PSRC Working Group J13

Modeling of Generator Controls for Coordinating Generator Relays

Power System Relaying and Control Committee

Report of working Group J13
with the cooperation of ESCS, EDGP and PSDP

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KEYWORDS

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1. Introduction to the paper and discussion on disturbances and stressed system conditions

Guidance for setting protective relays on generating units has traditionally been provided in the form of equations and graphical methods based on steady-state conditions or static approximations of the dynamic response of generators to system disturbances. Several guidelines are presented within IEEE Standard C37.102-2006, IEEE Guide for AC Generator Protection. For example:

- Loss of Field (40): C37.102 provides typical time delays to ride through stable swings and system transients and indicates that transient stability studies are used to determine the proper time-delay setting for loss of field protection.

- Loss of Synchronism (78): C37.102 states that for specific cases, stability studies may determine the loci of an unstable swing so that the best selection of an out-of-step relay or relay scheme may be made. It also states that transient stability studies should be performed to determine the appropriate relay settings.

- Phase fault backup (21): C37.102 discusses that certain conditions that cause the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance to fall within the operating characteristic of the distance relay (21); and provides guidance on setting criteria to provide coordination for stable swings, system faults involving infeed, and normal loading conditions. It also states that stability studies may be needed to help determine a set point to optimize protection and coordination.

- Over/underfrequency protection (81): C37.102 discusses the under and overfrequency capability and protection of generators. This protection needs to allow the turbine governor function to control the speed before any protection operation. The underfrequency protection will normally be required to allow system controls such as underfrequency load shedding to operate before tripping of a generator for underfrequency events.

Guidelines as those listed above have been extremely useful for determining generator relay settings when detailed stability studies are not available. However, for some relay settings there is a benefit to supplementing static calculations with detailed stability studies considering the NERC reliability standards and the advanced computer software for the modeling of power systems. Stability simulations can address dynamic effects present in a large power system that cannot be reflected in textbook examples based on simple two-machine models or static calculations. In other words, there is a benefit to performing detailed stability studies when determining generator relay settings for significant assets to provide more precise information for the corresponding calculations. This document presents the basic concepts required to begin modeling of generating units, and their associated control systems for the performance of detailed stability studies.

In the dynamic analysis of electrical machines, the operation of the control systems must be considered, particularly when it comes to electrical protections. The controls include the voltage regulator and the interaction with the power system stabilizer (PSS), if it is applied, and the governor. In some procedures, it is a common practice to ignore these control devices, which could be valid when analyzing very fast transients, but may not be valid for longer duration disturbances. Section 4 of this document makes emphasis in considering proper generator control modeling when analyzing disturbances, which occur for a duration longer than the protective relay operating time.

For certain relay settings, such as phase distance backup, loss of field and loss of synchronism protection, a transient analysis is convenient as mentioned above, considering a complete dynamic analysis of the rotating machines can provide additional confidence that derived settings will be dependable and secure. This document is not intended to present comprehensive recitation of the stability theory but rather to present the fundamental concepts illustrated by simple examples. These will help the reader to review concepts without referring to other sources. It also presents applicable NERC standards, which are closely related to the operation of protection systems that are influenced by the transient behavior of the rotating machines. In particular, NERC Reliability Standards PRC-019, PRC-024, PRC-025, and PRC-026 are discussed in this paper, with some examples illustrating their application. Note that references to these standards are based on the versions in effect at the time this paper was written and are made for illustrative purposes. For matters related to compliance with these standards, the reader should refer to the current enforceable versions of the standards.

1.1 Transient simulation fundamentals

The goal of transient stability simulation of power systems is to analyze the voltage and frequency parameters in a time window of a few seconds to several tens of seconds after a disturbance. Stability in this aspect is the ability of the system to quickly return to a stable operating condition after being exposed to a disturbance such as a three-phase fault or tripping of a transmission element (e.g., line or transformer). In simple terms, a power system is deemed stable if the bus voltage levels and the frequencies of motors and generators return to their nominal values in a quick and continuous manner.

For a power system consisting of a generator (or group of coherent generators) (or group of electrically close) connected to an infinite bus, the swing equation and the power angle equation can be used to derive equations for critical clearing time and critical angle [1]. The equations for critical clearing angle and critical clearing time are:

$$\delta_{cr} = cos^{-1}[(\pi - 2\delta_0)sin\delta_0 - cos\delta_0]$$

$$t_{cr} = \sqrt{\frac{4H(\delta_{cr} - \delta_0)}{\omega_s P_m}}$$

Where:

δ_0 is the initial rotor angle in electrical degrees,

H is the moment of inertia of the generator,

ω_s is the synchronous frequency in radians, and

P_m is the output power at the beginning of the event in pu.

Note the following assumptions:

1. The fault type is a solid, three-phase fault. This means that power transfer is zero during the fault.
2. The generator terminal voltage remains constant following the clearance of the fault.

The following example is presented in [1].

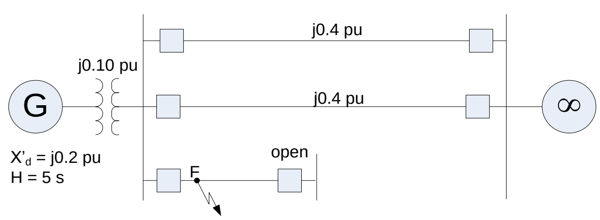


Figure 1 – Example Power System

It is well known that the relationship between the electrical power of a generator and its rotor angle is given by:

$$Pe = \frac{E_g E_T}{X_T} \sin \alpha$$

Where:

Pe is the electrical power output,

E_g is the generator internal voltage,

E_T is the terminal voltage,

X_T is the generator internal reactance (steady-state), and

α is the power angle, alpha.

In this example, the transfer impedance X_T is the sum of the transformer impedance and the parallel impedance of the two transmission lines,

$$X_T = 0.1 + \left(\frac{0.4 \times 0.4}{0.4 + 0.4}\right) = 0.3$$

If the voltage magnitude at both the generator terminals and the remote bus is 1 pu and the generator is initially operating at 1 pu power (Pm), then the voltage angle at the generator terminals relative to the remote infinite bus is:

$$\alpha = \sin^{-1}(\frac{P_E X_T}{E_g\, E_T})$$

Then with the values provided:

$$\alpha = \sin^{-1}(\frac{P_E X_T}{E_g\, E_T}) = \sin^{-1}\left(\frac{1.0 \times 0.3}{1.0 \times 1.0}\right) = \sin^{-1}(0.3) = 17.5°$$

The terminal voltage is

$V_t = 1 \angle 17.5°$.

The generator current is

$I = \frac{V_t - 1 \angle 0}{j0.3} = 1.01 \angle 8.7°$.

The generator internal transient voltage is

$$E' = V_t + j0.2 \cdot I = 1.05 \angle 28.5°.$$

The initial rotor angle is

$$\delta_0 = 28.5\,°.$$

Solving for the critical angle and critical clearing time:

$$\delta_{cr} = cos^{-1}[(\pi - 2\delta_0)sin\delta_0 - cos\delta_0] = 81.72°\text{ , and}$$

$$t_{cr} = \sqrt{\frac{4H(\delta_{cr} - \delta_0)}{\omega_s P_m}} = 0.222\text{ seconds or 13.3 cycles at 60 Hz.}$$

The power system of Figure 1 was modeled in MATLAB Simulink, with the model shown in Figure 2.

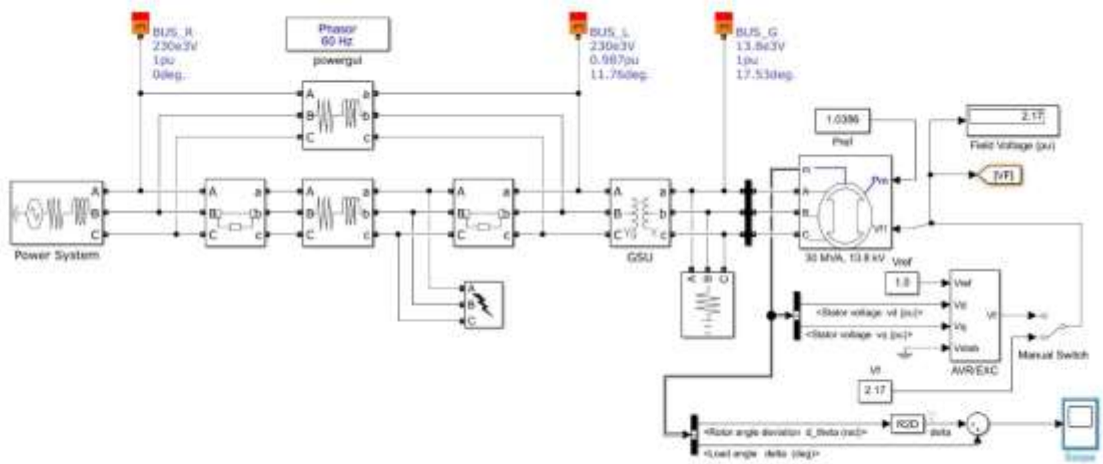


Figure 2 – Simulink Model

The model was used to plot the rotor angle for various fault clearing times. Note that the generator is stable for a clearing time of 13 cycles but is unstable for a clearing time of 14 cycles, as shown in Figure 3. This is consistent with the calculated critical clearing time above.

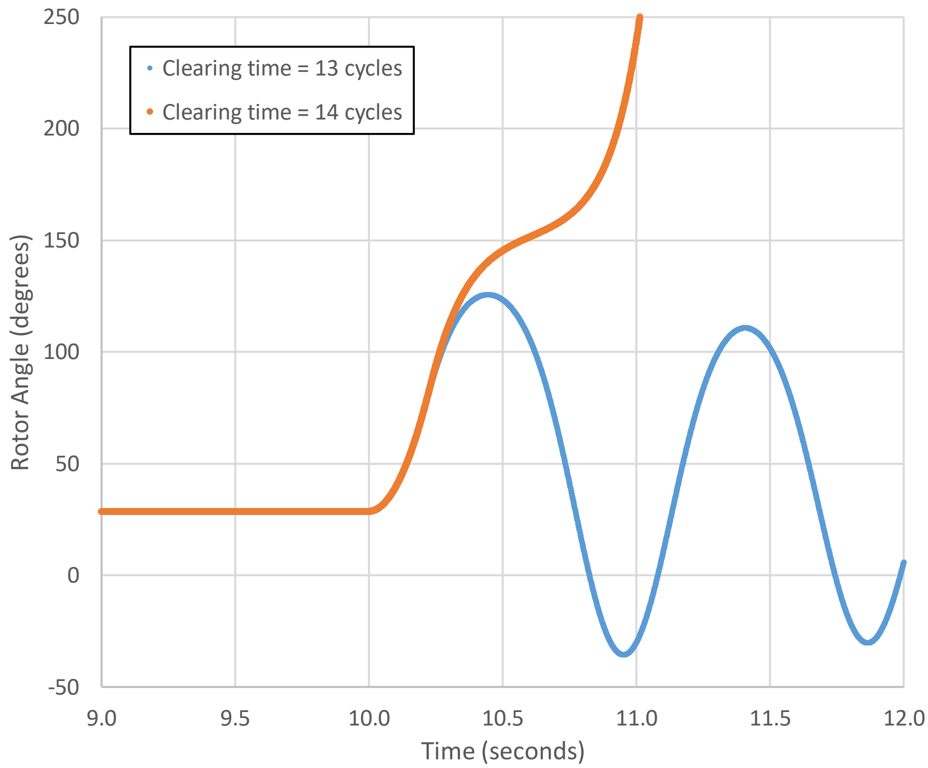


Figure 3 – Rotor Angle Plot

1.2 Loss of Synchronism (Out of Step) Conditions

Loss of synchronism or out of step (OOS) protection is used to protect the generator from damaging conditions resulting from loss of synchronism between the generator and the transmission system, including pole slip conditions. OOS protection Function 78 needs to be set to trip the generator under true loss of synchronism conditions and to prevent operation during stable power swings. There are basically two types of schemes to implement this function. The most common for generator protection is the single blinder scheme that uses one pair of blinders along with a supervisory offset mho element. The positive sequence impedance must start outside of both blinders then enter and pass through all three areas of the impedance plane.
Some manufacturers' schemes also include a minimum time that the impedance must remain between the blinders to produce a trip. If these requirements are satisfied, then a trip occurs if a complete transit of the characteristic is confirmed.

The other common scheme used is the double blinder scheme, where the detection of the rate of change of positive sequence impedance compares the actual elapsed time required by the impedance locus to travel between two impedance characteristics with a delay setting. In this case the two impedance characteristics are simple blinders, each set to a specific resistive reach on the R-X plane. Typically the two blinders on the left half plane are the mirror images of those on the right half plane.

The setting criteria for the schemes mentioned above and other schemes available, are beyond the scope of this work. A thorough discussion on this is presented in the PSRC J5 paper entitled Application of Out-of-Step Protection Schemes for Generators.

For single blinder schemes a stability stud y can be used to help the setting of the supervisory offset mho element. For double blinder schemes a stability study can be used to verify settings of the blinders and timer.

To minimize the possibility of damage to the generator, IEEE Std. C37.102 recommends tripping the unit without time delay, preferably during the first half slip cycle of a loss of synchronism condition (Section 4.5.3 – Page 59). A stability study may be beneficial for assessing this objective when using a double blinder scheme

A typical Function 78 single blinder protective scheme includes one set of blinders and a supervisory mho element. Settings for this scheme include:

a. Diameter and offset of the supervisory mho element
b. Blinder impedance and angle
c. Some manufacturers use a time delay for this function.

IEEE Std. C37.102 provides precise recommendations to set the diameter and offset of the supervisory mho element, and blinder impedance and angle, based on generator and system impedances.

The stability study allows to:

a. Determine the fault clearing time, which results in the generator losing synchronism with the transmission system. Faults cleared longer than this time result in the angle between the generator and system voltages to grow continuously.
b. Obtain the trajectory of the impedance as seen by the Function 78 relay prior to fault inception, during the fault, and after fault clearing.
c. Verifies that the Function 78 relay picks up and trips for all unstable fault conditions and clearing times, including different transmission system impedances.

For example, operation of the Function 78 single blinder scheme (Figure 4) requires that the impedance point originate outside either blinder A or B, swing through the pickup area for a time greater than or equal to the time delay, and progress to the opposite blinder from where the swing had issued. When this scenario happens, the tripping logic is complete and a trip signal is originated.

1.3 Application to Analyze a LOF Function

Function 40 Zones 1 and 2 for a negative offset loss of field scheme are set following recommendations from IEEE Std. C37.102 based on generator parameters.

Function 40 timers for a negative offset scheme are set per the following recommendations from IEEE Std. C37.102:

- Zone 1 timer is set at 0.1 sec to prevent misoperation during switching transients
- Zone 2 timer is set at 0.5 sec to prevent misoperation during power swing conditions

The negative offset mho scheme has a much reduced reach relative to the positive offset mho scheme. The positive offset mho scheme is more susceptible to assertion on a swing owing to its closer characteristic relative to the GCC and UEL and uses a longer delay with an undervoltage acceleration scheme. Verification for a positive offset scheme would follow a similar approach as described herein for the negative offset scheme.

Per NERC PRC-019, coordination of relay settings and control systems may be verified with a diagram (R-X or P-Q plane). The diagram should include the equipment capabilities and the operating region for the limiters and protection functions. The following are typical functions to coordinate:

- Generator Capability Curve (GCC) (underexcited and overexcited operation)
- Field Winding Overexcitation Limiter (OEL)
- Underexcitation Limiter (UEL)
- System Steady-State Stability Limit (SSSL)
- Loss of Field Protection (40)

The graphical review of the Function 40 characteristics should confirm:

- Zone 1 and Zone 2 do not trip the unit for operating conditions within the GCC (Zone 1 and 2 should not intercept the GCC curve)
- Zone 1 and Zone 2 do not trip the unit for operating conditions set by the Underexcitation Limiter UEL (Zone 1 and 2 should not intercept the UEL curve)
- When setting the 40 element, it is acceptable to encroach on the SSSL because the SSSL only applies when the AVR is not in service; the stability limit with the AVR in service is higher. The only justification for coordinating the UEL with the SSSL is that, if the AVR fails, the machine will be prepositioned in a safe state for being taken off line. The SSSL should help inform the UEL setting. The relay has to be coordinated with the UEL.

The stability study can be performed to verify that the trajectory of the impedance seen by the Function 40 relay in the R-X plane:

- Does not initiate a relay trip during fault conditions with normal clearing times
- Terminates inside of Zone 1 or Zone 2 relay characteristics after a loss of excitation condition
- Does not initiate a relay trip during stable power swing conditions (the impedance trajectory leaves the relay characteristic before the relay times out)

1.4 Application to Analyze an OOS Function

Function 78 diameter and offset of the mho element are set based on generator and system impedances following guidelines from IEEE Std. C37.102.

The blinder impedance is set at:

- Blinder = (1/2) ($X'_d + X_T + X_{maxSG}$) tan (θ – (δ/2)), where θ is the reactance angle and δ (angle between generator and system voltages) is typically 120^o.

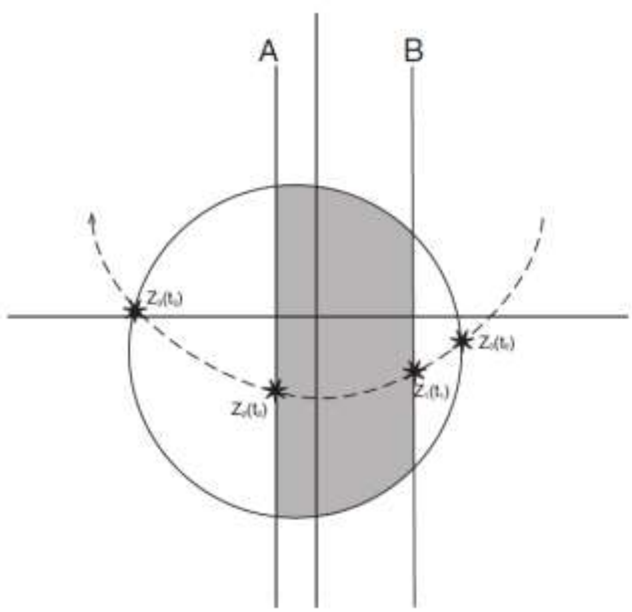


Figure 4 – Out of Step Relay Operation

The stability study helps to determine the actual trajectory and time stamps for the impedance seen by the relay during an unstable power swing. Setting the Generator Phase Distance Element according to NERC PRC-025

The purpose of PRC-025 is to define setting criteria for load-responsive elements that provide security against tripping for a power system disturbance while still providing effective coverage of the protected equipment. The requirements in the standard are based on conditions observed during events that led up to the August 14, 2003 Northeast Blackout in North America. Similar conditions have been observed during some subsequent major system disturbances. Three options are provided in Table 1 of the document for determination of the reach of the backup distance element. In comparing the three options (1a, 1b, 1c), it is noted that the initial assumptions become progressively less conservative while the calculations require increasingly more effort. The three options will likely yield different restrictions on the setting of the element. The option choice is left to the generator owner. Option 1b offers the advantage that it allows more coverage than option 1a for little added effort, while avoiding the need for a stability study as required in option 1c. The additional effort of a stability study would more likely be used when a longer reach is required, such as when as the phase distance element provides breaker failure protection for the remote station because direct transfer trip is not used.

In option 1a, the generator step-up (GSU) low-voltage (LV) bus voltage is specified as 0.95 pu, the generator real power is specified as 100% of the gross MW capability, and the generator reactive power as 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor. A simple calculation of impedance (including a margin of 15%) is carried out as shown in Figure 5a.

In option 1b, the GSU high-voltage (HV) bus voltage is specified as 0.85 pu and the generator real and reactive power have the same specifications as option 1a. An iterative calculation is carried out to determine the GSU LV voltage as shown in Figure 5a.

Impedance can then be calculated using a margin of 15%. Note that, the example of option 1b in Figure 5a typically yields a higher value for impedance than option 1a.

$PF := 0.8$	Generator rated power factor
$S := (1 + j1.5) * PF$	Specified generator power output
Option 1a	
$V1a_{LV} := 0.95$	Specified GSU Low-side voltage
$I1a := \dfrac{\bar{S}}{V1a_{LV}} = 0.842 - j1.263$	
$Z1a := \dfrac{V1a_{LV}}{1.15 * I1a}$	
$\lvert Z1a \rvert \coloneqq 0.544$	Option 1a apparent impedance
$ang(Z1a) \coloneqq 56.31^{o}$	
Option 1b	
$V_{HV} := 0.85$	Specified GSU high-side voltage
$Z_T := 0.005 + j0.1$	GSU rated impedance
Initial Guess	
$V_{LV} := V1a_{LV}$	First approximation for the GSU low-side voltage and current equal to the option 1a values
$I := I1a$	
Given	Find a solution to the following equations
$S := V_{LV} * \bar{I}$	
$H_{HV} := V_{LV} - I * Z_T$	
$\begin{pmatrix} V1b_{LV} \\ I1b \end{pmatrix} := Find(V_{LV}, I) = \begin{pmatrix} 0.970 + j0.087 \\ 0.928 - j1.154 \end{pmatrix}$	
$Z1b := \dfrac{V1b_{LV}}{1.15 * I1b}$	
$\lvert Z1b \rvert \coloneqq 0.572$	Option 1b apparent impedance
$ang(Z1b) \coloneqq 56.31^{o}$	

Figure 5a – Mathcad printout of the example calculations for options 1a and 1b

In option 1c, a transient stability simulation is performed lowering the GSU HV bus voltage to 0.85 pu by connecting a shunt reactor. The generator real power has the same specifications as option 1a and the generator reactive power and corresponding GSU LV voltage are determined by simulation. The voltage value obtained from the simulation is the simulated voltage coincident with the highest reactive power achieved during field-forcing. Thus, the generator controls are modeled to include field-forcing. It is not necessary to model the excitation system overexcitation limiter (OEL) because the level of field-forcing observed in these simulations would not result in the OEL acting prior to operation of the phase distance element. As noted in Clause 2.6, the limiter is typically set up to match the machine's field winding thermal capability and for cylindrical (round) rotor machines, the short term thermal overload rating permits 209 percent field current for 10 seconds. The simulation results are used to calculate impedance using a margin of 15%.

Figure 5b documents the response of the generator. The plot contains the GSU LV bus voltage, the GSU HV bus voltage, and the real and reactive power measured at the generator terminals. The transmission system voltage, plotted in dark blue, initially drops to 0.85 per unit and then recovers to 0.923 per unit as the generator reactive power output is increased.

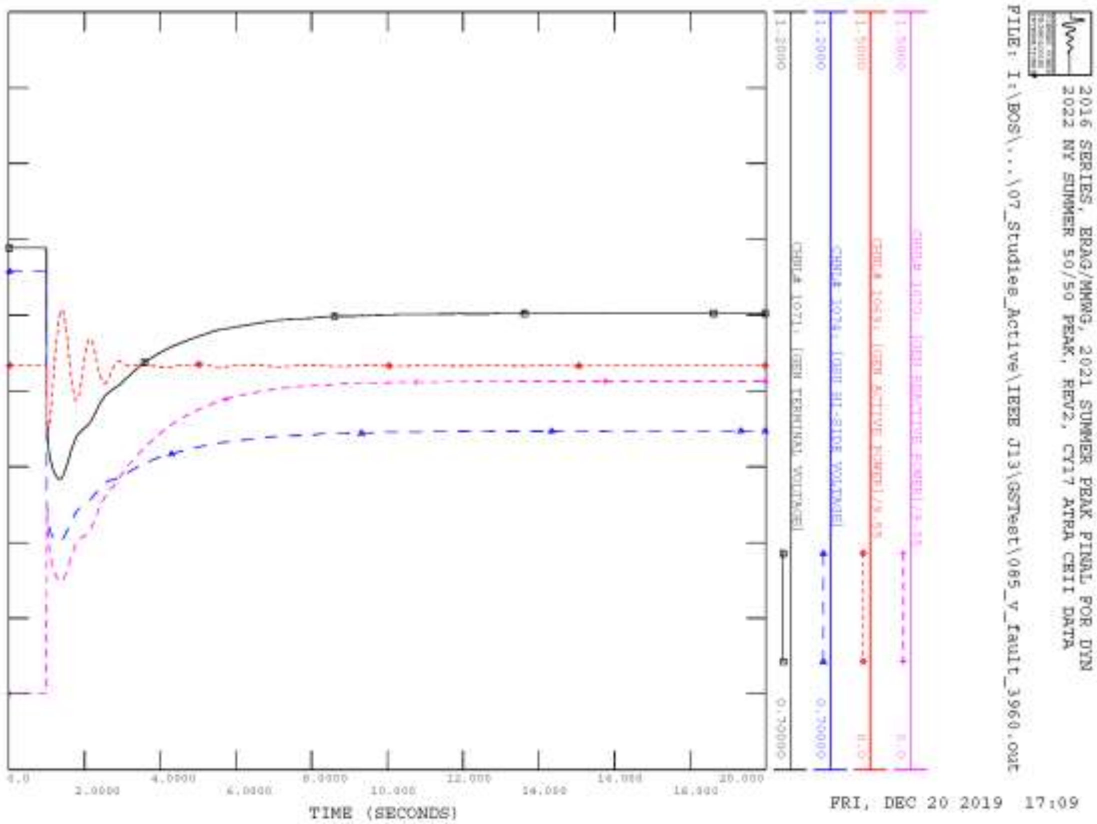


Figure 5b – Option 1c Example Transient Stability Simulation

The output data from the simulation was reviewed to determine the time of the highest reactive power output from the generator. The generator output reaches maximum reactive power after approximately 10 seconds. The relevant quantities observed from the simulation are as follows:

$P_{electrical}$ = 0.800 per unit

$Q_{electrical}$ = 0.767 per unit

$E_{terminal}$ = 1.000 per unit

From these quantities, the relay setting requirement, including a 15 percent margin, is calculated. For the generator in this example, the reactive power is lower than the conservative value defined for options 1a and 1b. As a result, a higher allowable impedance is determined.

$$I_{1c} = \frac{S^*}{V} = \frac{0.800 - j0.767}{1.000} = 1.108 \angle -43.79°$$

$$Z_{1c} = \frac{V}{1.15 * I_{1c}} = \frac{1.000 \angle 0°}{1.15 * 1.108 \angle -43.79°} = 0.785 \angle 43.79 °$$

Figure 5a presents two example calculations for options 1a and 1b. Figure 5b presents an example related to option 1c. The Application Guidelines section of PRC-025 includes additional examples for all compliance options.

1.5 Characteristics of governor control systems and relationship with generator frequency relays (81)

The primary function of a generator governor is to regulate mechanical input to control the speed at which the prime mover operates. When a sudden change in loading or system conditions occurs, the governor reacts to limit the resulting change in speed of the generator and therefore in the frequency of the system. For synchronous generators, the speed of the prime mover (defined in revolutions per minute) is directly related to the operating frequency. For this reason, governor operation must be considered when evaluating frequency protection for a generator.

Generator overfrequency conditions can occur when the loss of a major load or transmission system disturbance results in excess of generation. The generator governor can quickly address the overfrequency condition by reducing the power output to the prime mover, thereby decreasing the frequency to a safe level. For most synchronous generators, overfrequency protection is provided primarily by the governor. Commonly, an overfrequency relay is used to signal an alarm to alert the operator in the event the governor fails to adequately address the overfrequency condition. In protection schemes where an overfrequency relay is used to trip the generator, the trip setpoints should be properly coordinated with the governor operation to ensure the governor has enough time to react to an overfrequency condition before a trip is initiated.

Generator underfrequency conditions can occur when an increase in loading or loss of generation results in a generation deficiency. The initial response to an underfrequency condition is to achieve a coordinated operation of the speed governors. When the generation deficiency exceeds the ability of spinning reserve to restore system frequency to an adequate level, system load shedding is utilized as a last-resort effort. Some synchronous generators employ underfrequency relays set near the machine capability limits to trip the units in the event of major frequency excursions. Since tripping additional generators during a major disturbance will decrease system frequency further, it is important that the generator underfrequency protection is coordinated with both the generating unit capability and the system underfrequency relaying.

2. Synchronous Generator Operating Limits

Synchronous generator operation is constrained by a number of limiting factors. Excitation systems are designed to keep the operating point of the generator within these limits. This section will discuss the limits that apply to synchronous generation operation and the limiters that are implemented in excitation systems.

2.1 Synchronous Generator Capability Curve

Safe operation of a synchronous generator depends upon keeping the real and reactive power output of the machine within the capability limits provided by the generator manufacturer. These limits include armature and field winding heating limits, armature core heating, armature core end region heating limit during leading power factor operation, and steady-state stability limits. Limits are also placed on the generator by the prime mover and the excitation system.

2.1.1 Armature Winding Heating Limits

The armature winding is typically located on the stationary portion of the generator known as the stator. Limits associated with these windings are sometimes known as stator heating or stator current limits. Heating limits for the armature winding are a function of the magnitude of the current flowing in the winding along with the winding AC resistance. The power loss associated with armature current flow, also known as $I_a^2R_a$ loss, causes a temperature rise in the windings. The armature heating limit is based on the allowable operating temperature of the insulation system along with the cooling system used. These various factors result in a maximum allowable current rating for the armature winding. When plotted on the complex power plane, also known as the P-Q plane, the armature heating limit for a synchronous machine is proportional to the magnitude of the terminal voltage but independent of the phase relationship between the voltage and the current. This limit is shown as a semicircle on the P-Q plane indicated as the “Armature Winding Heating Limitation” on the capability curve shown in Figure 6.

