Practical Utility Experience with Application of Power System Stabilizers

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INTRODUCTION

This paper discusses Ontario Hydro's long history of power system stabilizer design and application on all types of utility generation. The focus is on practical implementation issues covering three decades of experience with in-service units of a variety of different designs.

ONTARIO HYDRO AND GENERATOR CONTROLS

Ontario Hydro (OH) is a publicly-owned utility with an installed capacity of 31,000 MW and almost 3,000 MW of mothballed generation. The generation mix, as of mid-1996, consisted of nuclear (44%), coal-fired thermal (24%), hydroelectric (23%), oil-fired thermal (4%), and independent power producers (5%).

The OH bulk transmission system consists of 3,395 km (2,109 mi) of 500 kV lines, 13,931 km (8,652 mi) of 230 kV lines and 11,659 km (7,242 mi) of 115 kV lines. Ontario Hydro is interconnected at several points to its neighbors in New York, Michigan, Minnesota and Manitoba

The historical development of our power system and the long distances between the sources of generation and major load centers have led to a wide variety of operating challenges. In response to these challenges, Ontario Hydro became one of the first utilities to explore the use of advanced generator control schemes to maintain system security following power system disturbances.

HISTORICAL PERSPECTIVE

Despite their relative simplicity, Power System Stabilizers (PSS) may be one of the most misunderstood and misused pieces of generator control equipment. The ability to control synchronous machine angular stability through the excitation system was identified with the advent of high-speed exciters and continuously-acting voltage regulators. By the mid-1960's several authors had reported successful experience with the addition of supplementary feedback to enhance damping of rotor oscillations [1-2].

Ontario Hydro's experience in this area began with the introduction of static excitation systems to new hydroelectric power developments in the northern part of the province. By the end of 1963, several stations had been equipped with full mercury-arc rectifier systems, followed by the installation of several full thyristor exciters at nearby stations. These fast-responding systems were equipped with high-gain voltage regulators to provide the maximum possible benefit to steady-state stability. In some cases the improvements in steady-state stability were necessary to allow the entire capacity of remote generating stations to be transmitted over limited transmission facilities to the remainder of the system. Use of the excitation system in this manner remains a highly cost-effective alternative to the construction of new transmission facilities.

It was soon recognized that the increased bandwidth of the closed-loop voltage regulator contributed to a reduction in damping torque acting on generator rotors. In some cases the natural damping provided by the turbine, amortisseur windings and power system load characteristics were not enough to ensure positive damping of rotor oscillations, resulting in output power limitations under certain conditions.

The solution to this problem involved the introduction of supplementary damping signals that restored the damping forces acting on the rotor of the generator. The supplementary signal is normally introduced through the excitation system's voltage regulator input, using field flux changes to produce the required transient electrical torque changes. The combination of high-initial response excitation and a PSS produces the largest possible overall gain in stability.

Since the early 1960s, power system stabilizers have been considered as integral components of the excitation systems installed on all large generators on the Ontario Hydro system. The use of these PSS units continues to produce millions of dollars of annual benefits.

To date, almost 100 PSS units have been installed on the system, representing over 1,500 service-years of operating experience. Due to the large installed base, Ontario Hydro has a unique body of experience related to the benefits and reliability of these units.

This paper provides a brief overview of the development and refinement of stabilizers from the earliest systems to the modern and almost universally adopted integral-of-accelerating-power design.

EVOLUTION OF THE STABILIZER

Figure 1 depicts a simple, early design of a speed-based stabilizer that introduces the basic components that are present in virtually all power system stabilizers. The stabilizer's input signal is obtained using a transducer consisting of a toothed-wheel and magnetic speed probe supplying a frequency-to-voltage converter. The resulting signal is "washed-out" or reset, using a high-pass filter, so that the stabilizer will not modify the terminal voltage for steady state (or very slow) changes in shaft speed as could occur during power system operation at off-nominal frequency. The stabilizer output signal is injected into the voltage regulator input to produce the required variation in the exciter output and field voltage.

Although measured shaft speed deviation ($\Delta\omega$) appears to be the most logical and direct candidate for the input signal to power system stabilizers, there are some disadvantages to its use. Several alternative inputs [3-6] have been designed and tested over the last 30 plus years since the first stabilizer went into service. The following sections summarize our experience with some of these structures, including the decision to standardize on the dual-input accelerating power design (referred to as $\Delta P\omega$ in this paper) for all future applications.

