Power System Instability—What Relay Engineers Need to Know

Charles J. Mozina
Beckwith Electric Company
6190-118th Avenue North, Largo, FL 33773
cmozina@aol.com

I. INTRODUCTION

This tutorial paper discusses what relay engineers need to know about power system stability. The understanding of power system stability has taken on renewed importance because it has played an important role in recent blackouts and power system events investigated by NERC. The paper discusses the four basic types of power system instability: Voltage instability, Steady-state instability, Transient instability and Dynamic instability. The paper relates how these various forms of instability relate to generator and transmission system protection.

The paper also discusses system schemes used to address instability including: Generator Fast Valving, Generator Tripping, Generator High-speed Excitation Systems, Independent Pole Circuit Breaker applications and various types of Special Protection Schemes (SPS). Recent system instability events have interacted with both transmission and generation protection in ways not always envisioned by the protection engineer.

II. TYPES OF POWER SYSTEM INSTABILITY DURING SYSTEM DISTURBANCES

A. Basics – Voltage vs. Frequency Stability

In a power system, frequency is a measure of the balance of MW generation and MW load. When MW generation and MW load are exactly in balance, the frequency is at the normal level of 60 Hz. When load exceeds generation, the frequency goes down. The rate of decline depends on the inertia of the generators within the system. Under normal conditions, there are slight changes of frequency when load suddenly increases or generation trips off-line which results in a slight (generally in the hundreds of a Hz) reduction in frequency until the aggregate generation in the system can be increased to meet the new load condition. If there is a large negative unbalance between MW load and MW generation, the frequency will go down. Under frequency load shedding schemes (UFLS) on the utility system are designed to restore the balance by shedding load.

Voltage in a power system is a measure of the balance of MVAr load and MVAr capability within the system. If that reactive support is not available, the voltage will go down. The impact of reduced voltage on load depends on the nature of the load. For resistive load, the load current will decrease and help limit the need for local reactive support. Motor loads are essentially constant kVA devices. The lower the voltage, the more current they draw—increasing the need for local reactive support. Power system loads consist of both resistive loads as well as reactive motor loads. During hot weather, however, air conditioning motor loads make up a large portion of total load, thereby making the system more susceptible to voltage collapse. Undervoltage load shedding schemes (UVLS) are designed to shed load to restore system voltage to avoid a complete system voltage collapse.

Reactive power system support can only come from two sources: shunt capacitors and generators/synchronous condensers. Shunt capacitors are a double-edged sword. They do provide reactive support, but they also generate fewer VArs as the voltage dips. The VAr output of a capacitor bank is reduced by the square of the voltage. Shunt capacitor banks cannot quickly adjust the level of reactive power.

Generation at the load center can provide a dynamic source of reactive power. As the voltage goes down, the generator can quickly provide increased reactive support within its capability limits. Unlike shunt capacitors, the amount of reactive support does not drop as system voltage goes down. The amount of reactive power is controlled by the generator automatic voltage regulator (AVR). It is essential that the AVR control be properly set and the generator protection system allow the generator to contribute the maximum reactive power to support the system without exceeding the generator's capability.

B. Voltage Instability

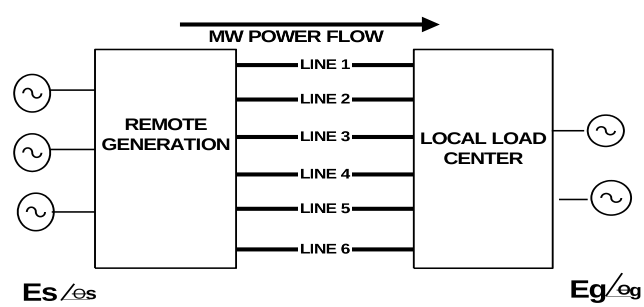

Fig. 1. Power system with remote generation

Fig. 1 illustrates a simplified power system with remote generators supplying a substantial portion of the load at the load center through six transmission lines. Es is the voltage at the remote generator buses and Eg is the voltage at the load center buses.

Fig. 2 illustrates how voltage decays as real power transferred to the load center increases. This type of P-V analysis (real power relative to voltage) is an analysis tool, used by utility system planners, to determine the real power transfer capability across a transmission interface to supply local load. These curves are also called nose curves by system planning engineers. Starting from the state of a base-case system (all lines in-service), computer-generated load flow cases are run with increasing power transfers while monitoring voltages at critical buses. When power transfers reach a high enough level, a stable voltage cannot be sustained and the system voltage collapses. On a P-V curve (see Fig. 2), this point is called the “nose” of the curve. The shape of the nose of the curve depends on the nature of the load at the load center. High levels of motor load combined with capacitor bank support of load center voltage tend to make the voltage drop very rapidly for a small increase of power at the nose of the curve.