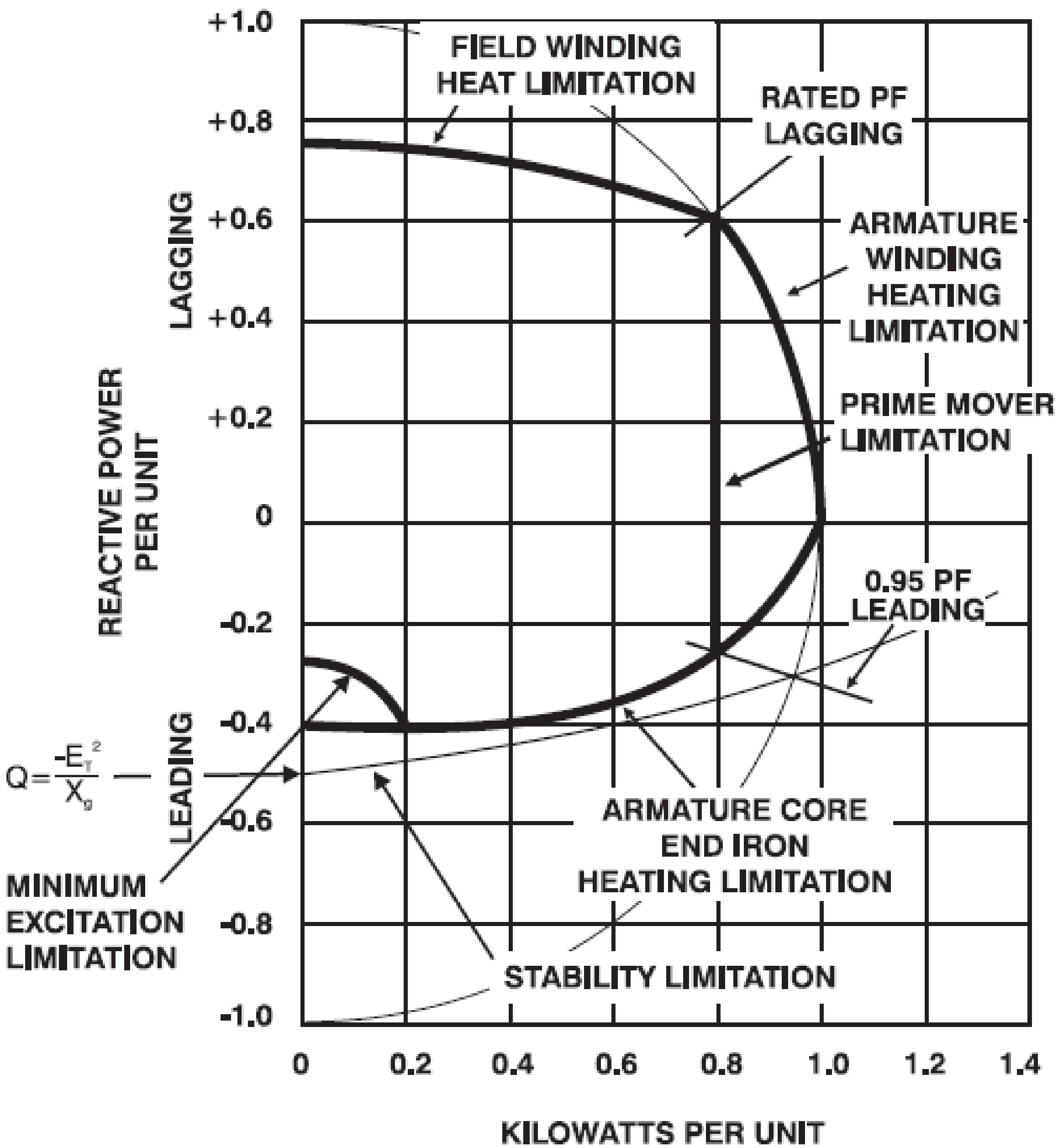


Figure 6 – Capability Curve of a Synchronous Generator

As terminal voltage increases or decreases, the armature winding heating limit increases or decreases in proportion to the terminal voltage.

2.1.2 Field Winding Heating Limits

The field winding is typically located on the rotating portion of the generator known as the rotor. Limits associated with this winding are sometimes known as rotor heating limits. Heating limits for the field winding are a function of the magnitude of the current flowing in the winding along with the winding resistance. The power loss associated with field current flow, also known as $I_{FD}^2R_{FD}$ loss, causes a temperature rise in the windings. The field heating limit is based on the allowable operating temperature of the insulation system along with the cooling system used. These various factors result in a maximum allowable current rating for the field winding. When plotted on the P-Q plane, the field heating limit for a synchronous machine is inversely related to the magnitude of the terminal voltage and is dependent on the phase relationship between the voltage and the current. This limit is shown as an arc on the P-Q plane in the overexcited or "lagging" power factor region of the graph and is indicated as the "Field Winding Heating Limitation" on the capability curve shown in Figure 6.

2.1.3 End Iron Heating Limit

There is an additional limit imposed by the end iron region of the stator core which is most prevalent on round rotor machines. This is due to flux produced by the end turns of the rotor winding crossing the air gap and entering perpendicular to the stator core laminations. This causes eddy currents to flow in the laminations and causes significant heating. Also, at leading power factor, the stator leakage flux adds with the rotor end turn leakage flux to produce larger eddy currents and hence increasing heating of the end iron region. This limits operation in the underexcited or "leading" power factor region and is indicated as the "Armature Core End Iron Heating Limitation" on the capability curve shown in Figure 6.

2.1.4 Steady-State Stability Limits

Operation in the extreme underexcited region is limited to ensure the machine remains in synchronism with the grid. During underexcited operation, the synchronizing power coefficient or strength of a generator is lower, requiring a higher load angle to produce the same power compared to overexcited operation. This limit is a function of the operating mode of the excitation system, internal impedance of the machine, and system impedance If the excitation system is operating in Manual Mode, with a constant fixed excitation current, then this limit is indicated as the manual steady-state stability limit (shown as "stability limitation" in Figure 6). If the excitation system is operating in Automatic Mode, then the AVR will allow more margin for this stability limit.

2.1.5 Minimum Excitation Limits

Some machines utilize excitation systems that cannot decrease the field current to zero. This also limits operation in the underexcited region to the area outside of a circle, centered at

$$Q = -{E_T}^2/X_g$$

and is indicated as the “Minimum Excitation Limitation” on the capability curve shown in Figure 6.

2.1.6 Prime Mover Limits

The prime mover provides the mechanical power input to the synchronous generator. The limitation due to the prime mover on the machine’s capability curve appears as a vertical line at a constant real power level and is indicated as the “Prime Mover Limitation” on the capability curve shown in Figure 6.

2.2 Capability Curve Dependency on Voltage

Many of the limits described above are a function of terminal voltage. The Armature Winding Heating Limitation is a function of the magnitude of armature current. This is plotted on the P-Q plane as a constant Volt-Ampere (VA) circle. If terminal voltage decreases, then the constant VA circle decreases proportionally. This can be seen for a 2500 kVA, 13.8 kV generator as changes in the machine’s capability on the real power axis for 100%, 95% and 90% of rated terminal voltage in Figure 7.

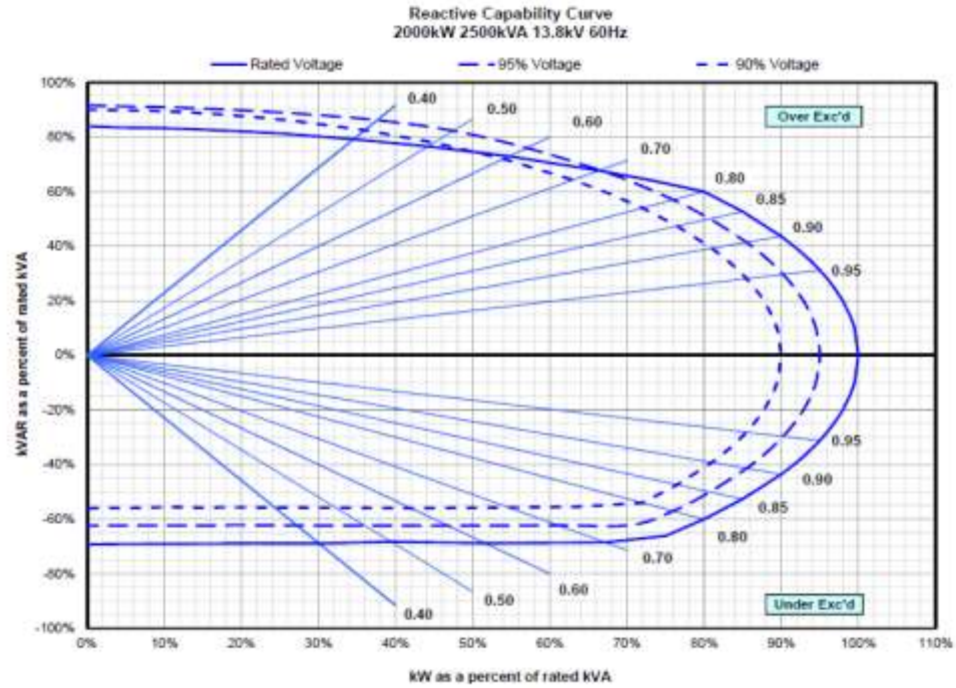


Figure 7 – Capability Curve as a Function of Voltage

Some manufacturers plot the machine's capability curve with the axes swapped, where the vertical axis is active power and the horizontal axis is reactive power as seen in Figure 8. Note the overexcited region is to the right and labeled as "Reactive Power Supplied." The dependency on terminal voltage can be seen for this generator for 1.05, 1.00 and 0.95 per unit (pu) voltage. Note that the apparent power base for this machine was adjusted to 1.0 pu at 0.95 pu voltage on this particular capability curve.

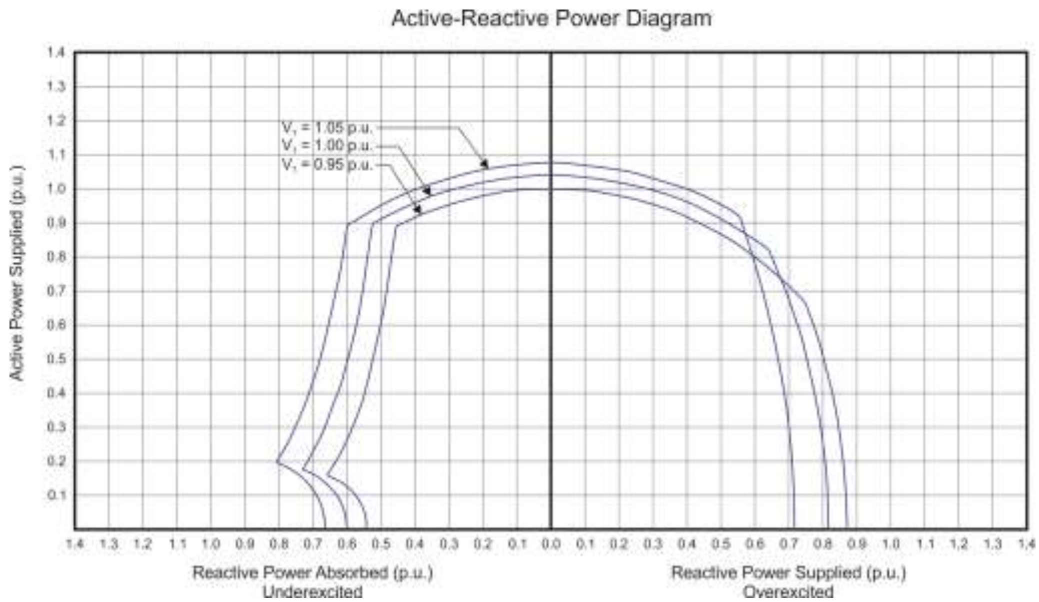


Figure 8 – Capability Curve as a Function of Voltage with Axes Swapped

The rotor winding heating limitation increases as terminal voltage decreases as can be seen in Figures 7 and 8. This change is not as straightforward as the armature winding heating limitation. The relationship between terminal voltage and the machine's capability on the positive Q-axis does not directly follow the terminal voltage for the machine described in Figure 7. The 100% rated voltage curve is the most limiting on the positive Q-axis where the 90% and 95% curves are nearly the same. The machine described in Figure 8 shows a more predictable limit as a function of terminal voltage.

Operation in the underexcited region is limited by a number of factors: steady-state stability SSSL and, in some cases, end iron heating and the limits associated with the excitation system. The dependency on terminal voltage can be quite complex. The steady-state stability limit.is defined by the following expressions:

$$Q_{Center} = \frac{V_T^2}{2}\left[\frac{1}{X_e} - \frac{1}{X_d}\right]$$

Where:

V_T – Terminal Voltage

X_e – External Reactance from Machine Terminal to Infinite Bus

X_d – Direct Axis Synchronous Reactance of the Machine

The radius of this arc is greater than the offset of the center and appears in the underexcited region. The radius is given by:

$$Radius = \frac{V_T^2}{2}\left[\frac{1}{X_e} + \frac{1}{X_d}\right]$$

The SSSL is purely a function of the transfer impedance. It will move on the PQ plane by the square of the terminal voltage which is evident in the two equations. The SSSL is proportional to the square of the terminal voltage on the PQ plane. The end iron heating limitation is also dependent on voltage, moving outward with lower terminal voltage and inward with higher terminal voltage. *[Add reference to paper by Finney, et al.]*

Figure 8 also shows the effects of the excitation system. The semicircular feature of the capability curve in the extreme leading power factor portion of the graph is due to the minimum excitation limitation. The radius of this semicircle is a function of terminal voltage, but the offset from the origin of its center is a function of terminal voltage squared.

2.3 Capability Curve Dependency on Cooling Air Temperature

Machines that are air-cooled have a capability curve that changes as a function of the cooling air temperature. In general, as cooling air temperature increases, the thermal limits will decrease; i.e., armature winding, field winding and armature core heating limits. The prime mover limit may also be reduced with air temperature for a combustion turbine due to the effect on air density and compressor pressure. The steady-state stability limit and minimum excitation limit are not functions of winding or core temperature and remain unchanged. These dependencies can be seen in Figure 9 with the exception of the limitation due to armature core end iron heating. This particular machine does not exhibit changes in the end iron heating limit

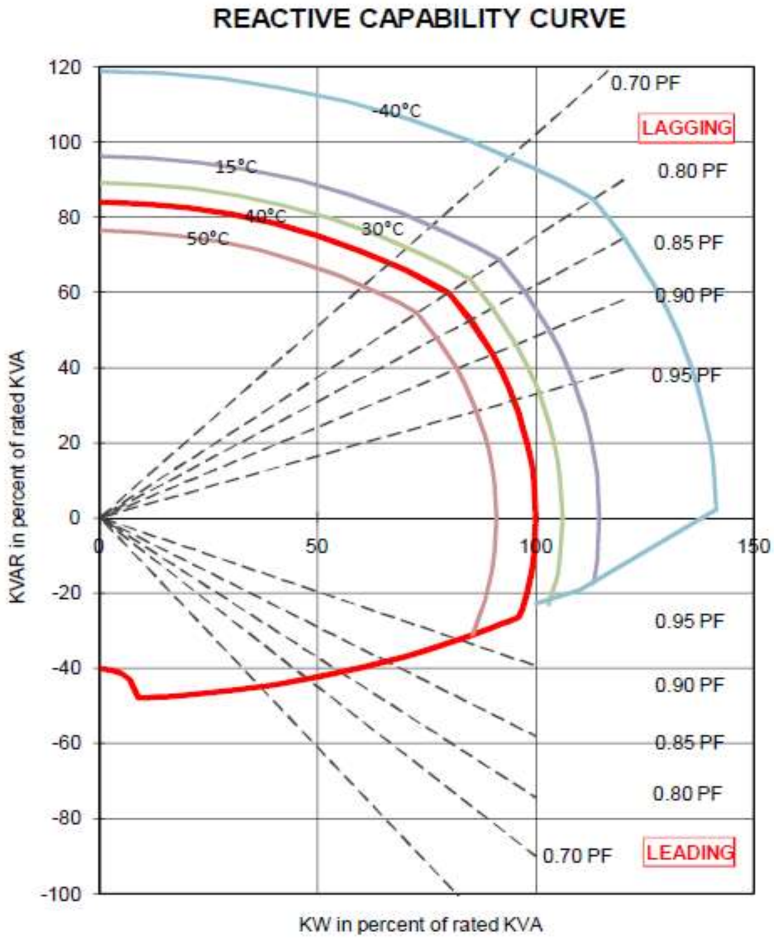


Figure 9 – Capability Curve as a Function of Cooling Air

2.4 Capability Curve Dependency on Hydrogen Pressure

Hydrogen-cooled machines have a capability curve that changes as a function of the hydrogen pressure. Since hydrogen is used as the cooling medium, a reduction in hydrogen pressure relates to a reduction in the machine's ability to cool itself. In general, as hydrogen pressure decreases, the thermal limits will decrease; i.e., armature winding, field winding and armature core heating limits. The steady-state stability limit is not a function of winding or core temperature and remains unchanged. This can be seen in Figure 10.

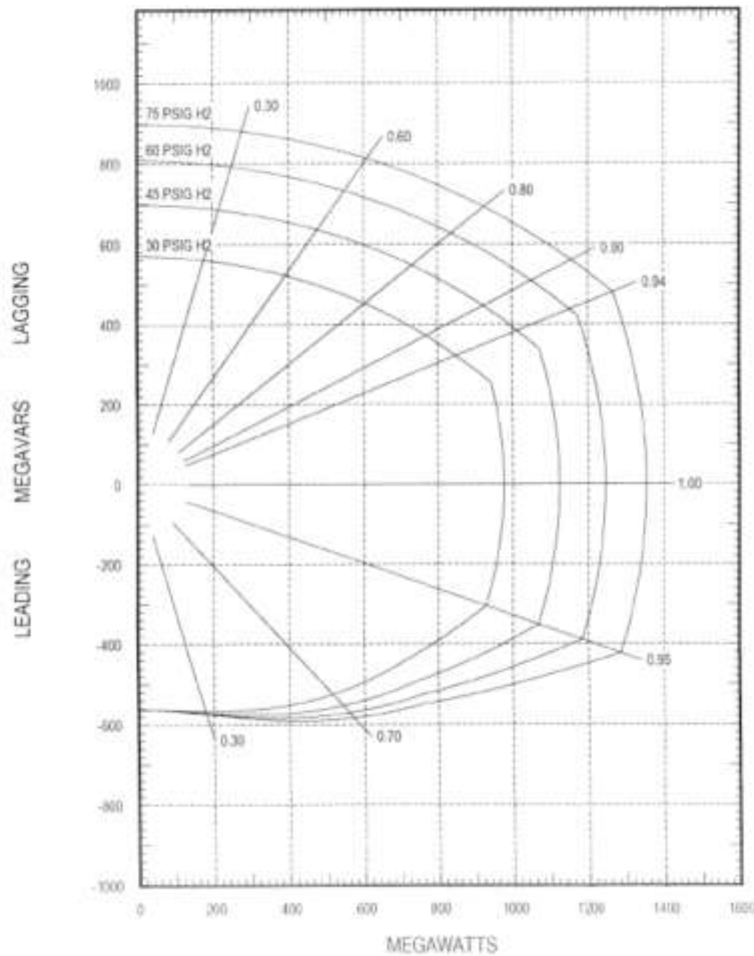


Figure 10 – Capability Curve as a Function of Hydrogen Pressure

2.5 Excitation Limiters

Excitation systems implement supplemental control functions that can limit operation of the machine to within the allowable operating region of the synchronous generator. These supplemental control functions are known as “limiters” and interface to the excitation system in multiple ways. Figure 11 shows a block diagram of an excitation system along with a rotary excited synchronous generator.

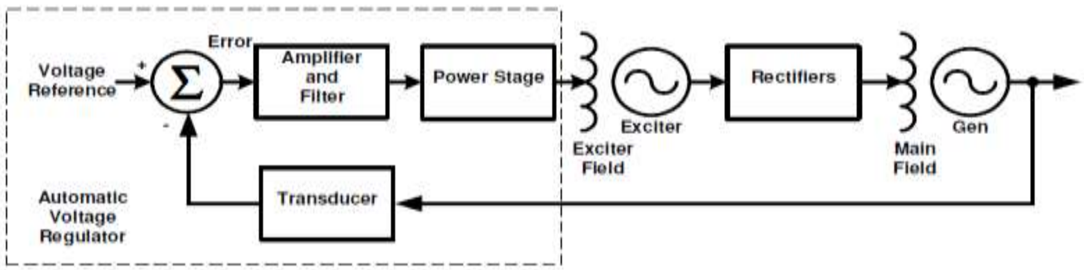


Figure 11 – Excitation System Block Diagram

The excitation system encompasses all of the elements shown in Figure 11 but excludes the generator and main field winding. The excitation system includes the Automatic Voltage Regulator (AVR) shown within the dashed lines in Figure 11, along with an AC rotary exciter and rectifiers. The AVR includes a transducer to convert the generator's terminal voltage to a signal compatible with the low-level electronics implemented in the AVR. Also, a voltage reference is compared at the summing point (the circle enclosing the Σ) to the signal proportional to the terminal voltage. The output of this summing point is an "error" signal, which is proportional to the difference between the reference and the terminal voltage signal. The error signal is amplified and filtered before it is converted to appropriate voltage/current by the power stage to excite the field of the rotary exciter.

There are two methods by which limiters can interface with the AVR. The first adds a signal to the summing point within the AVR to bias the reference. In this method, the main loop of the AVR is functional when the limiter is active. This can be seen in Figure 12.

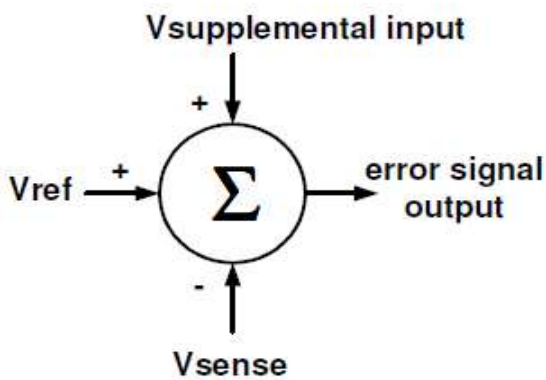


Figure 12 – Summing Point Interface

The second method utilizes High Value (HV) or Low Value (LV) gates as seen Figure 13.

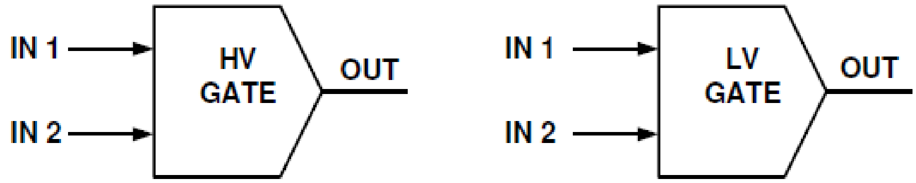


Figure 13 – High Value and Low Value Gates

In the HV (LV) gate, the higher (lower) of the two inputs, IN1 or IN2 is connected to the output of the gate. These blocks are used in a "takeover" style limiter. As the name implies, this method allows the limiter to take over control from the AVR. In this method, the main loop of the AVR is bypassed when the limiter is active.

Supplemental control functions, either summing point or takeover style can interface with the excitation system at multiple points. These functions include Overexcitation Limiters (OEL), Underexcitation Limiters (UEL), Stator Current Limiters (SCL) and Power System Stabilizers (PSS). This can be seen in Figure 14 along with signals associated with the Reference (V_{ref}) and Terminal Voltage Sensing (V_{sense}).

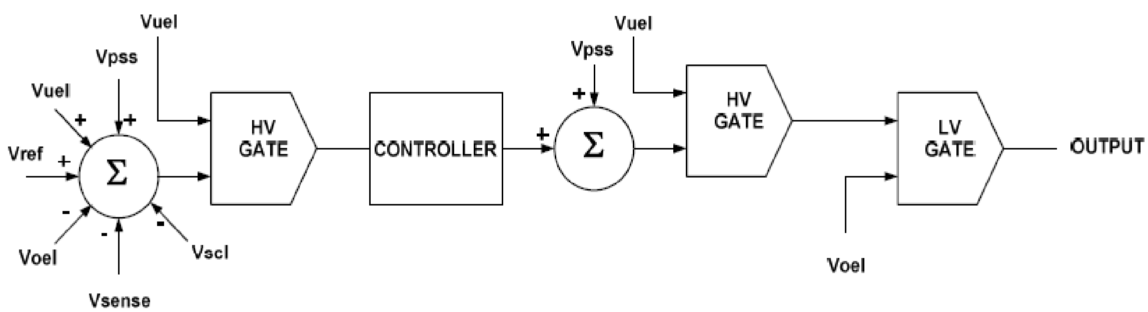


Figure 14 – Various Interface Points for Takeover Style Limiters

2.6 Overexcitation Limiters

Overexcitation limiters are supplemental controls used to prevent excitation levels from exceeding the machine's capability. There are many types of overexcitation limiters. Most of them operate by measuring field current and detecting when field current exceeds a setpoint. There may be two setpoints, an instantaneous and a timed setpoint. If field current is greater than the instantaneous setpoint, the limiter reduces field current with no intentional delay. If field current is less than instantaneous setpoint but still above the timed setpoint, the limiter allows the overexcitation condition to exist for a prescribed amount of time, then it reduces excitation to safe levels. The setpoint may be a function of time and cooling medium temperature or pressure. Models for excitation systems and their supplemental control functions can be found in IEEE Std 421.5™-

2016, IEEE Recommended Practice for Excitation System Models for Power System Stability Studies [2]. OEL models for overexcitation limiters were developed by members of the IEEE/PES Excitation Systems and Controls Subcommittee. One of these, OEL1B, was developed as a flow chart and is repeated in Figure 15.

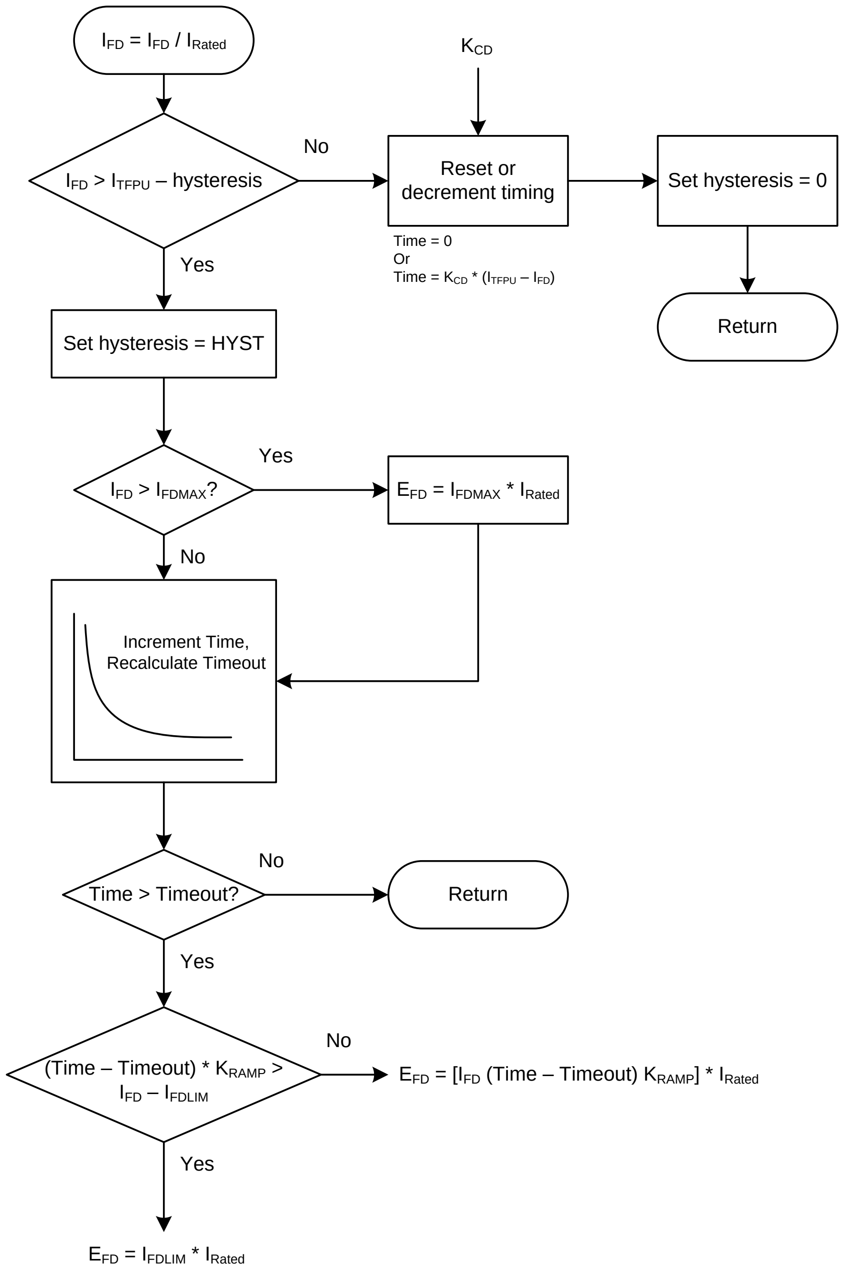


Figure 15 – IEEE Std 421.5™-2016 Overexcitation Limiter Model [2]

Where:

E_{FD} – Main field voltage
I_{FD} – Main field current

I_{Rated} – Field current required by the generator to produce rated output power at rated power factor
I_{TFPU} – Timed-limit pickup – typically 105% of I_{Rated}
I_{FDMAX} – Instantaneous field current limit – typically 150% of I_{Rated}
I_{FDLIM} – Timed field current limit – typically equal to or slightly above the I_{TFPU} value
K_{CD} – Cool down time constant
K_{RAMP} – Time constant associated with ramp down of field current

There are many other more traditional Laplace Transform based s-domain models of overexcitation limiters included in IEEE Std 421.5™-2016.

The limiter is typically set up to match the machine's field winding thermal capability. This is defined for cylindrical (round) rotor machines in IEEE Std. C50.13™-2014 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above [3]. The short term thermal overload ratings are as follows:

% of Rated Field Current	Time
209	**10 s**
146	**30 s**
125	**60 s**
113	**120 s**

2.7 Stator (Armature) Current Limiters

Stator Current Limiters (SCL), also known as armature current limiters, are used to limit armature current to within the machine's capability by affecting excitation. The correct control action for an SCL depends on the power factor of the machine. This can be seen by examining the "V-curves" associated with a synchronous generator tied to the grid as seen in Figure 16.

