Standard Development Timeline

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

Development Steps Completed

1. The Standards Committee approved the SAR for posting on August 12, 2010.
2. SAR posted for formal comment on August 19, 2010.
3. SAR was revised to add one directive from paragraph P. 224 relating to Phase I on November 1, 2010.
4. SC authorized moving the SAR (Phase II – Generator Relay Loadability) forward to standard development on March 20, 2012.

Description of Current Draft

The Generator Relay Loadability Standard Drafting Team (GENRLOSDT) is posting Draft 1 of PRC-025-1, Generator Relay Loadability for a 30-day formal comment period.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	October 2012
45-day Formal Comment Period with Parallel Initial Ballot	December 2012
30-day Formal Comment Period with Parallel Successive Ballot	March 2013
Recirculation ballot	June 2013
BOT adoption	August 2013
File with FERC	September 30, 2013 (regulatory directive)

Effective Dates

See PRC-025-1 Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

Version	Date	Action	Change Tracking

Definitions of Terms Used in Standard

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

No new or revised term is being proposed.

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

A. Introduction

1. **Title:** **Generator Relay Loadability**
2. **Number:** **PRC-025-1**

   Purpose: To set load-responsive generator protective relays at a level such that generators do not trip during system disturbances that are not damaging to the generator thereby unnecessarily removing the generator from service.

3. **Applicability:**

   3.1. Functional Entities:

   3.1.1 Generator Owner that applies load-responsive protective relays on Facilities listed in 3.2, Facilities.

   3.2. Facilities: The following Elements of the Bulk Electric System generation Facilities, including those identified as Blackstart Resources in the Transmission Operator's system restoration plan:

   3.2.1 Generating unit(s).

   3.2.2 Generator step-up (i.e., GSU) transformer(s).

   3.2.3 Auxiliary transformer(s) that supply overall auxiliary power necessary to keep generating unit(s) online.[1]

4. **Background:**

   After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout' in the northeastern North American continent.[2]

   During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability

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[1] These transformers are variably referred to as station power, unit auxiliary, or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the Guidelines and Technical Basis for more detailed information concerning auxiliary transformers.

[2] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf)

during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

B. Requirements and Measures

R1. Each Generator Owner shall install settings that are in accordance with *PRC-025-1 – Attachment 1: Relay Settings*, on each load-responsive protective relay while maintaining reliable protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay in accordance with *PRC-025-1 – Attachment 1: Relay Settings*, each Generator Owner shall have and provide as evidence, dated documentation of: (1) settings calculations, and (2) that settings were installed.

Rationale for R1:

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, "while maintaining reliable protection" in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity.

1.2. Evidence Retention

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

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	To be determined	To be determined	To be determined	To be determined

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

PRC-025-1 – Attachment 1: Relay Settings

Each Generator Owner that applies load-responsive protective relays shall use one of the following Options 1-17 in Table 1, Relay Loadability Evaluation Criteria (“Table 1”), to set each load-responsive protective relay according to its application. The bus voltage is determined by the criteria for the various applications listed in Table 1.

Synchronous generator output pickup setting criteria values are determined by the unit’s maximum seasonal gross Real Power capability, in megawatts (MW), as reported to the Planning Coordinator; and the unit’s Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the rated MW based on the unit’s nameplate megavoltampere (MVA) at rated power factor.

Asynchronous generator output pickup setting criteria values are determined by the site’s aggregate maximum seasonal gross Real Power capability, in MW, as reported to the Planning Coordinator; and the Reactive Power capability, in (Mvar), as determined by calculating the rated Mvars based on the aggregate MVA at rated power factor and adding the Mvar output of any static or dynamic reactive power devices. Asynchronous generator criteria also include inverter-based installations.