The set of P-V curves illustrates that for baseline conditions shown in curve A, the voltage remains relatively steady (changing along the vertical axis) as local load increases. System conditions are secure and stable to the left of point A1. After a contingency occurs, such as a transmission circuit tripping, the new condition is represented by curve B, with lower voltages (relative to curve A). This is because the power being transmitted from the remote generators are now following through five rather than six transmission lines. The system must be operated to stay well inside the load level for the nose of curve B. If the B contingency occurs, then the next worst contingency must be considered. The system operators must increase local generation (Eg) to reduce the power being transmitted for the remote generators to reduce losses as well as increase voltage at the load center to within the safe zone to avoid going over the nose of curve C.

In the case of the 2003 East Coast blackout [1], three key transmission lines were lost in succession due to tree contacts. The voltage at the load center was reduced before the system operators could take effective corrective action. Effective operator action was inhibited by the lack of data from key transmission system substations due to a computer problem at the system operating center. In the case of the 2003 East Coast blackout, voltage decay was relatively slow and there was time for system operator intervention to address the voltage decay problem.

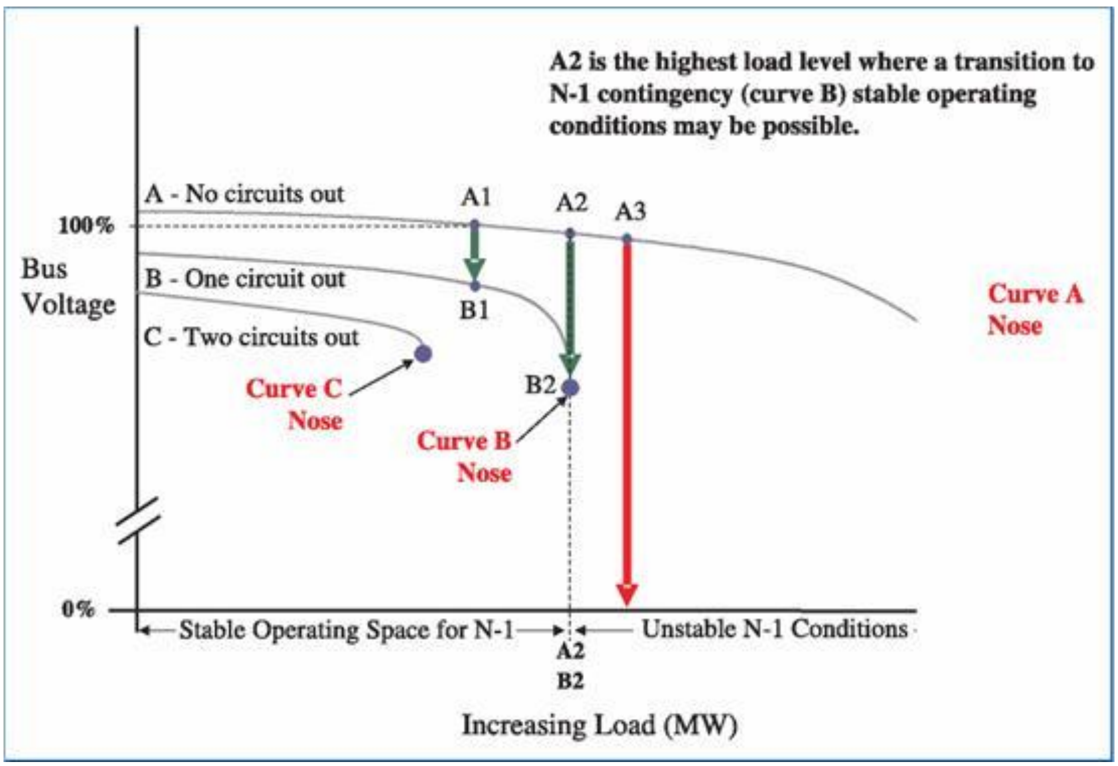

Fig. 2. Real power (MW) vs. voltage (P-V) curve -- nose curve

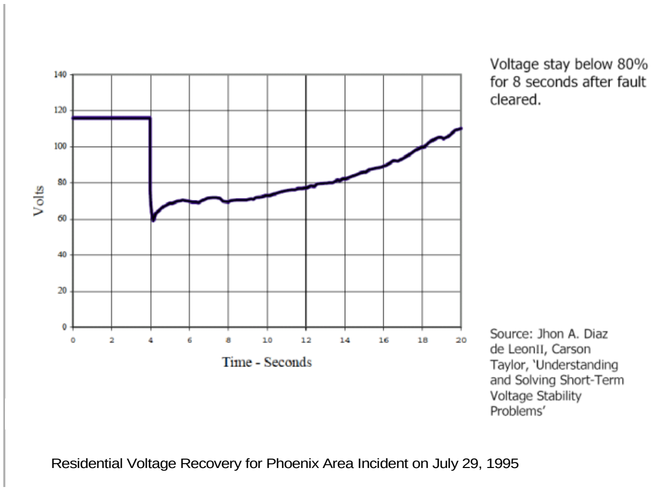

Fig. 3. Example of delayed voltage recovery resulting from slow- clearing transmission fault

There have been cases where the voltage decayed so rapidly that operator action was not possible. These cases involve slow-clearing multi-phase transmission system faults that occur during heat storm conditions when the utility load is primarily made up of air conditioning motors. Due to the extended length of the voltage dip resulting from the slow-clearing transmission system fault, motors in the area began to stall and draw large amounts of reactive power after the fault is cleared. The rapid change in load power factor results in low system voltage as shown in Fig. 3. Since there is little reserve of reactive power during peak load periods, the area voltage collapses. Such an event occurred in western Tennessee (City of Memphis) and resulted in an outage to 1100 MW of load. The entire event took less than 15 seconds.