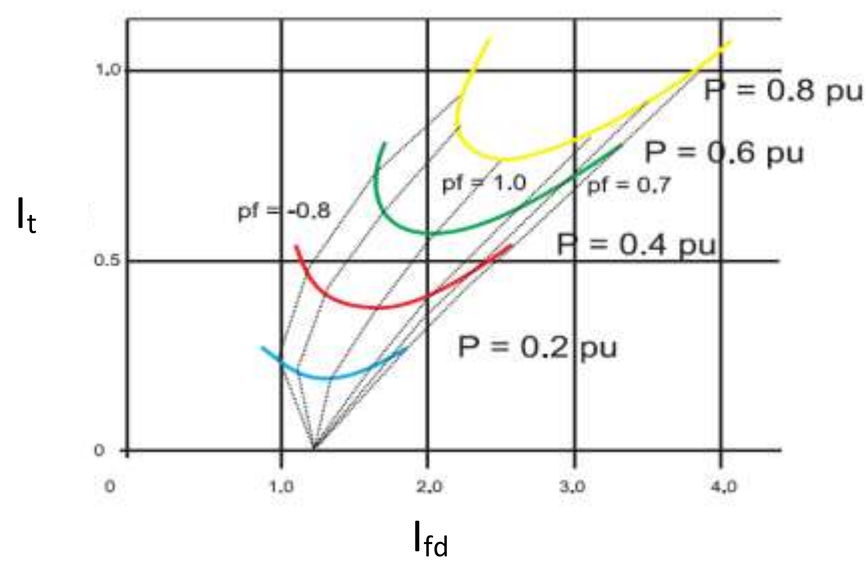


Figure 16 – Synchronous Generator V-Curves

A V-Curve is a plot of armature (stator or terminal) current versus field current. It can be seen from Figure 16 that there are two levels of excitation that result in armature current equal to 1.0 pu, when the machine is generating 0.8 per unit real power. In this example, armature current equals 1.0 pu in the underexcited region at a field current of about 2.3 pu. In the overexcited region, this occurs at a field current of about 3.8 pu. Note: the definition of 1 pu field current for this graph is the field current required to produce rated terminal voltage on the air-gap line. This is significantly less than the "rated" field current of the machine.

As can be seen in Figure 16, the proper control action to reduce armature current is dependent on the operating power factor of the machine.

When the machine is exporting reactive power (vars), it is operating in the "lagging" power factor mode and is "overexcited." The proper control action to limit armature current in this mode is to reduce excitation when the limit is reached.

On the other hand, if the machine is importing vars, operating in the "leading" power factor mode, then it is "underexcited." The proper control action in this mode of operation is to increase excitation to reduce armature current.

2.8 Stator Current Limiter Types

Many types of SCLs exist. Most contain the following features: measure stator current and power factor, detect when stator current exceeds a setpoint, if power factor is lagging, reduce field current, if power factor is leading, increase field current. The setpoint may be a function of time and cooling medium temperature or pressure. Like the field current limiter, the stator current limiter is typically set up to match the machine's armature winding thermal capability. This is also defined for cylindrical rotor machines in IEEE Std. C50.13. The short term thermal overload ratings are as follows:

% of Rated Stator Current	Time
218	**10 s**
150	**30 s**
127	**60 s**
115	**120 s**

Note: Stator current can be measured directly by the AVR and is typically accomplished using internal current transformers that derive their input from the generator's CTs. The AVR measures stator voltage from the generator's VTs and uses both measurements to calculate the power factor. This is accomplished numerous ways depending on the specific AVR design.

2.9 Underexcitation Limiters

Underexcitation limiters are supplemental controls used to prevent operation in the underexcited mode from exceeding the machine's capability. The IEEE has condensed the many types of underexcitation limiters into two basic types. Most operate by measuring terminal voltage and current, then calculate the real and imaginary components of complex power and compare the complex power operating point to an Underexcitation Limiter (UEL) characteristic. If the operating point is outside the UEL characteristic, then the control action is to increase field current to bring back operation within the allowable region of the machine's capability curve. The UEL characteristic may be a function of time and cooling medium temperature or pressure. Models for UELs can be found in IEEE Std 421.5™-2016. The first type of UEL model, known as UEL-1, is shown in Figure 17.

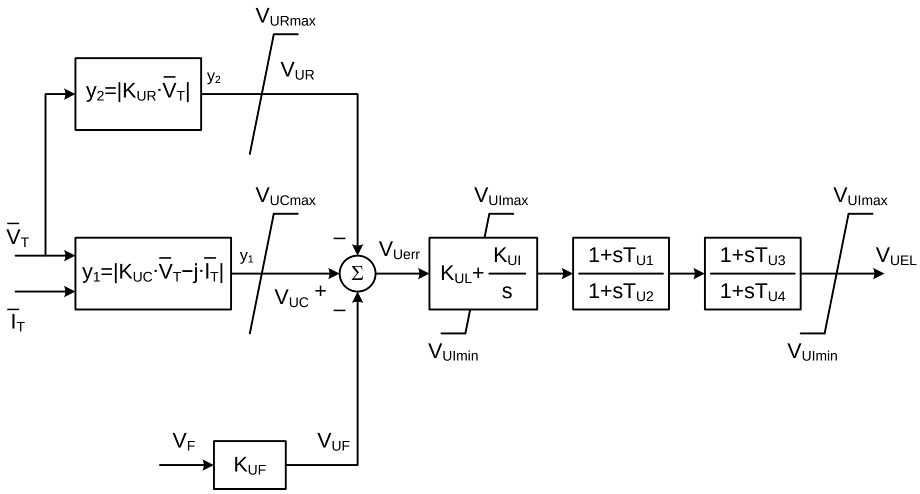


Figure 17 – IEEE Std 421.5™-2016 Type UEL-1 Model for Circular Characteristic UELs [2]

Where:

K_{UR} – Radius of UEL Characteristic
K_{UC} – Center of UEL Characteristic
K_{UL} and K_{UI} – Proportional and Integral Gains
K_{UF} – Stabilizing signal gain
T_{U1} – T_{U4} – Time constants of lead-lag block
V_F – Excitation System Stabilizing Signal from AVR
V_{Uerr} – If positive, then Limiter is active
V_{UR} -UEL radius phasor magnitude
V_{UC} - UEL center plus operating point phasor magnitude

The parameters and operation of this model are explained in Figure 18.

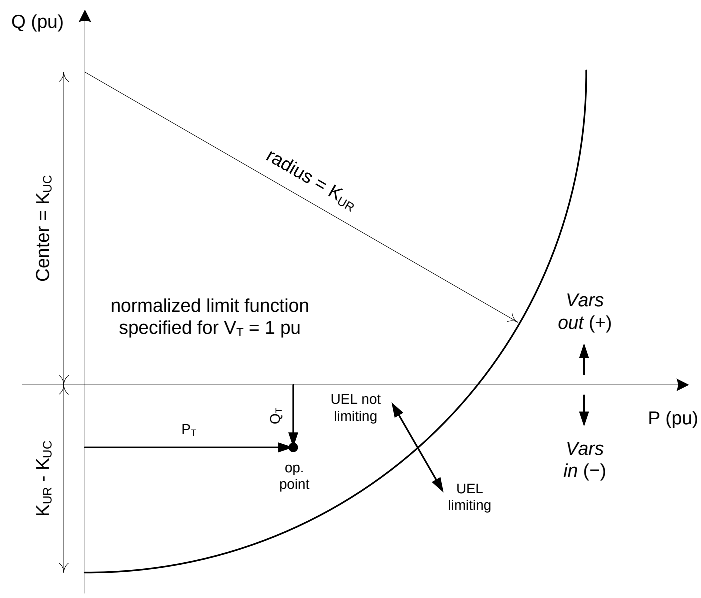


Figure 18 – IEEE Std 421.5™-2016 Type UEL-1 Circular Limiting Characteristics [2]

Since the UEL-1 model derives the operating point using I_T and compares it with a radius and center proportional to V_T, this model essentially represents a UEL that utilizes a circular apparent impedance characteristic as its limit.

The UEL boundaries in terms of P and Q vary with V_T^2 as does the steady-state stability limit. The second type of UEL model, known as UEL-2C, is shown in Figure 19.

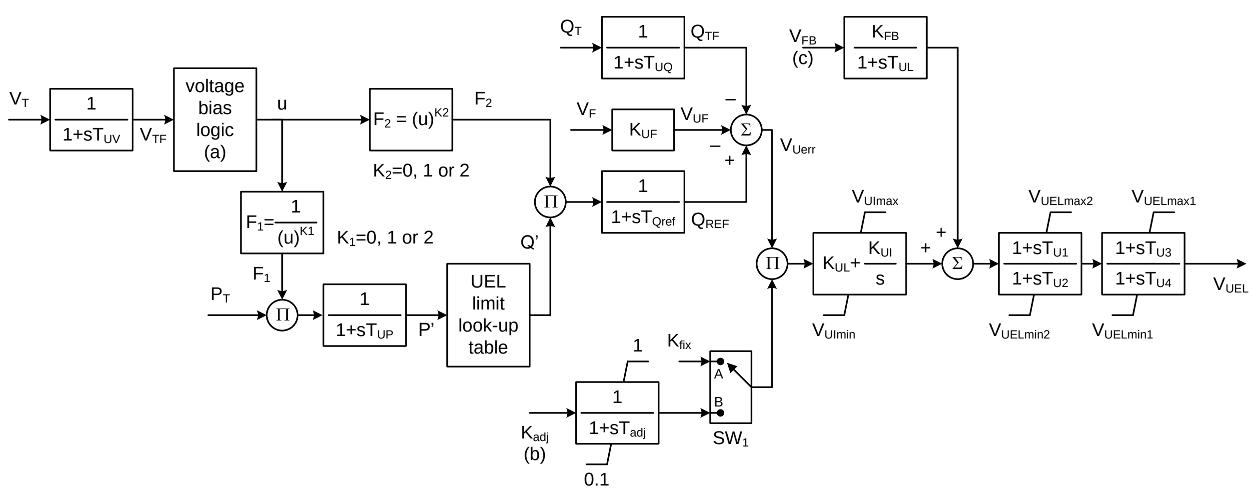


Figure 19 – IEEE Std 421.5™-2016 Type UEL-2C Model for Straight Line or Multi-Segment UELs [2]

Where:

- Q_T – Generator reactive power, vars
- P_T – Generator real power, Watts
- V_F – Excitation system stabilizing signal from AVR
- V_T – Terminal voltage
- V_{FB} – Feedback signal used for non-windup integrator function
- K_{FB} – Feedback signal gain constant
- T_{UL} – Feedback signal filter time constant
- T_{U1} – T_{U4} - Lag/Lead time constants
- T_{UP} , T_{UQ} and T_{UV} – Filter time constants for watts, vars and voltage inputs
- K_1, K_2 – Voltage dependency exponent constants
- K_{UF} – Multiplier for field voltage influence
- K_{UL} and K_{UI} – Proportional and Integral gains
- See IEEE Std 421.5™-2016 for additional details

The straight line characteristic can be seen in Figure 20

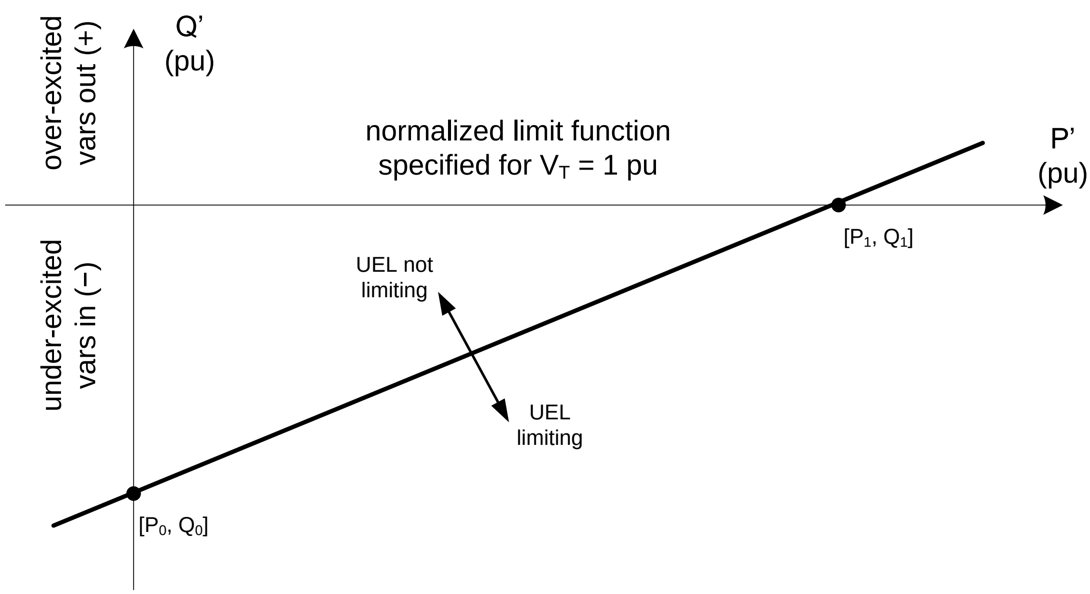


Figure 20 – IEEE Std 421.5™-2016 Type UEL-2 Straight-Line Normalized Limiting Characteristic [2]

The multi-segment limiting characteristic, utilizing 6 segments, can be seen in Figure 21

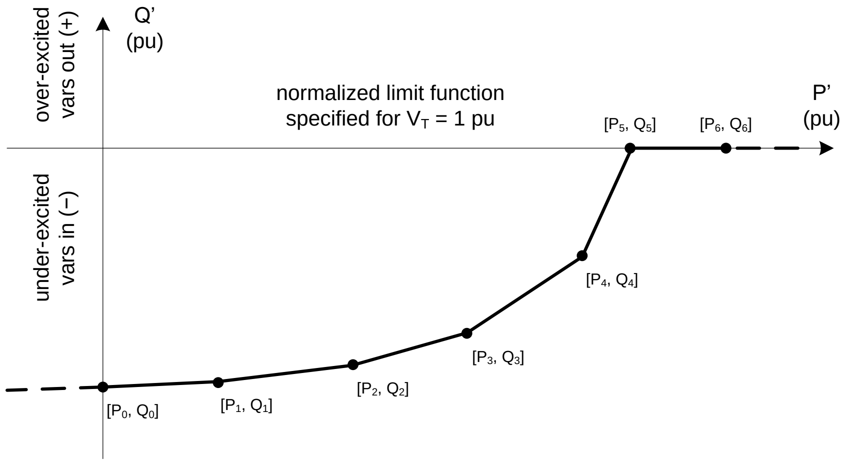


Figure 21 – IEEE Std 421.5™-2016 Type UEL-2 Multi-Segment Normalized Limiting Characteristic [2]

The UEL-2 model uses parameters K_1 and K_2 to represent voltage dependency as follows:

- K_1 and K_2 = 0, UEL based on sensed real and reactive power
- K_1 and K_2 = 1, UEL based on sensed real and reactive current
- K_1 and K_2 = 2, UEL based on sensed real and reactive admittance (conductance and susceptance)
- K_1 and K_2 = 2 coordinates with impedance based Loss of Excitation relays
- Most use $K_1 = K_2$ but some suggest $K_1 = 0$ and $K_2 = 2$, UEL based on sensed real power and susceptance
- Older limiters use linear dependency $K_1 = 1$ or no dependency ($K_2 = 0$)
- Some manufacturers used reactive current instead of reactive power

3. Characteristics of PSS control systems and relationship with generator protective systems

Power oscillations can occur when synchronous generators are tied to the grid under specific operating conditions. Generators can participate in a low frequency power oscillation with respect to other machines on the grid when they are equipped with fast acting excitation systems. This is most likely to occur when exporting large amounts of power over relatively high impedance transmission lines.

The potential for these oscillations can limit the export of real power from the machine. Modulating excitation via a power system stabilizer can damp these oscillations. This section will discuss the basis for these oscillations and present solutions to the problem.

3.1 Steady-State Stability

After a generator is synchronized to the grid, increasing the mechanical torque input to the generator, T_M, accelerates the rotor above synchronous speed, ω_S. As the rotor speeds up, the electrical real power exported from the machine to the grid increases. The resulting armature current creates a Magneto-Motive Force (MMF), $\mathbf{F_1}$ that interacts with the MMF produced by the field winding on the rotor, $\mathbf{F_2}$. These two MMFs add to create a resultant, **R**. The angle between the rotor MMF and the resultant MMF increases. This angle, lower case delta (δ) is known by numerous names including power angle, torque angle or rotor angle as seen in Figure 22.

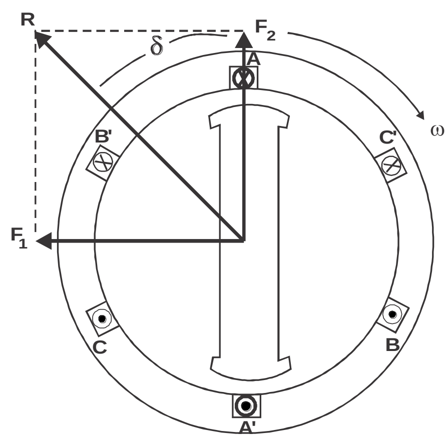


Figure 22 – Power Angle, δ

As the rotor angle increases, there is a torque produced by the generator in a direction opposite rotation, known as the “electrical torque.” The electrical torque increases and tends to slow the rotor speed. Steady-state operation is attained once an equilibrium condition is reached where the mechanical torque produced by the prime mover is equal in magnitude to the electrical torque required by the generator, as shown in Figure 23. During steady-state operation, the rotor speed equals synchronous speed; the power angle and electrical power output are constant.

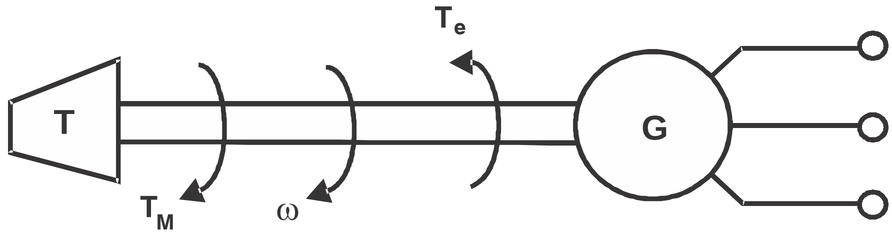


Figure 23 – Mechanical and Electrical Torque

The system can be simply modeled as a pair of voltage sources separated by impedance. This is commonly known as a Single Machine Infinite Bus (SMIB). The generator is modeled with a voltage source, E_g, behind an inductive reactance, X_g. The output voltage of the generator, E_T is increased by the generator step-up (GSU) transformer, represented by an inductive reactance, X_T, to a voltage level E_{HV} suitable for transmission to the grid over lines that are represented by an inductive reactance, X_L. The grid is represented as a voltage source, E_O. The total impedance between the machine's terminals and the grid is modeled by an external inductive reactance, X_E. This is shown schematically in Figure 24.

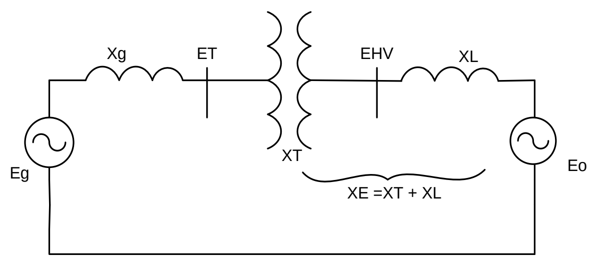


Figure 24 – Single Machine Infinite Bus Model

A phasor diagram of the SMIB representation showing the power angle, δ is shown in Figure 25.

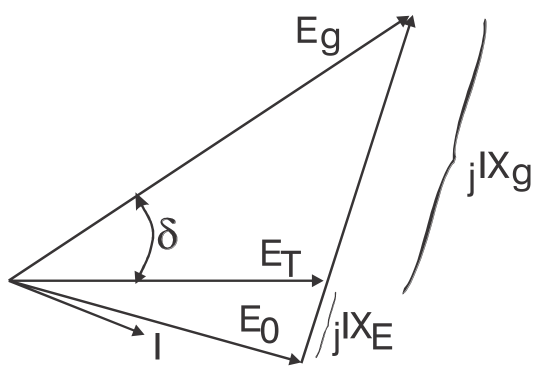


Figure 25 – Phasor Diagram of SMIB Model

The electrical power out of the generator is a function of the internal voltage, terminal voltage, internal impedance, and power angle as shown below.

$$Pe = \frac{E_g E_T}{X_g}\sin\delta$$

Where:
Pe – Electrical power output
E_g – Generator internal voltage
E_T – Terminal voltage
X_g – Generator internal reactance (steady-state)
δ – Power angle, delta

During steady-state operating conditions, the mechanical power from the prime mover, P_M, is equal to the electrical power exported from the generator, P_E (neglecting losses), and the power angle is constant at the steady-state operating point as shown in Figure 26.

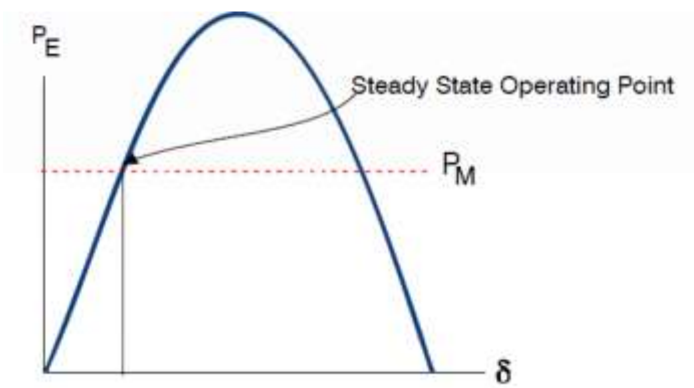


Figure 26 – Steady-State Operating Point on Electrical Power Curve

Oscillations in the rotor speed are typical when changing load levels. The rotor angle increases and decreases around the new operating power due to a change in the load level. Damping of these oscillations is partially provided by the amortisseur windings (damper bars). The amortisseur windings apply a damping torque that opposes a change in power angle. Steady-state operation returns after the rotor oscillations damp out.

3.2 Transient Stability

A fault on the transmission system can cause a reduction in voltage at the point of the fault. This reduction in voltage decreases the generator's ability to provide power to the load. With a reduction in electrical output power from the generator, there exists a difference between the mechanical torque and the electrical torque. This difference acts as accelerating torque causing the rotor to speed up and absorb the excess energy. The rotor spins faster than the grid and advances the rotor angle. Once the fault is cleared, the generator can again supply electrical power to the load. At this point, the rotor is spinning faster than the grid and has advanced in rotor angle. The electrical power out of the generator is now greater than the mechanical power into the generator.

This difference produces decelerating torque and the rotor slows down. The power angle advancement during the fault will cease once the area below the mechanical power line, P_M, is equal to the area above this line. This is known as the "equal area criteria" and, if it can be met, the unit will be "first swing stable." This can be seen graphically in Figure 27. However, if the area below P_M is greater than the area above P_M then the unit will go unstable and lose synchronism.

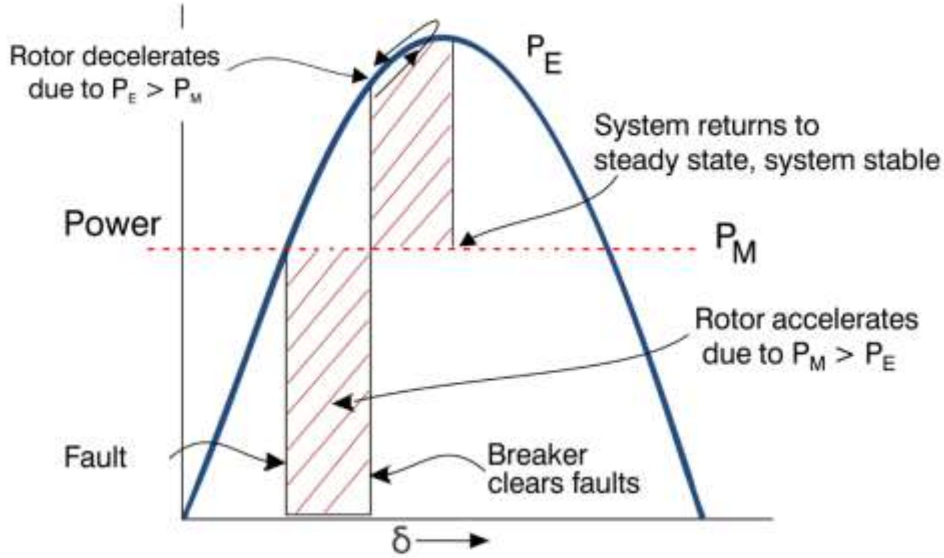


Figure 27 – First Swing Stable Fault

If the clearing of the fault is delayed, there is less time for the energy absorbed by the rotor during the fault to be transferred to the load after the fault is cleared. If the power is transferred before the power angle exceeds the intersection of the electrical power curve and the mechanical power line, beyond 90 degrees, the swing will be stable. If the power is not transferred before the power angle exceeds the intersection of the electrical power curve and the mechanical power line, then the mechanical power will exceed the electrical power, causing the rotor to reaccelerate. In this case, the angle will continue to advance, the electrical output is reduced further, and the generator will start to slip poles and operate asynchronously with respect to the grid. See illustration in Figure 28.

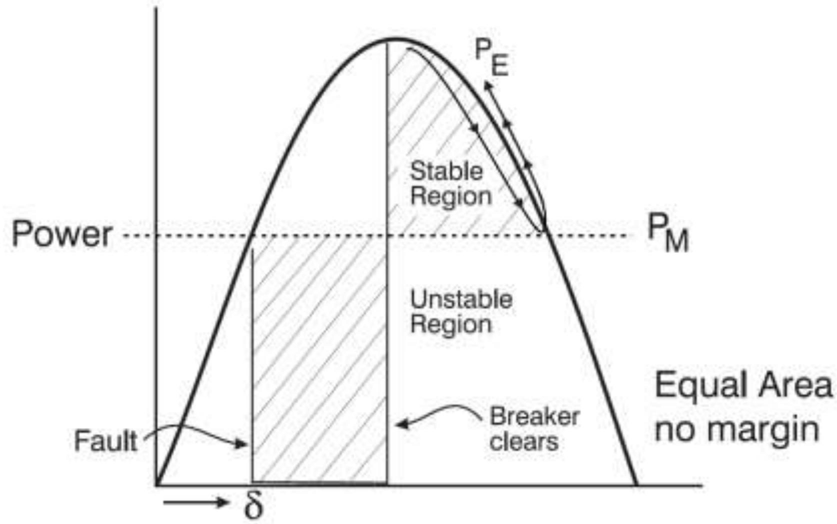


Figure 28 – Effect of Delayed Fault Clearing

3.3 Effect of the Excitation System

The excitation system can improve the generator's ability to survive the first swing after a fault. This is achieved by using a high initial response, high ceiling voltage exciter. Ceiling voltage is the maximum direct voltage that the excitation system is designed to supply from its terminals under defined conditions where high initial response is defined as an excitation system capable of attaining 95% of the difference between ceiling voltage and rated field voltage in 0.1s or less under specified conditions [4].

During the fault, the voltage regulator commands full positive ceiling from the exciter. Field current increases quickly, increasing the internal generator voltage, E_g. Increasing E_g results in a greater area above the mechanical power line, aiding in the unit's ability to survive the first swing. This can be seen in the electrical power equation and graphically comparing curves A and B in Figure 29.

$$Pe = \frac{E_g E_T}{X_g} \sin \delta$$

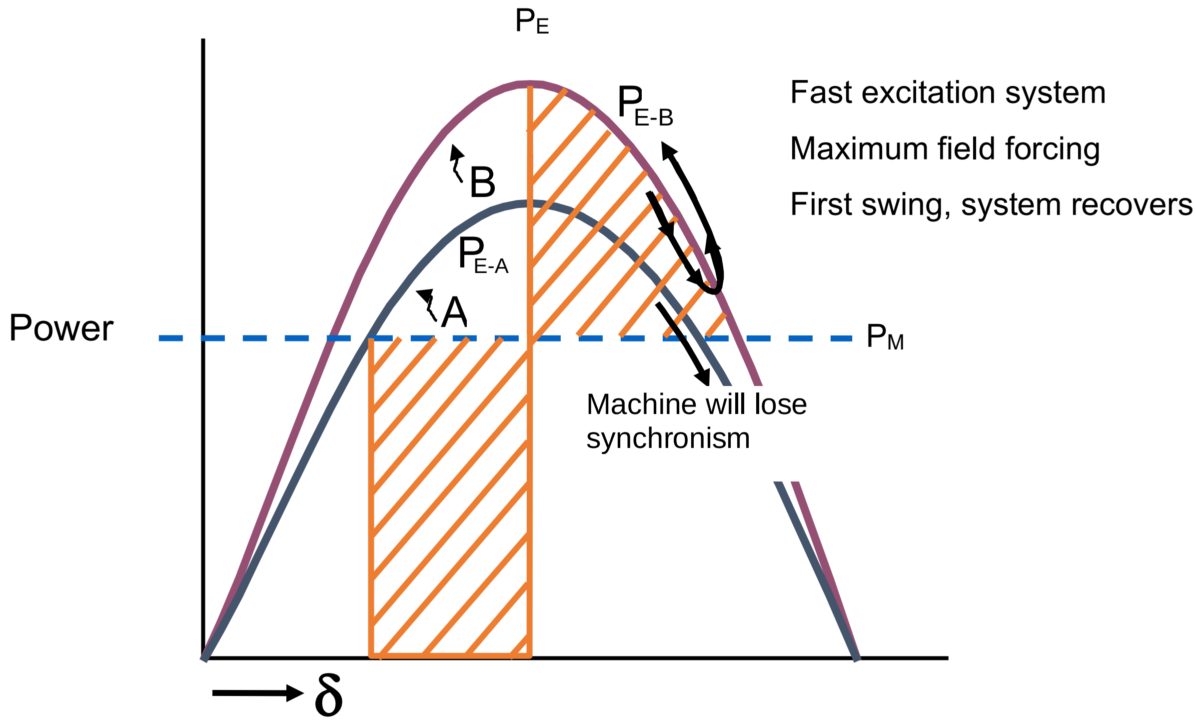


Figure 29 – Effect of Fast Excitation System on First Swing Stability

Curve A represents the “pre-fault” excitation level and would result in the machine losing synchronism with the grid if excitation were not increased quickly where curve B represents the increase in area due to a fast responding excitation system.