Table 1. Relay Loadability Evaluation Criteria

Relay Type	Option	Application	Bus Voltage	Pickup Setting Criteria
Phase Distance Relay (21) – Directional toward the Transmission System	1	Synchronous generators	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the impedance derived from 115% of: (1) Real Power output – 100% of maximum seasonal gross MW reported to the Planning Coordinator, and (2) Reactive Power output – a value that equates to 150% of rated MW

Table 1. Relay Loadability Evaluation Criteria

Relay Type	Option	Application	Bus Voltage	Pickup Setting Criteria
Phase Distance Relay (21) – Directional toward the Transmission System	2	Synchronous generators	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the impedance derived from 115% of: (1) Real Power output - 100% of maximum seasonal gross reported to the Planning Coordinator, and (2) Reactive Power output – a value that equates to 150% of rated MW
Phase Distance Relay (21) – Directional toward the Transmission System	3	Synchronous generators	Simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the impedance derived from 115% of: (1) Real Power output – 100% of maximum seasonal gross MW reported to the Planning Coordinator, and (2) Reactive Power output – a value that equates to the Maximum Mvar output determined by simulation
Phase Distance Relay (21) – Directional toward the Transmission System	4	Asynchronous generators (including inverter-based installations)	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the impedance derived from 130% of the total aggregate MVA output at rated power factor

Table 1. Relay Loadability Evaluation Criteria				
Relay Type	**Option**	**Application**	**Bus Voltage**	**Pickup Setting Criteria**
Phase Time Overcurrent Relay (51V) voltage-restrained	5	Synchronous generators	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than the calculated current derived from 115% of: (1) Real Power output – 100% of maximum seasonal gross MW reported to the Planning Coordinator, and (2) Reactive Power output – a value that equates to 150% of rated MW
Phase Time Overcurrent Relay (51V) voltage-restrained	6	Synchronous generators	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than the calculated current derived from 115% of: (1) Real Power output – 100% of maximum seasonal gross MW reported to the Planning Coordinator, and (2) Reactive Power output – a value that equates to 150% of rated MW

Table 1. Relay Loadability Evaluation Criteria

Relay Type	Option	Application	Bus Voltage	Pickup Setting Criteria
Phase Time Overcurrent Relay (51V) voltage-restrained	7	Synchronous generators	Simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than the calculated current derived from 115% of: (1) Real Power output – 100% of maximum seasonal gross MW reported to the Planning Coordinator, and (2) Reactive Power output – a value that equates to Maximum Mvar output determined by simulation
Phase Time Overcurrent Relay (51V) voltage-restrained	8	Asynchronous generators (including inverter-based installations)	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than the current derived from 130% of total aggregate MVA output at rated power factor
Phase Time Overcurrent Relay (51C) – Enabled to operate as a function of voltage (e.g., Voltage controlled relay)	9	Synchronous or asynchronous generators (including inverter installations)	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the nominal generator bus voltage

Table 1. Relay Loadability Evaluation Criteria				
Relay Type	**Option**	**Application**	**Bus Voltage**	**Pickup Setting Criteria**
Phase Time Overcurrent Relay (51)	10	Generator step-up transformer – Synchronous generators	0.85 per unit of the high-side nominal voltage	The element shall be set greater than the calculated current derived from 115% of: (1) Real Power output – 100% of connected generation reported, and (2) Reactive Power output – a value that equates to 150% of connected generation rated MW
Phase Time Overcurrent Relay (51)	11	Generator step-up transformer – Synchronous generators	0.85 per unit of the high-side nominal voltage	The element shall be set greater than the calculated current derived from 115% of: (1) Real Power output – 100% of connected generation reported, and (2) Reactive Power output – a value that equates to the Maximum Mvar output determined by simulation
Phase Time Overcurrent Relay (51)	12	Generator step-up transformer – Asynchronous generators only (including inverter-based installations)	0.85 per unit of the high-side nominal voltage	The element shall be set greater than the calculated current derived from 130% of aggregate installed maximum rated MVA output of the connected generators at rated power factor

Table 1. Relay Loadability Evaluation Criteria				
Relay Type	**Option**	**Application**	**Bus Voltage**	**Pickup Setting Criteria**
Phase Distance Relay (21) – Directional toward the Transmission System	13	Generator step-up transformer – Synchronous generators	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the impedance derived from 115% of: (1) Real Power output – 100% of connected generation reported, and (2) Reactive Power output – a value that equates to 150% of connected generation rated MW
Phase Distance Relay (21) – Directional toward the Transmission System	14	Generator step-up transformer – Synchronous generators	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the impedance derived from 115% of: (1) Real Power output – 100% of connected generation reported, and (2) Reactive Power output – a value that equates to 150% of rated MW
Phase Distance Relay (21) – Directional toward the Transmission System	15	Generator step-up transformer – Synchronous generators	Simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the impedance derived from 115% of: (1) Real Power output – 100% of connected generation reported, and (2) Reactive Power output – a value that equates to the Maximum Mvar output determined by simulation