C. Phase Angle Instability

When the voltage phase angle between remote generators and local generators (θg – θs in Fig. 4) becomes too large, phase angle instability can occur. In many cases, this event happens in conjunction with the voltage collapse scenario described above. There are two types of phase angle instability.

1) *Steady-State Instability*: Steady-state instability occurs when there are too few transmission lines to transport power from the generating source to the local load center. Loss of transmission lines into the load center can result in voltage collapse as described previously, but it can also result in steady-state phase angle instability.

Fig. 4 illustrates how steady-state instability occurs. The ability to transfer real (MW) power is described by the power transfer equation and is plotted graphically. From the power transfer equation in Fig. 4, it can be seen that the maximum power (Pmax) that can be transmitted is when $\theta g\text{-}\theta s = 90^{\circ}$, i.e. $\sin 90^{\circ} = 1$. When the voltage phase angle between local and remote generation increases beyond 90°, the power that can be transmitted is reduced and the system becomes unstable and usually splits apart into islands. If enough lines are tripped between the load center and the remote generation supplying the load center, the reactance (X) between these two sources increases, thereby reducing the maximum power (Pmax), which can be transferred. The power angle curve in Fig. 4 illustrates this reduction as line 1 trips the height of the power angle curve and maximum power transfer is reduced because the reactance (X) between the two systems has increased. When line 2 trips, the height of the power angle curve is reduced further to where the power being transferred cannot be maintained and the system goes unstable.

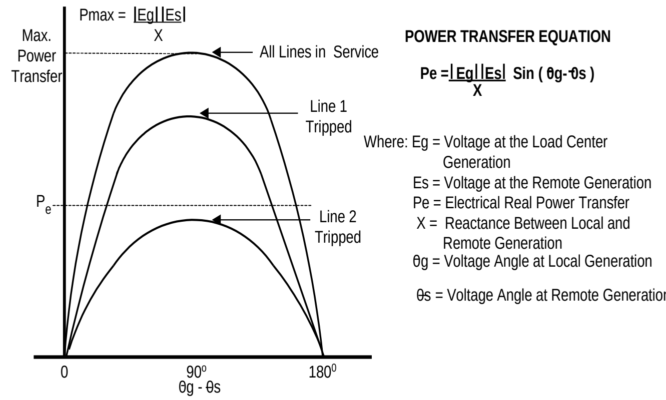

Fig.4. Power angle analysis - steady-state instability

At this point, the power system is in deep trouble. During unstable conditions, the power system breaks up into islands. If there is more load than generation within the island, frequency and voltage go down. If there is an excess of generation in an island, frequency and voltage generally go up. Voltage collapse and steady-state instability occur together as transmission line tripping increases the reactance between the load center and remote generation. Generally, the voltage drop at the load center is the leading indicator that the system is in trouble with low frequency occurring only after the system breaks up into islands. Analyses of major blackouts indicate that voltage is more of a leading edge indicator of power system impending collapse. Waiting for the frequency reduction may be waiting too long to shed load to save the system.

2) *Transient Instability:* Voltage phase angle instability can also occur due to slow-clearing transmission system faults. This type of instability is called transient instability. Transient instability occurs when a fault on the transmission system near the generating plant is not cleared rapidly enough to avoid a prolonged unbalance between mechanical and electrical output of the generator. A fault-induced transient instability has not been the cause of any major system blackout in recent years. However, generators need to be protected from damage that can result when transmission system protection is slow to operate.