3.4 Effect of High Initial Response Excitation Systems

Fast acting excitation system will improve first swing stability. However, there are negative side effects to using a high initial response exciter, particularly during post-fault recovery when the generator moves to a new power equilibrium. To achieve high initial response, the automatic voltage regulator utilizes high gain within the close loop control system. Applying high gain can reduce the natural damping of the generator. Operating the generator with low levels of excitation while exporting a large amount of real power load through high impedance tied to the infinite bus can cause a low frequency power oscillation to occur. This topic is more fully discussed in Prabha Kundur’s book titled ‘Power System Stability and Control.’ [5] This oscillation can grow and potentially result in tripping of the generator by the loss of synchronism element (device 78) if the swing locus passes through the generator or GSU. The small signal model of a generator connected to the grid, known as the “K-constant model” shown in Figure 30, helps explain the cause of these low frequency oscillations. Normally, the K-constants are positive. For the conditions described above, the K5 constant can become negative. This results in a phase reversal of the feedback signal from the power angle, $\Delta\delta$. This signal is an input to the terminal voltage input, ΔV_t of the Automatic Voltage Regulator. Reversal of this input signal results in a destabilizing change in electrical torque, ΔT_e. This change in electrical torque causes changes in the power angle, δ, which will result in changes in the electrical power output of the generator.

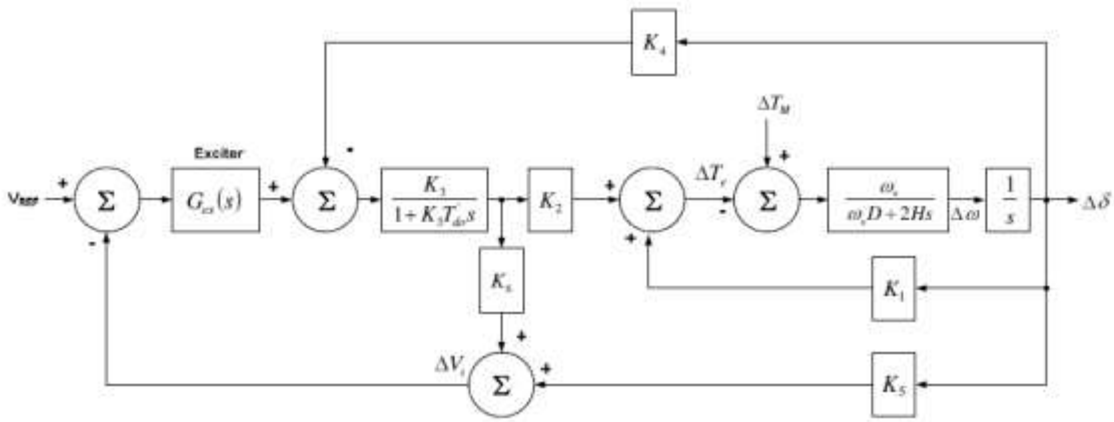


Figure 30 – K-constant Model of a Generator tied to the Grid

3.5 Modes of Power System Oscillations

The power oscillations can be categorized in a number of ways.

First, a mode of oscillation can exist where two or more units supplying a common GSU can participate in an oscillation with respect to each other. This is known as an inter-unit mode of oscillation and results in a relatively high frequency oscillation, ranging from about 1.5Hz to 3Hz. as shown in Figure 31.

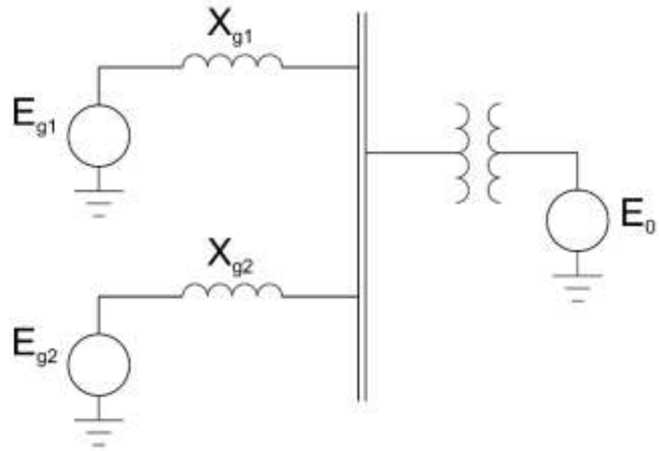


Figure 31 – Inter-Unit Mode of Oscillation

Second, a mode of oscillation can exist where a single unit or group of units participates in an oscillation with the machines that make up the rest of the grid. This mode is localized to one plant and is known as the local mode of oscillation. . The frequency of this mode is somewhat lower, ranging from about 0.7Hz to 2Hz as shown in Figure32

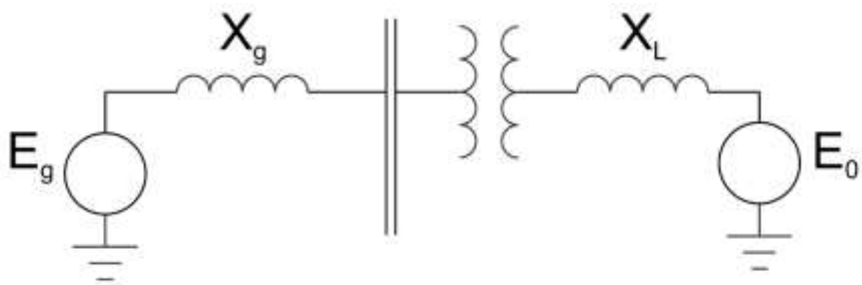


Figure 32 – Local Mode of Oscillation

Finally, a mode of oscillation can exist where a group of units in one region participates in an oscillation with a group of units in another region. This is known as an inter-area mode of oscillation and results in a low frequency oscillation typically less than 0.8 Hz.(Figure 33)

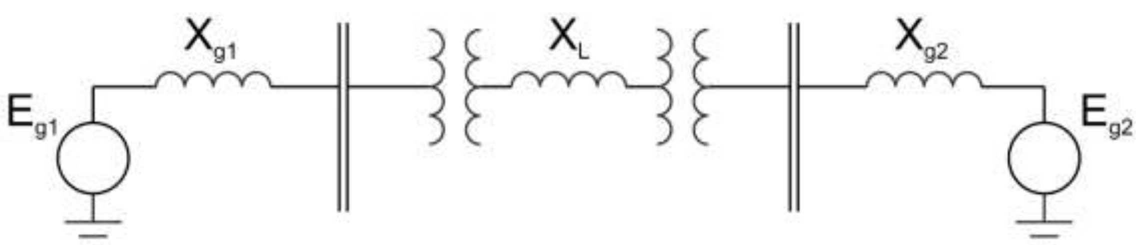


Figure 33 – Inter-Area Mode of Oscillation

3.6 Power System Stabilizers

Since damping torque may be reduced due to the use of high gain excitation systems, it stands to reason that supplemental damping can be restored by modulating excitation. Power System Stabilizers (PSS) are supplemental controls that provide the appropriate modulation. A PSS is defined as a function that provides an additional input to the voltage regulator to improve the damping of power system oscillations [4]. The implementation of a block with suitable gain and phase lead characteristics can be added to the K-constant model. The model, including the PSS block, with transfer function $G_{PSS}(s)$, can be seen in Figure 34. The input of the PSS block is the change in rotor speed signal, Δω and the output is connected to the summing junction input of the AVR.

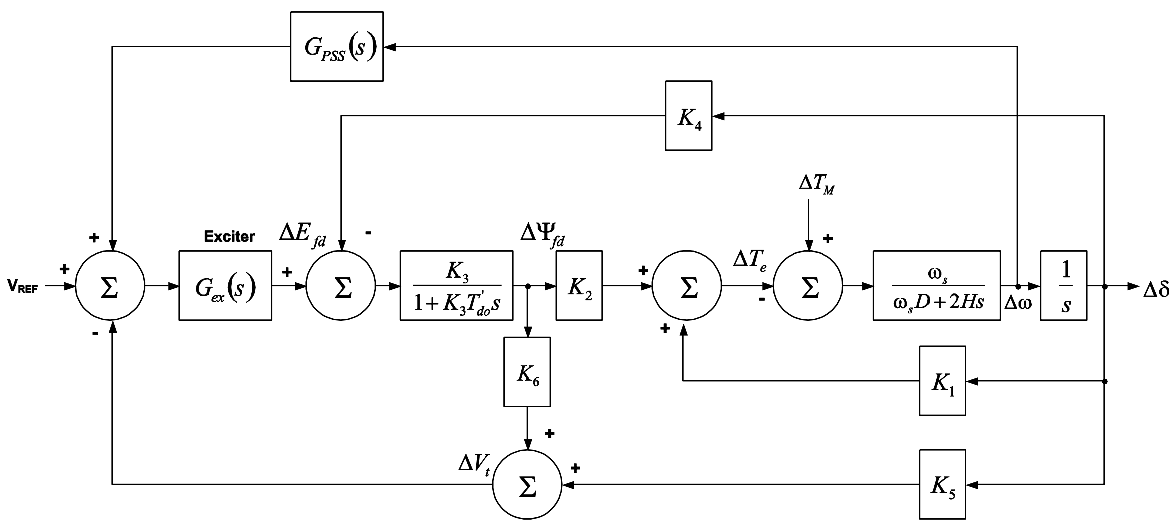


Figure 34 – K-constant Model with PSS Block

3.7 Types of PSS - Single Input Stabilizers

PSS1A is an IEEE Std 421.5™-2016 definition for a PSS that utilizes only one input variable, V_{SI}. Common input variables (16) are: shaft speed, terminal frequency, compensated frequency, or electrical power. The block diagram is shown in Figure 35. This is further discussed in Prabha Kundur's book'Power System Stability and Control'

[5] previously mentioned. and also in the book "Excitation Control Systems" by Michael Basler, et al. [6]

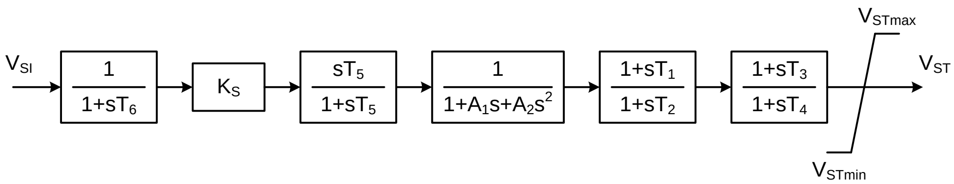


Figure 35 – Single Input Type PSS1A Block Diagram

Where:
V_{SI} – Stabilizer Input Variable
T_6 – Represents Transducer Time Constant
T_5 – "Washout" Time Constant
K_S – Stabilizers Gain
A_1 and A_2 used for Torsional Filter
T_1 through T_4 used for Phase Lead
V_{STMin}, V_{STMax} – Output Limits

The first stage of the model is a low pass filter used to represent the time constant of a practical transducer. The washout time constant is used to remove the steady-state component of the input variable such that the stabilizer only reacts to a change in that variable. A torsional filter is implemented to avoid exciting torsional modes of oscillation of the prime mover / generator combination. Some long shaft machines, like turbo alternators, can exhibit such an oscillation and modulating excitation could excite this mode, potentially causing damage to the machine. The resulting stabilizer signal is amplified by the gain constant K_S before it is applied to the phase lead blocks. The phase lead time constants are selected to provide the appropriate phase characteristics to compensate for the phase lags associated with the exciter and main field blocks of the K-constant model. To achieve a phase lead from these blocks, $T_1 > T_2$ and $T_3 > T_4$. Output limits are added to prevent large swings in terminal voltage due to stabilizer action.

3.8 Dual-Input Stabilizers

PSS2C is used to model PSS that utilize two input variables. Common inputs are: shaft speed, terminal frequency or compensated frequency, and electrical power. There are two types of stabilizer implementations:

1. Stabilizers that act as electrical power input stabilizers set up to make the stabilizing signal insensitive to mechanical power changes. These are sometimes known as "Integral of Accelerating Power PSS."

2. Stabilizers that use speed directly and add a signal proportional to electrical power to achieve the desired stabilizing signal.

A block diagram of the dual input stabilizer is shown in Figure 36.

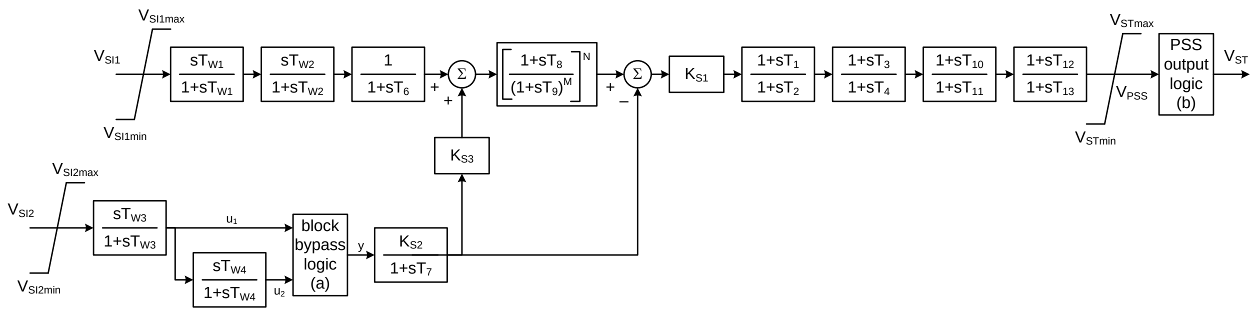
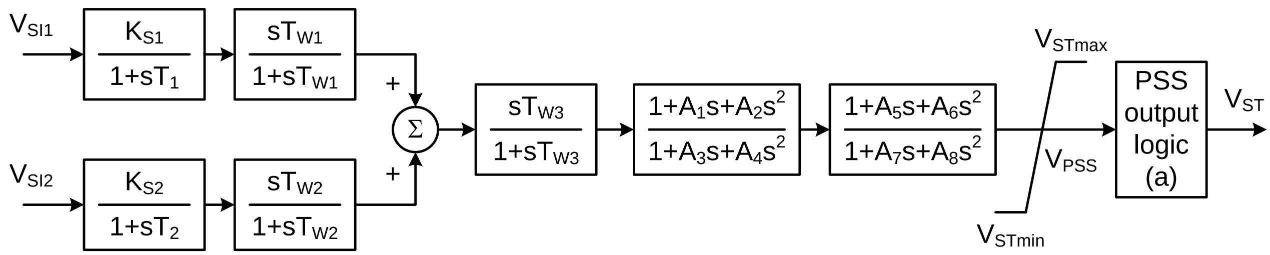


Figure 36 – Dual Input Type PSS2C Block Diagram

Where:
V_{SI1}, V_{SI2} – Stabilizer Input Variables
T_{W1} - T_{W4} – "Washout" Time Constants
K_{S1} - Stabilizers Gain
T_6 , T_7 –Transducer or Integrator Time Constants
T_8 , T_9 , M N – Low Pass Filter applied to Derived Mechanical Power Signal
T_1 - T_4 and T_{10} and T_{13} used for Phase Lead
V_{STMin}, V_{STMax} – Output Limits

The stabilizer input, V_{SI1} is normally speed or frequency and V_{SI2} electrical power. There are two washout time constants for each signal path. The first type of dual-input stabilizer is typically set up for K_{S3} equal to 1 and K_{S2} equal to $T_7/2H$, where H is the inertia constant of the synchronous machine. In this style PSS, the output of the upper left summing junction is a signal equivalent to mechanical power. This is filtered by the block containing time constants T_8 and T_9. The exponents, M and N can be selected to implement a simple low pass filter or one with "ramp-tracking" characteristics. The ramp-tracking characteristic makes the PSS insensitive to ramping power input to avoid undesired PSS output for fast loading machines. The electrical power signal is integrated and added back to the derived mechanical power signal to form the "integral of accelerating power" signal at the output of the right most summer. This is equivalent to the change in rotor speed, $\Delta\omega$, and is amplified by the gain constant, K_{S1}, before it is applied to the phase lead blocks. This model contains a third phase lead block to represent some manufacturers' implementations. Output limits are added to prevent large swings in terminal voltage due to stabilizer action.

PSS3B is another implementation that utilizes two input variables. Input V_{SI1} is electrical power, P_E and V_{SI2} is rotor angular frequency deviation, $\Delta\omega$. These signals are combined to produce a signal proportion to accelerating power. The block diagram is shown in Figure 37.



footnotes:

(a) PSS output logic uses user-selected parameters P_{PSSon} and P_{PSSoff}. It also uses the signal V_{PSS}, shown in the block diagram, and the generator electrical power output P_T. The output logic implements the following hysteresis to define the output signal V_{ST}:

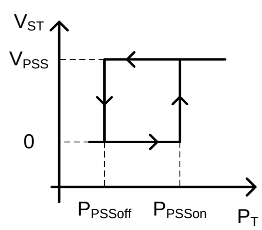


Figure 37 – Dual Input Type PSS3B Block Diagram

Where:
V_{SI1}, V_{SI2} – Stabilizer Input Variables
T_1, T_2 –Transducer Time Constants
T_{W1} – T_{W3} - “Washout” Time Constants
K_{S1} – Electrical Power Signal Gain
K_{S2} – Rotor Angular Frequency Deviation Signal Gain
A_1 – A_8 - Used for Phase Lead
V_{STMin}, V_{STMax} – Output Limits
A signal proportional to the mechanical power is developed at the output of the summer and washed out by time constant T_{W3}. Phase compensation is achieved by parameters A_1 through A_8.

PSS4C is a unique implementation that utilizes two input variables and breaks the stabilizing signal into multiple bands of frequencies to apply the necessary phase lead required to address the various modes of oscillation that are present in some power systems. The stabilizer inputs are a function of the change in speed, $\Delta\omega$, but the measurement is made in two different ways; one for the low and intermediate frequencies and the other for the high frequency bands. The low frequency band is used to address global modes of oscillation where the intermediate and high bands are used for inter-area and local modes respectively. Each band can be set up to use different filters, gains, and limiters. The block diagram is shown in Figure 38.

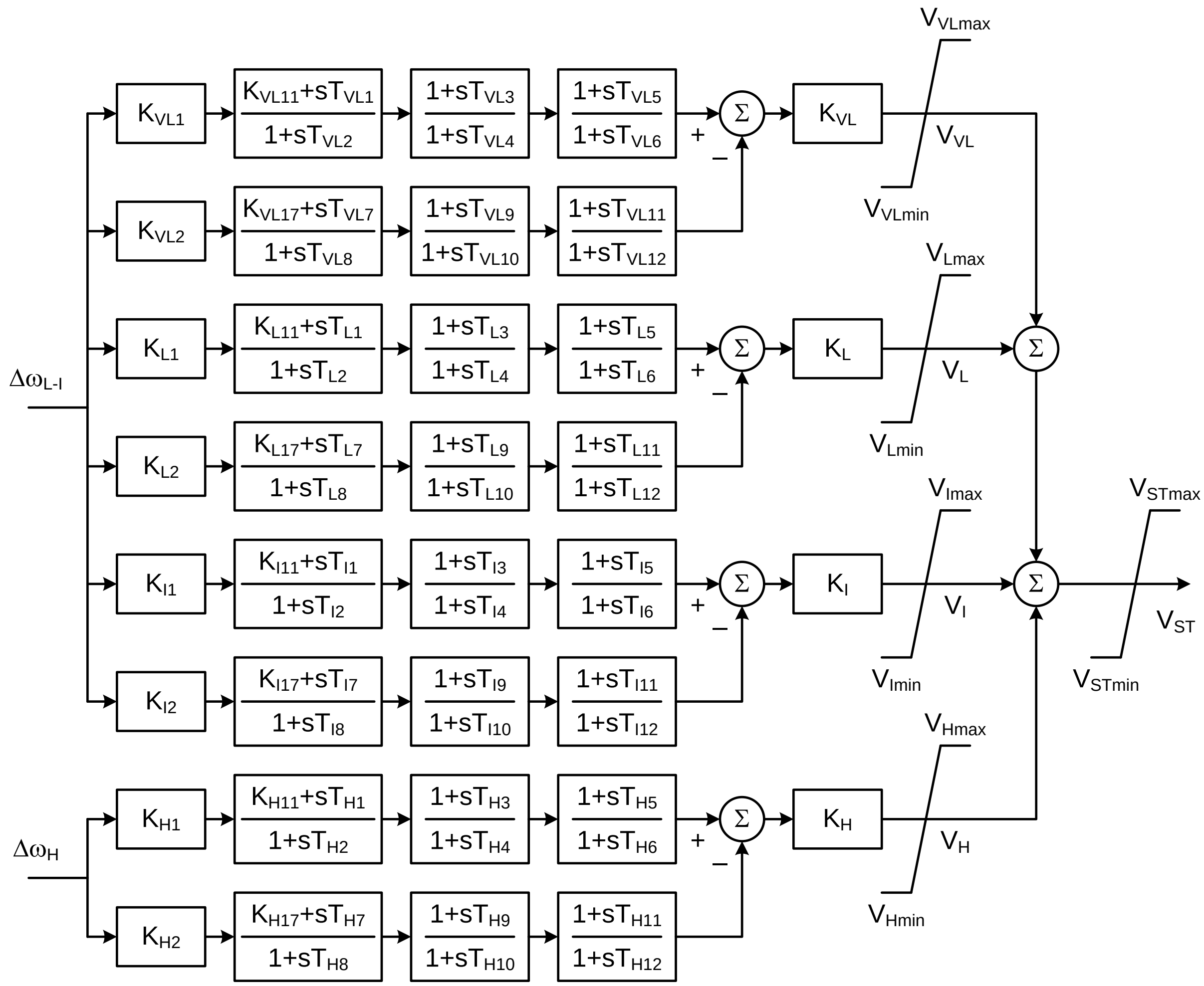


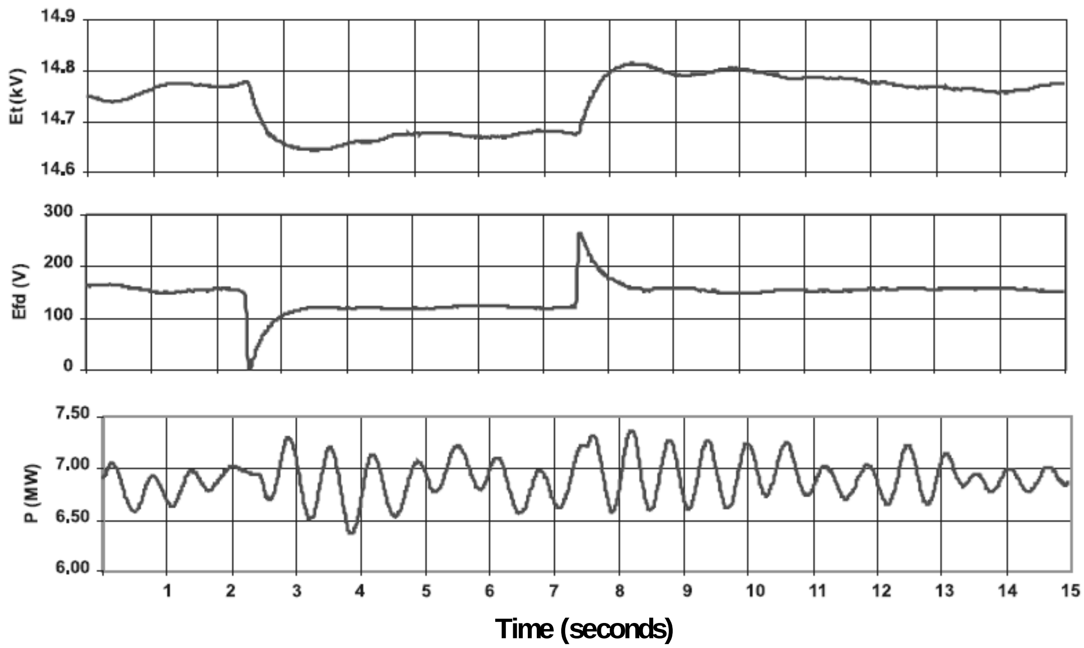
Figure 38 – Dual Input Type PSS4CMulti-Band PSS Block Diagram

3.9 Case Studies

Four case studies are presented, each one of them with a number of oscillographs. The case studies were added as an aid to the reader in understanding the nature of power system oscillations. They were chosen to bring out four unique issues with PSS. The first shows the difference in real power behavior with and without PSS. The second shows the difference between a single input and a dual input PSS. The third shows the performance on reciprocating prime movers where the acceptance criterion was based on providing the required phase lead. The fourth shows that PSS can be applied to excitation systems with non-linear behavior along with showing typical phase lag and lead characteristic.

Case 1: Hydraulic Turbine Generator Instability

A small hydro turbine generator (~25 MW) was upgraded by replacing the rotary exciter with a fast acting static exciter. Afterwards, when certain transmission line conditions occurred, this unit participated in a power system oscillation with the local grid, including a large nuclear unit. A dual input Integral of Accelerating Power type PSS was added. The oscillograph recording in Figure 39 shows the performance with the PSS off. Typically, a "step of reference" test is performed on the machine to determine the stability by introducing a step response in the AVR reference. In this picture, the unit was exporting about 7 MW when the AVR reference was stepped down, then up, by about 100 V around the 14.75 kV operating point. The exciter output voltage, E_{fd}, changed rapidly when the step was initiated and returned to the level needed to maintain terminal voltage in a smooth exponential manner. The electrical power out of the machine was experiencing a continuous 1.5 Hz oscillation with a magnitude of 250 kW to 500 kW when the step occurred. This perturbation caused an even larger oscillation, on the order of 750 kW, which took 3 to 4 seconds to dampen.



.Figure 39 – Small Hydro Supplying ~7 MW without PSS

The PSS was tuned to provide adequate phase lead and gain. The PSS was enabled and the step of reference was repeated, at a higher power level, ~12 MW. The resulting oscillation damped in about 1 second. See oscillograph recording shown in Figure 40. The PSS modulation can be seen in the field voltage waveform by comparing the two oscillograph recordings. This modulation provides supplemental damping to stabilize the power swings due to a perturbation on the grid.

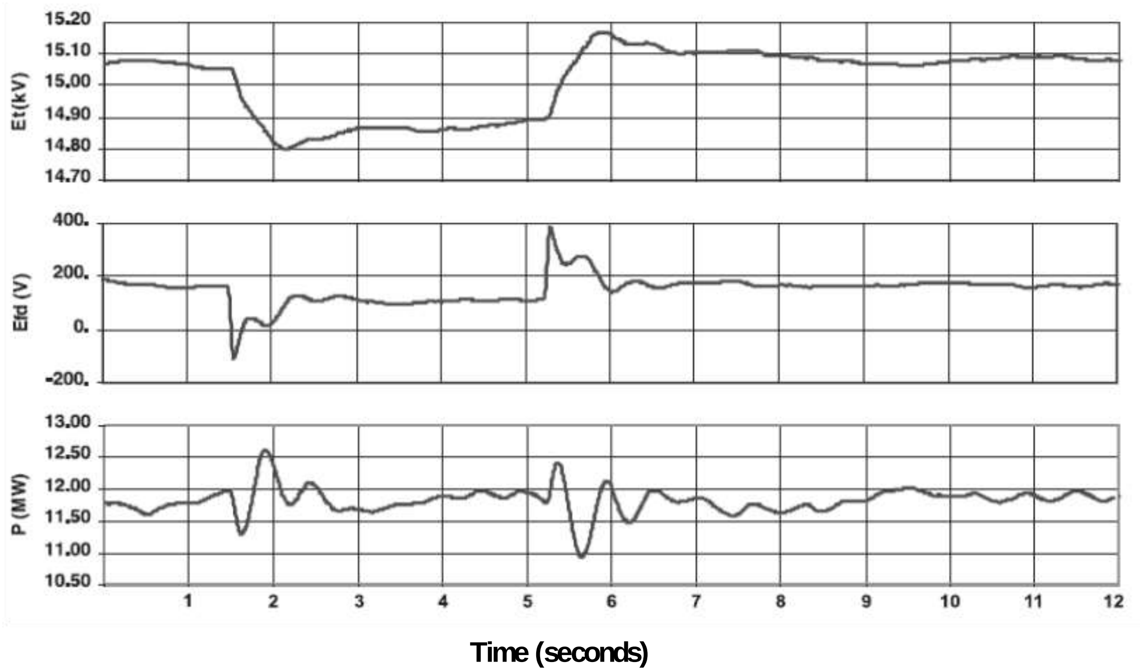


Figure 40 – Small Hydro Supplying ~12 MW with PSS

Case 2: Single Input vs. Dual Input Stabilizer

A medium sized hydro turbine generator (~90 MW) had the PSS upgraded from a single input Frequency type power system stabilizer to a dual input Integral of Accelerating Power type. The reduction in noise from the stabilizer signal allowed the PSS gain to be increased, resulting in a significant improvement in damping. The first picture shows the performance with the frequency based stabilizer. The noise in the stabilizer signal (PSS Out) can be seen in Figure 41.

