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Why Use Power System Stabilizers?

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WHY USE POWER SYSTEM STABILIZERS?

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Abstract – In the past number of years, “power system stability” has become an increasingly popular term used in generation and transmission. The sudden requirement for power system stabilizers for use with new and existing excitation equipment has created much confusion about their applicability, purpose, and benefit to the power system. This paper will discuss the fundamentals of the power system stabilizer and its effectiveness in the system. An explanation will be provided concerning the various types of power system stabilizers and the benefit of some types over others. Lastly, the paper will address regulatory commission guidelines identified by NERC that will impact generation connected to the transmission system.

SPEED BASED STABILIZERS

To supplement the unit’s natural damping after a disturbance, the power system stabilizer must produce a component of electrical torque that opposes changes in rotor speed [4, 6, 7]. One method of accomplishing this is to introduce a signal proportional to measured rotor speed deviation into the voltage regulator input, as depicted in Figure 1.

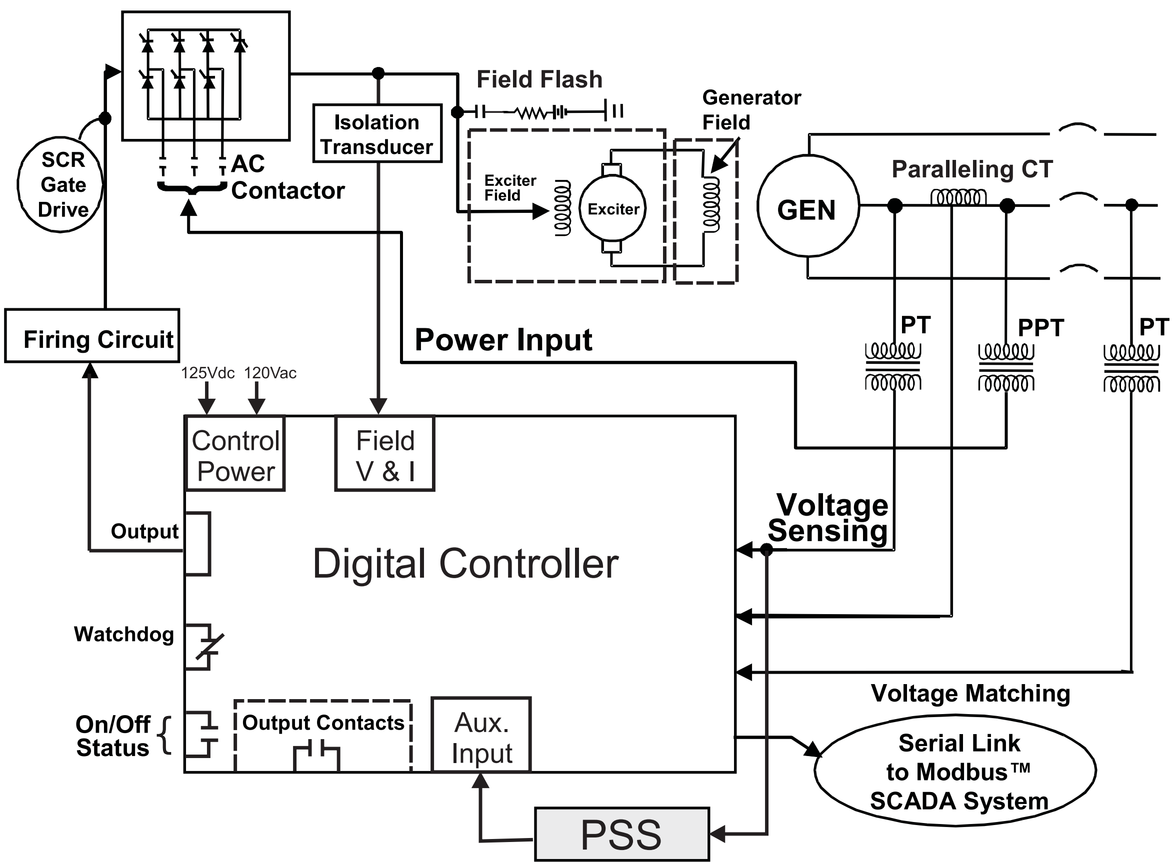


Figure 1: Block Diagram of Excitation System and PSS

Figure 2 illustrates the steps used within the speed-based stabilizer to generate the output signal. These steps are summarized below:

- Measure shaft speed using a magnetic-probe and gear-wheel arrangement.
- Convert the measured speed signal into a dc voltage proportional to the speed.
- High-pass filter the resulting signal to remove the average speed level, producing a "change-in-speed" signal; this ensures that the stabilizer reacts only to changes in speed and does not permanently alter the generator terminal voltage reference.
- Apply phase lead to the resulting signal to compensate for the phase lag in the closed-loop voltage regulator.
- Adjust the gain of the final signal applied to the AVR input.

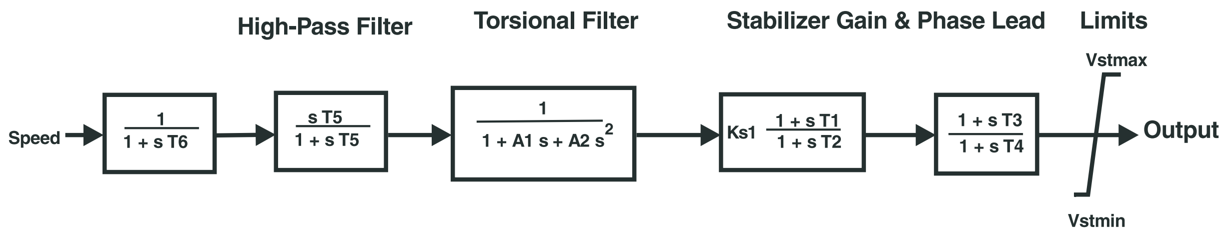


Figure 2: Speed-based Stabilizer

With some minor variations, many of the early power system stabilizers were constructed using this basic structure.

DUAL INPUT STABILIZERS

While speed-based stabilizers have proven to be extremely effective, it is frequently difficult to produce a noise-free speed signal that does not contain other components of shaft motion such as lateral shaft run-out (hydroelectric units) or torsional oscillations (steam-driven turbogenerators). The presence of these components in the input of a speed-based stabilizer can result in excessive modulation of the generator's excitation and, for the case of torsional components, in the production of potentially damaging electrical torque variations. These electrical torque variations led to the investigation of stabilizer designs based upon measured power.