Differential Angle ($\partial\delta$) Stabilizer

The first application of PSS on the Ontario Hydro system, in the early 1960s, made use of a stabilizing signal proportional to the derivative of the angle between voltages representing the machine and system [3]. This stabilizer suffered from two principal shortcomings. Variations in system impedance, seen from the generator terminals and unavoidable time lags in the measurement process produced sub-optimal stabilizer performance. The method was therefore quickly abandoned in favour of direct measurement of shaft speed.

Speed-Based ($\Delta\omega$) Stabilizer

As the name implies, the speed-based power system stabilizer relies on the measurement of the generator shaft speed for the stabilizing signal. This is the most direct implementation of the PSS function, and its early usage on the Ontario Hydro system is described in [1].

On hydroelectric units, the required speed input signal was obtained from a custom toothed-wheel and magnetic pickup arrangement. Special probe arrangements were required to mitigate the effects of shaft runout on the transduced speed signal. Because of the high signal resolution required, and the relatively high bandwidth of the PSS control loop, the normal speed pickups employed with governors and other systems were not adequate for this application. This approach, while successful, became expensive to construct, calibrate and maintain.

On the early applications of speed-based stabilizers on horizontal-shaft round-rotor machines, a different problem was encountered [7]. The relatively long, small-diameter shafts are subject to lightly-damped torsional modes of oscillation. Each torsional mode represents the exchange of energy between different rotating masses through the interconnecting shaft sections. Torque introduced at the generator end of the system has the potential to de-stabilize one or more of these modes. Solutions to this problem were developed including alternate placement of the speed probes and tuned notch filters. The notch filters introduced control system modes, often referred to as "exciter modes" which frequently limited the maximum in-service gains. The additional cost and complexity led to the search for alternatives.

Frequency-Based (Δf) Stabilizers

Terminal frequency continues to be used as the input signal for PSS applications at many locations outside of Ontario [4]. Normally, the terminal frequency signal is used directly. In some cases, terminal voltage and current inputs are combined to generate a signal that approximates the machine's rotor speed.

Although widely applied, the frequency-based stabilizer suffers from several shortcomings. Phase shifts in the ac voltage, resulting from changes in power system configuration, produce large frequency transients that are then transferred to the generator's field voltage and output quantities. Measured frequency is susceptible to noise produced by large non-linear industrial loads such as arc furnaces [4]. High noise signal levels often set an upper limit on the PSS gain that can be used with this structure.

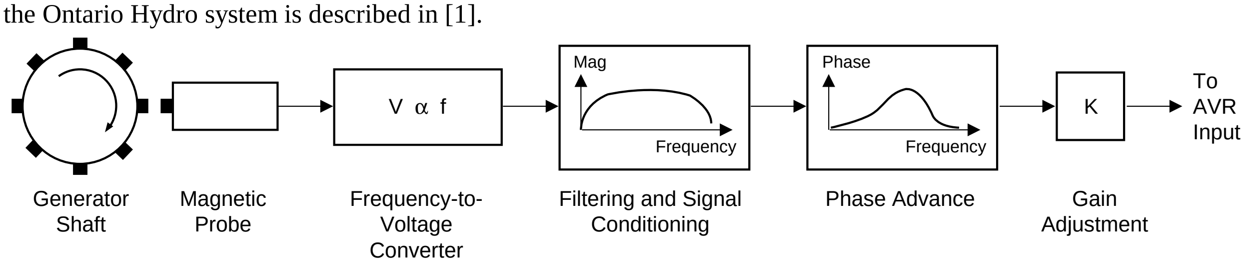

Figure 1: Simple Speed-Based Stabilizer

The terminal frequency quantity has a lower content of local plant modes relative to inter-area modes. Depending on the application this may be desirable, but it can result in inadequate contribution to the damping of modes that only involve individual machines. Frequency input signals have however been used successfully, in place of measured speed, in multi-input PSS.

Power-Based Stabilizers (ΔP)

Electrical power signal based stabilizers were tested at some locations within Ontario Hydro. Electrical power and torque are nearly equal for the small changes in speed associated with electromechanical oscillations of generators synchronized to large systems. When inverted, measured electrical power changes are in-phase with rotor acceleration (i.e. lead speed changes by 90°). Combining a measured power signal with a component of measured speed produces a signal that is advanced in phase relative to speed. By changing the relative gain of the two signals, different amounts of phase lead are achieved. In this manner, a stabilizer that does not require a phase lead circuit is achieved.

