Power System Stabilizer Performance With Summing Point type Var/Power Factor Controllers

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Abstract –Var/Power Factor Control for generators has often been the preferred operating control mode for Pulp and Paper power plants over voltage regulation to reduce the need for constant reactive power monitoring by plant operators. Today, for those machines located in the Western United States, the North American Reliability Council (NERC) and Western Electric Co-coordinating Council (WECC) are ruling that machines rated more than 35 MVA or group of machines equal to or more than 75 MVA connected to the transmission grid through one transformer be operating in voltage regulating mode and be equipped with power system stabilizer to improve the transient stability of the system.

The latest NERC and WECC standards do not allow for generators meeting these criteria to be operating in Var/Power Factor control. Over the years various types of Var/PF control have been provided. Two types of Var/PF controllers are available as described in IEEE 421.5. Type 1 Var/PF controller uses raise/lower signal based on generator output changes. The amount of raise/lower signal is a fixed voltage. The Var/PF controller of type 2 uses a PI controller, which changes a desired voltage setpoint smoothly in linear fashion. Both types are considered as a summing point type Var/PF controller. In this paper, the PSS performance is studied with type 2 Var/PF controller that does not have an undesirable PSS action caused by a sudden change in setpoint adjustment from the Var controller. The results illustrate that power system stabilizer performance is not deteriorated when the type 2 Var/PF control is implemented. This type of performance response can benefit Pulp and Paper Mills who desire constant VAR/PF control but also requiring to meet the WECC regulation guidelines.

1. INTRODUCTION

In modern power systems, improved transient and dynamic stability are very important considerations to provide reliable and efficient operation of the transmission system. Several types of power system instabilities were reported in the study [1] and analyzed to improve the power system dynamic stability. NERC and the WECC require a power system stabilizer for machines rated 35 MVA or a group of machines 75 MVA and above that are one transformer removed from the transmission system and operating at a voltage of 69 kV and above. For these machines, the generators are recommended to be operated in voltage regulation mode to improve the transient stability of the system.

The power system stabilizer (PSS) was designed to add damping to the generator rotor oscillations by controlling its excitation system using a supplemental stabilizing signal into the voltage regulator summing point. To supplement the generator's natural damping, it produces a component of electrical torque that opposes changes in rotor speed and introduces a signal proportional to measured rotor speed deviation into the automatic voltage regulator (AVR) input as shown in Figure 1.

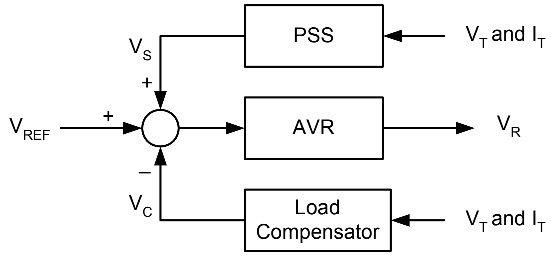


Figure 1. AVR with PSS Implemented

Based on the theoretical concepts and practical problems associated with the application of stabilizers on hydraulic and thermal units in the early days, frequency, speed, or power-based stabilizers were utilized. These approaches have been almost entirely obsoleted in favor of the integral-of-accelerating-power type stabilizer, the more effective approach to improving system stability. This type of stabilizer is modeled in IEEE 421.5 standard [2] as a dual input power system stabilizer, PSS2B. It utilizes a combination of power and speed to derive the stabilizing signal. The integral-of- accelerating power is noted for its low noise content and hence higher output gains that results in better damping to local and interarea power system oscillations. This type of PSS has become the favorite of hundreds of machine installations for both small and large units including hydraulic, thermal, nuclear, and gas turbine applications.

Many gas turbine units are equipped with a Var/PF controller that is in service whenever the unit is on-line. The Var/PF controller is an outer-loop control that monitors generator current and controls to a fixed PF or Var setpoint. The control structure is an integrator with gain feedback to the AVR setpoint. It has adjustable settings that are time delayed between pulses to drive at the motorized voltage regulator setpoint potentiometer. To ride through system transient disturbances, the control should be as slow as possible without too long a delay that would cause the operator intervention and overshoot in the resulting unit operating point. In order to provide voltage support during system disturbances, which affect reactive resources, voltage supervision is required. WECC requires that Var/PF controllers be switched off when required during system disturbances.

