APPLICATION OF STATIC EXCITATION SYSTEMS FOR PILOT AND ROTATING EXCITER REPLACEMENTS

ABSTRACT

Many power generation plants' excitations systems are faced with parts obsolescence, high maintenance and down time due to problems with the excitation system. These problems can include dc field breakers, motorized rheostats, rotating exciter failures, commutator deterioration, vibration, and obsolescence of the existing voltage regulator. Problems such as those listed can affect machine availability and have the potential to result in long down time of the generator system. In addition, performance can be an issue as more and more systems are required to have power system stabilizers.

The replacement of the pilot exciter alone for a new bus fed voltage regulator or replacing the entire rotating exciter and associated equipment with a new static excitation system provide positive solutions to these problems. When the rotating exciter life expectancy is an issue, the static exciter offers the design flexibility of an easy retrofit for both small and larger exciter systems. Additionally, it eliminates the maintenance overhead common to the brush type exciter where the rotating exciter needs to be replaced. Brushless exciters with rotating diodes and no slip rings were once viewed as the next generation solution to brush type exciter's maintenance issues. As experience with brushless exciters grew, it became obvious that they too were susceptible to their own peculiar set of problems. Once again, the solution of converting the system to a static exciter gave promise to re-solving those problems. Other advantages of static excitation systems include:

- 6 SCR Power conductor for optimum speed of response
- ¼% voltage regulator
- Field Current Regulator for commissioning purposes
- Limiters, protection
- Oscillography and sequence of events

INTRODUCTION

This paper will discuss the static excitation system that includes the power control devices (SCRs, also called thyristors), power transformer, and automatic voltage regulator. The elimination of the dc field breaker can offer substantial cost savings. Solid state fast de-excitation circuits benefits will be discussed. Selection criteria and application considerations regarding types of static exciters will be reviewed. Where the pilot exciter is replaced with a new static exciter/voltage regulator, differences will be noted as they apply to the power bridge sizing and tuning of the controls. When an exciter upgrade is being considered, special functions and software tools that are available in today's modern digital exciter systems to aid testing and system troubleshooting are explored.

THE OPERATION OF THE STATIC EXCITER

A static exciter/regulator behaves functionally like a simple automatic voltage regulator working into the exciter field. When the excitation system senses a low generator voltage, field current increases to the field; when a high generator voltage is sensed, field current is decreased. Functionally, a static exciter applies dc power into the main field for a slip ring machine, while a voltage regulator applies dc power into the exciter field. The static exciter system consists of three basic components: the control electronics (for example, Basler Electric's DECS or ECS family of Digital Excitation Controllers), the power rectifier bridge, and the power potential transformer. Together, they provide accurate generator field control to maintain generator output voltage. Figure 1 illustrates a typical static excitation system working directly into either the main field.

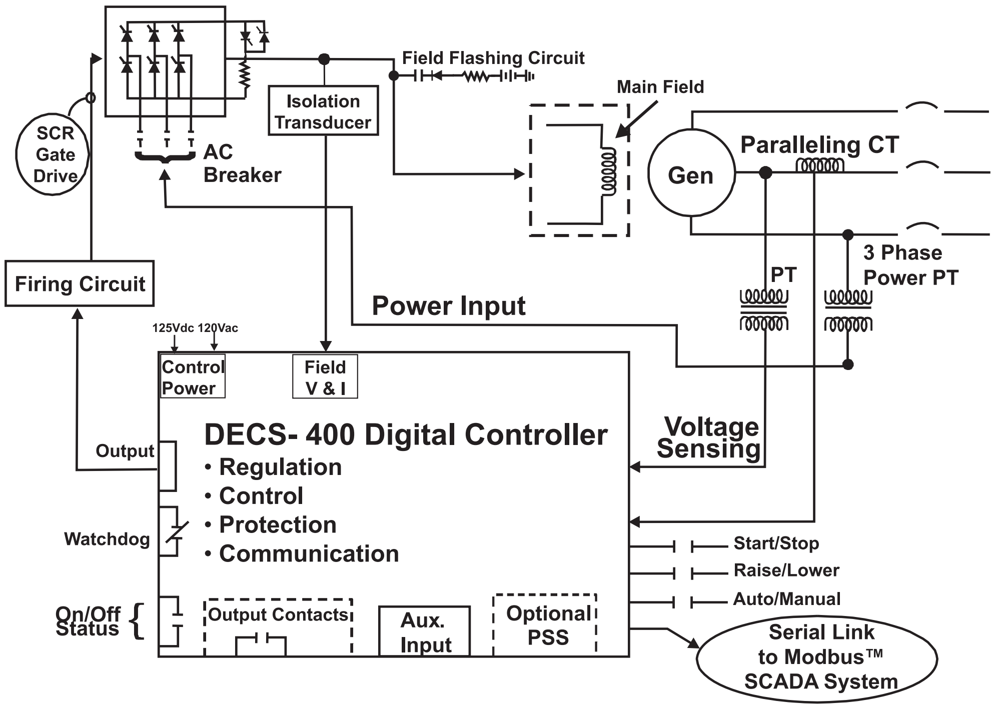

Figure 1: Block Diagram of Static Exciter System

POWER POTENTIAL TRANSFORMER

Power for the excitation system is derived by the generator via a large kVA transformer. The transformer steps down the generator terminal voltage to be compatible with the field requirements of the generator. The transformer will provide the excitation system's full load rating, plus a voltage and kVA margin for accommodating short time field forcing to handle generator transient overload requirements. The secondary voltage of the power transformer is designed based upon the amount of field forcing provided for the system. Typical field forcing levels are 145-150% of nominal rated field voltage. Some system designs incorporate much higher field forcing levels to improve first swing transient response for better power system stability.

Additionally, transformers are designed with BIL ratings (Basic Impulse Level) in accordance with ANSI C57.12. A high BIL rating ensures that the electrical insulation system of the transformer withstands any lightning-induced voltage spikes or transients introduced by a generator short circuit.

AC Field Shutdown Contactor

The output of the power potential transformer, shown in Figure 1, connects to input contacts of a shutdown contactor, and the output contacts are connected to the rectifier bridge. Unlike the common dc field breaker used at the field of the generator for shutdown, the ac field contactor or ac breaker is used to interrupt the power input to the excitation system for de-exciting the generator. When the ac contactor opens, the energy from the field flows through the thyristor and a series discharge resistor, known as a rapid de-excitation circuit. See Figure 4.

The use of an interrupt switch at the ac input is the preferred method of shutdown over a dc field breaker because of its availability, economy and small space requirement. Furthermore, it still provides electrical field isolation from the ac power source.

For large excitation systems that work direct into the main field and using an ac field breaker, the system often is shut down electronically. In this case, the firing circuit causes the full converter bridge to fully invert, forcing the field voltage negative and collapsing the generator voltage very quickly. Using the electronic shutdown approach reduces the mechanical wear out mechanisms associated with the breaker and will extend its life.

Field Flashing the Generator

With a rotating exciter application, there typically is enough residual magnetism in the exciter's iron to facilitate generator voltage buildup when the generator is brought up to speed. When converting to a static exciter, there usually is inadequate residual magnetism in the rotor iron for the static exciter to build excitation voltage from when the static exciter is shunt fed from the generator terminals. To remedy this, external means need to be provided to build generator voltage. A battery source meets this requirement of external dc. Hence, the external battery source forces a current in the field circuit, generating some ac voltage from the generator sufficient to allow the thyristors to begin rectifying.

A diode in series with the positive battery source prevents the current from the power thyristor charging the battery. Typically, the battery source is 125 Vdc, although 250 Vdc is not uncommon. In special cases, an ac source that is rectified and supplied to the field as an alternate flashing source may be used. The battery source for field flashing usually is removed as generator voltage increases to 50-70 percent of rated voltage by the excitation system. The voltage buildup circuit includes a timer that removes the battery source to prevent excessive battery drain when the ac field contactor closes and the generator voltage does not build up. Field flashing typically is applied when the generator has reached at least 80% of rated speed.

Power Rectifier Bridge

The rectifier bridge includes: heat sinks containing the power semiconductors, in-line current limiting fuses, and a surge suppressor to clamp and limit high voltages induced into the generator field from the stator. These components are mounted together on a chassis forming the rectifier bridge.

Three Thyristor System

The power rectifier bridge can be either half-wave or full wave controlled to rectify and control the field of the generator. The rectifier bridge is equipped with power fuses and R-C snubber circuits for proper control of the power thyristors. Figure 2 illustrates a schematic of a three-thyristor system and the accompanying output waveform for high and low output in Figure 3. The vertical rising portion of the waveform indicates the instant the thyristors are turned on. Note that as turn-on is delayed in time (moved to the right), the average dc output voltage decreases. By this scheme, bridge output varies from zero to maximum output. A fourth diode, called a freewheeling diode, connects across the output terminals of the bridge to provide a safe path for field current when the thyristors are commutating (switching on and off). The freewheeling diode substitutes for a dc field breaker and discharge resistor when used with small generator systems to reduce the cost of new excitation equipment. Here, the three-thyristor bridge often is the bridge of choice for smaller generators where replacement excitation system budgets are limited.

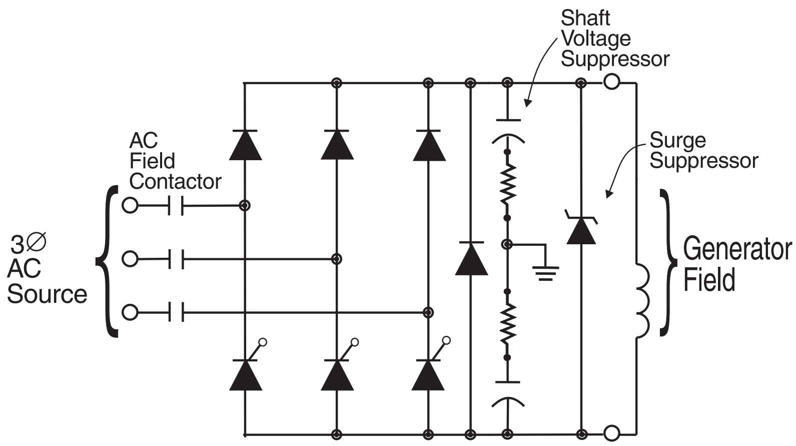

Figure 2: Schematic of Half Wave (3 Thyristor) Rectifier Bridge

The three-thyristor system identified in Figure 2 conforms to a one quadrant system, because the output can be controlled from zero to some maximum positive field voltage with no negative field forcing. The application of the three-thyristor system can be used on any size generator, although they are predominately used on machines below 2-3 MVA and/or up to 150 Amperes on the main field.

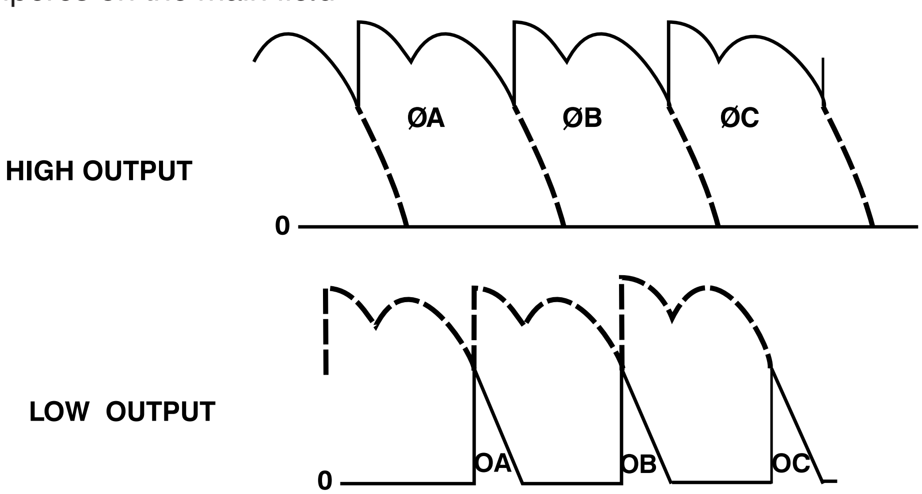

Figure 3: Waveform of 3 Thyristor Rectifier Output Voltage

Six Thyristor System
For machines greater than 3-4 MVA or above 150 Amperes on the field, the six-thyristor system generally is preferred. Although the reaction time of the three-thyristor system can be very responsive, its output performance is limited to a zero-to-positive ceiling voltage in the field circuit. See Figure 3. When fast generator voltage changes are required, the zero minimum voltage on the three-thyristor bridge limits the speed of voltage decay, while the voltage recovery time will be related to the rate of field decay, machine time constant, caused by the freewheeling diode located across the field.

