

# NERC

NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

## Power Plant and Transmission System Protection Coordination

Reverse Power (32), Negative Sequence Current (46),  
Inadvertent Energizing (50/27), Stator Ground Fault (59GN/27TH),  
Generator Differential (87G), Transformer Differential (87T),  
and Overall Differential (87U) Protection

System Protection and Control Subcommittee

Protection Coordination Workshop

Phoenix, AZ

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to ensure  
the reliability of the  
bulk power system

- Objectives
- The Need for Protection Functions
- Discuss and Describe System Events that Could Create Conditions that Would Cause Operation of These Functions
- Functions that do not Require Coordination with the System Functions
  - 32 – Reverse Power Protection
  - 87G - Generator Differential Protection
  - 87T - Transformer Differential Protection
  - 87U - Overall Differential Protection
- Functions that Require Coordination with the Transmission System Protection Functions
  - 46 - Negative Sequence Current Protection
  - 50/27 – Inadvertent Energizing Protection
  - 59GN/27TH - Stator Ground Fault Protection

- Seven Step Process for Functions 46, 50/27 and 59GN/27TH
- What is Important to Coordination
  - Settings that Protect the Generator
- Questions and Answers

- Increase knowledge of recommended generator protection for:
  - 32 – Reverse Power Protection
  - 46 - Negative Sequence Current Protection
  - 50/27 – Inadvertent Energizing Protection
  - 59GN/27TH - Stator Ground Fault Protection
  - 87G - Generator Differential Protection
  - 87T - Transformer Differential Protection
  - 87U - Overall Differential Protection
- Facilitate improved coordination between power plant and transmission system protection for these specific protection functions when required.



# The Need for Reverse Power Protection – Function 32

- *“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 anti-motoring protection, the two functions should not be confused.*
- *Anti-motoring 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.”*

IEEE C37.102-2006 – Guide for  
AC Generator Protection, Section 4.5.5

# The Need for Negative Phase Sequence or Unbalanced Overcurrent Protection – Function 46

- *“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  $I_2^2 t = K$ , as shown in Figure 4-39 (curve drawn using data from IEEE Std C50.13).”*

# The Need for Inadvertent Energizing Protection – Function 50/27

- *“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.*
- *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.”*

IEEE C37.102-2006 – Guide for AC Generator Protection, Section 5.4 (emphasis added)

# The Need for Stator Ground Relay Protection – Function 59GN/27TH

- *“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.”*
- *“Generator faults are always 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 very costly repairs.”*

IEEE C37.102-2006 – Guide for  
AC Generator Protection, Section 4.3.3



# The Need for Generator Differential Relay Protection – Function 87G

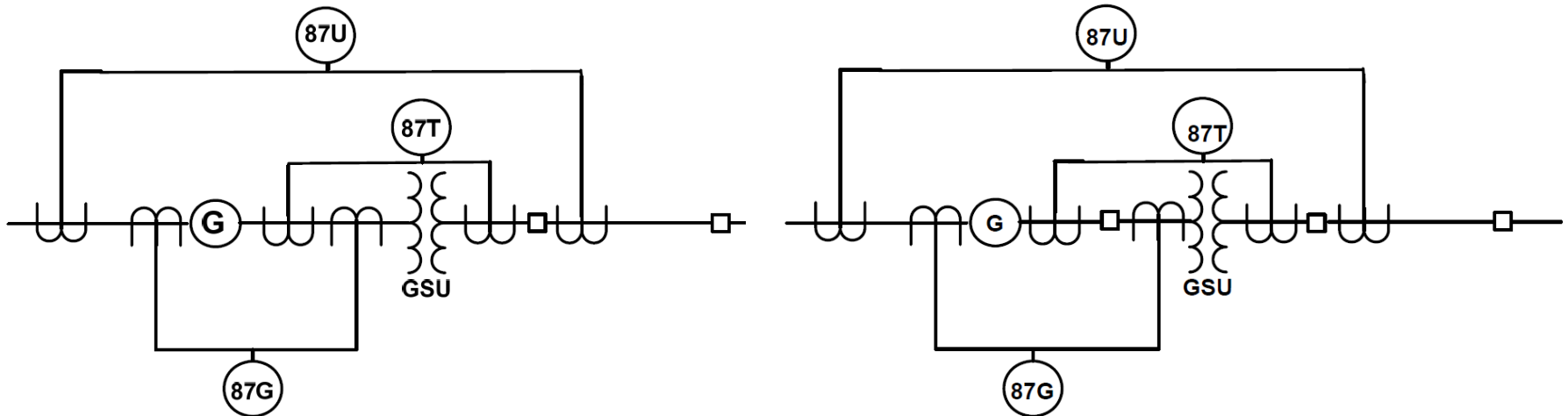
- *“Some form of high-speed differential relaying is generally used for phase fault protection of generator stator windings.*
  - *Differential relaying will detect three-phase faults, phase-to-phase faults, double-phase-to-ground faults, and some single-phase-to-ground faults, depending upon how the 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.*
  - *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.”*