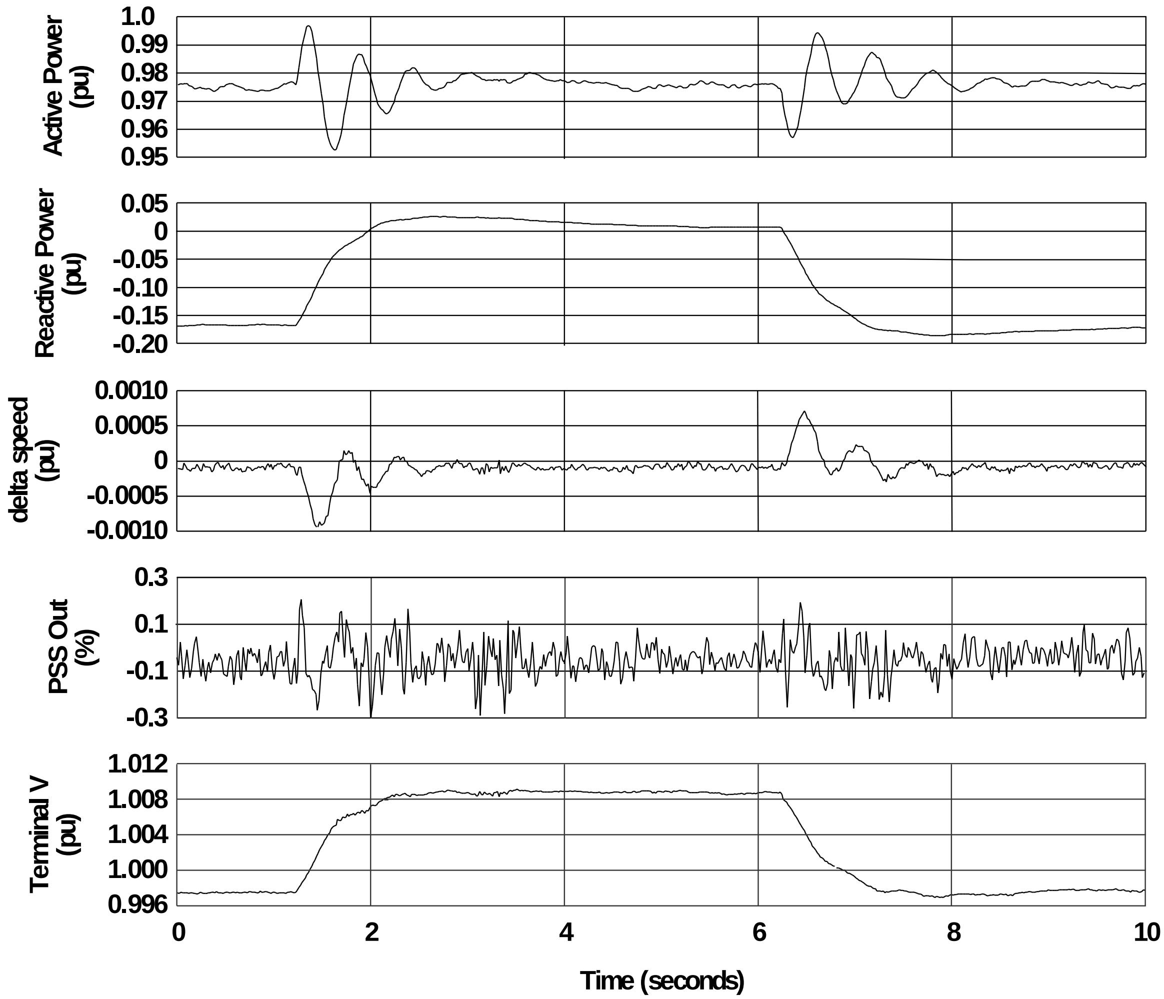


Figure 41 – Medium Sized Hydro Supplying ~90 MW with Frequency Based PSS with Ks=6

The reduction in stabilizer signal noise as a result of upgrading to a dual input Integral of Accelerating Power type PSS allowed the stabilizer gain, Ks, to be increased from 6 to 7.5. This resulted in improved damping. See oscillograph recording in Figure 42.

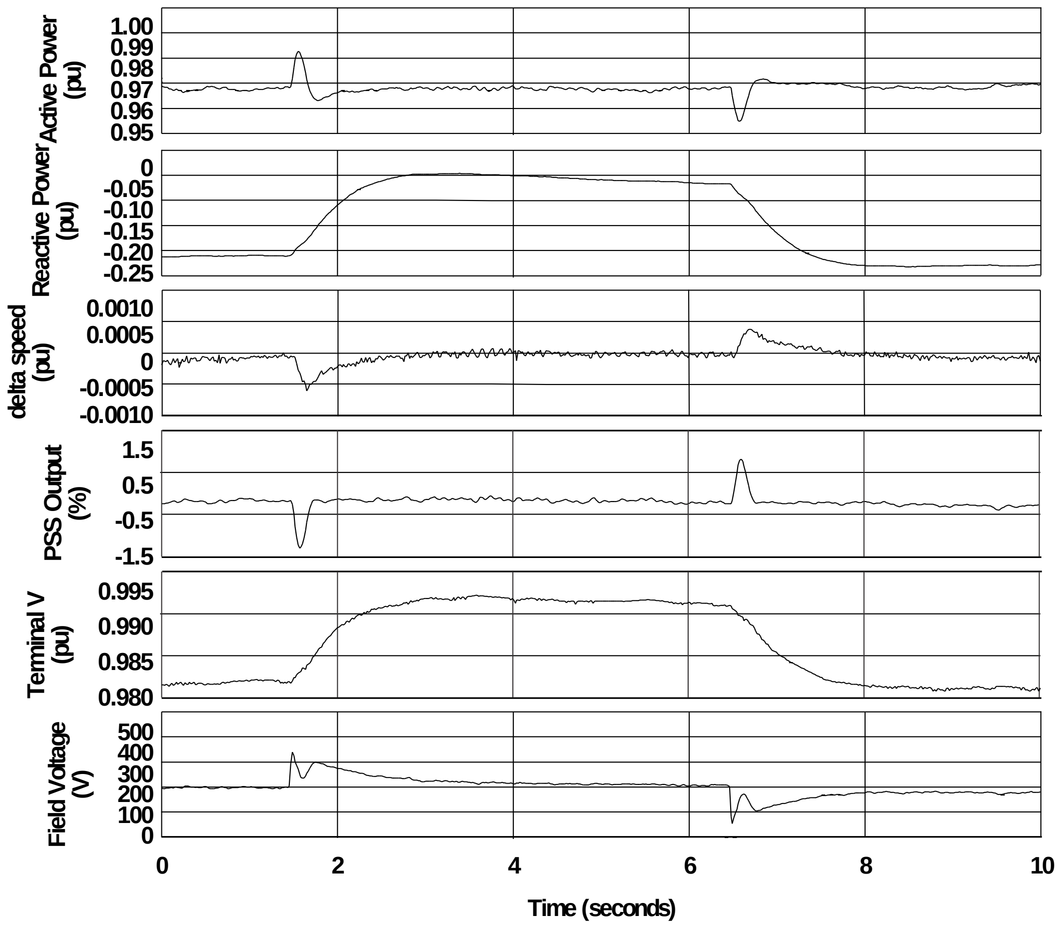


Figure 42 – Medium Sized Hydro Supplying ~90 MW with Dual Input Type PSS with Ks=7.5

Case 3: MagAmp Based Exciters

The application of PSS with excitation equipment based on magnetic amplifier technology was thought to be problematic due to a concern that the phase lag associated with this type of exciter could change with load level on the generator. This theory was proven otherwise based on testing performed at different load levels from 7 to 53 MW on a combustion turbine generator, as seen by the graph in Figure 43.

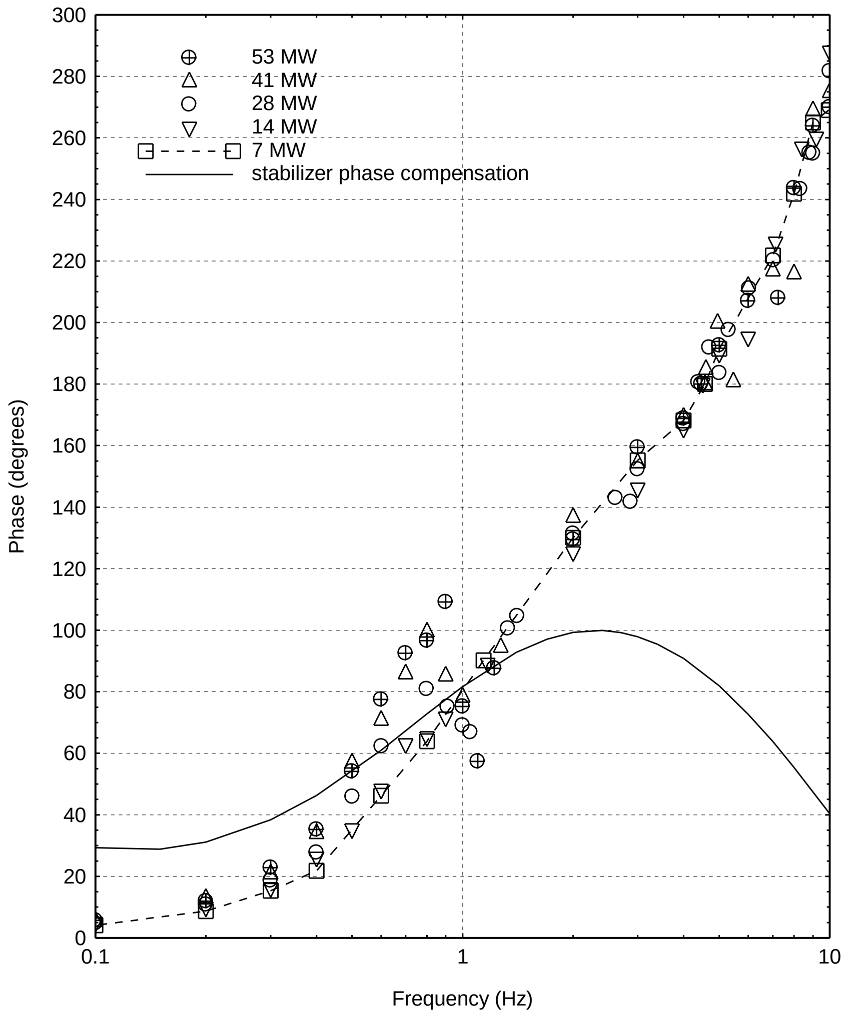
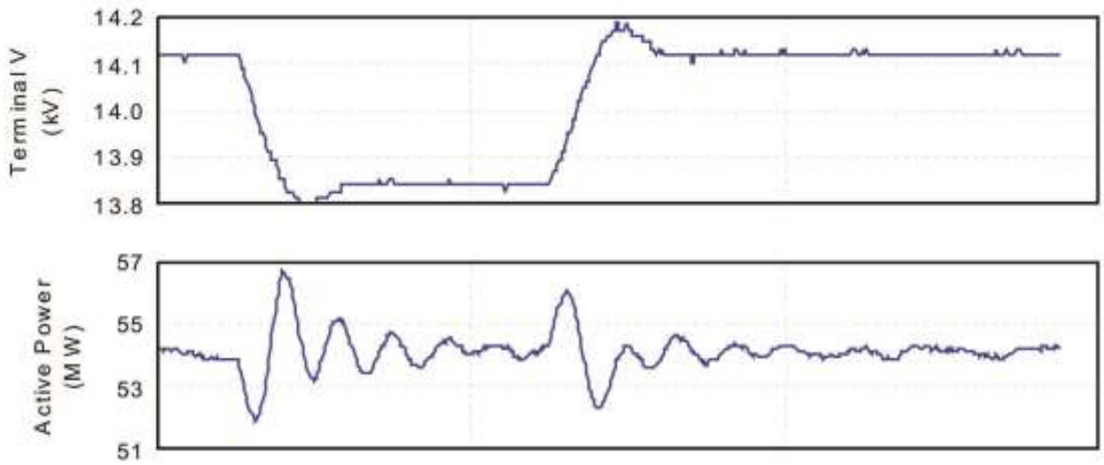


Figure 43 – Phase Lag Associated with MagAmp Based Exciter and Phase Lead from PSS

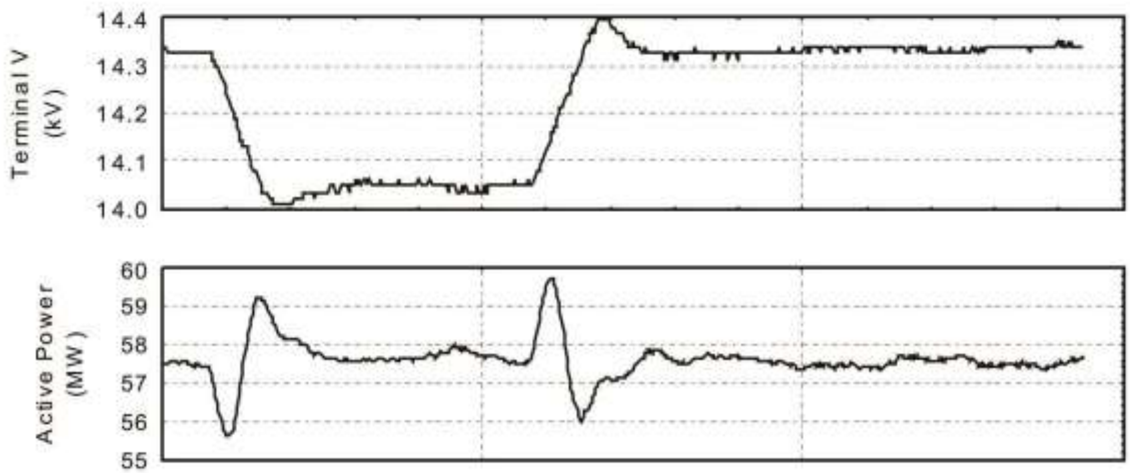
As can be seen in Figure 43, the phase lag of the exciter is fairly independent of the real power load on the machine. The smooth curve plotted on the same graph represents the stabilizer phase compensation (phase lead characteristic) of the PSS. The phase lead is within 30 degrees of the phase lag over the frequency range of 0.1 to about 2 Hz.

The resulting improvement in power system stability can be seen by comparing the two oscillograph recordings in Figures 44 and 45.



5 Seconds/Division

Figure 44 – Combustion Turbine Generator with MagAmp Based Exciter – PSS Off



5 Seconds/Division

Figure 45 – Combustion Turbine Generator with MagAmp Based Exciter – PSS On

4. Generator dynamic response modeling

This section discusses the impact of transient studies in the setting of generator relays and makes emphasis in considering proper generator control modeling in the studies to coordinate relays.

Generating unit response to power system disturbances caused by faults or switching events can create transient conditions during which generator parameters fall outside the ranges typically encountered during steady-state conditions. In addition, these conditions are not accurately represented by using a simple Thévenin equivalent model of the generators. Coordination of generator relays must consider such transient conditions, including generator dynamic behavior and controller actions, when the transient conditions occur for a duration longer than the protective relay operating time. For example, during a system fault, the dynamic response of a generator excitation system may cause the relay apparent impedance to exceed the standard load encroachment boundaries of a backup distance scheme. Consideration of these transient conditions can prevent unnecessary generator tripping for conditions under which the generator is operating within its capabilities. Avoiding unnecessary tripping, and avoiding equipment stress, also benefits overall power system performance. Under severe conditions these benefits could be instrumental in avoiding a wide-spread system outage or blackout. Of course, protection of the generating unit is the primary concern, so while it is important to coordinate protective relays for transient operating conditions, the overriding requirement is always to coordinate protection with equipment capability.

4.1 Generator Models

Generator data is typically the easiest generating unit data to obtain as it relates to physical parameters of the generator; i.e., impedances, time constants, inertia, and saturation. In fact, many regulatory bodies now require periodic validation of such parameters (e.g., NERC MOD-026 and MOD-027). Most manufacturer design parameters are close to values validated through field tests, so that manufacturer data is typically accurate enough for protection coordination studies. As with all transient stability models, it is necessary to consider the range of operating conditions for which the models are valid. Models were initially developed to be valid for evaluation of first swing rotor angle stability. As computing capability has grown, system planners have utilized transient stability simulations to study a broader range of conditions, including extended duration simulations to assess power systems operating under severely stressed operating conditions.

One such example is the generator saturation model. During a short circuit near the generator terminals the terminal voltage is significantly dropped and the stator flux is forced to pass through air for the first few seconds – so inclusion of the saturation model will not make much difference to the calculation results. However, during remote faults or non-fault disturbances that do not significantly impact the terminal voltage, it is necessary to have the saturation characteristic modeled. Transient stability models include a generator saturation characteristic developed from two points on the generator open-circuit magnetization curve. The model calculates saturated reactance values at each time step based on the corresponding instantaneous internal flux level. As noted in [7], a standard transient stability program generator model may not accurately model saturation, and therefore the generator reactive output and terminal voltage, during extreme events. In the referenced study, the transmission system voltage was depressed for an extended duration (on the order of 50 seconds) due to a protection system failure that resulted in delayed, remote clearing of a 230 kV fault. As a result, the generator reactive support provided to the system was overstated by the transient stability simulation compared to the actual event recordings. Such performance differences are important to consider when coordinating protective relays that could operate during a field-forcing event. For example, setting generator phase distance protection to ride through such an event based on a model that overstates the generator reactive support could result in an overly conservative setting that reduces the generator protection level. Other types of model limitations could potentially result in a setting that overprotects the generator and limits its ride-through capability for events that do place the generator at risk of damage. Thus, it is important that the engineer uses a proper model and understands its limitations.

The following example illustrates this issue by simulating a generator response to depressed transmission system voltage. The first simulation is based on a generator model that models the saturation as a function of only the air-gap flux. However, testing of generators has demonstrated that saturation is also a function of the armature current magnitude. The second simulation is based on a generator model that recognizes the leakage flux components induced in the stator teeth by high stator currents can increase the reluctance of the magnetic circuit. To model this, the saturation calculated from air-gap flux is increased by a second component that is proportional to the armature current.

Figure 46 presents the response of a generator to depressed system voltage. In this case, a disturbance lowers the voltage at the high-voltage side of the GSU transformer to 0.85 per unit voltage (red trace). The excitation system responds by raising the field voltage to produce additional reactive power (blue trace) to support voltage. The generator reactive output rises rapidly in response to the disturbance from approximately 150 Mvar to nearly 800 Mvar, before the maximum excitation limiter reduces the reactive power output. For the purposes of this example, the maximum excitation limiter parameters were adjusted to speed up the limiter action. While the field voltage exceeded the steady-state limit, the voltage depression was not severe enough to reach the maximum field voltage and, in reality, the limiter would have taken longer to respond. This figure does illustrate, however, that even with the faster response the excitation remains high for a time that exceeds the longest time delay for generator's system backup protection.

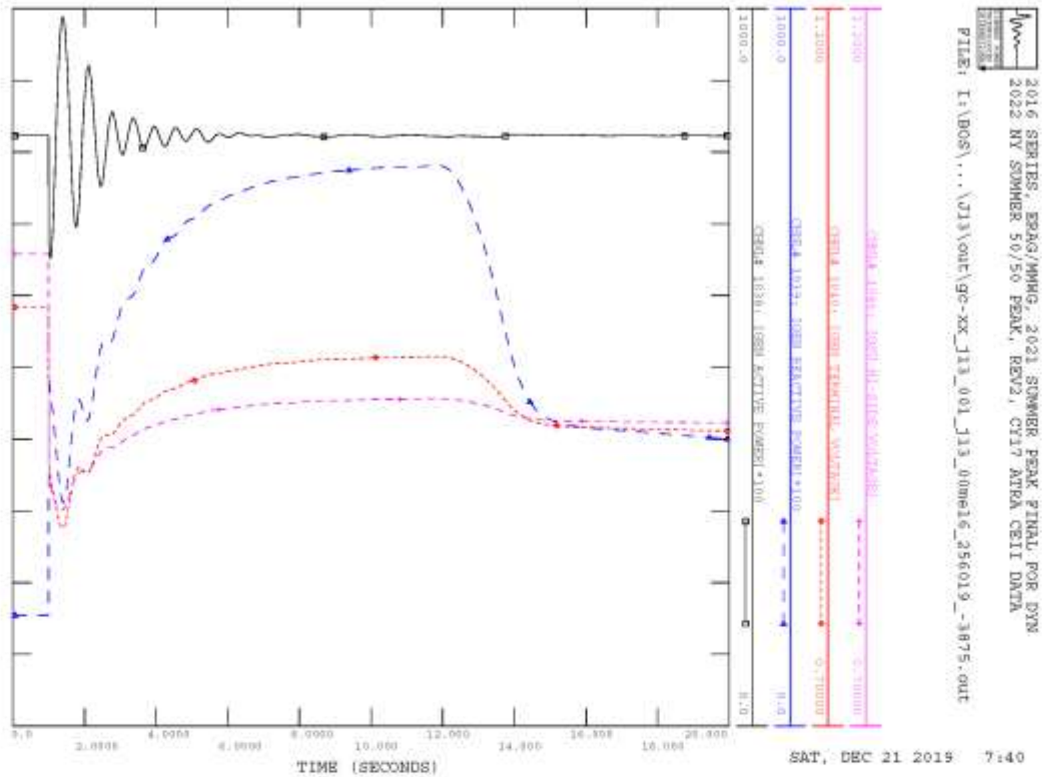


Figure 46– Generator Response to Depressed System Voltage

Figure 47 presents a comparison of the conventional generator model to the model that includes a component of saturation proportional to armature current. In Figure 47, only the system voltage and generator reactive output are plotted for comparison. In the case with the revised generator model, the reactive output is reduced by approximately 100 Mvar due to the higher level of generator saturation (red trace with revised model versus black trace with conventional model). While static calculation methods are intended to be more conservative, this example illustrates that it is possible for a more detailed approach using transient stability simulation to result in a more conservative result than a static calculation if the model overstates the generator reactive output.

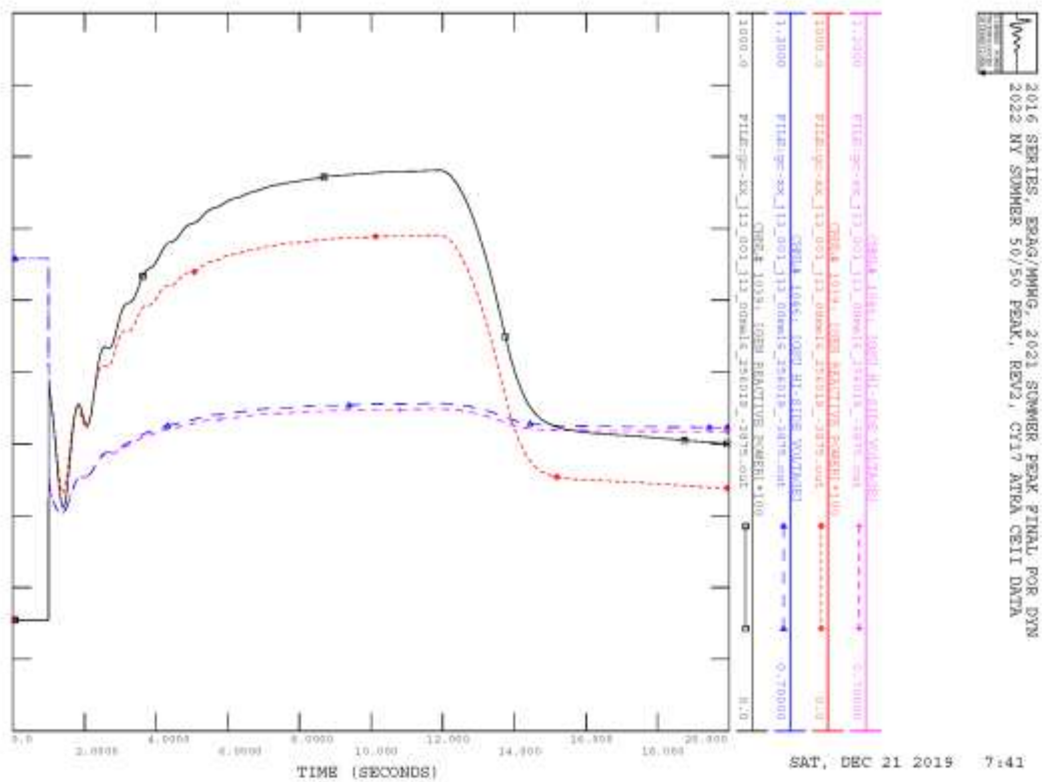


Figure 47– Comparison of the conventional generator model to the model that includes a component of saturation

4.2 Excitation System Models

Transient stability models include the excitation system, composed of the automatic voltage regulator (AVR), different limiters (frequency, excitation, current, etc.), a power system stabilizer (PSS), if active, and the exciter; however, the overexcitation and underexcitation limiters (OEL and UEL) are frequently omitted from the power system models used for transmission planning studies. When coordinating generator protection for overexcited and underexcited generator operation, it is important to consider the excitation limiters. This is important for coordination of both the generator protection and the exciter protection. By virtue of their settings in the AVR system, the OEL and UEL functions are coordinated with the corresponding protection functions.

The Under Excitation Protection (UEP) is also called as Minimum Excitation Protection (MEP). The MEP in the AVR system is set to coordinate with Under Excitation Limiter (UEL) before actuating a trip. However, in some AVR system, the MEP is used to transfer the UEL control system from one channel to a backup channel before transferring to manual control.

Minimum Excitation Protection (MEP) takes a few seconds to declare a fault in the first UEL channel before initiating the transfer to the backup UEL channel. If there is no coordination between the MEP and Zone 2 LOF relay (Device 40), The Zone 2 LOF relay will operate before MEP has the opportunity to transfer the UEL control system from one channel to the backup channel.

The OEL and UEL can provoke a dynamic transient response in the generator voltage regulation loop when they either take over the voltage setpoint or modulate it, affecting the magnitude and duration of generator reactive power response under lagging and leading conditions respectively. The limiters affect the generator terminal voltage and apparent impedance as a function of the reactive power generated or absorbed by the generator. For instance, following a system transient overvoltage, the generator will transiently absorb reactive power and depending on the operating point, this may activate the UEL. In an attempt to avoid loss of excitation, the UEL activates with a sudden change in setpoint, which may resemble a voltage step response on the AVR. This may cause a substantial overshoot followed by a stabilization time to the excitation limit and if the control loop gains are not set for enough damping, the apparent impedance seen by a loss of excitation (LOE) protection can lead to a trip of the unit. The limiter gains are not always well tuned for different reasons, which make modeling of the limiters even more important to consider in protection coordination.

Whether the limiter affects coordination of a generator relay depends, in part, on the time delay of the protective relay compared to the operating time characteristic of the limiter. When the relay responds in a definite time, prior to limiter operation, modeling of the limiter may be unnecessary. When the definite time relay operates more slowly than the limiter, or when the limiter and protective relay both have inverse-time characteristics, it is important to consider limiter operation when verifying coordination.

Excitation system limiters must be coordinated with the generator and exciter protection, which must in turn be coordinated with the excitation system and generator capabilities. As a result, when transient stability simulations are used to verify coordination, it is necessary to model the limiters. Modeling the limiters makes it possible to simulate overexcitation or underexcitation conditions to ensure that the limiters operate to reduce or increase the excitation to achieve a sustainable operating condition prior to operation of the generator or exciter protection.

4.3 Governor Control Systems

Turbine-governor controls may be included in a transient stability model, except for specific cases in which a unit may not provide governor response due to its design or operation. In the context of coordinating generator protection, these controls generally operate in a longer time frame than generator protection and so these controls are not critical to coordinating most generator protective functions. When governor response is important to verifying coordination, it is necessary to also consider plant control systems that may override the governor response such as a plant power setpoint that squelches governor response during an underfrequency condition.

One area in which the governor control systems is particularly important is in analysis of underfrequency load shedding (UFLS) programs and analysis of system disturbances, particularly when a portion of the system is isolated. As generator frequency protection must be coordinated with the generator and turbine capabilities, these studies are not focused on coordinating the generating unit protection per se, but rather to assure that transmission and distribution system protections are coordinated with the generator protection. These studies verify that appropriate actions, such as UFLS operation, are initiated in a coordinated manner to take action prior to generator tripping to preserve overall system integrity.

Governor control systems are included in models used by Planning Coordinators to assess UFLS programs. These assessments determine setting criteria for generator underfrequency and overfrequency relays that are published in reliability standards such as NERC PRC-024, and sometimes in supplemental regional standards. As a result, additional studies are typically not needed to assure coordination when setting generator underfrequency and overfrequency relays.

5. Modeling of protective relays in transient stability modeling software

The interaction of controls in the generators and protection strongly determine the stability of a power system. Modeling dynamics of the power system and protection devices permit in-depth study of those conditions that may affect the integrity of the power system.

A number of computer programs are available to model power systems for stability purposes, both commercial and non-commercial. These may fall on the so-called category of either transient stability (TS) or electromagnetic transient (EMT) programs. TS programs are perhaps the most favored choice for this kind of studies.

TS and EMT programs have different mathematical approaches for solving the dynamics of power systems. TS programs are generally positive-sequence only, while EMT programs are full three-phase models. In addition, EMT programs use a smaller simulation time step and, therefore, are able to analyze faster transients than TS programs. This section discusses, the most important points of the protection modeling task, according to the computer program performing the stability study.

5.1 Relay models

Figure 48 shows an example of a block logic of a typical relay model for its use in stability studies.

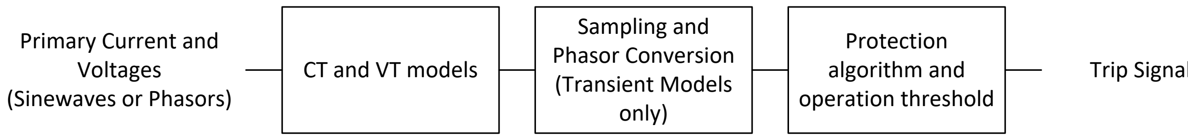


Figure 48 – Block Logic of Typical Relay Model

For stability simulation, representation of generator protection is necessary. Modeling of other protection that could trip the generator may also be necessary; e.g., if load responsive relays are applied on the GSU transformer, or in studies where the ability to maintain adequate auxiliary bus voltage is a concern. Likewise, protection function models for transmission lines, power transformers, power buses, distribution feeders, etc., could also be included.

The use of relay models, in any kind of power system analysis, should be based on an understanding of the model limitations.

Informally, the protective relay models may be classified following diverse criteria. Some of these classifications are shown below.

A. According to the type of input data utilized to determine operation:

- Phasor domain models – Magnitude and phase of secondary RMS voltages and currents under steady-state conditions are provided as inputs to the relay model. Phasor relay models are typically used in short circuit programs and transient stability programs. In these models, fast transients are ignored.
- Point-on-wave relay models – Peak-to-peak waveforms (instantaneous time-dependent information) of secondary voltages and currents are provided to the relay models. The up-front signal processing typically found in modern numerical relays is implemented in the model to produce phasors used by the relay operating algorithm. Special, manufacturer-specific data manipulation and protection algorithms may be implemented in the model as well, if detailed information is available. Similarly, the lack of this information may result in an insufficient relay model, which may result in important differences between the model output and the actual device.

B. According to the level of detail included in the model:

- Generic models – These models are not associated with a specific manufacturer or relay version. Generic models include the most significant protection thresholds (pickup, reach, etc.) and operation criteria, but may ignore specific features developed by the relay designer (manufacturer-specific equations, blocking/permissive supervision, memory voltage, voltage control/restraint, special logic, etc.). These models are easy to implement and understand, but tend to oversimplify otherwise complex processes.

- Detailed models – These models are closer representations of actual relays than the generic relay models. They include relay-specific setting names, setting ranges, and setting functionality in the relay algorithm. Detailed relay models use operation equations, specific thresholds, supervision, memory voltages, and operation logic designed by the manufacturer for a specific device, relay family, or style.

