U Data to be Exchanged Between Entities		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Function 87G — Generator Differential	None	None
Function 87T — Transformer Differential	None	None
Function 87U — Overall Differential	None	None

Appendix A – References

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2. IEEE Std. 421.1–2007 IEEE Standard Definitions for Excitation Systems

3. IEEE Std. 421.5–2006 IEEE Recommended Practice for Excitation System Models

4. IEEE Std. C50.12–2005 IEEE Std. for Salient-Pole Synchronous Generator/Motors for Hydraulic Turbine Applications Rated 5 MVA and Above

5. IEEE Std. C50.13–2005 IEEE Std. for Cylindrical-Rotor Synchronous Generators Rated 10 MVA and Above

6. IEEE Std. 67–2005 IEEE Guide for Operation and Maintenance of Turbine Generators

7. IEEE Std. C37.102–2006 IEEE Guide for AC Generator Protection

8. IEEE Std. C37.106–2003 IEEE Guide for Abnormal Frequency Protection for Power Generating Plants

9. IEEE Std. C37.96–2012 IEEE Guide for AC Motor Protection

10. IEEE Std. C37.012–2005, IEEE Application Guide for Capacitance Current Switching for AC High-Voltage Circuit Breakers

11. IEEE Std. 1547–2003, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.

12. IEEE Std. C37.119–2005, IEEE Guide for Breaker Failure Protection of Power Circuit Breakers

13. C37.96–2012, IEEE Guide for AC Motor Protection

14. C37.112-1996, IEEE Standard Inverse-Time Characteristic Equations for Overcurrent Relays

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16. *Coordination of Generator Protection with Generator Excitation Control and Generator Capability*, IEEE/PSRC WG J-5 Paper/Power Engineering Society General Meeting, 2007. IEEE, Publication Date: 24-28 June 2007, On page(s): 1-17, Location: Tampa, FL, USA, ISSN: 1932-5517, ISBN: 1-4244-1298-6, Digital Object Identifier: 10.1109/PES.2007.386034, Posted online: 2007-07-23 09:42:51.0

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25. Section 11, "System Backup Protection" by P.W. Powell, IEEE Tutorial on the Protection of Synchronous Generators, IEEE catalog No. 95 TP 102

26. IEEE Std. C37.91–2008, (Guide for Protecting Power Transformers) Appendix C.1

27. IEEE/PSRC Working Group Report, "Sequential Tripping of Steam Turbine Generators," *IEEE Transactions on Power Delivery,* Vol. 14, No. 1, January 1999, pp. 132–141.

28. IEEE Std. 741–2007, IEEE Standard Criteria for the Protection of Class 1E Power Systems and Equipment in Nuclear Power Generating Stations

29. IEEE Std. 765–2006, IEEE Standard for Preferred Power Supply (PPS) For Nuclear Power Generating Stations (NPGS)

30. NERC Standard NUC-001-2.1 — Nuclear Plant Interface Coordination

31. NERC Standard PRC-024-1 — Generator Frequency and Voltage Protective Relay Settings

32. IEEE/PSRC, Working Group Report C12 — Performance of Relaying during Wide-Area Stressed Conditions, May 14, 2008

33. NERC Reliability Standard PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Appendix B – Step Response of Load Rejection Test on Hydro Generator

Example of a load rejection test result (100.5 MW, -4.5 Mvar)

Record No:	0003			
Time of Record:	06 Mar 00	11:52:12		
Record size:	29127 samples	Record window:	2.43 min	
Pre-Trigger:	2912 samples	Post-trigger:	26215 samples	
Playback time base:	200.00 ms/mm (or 1 sec/5 mm)			
Play back window:	3361-14624 samples			

Ch	Range	Offset	Dc/Gnd Note
01	20.000 V	119.10 Vdc	Stator Voltage (Vn=13.8 KV)
02	10.000 V	5.00 V dc	Stator Current
03	02.000 V	119.10 Vdc	5V Full Scale=200 RPM, Rated=120 RPM
04	150.00 V	119.10 Vdc	Field Breaker (41)

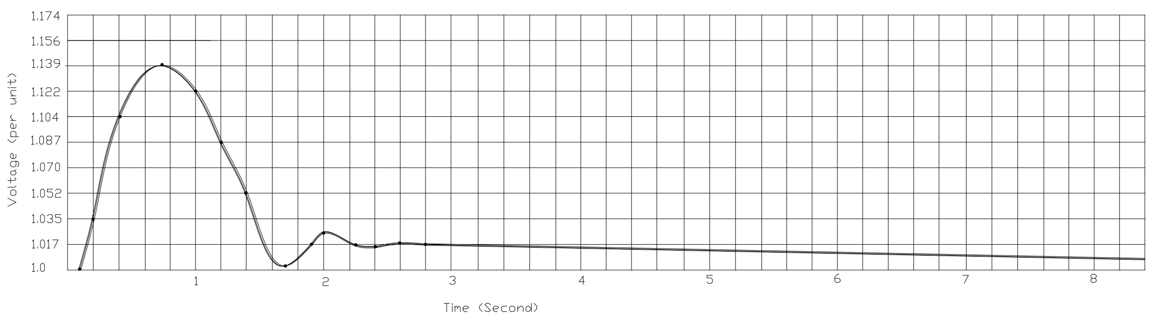

Figure: B-1

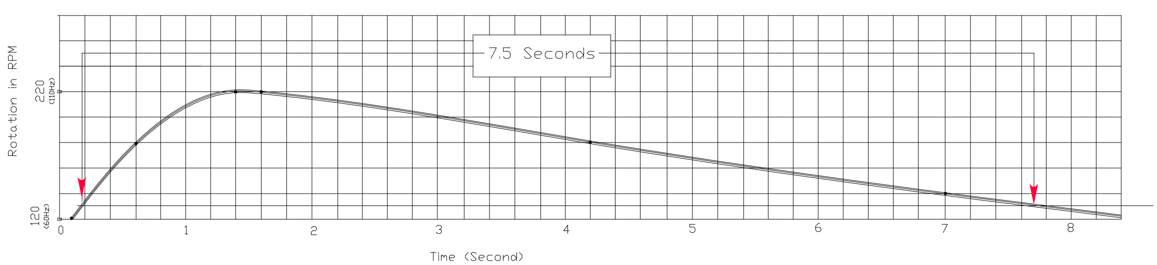

Figure: B-2

Appendix C – TR-22 Generator Backup Protection Responses in Cohesive Generation Groups

Observation

Generators that are electrically close to one another can behave as a cohesive group, such as when islanded from the rest of the interconnection. Generators can also remain in synchronism with each other within a zone and slip in frequency together with respect to the rest of the interconnection when weakly tied to the interconnection. Such was the case in southeast Michigan—protective relay functions can and did respond differently under such conditions.

The cohesive generator group can experience lower voltage, underfrequency, and large power flows brought on by large angles across its ties to the interconnection. In the cascade, a number of relaying schemes intended to trip generators for their own protection operated. Examples include inadvertent energization protection, volts/hertz overexcitation, voltage-restrained overcurrent, undervoltage, and loss of excitation relays. The operations of these relays are sensitive to abnormal voltages and frequencies.

A number of generators reported tripping operations from these devices:

Initiating Tripping Relay	Number of Generators Tripped
Inadvertent energizing	6
Volts/Hertz	10
Voltage-restrained overcurrent	4
Undervoltage	25
Overcurrent	15
Loss of excitation	11

Discussion

Inadvertent energizing is a protection scheme intended to detect an accidental energizing of a unit at standstill or a unit not yet synchronized to the power system. Two schemes used to detect inadvertent energizing are frequency-supervised overcurrent and voltage-supervised overcurrent. In frequency-supervised overcurrent schemes, the underfrequency relays are set to close their contacts when the frequency falls below a setting in the range of 48–55 Hz, thus enabling the overcurrent relay. Voltage-supervised overcurrent schemes use undervoltage and overvoltage relays with pickup and dropout time delays to supervise instantaneous overcurrent tripping relays. The undervoltage detectors automatically arm the overcurrent relays when their generation is taken off-line. Overvoltage relays disable the scheme when the machine is put back in service.

Volts/Hertz relays are used for overexcitation protection of generators. These relays become more prone to operation as frequency declines, given a particular voltage.

Voltage-restrained time-overcurrent relaying is remote backup protection used to protect generators for distant faults and is not intended to trip on load.

Undervoltage relays respond to system conditions especially when connected to transmission-level voltage transformers. Overcurrent relays respond to faults and to some non-fault conditions such as system swings.

The loss of excitation relay protects a generator in the event of an exciter failure. As with the Volts/Hertz relay, the loss of excitation relay should coordinate with generator excitation controls when these controls are functioning properly and exciter failures have not occurred.

51V Voltage-controlled overcurrent protection is backup protection to use when overcurrent does not provide adequate sensitivity. It can discriminate between load current and steady-state fault current. The latter can be smaller than full load current due to the large X_d and AVR constraints. It is susceptible to operation for sustained undervoltage conditions as confirmed during pre-blackout disturbance.

Recommendation TR–22

TR-22. NERC should evaluate these protection schemes and their settings for appropriateness, including coordination of protection and controls when operating within a coherent generation weakly connected to an interconnection or in as an electrical island. Generators directly connected to the transmission system using a 51V should consider the use of an impedance relay instead.