This design, however, still suffers from some practical drawbacks. First of all the phase characteristic of the overall PSS is somewhat limited, and cannot be easily tailored to match complex machine-system transfer functions. Second, and most important, power-based stabilizers, whether using only electrical power or power combined with speed, require some compensation to prevent large terminal voltage changes from occurring whenever the mechanical power is changed. This frequently limits the maximum practical gains that can be employed with these stabilizers.

Accelerating Power-Based (ΔPω) Stabilizers

The limitations inherent in the other stabilizer designs led to the development of stabilizers that measured the accelerating power of the generator. The earliest systems combined an electrical power measurement with a derived mechanical power measurement to produce the required quantity. On hydroelectric units this involved processing a gate position measurement through a simulator that represented turbine and water column dynamics [3]. For thermal units a complex system that measured the contribution of the various turbine sections was necessary [5].

Due to the complexity of the design, and the need for customization at each location, a new method of indirectly deriving the accelerating power was developed. The operation of this design of stabilizer is described in references [7-8] and the appendix to this paper. The IEEE standard PSS2A model used to represent this design, is shown as Figure 2 [9].

The principle of operation is based on applying signal conditioning to a measured electrical power and speed input signal (either measured directly or synthesized using a frequency input) so that they can be combined to derive a signal proportional to the mechanical power of the unit. Since the normal rate-of-change of mechanical power is limited, low-pass filtering can be applied to this signal without the loss of any useful information. This filtering serves to remove the unwanted higher frequencies (associated with measurement noise or torsional frequencies of oscillation) from the speed input signal. The original electrical power input is subtracted from the derived mechanical power to produce a signal proportional to the acceleration of the generator rotor.

The implementation depicted in Figure 2, actually combines signals proportional to the integral of the power components, thus deriving a signal proportional to speed. The resulting output can now be treated as a direct shaft speed measurement with phase lead, adjustable gain, and signal limiting applied to produce the final PSS output.

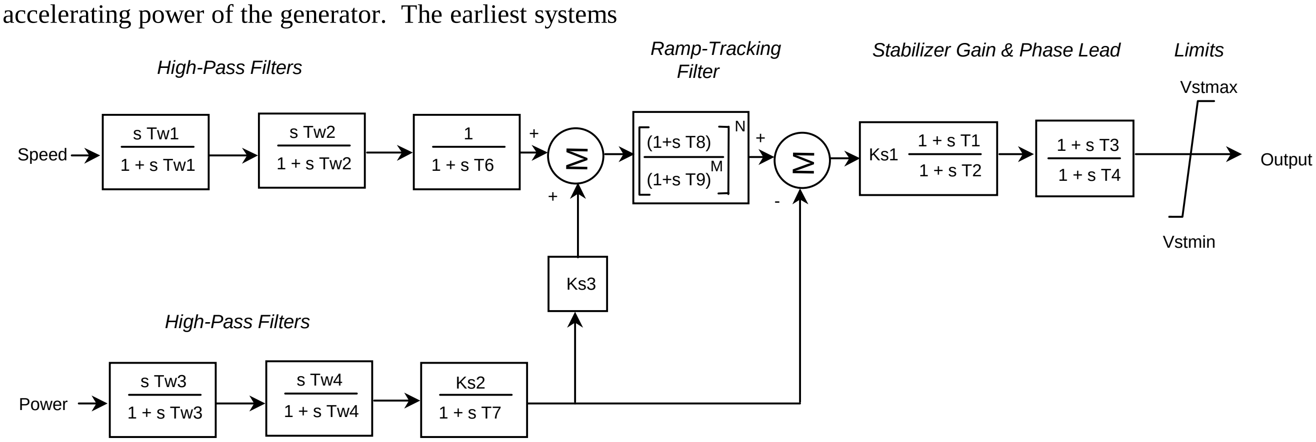

Figure 2: Accelerating Power PSS Model (PSS2A)

This basic configuration has remained the standard for all new applications within Ontario Hydro for the past two decades. Numerous refinements have been made to the original design. These include replacement of the measured speed input with a quantity derived from the generator terminal quantities, replacement of the mechanical power low-pass filters with a ramp-tracking design, and the addition of self-diagnostic and security features. For the past several years all new units have been implemented digitally, with many of them being supplied as part of new excitation system replacements.

Practical Application Issues

With our large base of installed units, and long history of usage, we have developed experience with many different vintages of hardware. Early designs suffered from failures due to mechanical components such as speed pickups. Replacement of the measured speed signal with a derived frequency signal has greatly improved reliability at many of our facilities. The early analog-electronic designs also suffered from reliability problems due to failures of components used to implement the adjustable settings (e.g. switches, potentiometers). Digital designs have eliminated these components and improved reliability and ease-of-use. Further gains in reliability are achieved when the PSS is implemented as an internal component of a complete digital excitation system, since this eliminates any additional hardware.