C. According to the type of technology used by the physical device:

- Electromechanical – These models represent the electro-magnetic and mechanical behavior of the actual relay. The main concern in modeling these relays is the torque effect produced by different windings and units that produce the relay operation. Their operation is sensitive to mechanical wear, temperature fluctuations, and spurious external electric and magnetic fields, which cannot be accounted for in the models.
- Solid-state – These models represent the analog signal processing occurring in the analog electronics of these devices. These analog processes include how the analog voltage and current input signals are converted into suitable voltage analog signals, scaled down, filtered and squared for magnitude and phase comparison. When suitable thresholds are met, the relay trips.
- Numerical – These models represent the electronic microprocessor technology and communication used to provide extremely flexible and reliable protection. The analog current and voltage inputs are digitized, allowing manipulation and combination of phase and/or sequence phasors of various frequencies (fundamental, 2nd harmonic, etc.) to produce improved relay operation algorithms. Multiple protection functions are provided in a single device. Multiple processor chips and memory allows multiple threading. User-customized operation characteristics and logic can be implemented.

5.2 Relays modeled in stability studies

The following list identifies the protective functions or relays normally modeled for stability studies. These may represent generator protection and network protection as necessary for the analysis.

- Distance –Transmission network primary or backup protection; may include the GSU transformer in the protection zone.
- Overcurrent – Generator protection or transmission network protection backup. Voltage-restrained and voltage-controlled overcurrent functions are common generator protection.
- Voltage – Generator protection for depressed voltage; may also represent protection used in load shed schemes.

- Out of step –Generator or network protection for specific harmful power swing conditions. Typically, the protection trips generators at risk of damage or initiates power system separation.
- Loss of field – Generator protection against overheating due to partial or complete removal of the field.
- Underfrequency/Overfrequency – Generator protection for off-nominal frequency system conditions that may damage the generating unit, in particular, the turbine blades during underfrequency conditions; may also represent protection used in load-shedding schemes.
- V/Hz – Generator protection for overvoltage and/or underfrequency conditions resulting in excessive flux that may lead to overheating and eventual breakdown of insulation.

Currently available transient stability and electro-magnetic transient software usually support some type of pre-defined protection modeling capabilities, generic relay models being what is typically available. User-defined protection is possible, but adds more work to the study preparation. Computational collaboration of transient stability programs with specialized protective relay model software is possible. In this latter approach, the transient stability power system models overlap with the detailed protection system model for a closed-loop simulation, as presented in Figure 49.

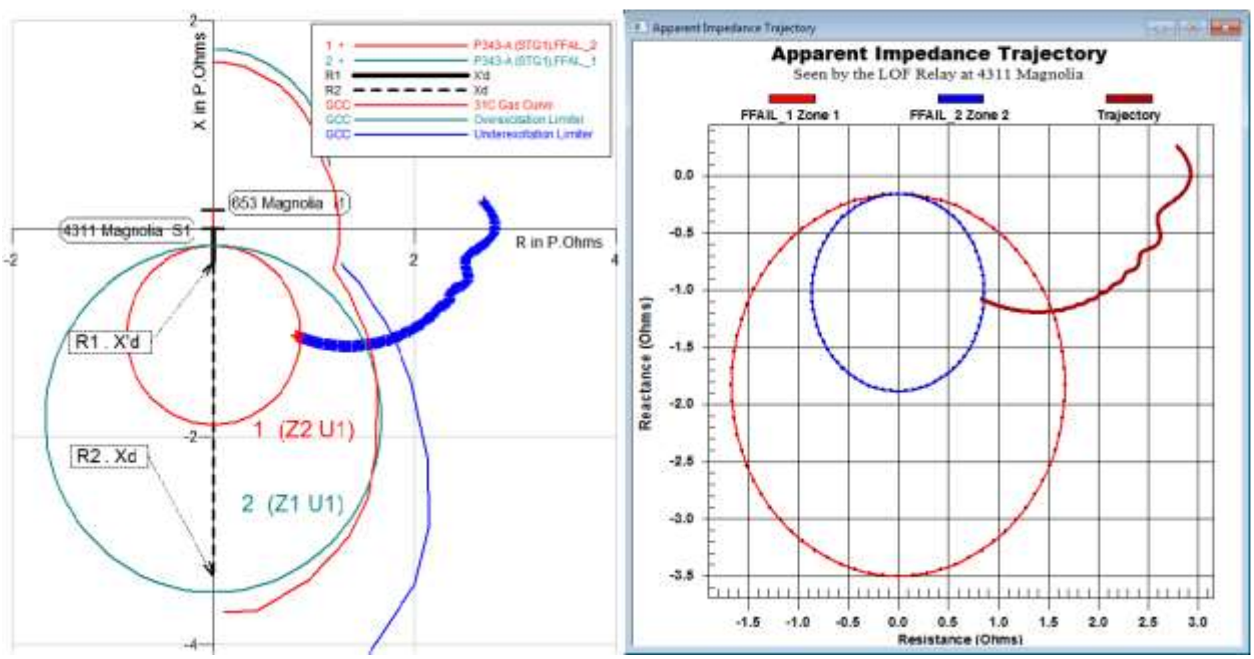


Figure 49– Closed-Loop Simulation Driven by TS Program and Specialized Protection System Model Software – Loss-of-Field Protection Study

5.3 Other considerations

5.3.1 Special protection schemes

In addition to the protection mentioned in the previous paragraph, transient stability protection studies allow design, modeling, and simulation of Special Protection Schemes (SPS) and Remedial Action Schemes (RAS).

5.3.2 Relay models and NERC Standard compliance

Relay models may be used to justify compliance with NERC standards (PRC-019, PRC-024, PRC-025, PRC-026, and others) or other regulatory requirements. Field relay settings included in the models could be used to present graphical results of coordination of generator controls with loss of field protection, voltage, frequency, etc., such as presented in Figure 50, which presents phase distance protection coordination for stable power swings.

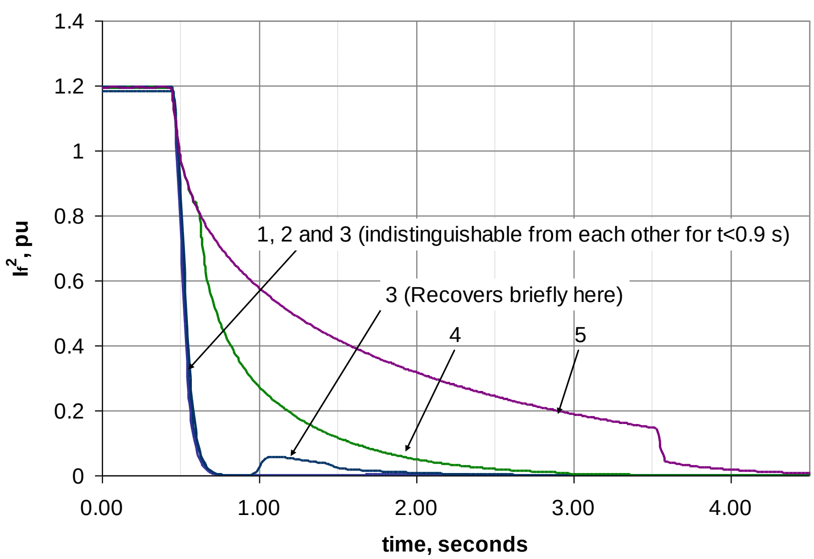
Figure 50 – Stability Boundary Check for NERC PRC-026 Compliance Study Using Detailed Relay Models

6. Modeling tripping of the generator and delaying tripping of the excitation system

An additional issue of coordinating generator protection with exciter controls is coordinating the tripping pattern with the exciter functionality. Although the generator protection tripping pattern is not a relay setting it is part of the design of the protection system, Protection engineers may find it helpful to consider the capabilities of the excitation system when designing the tripping pattern.

Some generator excitation systems may include a feature to invert the field voltage to accelerate the decay of the field in the event of a short circuit on the generator. A possible application might be to delay tripping of the generator excitation system (in the event of a generator fault) for a short time. Such a delay will allow the exciter to invert the field voltage and thus more quickly reduce the energy dissipated in the fault during rotor coast down. For instance, tests performed on a 180 MVA, steam turbine generator as reported in [9] elaborate on different energy dissipation times depending on when the field breaker was tripped, and whether or not the field voltage was inverted. In Figure 51, five different curves are shown with different tripping times of the AC field breaker (FCB), with and without field voltage inversion. Assuming the energy in the field is proportional to the square of the field current (I_f^2) the following decrement curves are plotted:

- Curve 1 – 3 second delay in tripping FCB with inversion
- Curve 2 – 1 second delay in tripping FCB with inversion
- Curve 3 – 0.4 second delay in tripping FCB with inversion
- Curve 4 – No delay in tripping FCB without inversion
- Curve 5 – 3 second delay in tripping FCB without inversion



. Figure 51 – Field Energy Dissipation for Different Field Breaker Tripping

It can be seen from Figure 51 that the use of voltage inversion results in significantly faster decay of field current, which would be helpful in reducing damage to short circuited equipment that might remain connected to the generator during coast down. Figure 51 shows negligible difference in initial energy decay rate whether the FCB is opened after 0.4, 1, or 3 seconds. This demonstrates that the effect of the voltage inversion is most pronounced in the first half second of inversion. Even tripping after a delay of only 400 ms (curve 3), the difference in energy dissipation is negligible in spite of the slight recovery in field stored energy between 1 and 1.5 seconds owing to the stored energy in the short circuited damper bars.

In cases where the excitation power comes from a transformer connected to the generator terminal, it may be beneficial to consider exactly which faults should include voltage inversion and delayed tripping of the excitation system. For instance, delayed tripping of the excitation system might be ineffective or possibly undesirable in the following cases:

1. A short circuit fault in the excitation system itself which would be aggravated by delayed tripping of the excitation, especially if it is downstream of the field breaker as shown as fault F2 in Figure 52.

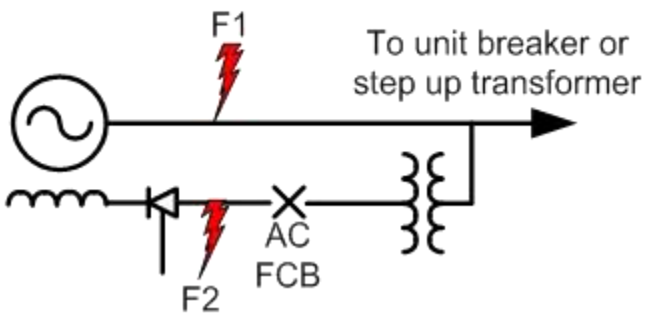


Figure 52 – Short circuit at two different locations close to the generator

   It is clear that if there is a short circuit at Location F2, there is no point in delayed tripping of the FCB to allow voltage inversion to help collapse the generator field.

2. Operation of field failure protection. Since this is indicative of a problem in the excitation system, it is probable that reversal of the field voltage will be ineffective.

3. A multiphase short circuit on the generator terminals or medium voltage isophase bus (Location F1 in Figure 52). In this case it is possible that due to the unbalanced ac voltage presented to the exciter, the excitation control system may not be effective in reversing the voltage.

4. Other excitation related problems such as overvoltage or volts/Hz protection which could be indicative of exciter control problems. Since these are not short circuits, and the exciter controls are not working reliably, there is little point in delaying tripping of the exciter to try to accelerate the field current rate of decay.

In other cases, such as faults on the high-voltage side of the unit transformer, the delayed tripping of the field to allow voltage reversal to reduce the energy supplied to the fault could be helpful.

The above comments illustrate the value of carefully considering which type of generator protection trips should initiated delayed tripping of the field.

7. Operating characteristics, settings, and coordination of overexcitation and underexcitation limiters

Referring to Section 2.2 the stator current limit can be represented on the P-Q plane as the arc of a circle with center at the origin and radius at the MVA rating of the machine for MVA values between rated leading and lagging power factors. Outside of the rated leading and lagging power factors, the stator current is further limited by field and end iron heating.

The field heating limit is derived from the design of the rotor and field winding. Thermal protection of the field windings is difficult. Primarily, field thermal protection is provided by the Overexcitation Limiter (OEL) and field overcurrent elements.

Stator end iron heating limit occurs since an underexcited generator receives a significant fraction of its excitation from the system to which it is connected. For complete loss of excitation, the machine operates as an induction generator, drawing large reactive currents from the system. This results in eddy currents being induced in the stator iron near the ends of the stator which produces damaging local heating. Loss of field (LOF) relaying provides protection against, among other hazards, thermal damage to the end iron and stator winding turns. Small generators with less advanced relays may utilize a definite level reactive power trip instead of a LOF relay or element. An example of this coordination is shown in Figure 53.

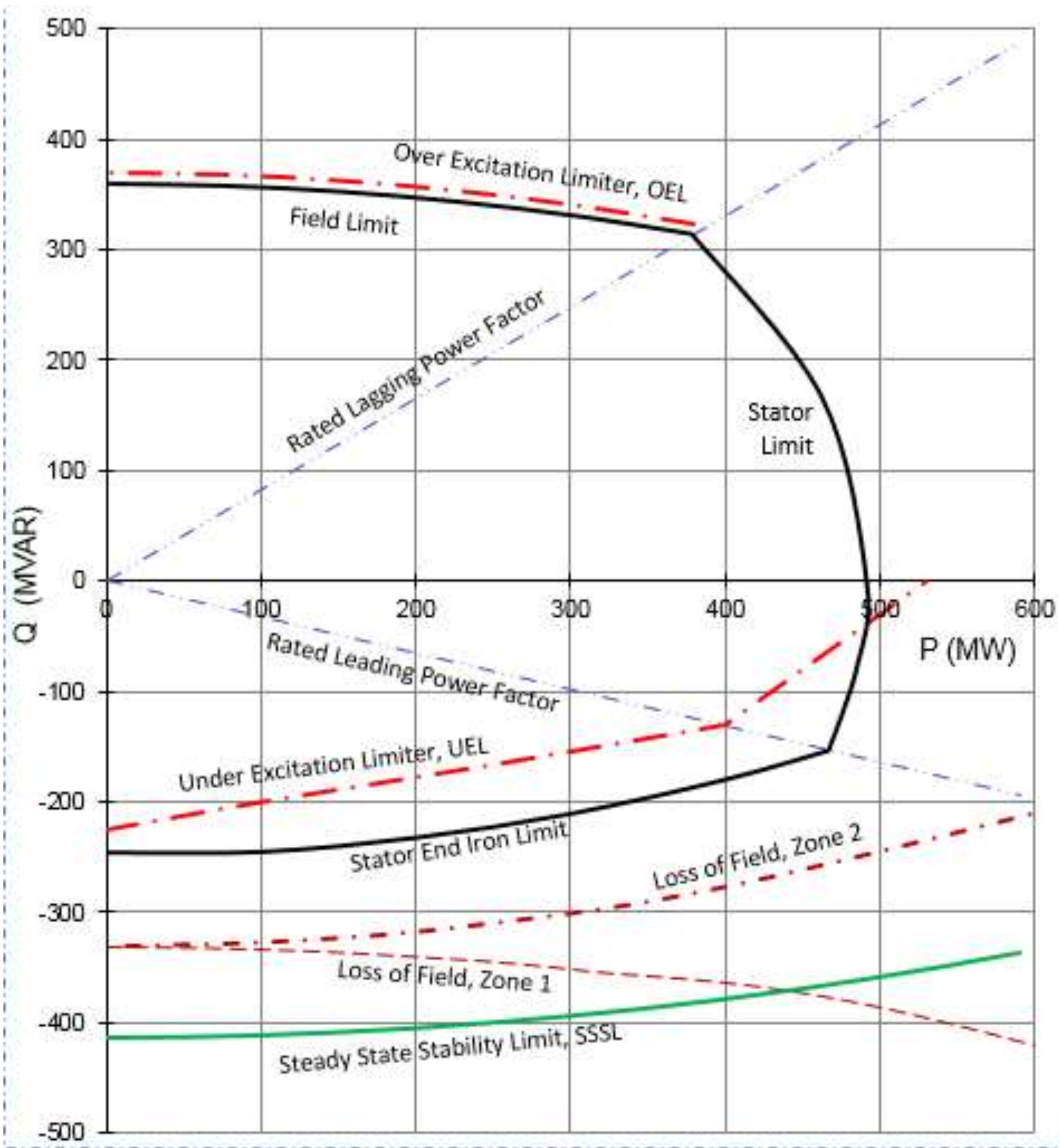


Figure 53 - IEEE C37.102 (2006) Annex A example generator capability curve in the P-Q plane including over/underexcitation limiters (OEL/UEL), steady-state stability limit, and loss of excitation protection.

7.1 Steady-State Stability Limit (SSSL) in the P-Q plane

Synchronous machines experience their lowest stability margin when operating underexcited; i.e., at leading power factor with generator voltage, $E_g < 1.0$ per unit. The steady-state stability limit (SSSL) curve is derived by modelling a “weak” transmission system representing minimum generation and plausible contingency conditions. These system conditions result in the largest expected system equivalent impedance, X_s, for the connected generator. Both generator and system voltage also impact the maximum power transfer capability, so that the generator is generally modelled near $E_g = 0.95$ per unit, while the system Thévenin equivalent voltage is typically assumed at 1.0 per unit.

Where kV_{LL} is the machine's rated line-to-line (L-L) voltage, X_d is the machine direct axis synchronous reactance, and X_s is the impedance of the system beyond the terminals of the machine (step up transformer plus Thévenin equivalent impedance of the transmission system), with both impedances in generator primary ohms. When plotting the SSSL against a UEL characteristic, consideration must be given to voltage dependency of the UEL characteristic. When the UEL characteristic is not voltage dependent, the SSSL should be plotted using a voltage of 0.95 per unit to result in worst case stability conditions for the generator. When the UEL is voltage compensated using a voltage dependency exponent of 2, the UEL and SSSL have the same voltage dependency and the SSSL characteristic can be translated to the R-X plane at 1.0 per unit voltage.

Since the SSSL curve is derived from a leading power factor, it is always plotted in the negative region (-) Mvar range and generally falls near (just outside or inside) the rotor end iron heating curve limit.

7.2 Generator Capability and SSSL in the Impedance (R-X or Z) plane

The generator capability curve and SSSL can be represented in the R-X plane of the generator characteristics as well as an aid in coordinating with protection settings for loss of field. The conversion between P-Q and R-X planes is relatively straightforward beginning with the relationship in the R-X plane:

$$\text{SSSL Center Offset} = -\tfrac{1}{2}(X_d - X_s)$$

$$\text{SSSL Radius} = \tfrac{1}{2}(X_d + X_s)$$

Where X_d and X_s are the generator and system impedances in relay secondary ohms. [C37.102]

The generator capability curve and minimum excitation limiter may also be plotted on the impedance plane using point-by-point conversions. It must also be remembered that the generator capability P-Q curves are usually plotted in primary MVA (MW and Mvar), while the R-X plane impedance data are plotted in relay secondary ohms, resulting in a direct conversion.

$$Z_{RX} = \frac{(kV_{LL})^2\ CTR}{MVA_{PQ}\ PTR}$$

Where kV_{LL} is the operating voltage, MVA_{PQ} is the (P + jQ) point in the P-Q plane, Z_{RX} (R + jX) is the point in the R-X plane, and CTR and PTR are the current and voltage transformer ratios. Resulting impedance values are in relay secondary ohms. When converting the SSSL curves from the P-Q to the R-X plane, the voltage used for the translation should be based on voltage dependency of the UEL characteristic to which it will be compared as discussed above.

Similarly, points on the R-X plane for the loss of excitation curves can be converted to plot in the P-Q plane.

$$MVA_{PQ} = \frac{(kV_{LL})^2\ CTR}{Z_{RX}\ PTR}$$

However, for the case of loss of excitation curves, the value of kV_{LL} is the generator rated voltage. These curves are shown in Figure 54.

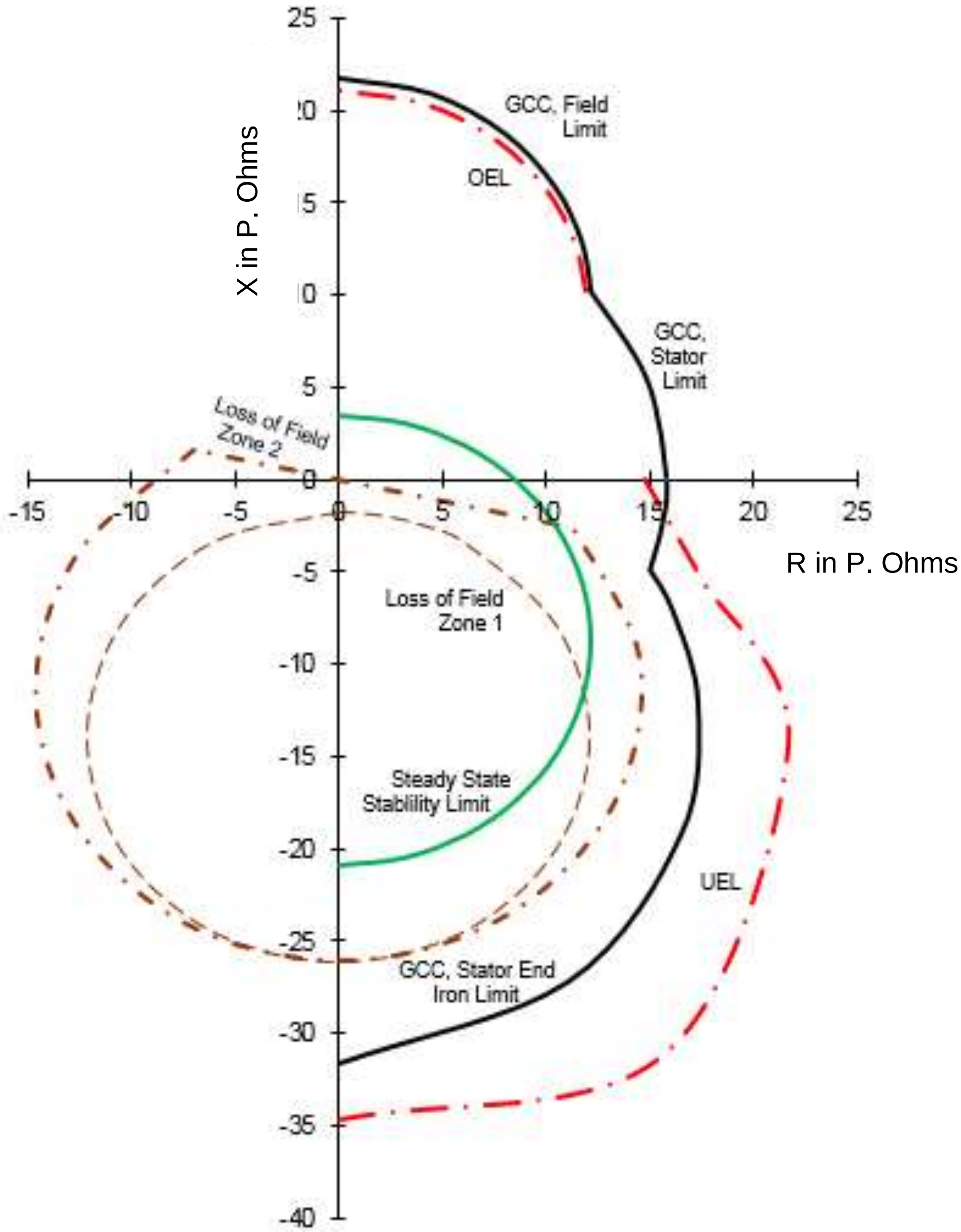


Figure 54 - IEEE C37.102 Annex A example generator capability curves in the RX plane including characteristics for over/underexcitation limiters (OEL/UEL), steady-state stability limit, and loss of excitation protection for the same machine

7.3 Transfer Assumptions from the P-Q Plane to the R-X Plane

From the equations above, the assumptions that influence the SSSL are the generator and transmission system equivalent impedances and generator excitation voltage. The generator synchronous impedance and GSU impedance are fixed by the equipment design parameters. The equivalent transmission system impedance should be modelled based on minimum generation conditions and one or more contingencies as determined by the governing planning criteria and engineering judgment. An assumed transmission system equivalent voltage of 1.0 per unit is usually satisfactory. The minimum generator terminal voltage should be based on the minimum rated leading power while avoiding the loss of excitation protection characteristics with some margin. Typically, this means a terminal voltage of about 0.95 per unit to represent the worst case underexcited (and leading power factor) condition. This terminal voltage is used because it is the lowest continuous operating condition for which the generator is rated.

7.4 Limitations of this Method

The generator capability curve is plotted at nominal voltage. It has been indicated that the sections of the capability curve are proportional to the terminal voltage or the square of the voltage. Users must be aware of the range of expected voltages over the entire range of generator loading to ensure that plant auxiliaries' voltage limits are not exceeded, typically ±5%. Generator terminal and plant auxiliary voltages are also functions of the GSU and station service transformer taps.

7.5 Determining Steady-State Underexcitation and Overexcitation Limits

The OEL characteristic is normally set near the generator capability curve. It is usually set a few percent outside (above) the field limit to accommodate equipment tolerance and allow for full use of generator capability or occasionally just inside (below) the generator capability curve to ensure that generator capability is not exceeded [8]. The OEL will typically be set within 10% of the field winding limit of the generator capability curve.

The UEL characteristic is typically set just inside the under-excited section of the generator capability curve with a short or no delay. The under-excited section of the curve is based on end-iron heating limits in cylindrical rotor machines. Generally, the UEL should also consider the SSSL. The SSSL may be more limiting than the end-iron heating limit if the generator is connected to a weak system or when the connection may be weak under an N-1 condition. If the generator is a salient pole machine, it typically has no end iron heating limit and so the SSSL is more restrictive than the under-excited section pf the generator capability curve.

7.6 Transient Exciter Operation above the Steady-State Overexcitation Limit

When a fault occurs on the transmission system, especially near a power plant, the voltages at the GSU high-voltage and generator terminals will be significantly reduced until the fault is cleared. Subsequent to fault clearing in less than the critical clearing time, the voltages will at least partially recover, but voltage and current transients ("swings") occur on both generator and transmission system until the generator and system settle at new, stable line flows and voltages, usually within a few seconds. The transients will be more severe for a fault location closer to the generator and/or for longer fault duration.

The generator exciter controls will attempt to restore the generator terminal voltage and aid in stabilizing the system by increasing field current. This action can result in exceeding the steady-state rated field current. The generator is rated to handle short-term field overcurrents, typically ranging from 209% for 10 seconds to 113% for 120 seconds [C57.13]. This short-term overload capability is actually a significant advantage in maintaining generator and system stability during and following system faults, because the maximum power transfer increases. The exciter is designed to accommodate the transient overcurrent and voltage while the exciter limiters are designed to bring the excitation current back within the overexcitation limit within the time that the machine is designed to tolerate.

7.7 Coordinating Loss of Excitation Protection with Over/Underexcitation Limits

NERC reliability standard PRC-019 requires generator owners to verify coordination between the generating unit voltage regulating controls and generator protection system settings. PRC-019 requires the generator owner to demonstrate that the in-service limiters (field overexcitation and underexcitation limiters) are set to operate before the protection system to avoid disconnecting the generator under conditions that can be corrected by the in-service limiters.

Underexcitation limiters must be coordinated with loss of field characteristics (Function 40) to allow the limiter to operate to prevent an unnecessary trip of the generator. It must be kept in mind that Function 40, loss of field, is a protective function that basically operates for a severe under-excitation condition. Therefore, it is expected that Function 40 trips the generator only after all control action by the underexcitation limiter has been exhausted, and tripping the unit is the only action left to prevent damage to the generator.

Overexcitation limiters do not require coordination with loss of field characteristics but must be coordinated with any field overcurrent protection. Function 40, loss of field, does not operate for overexcitation of the generator, and consequently, coordination with the overexcitation limiter is not required.

7.8 Other OEL and UEL Coordination Considerations

UELs and OELs typically take control during system voltage disturbance at times when generator current is often at its highest non-fault magnitude. If the generator protection incorporates any type of overcurrent elements on the armature, exciter field, or main field, the UEL/OEL and overcurrent elements should be coordinated to prevent any overcurrent trips for currents that can be produced while operating at or within the UEL/OEL settings.

8. NERC Reliability Standards

When developing generator relay settings, it is necessary to consider any applicable grid codes that specify ride-through or other coordination requirements, in addition to consideration of equipment capabilities and operating characteristics. In North America, the following NERC standards are relevant:

Standard PRC-019 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protections

Standard PRC-024 — Generator Frequency and Voltage Protective Relay Settings

Standard PRC-025— Generator Relay Loadability

Standard PRC-026 - Relay Performance During Stable Power Swings

The following subsections provide a summary of the requirements in each standard. While these summaries give a general overview, they only address a limited number of protective functions and applications. The standards provide additional information on other protective functions and applications and entities subject to compliance should consult the current versions of these standards.

It is possible to obtain different results when applying IEEE guidelines and NERC regulations for setting generator relays. If differences arise when applying both methodologies, a thorough analysis should be conducted. Normally the NERC standards prevail since those are mandatory, unless the facility engineer in charge determines otherwise for technical reasons well supported.

8.1 NERC Reliability Standard PRC-019

NERC reliability standard PRC-019 requires generator owners to verify coordination between the generating unit voltage regulating controls, limit functions, equipment capabilities, and generator protection system settings.

NERC Reliability Standard PRC-019 requires that at a maximum of every five years, each Generator Owner must coordinate the voltage regulating system controls (field limiters) with the applicable equipment capabilities and settings of the applicable protection system devices and functions. PRC-019 was approved by FERC on May 29, 2015.

NERC PRC-019 requires the generator owner to verify the following coordination items:

a. The in-service limiters (field overexcitation and underexcitation limiters) are set to operate before the protection system to avoid disconnecting the generator unnecessarily.
b. The generator protection system devices are set to operate to isolate equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits (steady-state and transient).

The evidence of coordination associated with loss of field conditions may be in the form of:

a. P-Q Diagram
b. R-X Diagram

The example of coordination in NERC PRC-019, includes a diagram that includes the equipment capabilities and the operating region for the limiters and protection functions. The following are typically plotted::

- Generator Capability Curve (underexcited and overexcited operation)
- Overexcitation Limiter (OEL) and Overexcitation Trip (OEP)
- Underexcitation Limiter (UEL) and Minimum Excitation Trip (MEP)
- System Steady-State Stability Limit (SSSL)
- Zone 1 and 2 of Loss of Field Protection (40)

The Steady-State Stability Limit (SSSL) is the limit to synchronous stability in the underexcited region with fixed field current. It can be calculated using generator reactance parameters and system impedances. Part 1.1 of Requirement R1 states that coordination should assume the normal automatic voltage regulator control loop; thus, it is acceptable to encroach on the SSSL as discussed in Section 1.3 of this report.