The summing point type of Var/PF controllers consists of a fast AVR loop and a slow Var/PF loop. This type of control provides fast changes in excitation levels during system disturbances, along with Var or PF regulation in the presence of slow changes in system voltage. Quadrature Droop Compensation (QDC) is used with the AVR to limit Var flow during fast changes in system voltage. The QDC function is calculated at the same rate as the AVR loop.

With the summing point type of Var/PF controllers with voltage supervision, a desirable response can be achieved without operator intervention during system disturbance.

2. NEED FOR VAR/POWER FACTOR CONTROLLERS

The trend towards automation has prompted increased demand for the Var/PF controller to be an integral part of voltage regulator. Hurley, Bize and Mummert [3] discuss pros and cons of the use of Var/PF controllers. The authors introduce the terminology of categorizing generators as either a "Voltage supporting machines" or as "Voltage following machines". The authors state that "Voltage Following Machines would not be expected to aid in the regulation of system voltage, but whose voltage would tend to be expected to follow the Variations of incoming system voltage. This category would tend to include small synchronous machines that are connected to lower voltage distribution systems, 69 kV and lower, whose incoming voltage is regulated by the utility with load tap changing transformers or other such devices [4]. These machines typically will be the units that could justifiably be selected to regulate Var or PF, but preferences may exist for 35 MVA and higher machines to be operated in Var/PF control.

In addition, the authors state that "One means of providing a limited amount of Var/PF control without significantly detracting from the ability of the excitation system to provide such voltage support would be to control Vars or PF when the voltage is within a reasonable normal band, e.g., 1-2% of the steady state terminal voltage but to respond to off-normal voltage when required." This philosophy has been in practice for some analog excitation systems, and is being implemented in some modern digital excitation systems.

The need for Var/PF controllers stems from the desire to automate generation plants. It is convenient to be able to set a plant for a specific Var output or to run at a specific PF level and walk away without further intervention. This setting should be held independent of minor variations of bus voltage. If a plant is operated with the excitation system utilizing quadrature droop compensation only, then bus voltage variations can significantly affect the Var output or PF at the machine operating level. Adding a Var/PF controller to supervise the AVR avoids these Variations.

3. DESIGN OF VAR/PF CONTROLLERS

The Var/PF loop is designed to provide a wide range of responses. Some applications require fast responding Var or PF control in order to "keep up" with relatively fast system voltage changes or changes in generator loading. Other applications desire a slower response to avoid the dynamics of the Var or PF controller from influencing the response of the excitation system to a system transient.

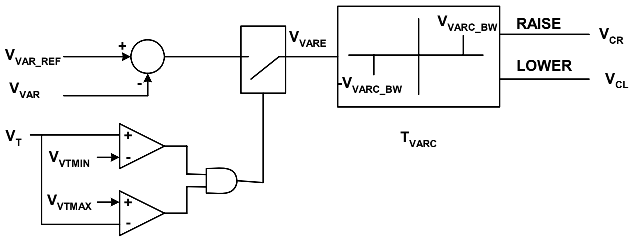
The Var/PF controller is normally implemented as a "Summing" type controller, as shown in Figure 2. In the "Summing" type controller, the Var/PF control makes up the outer loop of the control scheme with the voltage regulator forming the inner loop. The voltage regulator setpoint is modified by the Var/PF controller to achieve the desired level of Vars or PF. Eberly and Schaefer [5] discuss the use of Var/PF controllers with which the advantages of both a terminal voltage regulator and Var/PF operation can be achieved. During the initial disturbance, the voltage regulator will contribute to the voltage stability of the system, and then the Var controller faster reacts to achieve the desired Var requirement. In this case, the PID controller gains of the voltage regulator (inner loop) are designed for fast response. The PI gains of the Var/PF controller (outer loop) are selected for slow response. One reason for choosing a slow response for Var/PF control is to allow the voltage regulator to perform in a predictable manner during system transients. In this type of control, system voltage variations are reacted to by the voltage regulator, at the expense of Var/PF regulation over the short term. Since the PSS output is added to voltage summing point, no change is required to meet WECC requirement.