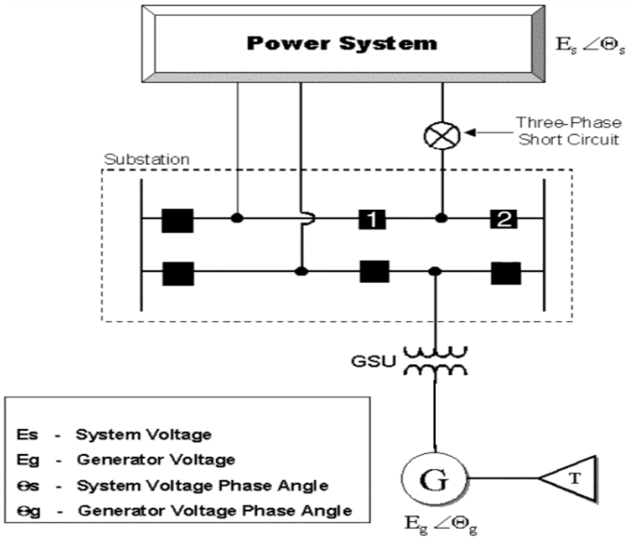

Fig. 5. Typical large power plant one-line diagram

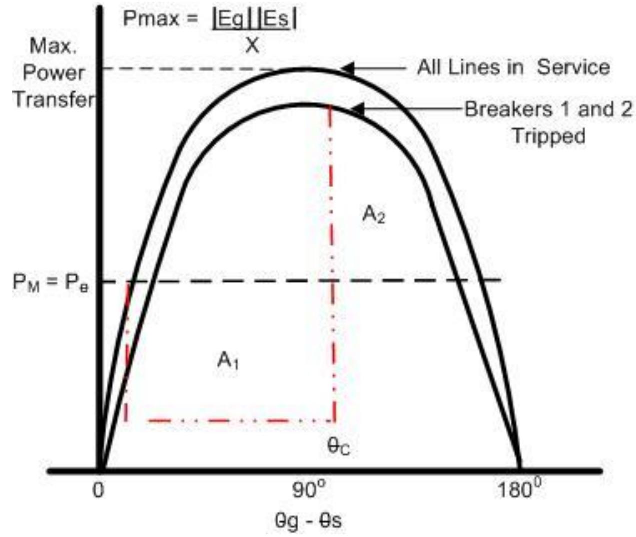

Fig. 6. Power angle analysis – transient instability

Relay engineers design transmission system protection to operate faster than a generator can be driven out of synchronism, but failures of protection systems have occurred that resulted in slow-clearing transmission system faults. It is generally accepted [3] that loss-of-synchronism protection at the generator is necessary to avoid machine damage. The larger the generator, the shorter is the time to drive the machine unstable for a system fault. Fig. 5 illustrates a typical breaker-and-a-half power plant substation with a generator and a short circuit on a transmission line near the substation. If the short circuit is three-phase, very little real power (MW) will flow from the generator to the power system until the fault is cleared. The high fault current experienced during the short circuit is primarily reactive or VAr current. From the power transfer equation (Fig. 4), it can be seen that when Eg drops to almost zero, almost no real power can be transferred to the system. The generator AVR senses the reduced generator terminal voltage and increases the field current to attempt to increase the generator voltage during the fault. The AVR control goes into field-forcing mode where field current is briefly increased beyond steady-state field circuit thermal limits.

During the short circuit, the mechanical turbine power (P_M) of the generator remains unchanged. The resulting unbalance between mechanical (P_M) and electrical power (P_e) manifests itself with the generator accelerating, increasing its voltage phase angle with respect to the system phase angle as illustrated in the power angle plot in Fig. 6. The speed with which the generator accelerates depends on its inertia. The larger the generator, the faster it will accelerate. If the transmission system fault is not cleared quickly enough, the generator phase angle will advance so that it will be driven out of synchronism with the power system.

Computer transient stability studies can be used to establish this critical switching angle and time. The equal area criteria can also be applied to estimate the critical switching angle (θ_c). When area $A_1 = A_2$ in Fig. 6, the generator is just at the point of losing synchronism with the power system. Note that after opening breakers 1 and 2 to clear the fault, the resulting post fault power transfer is reduced because of the increase in reactance (X) between the generator and the power system. This is due to the loss of the faulted transmission line. In the absence of detailed studies, many users establish the maximum instability angle at 120°. Because of the dynamic nature of the generator to recover during fault conditions, the 120° angle is larger than the 90° instability point for steady-state instability conditions. The time that the fault can be left on the system that corresponds to the critical switching angle is called the "critical switching time." If the fault is left on longer than that time, the generator will lose synchronism by "slipping a pole." For this condition, the generator must be tripped to avoid shaft torque damage. Out-of-step protection, which is also called loss-of-synchronism protection (Relay Function 78), is typically applied on large generators to trip the machine thereby protecting it from shaft torque damage and avoiding a system cascading event. This type of protection is discussed in Section III, B of this paper.

D. Dynamic Instability

Dynamic instability occurs when a fast-acting generator AVR control amplifies rather than damps some small low frequency oscillations that can occur in a power system. This problem has been most often associated with the western region of the U.S. It can, however, occur anywhere the load is remote from the generation. While fast excitation systems are important to improve transient stability as discussed above, a fast-responding excitation system can also contribute a significant amount of negative damping. This reduces the natural damping torque of the system, causing undamped megawatt oscillations after a disturbance such as a system fault. It can occur if the generator is interconnected to a weak system and loads are far from the generating plant. As discussed above, the operation of today's power grid makes this scenario much more likely in many regions of the U.S.

Small signal stability is defined as the ability of the power system to remain stable in the presence of small disturbances most often caused by remote faults. If sufficient damping torque does not exist, the result can be generator rotor angle oscillations of increasing amplitude. When these megawatt oscillations grow, the generator can eventually be driven unstable, lose synchronism and slip a pole. To address this problem, a Power System Stabilizer (PSS) is utilized in conjunction with the generator AVR to provide positive damping when megawatt oscillations occur.