Table 1. Relay Loadability Evaluation Criteria				
Relay Type	**Option**	**Application**	**Bus Voltage**	**Pickup Setting Criteria**
Phase Distance Relay (21) – Directional toward the Transmission System	16	Generator step-up transformer – Asynchronous generators (including inverter-based installations)	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the impedance derived from 130% of the total aggregate MVA output at rated power factor
Phase Time Overcurrent Relay[3] (51)	17	Auxiliary transformers	1.0 per unit nominal voltage on the high-side terminals of the auxiliary transformer	The element shall be set greater than the calculated current derived from 150% of the current derived from the auxiliary transformer nameplate maximum MVA rating

[3] Refer to the Applicability 3.2.3.

Guidelines and Technical Basis

Introduction

The document, "Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2010.[4]

The term, "while maintaining reliable protection" in Requirement R1, describes that the responsible entity ("Generator Owner") is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generation plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the responsible entity consider both the requirements within this standard and its desired protection goals, and perform modifications to its protection relays or protection philosophies as necessary to achieve both.

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be necessary to replace the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the responsible entity must understand the criteria and application of Table 1, Relay Loadability Evaluation Criteria ("Table 1"), in determining the settings that it must install on each of its load-responsive protective relays to achieve the required generator performance during the transient conditions anticipated by this standard.

Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field forcing," results in the Reactive Power exceeding the steady-state capability of the generator and the resultant increase in apparent power may result in operation of load-responsive generator protective functions, if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased output during field forcing is limited by the field winding thermal withstand capability. The excitation limiter may respond to begin reducing the level of field forcing in as little as one second, but may take much longer, depending on the level of field forcing and the characteristics of the excitation system. Since this time may be longer than the time-delay of the generator backup protection, it is important to evaluate load-responsive protective relay loadability to prevent its operation for this condition during which the generator is not at risk of thermal damage.

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[4] http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf

The criteria established within Table 1, are based on 0.85 per unit of Transmission system nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had not other, undesired, behavior occurred.

The dynamic load levels specified in Table 1 under column Pick Up Setting criteria, are representative of the maximum expected apparent power during field forcing with the Transmission system voltage at 0.85 per unit at the high-side of the generator step-up transformer. These values are based on values recorded during the events leading to the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified load operating points are believed to represent conservative, but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltage for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20% of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1 and 2, for example, are based on relatively simple, but conservative calculations. In recognition that not all units are capable of achieving this level of output, Option 3, for example, was developed to allow an entity to simulate the output of a generating unit when the simple calculation is too conservative to achieve the desired protective function setting.

Asynchronous generators, however, do not have excitation systems and will not respond to a Disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before a crowbar function will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. They also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated megawatts (MW).

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1, (e.g., Option 4), for induction generator installations.

Phase Distance Relay (Options 1-4)

Generator phase distance relays, whether applied for the purpose of primary or backup generator step-up transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generation plants, contributing to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. The Options 1 through 4 establish criteria for phase distance relays to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

Phase distance protection measures impedance derived from the quotient of generator terminal voltage divided by generator stator current. When phase distance protection is applied, its function is to provide backup protection for system faults that have not been cleared by Transmission system circuit breakers via their protective relays.

Section 4.6.1.1 of IEEE 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* ***which is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition which causes the generator voltage regulator to boost generator excitation for a sustained period that may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally a distance relay setting of 150 to 200% of the generator MVA rating at its rated power factor* (sic: This setting can be re-stated in terms of ohms as 0.66 – 0.50 per unit ohms on the machine base.) *has been shown to provide good coordination for stable swings, system faults involving infeed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. 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 must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *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 described above. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the generator step-up transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. Your 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 isolated-phase bus with partial coverage of the generator step-up 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."*

Table 1, Options 1, 2, and 3, are provided for assessing loadability for synchronous generators. The generator-side voltage during field forcing will be higher than the high-side voltage due to the voltage drop resulting from the Reactive Power flow through the generator step-up transformer. Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage.