Two types of Var/PF controllers are available, as described in IEEE 421.5 [2]. In this paper, only the Var controllers are illustrated in Figure 2. For the PF controller, the Var setpoint (V_{VAR_REF} or Q_{Ref}) and estimated values (V_{VAR} or Q) are replaced with the PF setpoint and estimate, respectively.

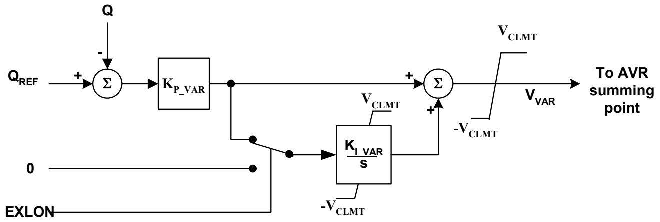
The model shown in Fig. 2a is used to represent a type I Var controller that operates by moving the voltage reference directly. The Var controller generates "Adjuster Raise" (V_{CR}) or "Adjuster Lower" (V_{CL}) signals, which may be used as inputs to adjust the voltage regulator setpoint (V_{REF}). This function operates after a time delay to raise or lower this reference setpoint until the generator reactive power is within the set "Deadband" value. Both outputs are low when V_{VARE} is between $–V_{VARC\_BW}$ and V_{VARC_BW}. When V_{VARE} exceeds V_{VARC_BW} for a time greater than T_{VARC} seconds the output V_{CR} is held high until V_{VARE} drops below V_{VARC_BW}. When V_{VARC_BW} is more negative than $–V_{VARC\_BW}$ for a time greater than $–T_{VARC}$ seconds, the output V_{CL} is held high until V_{VARE} becomes less negative than $–V_{VARC\_BW}$.

The Type II VAR controller is a summing point type controller. It makes up the outside loop of a two-loop system. As shown in Fig. 11.5, this controller is implemented as a slow PI type controller and the voltage regulator forms the inner loop and is implemented as a fast controller. The VAR controller generates the VAR controller signal (V_{VAR}), which may be used as input to the voltage regulator loop. The resulting control makes generator reactive power reach the desired VAR set point smoothly. No dead band and time delay is used. The controller response time depends on the PI controller gains. In the over excitation or under excitation state, the integral action is disabled to allow the limiter to play its role. Non-windup limit (V_{CLMT}) is used for bounding the VAR controller output voltages V_{VAR}.

The design of the Var/PF controller is based on a variety of criteria. Some applications require the Var or PF to be held steady, even in the presence of relatively fast changes in system voltage. The system voltage can change as quickly as 0.01 pu / second. It is desired that the Var or PF remain constant in the presence of these changes. In addition, generator loading can be changed at relatively fast rates, of 0.01 pu / second, and it is expected that Var or PF remains constant.



(a) IEEE Var Controller Type I model



(b) IEEE Var Controller Type II model
Figure 2. Implementation of Var/PF controller

4 SIMULATION RESULTS

Power system stabilizer performance is evaluated Pulp Mill steam generating unit consisting of a 62 MVA, 13.8 kV, 60 Hz unit supplying power to mill loads and an infinite bus through two transmission circuits as shown in Figure 3. The network reactances shown in the figure are in per unit on 62 MVA, 13.8 kV base. The real time digital simulation (RTDS) is utilized to model the test power system with generator, loads and step-up transformer. A digital excitation controller was connected to a thyristor excited 62MVA generator. The output of the generator, 13.8kVac, was stepped up to 230kV, and connected to a 230kV transmission line rated at 500MVA with 15% reactance. The 230kV distribution bus is rated at about 500MVA, making it essentially an infinite bus, as compared to the generator. The digital excitation control system with positive and negative field forcing is connected to the RTDS. A summing point type Var/PF controller (IEEE Var Controller Type II) and PSS2B are implemented in this voltage regulator.

The simulated generator output and current are amplified to connect to the voltage regulator. The PID gains for inner voltage loop are selected as Kp=80 and Ki=20 for 0.2 sec rising time. For the outer Var/PF loop, Kp=1 and Ki=1 for slow response (30 sec). The PSS performance in the AVR mode is compared with one in the VAR when the system disturbances occur. System operating conditions are simulated by the change in the load and a fault in transmission bus.