III. IMPACT OF POWER SYSTEM INSTABILITY ON SYSTEM PROTECTION

A. Voltage Instability

Reduced system voltage can have a major impact on the protective relays' system security. In the transmission line protection area, Zone 3 distance relays are widely applied for the backup clearing of remote faults. In some cases, use of these relays can avoid the necessity for local breaker failure protection on the remote bus or transfer trip channels. The required reach for these backup elements is a function of the apparent impedance to the remote point on the next line section; consequently, the impedance setting can be very large. During system low-voltage conditions, distance relays are susceptible to false operation on load. While the ohmic characteristic of a distance relay is independent of voltage, the load is not a constant impedance. The apparent impedance presented to a distance relay as the load voltage varies will depend on the voltage characteristics of the load. In recent major blackouts, including the 2003 East Coast and 1996 California events, this reduced voltage played a major role in causing improper relay operations. As a result, NERC (North American Electric Reliability Council) has required utilities to "test" their impedance settings against observed transmission system low voltage conditions. The criterion chosen for transmission line loadability under low voltage condition is at a 0.85 pu voltage and at an angle of 30° distance relays should have a 115% margin over emergency load. Fig. 7 illustrates this point on an R-X diagram.

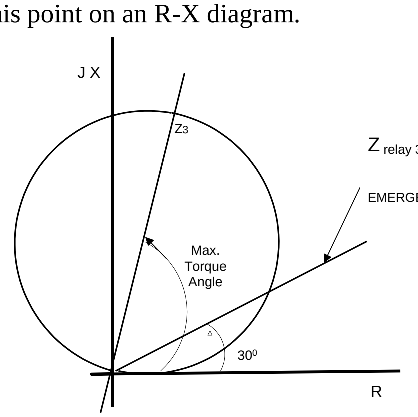

Fig. 7. Transmission system impedance relay loadability at reduced voltage

Generator backup protection with impedance relays or voltage-controlled or -restrained overcurrent relays (51V) have caused unnecessary generator tripping during stressed system low voltage conditions. The NERC "white paper" on coordination of generator protection with transmission line protection entitled: *"Power Plant and Transmission System Protection Coordination –July 2010"* [2] provides guidance on setting margins that will be secure under system low voltage conditions. The R-X diagram shown in Fig. 8 shows the suggested margin over the generator capability curve at rated generator power factor angle (RPFA) and at the relay maximum torque angle.

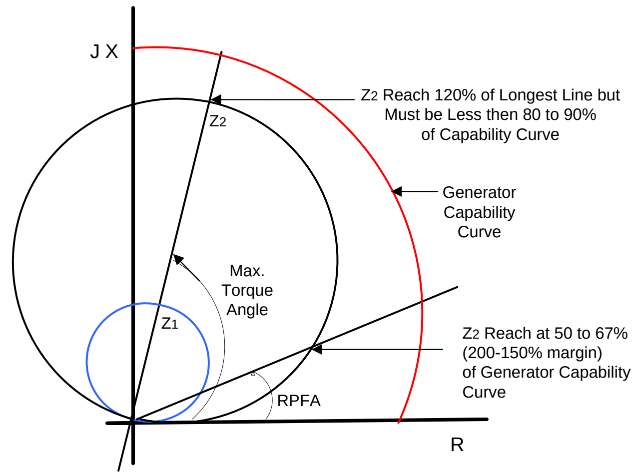

Fig. 8. Generator impedance relay margins over generator capability

Generator backup protection is also done with voltage-restrained or -controlled overcurrent relays (51V). These relays also have to be set to avoid tripping under system low-voltage conditions. NERC recommends that the voltage restraint type 51V relay pickup be set with a 150% margin over generator full load. When generator terminal voltage goes down, this type of 51V relay automatically reduces its pickup linearly with voltage down to 0.25 pu voltage. The voltage control type of 51V logic inserts the overcurrent relay when voltage drops below the voltage setting within the relay. NERC recommends that the voltage setting be no higher than 75% of normal. The current pickup is set below full load of the generator. The time delay for both relays is set to coordinate with transmission system backup relaying.

Specific credible undervoltage scenarios are frequently addressed through Special Protection Schemes (SPS) which are designed to automatically initiate corrective action. These schemes trigger undervoltage load shedding (UVLS) which initiate load reduction to attempt to increase system voltage by reducing load. Two types of load shedding schemes are being applied: distributed and centralized. A distributed scheme has each protective relay closely coupled to a segment of load to be shed. As voltage conditions at a relay enter the region where collapse is predicted, load assigned to that relay is shed. This philosophy is very similar to common underfrequency load shedding schemes. A centralized scheme has measurements taken at one or more key busses within the area, and trip signals transmitted to shed load at various locations within the area. Since voltage instability may be recognized by low voltages across the region, the basis of centralized measurement lies in the notion that if the voltage is low at certain key locations, it is also likely to be low throughout the area. This scheme requires communications and may use parameters other than voltage to initiate load shedding.

B. Phase Angle Instability

As previously discussed in this paper, there are two types of phase angle instability—steady-state and transient instability. Both these instability conditions impact transmission as well as generator protection and manifests them as power system swings as the phase angle separate. Interestingly, the industry practice is to block tripping for swings on the transmission system using out-of-step blocking logic and to trip on generators if the power swing passes through the generator or generator step-up transformer. The basic scheme used for transmission line out-of-step blocking uses two ohm circles to block operation of distance relaying to avoid tripping on swings. For a power swing, the outside blocking ohm circle will pick up first and then the tripping ohm element. For a transmission line fault within the relay's zone of protection, both units will pick up simultaneously. Thus, if there is a time delay between operations of the two relays, a power swing condition is declared and the tripping is blocked. Fig. 9 illustrates this point. Blocking on power swing will tend to keep the power system from separating into islands.