Appendix D – Conversion Between P-Q And R-X

From R-X to P-Q:

$$Sin\Theta = \frac{X}{\sqrt{R^2 + X^2}} \qquad Cos\Theta = \frac{R}{\sqrt{R^2 + X^2}}$$

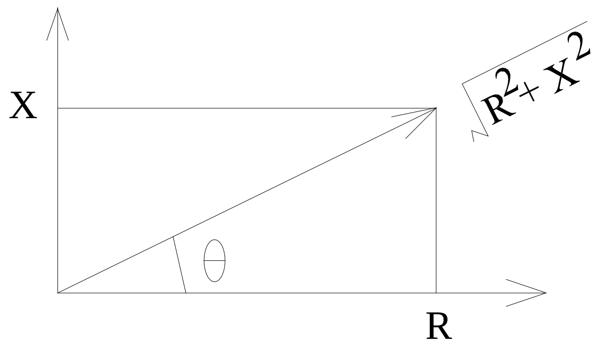

Figure D-1: R-X Diagram

$$MVA_{prim} = \frac{V_{LL,prim}^2}{Z_{prim}} = \frac{V_{LL,prim}^2}{Z_{\sec}\left(\frac{VTR}{CTR}\right)} = V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{1}{Z_{\sec}}\right)$$

- $P_{prim} = MVA_{prim}\cos\Theta = V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{1}{Z_{\sec}}\right)\left(\frac{R}{\sqrt{R^2 + X^2}}\right)$

$$= V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{1}{\sqrt{R^2 + X^2}}\right)\left(\frac{R}{\sqrt{R^2 + X^2}}\right) = V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{R}{R^2 + X^2}\right)$$

- $Q_{prim} = MVA_{prim}\sin\Theta = V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{1}{Z_{\sec}}\right)\left(\frac{X}{\sqrt{R^2 + X^2}}\right)$

$$= V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{1}{\sqrt{R^2 + X^2}}\right)\left(\frac{X}{\sqrt{R^2 + X^2}}\right) = V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{X}{R^2 + X^2}\right)$$

From P-Q to R-X:

$$Sin\Theta = \frac{Q}{\sqrt{P^2 + Q^2}} \qquad Cos\Theta = \frac{P}{\sqrt{P^2 + Q^2}}$$

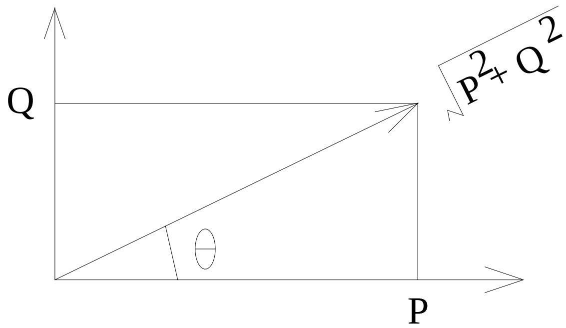

Figure D-2: P-Q Diagram

$$MVA_{prim} = \frac{V_{LL,prim}^2}{Z_{prim}} = \frac{V_{LL,prim}^2}{Z_{sec}\left(\frac{VTR}{CTR}\right)} = V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{1}{Z_{sec}}\right)$$

$$= Z_{prim} = \frac{V_{LL,prim}^2}{MVA_{prim}} = \frac{V_{LL,prim}^2}{\sqrt{P^2 + Q^2}}$$

Also, $Z_{sec} = Z_{prim}\left(\frac{CTR}{VTR}\right) = \frac{V_{LL,prim}^2}{\sqrt{P^2 + Q^2}}\left(\frac{CTR}{VTR}\right)$

- $R_{sec} = Z_{sec} \cos\Theta = \frac{V_{LL,prim}^2}{\sqrt{P^2 + Q^2}}\left(\frac{CTR}{VTR}\right)\left(\frac{P}{\sqrt{P^2 + Q^2}}\right)$

$$= V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{1}{\sqrt{P^2 + Q^2}}\right)\left(\frac{P}{\sqrt{P^2 + Q^2}}\right) = V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{P}{P^2 + Q^2}\right)$$

- $X_{sec} = Z_{sec} \sin\Theta = \frac{V_{LL,prim}^2}{\sqrt{P^2 + Q^2}}\left(\frac{CTR}{VTR}\right)\left(\frac{Q}{\sqrt{P^2 + Q^2}}\right)$

$$= V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{1}{\sqrt{P^2 + Q^2}}\right)\left(\frac{Q}{\sqrt{P^2 + Q^2}}\right) = V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{Q}{P^2 + Q^2}\right)$$

Appendix E – Supporting Calculations and Examples for Phase Distance Protection (Function 21)

Appendix E provides details in the form of equations and graphs to support the conclusions presented in the section titled Phase Distance Protection (Function 21), which can be set using two different approaches.

One approach is to set the function focusing on thermal protection of the generator for a transmission fault that is not cleared by transmission relays. Often this approach leads to setting the function at about 150 percent to 200 percent of the generator MVA rating at its rated power factor. A method for loadability testing of this setting is presented using an example unit.

The second approach to setting function 21 is to provide generator trip dependability for transmission faults that are not cleared on all elements connected to the generator step-up transformer high-side bus. An example is provided to demonstrate the impact of infeed from other lines (apparent impedance) when setting function 21. The desired setting is much larger than the relay characteristic based on 0.50–0.66 per unit impedance on the machine base. The same loadability test is applied to this example to determine if the setting will trip the unit for stressed system conditions. Alternatives are discussed for modifying the relay characteristic when necessary to meet the loadability requirement.

The following equations are used to model a generating unit connected to a power system undergoing stress. Stress will be defined as a degraded transmission voltage at the terminals of the unit step-up transformer. Refer to Figure E-1 below:

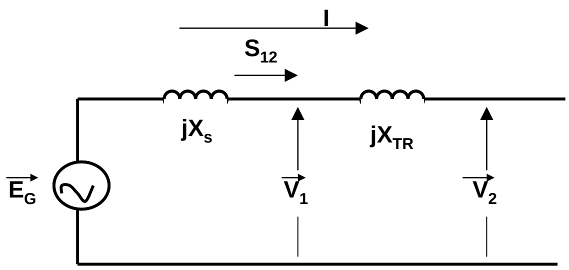

Figure E-1: Generator and Generator Step-up Transformer Impedance Model

The basic equations[3] apply to the above circuit:

$$S_{12} = V_1 I_1^* = V_1 \left(\frac{V_1 - V_2}{Z} \right)^* = V_1 \left(\frac{V_1^* - V_2^*}{Z^*} \right) = \frac{V_1 V_1^* - V_1 V_2^*}{Z^*} = \frac{|V_1|^2}{|Z|} \angle z - \frac{|V_1||V_2|}{|Z|} \angle (z + \theta_{12})$$

In this equation, θ_{12} is the angle across the step-up transformer. If V_2 is assumed to have the reference angle of 0 degrees, then θ_{12} can be expressed as θ_1 and it is an unknown in the equation.

Substituting θ_1 for θ_{12} and 90° for $\angle z$, the equation can be simplified as follows:

$$S_{12} = V_1 I_1^* = \frac{|V_1|^2}{|X_{TR}|} \angle 90 - \frac{|V_1||V_2|}{|X_{TR}|} \angle (90 + \theta_1)$$

[3] Power System Analysis, Hadi Sadat, McGraw Hill Publishing, pp 26–28.

V_2 will have a magnitude of 0.85 per unit, and $V_1\angle\theta_1$ will be calculated based on the two generator load conditions with the stressed system.

Using the above equation, an iterative process can be developed to calculate the following parameters: generator terminal voltage V_1 and its corresponding angle θ_1. From these quantities, the generator phase current I_1 and the apparent impedance Z that is presented to the relay for the stressed system condition can be calculated algebraically. This process is delineated in the following equations, beginning with the equation above that defines the quantities in Figure E-1.

Eq. 1. $$S_{12} = V_1 I_1^* = \frac{|V_1|^2}{|X_{TR}|}\angle 90 - \frac{|V_1||V_2|}{|X_{TR}|}\angle(90+\theta_1)$$

Starting from equation 1, we can derive two equations: one for the real components and one for the imaginary components.

Eq. 2. $$P_{12} = \mathrm{Re}[-\frac{|V_1||V_2|}{|X_{TR}|}\angle(90+\theta_1)] = -\frac{|V_1||V_2|}{|X_{TR}|}\cos(90+\theta_1) = \frac{|V_1||V_2|}{|X_{TR}|}\sin(\theta_1)$$

Eq. 3. $$Q_{12} = \mathrm{Im}[j\frac{|V_1|^2}{|X_{TR}|} - \frac{|V_1||V_2|}{|X_{TR}|}\angle(90+\theta_1)] = \frac{|V_1|^2}{|X_{TR}|} - \frac{|V_1||V_2|}{|X_{TR}|}\sin(90+\theta_1) = \frac{|V_1|^2}{|X_{TR}|} - \frac{|V_1||V_2|}{|X_{TR}|}\cos(\theta_1)$$

Multiplying both sides of equation 3 by X_{TR} yields:

Eq. 4. $$Q_{12}|X_{TR}| = |V_1|^2 - |V_1||V_2|\cos(\theta_1)$$

Subtracting $Q_{12}X_{TR}$ from both sides of equation 4 yields a quadratic equation for V_1:

Eq. 5. $$0 = |V_1|^2 - |V_1||V_2|\cos(\theta_1) - Q_{12}|X_{TR}|$$

Solving equation 2 for Θ_1 and equation 5 for V_1 yields:

Eq. 6. $$\theta_1 = \arcsin\left(\frac{P_{12}|X_{TR}|}{|V_1||V_2|}\right)$$

Eq. 7. $$|V_1| = \frac{|V_2|\cos(\theta_1) \pm \sqrt{|V_2|^2 \cos^2(\theta_1) + 4Q_{12}X_{TR}}}{2}$$

Note: By inspection, the solution of V_1 formed by the sum is the desired root of the quadratic equation (the sum will be near unity and the difference will be near zero).

The known values of P_{12}, Q_{12}, V_2, and X_{TR} and an initial guess for a value of V_1 (e.g., 1.0) can be used to solve equation 6 for Θ_1 . The calculated value of Θ_1 can then be used to solve equation 7 for V_1. The calculated value of V_1 can be used as the next guess for V_1 in equation 6, and this process may be repeated until the value of V_1 calculated from equation 7 is the same as the previous guess. This process typically converges in two to three iterations.

Once V_1 and Θ_1 are calculated, calculation of the generator phase current I_1 and the apparent impedance Z are straightforward using equations 8 and 9:

Eq. 8. $$I_1 = \frac{V_1 - V_2}{jX_{TR}}$$

Eq. 9. $$Z = \frac{V_1}{I_1}$$

This mathematical process will be used to calculate the stressed system condition apparent impedance operating points necessary to validate coordination for Method 1.

Example 1: Given a hypothetical function 21 setting on an actual generator rated 904 MVA at 0.85 power factor, perform a loadability test. The hypothetical function 21 in this example is set at 0.50 per unit ohms on the machine base and at rated power factor.