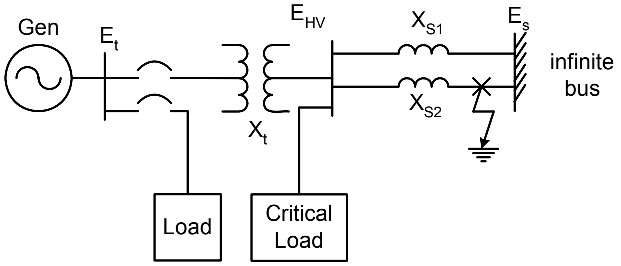
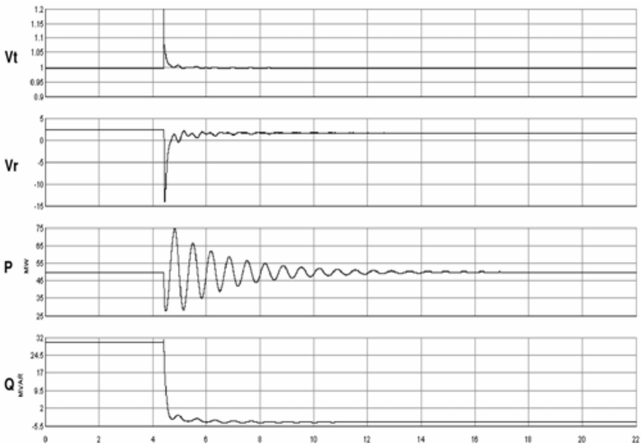


Figure 3. Overview of System

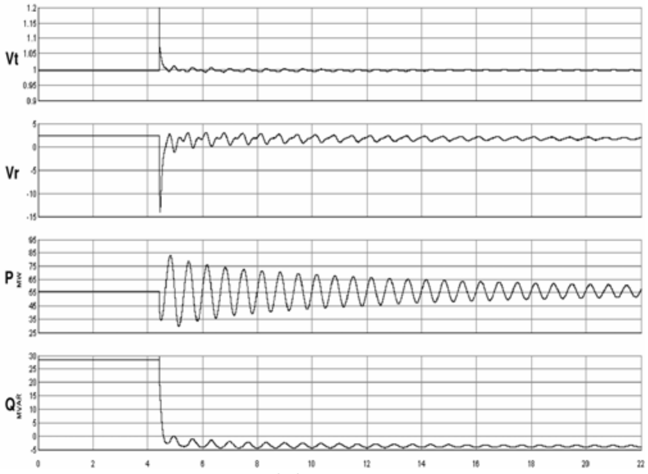
Power Oscillation Damped by PSS: The initial system operating condition is that generator is in the automatic voltage regulator (AVR) mode exporting 0.8 p.u. real power with a fixed voltage setpoint 1.0. p.u. A system disturbance is applied by rejecting local load. Figure 4 shows the generator response to the change in local load, which indicates that a PSS is required for a proper operation. As shown in Fig 4-b, power oscillation is getting worse as generator real power increases to P=0.9. This oscillation can be damped when the generator voltage setpoint is increased which requires operator intervention. Figure 5 shows the generator response with generator voltage setpoint 1.04. An effective way to damp the power oscillation is to use the power system stabilizer (PSS). The effectiveness of PSS for damping power oscillation is shown in Figure 6.

Reactive Power Requirement: Another concern of operation is the reactive power requirement. With a large change in load, the reactive power is changed by about 35 MVar (see Figure 5 and 6) since generator setpoint is fixed, This results in operator intervention to get the reactive power requirement. Figure 7 shows the results of the Var controller with and without PSS, voltage regulator in the Var mode. By comparing Figures 6-b and 7, we see that the power oscillation due to system disturbance is damped in about two seconds by the PSS action and generator voltage approaches to a desired Var level slowly by the Var controller. The simulation results show that power system stabilizer performance is not deteriorated in the Var mode and no operator intervention is required.