Figure 3 illustrates a 2% voltage step change introduced into the voltage regulator summing point that causes the generator voltage to change by 2%. Here, a speed type power system stabilizer provides damping after the small signal disturbance to resolve the momentary MW oscillation after the disturbance. Note that the "PSS Out" changes abruptly during the disturbance to provide damping, but a constant modulation that is being applied into the excitation system even during normal operation is also observed. Although field voltage has not been recorded, one can conclude that the field voltage is also moving aggressively in response to the "PSS Out" driving the voltage regulator. The reason for the constant changing is the high noise content at the input of the speed type stabilizer. For years, the constant changes in the field voltage have alarmed operators using this type of power system stabilizer. Notice in the example that, while the generator active power is oscillatory for a few cycles after the disturbance, the terminal voltage and reactive power are very constant.

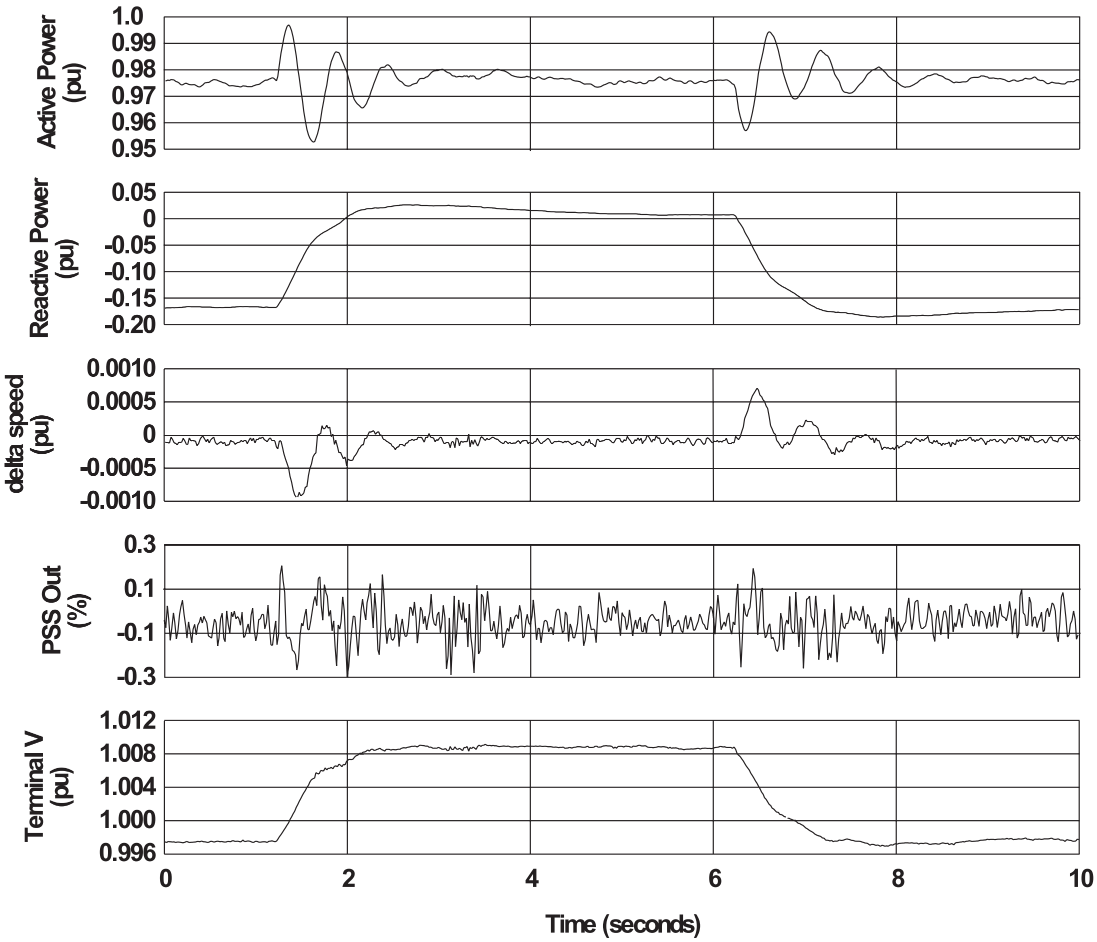


Figure 3: On-line Step Response, Frequency Type PSS
Ks=6, 92MW Hydro Turbine Generator

Incremental improvements were made to the power system stabilizer by manipulating the swing equation to derive a better method of improving the damping signal input.

$$\Delta T_e = T_s \Delta\delta + T_D \Delta\omega$$

Equation 1: Small Signal Version of "Swing Equation"

$$\frac{d}{dt}\Delta\omega_r = \frac{1}{2H}(\overline{T_m} - \overline{T_e} - K_D \Delta\overline{\omega_r})$$

Equation 2: Speed Deviation from Net Accelerating Power

The simplified swing equation can be rearranged to reveal the principle of operation of early power-based stabilizers. Based on Equation 2, it is apparent that a speed deviation signal can be derived from the net accelerating power acting on the rotor; i.e., the difference between applied mechanical power and generated electrical power. Early attempts at constructing power-based stabilizers used the above relationship to substitute measured electrical and mechanical power signals for the input speed. The electrical power signal was measured directly using an instantaneous watt transducer. The mechanical power could not be measured directly, and instead was estimated based on the measurement of valve or gate positions. The relationship between these physical measurements and the actual mechanical power varies based on the turbine design and other factors, resulting in a high degree of customization and complexity.

This approach was abandoned in favor of an indirect method that employed the two available signals, electrical power and speed. The goal was to eliminate the undesirable components from the speed signal while avoiding a reliance on the difficult to measure mechanical power signal. To accomplish this, the relationship of Equation 2 was rearranged to obtain a derived integral-of-mechanical power signal from electrical power and speed:

$$\Delta\omega = \frac{1}{2H}\left[\int \Delta T_m - \int \Delta T_e\right]$$

Equation 3: Accelerating Power Based on Integral of Mechanical and Electrical Power

Since mechanical power normally changes slowly relative to the electromechanical oscillation frequencies, the derived mechanical power signal can be band-limited using a low-pass filter. The low-pass filter attenuates high-frequency components (e.g. torsional components, measurement noise) from the incoming signal while maintaining a reasonable representation of mechanical power changes. The resulting band-limited derived signal is then used in place of the real mechanical power in The Swing Equation to derive a change-in-speed signal with special properties.