A function 21 that is set at 0.5–0.66 per unit ohms on the machine base at rated power factor is strictly set from a stator thermal rating perspective. Loadability calculations should be performed to ensure the relays will not trip during stressed system conditions when the unit is not thermally stressed. As stated in the Coordination of Generator and Transmission Systems subsection under Phase Distance Protection, the two points used with the Method 1 calculation in this example are operating points calculated based on (1) rated MW and a Mvar value of 150 percent times rated MW output, and (2) a declared low active power operating limit and a Mvar value of 175 percent times rated MW output. In this example, 40 percent of rated MW is used as the declared low active power operating limit. In both cases, the generator terminal voltage is calculated based on the stressed system condition of 0.85 per unit voltage on the high side of the generator step-up transformer.

Machine data:

- 904 MVA unit at 0.85 power factor
- Operating Condition (1) — Generator at rated MW and a Mvar value of 150 percent times rated MW output (768 MW + j1152 Mvar) with the stressed system condition of 0.85 per unit voltage on the high side of the generator step-up transformer.

- Operating Condition (2) — Generator at 40 percent of rated MW and a Mvar value of 175 percent times rated MW output (307 MW + j1344 Mvar) with the stressed system condition of 0.85 per unit voltage on the high side of the generator step-up transformer.
- X_S, the synchronous reactance, is 1.725 per unit on the generator base.
- X_{TR}, the generator step up transformer reactance, is 0.1 per unit on the generator base.

Calculate the impedance measured by a function 21 set at 0.50 per unit during a stressed system condition to ensure that the relay as set will not trip the unit.

The test applies 0.85 per unit steady-state voltage on the terminals of the generator step-up transformer and then calculates V_{relay}/I_{relay}, where V_{relay} equals the generator terminal voltage and I_{relay} equals the generator stator current. The stator current is calculated based on the two operating conditions: (1) generator at rated MW and a Mvar value of 150 percent times rated MW output (768 MW + j1152 Mvar), and (2) generator at 40 percent of rated MW and a Mvar value of 175 percent times rated MW output (307 MW + j1344 Mvar). In both cases, the generator terminal voltage is based on the stressed system condition of 0.85 per unit voltage on the high side of the generator step-up transformer.

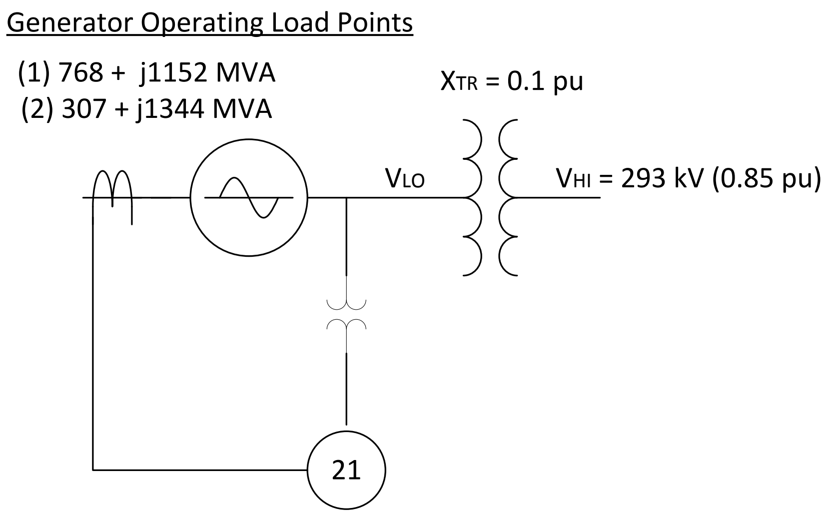

Figure E-2: Example 1: Model of a Generator Connected to a Stressed System

Operating Condition 1

Given:

1. $S_{Rated} = P_{Rated} + j\,Q_{Rated}$ = 768 + j477 MVA = 904 $\angle$ 31.8° MVA (pf = 0.85)
2. System stressed such that V_{HI} = 293 kV = 0.85 pu (V_{rated} = 345 kV)
3. Unit at stressed level output = 768 + j1152 MVA = 1384.5 $\angle$ 56.31° MVA (pf = 0.555)
   = 1.532 $\angle$ 56.31° pu

Operating Condition 2

Given:

1. $S_{Rated} = P_{Rated} + j\,Q_{Rated}$ = 768 + j477 MVA = 904 $\angle$ 31.8° MVA (pf = 0.85)

2. System stressed such that V_{HI} = 293 kV = 0.85 pu (V_{rated} = 345 kV)
3. Unit at stressed level output = 307+ j1344 MVA = 1378.6∠77.13° MVA (pf = 0.223)
   = 1.525∠77.13° pu

Using the above mathematical process, θ_1 and V_1 can be solved iteratively and will then result in the solution of I_1 and Z.

Operating Condition 1

Solving iteratively,

θ_1 = 5.88°

$|V_1|$ = 0.9761

I_1 = 1.570∠-50.43°

As a check, S_{12}=V_1I*=0.9761∠5.88° x 1.570 ∠50.43°= 1.532 ∠56.31°

Having determined V_1 and I_1, the apparent impedance measured by a backup impedance relay on the terminals of the machine becomes:

$$Z = \frac{V_1}{I_1} = \frac{.9761\angle 5.88°}{1.570\angle -50.43°} = .6217\angle 56.31°\,pu$$

Operating Condition 2

Solving iteratively,

θ_1 = 2.30°

$|V_1|$ = 0.9983

I_1 = 1.528∠-74.82°

As a check, S_{12}=V_1I*=0.9983∠2.2963° x 1.528∠74.83°= 1.525 ∠77.12°

Having determined V_1 and I_1, the apparent impedance measured by a backup impedance relay on the terminals of the machine becomes:

$$Z = \frac{V_1}{I_1} = \frac{.9983\angle 2.2963°}{1.5280\angle -74.8248°} = .6533\angle 77.12°\,pu$$

Figure E-3 plots the apparent impedance for the two operating points calculated for the stressed system condition defined in the example above against a mho circle with a maximum torque angle of 85° and a reach of 0.50 pu at the machine-rated power factor angle (31.8°), set per the IEEE recommended range for the maximum reach for a backup impedance relay. It also plots the reduced-reach characteristic required to meet the restriction of the calculated operating points with margin.

The equation below adjusts the reach at the rated power factor angle to the calculated apparent impedance (load) angle. The cosine term in the denominator converts the reach at the rated power factor angle to the reach at the maximum torque angle, and the cosine term in the numerator converts the reach from the maximum torque angle to the apparent impedance angle.

$$Z = Z_{RatedPF} \frac{\cos(MTA - LoadAngle)}{\cos(MTA - RatedPFAngle)}$$

The relay reach at the generator load angle calculated for operating condition (1), 768 + j1152 MVA = $1384.53\angle 56.31°$ MVA, is 0.7322 per unit.

$$Z = \frac{0.50\cos(85° - 56.31°)}{\cos(85° - 31.8°)} = 0.7322\angle 56.31°\, pu$$

The relay reach at the generator load angle calculated for operating condition (2), 307 + j1344MVA = $1378.62\angle 77.13°$ MVA, is 0.8268 per unit.

$$Z = \frac{0.50\cos(85° - 77.12°)}{\cos(85° - 31.8°)} = 0.8268\angle 77.12°\, pu$$

Both of the calculated apparent impedances in this example fall within the relay characteristic. The relay characteristic must be modified to coordinate with the loadability requirements calculated above and include adequate margin. Therefore, the more restrictive load operating point must be determined. This will be accomplished by calculating the reach of a mho characteristic at 85° that passes through each of these operating points to determine which is more restrictive.

Operating point (1): Z_{85} = 0.6217/(cos(85° - 56.31°)) = 0.7087 $\angle$ 85° pu

Operating point (2): Z_{85} = 0.6533/(cos(85° - 77.12°)) = 0.6595 $\angle$ 85° pu

Based on this comparison, at the common 85 degree angle operating point, (2) is more restrictive.

The reach of the distance relay at 85 degrees, the maximum torque angle (MTA) needs to be adjusted to this point plus margin, e.g., 15 percent margin or 0.85 times this value.

$Z_{Reach\ at\ MTA}$ = 0.85 x 0.6595 = 0.5606 $\angle$ 85° pu

To calculate the reach at rated power factor, use:

$Z_{Rated\ Power\ Factor}$ = 0.5606 (cos (85° - 31.8°) = 0.3358 $\angle$ 31.8° pu

With the revised setting, the calculated apparent impedance is outside the relay characteristic and provides 15 percent margin, as illustrated in Figure E-3.

A typical time-delay setting for this element would be similar to the zone 3 remote backup element time delay used for transmission relays. This provides time coordination between the generator phase distance backup protection and the protection systems on the transmission lines connected to the generator step-up transformer high-side bus, including breaker failure. In this example, a 1.5-second setting is selected.