A Coordination of PSS and Var Controller Response: For the IEEE type 2 Var controller, its response is determined by the PI gains, Kp_var and Ki_var. Figure 8 shows the system responses with two set of gain. The faster response can be obtained by increasing Ki_var. As shown in Figure 8, a large generator voltage is recognized with the integral gains (fast Var controller as shown in 8-b). The large variation of generator voltage causes power system instability as indicated in [3]. In order to avoid this situation, a slow response of Var controller is required. This can be done by adjusting Var controller gains for IEEE type 2 Var controller. In addition to the adjustment of PI gains for slow response, it is recommended that the Var controller output is limited for voltage support requirement. Too large a change in the system voltage is prevented by user setpoint (V_{CLMT}) in Figure 2.b. As seen in Figure 7, the inner voltage loop reacts quickly to system disturbance, and then the outer Var loop slowly takes over to provide the desired excitation level after system disturbance reaches a new operating condition.



(a) P=0.8



(b) P=0.9

Figure 4. Generator Responses to Load Change with a fixed voltage setpoint Vref=1.0

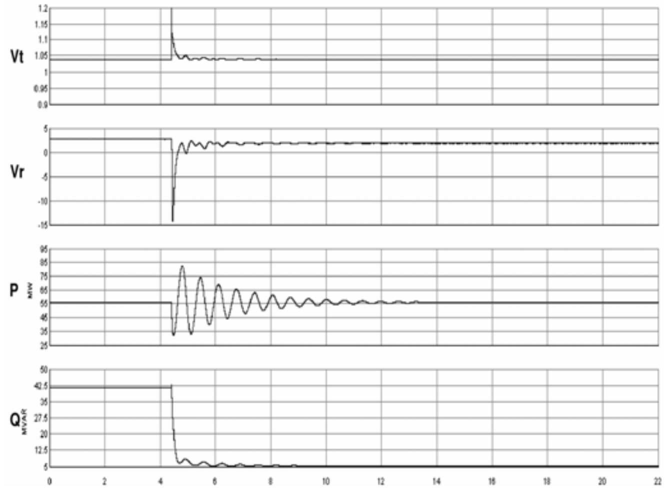
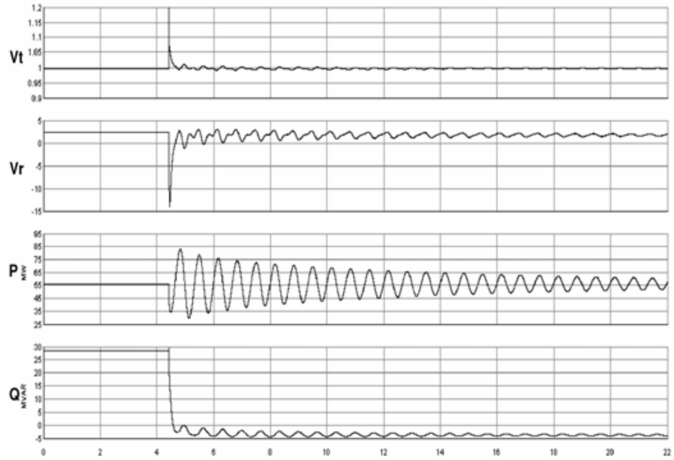
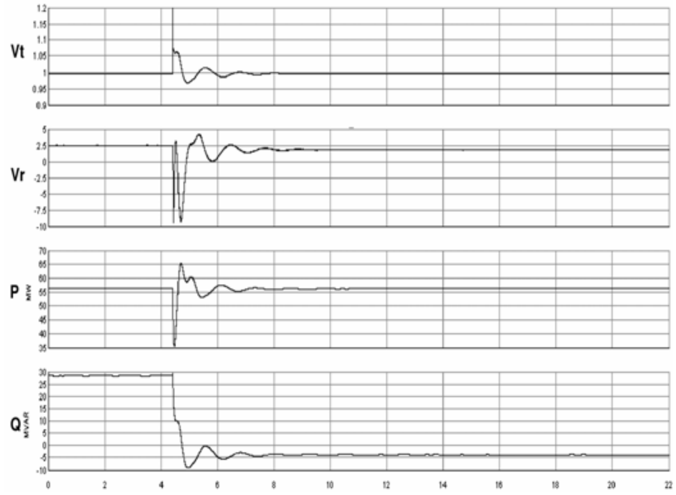


Figure 5. Generator response with a higher voltage setpoint, Vref=1.04 for P=0.9



(a) Without PSS



(b) With PSS

Figure 6. PSS Performance in AVR mode with P=0.9 and a fixed voltage setpoint Vref=1.0