# The Need for Transformer Differential Relay Protection – Function 87T

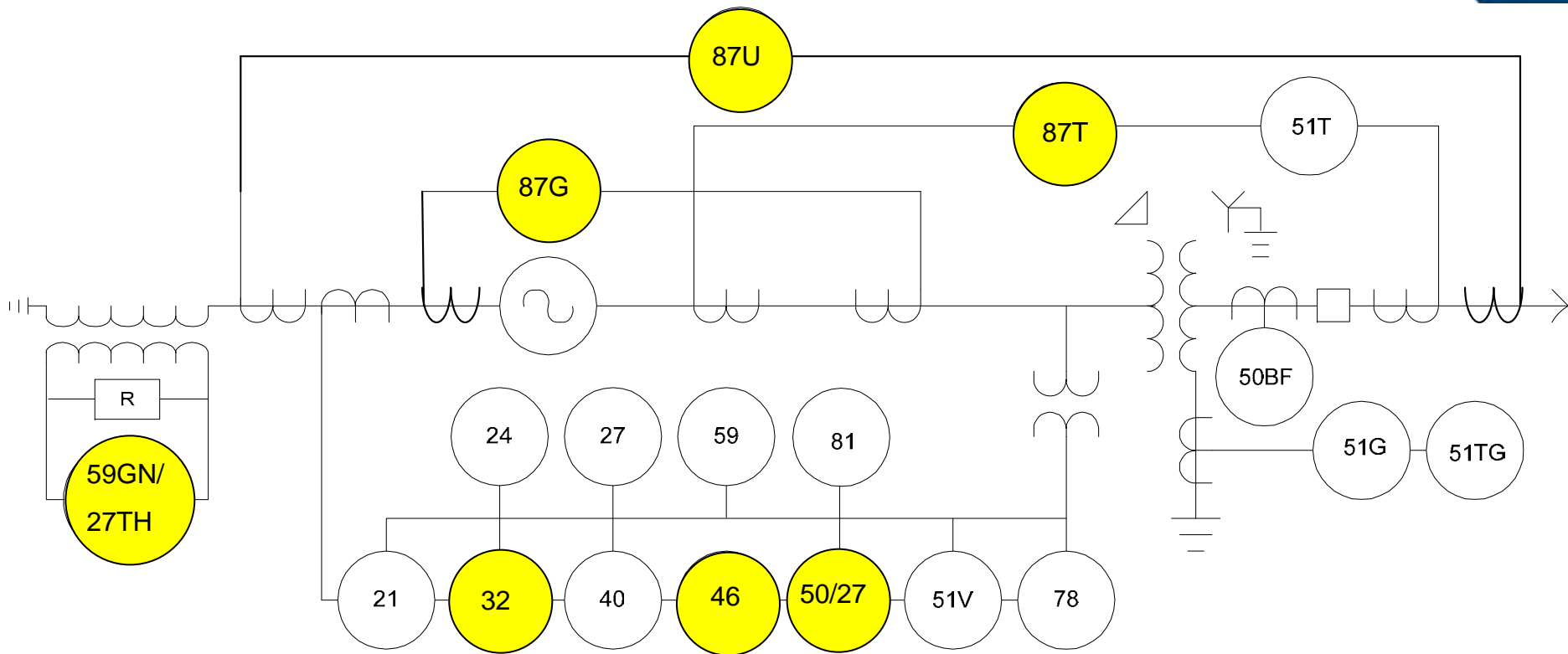
- The Transformer Differential relay is used solely for protection of a GSU transformer.

# The Need for Overall Differential Relay Protection – Function 87U

- The Overall Differential relay is applied usually on the unit generator-transformer arrangement with or without a low voltage generator unit breaker as shown in the figures 3.15.1 and 3.15.2. The advantage of this scheme is providing a redundancy protection of generator differential protection.