The six-thyristor bridge in Figure 4 identifies a two quadrant system because the field output voltage swings in both the positive and negative directions, allowing faster generator voltage recovery. When the six-thyristor full wave bridge gates in the negative direction, the power flows from the field back into the generator, via a power potential transformer. Figure 4 provides a schematic illustrating the six-thyristor system, while Figure 5 highlights the change in field output with different conduction angles of the power thyristors.

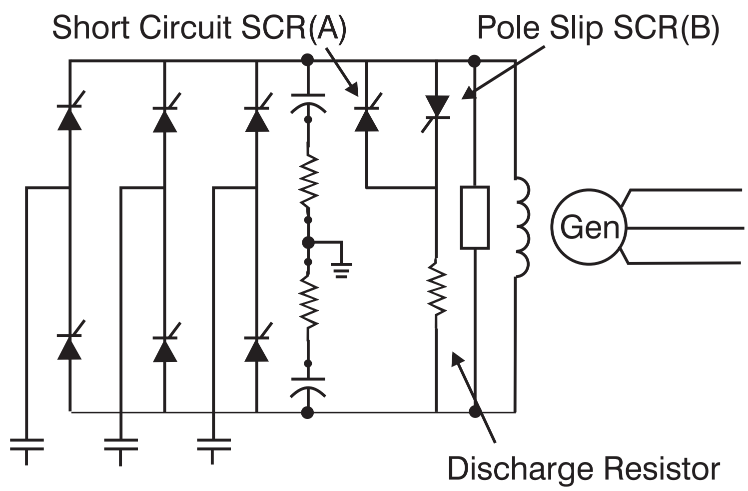

Figure 4: Schematic of Full-Wave (Six-Thyristor) Rectifier Bridge

The maximum thyristor conduction at the field occurs when the generator voltage becomes depressed, such as during a momentary system fault. Figure 5 identifies the power thyristors' output typical of a system that has a depressed generator voltage at locations A, B and C. Note how the conduction angle changes from 0 to 60 degrees positive as the AVR commands high field power. When a = 0, maximum field forcing voltage is available. During normal generator loading, the thyristors are phased on at Location D, with a conduction angle of approximately 90 degrees. When the generator voltage rises above the set point, thyristor output conduction immediately goes negative to quickly collapse the field flux. The thyristor output may vary from 120 to 150 degrees maximum conduction. See locations E and F in Figure 5.

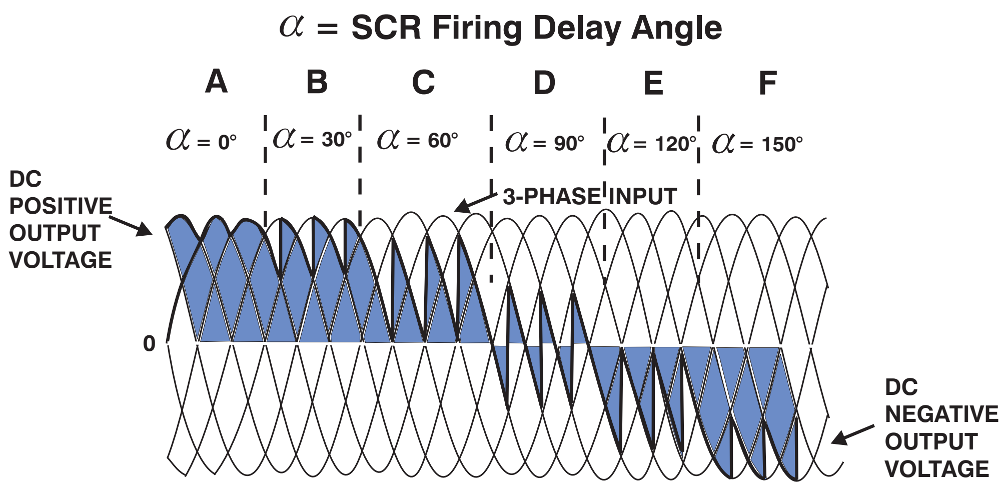

Figure 5: Excitation System Step Response

PERFORMANCE

Generator Response-Increased Voltage Step Change

Figure 6 highlights the performance of a six-thyristor system for a 42 MW hydro turbine generator using voltage step responses. Here, a 10% voltage step changes is introduced to measure performance off-line (generator breaker open). Notice, in Figure 6, with a 10% voltage increase, the static exciter momentarily forces maximum positive voltage into the field to quickly normalize to the new generator voltage. As noted, terminal voltage rises quickly and recovers within 0.4 seconds to nominal with less than 1% voltage overshoot. During a load-on transient, the behavior of 3 and 6 thyristor systems is nearly identical. They both momentarily force positive voltage into the field.

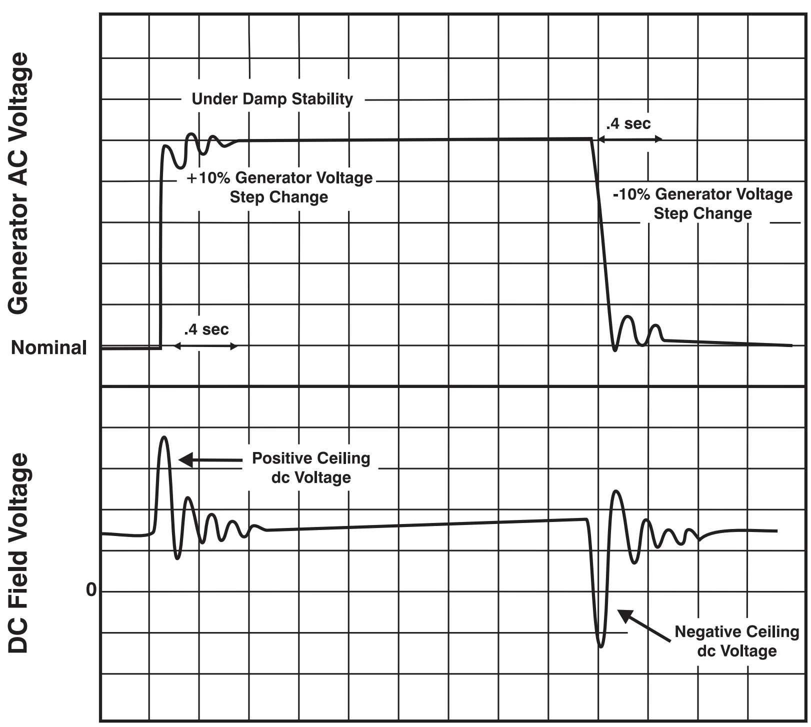

Figure 6: AVR +-10% Voltage Step Response

Generator Response-Decreased Voltage Step Change

When a 10% step change is introduced, causing a decrease in terminal voltage (See Figure 6), the six-thyristor static exciter system causes a momentary negative voltage to be applied into the field. The negative forcing voltage speeds generator recovery by quickly dissipating the field energy back into the synchronous machine. Notice the voltage overshoot again is less than 1% with a 0.4 second recovery time. The load-off transient performance differentiates the three-thyristor from the six-thyristor system.

Performance Differences between Three-Thyristor and Six-Thyristor Rectifier Bridges: Load-Off-Rejection

For small machines, six-thyristor bridge performance versus three-thyristor performance is relatively minor because the main field time constant tends to be small (<2 seconds). When larger machines, > 20 MVA, are involved they have longer field time constants that tend to slow machine response. The longer settling time and nonlinear control in the field of a three-thyristor system dampens the system's ability to provide faster voltage recovery. Slow voltage recovery to system oscillations may be too long when optimum stabilization is critical, since the field cannot go negative. On large machines that required power system stabilizers, the linearity at the machine output is critical toward good power system damping; hence, only full converter bridges meet this requirement. Figure 7 illustrates a slower voltage recovery for a 5% voltage step down for a 3 SCR and 3 diode bridge. Rise time for step up is 0.3 seconds, while the decay time is 0.6 seconds.

Note in Figure 7, the voltage response is much faster when a +5% voltage step is introduced as compared to the 5% voltage step down when load is removed. The slower voltage recovery is the result of the field never going more than 1.5 Volts negative due to the freewheeling diode. The six-thyristor bridge, however, can swing the field voltage in both the positive and negative directions. In Figure 6, notice the symmetrical performance at the generator output for positive and negative voltage steps. Here, the excitation system becomes transiently more responsive to system load changes through its ability to rapidly reduce the generator field flux, hence, provide extremely fast generator voltage recovery.

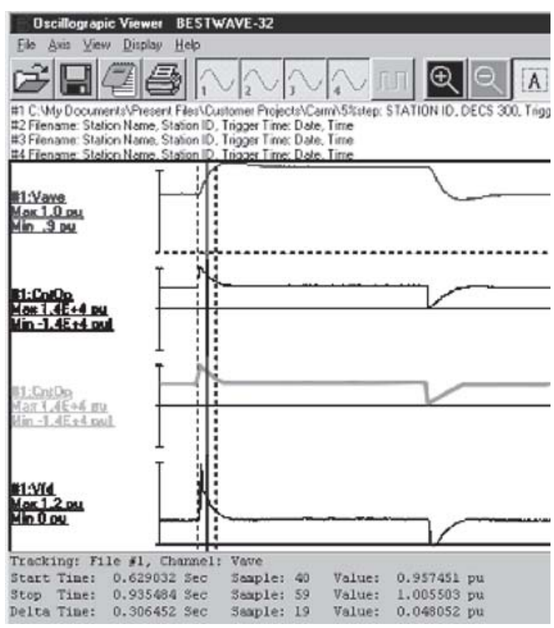

Figure 7: Performance with Pilot Exciter - 3 SCR Bridge

PILOT EXCITER PERFORMANCE IMPROVEMENT WITH DIGITAL CONTROL

Excitation systems have dramatically improved the performance of the generator system as new technology provides innovative tools to optimize unit performance. PID control provides flexibility to achieve response that was only available from static exciter systems working direct into the main field. Figure 8 highlights performance of a voltage regulator working into the exciter field of a 70 MW pump generate synchronous machine. The main field time constant is a 9 second time constant (T'do) while the exciter field (Te) is a 2 second time constant. Step response was performed with the machine open circuited to determine machine response. Here a 5% voltage step change is introduced. Terminal voltage rises to the new level in 1.2 seconds with less than 1% voltage overshoot. The high proportional gain, approximately 5 times greater than the integral gain, causes a fast rise time. While a nominal derivative gain value resulted in minimum voltage overshoot.

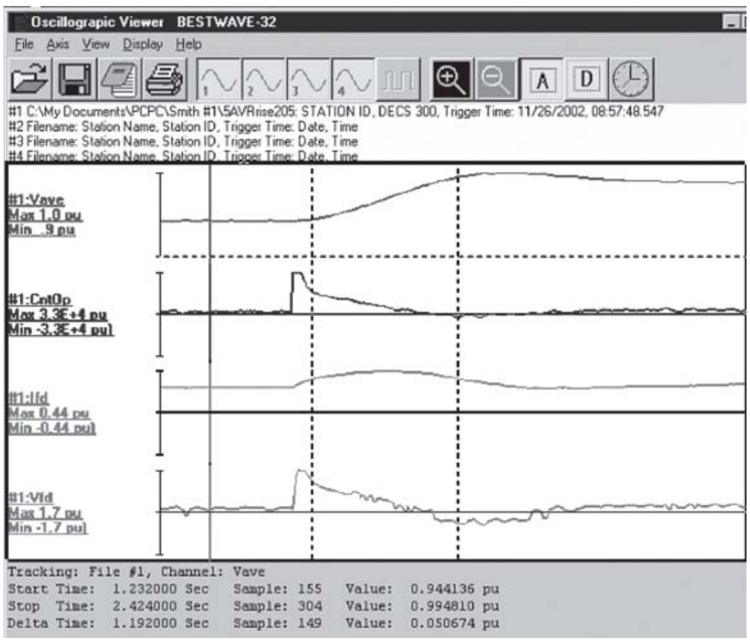

Figure 8: Performance with Pilot Exciter - High KP Gain Controller

Crowbar Fast De-Excitation Circuit

The rectifier bridge needs to be protected from voltage transients that can damage power semiconductors. The type of protection may vary depending upon the type of rectifier bridge utilized. For three-thyristor bridge systems, surge protection such as MOVs (metal oxide varistors), seleniums, or thyrites may be utilized. For six-thyristor bridge systems, the need to eliminate the dc field breaker due to its availability (See Figure 9) and substantial cost has prompted the use of solid state control insertion of a discharge resistor accompanied with MOV for additional protection. See Figure 10.