The Swing Equation has been written in the frequency domain using the Laplace operator “s”, to represent complex frequency. The final derived speed signal is derived from both a band-limited, measured speed signal and a high-pass filtered integral-of-electrical power signal. At lower frequencies the measured speed signal dominates this expression while at higher frequencies the output is determined primarily by the electrical power input.

The integral-of-accelerating-power arrangement is illustrated in the block diagram of Figure 4.

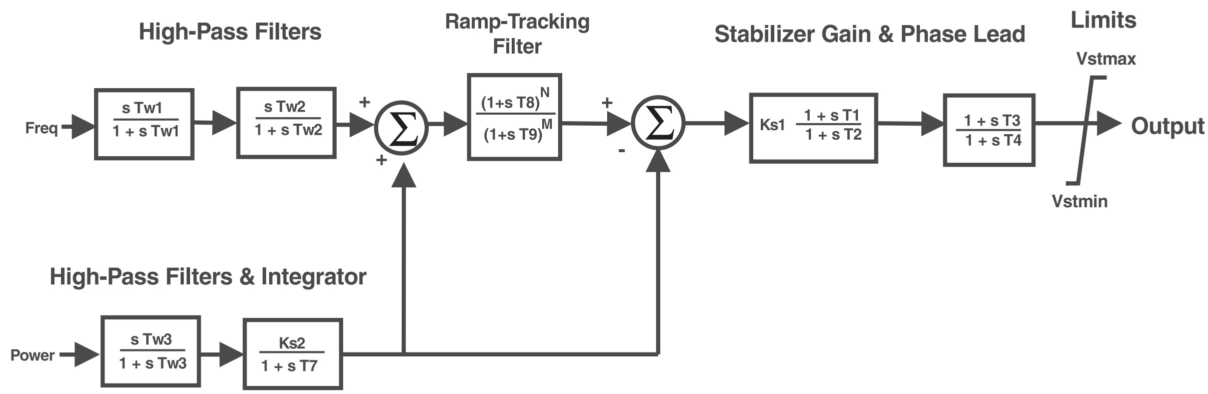


Figure 4: Block Diagram of Dual-Input Power System Stabilizer

SPEED SIGNAL

For the frequency or speed stabilizer, shaft speed was measured either directly or derived from the frequency of a compensated voltage signal obtained from the generator terminal VT and CT secondary voltages and currents. If directly measured, shaft speed is normally obtained from a magnetic-probe and gear-wheel arrangement. On horizontal turbo-generators, operating at 1800 RPM or 3600 RPM, there are normally several gear wheels already provided for the purpose of speed measurement or governing. The shaft location is not critical as long as it is directly coupled to the main turbo-generator shaft. On vertical turbogenerators (hydraulic) the direct measurement of shaft speed is considerably more difficult, particularly when the shaft is subjected to large amounts of lateral movement (shaft run-out) during normal operation. On these units, speed is almost always derived from a compensated frequency signal. In either type of generator, the speed signal is plagued by noise, masking the desired speed change information.

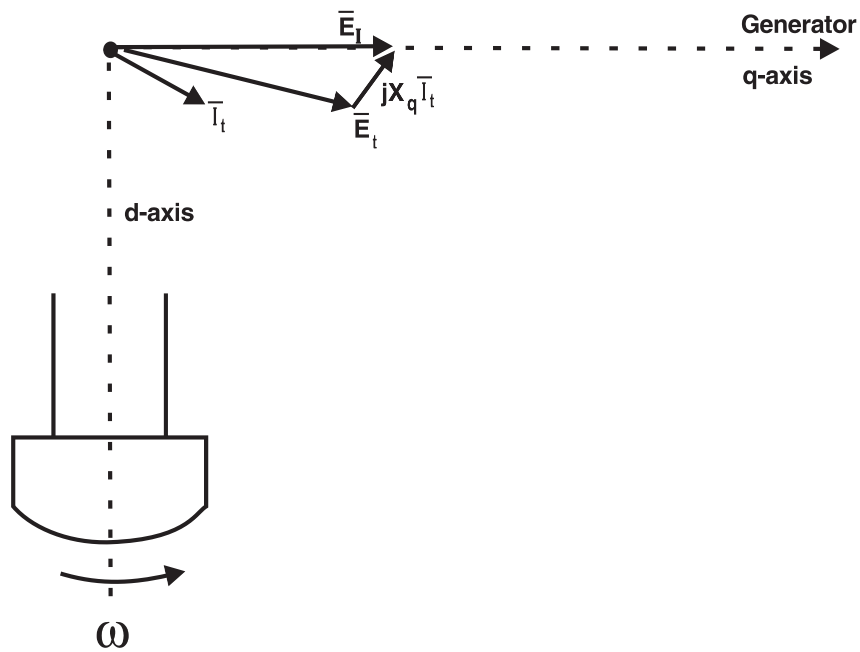


Figure 5: Speed derived from VT and CT signals

The derivation of shaft speed from the frequency of a voltage phasor and a current phasor is depicted graphically in Figure 5. The internal voltage phasor is obtained by adding the voltage drop associated with a q-axis impedance (Note: For salient pole machines, the synchronous impedance provides the required compensation.) to the generator terminal voltage phasor. The magnitude of the internal phasor is proportional to field excitation and its position is tied to the quadrature axis. Therefore, shifts in the internal voltage phasor position correspond with shifts in the generator rotor position. The frequency derived from the compensated phasor corresponds to shaft speed and can be used in place of a physical measurement. On round-rotor machines, the selection of the correct compensating impedance is somewhat more complicated; simulations and site tests are normally performed to confirm this setting.