# Relay One-Line Showing All Generator Protection and Identifying Functions 32, 46, 50/27, 59GN/27TH, 87G, 87T, 87U





# System Events that Could Cause Undesired Operation of These Protection Functions

- Fault Conditions
- Stressed System Conditions
- Events such as August 14, 2003 Blackout

# Functions that do not Require Coordination with the Transmission System Protection Functions

- These following functions do not require coordination with transmission system protection or dynamics:
  - 32
  - 87G
  - 87T
  - 87U
- Therefore these functions will not be discussed further as part of the coordination process.

# Functions that Require Coordination with the Transmission System Protection Functions

- These functions do require coordination:
  - 46
  - 50/27
  - 59GN/27TH
- Therefore these functions are discussed using the seven step process.

# Seven Step Process for Functions 46, 50/27, and 59GN/27TH

- This is the process used throughout the coordination document to address each protective function as appropriate.
- The following slides will take a step-by-step approach through Functions 46, 50/27, and 59GN/27TH that have some coordination requirements.
- The next two slides provide the general data and information requirements from the Generator, Transmission, and Distribution Owners.



# General Data Exchange Requirements – Generator Owner Data and Information

- The following general information must be exchanged in addition to relay settings to facilitate coordination, 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 axis, negative and zero sequence impedances and their associated time constants)
  - Documentation showing the function of all protective elements listed above

- The following general information must be exchanged in addition to relay settings to facilitate coordination, where applicable:
  - Relay scheme descriptions
  - Regional Reliability Organization's off-nominal frequency plan
  - 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 elements
  - Results of fault study or short circuit model
  - Results of stability study
  - Communication-aided schemes

# Document Format – Seven Sub-Sections for Each Protection Function

- Purpose
- Coordination of Generator and Transmission System
  - Faults
  - Loadability
  - Other Conditions, Where Applicable
- Considerations and Issues
- Setting Validation for the Coordination
  - Test Procedure for Validation
  - Setting Considerations
- Examples
  - Proper Coordination
  - Improper Coordination
- Summary of Detailed Data Required for Coordination of the Protection Function
- Table of Data and Information that Must be Exchanged

## ■ Purpose

- Negative sequence component of current is similar to the positive sequence system, except that the resulting reaction field rotates in the opposite direction to the DC Field system. Hence, a flux is produced which 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.
  - A less-sensitive setting that results in tripping.



## ■ 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 relay 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 and Generator Owners are:
  - 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.

# Coordination of Generator and Transmission System – Function 46

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

- For further discussion of negative sequence current protection see Section A.2.8 of C37.102-2006 — Guide for AC Generator Protection
- 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 the alarm.
- Untransposed transmission lines can result in negative sequence current circulation on the transmission system, which can be reflected into generators and thus cause negative sequence overcurrent operation.