Generator out-of-step protection on the generator initiates tripping of the generator if the power swing passes through the generator or generator step-up transformer. Impedance relaying (78) is used to detect the out-of-step condition. The most popular scheme to detect a generator out-of–step condition is the single blinder scheme illustrated in Fig. 10.

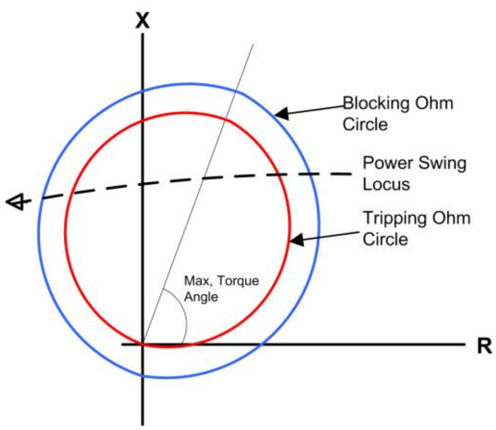

Fig. 9. Basic transmission system out-of-step blocking scheme

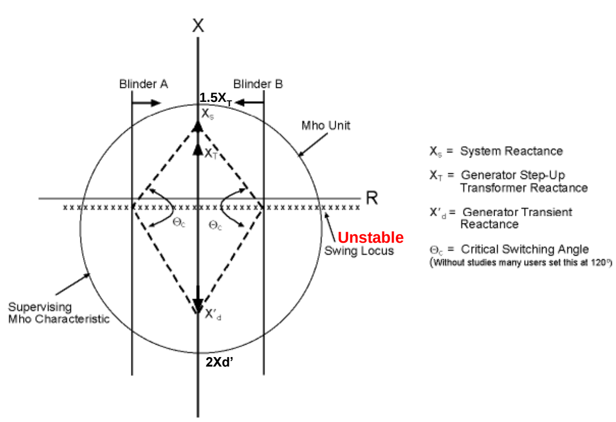

Fig.10. Generator out-of-step tripping scheme

When the power swing enters the supervising ohm characteristic, Blinder A will pick up. As the swing progresses, it will pass through Blinder B. The swing must remain between Blinders A and B for a programmable time (generally 2-4 cycles). When the power swing passes through the X axis, the generator is 180° out of phase with the power system and it has slipped a pole. As the power swing continues, it will exit Blinder A and the supervising ohm characteristic. Tripping occurs when the swing exits Blinder A or the supervising ohm circle. Out-of-step tripping of a generator is required to prevent shaft torque damage to the generator.

IV. SCHEMES BEYOND CONVENTIONAL RELAYING TO ADDRESS POWER SYSTEM STABILITY

A. Steady-State Instability

As discussed in Section II, C, 1 of this paper, steady-state instability occurs when the number of transmission lines exiting a power plant after a system event are reduced to the point that the impedance between the generator and the system is too high to allow the pre-event power to flow. The generator then slips a pole and goes out of synchronism with the system. Many large power plants have very few transmission lines which connect them to the system. As a result, there have been cases where the proper tripping of transmission lines exiting the power plant have left the generator connected with too high of an impedance connection to the system. Where this condition is credible, SPS schemes have to be put in service to trip the generator to address this instability.

B. Transient Instability

As discussed in Section II, C, 2 of this paper, transient stability is caused by a transmission system fault near the power plant not being cleared rapidly enough to prevent the generator from slipping a pole and going unstable. Stability studies are required to determine the critical switching time to clear the fault. Typically, the worst case condition is a three-phase fault at the power plant terminal of a transmission line exiting the plant combined with a breaker failure of a transmission breaker at the plant to clear the fault. The critical clearing time can be too short to prevent improper breaker failure operation. There are a number of techniques that have been applied on power systems to increase critical switching time to give the protection system more time to operate.

1) <u>*Generator Fast Valving:*</u> This method of increasing critical switching time is applied mainly on large steam generators. It involves reducing the mechanical energy of the generator during system fault conditions by high-speed closure of the generator steam valves. The advantage of this technique can be seen in the power angle analysis in Fig. 11 for a fault on a transmission line exiting the power plant. A comparison of Figs. 11b and 11c show the reduction in area A1 which is proportional to the energy that is accelerating the unit toward instability and an increase in area A2 which is de-accelerating the unit. Typically, fast valving can increase critical switching time by a few cycles.