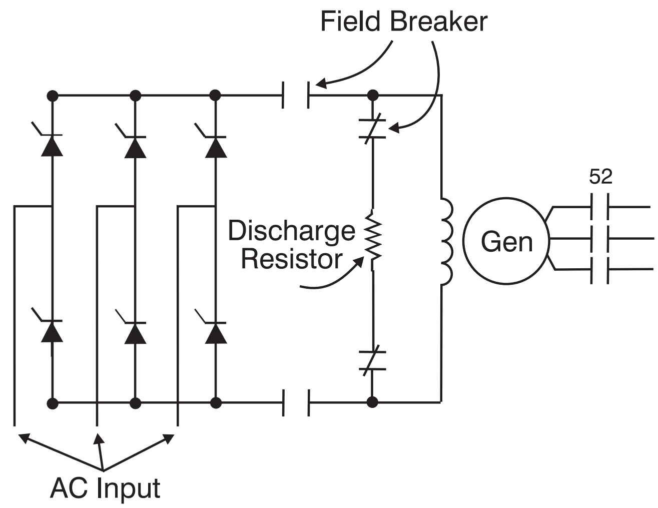

Figure 9: Full-Inverting Exciter System with Field Breaker

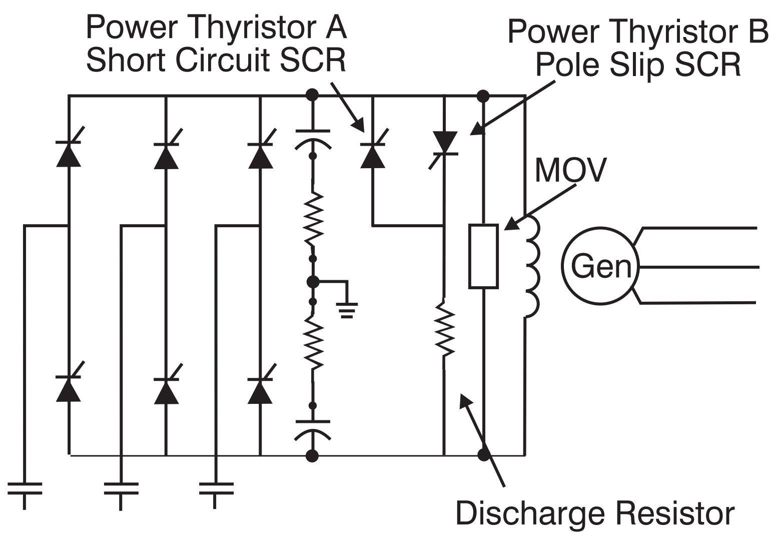

Figure 10: Crowbar Fast De-Excitation Circuit

This crowbar circuit consists of two power thyristors connected in anti-parallel with a series discharge resistor. A crowbar circuit provides a means of fast de-excitation to quickly dissipate the field energy during shutdown of the excitation system via a discharge resistor when the ac field contactor opens.

Crowbar fast de-excitation:

- Eliminates expensive dc breaker
- Keeps discharge resistor
- Optimum fault clearing time
- 50 times faster than dc breaker

It protects against

- Machine short circuit transients
- Machine pole slip

Power thyristors A or B in Figure 10 will be triggered on by an excessive voltage transient induced into the generator field. Without the crowbar circuit, the voltage transient can be of a magnitude that can damage the bridge power semiconductors. The crowbar circuit clamps the field at a specific voltage and dissipates the field energy via the discharge resistor. Voltage transients induced into the field can be caused by a machine pole slip or generator short circuit. During these conditions, the crowbar circuit senses the polarity of the overvoltage transient and causes the appropriate power thyristor (A or B) to turn on.

For a second level of field protection, the crowbar circuit can be triggered by an external contact typical of an 86 lockout relay. In this case, triggering the power thyristors (A and B) causes the field energy to rapidly dissipate through the discharge resistor. Unlike the dc field breaker, however, the operating time of the solid state circuit is 50 times faster. This occurs due to immediate triggering of the crowbar thyristors to conduct within 150 microseconds compared to 0.1 seconds of a dc field breaker. (See ANSI/IEEE C37.18). See Figure 11.

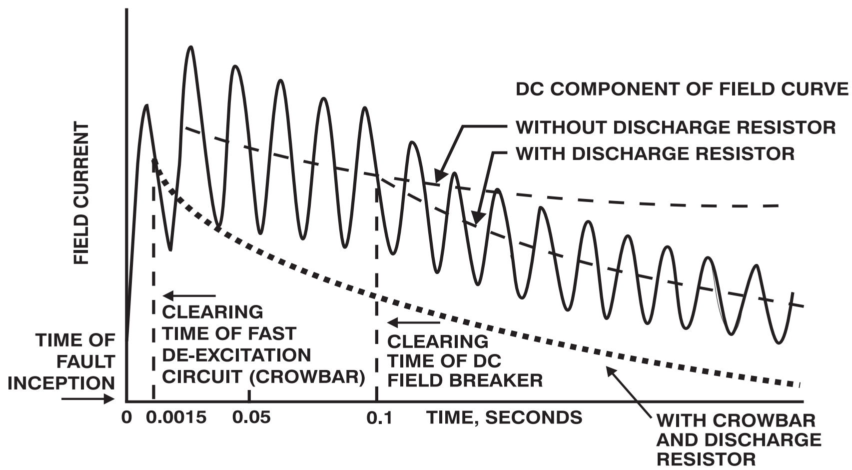

Figure 11: Fast De-Excitation versus dc Field Breaker Operating Time after Initiation of Fault

Machine Short Circuit Transients

When a generator short circuit occurs, a large negative voltage and positive current results that's induced into the field windings. The peak current induced into the field from the fault will combine with the rectifier bridge output if not suppressed.

If an adequate suppression network is not utilized, overload of the rectifier bridge can be imminent. With a crowbar circuit, a directional voltage sensitive circuit detects a specific voltage level at the field that's negative during a generator short circuit. The voltage detection level of the crowbar circuit is coordinated with the rating of the semiconductors and the field insulation. Upon detection of an excessive voltage transient, the gating of SCR (A) occurs. When SCR (A) turns on, positive current is shunted away from the field through the discharge resistor, while the rectifier bridge six-thyristors are blocked to prevent the discharge resistor from being overloaded.

Machine Pole Slip Transients

During a pole-slip condition, a negative current is induced into the field that's opposite of the normal positive current flow produced by the excitation system. A large negative induced current with no current path will result in a very high positive voltage transient across the power rectifiers. The large voltage transient can cause damage to the solid state devices and cause severe pitting of the generator slip rings. With the crowbar circuit, the positive induced field voltage will be detected and cause the gating of SCR (B). This allows the current to flow from the field through the discharge resistor. When the crowbar circuit turns on, the rectifier bridge six-thyristors are blocked to ensure proper thyristor coordination.

Short Time Transients

Additional surge protection is required for the first 150 microseconds due to the time delay in the crowbar operating time. Here, metal oxide varistors (MOV) are utilized.

Rectifier Bridge Construction and Redundancy

There are generally two categories relating to the construction of rectifier bridges, fixed or drawout type which are shown in Figure 12a and 12b respectively. Rectifier bridge failures are an uncommon event when appropriately sized for the application and consideration is given to the environment they are placed in with respect to temperature and moisture. For large, base loaded generators where availability is of utmost concern, there is a tendency to design a system that has redundancy built into it. Redundancy often is interpreted as having n+1 capability where n is equal to the number of bridges required for full load excitation current plus 1 extra bridge either in continuous service or in “hot standby” mode so that it can immediately take over operation in case of failure of one of the other rectifier bridges. Fixed bridges with n+1 system designs work well in situations where it is acceptable to continue operation with the backup rectifier bridge until an outage can be scheduled to make repairs. The drawout “power drawer” is designed to be able to perform repairs on a failed rectifier bridge while the exciter and generator remain on line.

The dc ceiling voltage attainable by the excitation system for field forcing is partially limited by the magnitude of ac input voltage applied to the rectifier bridge. For typical generator designs, the rated field voltage of a generator rarely exceeds 500 Vdc. However, to be able to apply sufficient field forcing of at least 1.5 P.U. of rated field voltage or to comply with regional NERC or Independent System Operator rules that can specify 2 P.U., 3 P.U., and sometimes higher ceiling voltages, special design considerations must be made for the rectifier bridge. Previously, only the fixed bridge design could accommodate ac input voltages greater than 600 Vac. Recently, Basler Electric has expanded the designs for the ac input ratings for the drawout type rectifier bridges. There are now 3 ac input voltage ranges for drawout rectifier bridge designs: low voltage 0 - 600 Vac, medium voltage 601 - 900 Vac and high voltage 901-1300 Vac.

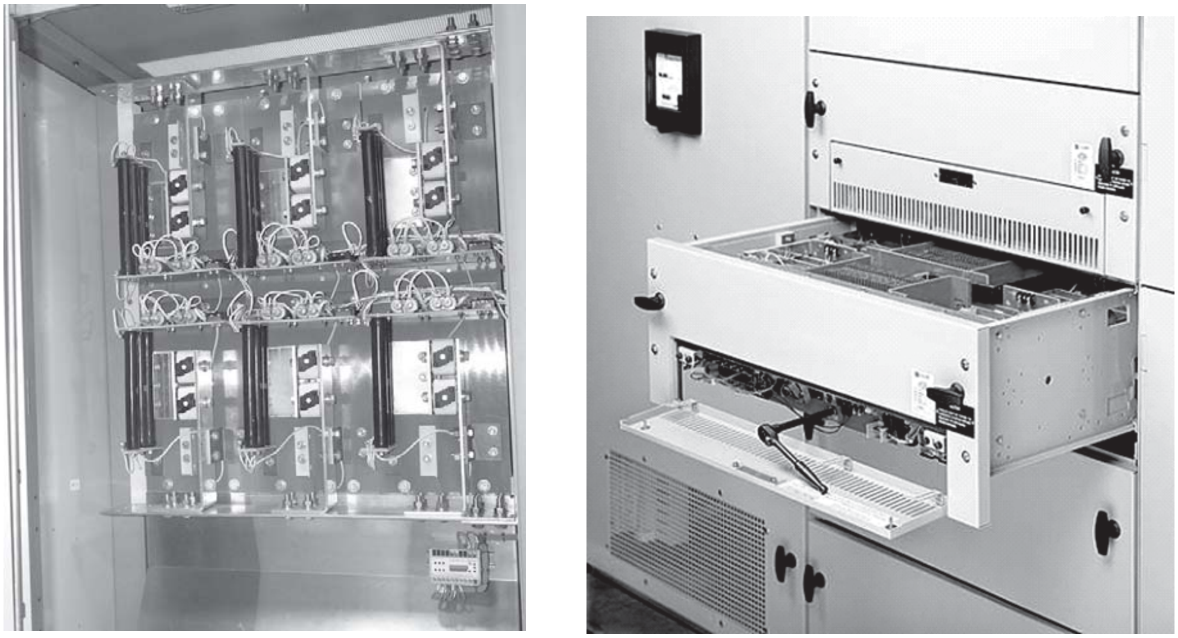

Figure 12a: (Fixed Rectifier Bridge) and 12b: (Drawout Rectifier Bridge)

PARALLELING RECTIFIER BRIDGES

New semiconductor technology developed over the last few decades has vastly increased the current capacity in power semiconductors which in turn has resulted in requiring less real estate to be taken up by rectifier bridges in static exciter applications. With all things being relative, it still may be necessary to parallel rectifier bridges to attain the thousands of dc amperes necessary to excite the field of very large generators. Paralleling rectifier bridges presents its own set of issues with regard to balancing the currents in a given parallel leg to acceptable levels. Slight variances in interconnecting bus resistance, inductance of the parallel leg thyristors as well as variations in the thyristors themselves can result in an imbalance of current. Heat is the enemy of all semiconductors so if one thyristor conducts more current than another in a parallel leg, it will be more prone to failure than the rectifier carrying the lesser load.