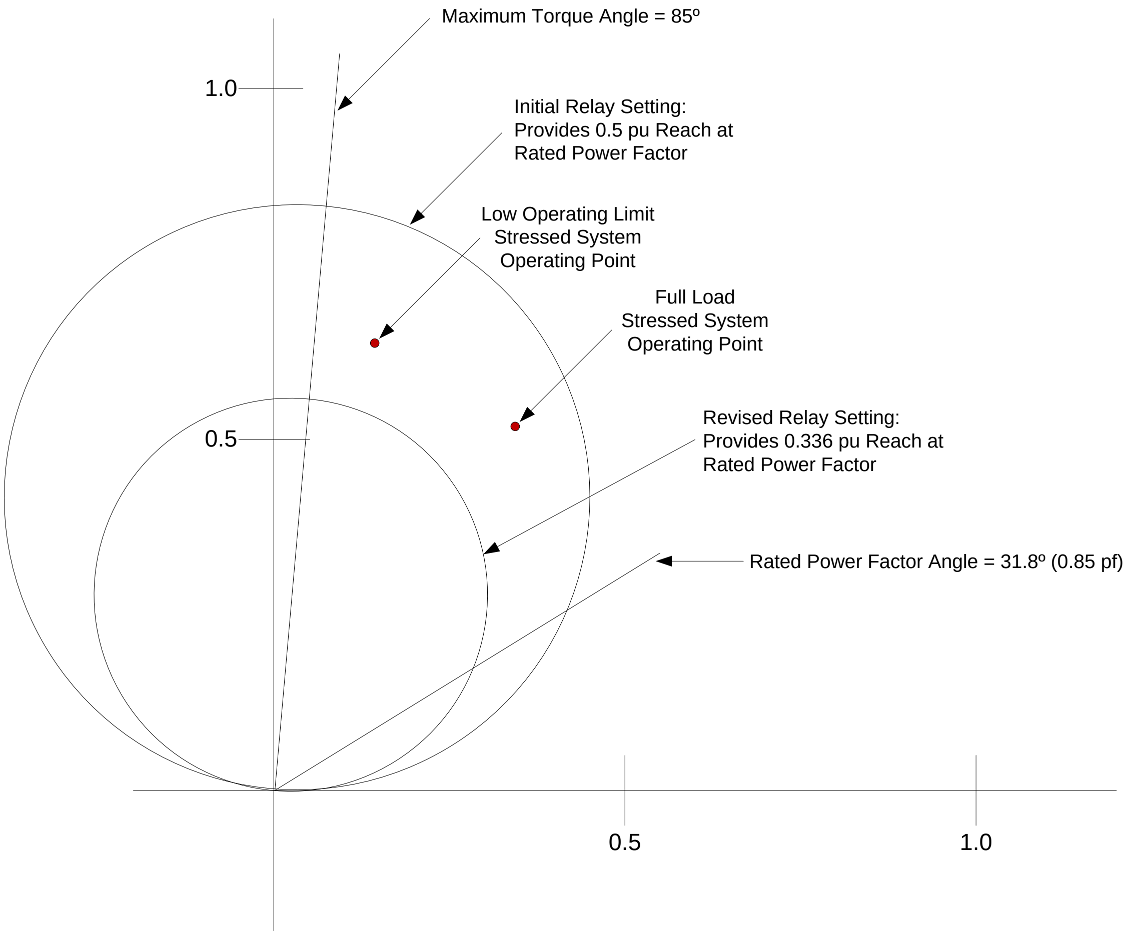

Figure E-3: Example 1 – Two Calculated Apparent Impedance Load Points Plotted against Desired and Reduced-Reach Phase Distance Backup Characteristics to Meet Restriction of Calculated Operating Points

Example 2: Given a hypothetical function 21 setting on the same generator as Example 1 (904 MVA at 0.85 power factor), perform a loadability test. In this example, the hypothetical function 21 desired reach is 1.883 per unit on the generator base at the transmission fault impedance angle to provide relay failure backup for transmission line faults (set at 120 percent of the longest line connected to the high-side bus and accounting for infeed).

Set the function 21 including the impacts of infeed from other sources of fault current.

In this example, the phase distance protection is set to protect the generator by providing generator trip dependability for transmission system faults.

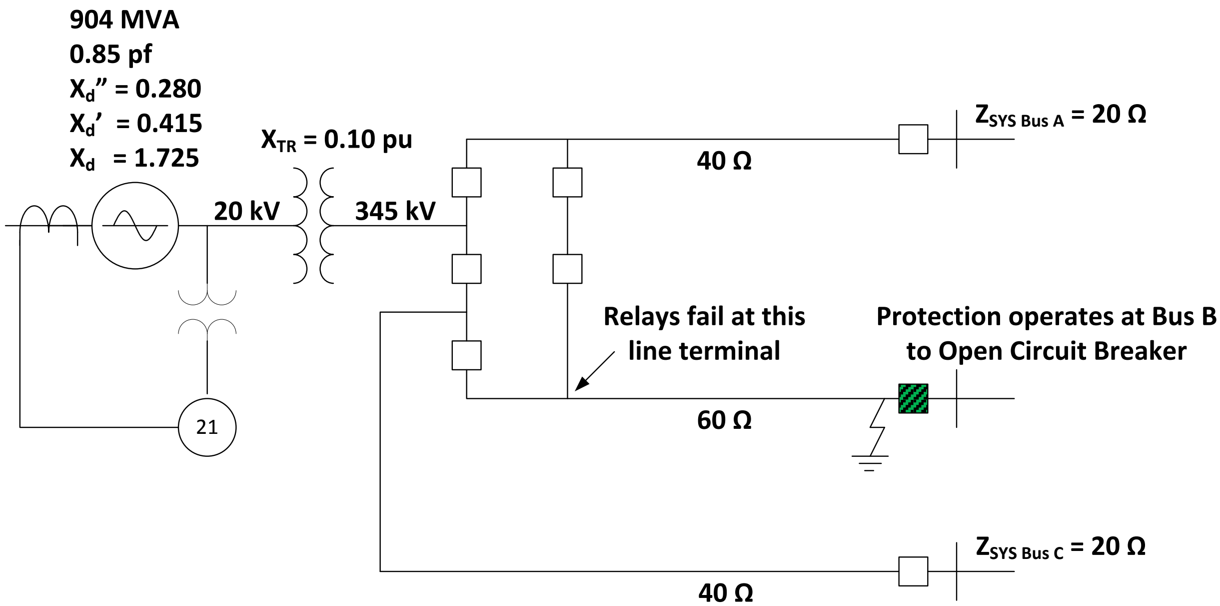

Figure E-4: Example 2 – 904 MVA Generator Connected to a 345 kV System by Three Lines

The longest line, 60 ohms, is faulted, three-phase, at its Bus B end. The Bus B circuit breaker for the line has opened. The backup relay for the generator must see this fault in the presence of infeed from Bus A and Bus C via their two 40 ohm lines.

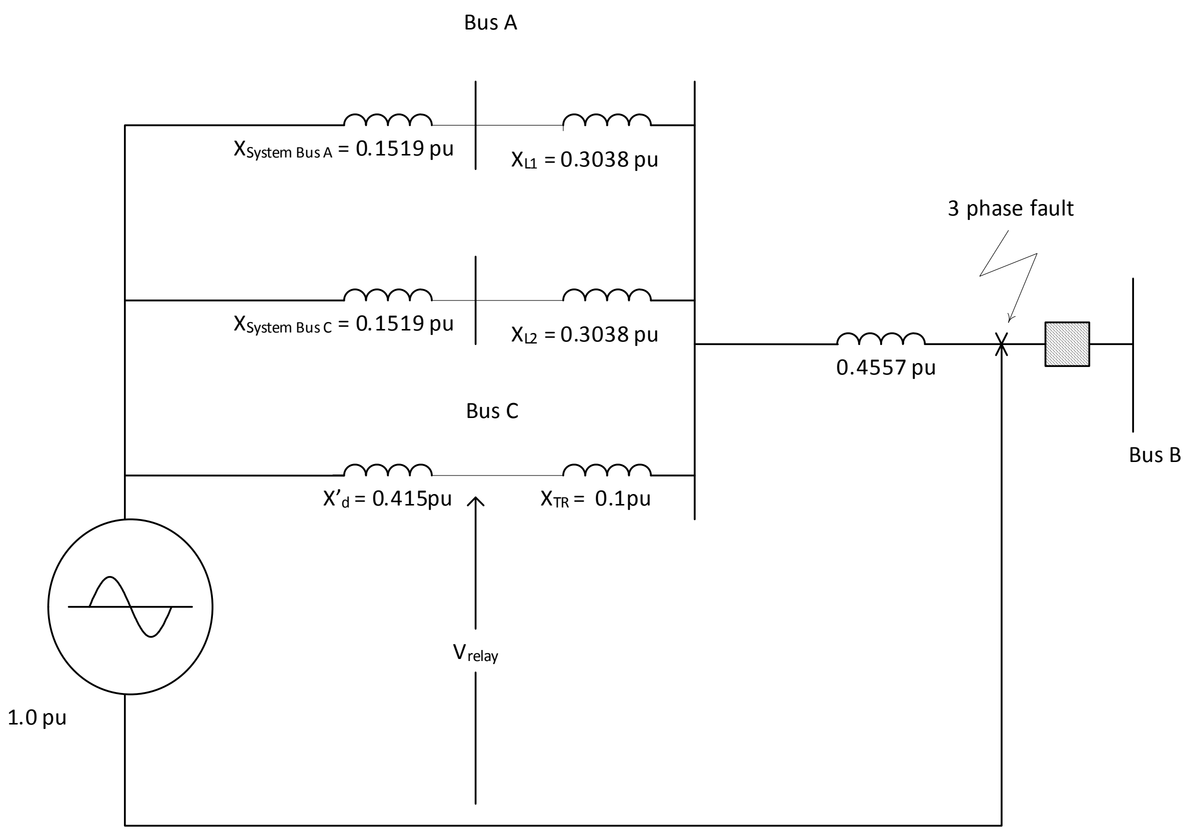

Figure E-5: Example 2 – Symmetrical Component Sequence Network

All system elements, generator transient reactance, transformer impedance, lines, and equivalent impedances behind the buses A and C are given in per unit on the generator base (904 MVA). The relay reach in per unit on the generator base at the fault impedance angle that is necessary to reliably detect the line-end fault with 20 percent margin is 1.883 per unit.

From the results in Example 1 above, with the stator current calculated based on the generator at rated MW and a Mvar value of 150 percent times rated MW output (e.g. 768 MW + j1152 Mvar) and the generator terminal voltage based on the stressed system condition of 0.85 per unit voltage on the high side of the generator step-up transformer, the resulting apparent impedance measured by the backup impedance relay on the terminals of the machine is $0.6217 \angle 56.31°$ per unit.

If the angle of maximum relay reach is 85°, then the reach at the angle of the full-load stressed system condition operating point (56.31°) is:

$$Z_{reachat\ 56.31°} = Z_{\max\ reachangle} \cos(\theta_{\max\ reach} - 56.31°) = 1.883 \cos(85 - 56.31) = 1.652\ pu$$

The calculated apparent impedance at the full-load operating point in this example is well inside the relay characteristic. Similarly, for the low operating limit, the resulting apparent impedance measured by the backup impedance relay on the terminals of the machine is $0.6532 \angle 77.12°$ per unit.

The reach at the angle of the low operating limit stressed system condition operating point (77.12°) is:

$$Z_{reach at 77.12°} = Z_{\max reach angle} \cos(\theta_{\max reach} - 77.12°) = 1.883 \cos(85 - 77.12) = 1.865\, pu$$

The calculated apparent impedance at the low operating limit operating point in this example also is well inside the relay characteristic. The relay characteristic must be modified to coordinate with the loadability requirements. The modification applied above for the relay set to provide generator protection only in Example 1 cannot be applied in this case, because reducing the reach of the relay will not provide trip dependability for faults on all elements connected to the generator step-up transformer high-side bus.