Figure 55 shows an example of a generator capability curve, limiters, and loss of field protection on a P-Q Diagram for a typical 645 MVA, 22 kV generator.

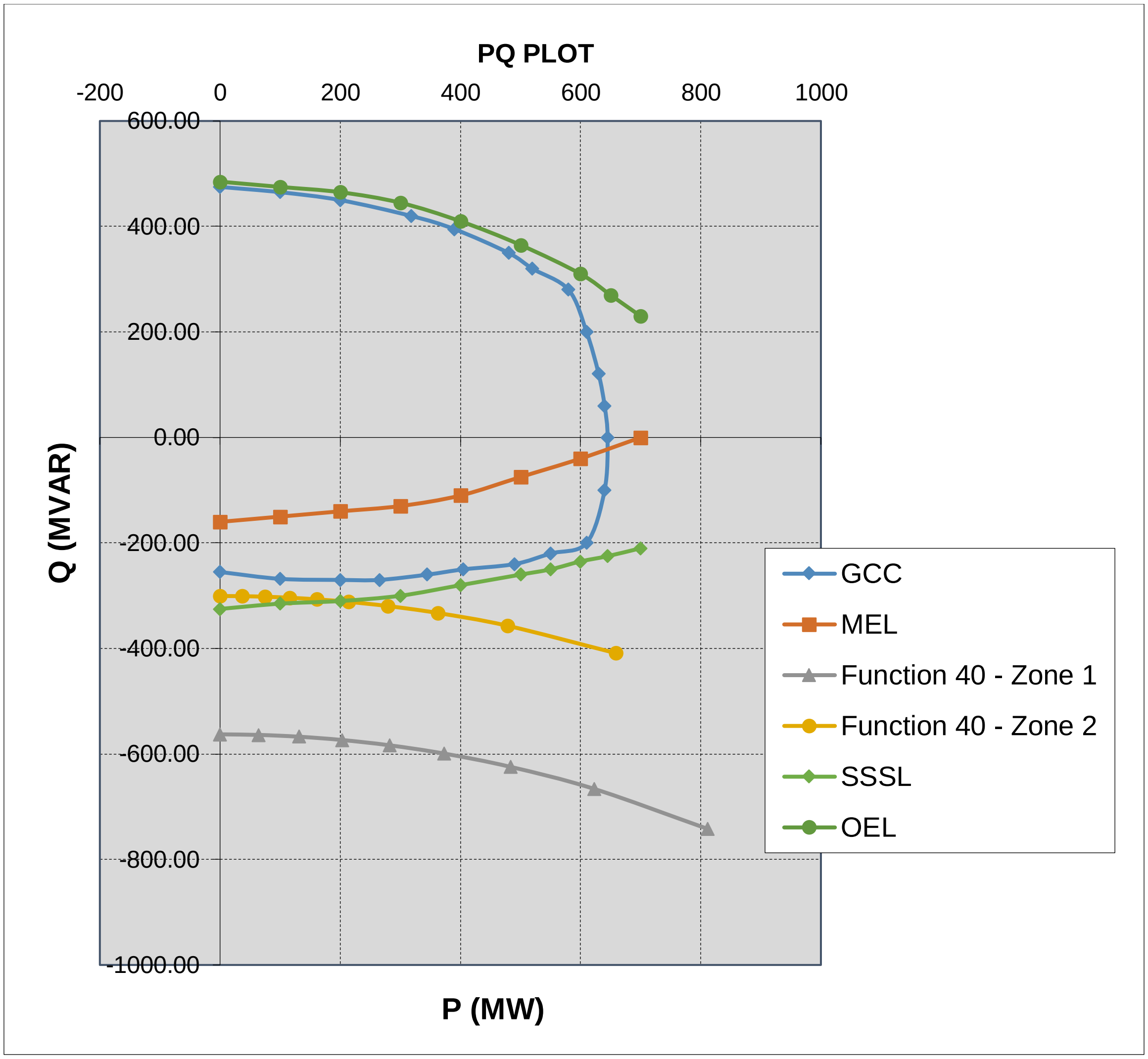


Figure 55 –Graphical Verification of Coordination per Standard PRC-019 Using a P-Q Diagram

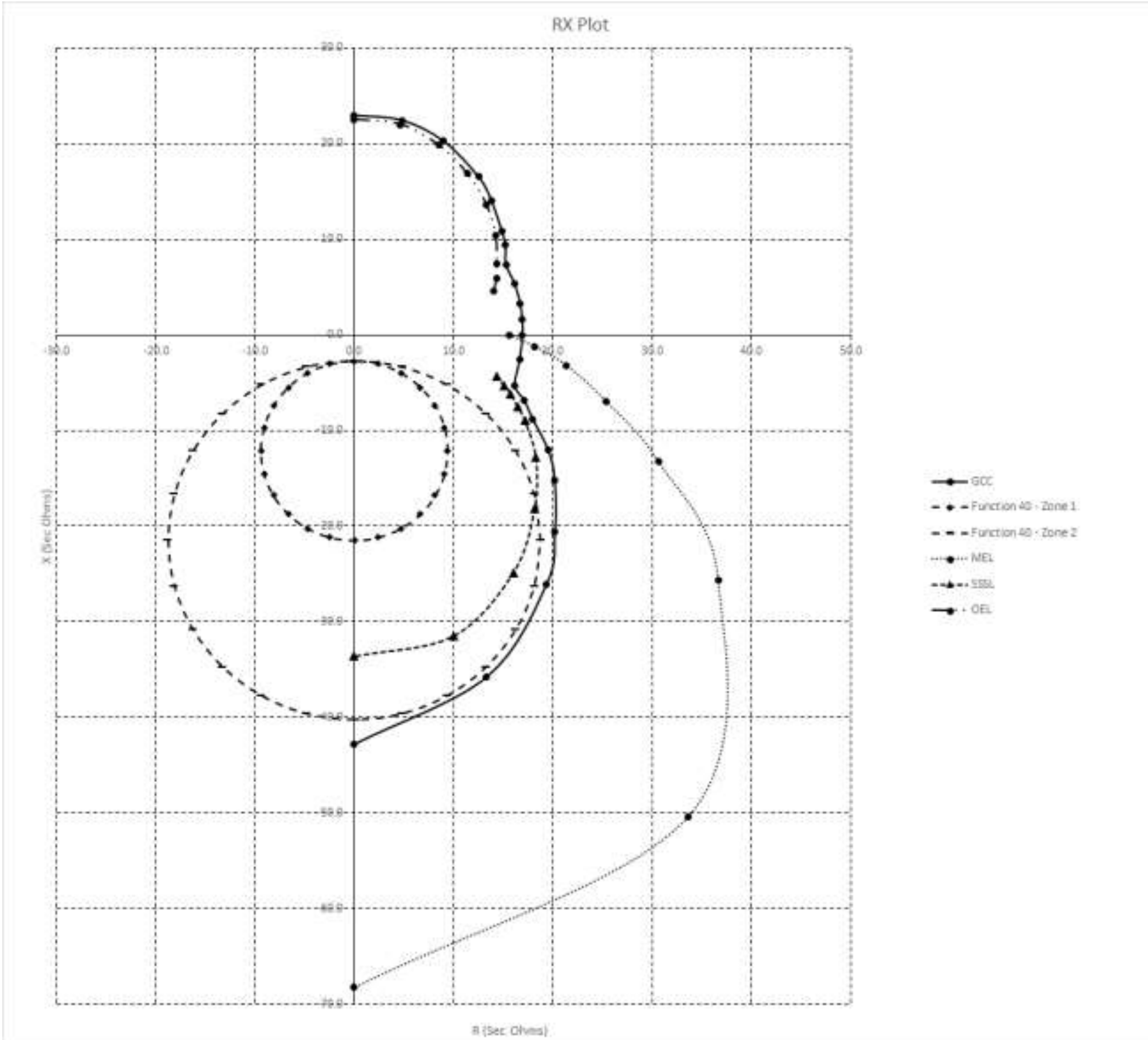


Figure 56 –Graphical Verification of Coordination per Standard PRC-019 Using a R-X Diagram

8.2 NERC Reliability Standard PRC-024

8.2.1 Frequency Relay Settings

Per NERC Std PRC-024, each Generator Owner that has generator frequency protective relaying activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no trip zone" of PRC-024 Attachment 1.

As an example, consider a turbine-generator with under and overfrequency elements set per manufacturer limits to the following values:

- Underfrequency 1: Alarm Pickup = 59.4 Hz, Time Delay = 300 seconds
- Underfrequency 2: Trip Pickup = 58.4 Hz, Time Delay = 30 seconds
- Underfrequency 3: Trip Pickup = 57.5 Hz, Time Delay = 0.2 seconds
- Overfrequency 1: Alarm Pickup = 60.6 Hz, Time Delay = 5 seconds

A plot of these characteristics is shown in Figure 57.

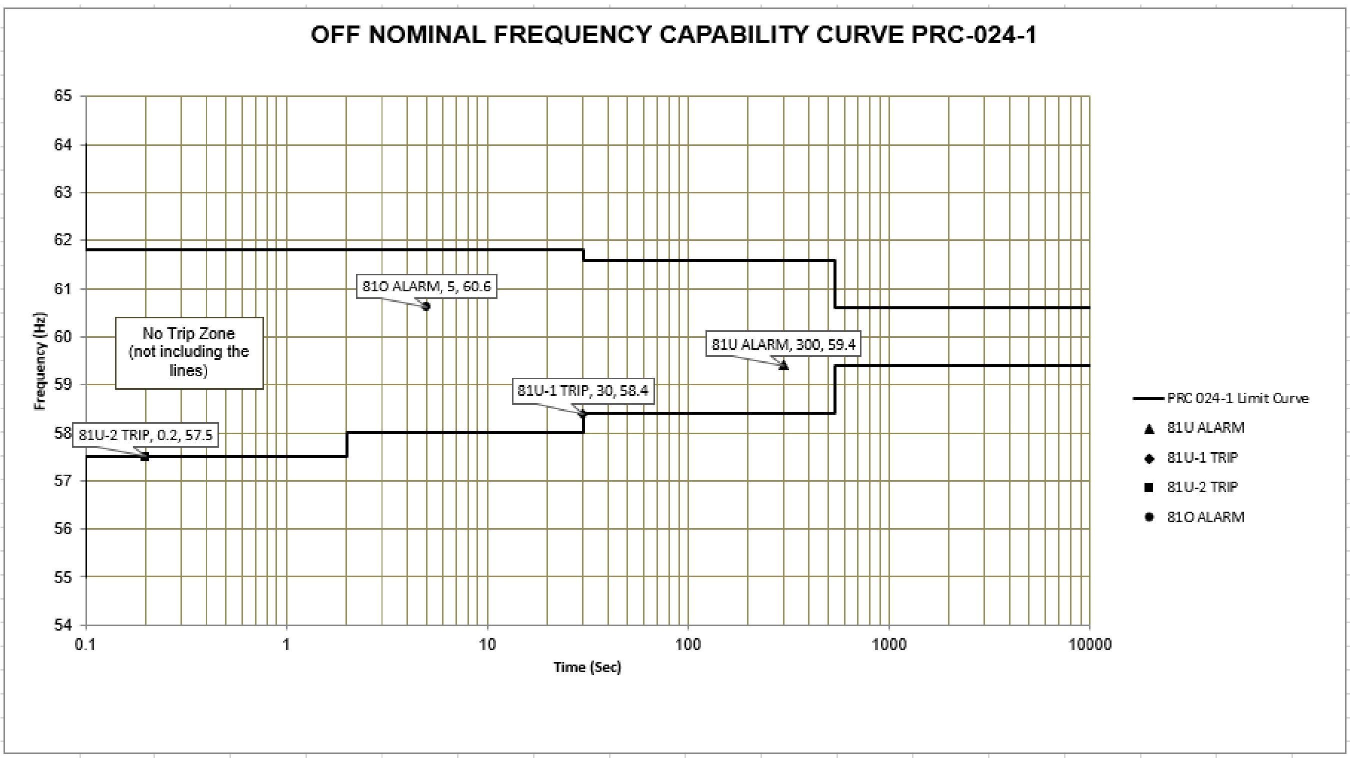


Figure 57 –Graphical Verification of Frequency – Time Coordination for ERCOT Interconnection per Std PRC-024

Therefore, the proposed frequency relay settings for this example within the ERCOT Interconnection meet the requirements established by NERC Reliability Std PRC-024, Attachment 1 for frequency relays.

8.2.2 Voltage Relay Settings

Per NERC Std PRC-024, each Generator Owner that has generator voltage protective relaying activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection) caused by an event on the transmission system external to the generating plant that remains within the “no trip zone” of PRC-024 Attachment 2.

As an example, consider a generator with overvoltage and undervoltage elements set as follows:

Overvoltage unit settings:
First stage: Alarm Pickup = 110% Vn, Time Delay = 10 seconds
Second stage: Trip Pickup = 150% Vn, Time Delay = 0.083 seconds

Undervoltage unit settings:
First stage: Alarm Pickup = 90% Vn, Time Delay = 10 seconds
Second stage: Trip Pickup = 74% Vn, Time Delay = 2.0 seconds.

See Figure 58 for a plot of these characteristics, along with the PRC-024 Voltage Ride-Through Time Duration Curve. Note that PRC-024 requires translation of the relay voltage settings from the relay voltage source location (typically at the generator terminals) to the point of interconnection for a specified set of operating conditions

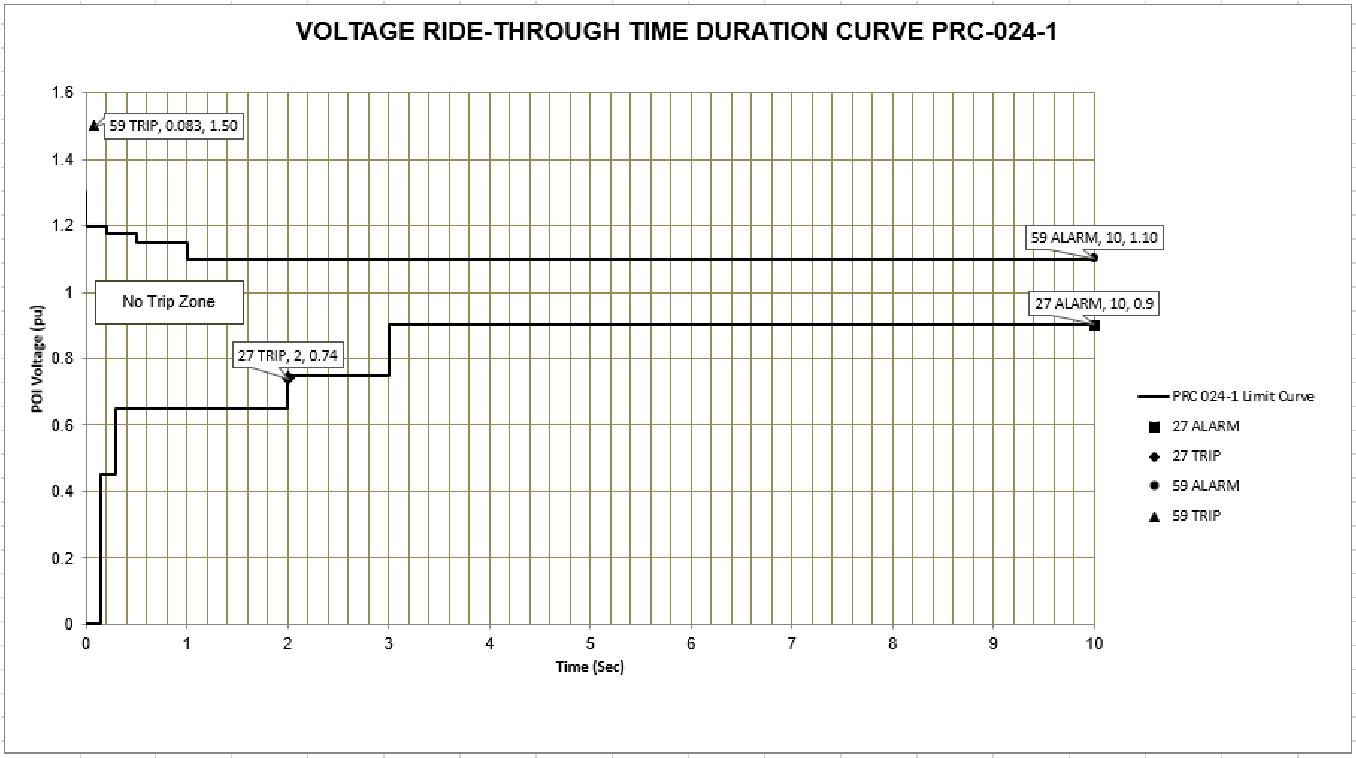
In this example it is only necessary to consider the overvoltage and undervoltage relay trip pickup values. The point of interconnection voltage differs from the generator voltage by the voltage drop across the GSU transformer and PRC-024 stipulates the voltage drop to be calculated at generator full load at 0.95 lagging power factor. For simplicity, the following assumptions are made in this example:

- Generator rated power factor is 0.95 lagging
- GSU transformer MVA base is the same as the generator
- GSU transformer reactance is 10 percent and the per unit turns ratio is 1.0

The voltage at the POI can be determined from the following equation:

$$V_{POI} = \left(\frac{MVA_{load}\ \angle \arccos{(pf)}}{V_{gen}}\right)(X_{GSU}\angle 90°)$$

Using this equation, the overvoltage setting of 1.50 pu at the generator translates to 1.48 pu at the point of interconnection, while the undervoltage setting of 0.74 pu at the generator translates to 0.71 pu at the point of interconnection. The translated trip points are plotted in Figure 58.


VOLTAGE RIDE-THROUGH TIME DURATION CURVE PRC-024-1
59 TRIP, 0.083, 1.50
59 ALARM, 10, 1.10
27 ALARM, 10, 0.9
27 TRIP, 2, 0.74
No Trip Zone
POI Voltage (pu)
Time (Sec)
PRC 024-1 Limit Curve
27 ALARM
27 TRIP
59 ALARM
59 TRIP

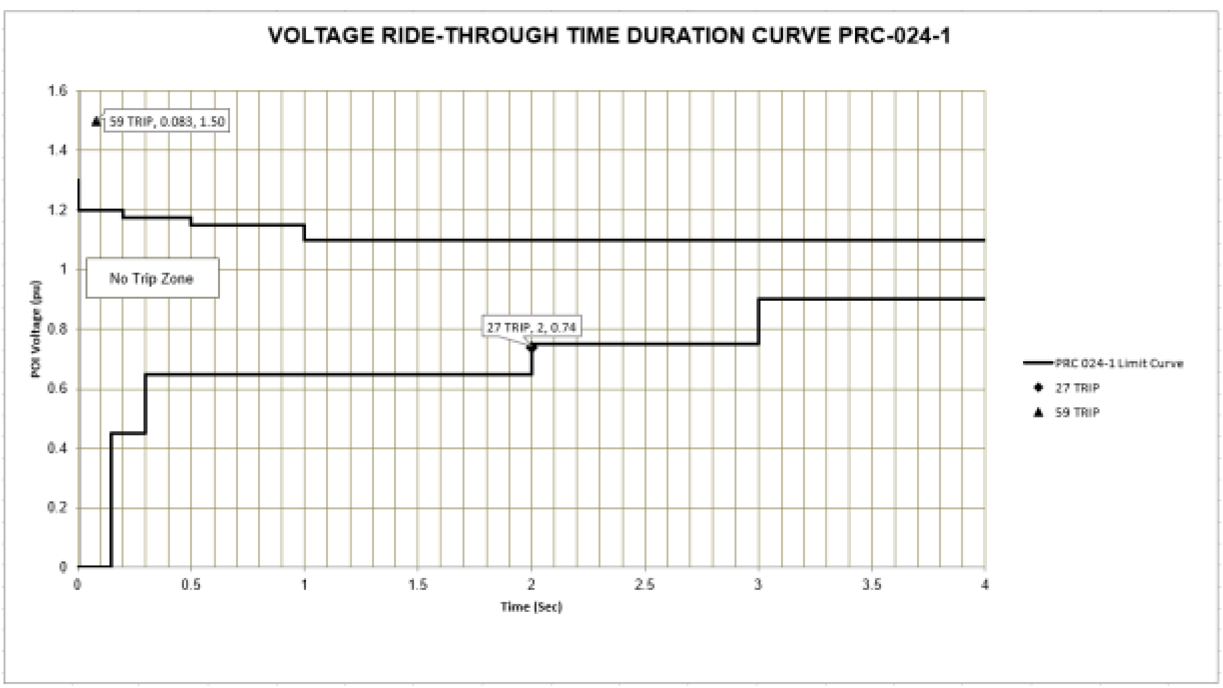

VOLTAGE RIDE-THROUGH TIME DURATION CURVE PRC-024-1
59 TRIP, 0.083, 1.50
27 TRIP, 2, 0.74
No Trip Zone
POI Voltage (pu)
Time (Sec)
PRC 024-1 Limit Curve
27 TRIP
59 TRIP

Figure 58 –Graphical Verification of Voltage – Time Coordination per Std PRC-024-3

The proposed trip set points do not fall within the 'no-trip zone' as defined by NERC Std PRC-024, Attachment 2

8.3 NERC Reliability Standard PRC-025

The purpose of the requirements of NERC Std PRC-025 is to verify that load-responsive protective relays associated with generation units are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

The standard defines requirements that apply to various relay types and applications. In most cases, more than one option is provided for demonstrating compliance based on calculations or transient stability simulation results.

As an example, one of the options (Option 1a in Table 1) for a phase distance relay function applied on a synchronous generator requires verification of the following:

- The impedance element shall be set less than the calculated impedance derived from 115% of:
  - Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and
  - Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
  - Generator bus voltage of 0.95 pu should be used to perform the verification

Evidence of compliance to the requirements of NERC PRC-025 for a phase distance relay function applied on a synchronous generator using Option 1a would be a calculation to determine the maximum allowable impedance setting for a relay. Refer to Figure 59.

Generator and Relay System Data						
Generator MVA Rating:		645	MVA			
Generator Rated pf:		0.9				
Generator Rated Voltage (Line-to-Line):		22	kV			
Real Power Output in MW as reported to the TP:		584	MW			
High Side Nominal System Voltage:		138	kV			
GSU High Side Rated Voltage:		136.8	kV			
GSU Low Side Rated Voltage:		20.9	kV			
CT ratio:		5000				
PT ratio:		200				
21 Relay MTA Setting:		90	Degrees			
Example Calculations: Option 1a						
Distance Relay (21) directional toward the Transmission System.						
Real Power output (P) (Gen MVA rating x Rated pf):				580.5	MW	Gen Rated MW output
Reactive Power Output (Q): (% of Real Power Output)		150.0%		870.75	MVAR	
Option 1a, Table 1 - Bus Voltage, calls for 0.95 p.u of the high-side nominal voltage for the generator bus voltage:						
Vgen = 0.95 pu x Vnom (High Side) x GSU ratio:		0.95		20.03	kV	
Apparent generator power (S):		P:		584	MW	Gross MW reported to TP
		Q:		870.75	MVAR	
		S:		1048.46	MVA	
		Angle:		0.9800	rad	
		Angle:		56.15	degrees	
Primary impedance (Zpri):		Vgen:		20.03	kV	
		S:		1048.46	MVA	
	Zpri:	(Vgen)^2/S:		0.3826	Prim Ohms	
		Angle:		56.15	degrees	
Secondary impedance (Zsec):		CT ratio:		5000		
		PT ratio:		200		
		Zsec:		9.5657	Sec Ohms	
		Angle:		56.15	degrees	
To satisfy the 115% margin in Option 1a:						
Zsec limit: (Zsec/% Margin)		115%		8.3180	Sec Ohms	
		Angle:		56.15	degrees	
For a Mho distance impedance relay with a maximum torque angle (MTA), then the maximum allowable impedance reach is:						
		Zsec limit:		8.3180	Sec Ohms	
		Angle:		56.15	degrees	
		Relay MTA setting:		90	Degrees	
		MTA - Angle:		33.85	Degrees	
		MTA - Angle:		0.5908	rads	
		Cos(MTA - Angle):		0.8305		
		Zmax:		10.0155	Sec Ohms	
		Zmax Angle:		90	Degrees	
The above is the maximum allowable impedance reach to meet the requirements of NERC PRC 025-1, under Option 1a.						

Figure 59 –Distance Relay Maximum Allowable Setting Calculation per Standard PRC-025, Option 1a

The proposed settings for Function 21 Zone 2 should be verified to be lower than the maximum allowable impedance calculated following NERC PRC-025 guidelines.

In some cases, the static calculation methods in Options 1a and 1b may result in a relay setting criterion that restricts the relay setting to a shorter reach or higher overcurrent threshold than is desired. In such cases, Option 1c can be utilized and may result in a less conservative relay setting criterion. An example of a transient stability simulation modeling the generator and associated controls in accordance with Option 1c is presented above in Section 1.5

8.4 NERC Reliability Standard PRC-026

The purpose of the requirements of NERC Std PRC-026 is to ensure that load responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.

The following should be provided:

- Determination whether applicable load-responsive protective relays meet the criteria given in Attachment B of PRC-026, and provide an evaluation of load-responsive protective relays based on PRC-026.
- Determination whether applicable load-responsive protective relays meet the criteria given in Attachment B of PRC-026 during their tripping operation in response to a stable or unstable power swing,
- Maintain dated evidence that demonstrates that evaluations were performed according to PRC-026. Evidence may include: apparent impedance characteristic plots, email, design drawings, R-X plots, software output, and other computer program outputs.
- A Corrective Action Plan for load-responsive protective relays found not to meet the criteria given in Attachment B of PRC-026. The Plan should bring such relays under compliance or modify their relay functions to be supervised by power swing blocking or use relay systems that are immune to power swings.

Attachment B of PRC-026 requires that an impedance-based relay used for tripping is expected to not trip for a stable power swing, when the relay characteristic is completely contained within the unstable power swing region. The unstable power swing region is formed by the union of three shapes in the impedance (R-X) plane: (1) a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7; (2) an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43; (3) a lens that connects the endpoints of the total system impedance (with the parallel transfer impedance removed) bounded by varying the sending-end and receiving-end voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance where the system separation angle is 120 degrees.

One noteworthy exception is the single blinder out of step scheme, for which it is acceptable for the blinders to fall outside the unstable power swing region. The single blinder scheme is inherently secure against operation during stable power swings because the apparent impedance trajectory must cross both blinders for the relay to operate. Therefore, the apparent impedance cannot cross both blinders without passing through the unstable power swing region defined in the standard.

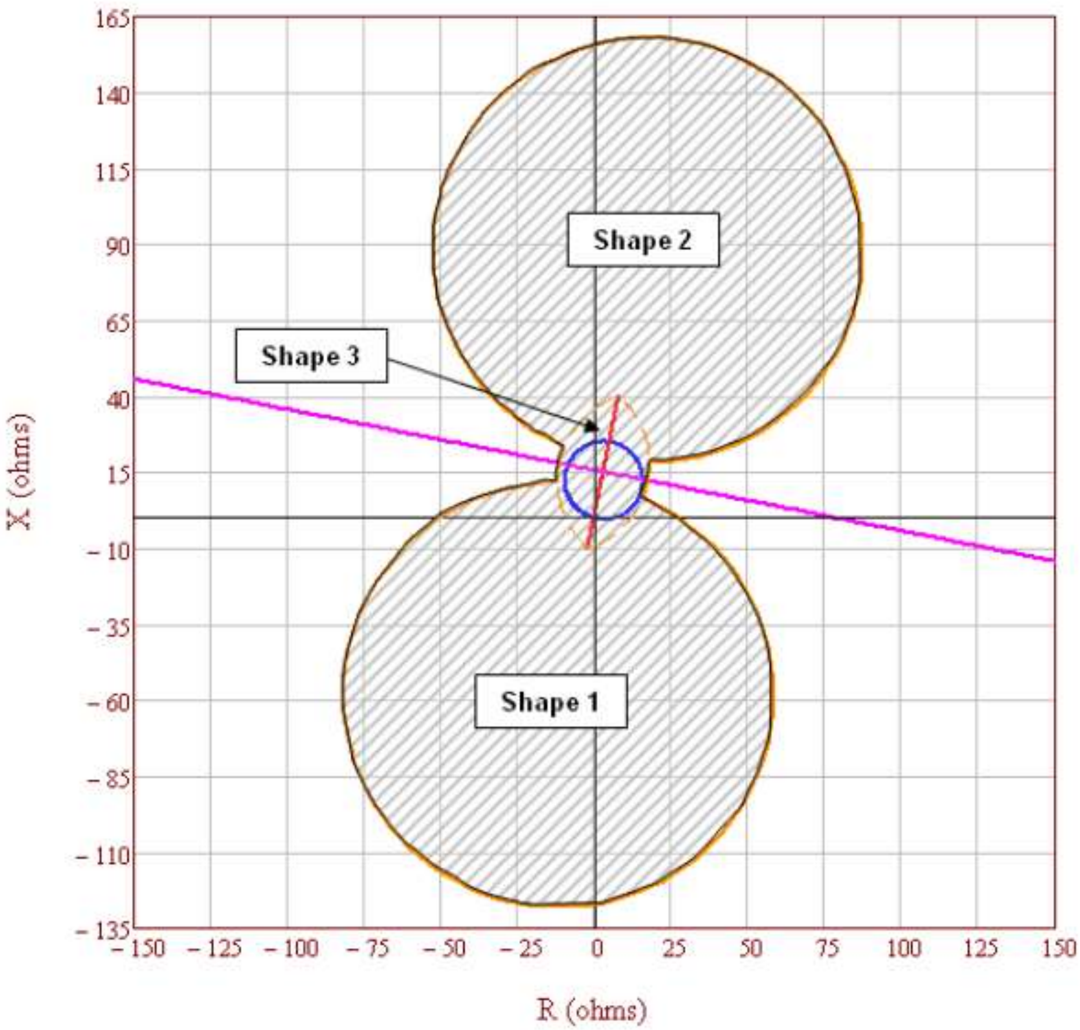


Figure 60 – Plot of unstable power swing region formed by the union of the three shapes in the RX plane as described in Attachment B of PRC-026 (reproduced from PRC-026)

9. Illustration of the Control Settings on a Protection Study

This section presents the calculations for a multifunction protective relay, applied to a generator rated 101.8 MVA, 13.8 kV, 60 Hz in order to illustrate the impact of AVR, PSS, and governor control and validate the impact of the theoretical sections that have been discussed in this paper.