In either case, the resulting signal must be converted to a constant level, proportional to speed (frequency). Two high-pass filter stages are applied to the resulting signal to remove the average speed level, producing a speed deviation signal; this ensures that the stabilizer reacts only to changes in speed and does not permanently alter the generator terminal voltage reference. Each high-pass filter is implemented with the following transfer function where the range of adjustment of the time constant is:

$$1.0 \leq T_w \leq 20.0 \text{ seconds}$$

Figure 6 shows the high-pass filter transfer function blocks in frequency domain form (the letter “s” is used to represent the complex frequency or Laplace operator).

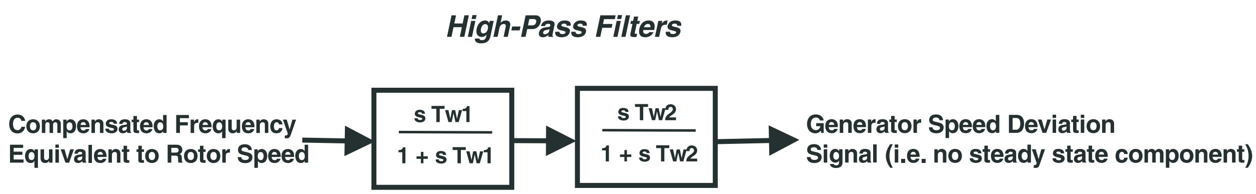


Figure 6: Accelerating-Power Design (Speed Input)

GENERATOR ELECTRICAL POWER SIGNAL

The generator electrical power output is derived from the generator VT secondary voltages and CT secondary currents. The power output is high-pass filtered to produce the required power deviation signal. This signal then is integrated and scaled, using the generator inertia constant (2H) for combination with the speed signal. Figure 7 depicts the operations performed on the power input signal to produce the integral-of-electrical power deviation signal.

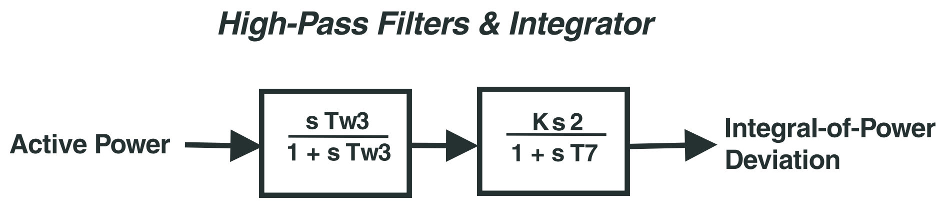


Figure 7: Integral of Electrical Power Block Diagram

DERIVED MECHANICAL POWER SIGNAL

As previously described, the speed deviation and integral-of-electrical power deviation signals are combined to produce a derived integral-of-mechanical power signal. This signal is then low-pass filtered, as depicted in the block diagram of Figure 8.

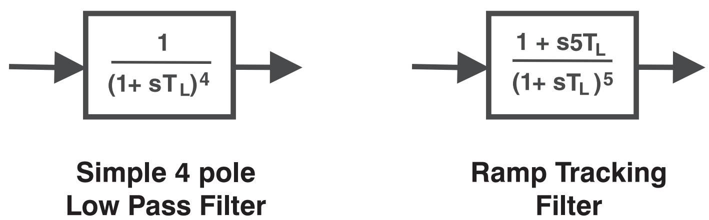


Figure 8: Filter Configurations for Derived Mechanical Power Signal

A low-pass filter can be configured to take on one of the following two forms:

- The first filter, a simple four-pole low-pass filter, was used to provide attenuation of torsional components appearing in the speed. For thermal units, a time constant can be selected to provide attenuation at the lowest torsional frequency of the turbogenerator set. Unfortunately, this design requirement conflicts with the production of a reasonable derived mechanical power signal, which can follow changes in the actual prime mover output. This is particularly problematic on hydroelectric units where rates of mechanical power change can easily exceed 10 percent per second. Excessive band-limiting of the mechanical power signal can lead to excessive stabilizer output signal variations during loading and unloading of the unit.

- The second low-pass filter configuration deals with this problem. This filter, referred to as a “ramp-tracking” filter, produces a zero steady-state error to ramp changes in the input integral-of-electrical power signal. This limits the stabilizer output variation to very low levels for the rates-of-change of mechanical power that are normally encountered during operation of utility-scale generators. The range of adjustment of the filter time constant is:

$$0.05 \le T \le 0.2 \text{ seconds}$$

STABILIZING SIGNAL SELECTION AND PHASE COMPENSATION

As depicted in the simplified block diagram of Figure 4, the derived speed signal is modified before it is applied to the voltage regulator input. The signal is filtered to provide phase lead at the electromechanical frequencies of interest i.e., 0.1 Hz to 5.0 Hz. The phase lead requirement is site-specific, and is required to compensate for phase lag introduced by the closed-loop voltage regulator.

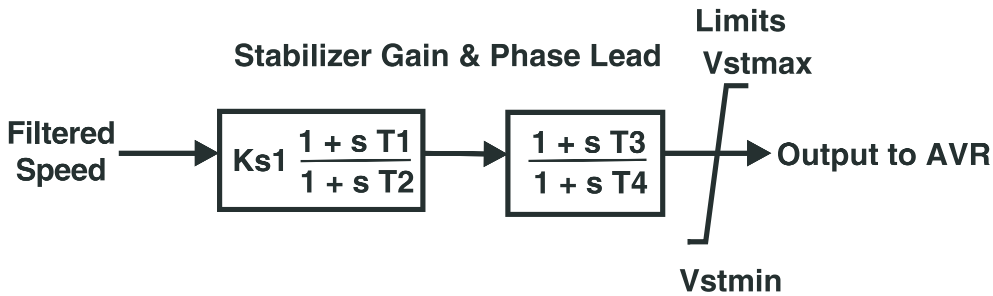


Figure 9: Output stage of PSS to AVR

The diagram of Figure 9 depicts the phase compensation portion of the digital stabilizer. The transfer function for each stage of phase compensation is a simple pole-zero combination where the lead and lag time constants are adjustable within the range:

$0.01\text{ s} \leq TLD \leq 6.0\text{ s}$

$0.01\text{ s} \leq TLG \leq 6.0\text{ s}$

Tests are performed to determine the amount of compensation required for the generator/excitation system by sending a low frequency signal into the voltage regulator auxiliary summing point input and then by measuring the generator output for phase shift and gain over the frequency range as compared to the input signal. These tests are normally performed with the generator at or above 75% load. Figure 10 illustrates the results of a typical test performed to determine the phase lag of the voltage regulator/generator interconnected to the system without the power system stabilizer. Compensation is then provided through the lead lag of the power system stabilizer to ensure that the voltage regulator will be responsive to the frequency range desired. Here, phase lead is needed above 1 Hertz as shown by the solid line in Figure 10.