Although the original requirement for the PSS units was based on supplementing the local plant modes of oscillation, many of our new installations and retrofits have been applied to improve damping of inter-area modes of oscillation [10] as is common in western U.S. utilities. In order to be effective at damping these modes of oscillation, the high-pass filters (parameters Tw1 to Tw4 in Figure 2) must be set to admit frequencies as low as 0.1 Hz without significant attenuation or the addition of excessive phase lead.

Early attempts at re-tuning PSS for these frequencies identified some side effects related to mechanical power variations on the units. Tests on the original $\Delta P\omega$ design on thermal units included fast intercept valve closures, that produced a step change in power of approximately 5%, followed by a ramp of 0.55%/s [7]. The maximum terminal change produced by a PSS configured with short washout time constants was below 2%, for the normal in-service gain. On the first tests of this design on hydraulic units, mechanical power ramp-rates of up to 10%/s were achieved under gate limit control.

The introduction of long high-pass filter time constants produced excessive terminal voltage and reactive power deviations. In response to this problem, the mechanical power low-pass filters were replaced with a ramp-tracking design with the following transfer function:

$$G(s) = \left[\frac{(1 + sT_8)}{(1 + sT_9)^M} \right]^N$$

where T_9, M and N are selected to produce the required attenuation of higher frequency components appearing in the speed signal, and T_8 is selected to provide the desired ramp-tracking behaviour, using the following relationship:

$$T_8 = M * T_9$$

With this design, the filtered integral-of-mechanical power signal can track rapid rates-of-change in the measured electrical power signal, greatly reducing the terminal voltage modulation produced by the PSS. The performance of this filter may also be critical to the behaviour of the unit, in the event of inadvertent islanded operation resulting in large frequency and mechanical power variations.

For the past five years all new PSS units installed on our system have been digitally-implemented. Altogether 43 digital units have been installed, with an accumulated service-life of approximately 180 years. Although this is a relatively short period of time in which to judge reliability, the units have been trouble-free, and have produced the expected benefits of ease of tuning, maintenance and performance verification. The digital implementation of the PSS has also permitted further refinements to the monitoring and signal conditioning, including:

- advanced input signal supervision, allowing the PSS output to be attenuated or turned off during failures (e.g. PT fuse failure)
- advanced limiting and digital filtering to remove unwanted signal noise and prevent the PSS from altering the generator's terminal quantities outside of acceptable bounds
- self-diagnostic features to warn operators of conditions for which the PSS performance may be compromised.

Testing and Tuning

Reference [10] describes the general approach that is followed for the initial selection of tuned parameters on PSS units installed on the Ontario Hydro system. The initial settings may be modified based on the results of on-site tests to produce a unit that exhibits robust performance for a wide range of system operating conditions.

Typical tests performed during commissioning include:

- measurement of the system phase compensation requirements,
- step response tests to measure damping improvement at local mode frequencies,
- load-ramping tests to ensure that the PSS does not produce undesirable modulation of the unit's terminal voltage under normal or emergency operating conditions.

Tests and simulations performed on all types of utility-scale generators, including large and small hydro, large fossil-fired units and combustion turbines, have consistently demonstrated that a conventional PSS tuned and tested in this manner, will improve stability for any reasonable operating scenario.

Figure 3 provides example test results obtained on a remote hydraulic unit with a PSS in and out of service. The large improvement in local mode damping is clearly visible in this record.