There have been several methods developed to force balanced current in paralleled rectifier bridges. The traditional method of current balancing using iron core inductors in the ac input conductors for each phase is shown in Figure 13. This method has been used for decades and has worked well to balance the currents to within ± 10 percent of each other. The downside of this achievement is that each rectifier bridge has to be derated from its design rating. For instance, if two 2,500 amp rated bridges are paralleled together, each bridge has to be derated by 250 amperes (10%). Therefore, instead of having 5000 amp capacity, the total capacity is reduced to 4,500 Adc.

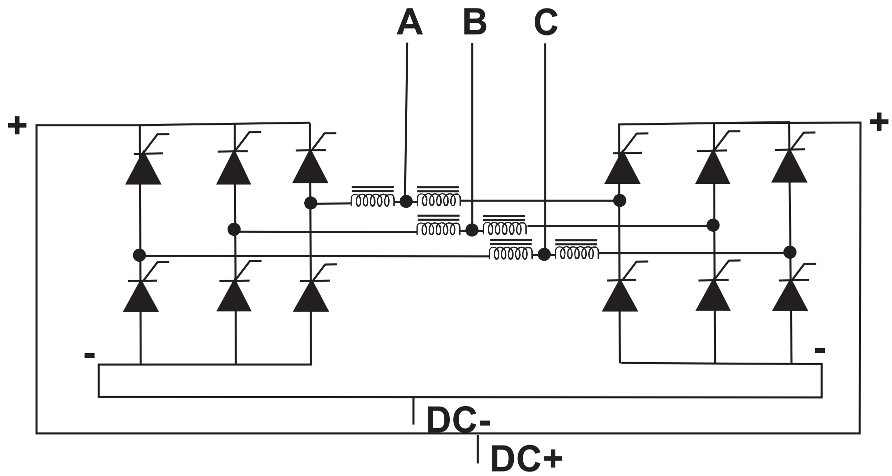

Figure 13: Iron core inductors used to promote current sharing between paralleled bridge legs

There are other techniques for paralleled bridge current sharing that include active current balancing**.** Figure 14 shows an example of a scheme using an active current balancing method known as “skip firing”. This method uses sophisticated electronics and algorithms to occasionally skip a thyristor gate pulse to a thyristor that is getting too warm. This forces other thyristors that are firing in the same paralleled leg to pick up a greater share of the generator’s excitation current.

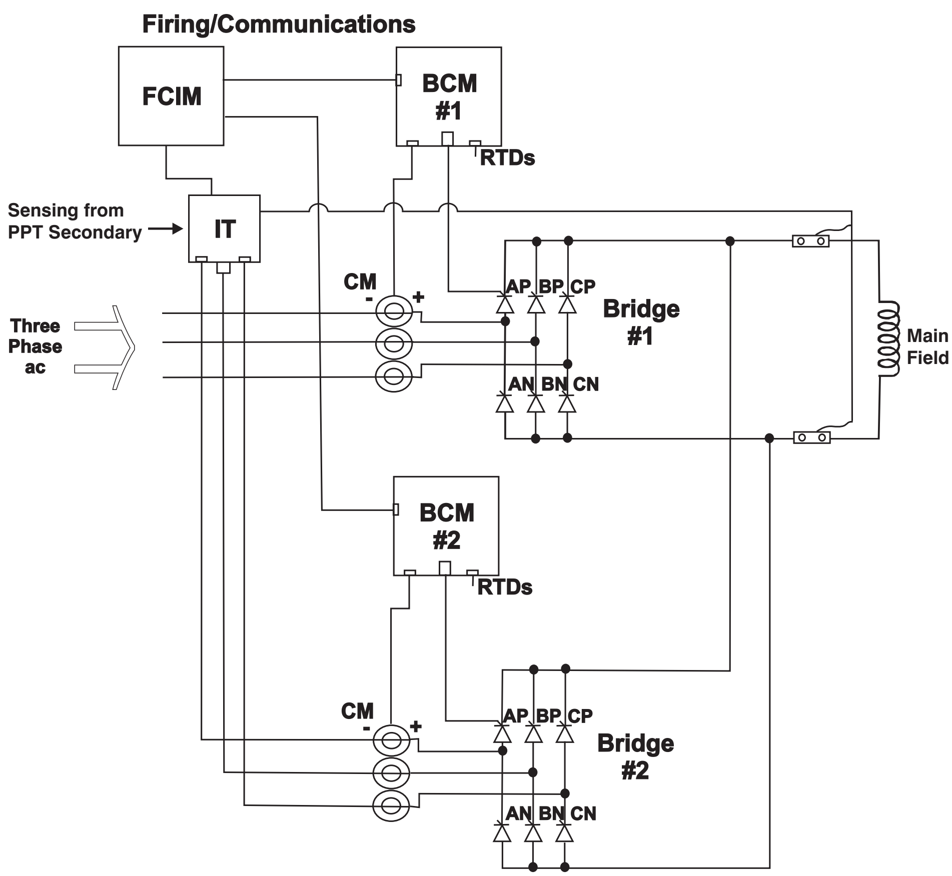

Figure 14: Active current balancing and firing control scheme for paralleled bridges

The active current balancing method simply depicted in Figure 14 uses RTDs directly attached to the various thyristor heatsinks as an input to Bridge Control Modules. By using this active current balancing method, paralleled rectifier bridges can be operated at their nameplate rating without derating. Figure 15 is an illustration of how the RTDs signal of a given rectifier bridge are brought into the Bridge Control Module for processing.

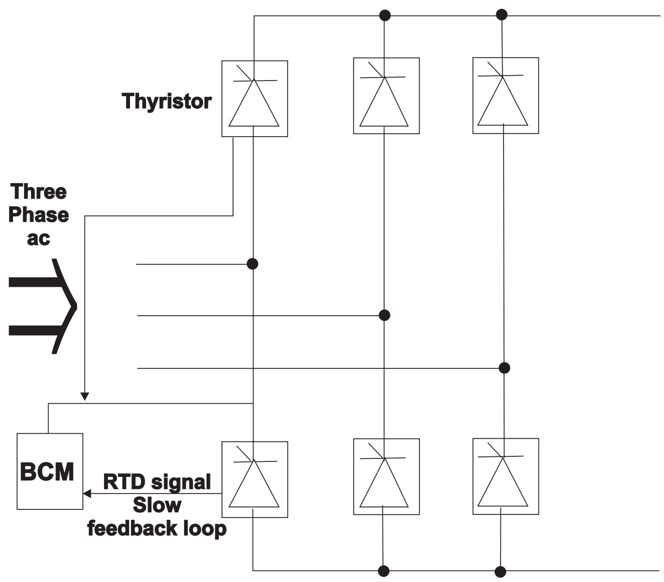

Figure 15: RTDs used for monitoring heatsink temperature and active current balancing

AUTOMATIC VOLTAGE CONTROL

To achieve automatic control, the combination of sensing transformers, an automatic voltage regulator and a firing circuit is utilized.

Sensing transformers

The sensing transformers provide isolation and voltage matching between the generator instrument transformer and the automatic voltage regulator.

Parallel compensation

Generators operating in parallel, in order to prevent circulating currents, need to share reactive power equally. Excitation systems accomplish this by the addition of a paralleling signal to each regulator. A quantity is derived from a current transformer from the generator output that adds with the vector quantity derived by the generator voltage via the sensing transformers. The composite signal enables the exciter to correct its output and attain balanced operation of reactive power between synchronous machines.

Automatic voltage regulator

Automatic voltage regulator features include:

- ¼% voltage regulation
- Volts/Hertz limiting
- Generator voltage soft start

- Reactive current sharing
- Excitation Limiting

The automatic voltage regulator rectifies and filters a sample of the generator voltage, and then compares it with a stable dc reference voltage. If it determines the generator voltage deviates from normal, an error signal results that passes to the firing circuit, it causes the rectifier bridge output to change appropriately to restore generator voltage to a normal level.

A hand-operated or remote adjustable set-point controller permits adjustment of the generator voltage either locally or remotely. Another signal, generated in the firing circuit and shaped by the stabilizing network, is directed to the automatic voltage regulator to prevent instability.

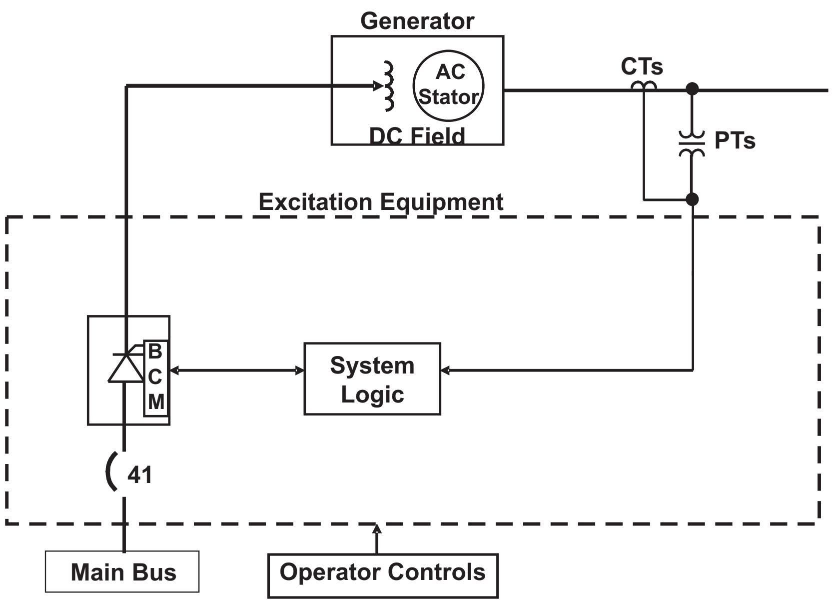

Figure 16: Single-Control Channel

EXCITATION LIMITERS OF DIGITAL EXCITATION SYSTEMS

Digital excitation systems typically include a variety of excitation limiter functions within the same control module. The flexibility of the software allows for simple setting of the parameters and will offer multiple choices to allow the use of various limiter styles and time delay options.

Overexcitation Limiters

The Overexcitation Limiter (OEL) monitors the magnitude of the field current supplied by the exciter and acts to clamp the field current at predetermined levels to prevent field overheating. Most digital controllers include limiter settings for both Off-Line and On-Line operating conditions. The OEL setpoints that would be used for On-Line protection would be set at high values coordinated with the generator's full load field current requirements and would offer no protection when the generator breaker is open and operating at no load. Therefore, Off-Line limiter settings would be set at much lower thresholds coordinated with the no-load excitation values of the generator. Figures 17 and 18 represent the action of off-line and on-line limiter action for a summing point type of limiter that utilizes definite time delays. When limiting at the high instantaneous level, after the first time delay expires, the field current will be reduced to the next lower level for the programmed time delay. The limiter will continue to limit field current at the low limit level indefinitely until the situation causing the overexcitation condition is removed.