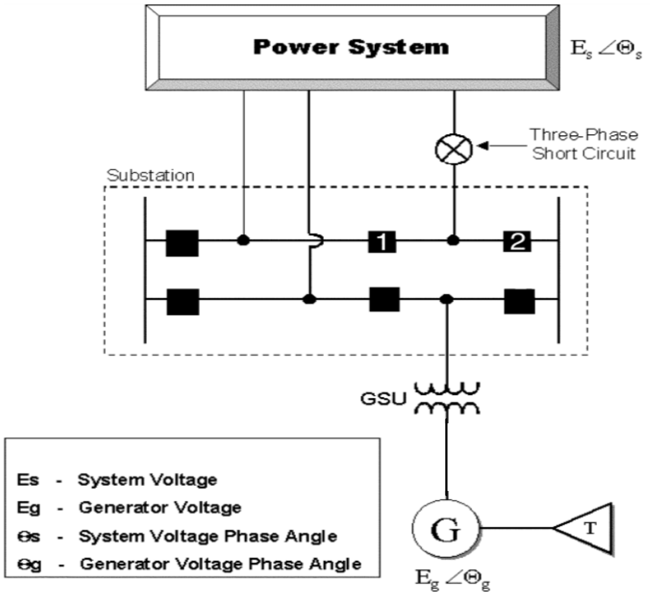

Fig. 11a. Three-phase fault on transmission line exiting power plant

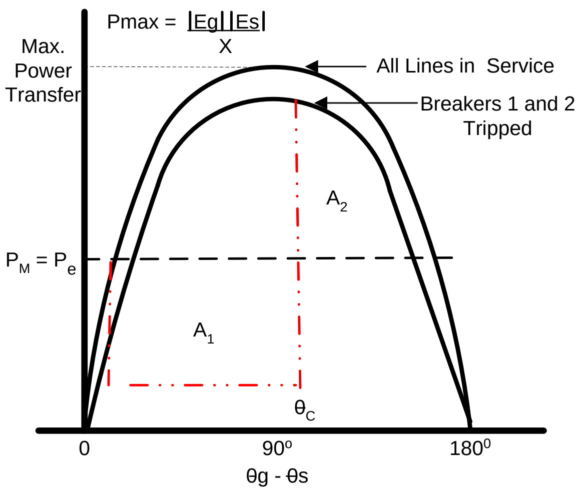

Fig. 11b. Power angle analysis without fast valving

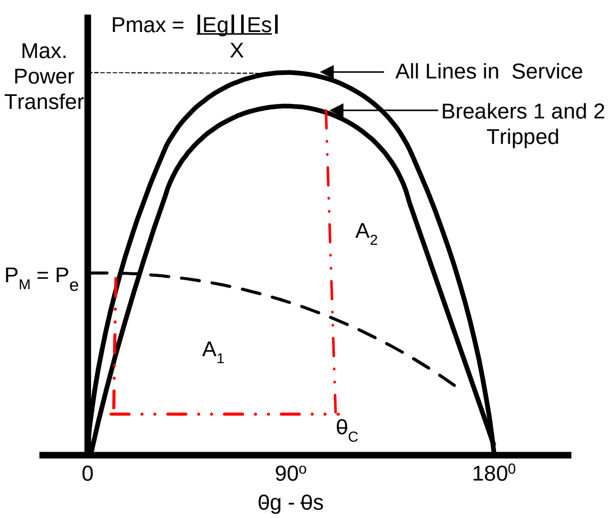

Fig. 11c. Power angle analysis with fast valving

2) *Generator High-Speed Excitation:* High-speed electronic generator voltage regulators (AVRs) are capable of quickly increasing the field current in a generator to increase internal machine voltage. During a fault condition, the AVR goes into the field-forcing mode. High rotor field current (typically in the range of 140-280% of rating) are permitted to flow for a short time without causing the exciter control to reduce field voltage because of the high field current. High-speed excitation systems are not very effective in increasing critical switching time for faults right at the generating station where a bolted three-phase fault will reduce voltage to zero at the point of fault—resulting in no real power flow to the system during the duration of the fault. This results in all the machine mechanical energy going to accelerating the generator. For faults further out from the generating station, the effect of high-speed AVRs are more pronounced. Fig. 12 illustrates, on a power angle curve, the effects of a high-speed AVR and field-forcing during a fault.

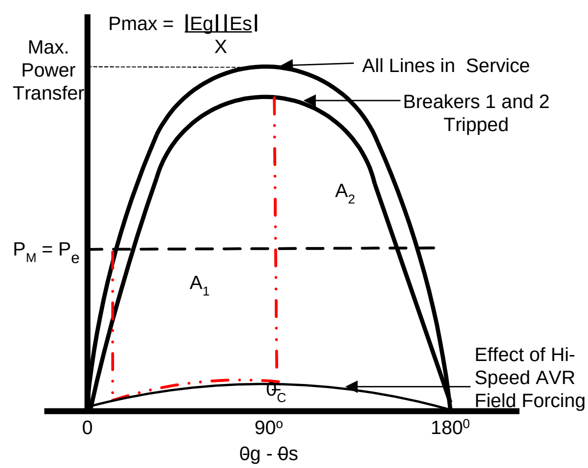

Fig. 12. High-AVR and field-forcing

One of the other effects of field-forcing and high-speed excitation systems is to push the power system swing out toward the system because the internal generator voltage is increased during the fault. Fig. 13 illustrates this point using a simplified graphical approach. When the voltage ratio E_A/E_B is equal to 1, the impedance locus is a straight line indicated by PQ, which is the perpendicular bisector of the total system impedance between A and B. The angle formed by the intersection of AP and BP on the PQ line is the separation angle α between systems. As E_A advances ahead of E_B, the impedance locus moves from P toward Q and α increases. When the locus intersects the total impedance line AB, the system is 180^0 out or phase. If E_A is larger than E_B due to AVR high-speed field forcing, the swing point is pushed out toward the system. There have been cases where the swing point has passed through Zone 1 of the transmission line impedance relaying resulting in separation by line protection rather than planned generator out-of–step protection (78) which is restricted to operating for swings that pass through the generator or generator step-up transformer.