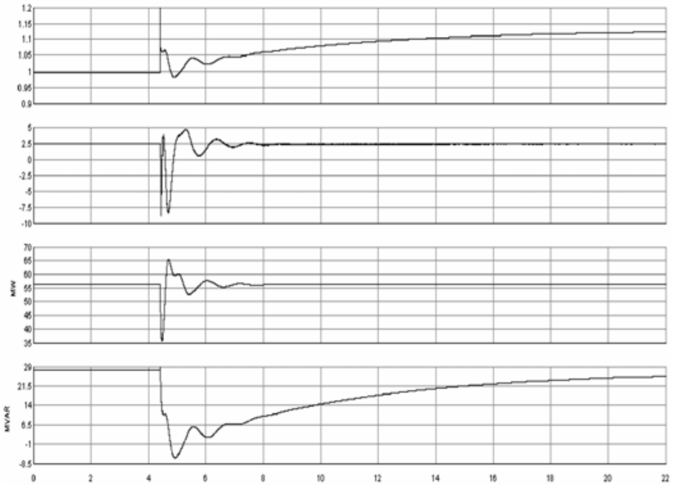
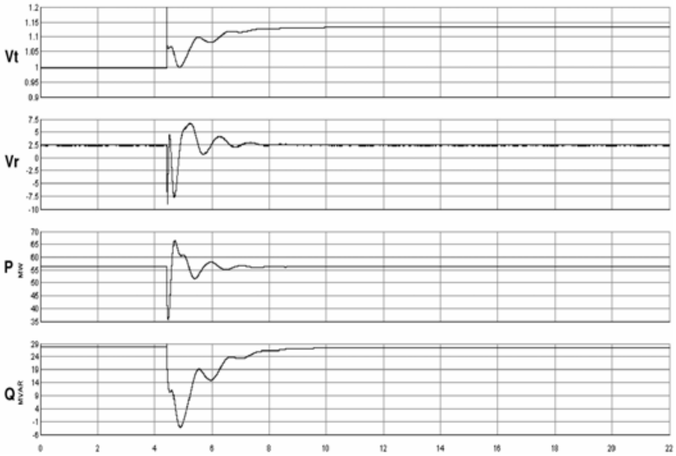
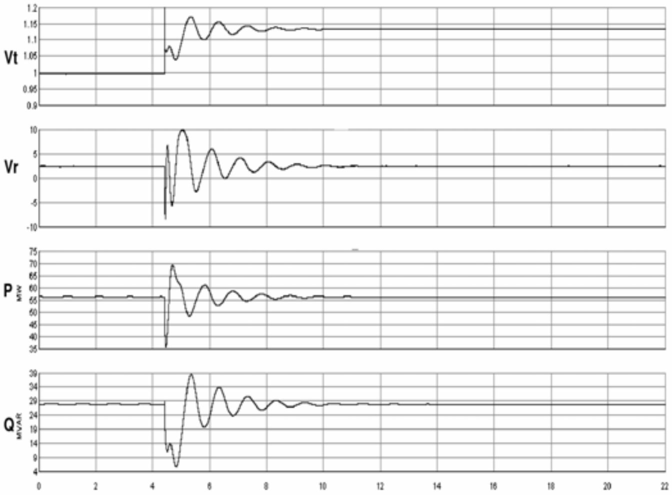


Figure 7. PSS Performance in Var mode with Var Controller gains, Kp_var=1 and Ki_var=2