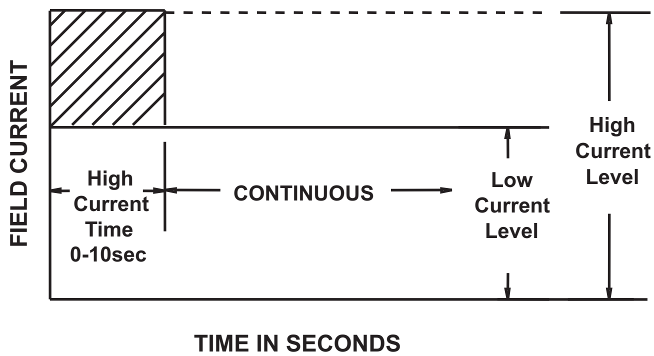

Figure 17: Off-Line Overexcitation Limiter, Definite Time Curve (Summing Point Style)

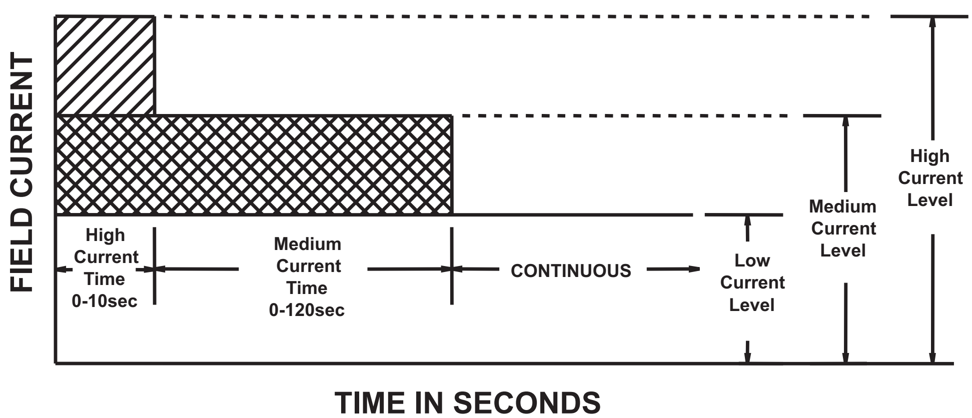

Figure 18: On-Line Overexcitation Limiter , Definite Time Curve (Summing Point Style)

For a takeover style limiter shown in Figure 19, an inverse time curve is utilized with the off-line and on-line limiter having a high level and low level setting. A “time dial” setting controls the slope of the curve to allow coordination with the generator characteristics.

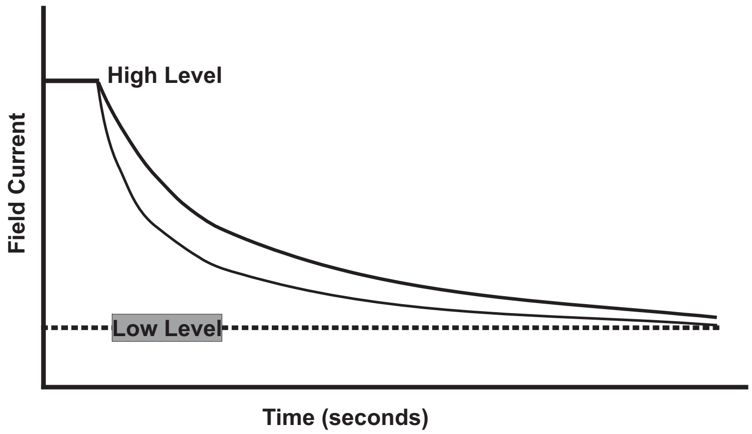

Figure 19: Inverse time characteristic for Takeover style OEL

Underexcitation Limiter

The purpose of an Underexcitation Limiter is to monitor and control the leading Var quantities being absorbed by a generator that is paralleled to the infinite grid or other generators. When the programmed threshold is reached, it acts to prevent a further decrease in excitation current so the generator will not enter an operating area where insufficient synchronizing torque will cause the generator to lose synchronism and slip rotor poles. The underexcitation limiter curve is coordinated with the generator's steady state stability limit and Loss of Excitation protective relays. Figure 20 is an example of defining the underexcitation limiter curve based on leading reactive power versus real power.

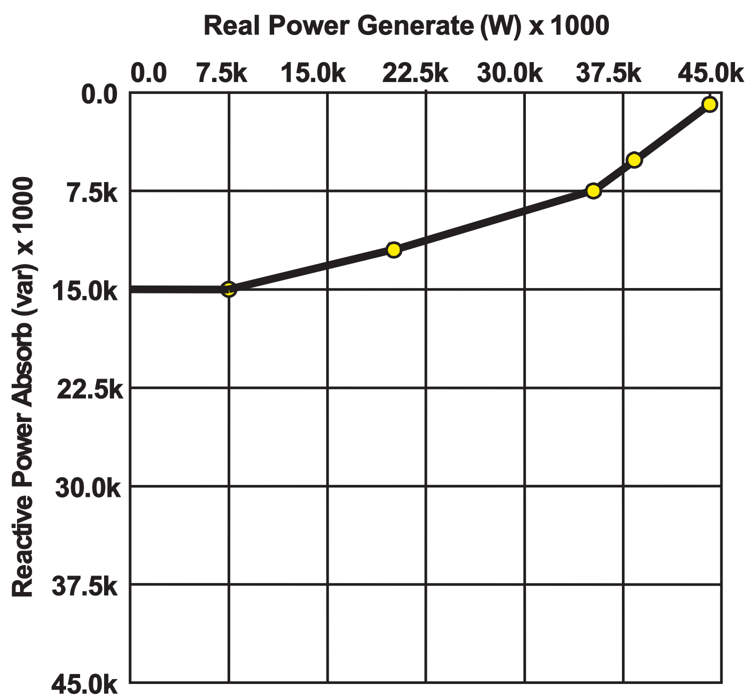

Figure 20: Underexcitation Limiter Curve

Stator Current Limiter

The stator current limiter monitors the level of generator stator current and by limiting the excitation current and ultimately the reactive power, prevents stator overheating. The stator current limiter has no effect on the governor/prime mover and the real power component of line current. Figure 21 shows an example of the stator current limiting high and low level settings with associated definite time delays.

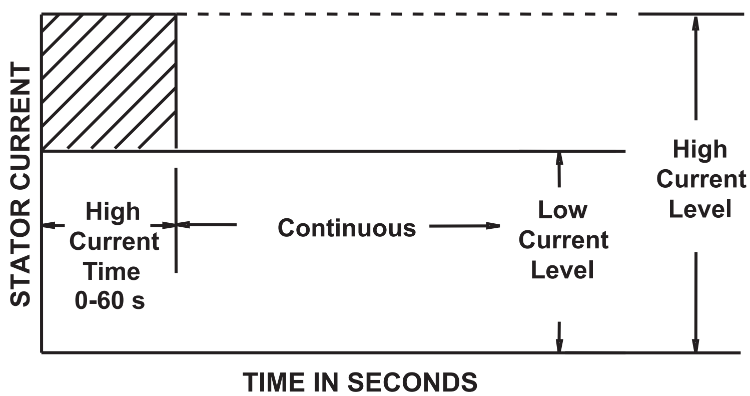

Figure 21: Stator current limiting with definite time curve

Volts/Hertz Limiter

A volts-per-Hertz (volts/Hertz) limiter is so named because the flux is proportional to the terminal voltage divided by the frequency. Excessive flux can result in overheating and damage to synchronous machine stator or transformer core iron laminations. The V/Hertz limiter is used to prevent overheating that may arise from excessive magnetic flux due to underfrequency operation or overvoltage operation, or both.

A V/Hertz limiter commonly is used to protect a synchronous machine (and any connected transformers) for conditions in which the synchronous machine excitation could be applied during start up or shutdown, possibly subjecting the synchronous machine (and connected transformers) to over-fluxing during reduced speed (and thus reduced frequency) operation. It also is used to protect the synchronous machine (and connected transformers) from high flux levels, as they may occur with the machine off-line during which there is no machine armature reaction current to oppose increases in terminal voltage for corresponding increases in excitation. Also, sometimes it is used when two synchronous machines are synchronously started together, one as a motor and the other as a generator. In this type of operation, the V/Hertz limiter acts to raise the terminal voltage as frequency increases.

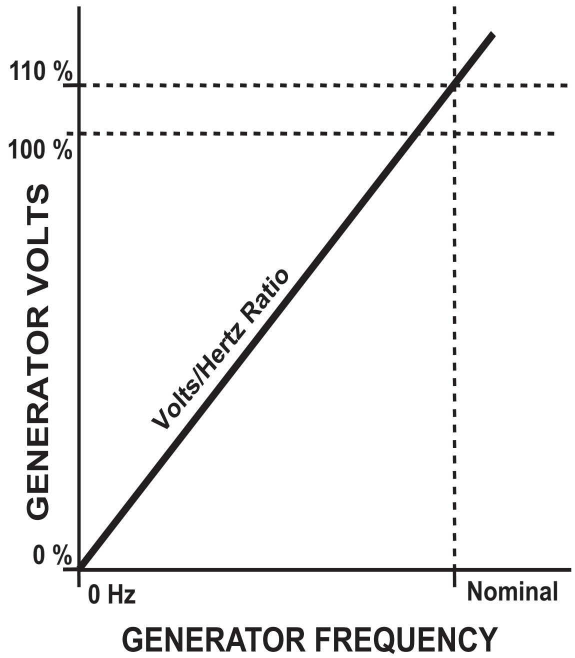

Figure 22: Typical 1.1 PU
Volts/Hertz Limiter Curve

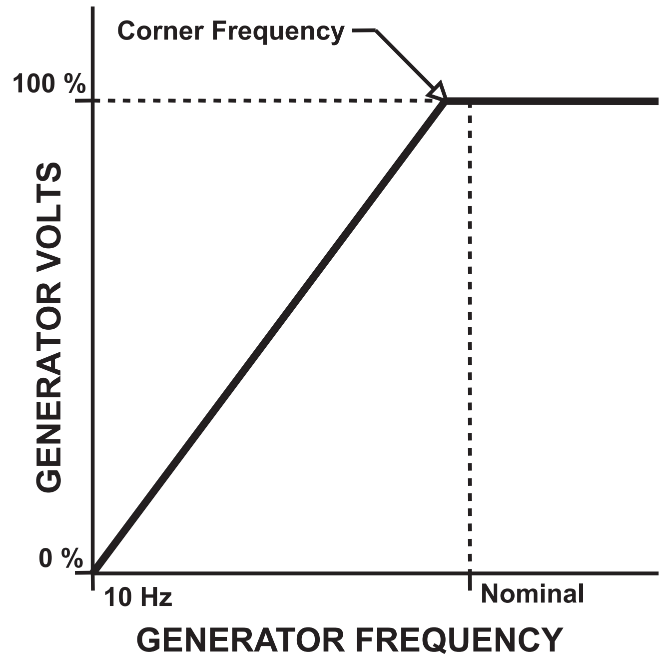

Figure 23: Underfrequency
Compensation Curve

There also is a variation of the volts/hertz limiter called Underfrequency Compensation. With this type of limiter, a corner frequency is determined to be the knee point of the underfrequency curve. For example, if the corner frequency is set at 58 Hertz, any time the generator frequency is at or below 58 Hz, the generator terminal voltage will follow the defined slope. For any generator frequency greater than 58 Hz, the generator terminal voltage will be regulated at the voltage regulator's setpoint value. A graphic example is given in Figure 23.

Generator Softstart

For many older excitation systems, it's not uncommon to see generator voltage overshoot upon energization of the excitation system. The generator voltage may overshoot 15-20% before stabilizing to its steady state value. Generator voltage overshoot occurs when the excitation system initially is energized and the static exciter forces the field with substantial power to quicken the generator voltage to steady state. Generator softstart is important because overvoltage can stress the machine windings and even cause corona (ionization of air due to a high voltage that can affect insulation life.)

By controlling the rate of generator voltage rise via the field excitation system, generator voltage will build up to rated value with little to no overshoot. In effect, softstart control also is considered a limiter function. Typically, the most restrictive limiter setting (V/Hz or Softstart) determines which function is in control. See Figure 24.