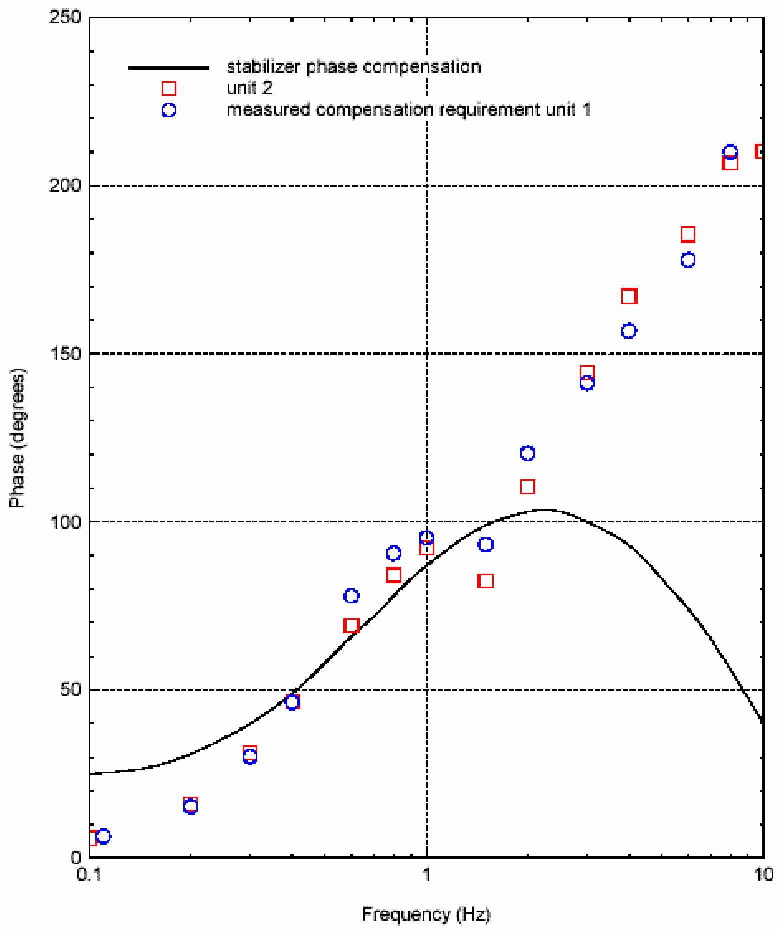


Figure 10: Phase Compensation denoted with and without the Power System Stabilizer

TERMINAL VOLTAGE LIMITER

Since the Power System Stabilizer operates by modulating the excitation, it may counteract the voltage regulator's attempts to maintain terminal voltage within a tolerance band. To avoid producing an overvoltage condition, the PSS may be equipped with a terminal voltage limiter that reduces the upper output limit to zero when the generator terminal voltage exceeds the set point, ET_LIM. The limit set point may be adjusted within the range:

0.9 pu Et $\leq$ ET_LIM ≤ 1.25 pu Et

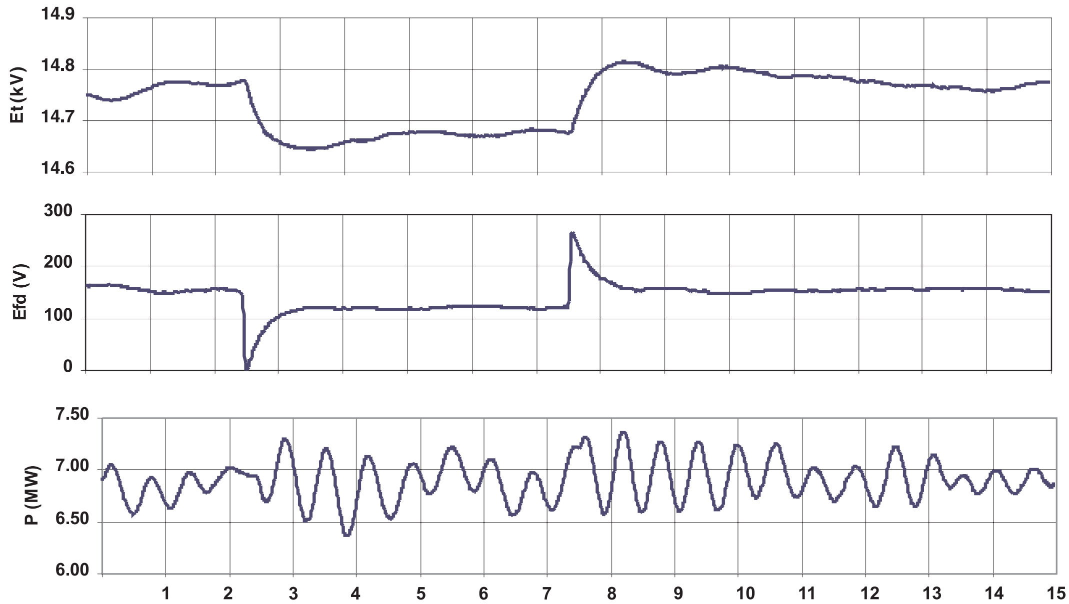
This level is normally selected such that the limiter will operate to eliminate any contribution from the PSS before the generator's time delayed overvoltage or V/Hz protection operates.

The limiter will reduce the stabilizer's upper limit, PSSPLUS, at a fixed rate until zero is reached, or the overvoltage is no longer present. The limiter does not reduce the AVR reference below its normal level; it will not interfere with system voltage control during disturbance conditions. The error signal (terminal voltage minus limit start point) is processed through a conventional low-pass filter to reduce the effect of measurement noise. The range of time constant adjustments is as follows:

$0.0 \text{ s} \leq TL \leq 5.0 \text{ s}$

CASE STUDIES

A small hydro turbine generator was experiencing potentially damaging power oscillations when the unit load was increased to more than 0.5 pu, with oscillations triggered by small changes in load or terminal voltage. The oscillations could be triggered by a step change in unit terminal voltage. The waveforms in Figure 11 illustrate the test results indicating that the oscillations under the test condition were damped, but with significant duration. This condition occurred after the unit was upgraded from manual control to a modern static exciter system with high initial response characteristic.