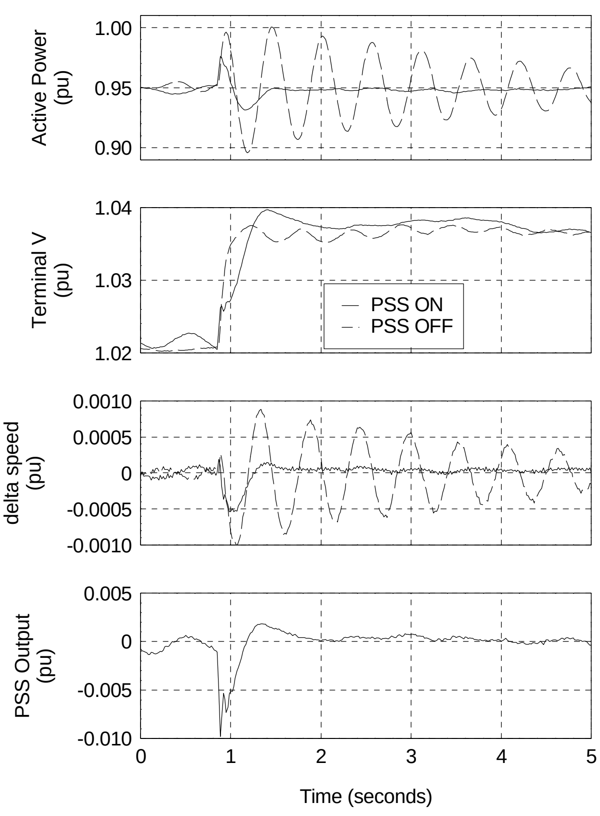

Figure 3. Digital Stabilizer Test

Digital units greatly reduce the time required to perform on-site tests and data collection. Our recent experience with our own units is that commissioning requires less than a day, and can even be performed remotely using a modem with minimal on-site supervision by the plant's technical group. Digital data recording features built into these units provide excellent sources of additional data on system performance following disturbances.

CONCLUSIONS & FUTURE RESEARCH AREAS

Ontario Hydro's reliance on power system stabilizers has been well rewarded by allowing significant increases in power transfer limits over restricted transmission facilities over the last four decades. The savings in transmission lines costs are in the tens of millions of dollars. This heavy reliance on PSS has meant that the company has devoted considerable efforts to the improvements of these devices, culminating in the widespread application of the $\Delta P\omega$ stabilizer with its built in self-monitoring. In addition, several digital excitation systems with a PSS built into the firmware have been installed.

Proper design, periodic testing and implementation of appropriate palliative measures in case of failures have yielded excellent overall reliability.

Our extensive experience with PSS application on all types of utility generators have satisfied us that conventional designs will satisfy all practical power system requirements. Operating security limits are based on simulations using standard representations for all of the system components. If the PSS algorithm is excessively complex it will have to be approximated in the simulations, in which case any benefits may not be reflected in the derived operating security limits. Despite this, further research in to the conventional PSS structure presented in this paper may still produce further improvements in overall PSS performance. Areas being considered for future research include:

- advanced digital filtering of the power signals to further reduce terminal voltage deviations caused by mechanical power changes
- self-adaptive tuning based on automatic monitoring of PSS performance during ambient and fault conditions
- automatic signature analysis to reduce manual re-verification of PSS performance

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Appendix
Principle of Operation of the Accelerating-Power PSS

The principle behind accelerating power stabilizers can be explained with reference to the equation-of-motion of the machine's rotor, the so-called "swing equation":

$$\Delta\omega = \frac{1}{2H}\int(\Delta T_M - \Delta T_e)$$

A change-in-speed signal may be derived by examining the integral of the accelerating power component in the above equation. Electrical power is easily measured, using a watt transducer, but mechanical power is significantly more difficult to measure directly. The earliest implementation derived the mechanical power from gate or valve positions (not an easy task). Electronic circuitry was then used to combine, integrate and scale these signals to produce the necessary stabilizing signal. This derived signal was inherently free of shaft run-out components and was used directly without the need for special filtering or processing. This method has permitted the use of much higher in-service stabilizer gains, producing more effective damping of electromechanical oscillations.

Although the derivation of mechanical power was tested at some locations it proved extremely difficult to produce an accurate signal. To overcome this difficulty, the following indirect approach is now employed. First the integral-of-mechanical power is derived from a measurement of speed and electrical power based on the swing equation, as shown below:

$$\int \Delta T_M = 2H * \Delta\omega + \int(\ \Delta T_e)$$

This value is then inserted in place of the measured mechanical power signal in the derivation of the speed signal. This entire process reverts back to using the original measured speed signal and, on the surface, it would appear that nothing has been gained. Although this is true, a subtle change is made to the derived mechanical power signal prior to re-introducing it into the equation. Normally, mechanical power changes are quite slow, relative to the electromechanical oscillations of interest. Based on this, the derived mechanical power signal can be band-limited using a low-pass filter without affecting the behaviour of its output signal for normal variations. When this filtered signal is combined with the electrical power signal, it still produces a valid accelerating power and derived speed signal. The input signals to the stabilizer are shaft speed and electrical power. The input shaft speed signal does not need to be separately processed to remove torsional components, since it passes through the mechanical power low-pass filter. Stabilizers utilizing this approach can normally be set to much higher gains than speed- or frequency-based designs and are therefore much more effective in stabilizing the generator.