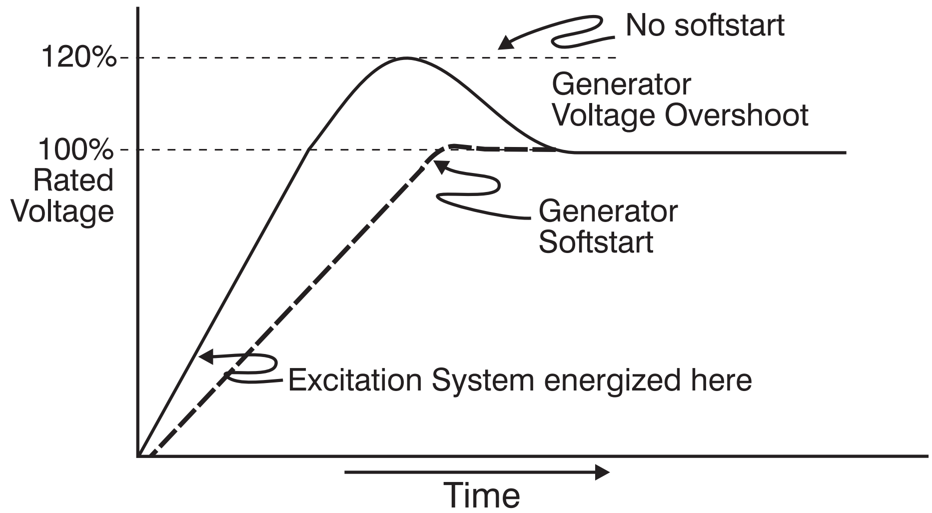

Figure 24: Generator Voltage Buildup Characteristic

Field Current Regulator
Often the manual controller (Field Current Regulator) is an integral part of the excitation system. The manual controller typically regulates the synchronous machine field voltage or field current from below the no-load field voltage to the maximum field voltage required by the synchronous machine at full load. The manual controller typically is used during initial commissioning and serves as backup control should the automatic voltage regulator lose the voltage sensing. Transfer between the automatic voltage regulator and manual control must be bumpless to avoid erratic changes in terminal voltage or system vars.

Power System Stabilizer
In applications where generators are connected to a voltage weak transmission system that has a high impedance, a power system stabilizer often is required to provide damping torque to power oscillations. Before retrofitting to a static exciter, slow responding voltage regulators and their rotating exciters typically have sufficient damping that inherently maintained a stable power system. Static exciters with a High Initial Response tend to reduce natural damping under the conditions mentioned above. The power system stabilizer is a device designed to restore damping and functions by injecting a signal into the voltage regulator and modulating the excitation – at the precise moment and in the appropriate direction.

The use of a power system stabilizer (PSS) in conjunction with a voltage regulator and rotating exciter or a static exciter dictates what type of rectifier bridge is to be used for the application. That is to say that a 3 SCR, one quadrant bridge with only positive field forcing capability has non-linear control and has a tendency to make the generator to which it is applied susceptible to being driven into overvoltage conditions. Therefore, an excitation system with a 6 SCR bridge that has positive and negative field forcing with it’s associated linear control is necessary for useful power system stabilizer applications

For this PSS application, the excitation system PID settings can be tuned to be very aggressive to optimize transient stability with the power system stabilizer to aid system damping.

Dual PID Setting Groups
In today's world of digital implementation, advanced controls can be provided to improve generator response depending upon its operational requirements. For excitation systems where system performance is important, implementing two different PID setting groups instead of one can be a direct benefit to improve unit operation.

The PID control allows for shaping the response of the synchronous machine to meet desired voltage response. Fast responding excitation systems can help to maximize the synchronizing torque on the rotor to quickly regain its steady state position after a fault.

The problem with having only one set of stability gains is that when the power system stabilizer is disabled, the PID gains can be too aggressive and can result in undamped power oscillations in the system after a disturbance. Therefore, where stabilizers are used, compromises in PID setting are required to ensure a stable system operation regardless when the power system stabilizer is enabled or disabled.

Figure 25 illustrates power system instability when aggressive gains are utilized in the excitation system. Note when a 2% voltage step change is introduced, terminal voltage and kVars are very stable, but the kWs begin to swing and the oscillation grows. The aggressive gains improve the transient stability of the system but introduce negative damping, causing kW oscillations on this voltage weak transmission system. When a power system stabilizer is added, as shown in Figure 27, damping is restored during the same 2% step change.

Normally, the power system stabilizer is disabled until a specific power threshold is achieved. With aggressive gains, this can become a problem, as shown in Figure 25. Using the second gain group for the voltage regulator with the lower gains assures a stable system until the power system stabilizer is enabled and the aggressive gains are utilized. Figure 26 illustrates performance when a 2% voltage step change is initiated with the slower PID setting group. Note the kW oscillation dampens after a few cycles, and observe how generator terminal voltage and kVars again are very stable.

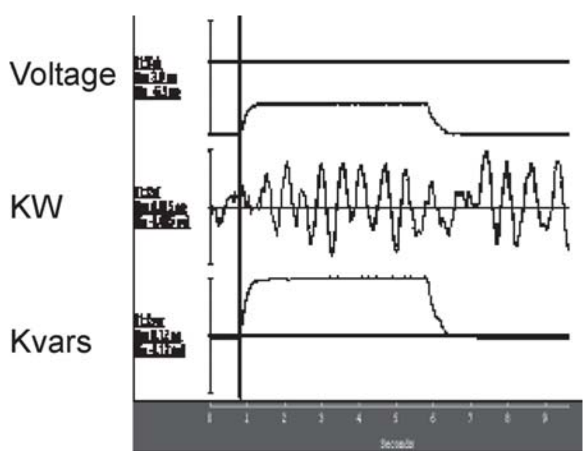

Figure 25: AVR 2% voltage step response with Fast gain and with PSS disabled

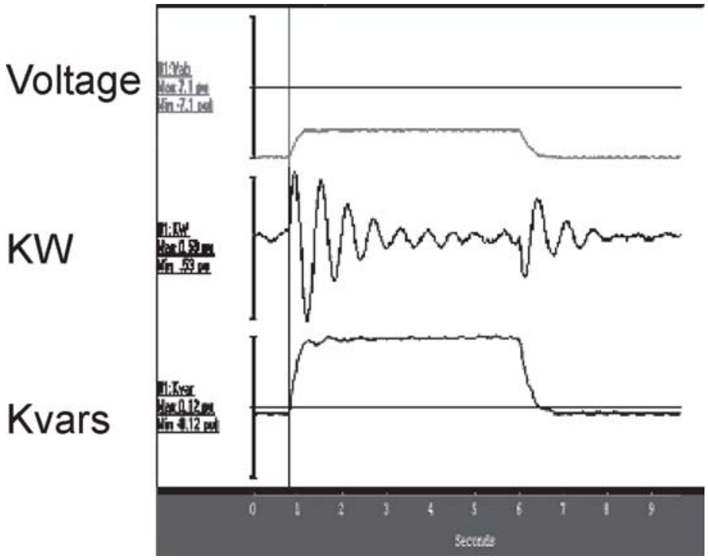

Figure 26: AVR 2% voltage step response with Slow PID gain and with PSS disabled

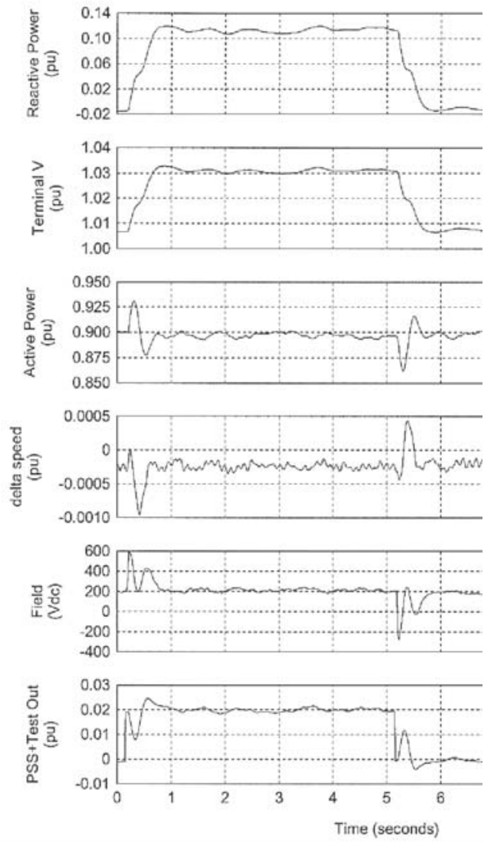

Figure 27: AVR 2% step response with fast gain and PSS at full load

Figure 27 illustrates, again, the aggressive PID group combined with power system stabilizer action. Here, a 2% voltage step change is introduced, but unlike Figure 25, kW oscillations are quickly damped with the aid of the power system stabilizer.

TUNING AND TESTING TOOLS

It is not uncommon for an Independent System Operator (ISO) or other regulating authority such as the North American Electric Reliability Council (NERC) to require generator testing to verify generator performance and validate power system models. With the powerful processors that are used in modern digital excitation systems, hardware and software combines to create powerful tuning and testing tools to assist in the generator testing and also to attain peak performance of the excitation system.

So far, in this paper, we have seen a number of examples where step changes in the regulator setpoint are used to disturb the generator output and analyze the response of the excitation system. The software tools normally include means to facilitate that step change in regulation setpoint. In the course of commissioning a new excitation system, step changes are used to tune and shape the response of the generator output. The results can be captured by the digital controller’s Real Time Monitor (in the Basler DECS-400) as seen in Figure 28 just as you could with an external chart recorder except without the need to connect multiple transducers to it.

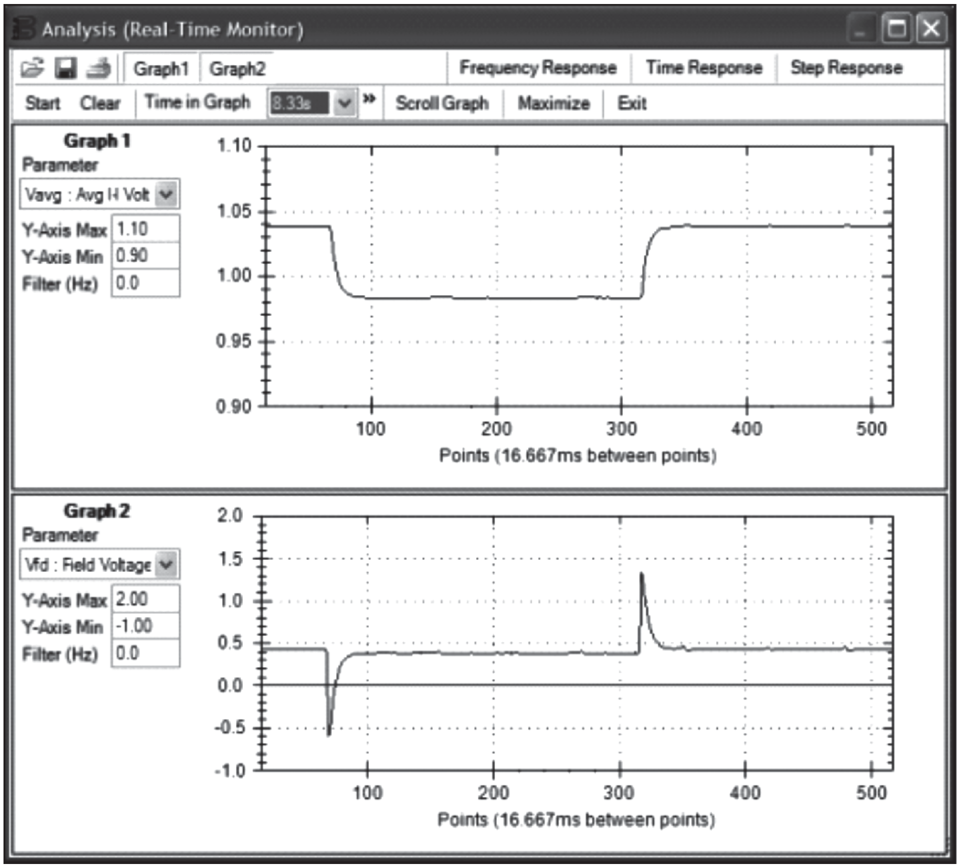

Figure 28: Real Time Monitor acts as digital strip chart recorder

The oscillography capabilities demonstrated in Figure 29 can prove to be an invaluable tool in analyzing post disturbance situations. For example, capturing multiple metered parameters such as line current, field voltage, generator voltage, Vars and watts during pre-fault and post fault conditions is a tremendous troubleshooting aid. Seeing what occurred first during an event is key to determining what equipment may be at fault. Capturing and having records of these same parameters simplifies the procedure of generator testing and reporting to appropriate authorities.