Option 1 accounts for the voltage drop across the generator step-up transformer using a conservative estimate of the generator-side voltage. This is based on referring a 0.95 per unit system nominal voltage at the high-side terminals of the generator step-up transformer through the turns ratio.

Option 2 uses a calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This option accounts for the voltage drop through the generator step-up transformer, including the turns ratio and impedance.

Option 3 uses a simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The responsible entity must perform simulations to determine the actual performance of its generator. The responsible entity that elects to determine the synchronous generator performance on which to base phase distance relay settings may simulate the response of a generator to depressed Transmission system by lowering the Transmission system voltage on the high-side of the generator step-up transformer. This can be simulated by means such as modeling switching of a shunt 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 observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator holding the assigned voltage schedule while at 100% of the maximum seasonal gross Real Power capability value as reported to the Planning Coordinator.

Option 4 is based on a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer. Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Since asynchronous generators do not produce as much reactive power as synchronous generators, the voltage rise due to reactive power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high side nominal voltage to the generator side based on the generator step-up transformer's turns ratio. The aggregate megavoltampere (MVA) output is determined by summing the total nameplate MW and megavoltampere-reactive (Mvar) capability of the generation equipment behind the relay. This should also include any static or dynamic reactive power devices that contribute to the power flow through the relay.

If a mho phase distance relay cannot be set to maintain reliable protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. 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 capability (i.e., field forcing). For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may restrict the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. The examples in Appendix E "Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee, illustrate the potential for encroaching on the generating unit capability.

If an entity is unable to meet the criteria established within Table 1, while maintaining reliable protection, the entity will need to utilize different protective relays or protection philosophies such that both goals can be met.

Generator Phase Overcurrent Relay – Voltage Restrained (Options 5-8)

Generator voltage-restrained phase overcurrent relays, which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup generator step-up transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generation plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by Voltage Restrained and Voltage Controlled protection functions together.

Table 1, Options 5 through 8, establish criteria for phase overcurrent relays which change their sensitivity as a function of voltage to help assure that generators, to the degree possible, will provide system support during disturbances in an effort to minimize the scope of those disturbances. These devices are variably referred to by IEEE function numbers (51V), (51R), (51VR), (51V/R), (51V-R), or other terms. The criteria provided for these relays are very similar to those provided for phase distance relays in Options 1 through 4. See clause 3.10 of "Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) for a detailed discussion of this protection function.

Refer to the discussion under Option 4 technical basis concerning asynchronous and inverter based generation.

Generator Phase Overcurrent Relays – Voltage Controlled (Option 9)

Generator voltage-controlled overcurrent relays, enabled as a function of voltage, are applied for the purpose of primary or backup generator step-up transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generation plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by Voltage Restrained and Voltage Controlled protection functions together, and many other generators were tripped by unknown protection functions.

Table 1, Option 9, establishes criterion for phase overcurrent relays which are enabled as a function of voltage to help assure that generators, to the degree possible, will provide system support during disturbances in an effort to minimize the scope of those disturbances. These devices are variably referred to by IEEE function numbers (51V), (51C), (51VC), (51V/C), (51V-C), or other terms. See clause 3.10 of "Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee for a detailed discussion of this protection function.

The criteria for a voltage control setting of less than 0.75 per unit of the nominal generator voltage is based on guidance in "Power Plant and Transmission System Protection Coordination," published by the NERC SPCS. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage is indifferent as to the current setting, and simply requires that the relays not respond for the depressed voltage.

Refer to the discussion under Option 4 technical basis concerning asynchronous and inverter based generation.

Generator Step-up Transformer Phase Time Overcurrent Relay (Options 10-12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. Table 1, Options 10 through 12, establish criteria for the generator protective relays to prevent the generator step-up transformer phase time overcurrent relays from operating during the dynamic conditions anticipated by this standard.

The stressed system conditions, anticipated by Options 10 through 12, reflect a 0.85 per unit Transmission system voltage; therefore, establishes that the ampere value used for applying the generator step-up transformer phase time overcurrent relay be calculated from the apparent power addressed within the Table 1, with application of a 0.85 per unit Transmission system voltage.