Hydro Generator without PSS
FIGURE 11

When the PSS, a dual input type power system stabilizer, was implemented, the response of the turbine generator was substantially improved, showing much greater damping capability compared to the performance in Figure 11. In operation, with the settings of the PSS set as indicated in Figure 12, the unit was able to deliver rated load once again, with no danger from power oscillations threatening to damage the machine. This is an example of a local area oscillation. The combination of high performance excitation and the compensation of the PSS provides the best combination of performance benefits for this hydro turbine installation.

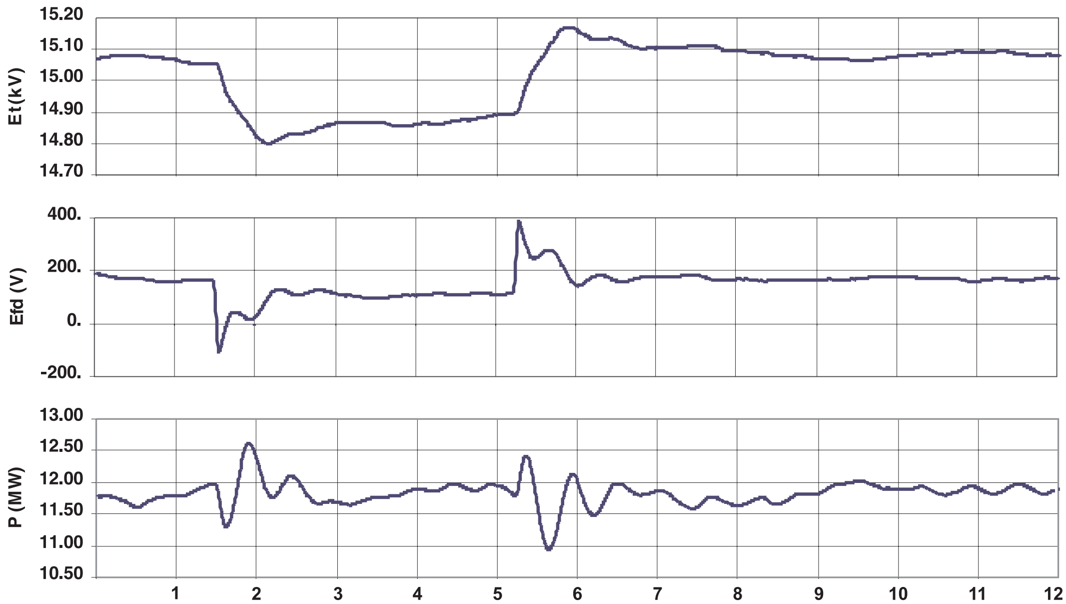


Figure 12: Hydro Generator with PSS
(Basler PSS-100 Stabilizer, Phase Lead = (1+0.05s)/ (1+0.01s), Gain = 40)

The benefits of a newly installed dual-input type power system stabilizer (Figure 13) versus those of the existing single input power system stabilizer (Figure 3) for the same machine can be seen in the on-line step response of a 92MW hydro turbine generator to system oscillations. The speed-based stabilizer produces a significant amount of noise in the stabilizing signal. This noise limits the maximum Ks gain to 6.2. With the dual-input type, the noise is considerably less, allowing higher gain, Ks=7.5s and more effective damping as illustrated in Figure 13.