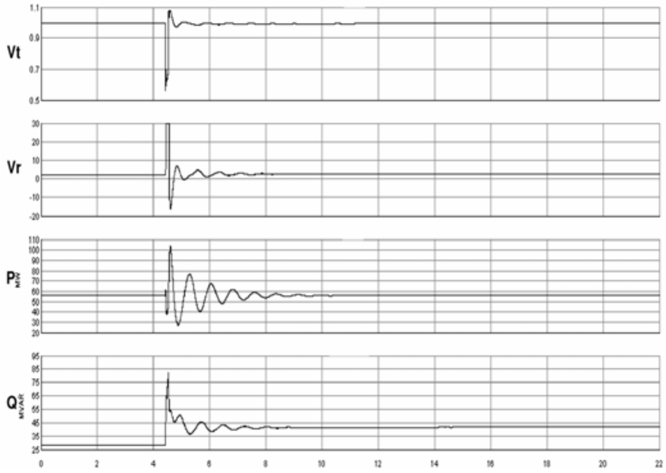
(a) Kp_var=1, Ki_var=10



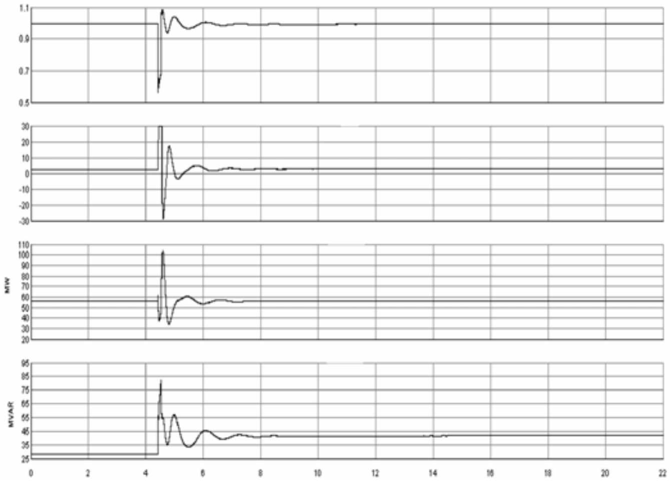
(b) Kp_var=1, Ki_var=40

Figure 8. PSS Performance in Var mode with fast Var controller gains.

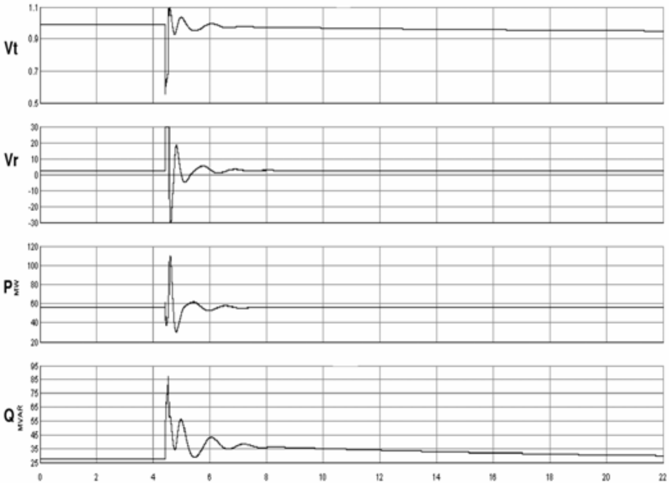
PSS Performance with a Fault on Transmission line: A three-phase fault on transmission line 2 is applied. This fault is cleared by isolating the faulted transmission line simultaneously at both ends. Transient response with the fault-clearing time 0.1 sec are shown in Figure 9-a and 9-b, without PSS in the AVR mode, with PSS in the AVR mode, respectively. The transient response of the Var mode operation is examined (Figure 9-c). As seen in Figure 9-b and 9-c, the inner voltage loop reacts quickly to system disturbance, and then the outer Var loop slowly takes over to provide the desired excitation level after system disturbance reaches a new operating condition. The simulation results show that bus voltage support requirement during system transient is provided if a slow Var controller is used.



(a) AVR mode without PSS



(b) AVR mode with PSS



(c) Var mode with PSS

Figure 9. PSS Performance with a three-phase fault on transmission line

5. CONCLUSIONS

A general discussion on var/PF controllers and the issues related to the need for these controllers have been presented. The design method of var/PF controller and voltage regulator for a modern digital excitation system are presented. A test system was modeled, simulated, and then tested.

In many Pulp and Paper Mills, VAR/PF control is often the preferred control mode over voltage control to maintain constant Reactive Power. Yet, for those larger machines requiring power system stabilizers due to size, desired performance has always been expected to be degraded when events that cause voltage sags occurs and the VAR/PF controller has been enabled. Today, with new digital excitation systems, the concerns of the past can be resolved by using high gains in the primary AVR control loop and lower gain in the supplementary VAR/PF control loop. The simulations shown in this paper demonstrates that Power System Stabilizer performance is not deteriorated during a system transient when voltage support is needed using a summing point VAR/PF control and does not require operator intervention.

6. REFERENCES

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