Given that the desired relay setting does not meet the relay loadability requirement, the Generator Owner has a number of options. The first option is to set the relay to provide only thermal protection for the generator as described above in Example 1. The second option is to modify the relay characteristic. In this example, it is assumed that the Generator Owner desires to provide trip dependability for uncleared transmission system faults and elects to modify the relay characteristic. With this option, the Generator Owner has the choice to modify the relay characteristic to meet the conservative operating points defined in Method 1 or to utilize Method 2 to determine generator-specific operating points from dynamic modeling of the apparent impedance trajectory during simulated events. The simulations should model the effect of stressed system conditions that result in 0.85 per unit voltage on the high side of the generator step-up transformer prior to field forcing. An example utilizing this process is described below.

The Methods to Increase Loadability subsection under Phase Distance Protection provides a number of methods that could be applied to modify the relay characteristic in a manner that meets the loadability requirement while maintaining the reach necessary for system relay failure backup coverage. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed system condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as reactive power support capability (field forcing). For this reason, adding blinders or reshaping the characteristic provide greater security than load encroachment or offsetting the zone 2 mho characteristic.

In this example, the Generator Owner elects to utilize blinders to modify the relay characteristic. If the Generator Owner utilizes Method 1, two potential concerns would be identified. The first is that setting the blinders to meet the loadability operating points calculated above would result in narrow blinder settings. Providing some reasonable margin from the loadability operating point, for example 15 percent, would result in a resistance setting of 0.075 per unit on the generator base as shown in Figure E-6. The second potential concern is that with only one zone of protection, the backup clearing time for generator step-up transformer faults and high-side bus faults would be relatively long—typically on the order of 1.5 seconds. This is because time coordination must be provided between the generator phase distance protection and the protection systems on the transmission lines connected to the generator step-up transformer high-side bus, including breaker failure. The clearing time may not be a concern depending on the level of protection redundancy provided.

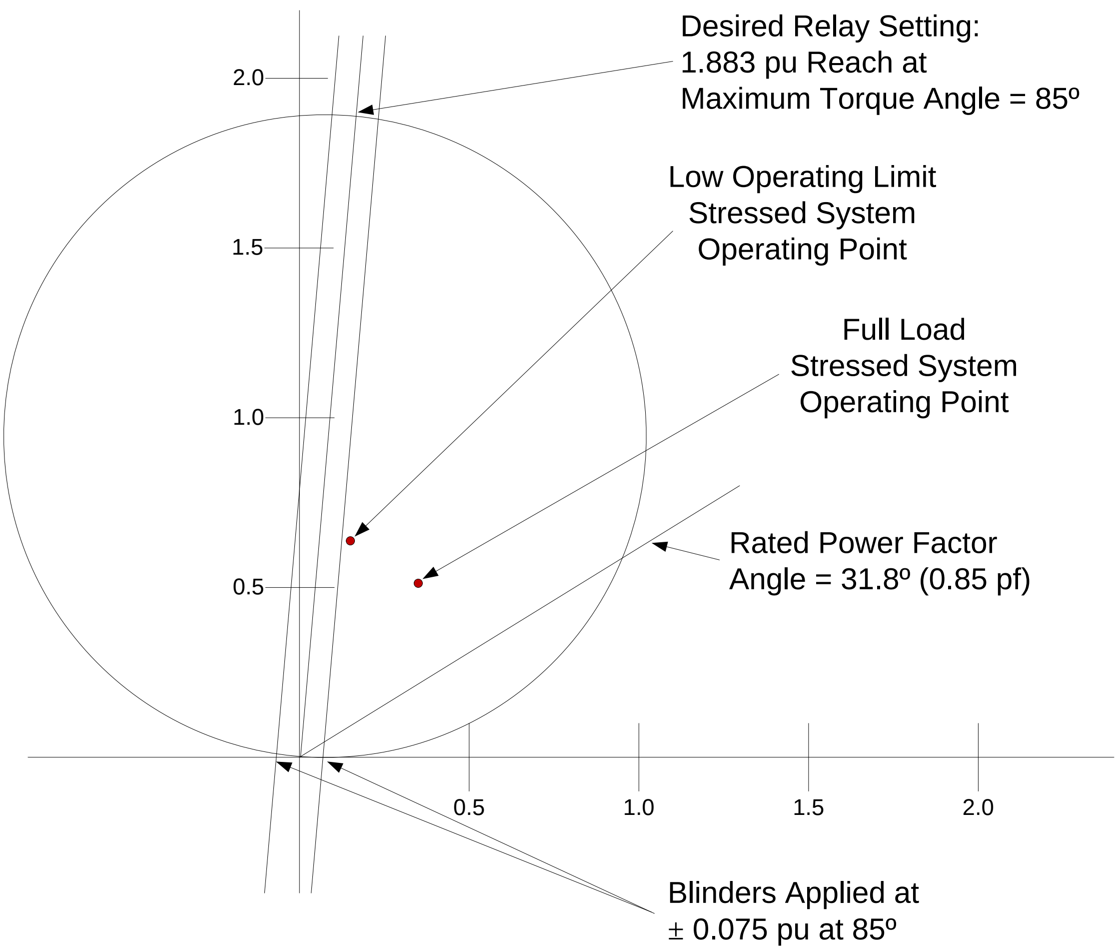

Figure E-6: Example 2 – Method 1 Apparent Impedance Plotted against Zone 2 Function with Blinders

To address these concerns, the Generator Owner in this example desires two zones of phase distance backup protection. One zone would be set with a shorter reach and a shorter time delay to provide faster clearing for nearby faults. The second zone would be set with a longer reach with blinders to provide the desired trip dependability coverage for transmission system faults. In this example, the Generator Owner elects to utilize Method 2 to identify whether a less-restrictive limit for setting the blinders can be derived.

Figure E-7 plots the simulated apparent impedance trajectories for operation at full load and at the low operating limit against a mho characteristic with the desired reach calculated in Example 2 (1.883 per unit). In this example, the apparent impedance was simulated by switching a reactor on the transmission system to lower the generator step-up transformer high-side voltage to 0.85 per unit prior to field forcing. The resulting step change in voltage is similar to the sudden voltage depression that was observed in parts of the system on August 14, 2003. In response to the reduced voltage, the generator excitation system goes into field-forcing to provide increased reactive power to support voltage. For reference, the Method 1 apparent impedances also are shown on the plot. In this example, the simulations in Method 2 result in less-conservative operating points for evaluating security of the phase distance protection settings. The full load and low operating limit (LOL) operating points for evaluating relay loadability derived through Method 2 are:

$$Z_{\text{Full Load}} = 0.8264\angle 46.35^\circ$$

$$Z_{\text{LOL}} = 0.9812\angle 71.65^\circ$$

In this example, the zone 1 reach is set based on not overreaching the zone 1 protection settings on the transmission lines connected to the generator step-up transformer high-side bus. In this example, zone 1 is set to reach 80 percent of the reach of the zone 1 relay on the shortest line. The effect of infeed is not included to ensure the relay does not overreach for conditions with transmission lines out of service. Neglecting infeed for the zone 1 reach provides the most conservative setting. Assuming that the zone 1 relays on each line are set to reach 80 percent of the line length, the reach of the generator zone 1 relay would be set at:

$$Z_1 = 0.8 \text{ x } (X_{TR} + 0.8\,(X_{line})) = 0.8 \text{ x } (0.1 + (0.8)(0.3038)) = 0.274 \text{ per unit}$$

This figure illustrates there still is a need to modify the zone 2 relay characteristic to maintain the desired reach while meeting the loadability requirement. In this example, blinders are applied to improve the loadability. The blinders are set at ± 0.15 per unit at an angle of 85˚and are set to provide 15 percent margin from the apparent impedance trajectory. The settling point in the simulation did not model the effect of an overexcitation limiter, which would move the apparent impedance away from the relay characteristic. This is because the response time of the limiter is longer than the time-delay setting of the phase distance backup protection. The response time of the limiter is on the order of 10 seconds or longer depending on the level of field forcing.

Typical time-delay settings for zone 1 and zone 2 would be similar to the zone 2 and zone 3 remote backup element time delay used for transmission relays. This provides time coordination between the generator phase distance backup protection and the protection systems on the transmission lines connected to the generator step-up transformer high-side bus, including breaker failure. In this example, a 0.5-second timer setting is selected for zone 1 and a 1.5-second timer setting is selected for zone 2.

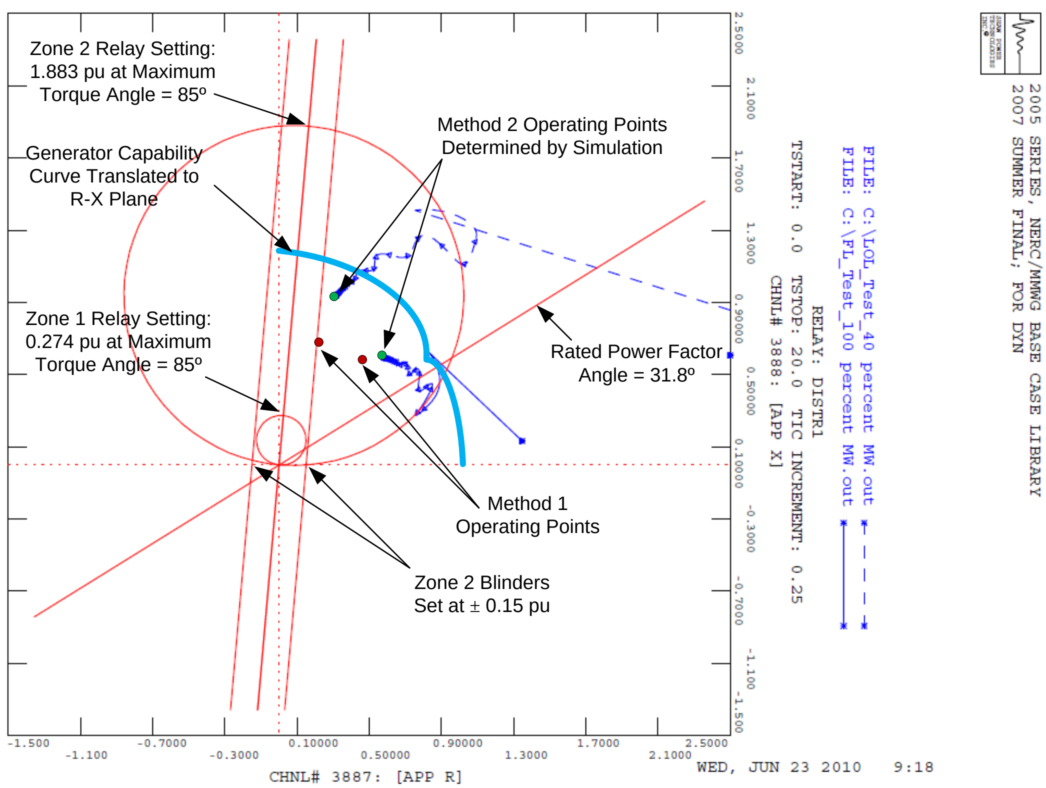

Figure E-7: Example 2 – Method 1 (Calculated) and Method 2 (Simulated) Apparent Impedance Plotted against Zone 1 and Zone 2 with Blinders