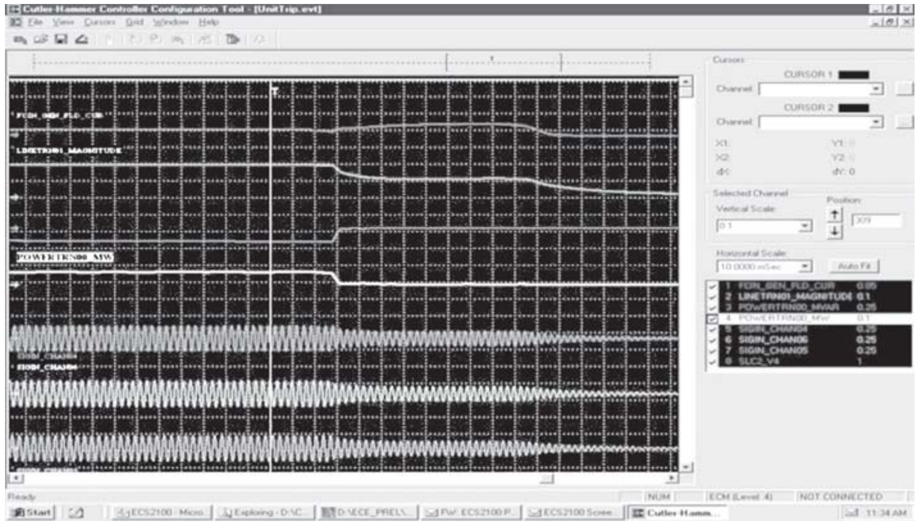

Figure 29: Oscillography captures pre-fault and post-fault quantities and actions

Tuning a power system stabilizer requires on site generator testing that include, among other things, determining the gain of the excitation system and the phase lag of the system. To accommodate this, several modern digital excitation controllers include the function of a signal generator and Dynamic System Analyzer. Tests such as frequency response and the associated results in a Bode Plot are facilitated by the use of software tools such as that depicted in the MS Windows™ screen shot shown in Figure 30 and 31 respectively.

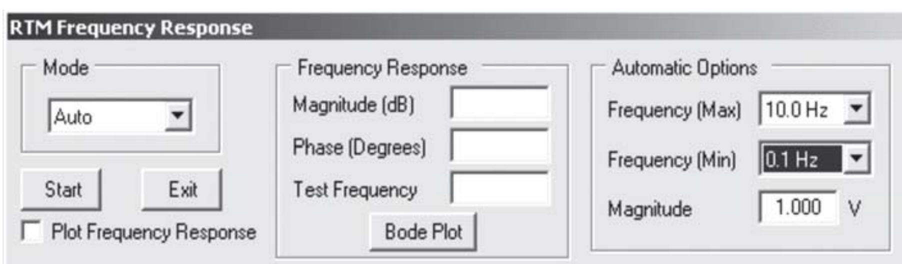

Figure 30: Software tools facilitate frequency response tests

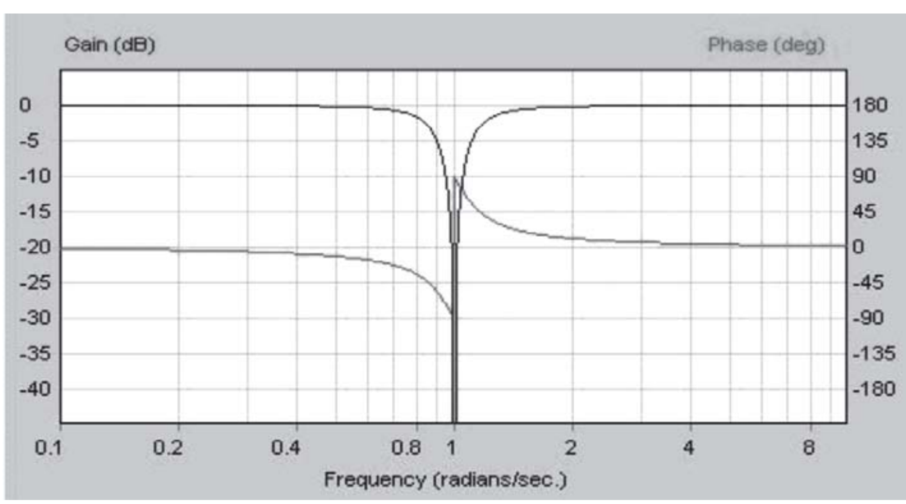

Figure 31: Bode Plot displays results of frequency response test

Exciter System Communication

Many power plant control rooms have incorporated sophisticated distributed control systems (DCS) to facilitate efficient operation of the plant and enable the operators to handle multiple control and information systems from a CRT and keyboard. In other cases, power plants in extremely remote places may be unmanned and totally automated and controlled from remote operation centers. Whatever the case may be, in order to integrate information and control of the excitation system into the DCS or SCADA system when an analog excitation system is used, it requires the use of numerous transducers and interposing relays. These additional interfaces increase the complexity of the system and also invite the possibility of additional components that could fail and possibly cause a loss of control of the system. The technology incorporated into modern digital excitation systems allow the exciter to communicate directly into the DCS or other master devices. The digital excitation controller acts as a slave, responding to control, metering information and status commands from the master device such as the DCS or other operator interface devices. For power plant device communications, the non-proprietary Modbus™ appears to be the most common communication protocol in use today. From the physical aspect for communicating between devices, RS 485 communication ports are widely used. Growing in popularity is Ethernet and/or TCP/IP compatibility. Figure 32 is an example of a touchscreen display that allows an operator to send control commands as well as receive metering and alarm status.

Figure 32: Touchscreen display communicating with digital excitation system

SELECTION CRITERIA FOR CHOOSING A STATIC EXCITER REGULATOR

The field power required by the generator is based on two factors.

1. Generator Size - The larger the machine, the greater the field power required to maintain rated generator voltage at rated load.
2. The Rotational Speed - Mr. Faraday, who discovered electromagnetic induction, observed that the faster a loop of wire passes through a magnetic field, the greater the magnetomotive force produced. In a synchronous generator, this indicates that it takes less field excitation to excite a generator operating at high speed than is required on the same generator operating at lower speeds.

The type of turbine used on a generator plays a dominant role in determining the size of the excitation system. It is not surprising, then, that a gas or steam turbine rotating at 3600 rpm requires a much smaller excitation system compared to a hydro turbine rotating at 120 rpm that has the same generator kW rating.

Choosing the Excitation Rating

The procedure for selecting an excitation system involves little more than the use of Ohm's Law to determine the rating of the static exciter appropriate for a given generator. In most applications, the excitation system normally is sized to meet the generator continuous field rating requirement with, perhaps, additional margin for contingency. For a static exciter working into the main field, this information can be obtained from the machine nameplate located on the side of the generator. If the machine has been rewound, it is most important to obtain operating dc Amperes and dc Volts required by the field that represents the maximum continuous machine loading at rated power factor. Often, a +10% operating margin will be added to the excitation system to obtain a more conservatively sized unit rating in the event the generation rating is increased. If the pilot exciter is being replaced, the field amps and voltage is required for the shunt field of the main rotating exciter. Power for these pilot voltage regulator systems generally is obtained by a dependable 480 Vac source unless field flashing is required for black start. If black start is required, power often is derived from the generator output directly with external dc used for momentary field flashing.

SHAFT VOLTAGE ON CYLINDRICAL TYPE TURBINE GENERATORS

Cylindrical rotor generators may have a voltage that exists between a rotating shaft and the stationary parts of the turbine-generator. Voltages, if sufficiently high, can produce a current between the rotor and the stationary parts to ground by way of the insulated bearing. See Figure 33.

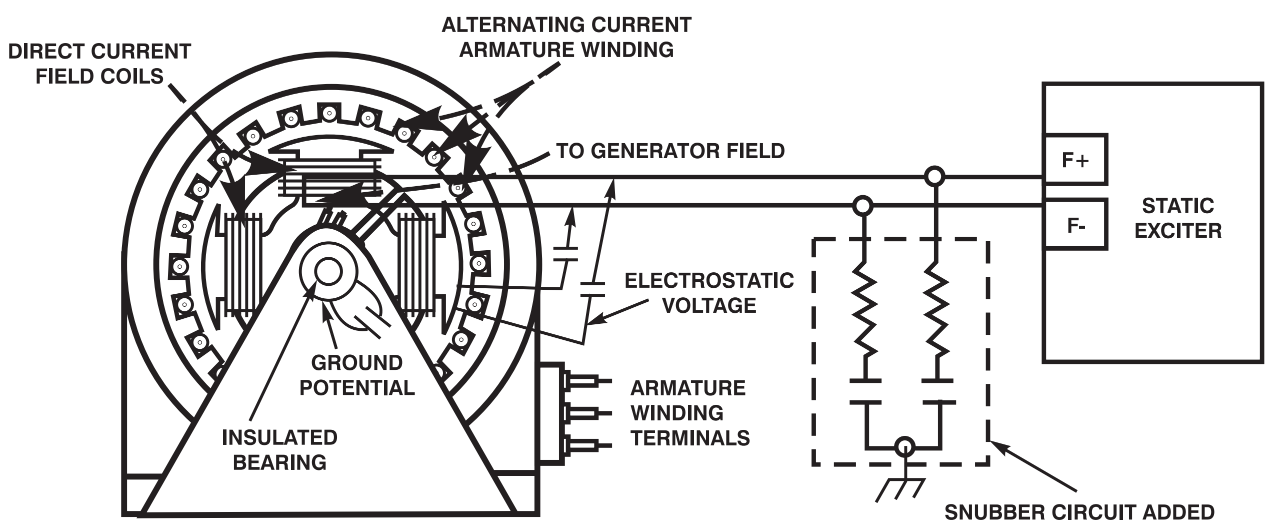

Figure 33: Shaft Voltage Suppression

These voltages are called "shaft" voltages. If not minimized, they can dramatically shorten the operating life of the insulated bearings. Shaft voltages are caused by magnetic irregularities in the generator long shaft and appear most commonly on high speed cylindrical generators. In these applications, it has been found that bearing deterioration (pitting) originates from electrostatic discharges. The electrostatic discharges may be caused by a number of noise sources. One of the sources may be the switching thyristors in the static exciter power rectifier bridge.

One solution to this problem involves adding a grounding brush seated at the end of the shaft that connects to ground. Stray currents will flow through the grounding brush rather than through the insulated bearing. However, this system requires regular maintenance checks to ensure good surface contact.

Today, resistor and capacitor snubber circuits are used to send high frequency noise to ground. See Figure 33. The snubber circuit consists of a symmetrical resistor and capacitor network connected across the field with a center tap to ground. The snubber circuit responds to high frequency noise generated by the power thyristors. The snubber circuit provides a low impedance circuit path that shunts high frequency currents caused by the thyristors to ground.

BEHAVIOR OF THE STATIC EXCITER DURING FAULT CONDITION

Many times the question arises: Is excitation support necessary for the generator? In reality, the application and type of fault that occurs determines behavior of the shunt static exciter in response to the fault.

Type of Fault	Impedance Limited	Exciter Output
Distance Fault	Yes	Static Exciter Output Reduced by % AC Input
Single Phase Fault	No	Reduced Field Forcing
3 Phase Fault at Generator	No	No Exciter Output

Table 1: Excitation System Response to Faults for Shunt Type Static Exciter

The location of the fault affects the response of the excitation system, hence, the generator output. Table 1 describes the output of the excitation system based on various system fault possibilities.

Generating systems can be divided into two categories: those systems that operate totally isolated, and systems that are connected in parallel with the utility bus. The information below offers an explanation of how the excitation system will behave without excitation support for each condition.