## ■ Coordination Procedure

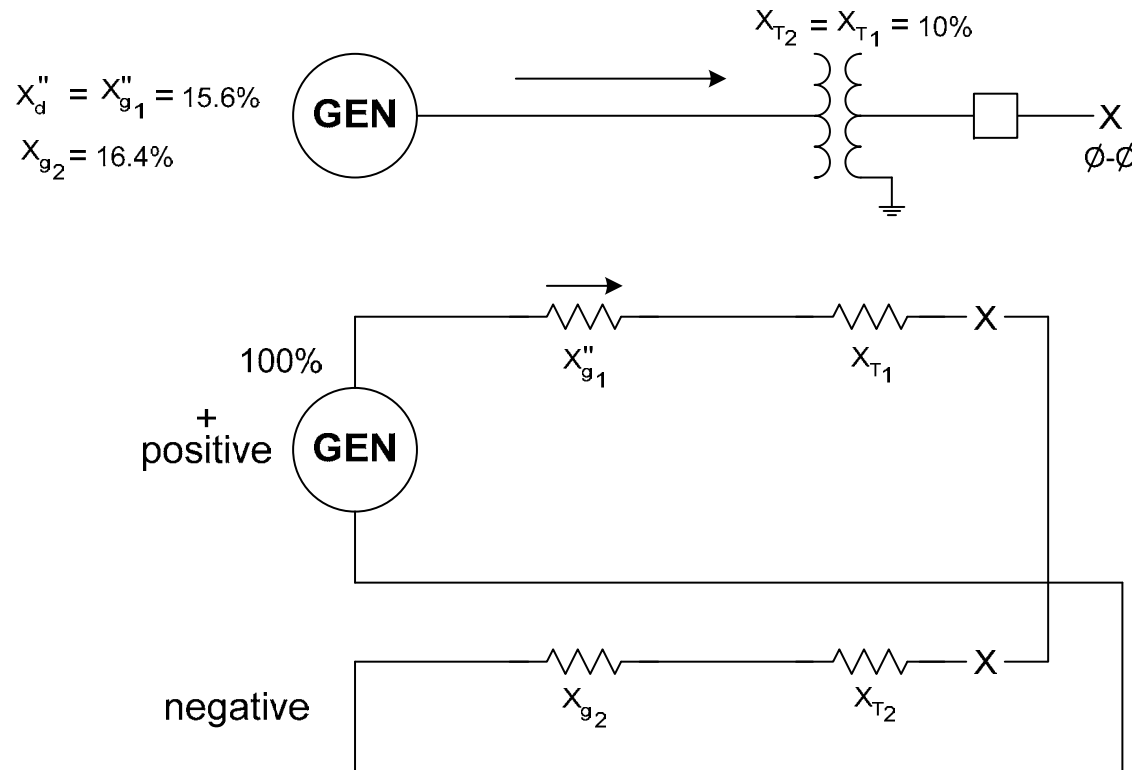
- The following areas should be examined to provide proper protection against excessive negative sequence current effects: short-time unbalanced current factor (K), and continuous negative sequence current level (%).
- Refer to ANSI C37.102-2006, clause 4.5.2; C50.12-2005, clause 4.1.6.1; and C50.13-2005, clause 4.2.3 respectively.

- The Generator Negative Sequence Protection when set according to the IEEE Guide C37.102 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 which is desired to protect 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 relay will not trip the generator for negative sequence currents that are less than the allowable continuous negative sequence current ratings of the machine.
- Generator Name plate:
  - Continuous negative sequence capability of the generator: 10%
  - The factor  $(I_2^2)t=K$ : 30
- Relay Settings:
  - Inverse Time Element
    - Pick-up for the inverse time element  $((I_2^2)t=K) = 29 \%$
    - $K = 29$
  - Definite Time Element for Alarm
    - Pickup = 5%
    - Time delay = 30 seconds

# Example - Proper Coordination

## – Function 46

- As an example the following generator configuration is used to verify coordination:



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

Figure 3.6.2 — Sequence Diagram of a Phase-to-Phase Fault



# Example - Proper Coordination

## – Function 46

- The time delay of the inverse time element 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 the second zone transmission line phase to phase fault protection time delay including the breaker failure time. The coordination is not a concern.
- 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 – Function 46

**Table 2 Excerpt — Device 46 Protection Coordination Data Exchange Requirements**

Generator Protection Device	Transmission System Protection Relays	System Concerns
46 — Negative phase sequence overcurrent	21 21G 46 67N 51N Longest time delay of transmission system protection including breaker failure time	<ul style="list-style-type: none"> <li>•Should be coordinated with system protection for unbalanced system faults</li> <li>•Plant and system operations awareness when experiencing an open-pole on the system</li> <li>•Transposition of transmission lines</li> <li>•System studies, when it is required by system condition</li> <li>•Open phase, single-pole tripping</li> <li>•Reclosing</li> <li>•If there is alarm, Generator Owners must provide <math>I_2</math> measurements to the Transmission Owner and Planning Coordinator and they must work together to resolve the alarm</li> </ul>

# Protection Function Data and Information Exchange Required for Coordination – Function 46

**Table 3 Excerpt — Device 46 Data To be Provided**

Generator Owner	Transmission Owner	Planning Coordinator
<p>Relay settings: negative phase sequence overcurrent protection characteristics, including time delays, at the generator terminals. Generator Owners must provide <math>I_2</math> measurements to the Transmission Owner and Planning Coordinator for resolution if significant unbalance is observed.</p>	<p>The time-to-operate curves for system relays that respond to unbalanced system faults. This would include the 51TG if the GSU is owned by the Transmission Owner.</p>	<p>None</p>

- Purpose

- 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 name plate (rating).
- This inrush current subjects the turbine shaft and blades to large forces, and with rapid overheating of the stator windings and potential for damage due to the excessive slip frequency currents. The impedance of the transformer and the stiffness of the system dictates 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.