It is important to note that even though the zone 2 setting with blinders provides security for the two operating points used to assess relay loadability, the setting still encroaches on the generator capability curve. Figure E-7 includes the generator capability curve in the R-X plane overlaid on the phase distance protection settings and operating points derived in this example. In this figure, the area above the generator capability curve represents the region in which the generator is operating within its capability. This figure illustrates that, under certain operating conditions, the generator apparent impedance may enter inside the blinders of the zone 2 operating characteristic. This condition would occur with the generator operating at a low active power (MW) level and high reactive power (Mvar) level. In this particular example, the apparent impedance would enter this region of the R-X plane when operating below the generator low operating limit. Thus, for this particular example, the risk of tripping the generator is limited to unit start-up and shutdown while the generator is ramping up or down below its low operating limit. Nonetheless, the generator is at risk of tripping unless the Generator Operator is aware of this potential and operation of the unit is limited to avoid the portion of the generator capability curve that is encroached on by the zone 2 setting.

The only way to ensure full security for the phase distance protection is to pull the reach back to be inside the generator capability curve. In fact, the reach must be pulled back even within the steady-state capability curve in order to provide security for generator dynamic response during field forcing, as illustrated by inclusion of the operating points derived by Method 2. In the limiting case, if the generator may be operated as a synchronous condenser, the low operating limit is 0 MW and the only alternative is to pull back the zone 2 relay reach. Figure E-8 provides an alternate solution in which the zone 2 reach is pulled back to ensure security for all steady-state operating conditions and to meet the relay loadability requirements for the operating points derived through Method 2. In this example, the zone 2 reach is reduced to 0.814 per unit compared to the desired reach of 1.883 per unit.

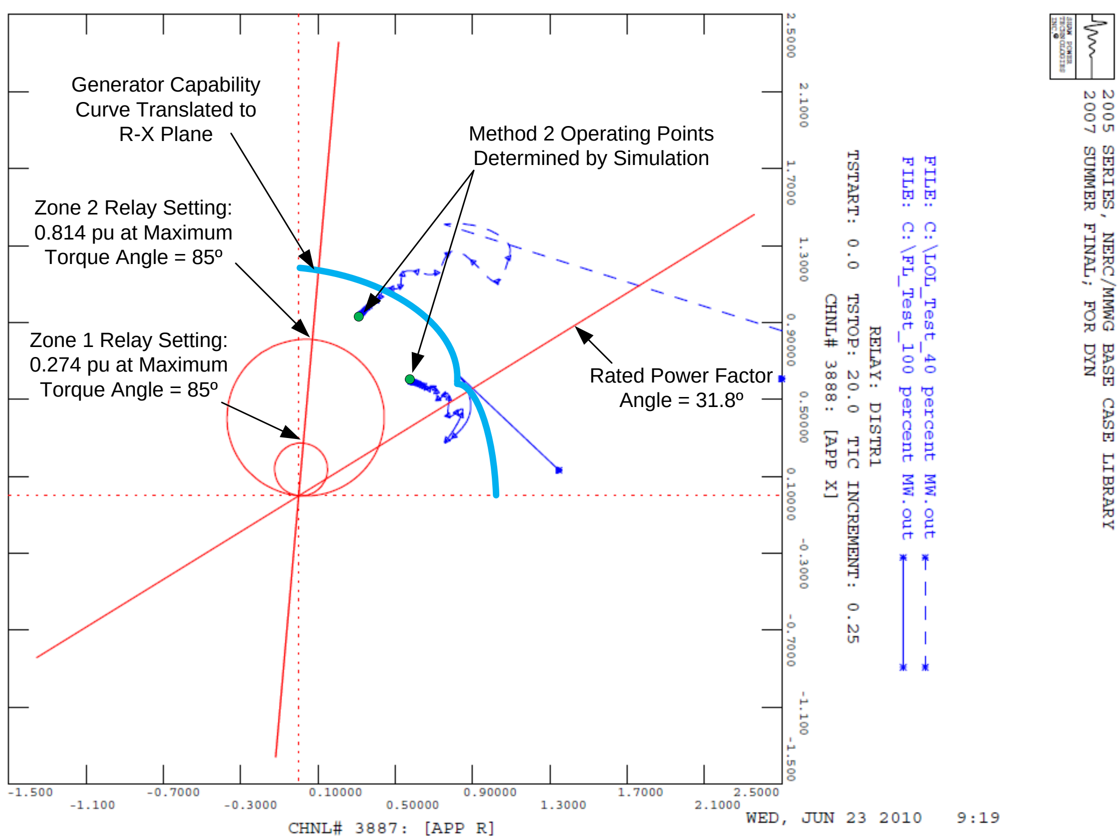

Figure E-8: Example 2 – Method 2 (Simulated) Apparent Impedance Plotted against Zone 1 and Zone 2 with Reduced Reach

Appendix F – Setting Example for Out-Of-Step Protection

Consider the power system in Figure F-1, corresponding to Example 14.9 from the book *Elements of Power System Analysis* by William D. Stevenson[4]. This case is used to illustrate the procedure to determine the critical clearing time and the traveling time within the blinders of an out-of-step relay by means of a transient stability study. The other settings of the relay are rather straightforward as they depend on the reactances of the elements and will not be illustrated here. The transient stability analysis will be carried out for a three-phase fault on line L_4-5, close to bus 4.

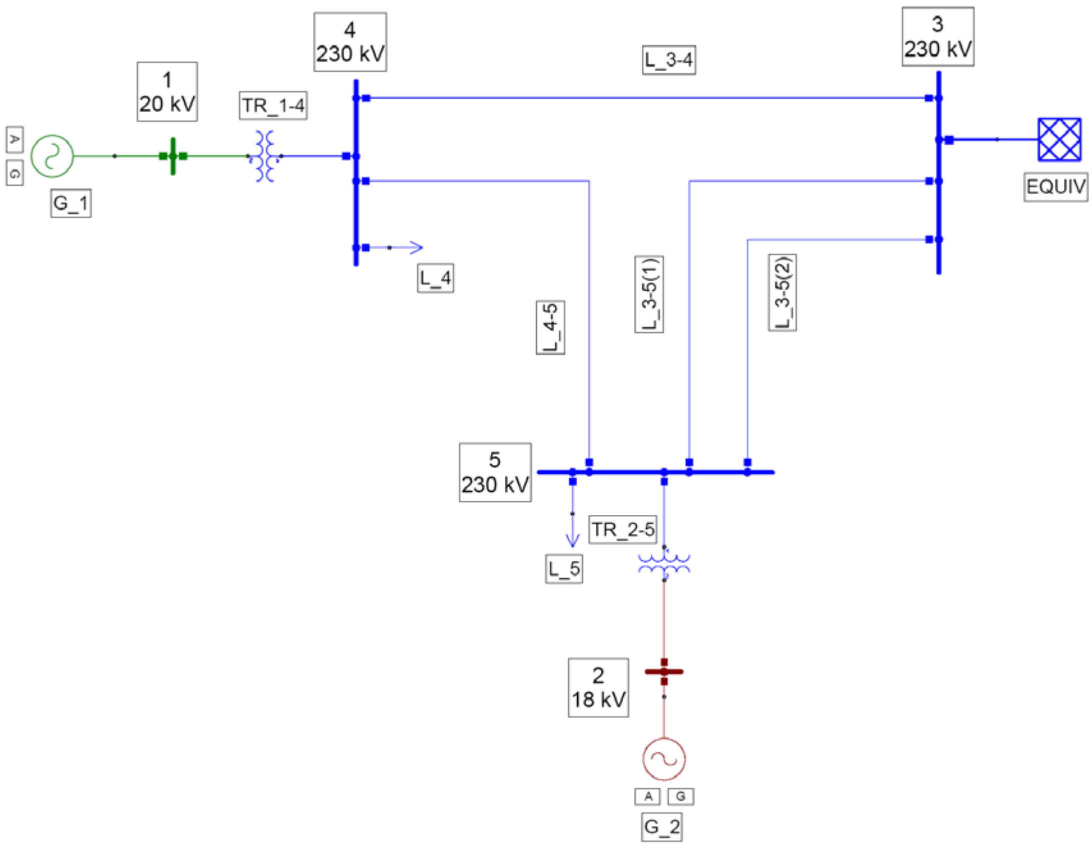

Figure F-1: Example Power System

Considerations

The following considerations are used in the stability study:

- The fault inception will be considered at t = 0.5 seconds.
- Clearing times starting at t = 90 ms (approx. 5 cycles) will be used in consecutive steps of 10 ms.
- For simplicity, the fault is removed with the consequent outage of the line.
- The voltage regulator is IEEE type ST1 Excitation System. This voltage regulator is of static excitation type where the rectifiers provide enough dc current to feed the generator field. The model represents a system

[4] Power System Analysis By John Grainger and William Stevenson, Jr.

with the excitation power supplied from a transformer fed from the generator terminals or from the auxiliary services and is regulated by controlled rectifiers.

- The turbine governor is IEEE type 1 Speed-Governing Model. This model represents the system of speed control (Mechanical-Hydraulic) and steam turbine.
- For this machine, a power system stabilizer is not available.