Isolated Bus-Motor Starting

When a generator provides isolated power to local loads, the machine(s) capacity normally provides for normal loading and some degree of overload depending upon the system.
If the loads are motors, the starting inrush kVA required by the motor must be considered. Depending on the size and type of synchronous or induction motor used, voltage dips of

various magnitudes can be anticipated due to the starting inrush kVA of the motor. Excessive voltage dips during motor starting may reduce the available field power from the excitation system and cause longer motor starting time. See Figure 34.

Computers often are used to model the generator with its reactance and the load in order to determine the expected voltage dip when motors are applied across the generator output. The models preview the system's performance by calculating the voltage dip and voltage recovery time. The factors that affect voltage dip include: reactances and time constant of the generator, the inrush kVA of the motor, and the static exciter transfer function and field forcing capability. The higher the field forcing level, the shorter the motor starting time. Typical amounts of field forcing range from 145 - 150%.

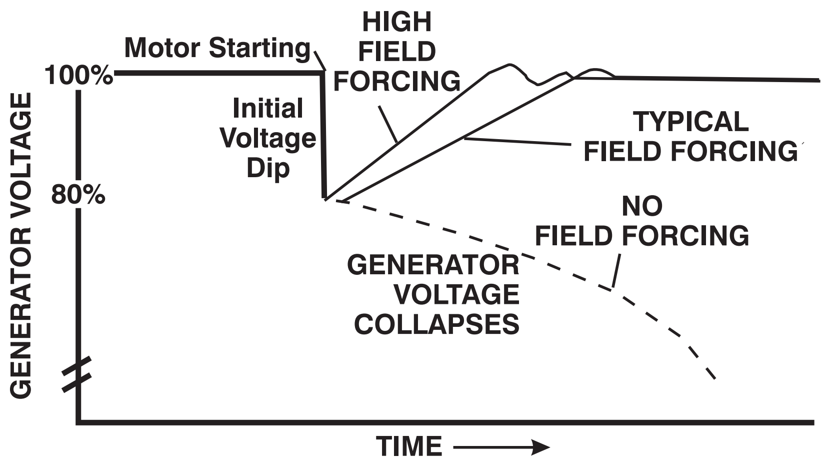

Figure 34: Motor Starting Characteristic with Various Levels of Field Forcing

Isolated bus-sustained generator short circuit
Another consideration involves a fault at the generator output terminals. Should a sustained three phase fault occur at the generator output, a shunt type static exciter output will collapse, eliminating the possibility of generator fault current contribution. See Table 1. Lack of a sufficient fault current from the generator may prevent proper relay coordination necessary to trip system breakers that may otherwise cause equipment damage. Here, careful selection of protective relays must be considered to ensure adequate generator protection upon loss of excitation.

Parallel Bus
The second category affects the use of a shunt static exciter on a machine connected to the utility bus. When the generator connects to the utility, the increased MVA capacity of the system improves motor starting and aids in minimizing the voltage dip in the system.

If a three phase fault occurs at the generator terminals, the generator's voltage decays, and there is insufficient voltage for the excitation system to feed power to the field. Unlike the discussion of an isolated bus, however, relay coordination may be achieved through the utility bus intertie that also is feeding current into the fault. Here, the fault current for relay tripping is provided by the stiffer power source (utility) and not from the generator relaying.

Where a fault occurs in the distribution system (See Table 1), often transformers and line impedance will limit the fault current between the generator and the source. See Figure 35. For these faults, the system impedance tends to limit the magnitude of the generator voltage drop, and the static exciter is able to force the generator field momentarily to support the voltage needed for high speed relays to clear the fault and bring the generator voltage back to normal.

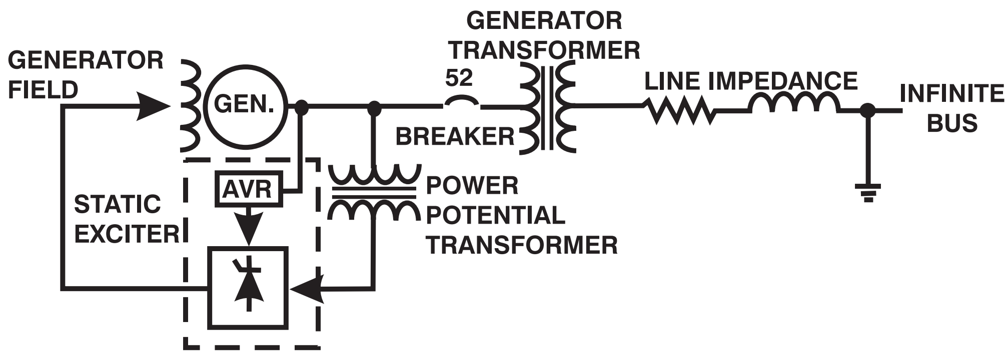

Figure 35: Generator Paralleled to the Infinite Bus with a Fault to Ground, Impedance Limited

Excitation Support for The Shunt Exciter

The use of excitation support must be evaluated based on the system's requirements for fault clearing at the generator output. To determine if excitation support is necessary, questions need to be asked. Can the fault current be derived from the utility, or must it be derived by generators independently? If the fault current must be derived independently from the generator, excitation support should be considered.

Excitation support added to the shunt static exciter can aid motor starting and sustain fault current for relay coordination by inserting large power current transformers into each of the generator lines. When the voltage drops below a set value, the output from the current transformers is rectified and applied into the generator field. See Figure 36.

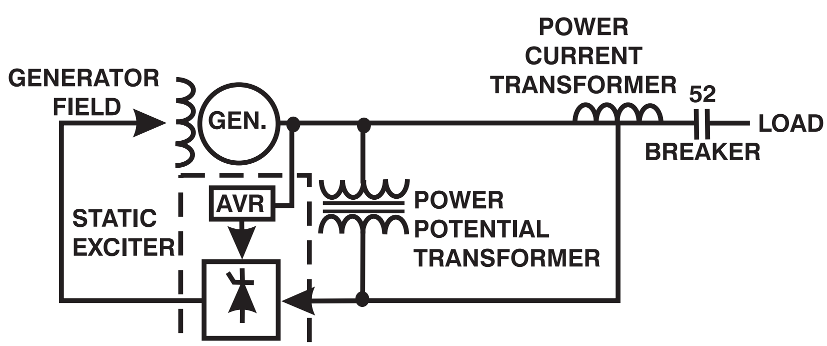

Figure 36: Excitation Support Added to Shunt Static Exciter

The amount of short circuit current required is based on the generator capability and relaying requirements.

Time (Seconds)	10	20	60	120
Generator Armature Current in % of rated	226	154	130	116

Table 2: Permissible Generator Overload Versus Time

ANSI C50.13 offer guidelines as indicated in Table 2 that show the permissible short time overload current plotted against time.

When excitation support is being considered, the following additional questions must be addressed.

- What is the generator short circuit current capability and permissible time allowed?
- Is the switchgear designed to handle the possible sustained PU short circuit current?
- Is sufficient machine data available to design the excitation system?
- What is the maximum allowable overcurrent time?
- Has there been proper consideration of relay coordination and tripping?

Redundant Voltage Regulators

Today many digital excitation systems have manual control integrated with the voltage regulator, hence one box utilizes the same processors. The older philosophy of separation between the voltage regulator and manual control no longer exists. Instead, the practice of having two controllers, which offers 100% redundancy with the voltage regulator, manual control, and limiters in each controller, is the most common and preferred method for backup. See Figures 37 and 39. The backup controller will track the primary controller to ensure a bumpless transfer between controllers if a scheduled or unscheduled transfer should occur. The transfer between the controllers can be performed manually or through a fault logic scheme, such as a watchdog processor in the digital controller and an internal or external independent overcurrent module.

Figure 37: Dual Controllers are the Preferred Method for Backup

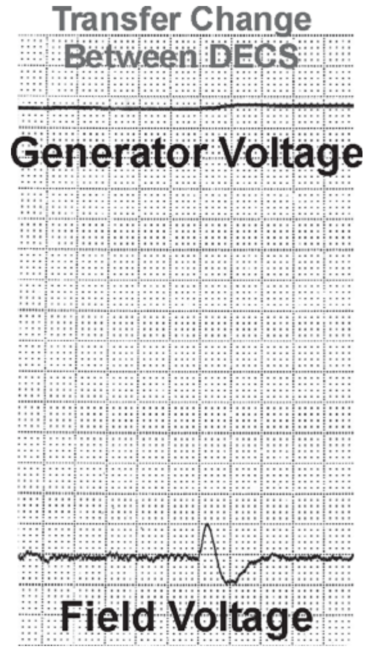

Figure 38: Bumpless Transfer Between Two Digital Controllers

Figure 38 illustrates a transfer between two digital controllers. The actual tracking time is adjustable to set the response time of how fast the backup controller will follow the primary controller. A less than 2% change at the generator output is considered bumpless.

The question that often arises when an excitation system upgrade is being considered: "Should the new exciter system include redundancy or is a single controller adequate?" There are no clear cut answers due to other circumstances such as budget constraints. However, there are a few prevalent factors that would suggest when redundant controllers should be strongly considered. For example, if the generator is a base load machine and/or the capacity is greater than 100 MW, redundant controllers are typically used. If the generator, regardless of size is critical to the power system or critical to an industrial process where power failure is not an option, then a redundant excitation system is advisable.

Custom designed excitation systems offer various levels of redundancy to fit the need of application. For example, Figure 39 illustrates the architecture of a redundant control system and the associated transfer logic. This type of system is designed such that if either controller detects a fault, it can initiate a transfer to the backup controller.

The level of redundancy shown in Figure 39 can be further expanded as shown in Figure 40 to include dual channel control with supervision. In this scheme, it requires a two out of three vote to determine whether the Main or the Redundant controller is in control.

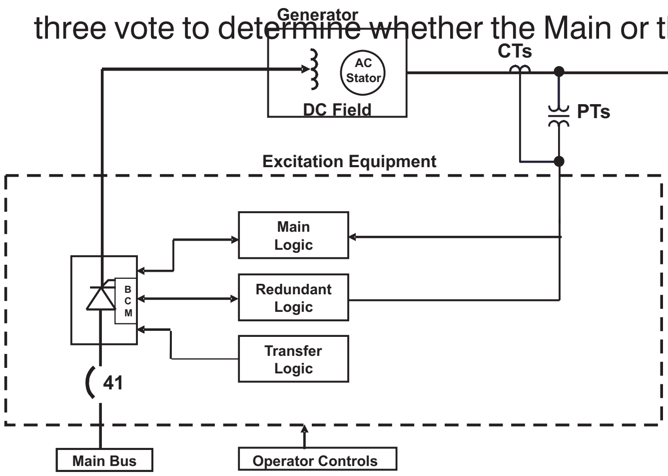

Figure 39: Dual channel excitation controller

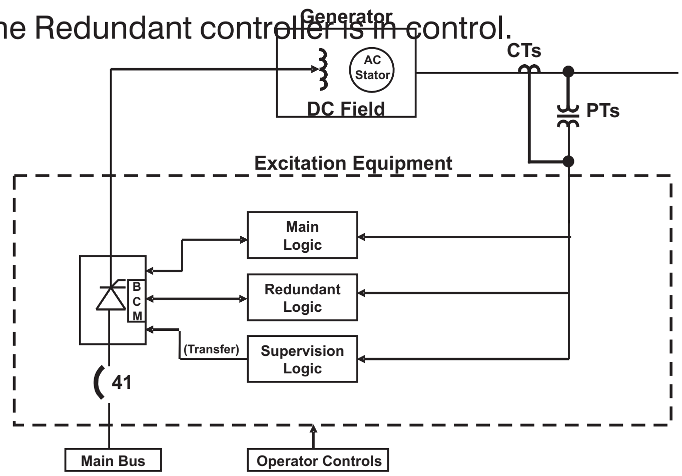

Figure 40: Dual Channel with Supervision

CONCLUSION

Static excitation systems provide valuable solutions to problems with equipment obsolescence. The benefits of retrofit to static excitation are far beyond the maintenance savings.

As synchronous machines are being continuously pushed to their design limit to meet system loading, it has become increasingly important that the system be stable under any condition. Today's excitation features help to provide the control for enhanced performance regardless if the excitation replacement involves updating the pilot exciter or complete retrofit of the rotating exciter to a main field static excitation system.

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