# Coordination of Generator and Transmission System – Function 50/27

## ■ Faults

- Step 1 — Generator Owner verifies the voltage supervision pick-up is 50 percent or less, as recommended by C37.102.
- 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 assure 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.
- If this function is not disarmed while the unit is in service, then in addition to assuring 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).
- 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).

# Coordination of Generator and Transmission System – Function 50/27

- Loadability
  - There are no loadability concerns with this protection function.



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

- **Test Procedure for Validation**
  - Check that the 27 function is set lower than 50 percent of the nominal voltage level or lower based on the specific application and engineering analysis.
  
- **Setting Considerations**
  - The 27 function must be set lower than 50 percent of the nominal voltage level or lower to avoid undesired operations.
  - Instantaneous overcurrent (Function 50) relay (or element) should be set sensitive to detect inadvertent energizing.

- 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.
- Improper Coordination
  - Use of undervoltage supervision settings of greater than 50 percent 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 – Function 50/27

**Table 2 Excerpt — Device 50 / 27 (Inadvertent Energization) Protection Coordination Data Exchange Requirements**

Generator Protection Device	Transmission System Protection Relays	System Concerns
50 / 27 — Inadvertent energizing	None	<ul style="list-style-type: none"> <li>• The device 27 must be set lower than 50 percent of the nominal voltage.</li> <li>• Instantaneous overcurrent (device 50) relay (or element) should be set to the most sensitive to detect inadvertent energizing (Breaker Close).</li> <li>• Timer setting should be adequately long to avoid undesired operations due to transients.</li> <li>• 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.</li> </ul>

# Protection Function Data and Information Exchange Required for Coordination – Function 50/27

**Table 3 Excerpt — Device 50 / 27 (Inadvertent Energization) Data To be Provided**

Generator Owner	Transmission Owner	Planning Coordinator
Under voltage setting and current detector settings pick-up and time delay	Review method of disconnect and operating procedures.	None

### ■ Purpose

- The stator ground relay (function 59GN) is intended to detect a ground fault on the stator windings connected to a delta-connected GSU transformer.
- IEEE C37.102-2006 – Guide for AC Generator Protection, Section 4.3.3



# Coordination of Generator and Transmission System – Function 59GN/27TH

## ■ 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 relays, during fault conditions, must be coordinated with the system fault protection to assure that the sensitivity and timing of the relaying overall results in tripping of the proper system elements.
- Ensure that proper time delay is used such that protection does not trip due to inter-winding capacitance issues or instrument secondary grounds.

# Coordination of Generator and Transmission System – Function 59GN/27TH

- Loadability
  - There are no loadability issues with this protection function.

- As stated in the purpose of this section, the 59GN relay is intended to detect a ground fault (phase-to-ground) within the stator windings of a generating unit connected to a delta-connected winding of a GSU transformer.

- Time delay settings for the 59GN/27TH relay 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 this relay tripping for system ground or unbalanced faults.
- Example
  - No examples are necessary for function 59GN/27TH.

# Summary of Protection Functions Required for Coordination – Function 59/27TH

**Table 2 Excerpt — Devices 59GN / 27TH Protection Coordination Requirements**

Generator Protection Device	Transmission System Protection Relays	System Concerns
59GN/27TH — Generator Stator Ground	Longest time delay for Transmission System Protection to Clear a close-in phase-to-ground or phase-to-phase-to-ground Fault	<ul style="list-style-type: none"> <li>•Ensure that proper time delay is used such that protection does not trip due to inter-winding capacitance issues or instrument secondary grounds.</li> <li>•Ensure that there is sufficient time delay to ride through the longest clearing time of the transmission line protection</li> </ul>

# Protection Function Data and Information Exchange Required for Coordination – Function 59GN/27TH

**Table 3 Excerpt — Devices 59GN / 27TH Data To be Provided**

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



# What is Important to Coordination

- Settings that Protect the Generator

# Settings that Protect the Generator

- The generator protection set-points are described in the IEEE Guide for AC Generator Protection (C37.102) for Function 32, 46, 50/27, 59GN/27TH, 87G, 87T, and 87U.
- The time to trip and set points are adjusted based on the specific generator, transformer, and system application.
- Examples of these were given in the presentation, but again, specific settings need to be determined by the entities.



# Question & Answer

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