The models for the voltage regulator and governor are shown in Figures F-2 and F-3.

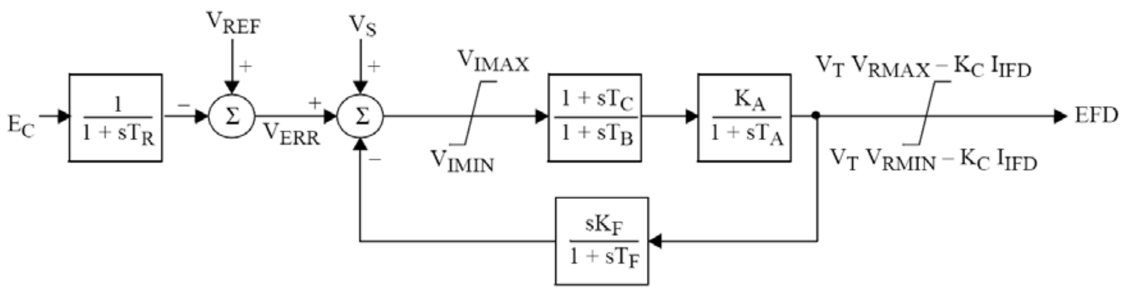

Figure F-2: IEEE Type ST1 Excitation System

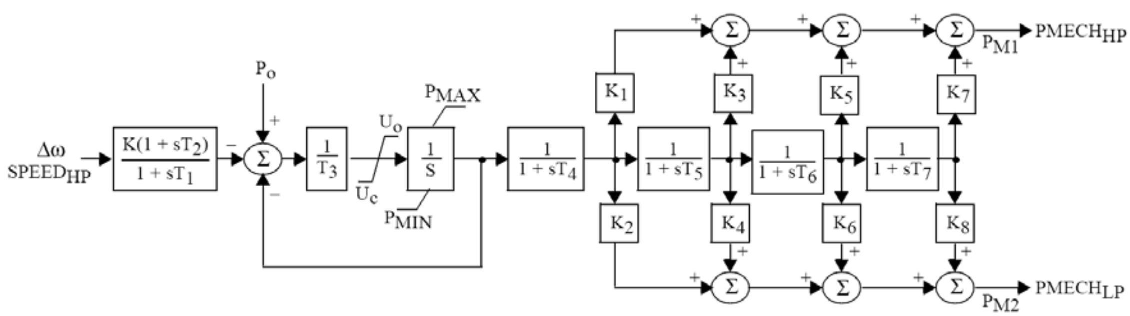

Figure F-3: IEEE Type 1 Speed-Governing Model

Critical Clearing Time

Determining the critical clearing time is perhaps the most elaborate part of the entire setting process. To achieve this, several simulations of the transient stability study have to be done to determine when the system loses synchronism or has the first slip.

Results

The transient stability analysis is simulated for a three-phase fault on line L_4-5, near bus 4. The solution can be obtained by using any commercially available software package.

Numerous cases were simulated with clearing times starting at t = 90 ms with increments of 10 ms in an iterative process until stability was lost. The results of three representative cases were analyzed and correspond to the critical clearing times obtained that are shown in the Table F-1:

Table F-1: Case Summary	
Case	**Fault Clearance Time (ms)**
1	90
2	180
3	190

Several plots from the transient stability runs can be obtained for a myriad of applications. For setting out-of-step functions, the most important information is the plots of Rotor Angle vs. Time and R + j X vs. Time. From the respective plots, it can be observed that in Case 1, with a clearing time of 90 ms, the system remains in synchronism. In Case 2, G1 and the system are still in synchronism with a clearing time of 180 ms. For case 3, G1 loses synchronism with a clearing time of 190 ms. From the above, it is evident that the critical time to clear the fault is equal to 180 ms after fault inception.

The rotor angles for the three cases are shown in Figure F-4, from which it can be seen that the critical angle is approximately 140°. The time for the swing locus to travel from the critical angle to 180° is approximately 250 ms. Therefore, the time-delay setting should be set to 250 ms. The most severe transmission fault should be simulated to verify dependable operation. The swing for this fault represents the fastest unstable swing, which must be differentiated from a change in apparent impedance associated with application of a fault.

Figure F-4 also illustrates the benefit of having voltage regulator and voltage governor responses, which are shown with the continuous lines. Under these conditions, the performance of the system is much better than when there are no controls or the controls are in manual mode.

It can be observed that when there are no controls, the excursions of the rotor angles are higher, especially from the second oscillation upward, and also that the system tends to stabilize faster.

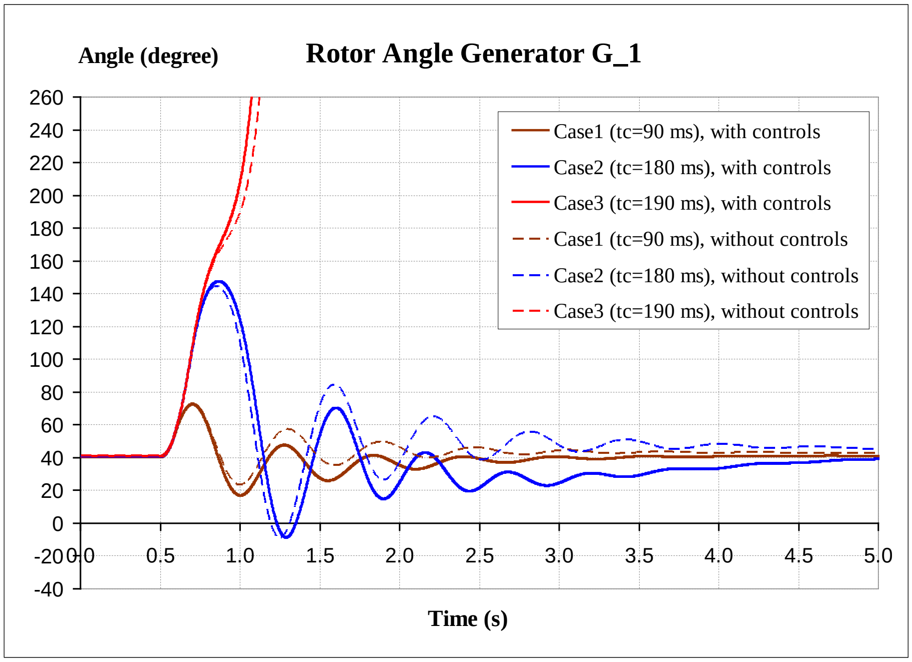

Figure F-4: Rotor Angle vs Time from the Three Cases Considered

R vs. X diagrams for the three cases show the trajectory followed by the impedance seen by the relay during the disturbances. When there is a stable oscillation in the generator, the swing locus does not cross the impedance line.

When a generator goes out of step, the transient swing crosses the system impedance line each time a slip is completed and the relay should trip the generator. Figures F-5.1 through F-5.3 show the diagram R vs. X for cases 1, 2, and 3. In the first two cases, it is clear that the load point does not cross the system impedance line. For case 3, the load point crosses the system impedance line, indicating that the synchronism is lost and, therefore, out-of-step tripping must be allowed. Figure F-6 shows the diagrams for all the three cases.