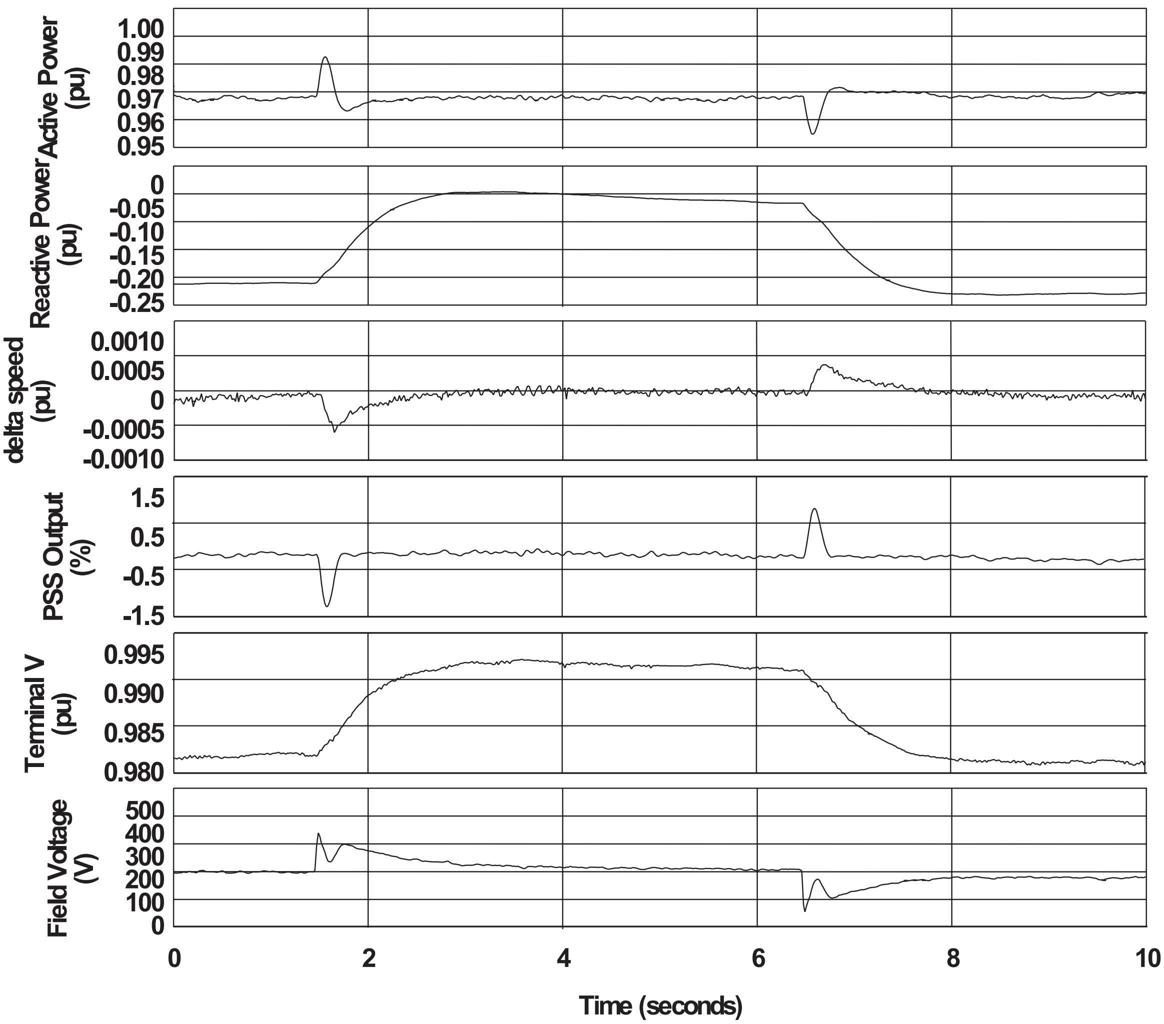


Figure 13: On-line Step Response, Basler PSS-100
Ks=7.5, 92MW Hydro Turbine Generator

600MW of generation was being added to a 345kV transmission line tying an existing nuclear plant to the grid. The nuclear plant contained two units, each rated at 1165MW.

One unit already had a PSS; the other did not. Power system studies revealed that a PSS was needed on the second unit when the new plant came on line. A dual-input Integral of Accelerating Power type PSS was selected. Step response tests were performed. The nuclear unit had a 1Hz local mode oscillation and a relatively low frequency 7Hz torsional mode. A modified version of the standard PSS was installed.

The “before” and “after” responses are shown in Figures 14 and 15. The PSS response shows an increase in the damping of an already well damped generator. The real test will come as the new 600MW plant comes on line.

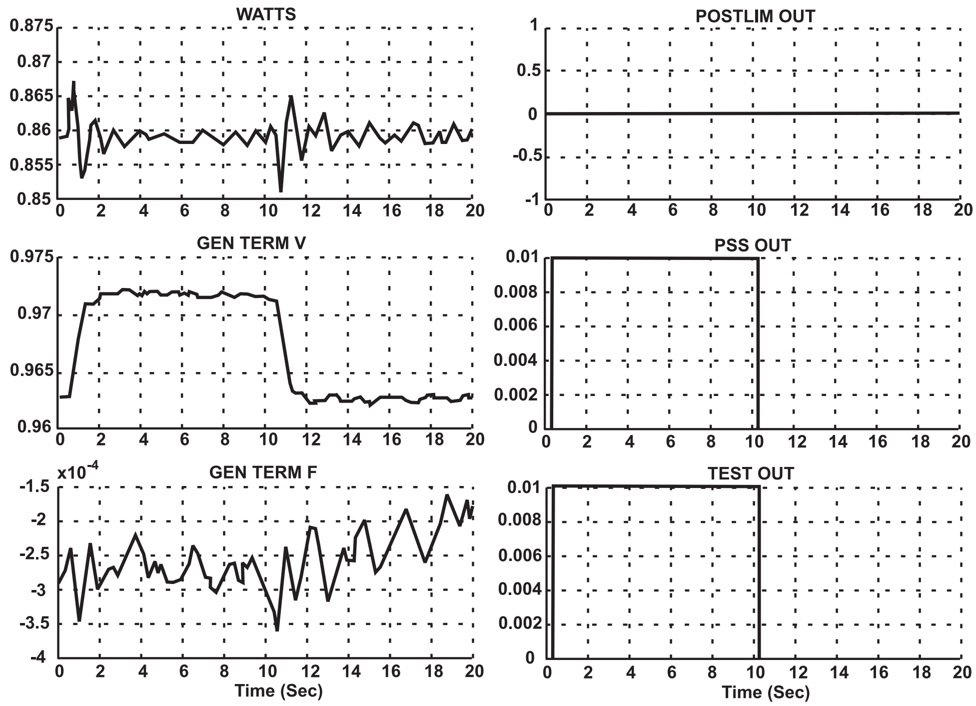


Figure 14: Baseline of 1165 MW Generator - 10 second step of 1.0% terminal voltage test with return to nominal operating voltage

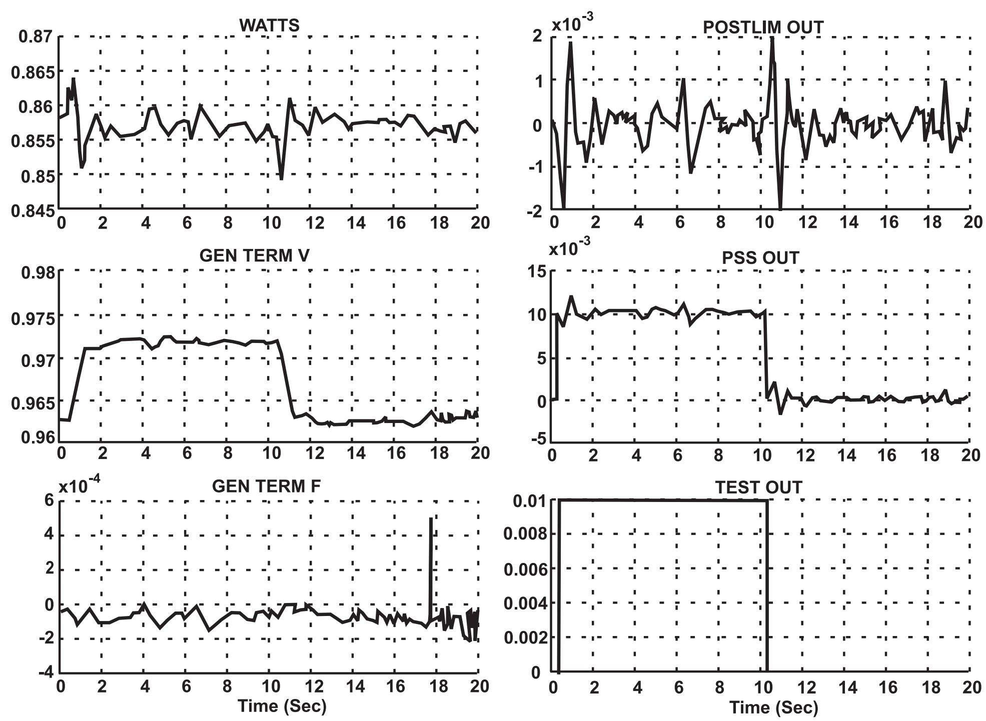


Figure 15: Final Settings of 1165 MW Generator - 10 second step of 1.0% terminal voltage test with return to nominal operating voltage