Options 10 and 11 apply to generator step-up transformers connected to synchronous generators. Option 12 only applies to generator step-up transformers connected to asynchronous generators (including inverter-based installations).

Please see clause 3.9.2 of "Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee for a detailed discussion of this protection function. However, the setting criteria established within Options 10-12 differ from that suggested in this paper. Rather than establishing a uniform setting threshold of 200% of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output based on whether the generator operates synchronous or asynchronous.

Refer to the discussion under Option 4 technical basis concerning asynchronous and inverter based generation.

Generator Step-up Transformer Phase Distance Relay (Options 13, 14, 15, and 16)

The FERC Order No. 733 paragraph 112, directs that NERC address relay loadability for protective relays applied for system backup protection. In paragraph 114, FERC further explains that their concern applies whether those relays are installed on the generator terminals or on the generator side of the generator step-up transformer. Their concerns regarding those relays connected to the generator terminals are addressed in Options 1, 2, 3, and 4 for the generator itself; Table 1, Options 13, 14, 15, and 16, for generator step-up transformer distance relays address those connected to the generator side of the generator step-up transformer.

The generator protective relays in Options 13, 14, 15, and 16 prevent generator step-up transformer phase distance relays from operating during the dynamic conditions anticipated by this standard.

Auxiliary Transformers Phase Time Overcurrent Relay (Option 17)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of auxiliary transformer(s) that supply normal station service for a generating unit. The Table 1, Option 17, for auxiliary transformers addresses phase time overcurrent relays protecting auxiliary transformers that are used to provide overall auxiliary power to the generating station when the generator is running (regardless of where these transformers are connected). This discussion refers to each of these transformers as a "unit auxiliary transformer" or "UAT." If the UAT trips, it will result in tripping of the generator itself, either directly or indirectly. Although the UAT is not directly in the output path from the generator to the system, it is an essential component for operation of the generating plant.

Refer to the figures below for example configurations:

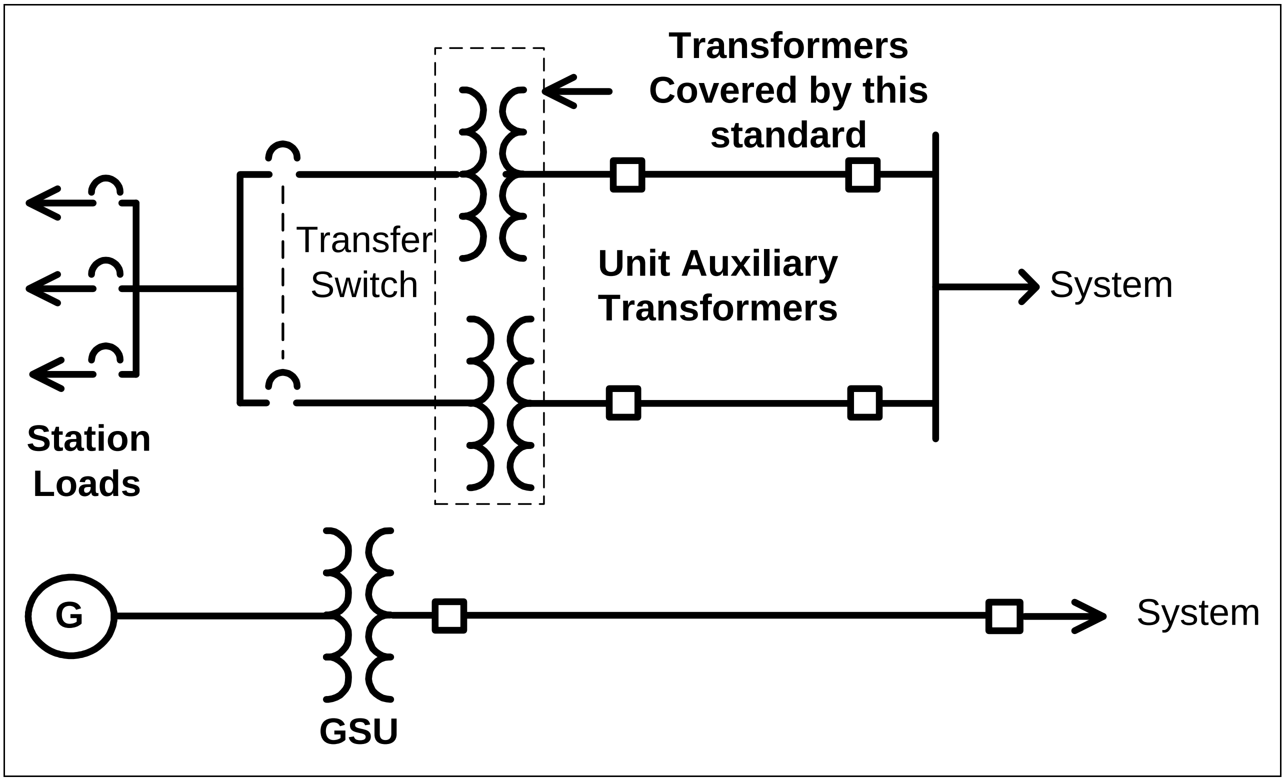

Figure-1 –Auxiliary Power System (Independent from Generator)

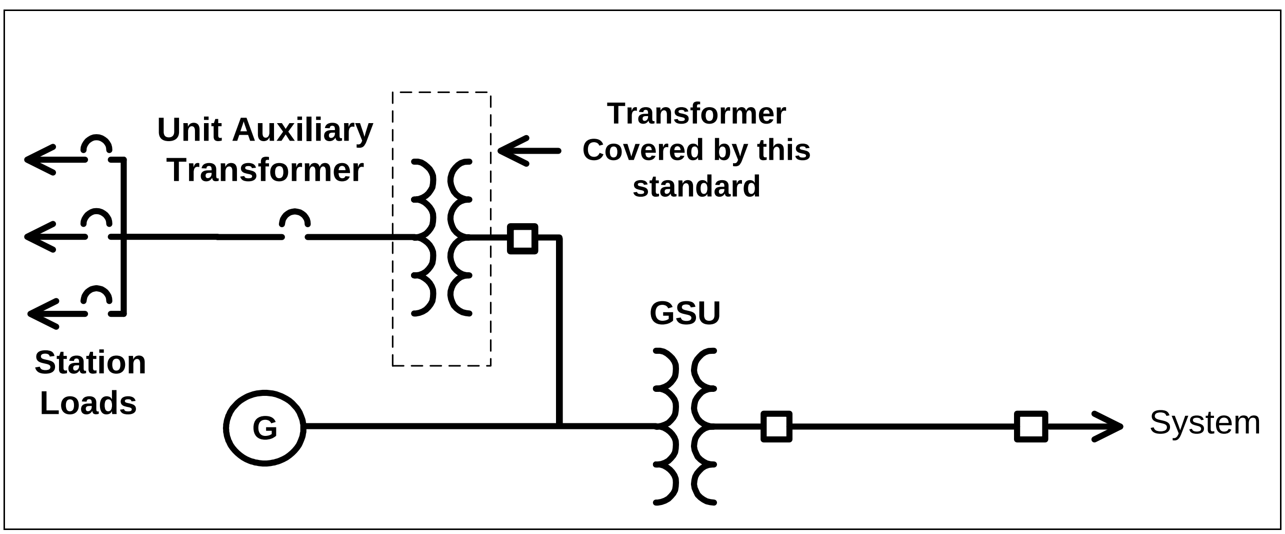

Figure-2 – Typical Auxiliary Power System for Power Plants

The UATs supplying power to the plant's electrical auxiliaries are sized to accommodate for the maximum expected auxiliary load demand at the highest generator output. Although the MVA size normally includes capacity for future loads as well as capacity for starting of large induction motors on the original plant design, the MVA capacity of the transformer may be near full load.

The performance of the auxiliary loads during stressed system conditions (depressed voltages) is very difficult to determine. Rather than requiring entities to determine the response of auxiliary loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150% from that used elsewhere in this standard (i.e., 115%) and use a generator bus voltage of 1.0 per unit. A minimum pickup current based on 150% of maximum nameplate MVA rating at 1.0 per unit generator bus voltage would provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased auxiliary load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.