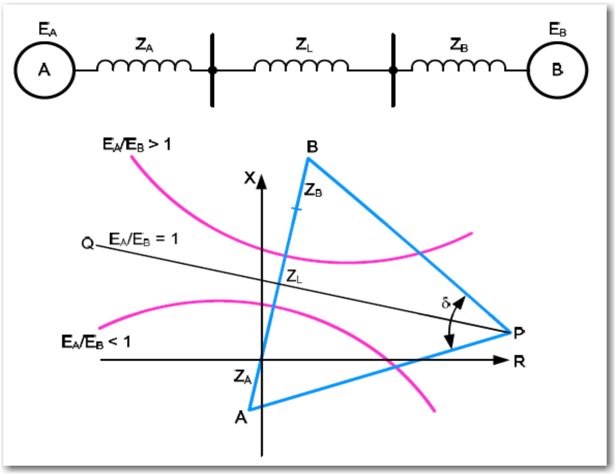

Fig. 13. Typical out-of-step impedance loci using simplified graphical method

3) *Independent Pole Tripping:* EHV circuit breakers (breakers 230 Kv and above) are designed such that they have independent phase operating mechanisms. Each phase has its own motor-operated tripping mechanism. One of the most powerful stability tools was developed in the 1970's. Since breaker failure clearing times are the limiting factor in determining critical switching time, the hypothesis was to re-define breaker failure as the failure of a single breaker pole as opposed to the failure of all three phases. The impact on stability was to reduce a three-phase fault to a line-to-ground fault which means that synchronizing power will flow during fault clearing. Fig. 14 shows the impact on an R-X diagram.

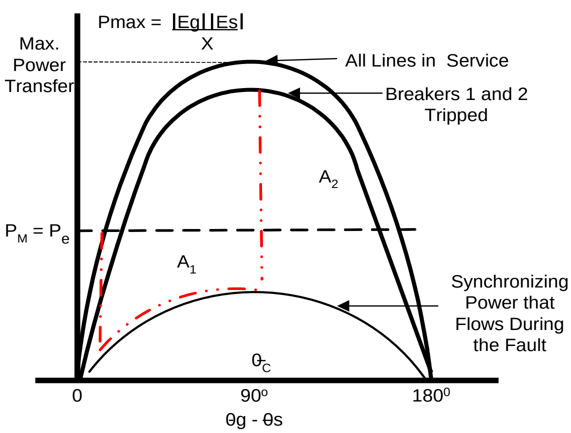

Fig. 14. Effect of independent pole tripping

V. CONCLUSIONS

Power system stability has taken on an important role in recent blackouts and power system event investigations conducted by NERC. It is important to understand the relationships of the various types of instability to protection so stability can be properly considered when designing protection schemes. There are stability solutions beyond fast-fault clearing and SPS schemes that provide attractive solutions to increase allowable fault clearing times. These schemes can add security to the protection system. The benefits of these schemes as well as how they relate to protection are key issues that relay engineers need to understand.

VI. REFERENCES

[1] "*Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*", U.S. – Canada Power System Outage Task Force, April 5, 2004.

[2] "*Power Plant and Transmission System Protection Coordination*" NERC Technical Report, July 2010

[3] "*Protective Relaying Theory and Applications*" edited by Walter A. Elmore, ABB Power T&D Company Inc., Coral Springs, FL, 1994.

VII. BIOGRAPHY

Charles (Chuck) J. Mozina (M02630234) is a Consultant, Protection and Protection Systems, for Beckwith Electric Co. Inc., specializing in power plant and generator protection. He is an IEEE Life Fellow, an active 25-year member of the IEEE Power System Relay Committee (PSRC) and is the past chairman of the Rotating Machinery Subcommittee. He is active in the IEEE IAS committees that address industrial protection. He is a former U.S. representative to the CIGRE Study Committee 34 (now B-5) on System Protection.

Chuck has a Bachelor of Science in Electrical Engineering from Purdue University and is a graduate of the eight-month GE Power System Engineering Course. He has more than 25 years of experience as a protection engineer at Centerior Energy (now part of FirstEnergy), a major investor-owned utility in Cleveland, Ohio where he was the Manager of the System Protection Section. For 10 years, Chuck was employed by Beckwith Electric as the Manager of Application Engineering for Protection and Protection Systems. He is a registered Professional Engineer in Ohio. He has authored a number of papers and magazine articles on protective relaying.