CHANGING TIMES FOR POWER SYSTEM STABILIZER IMPLEMENTATION

Since the blackouts in the Northwest in the late 90s and the more recent blackout in the Northeast, the frailty of the transmission system has become apparent. NERC (North American Reliability Council) [33] has issued guidelines trying to mandate testing to verify hardware to improve the reliability of the transmission system. These tests included verification of excitation models [32] with excitation system performance and verification of excitation limiters and protective relays to ensure coordination. Today, use of power system stabilizers is being mandated in the Western portion of the country for all machines 30 MVA and above or groups of machines that total 75 MVA. To help improve the reliability of the transmission system, power system stabilizers have proven to dampen oscillations, and new innovations in power system stabilizer technology continue to make them more user-friendly in regard to commissioning and implementation. Old potentiometer-type stabilizer adjustments are obsolete with new commissioning software to reduce time for commissioning. See Figure 16.

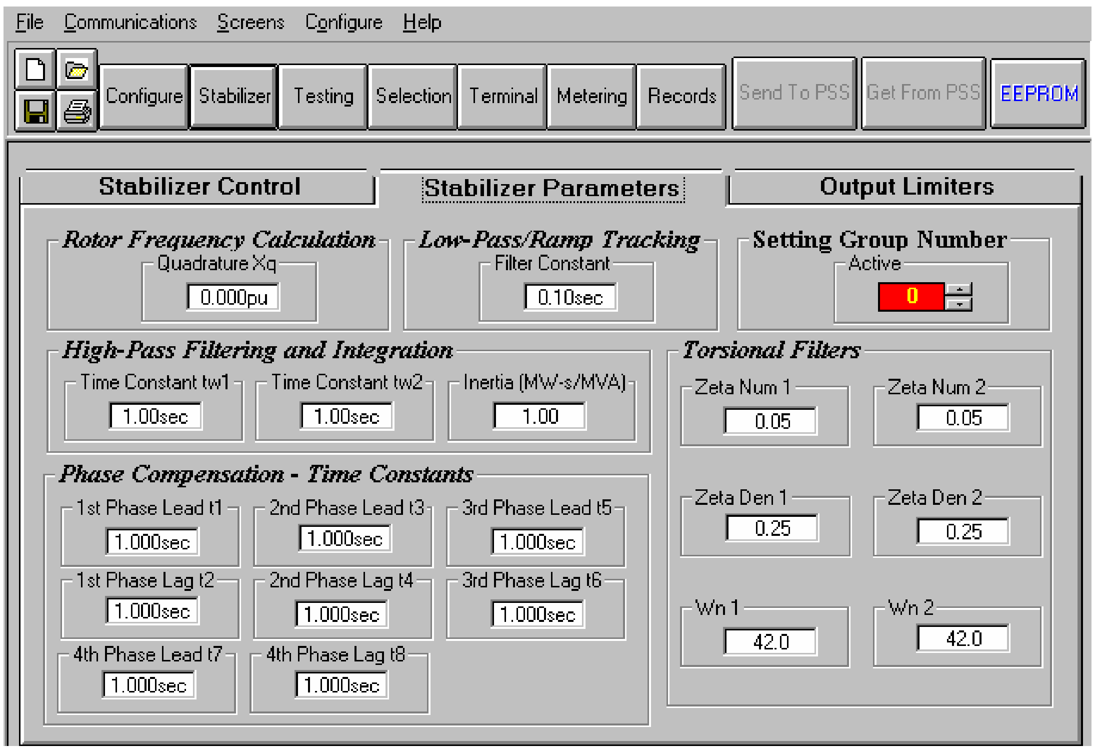


Figure 16: Setup Screen for Power System Stabilizer Tuning

Additional features provided in stabilizers, such as multiple setting groups, have made them more flexible to plant needs. Here, reduced PSS gains may be required as the turbine generator is moving through its rough zones during machine loading. Without another set of gains in the power system stabilizer, the voltage regulator could become excessively aggressive and result in poor power system performance.

CONCLUSION

In this paper, various types of power system stabilizers have been discussed with examples that help demonstrate their effectiveness. New guidelines by NERC will result in mandates for more machines requiring power system stabilizers. Today's stabilizers have greatly improved the performance of the system as new technology supercedes the old.

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BIOGRAPHIES

Richard C. Schaefer holds an AS degree in Electrical Engineering and is Senior Application Specialist in Excitation Systems for Basler Electric Company. Since 1975, Rich has been responsible for excitation product development, product application, and the commissioning of numerous plants. He has authored technical papers for conferences sponsored by IEEE Power Engineering Society, IEEE IAS Pulp and Paper, Society of Automotive Engineers, Waterpower, Power Plant Operators, and IEEE Transactions on Energy Conversion and IEEE Transactions on Industry Applications publications. He is IEEE 421.4 Task Force Chairman for modification of Preparation of Excitation System Specifications and committee work for IEEE PES and IAS.

Michael J. Basler graduated in Electrical Engineering in 1979 and obtained his MSEE in 1989 from the University of Missouri at Rolla. From 1979 to 1981, he worked at Emerson Electric Company in St. Louis, Missouri, on an automated, two-way communications system for electric utilities. He has worked at Basler Electric in Highland, Illinois, since 1981 in various design and engineering management positions related to the field of synchronous machine excitation systems. He is the manager of Electrical Engineering of the Power Systems Group and is on the IEEE Excitation Systems Subcommittee. He is an Adjunct Lecturer at Southern Illinois University at Edwardsville, teaching in the area of Power and Controls.