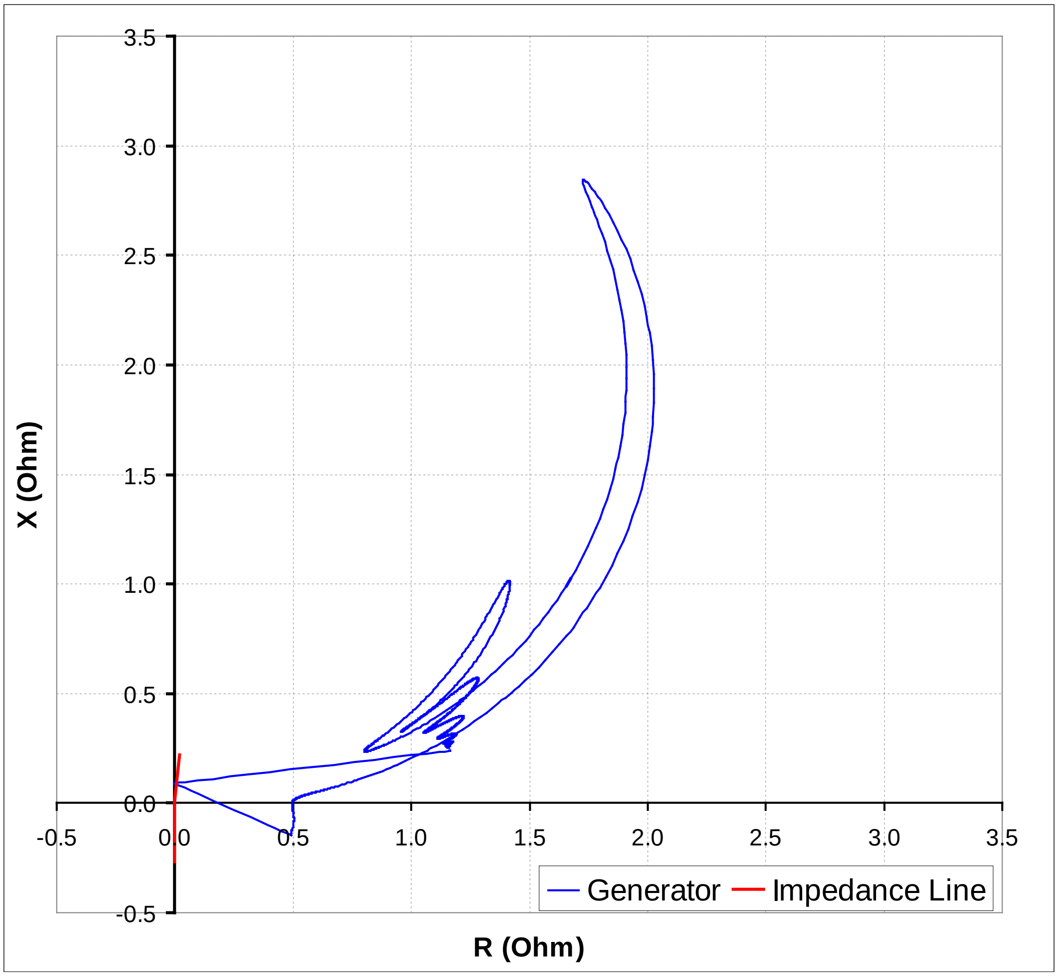

Figure F-5.1: Diagram R vs X for Case 1

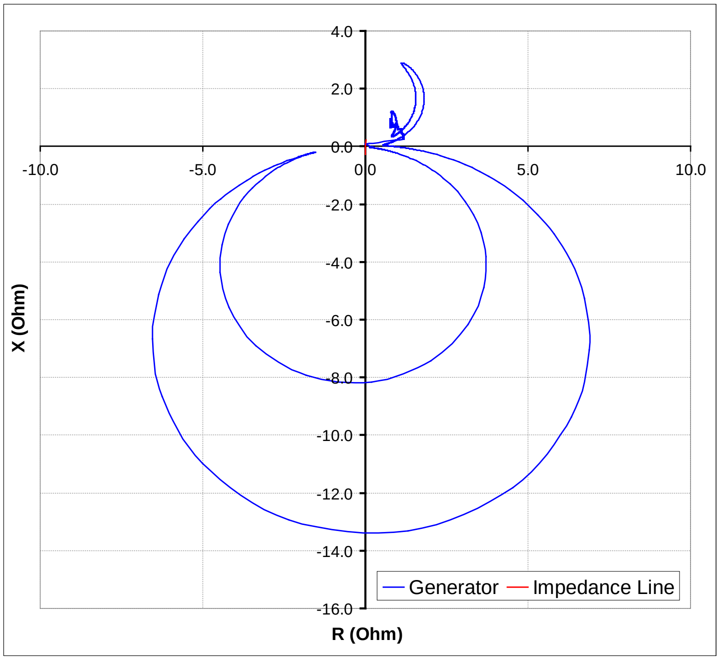

Figure F-5.2: Diagram R vs X for Case 2

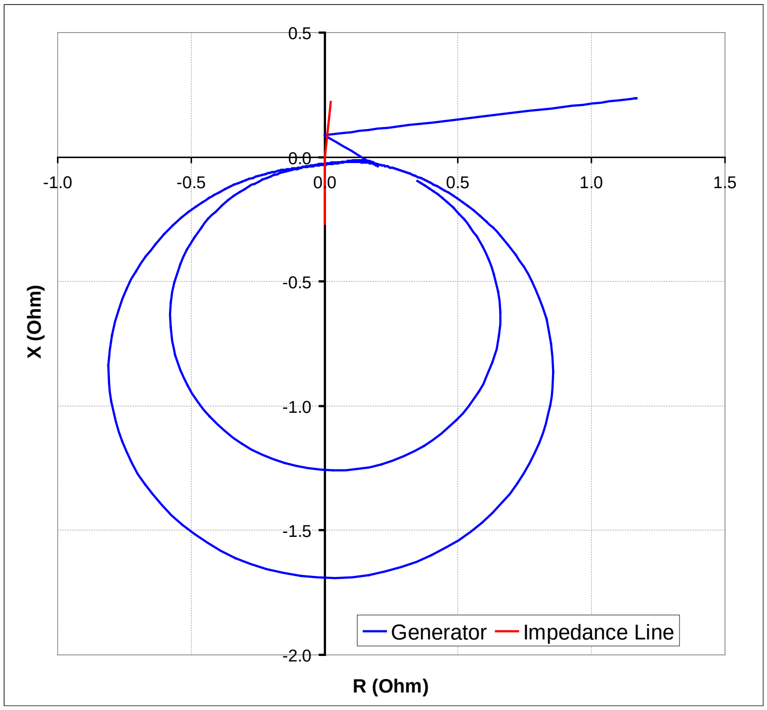

Figure F-5.3: Diagram R vs X for Case 3

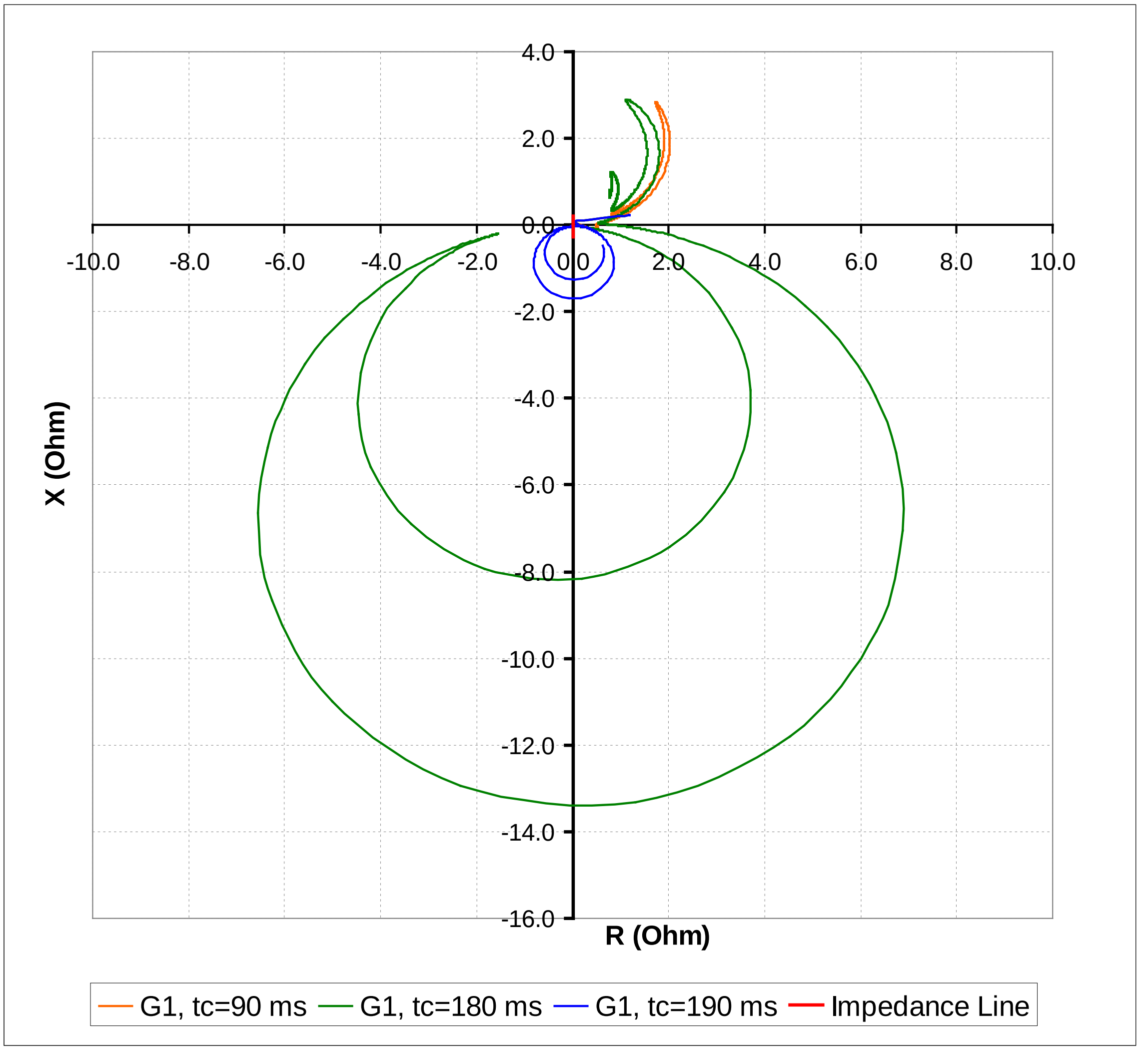

Figure F-6: Diagram R vs X for Cases 1, 2 and 3

Appendix G – System Protection and Control Subcommittee Roster

Name	Title	Organization
Philip Winston (Chair)	Chief Engineer, Protection and Control	Southern Company
Richard Quest (Vice Chair)	Principal Systems Protection Engineer	Midwest Reliability Organization
Bajarang Agrawal	Principal Engineer	Arizona Public Service Co.
Charles Rogers	Principal Engineer	Consumers Energy
Daniel McNeely	Engineer - System Protection and Analysis	Tennessee Valley Authority
David Penney	Senior Reliability Engineer	Texas Reliability Entity, Inc.
Forrest Brock	Transmission Compliance Specialist	Western Farmers Electric Coop.
George Wegh	Manager	Eversource Energy
Hai Quoc Le	Manager, System Planning and Protection	Northeast Power Coordinating Council
Jeffrey Iler	Principal Engineer, Protection and Control	American Electric Power
Joe Uchiyama	Senior Electrical Engineer	U.S. Bureau of Reclamation
Jonathan Sykes	Manager of System Protection	Pacific Gas and Electric Company
Mark Gutzmann	Manager, System Protection Engineering	Xcel Energy, Inc.
Michael Putt	Manager, Protection and Control Engineering Applications	Florida Power & Light Co.
Michael McDonald	Principal Engineer, System Protection	Ameren Services
Miroslav Kostic	P&C Planning Manager, Transmission	Hydro One Networks, Inc.
Samuel Francis	System Protection Specialist	Oncor Electric Delivery
Sungsoo Kim	Section Manager, Protections and Technical Compliance	Ontario Power Generation Inc.
William Miller	Principal Engineer	Exelon Corporation

Appendix H – Revision History

Version	Date	Modification(s)
0	December 9, 2009	Initial Document
1	July 30, 2010	Section 1: Added a reference to generator auxiliary system undervoltage protection; added additional explanation of Table 1. Section 3: Added additional explanation of references to Functional Model entities. Section 3.1 and Appendix E: Phase distance protection methodology and examples modified to provide more comprehensive guidance on generator relay loadability. Sections 3.3.2.2.1 and 3.3.2.3: Added discussion of the need for undervoltage protection and adjustable speed drives to ride through voltage depressions associated with transmission system faults. Section 3.10: Added a description of boundary conditions for coordinating voltage-restrained overcurrent in the text and annotation of Figure 3.10.5; updated coordination examples. Section 3.5: Updated Figures 3.5.1 and 3.5.3. Section 3.13: Updated coordination examples. General: Modifications to achieve common usage of terms; removed discrepancies between and among Tables 2 and 3 and the excerpts from these tables; corrected formatting problems.
2	July 30, 2015	Revised document in consideration of comments from the IEEE Power System Relaying Committee (PSRC) and other industry stakeholders