The single line of the overall system that will be used in the illustration, including the generator and GSU transformer, is shown in Figure 61. The system shown is the equivalent of a real system and so the information is very realistic.

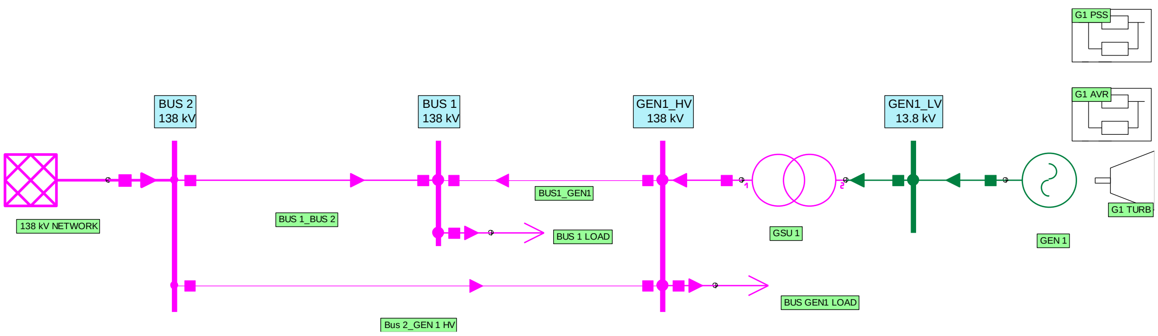


Figure 61 - Single line drawing corresponding to the illustrative example

9.1 Technical Information

The technical information data of the equipment, and generator controls is shown as follows.

System Data

System	Data
Three phase	2.19 kA
Voltage	138 kV
Xs	35.245 Ohm
Rs	9.022 Ohm

Generator Data

Generator	Data
Rated Power	101.8 MVA
Current	4259

Xd”	11.7 %
Xd´	16.3 %
Xd	198 %
Turbine	TGOV1
AVR	IEEE T1
PSS	IEEE PSS 1A

Transformer Data

Transformer	Data
Rated Power	100 MVA
Voltage	138/13.8 kV
Xt	9.27 %

9.2 Generator Controls

The controls of the generator are described as follows:

The governor control model is TGOV1 whose diagram is shown in Figure 62.

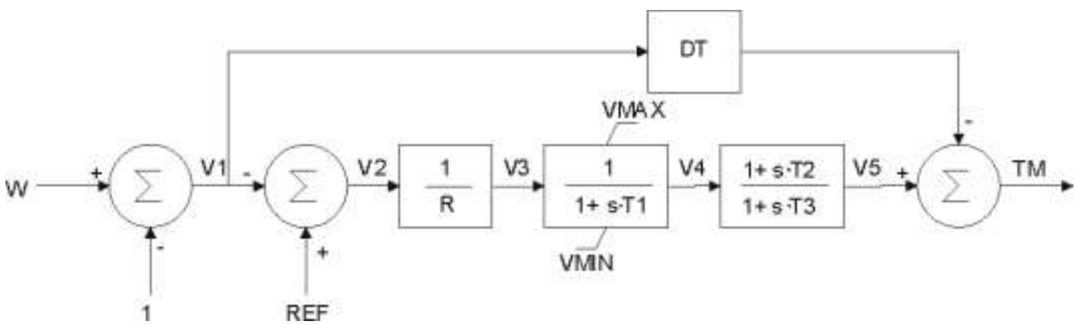


Figure 62 - Governor control model of the generator of Figure 61.

The AVR control System is IEEET1 whose diagram is shown in Fig. 63.

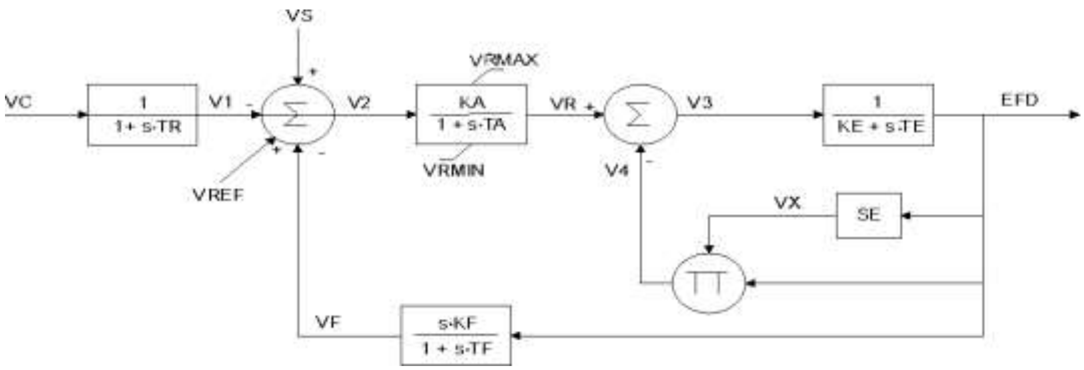


Figure 63 - AVR control system of the generator of Figure 61

The PSS control System corresponds IEEE PSS1A, whose function blocks are shown in Figure 64

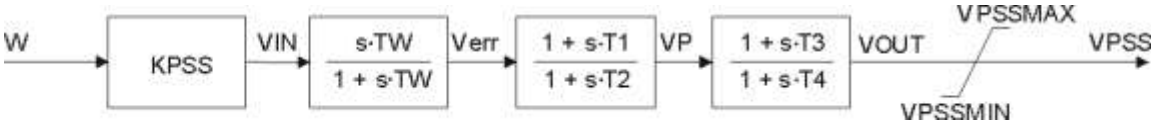


Fig. 64 - PSS control system of the generator of Figure 61

9.3 Loss of Field and Out of Step Settings

As the examples in this section pertain to loss of field and loss of synchronism events, the underexcitation and overexcitation limiters would not impact the simulations and were omitted from the model.

Based on the criteria of IEEE C37.102 and the information given above, the setting of functions 40 and 78 is as follows:

LOSS OF FIELD

FUNCTION (40)

	Setting	Unit	Criterion
Characteristic 1			
Diameter 1 (Ohm) primary	1.87	ohm	1.0 pu

Offset1 (Ohm) primary	0.15	ohm	Xd' / 2
Center 1 (Ohm) primary	1.09	ohm	
Time 1 (s)	0.5	s	
Characteristic 2			
Diameter 2 (Ohm) primary	3.70	ohm	Xd x factor (limit factor according to the generator rating)
Offset2 (Ohm) primary	0.15	ohm	Xd' / 2
Center 2 (Ohm) primary	2.00	ohm	
Time 2 (s)	1.0	s	

An illustration of the impedance trajectory is shown in Figure 65 when a loss of field condition happens.

The figure is obtained by means of a transient stability simulation with the electrical model made with the information in section 9.1, where a total loss of the generator field is established by disconnecting the DC source from the field supply.

In the simulation, the impedance trajectory enters and exits Zones 2 (blue color) and 1 (green color), but at 1.05 sec enters again Zone 1 and stays there until the simulation ends at 1.5 sec. According to this, the loss of field function operates at 1.55 sec (1.05 + 0.5).

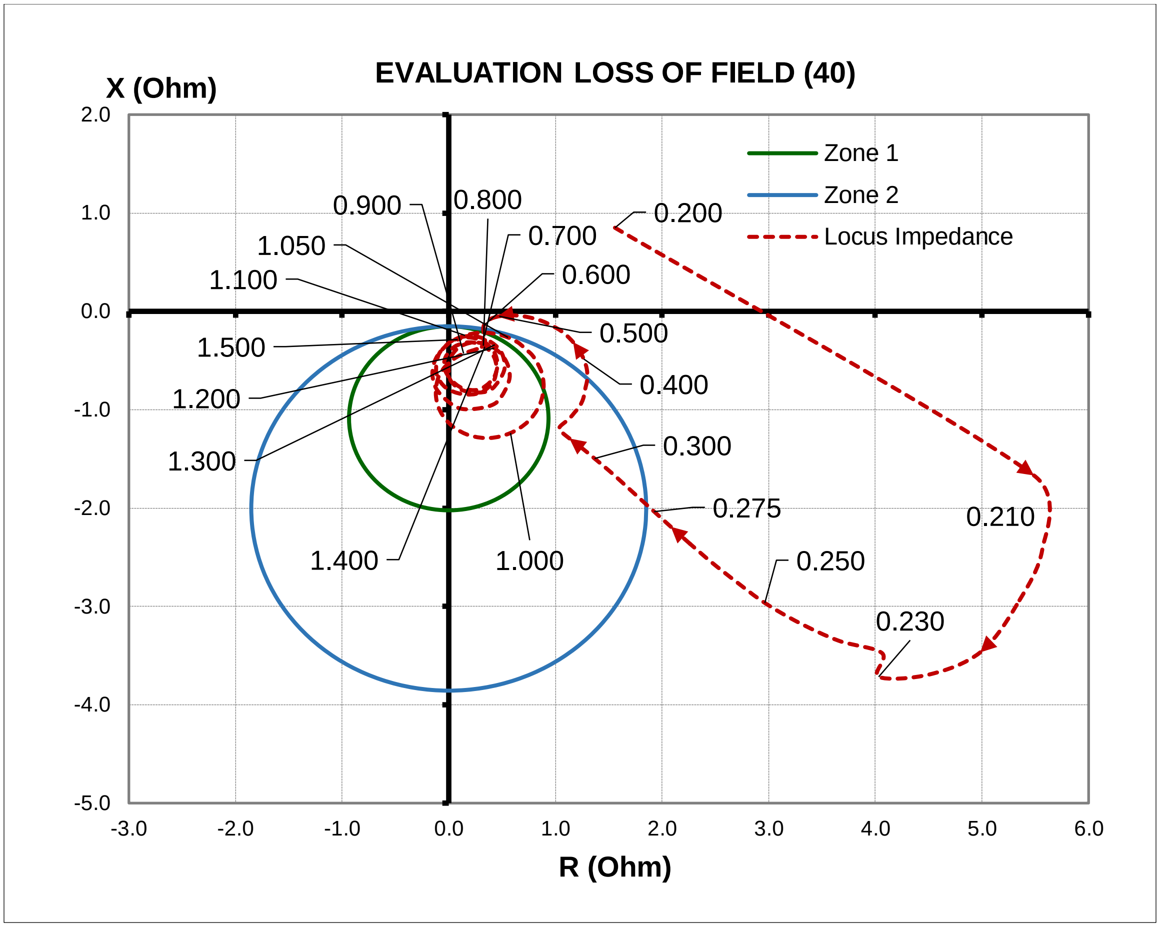


Figure 65- **Evaluation loss of field (40)**

OUT OF STEP

Mho and Blinder Characteristic

	Setting	Unit	Criterion
Mho Characteristic			
Forward Reach (Ohm) prim	0.26	Ohm	1.5 x Xt
Backward Reach (Ohm) prim	0.61	Ohm	2 x Xgen
Mho diameter (Ohm) prim	0.87	Ohm	
Angle	90	Degrees	
Blinder			
Impedance blinder d (Ohm) prim	0.24	Ohm	0.5 x (Xd' + Xt + Xsys) x Tan(θ - δ/2)
Time (s)	0.10	s	

The following figures 66 and 67 are obtained through transient stability simulations with the electrical model in figure 61, in which the application of a three-phase fault is considered, then subsequently eliminated by the actuation of the associated protections in its operating response time. The simulation does not consider the disconnection of the generator due to the operation of the protection, which is why the complete slippage of the loss of synchronism is observed.

For the first case, a power swing without loss of synchronism is presented which is shown in figure 66. The impedance trajectory in the R-X plane travels and crosses the right blinder during the failure, to then transit out of this characteristic. In this situation, the protection function does not produce operation, since a step was not taken from the right blinder to exit the left.

For the second case, a power oscillation with loss of synchronism is presented, which is shown in figure 67. In this loss of synchronism condition, the impedance path in the R-X plane travels and passes through the right blinder to exit through the left blinder, where the relay detects the condition, to produce the generator trip.

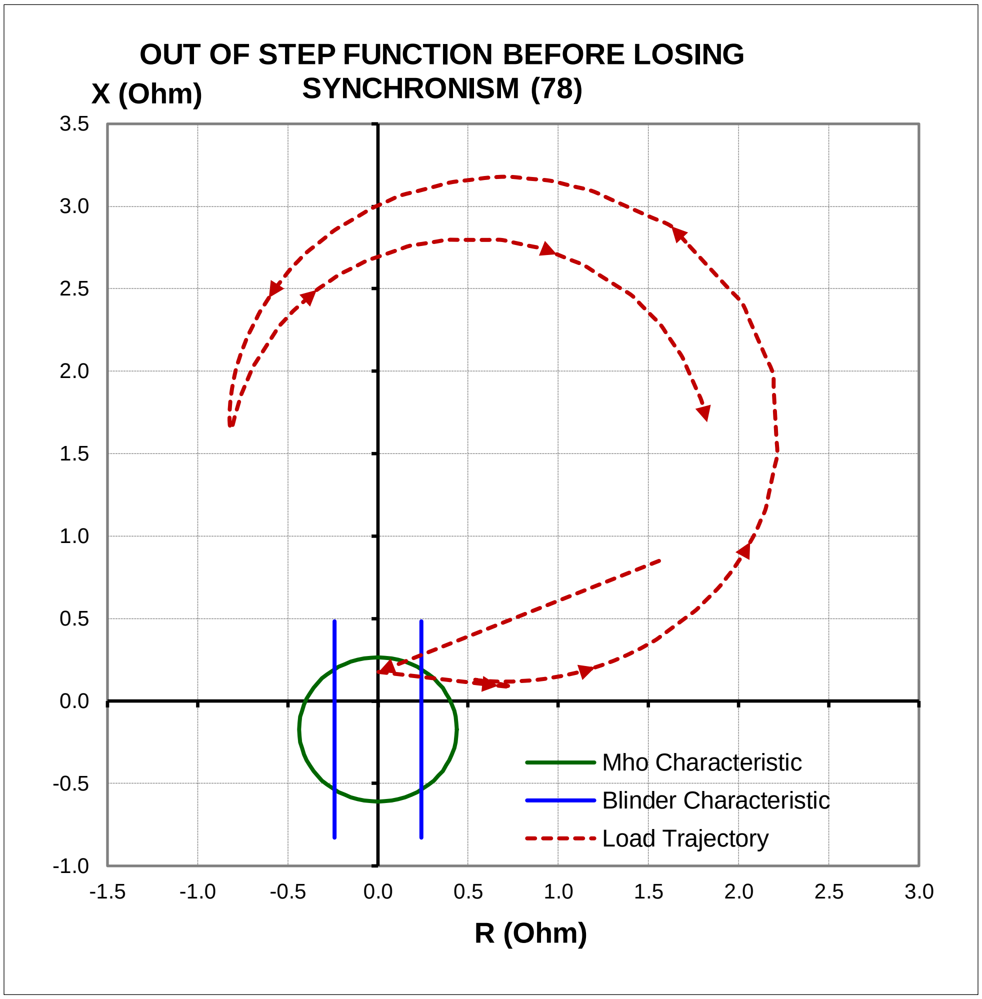


Figure 66 - Out of step function for a stable power swing

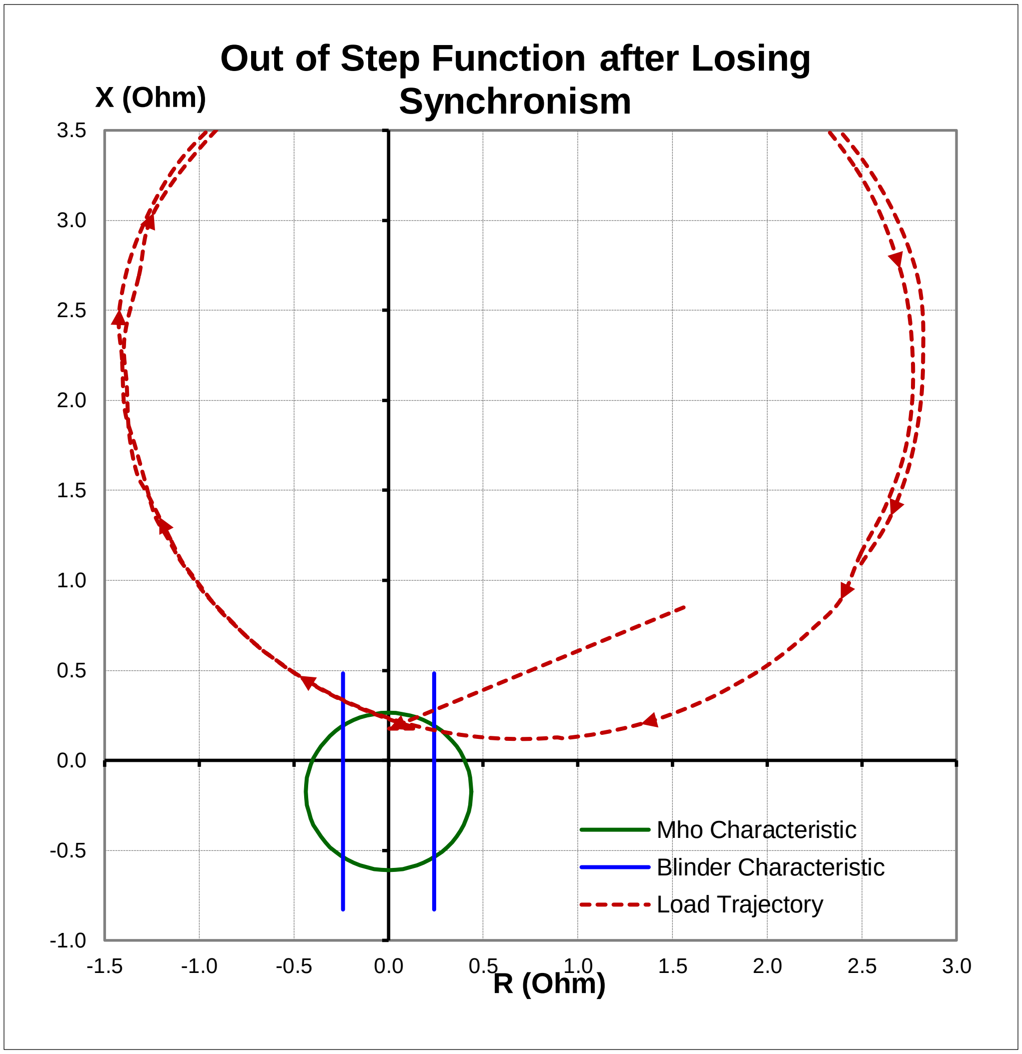


Figure 67 - Out of Step function for an unstable power swing

Effect due to loss of synchronism

With the above settings it is interesting to compare the performance of the system with and without the generator controls. Figure 69 shows that the power output stabilizes faster when the generator controls are enabled. In particular this can be due to the effect of the power system stabilizer that helps to provide supplemental damping to reduce power system oscillations.

Figure 70 shows that the system voltage magnitude recovers more quickly and to a higher level at the end of the event, due to the operation of the generator control. If the generator controls are not modeled, the voltage at the end of the simulation is lower than the voltage at the beginning of the simulation. This could present problems with the voltage relay setting meeting requirements in applicable reliability criteria.

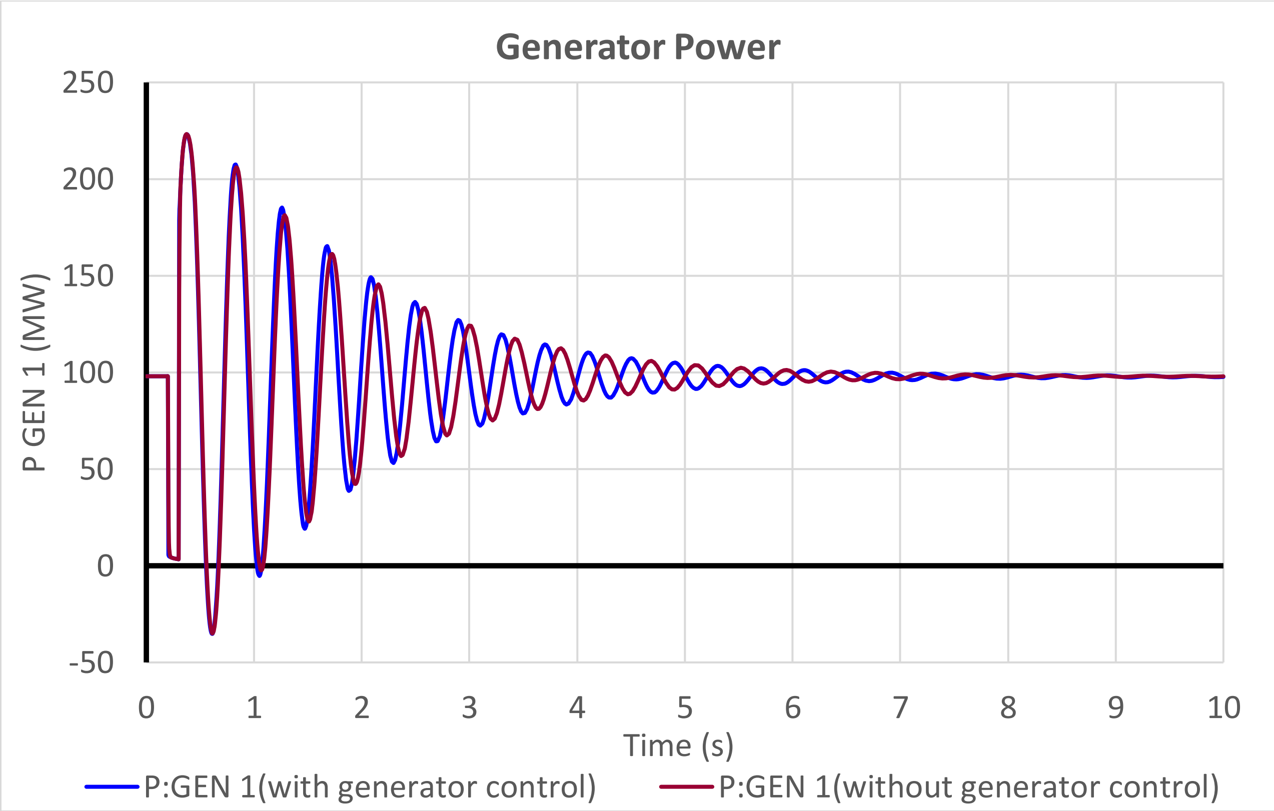


Figure 69 Differences in power output with and without controls

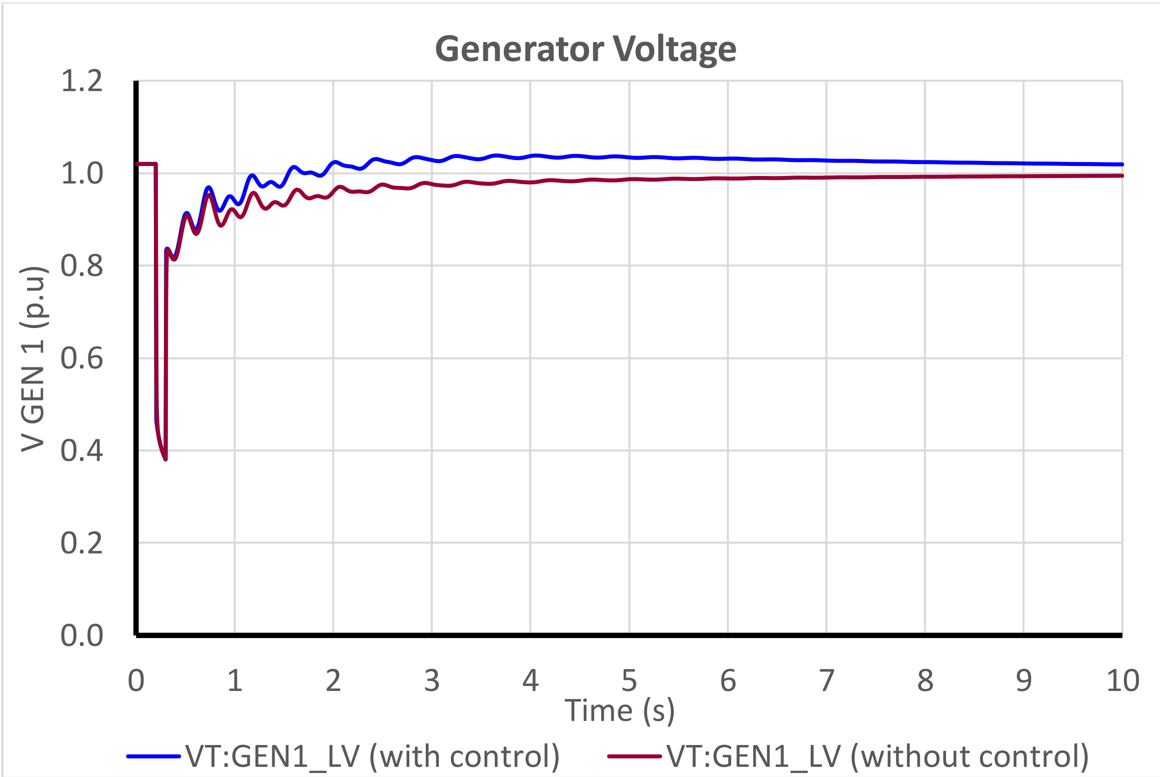


Figure 70 - Differences in voltage with and without generator controls

10. Conclusions

Setting of relays associated with generators must consider the proper characteristics of power system elements, including generators, transformers, and transmission lines. While generator relay settings can be determined using static calculations, the effects of generator controls must be considered in these calculations. It is beneficial for some relay settings to supplement calculations with transient stability studies. When transient stability studies are used to determine settings or to verify settings determined by calculation, the generator controls (excitation systems, power system stabilizers (PSS), and governors) are explicitly modeled.

Synchronous generators need to operate within their designed capability curve to ensure safe, reliable operation and long life. To facilitate this, excitation systems take into account the armature and field winding heating limitations, along with armature core end iron heating and steady-state stability limitations. These limitations are typically plotted on the complex power plane and exhibit a dependency on terminal voltage. Cooling air temperature for air cooled machines or hydrogen pressure for hydrogen cooled machines also have an impact on a machine's limitations. Various supplemental control functions are implemented in the excitation system, including overexcitation, stator current and underexcitation limiter. These limiters are implemented and modeled in IEEE Std. 421.5.™-2016.

First swing stability is a function of protective relay operating time, fault location, fault type, system configuration, etc. and can be improved by the use of high initial response excitation systems. These types of excitation systems may cause a reduction in damping to the point where low frequency oscillations can exist with generators connected to the power system. A PSS is used to provide supplemental damping to reduce power system oscillations. The PSS provides damping by modulating excitation. Many different stabilizing schemes exist, categorized by single input or dual input type PSS.

Proper coordination of limiters and protection functions will improve the availability of the machine and stability of the system. Developing protection schemes based on the thermal limits of the machine will ensure optimal protection for the machine. The overall coordination of these functions will result in the generator being able to provide maximum reactive power support without risk of damage or tripping when the reactive support is most needed by the power system.

The dynamic interaction of generator control systems with protection schemes strongly influences the stability of a power system. Modeling of dynamic power systems and protection functions permit in-depth study of conditions that may affect the integrity of the power system. Several computer software are available to model power systems for stability purposes.

For adequate stability simulation results, the accurate representation of generator protection is necessary. Likewise, protection function models for transmission lines, power transformers, power buses, etc., could also be included. Currently available software support some type of pre-defined protection modeling capabilities, with generic relay models being the most common. Detailed protection models are possible, but add more work to the study preparation. Software vendors should at the minimum include detailed relay models for phase time overcurrent, phase distance, loss of excitation, and out-of-step protection. In addition, these relay models should align with IEEE or other industry standards to ensure consistency. It would also be more convenient for the engineer performing the system stability modelling if the relay models easily translate settings for common relays from major manufacturers.

Computational collaboration of transient stability programs with specialized protective relay models is possible. For example, at least one software vendor's program can communicate between separate stability and fault calculation programs, allowing direct use of the models available in each type of program.

Detailed relay models may be used to verify coordination and to demonstrate compliance with grid code requirements, such as NERC standards PRC-019, PRC-024, PRC-025, PRC-026, and others. Including relays in the stability models, simulation results could be used to develop graphical results of coordination for generator controls with loss of field, voltage, frequency, and other generator protection functions, similar to the usual presentations for other stability model results.

Settings for generator protection should protect the generating unit from damage, while allowing the generator to remain in service for abnormal conditions during which the unit is not at risk. Thus, consideration must be given to coordination between the generator voltage regulating controls, limit functions, equipment capabilities, and generator protection system settings. This coordination may be demonstrated through graphical analysis in the R-X or P-Q planes to verify that the generator limiters are set to operate before the protection system to avoid disconnecting the generator unnecessarily, and that generator protective devices are set to trip equipment to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits. Some grid codes may require such coordination, such as NERC Reliability Standard PRC-019.

Similarly, it is important to set generator frequency and over/under voltage protective relaying to provide ride-through for voltage and frequency excursions during which the generating unit is not at risk. Some grid codes may define a “no trip zone” to ensure generator frequency and voltage relays permit generating units to remain connected during defined frequency and voltage excursions, such as NERC Reliability Standard PRC-024.

It is also important to consider ride-through capability for load-responsive protective relays associated with generating units, so that settings are at levels that prevent unnecessary tripping during a system disturbance. Grid codes may specify conditions for which generators are expected to remain on line, such as NERC Reliability Standard PRC-025. Response of protective relays during power swings is an additional concern for load responsive relays, and grid codes may require that load responsive protective relays do not trip in response to stable power swings during non-fault conditions. The use of a transient stability study and proper generator control modeling may be required to mitigate the risk of undesired tripping. In other cases, graphical methods may be allowed, such as with NERC Reliability Standard PRC-026.

11. References

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