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Practices for Generator Synchronizing Systems

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ABSTRACT

A synchronizing system that is designed and verified to operate within a generator's synchronizing limits is critical in helping maintain the life of generating plant assets and improving stability of the power system. There have been an increasing number of reported out-of-phase synchronizing events that have damaged generators and generator step-up transformers. This report presents the current practices for generator synchronizing systems. It includes an overview of synchronizing system components, their design considerations for different system and generating plant configurations, commissioning practices to verify that a synchronizing system will perform within limits, methods to monitor synchronizing system performance, and detect and alarm or trip for out-of-phase synchronizing events.

KEYWORDS

autosynchronizer, electrical torque, incoming bus, mechanical torque, out-of-phase synchronization (OPS), running bus, slip, slip-compensated advanced angle, synchronism-check, synchronization failure

CONTENTS

1. Introduction

1.1 Purpose of Synchronization

A synchronous generator, when energized and disconnected from the power system, is free to operate at a voltage magnitude, frequency, and phase angle that is different from the power system. Once connected to the power system, due to synchronizing torque, the generator voltage magnitude, frequency, and phase angle matches that of the power system at the generator bus. To minimize electrical and mechanical stress to both the generator and the power system, the generator is synchronized to the system such that differences in the following variables are minimized at the moment the breaker is closed:

1. Voltage Magnitude
2. Voltage Phase Angle
3. Frequency

Figure 1 shows one cycle of a single-phase voltage waveform of a generator and power system with different voltage magnitude, frequency, and phase angle between them [1].

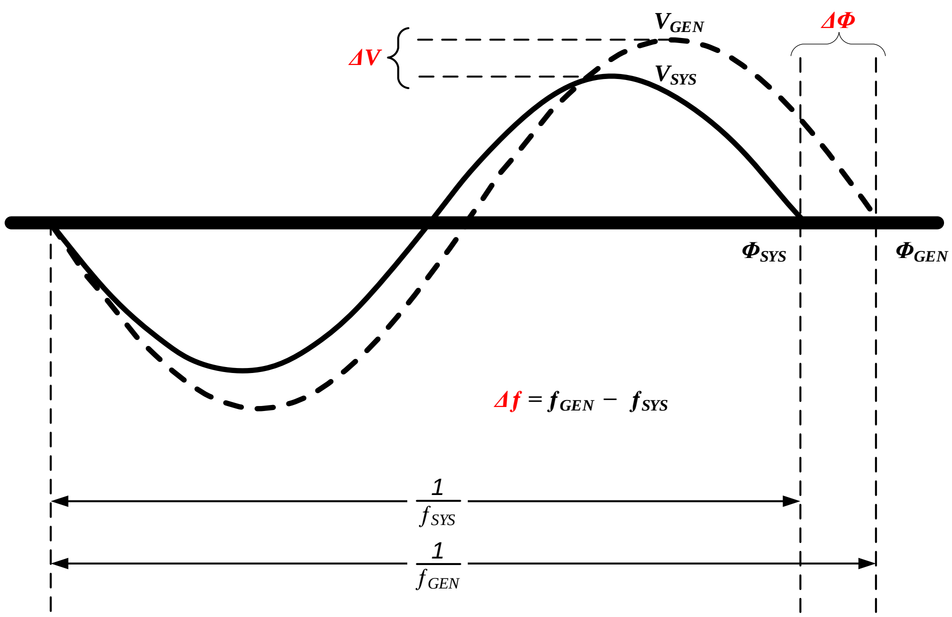

Figure 1: Synchronizing Quantities (one cycle shown) [1]

In three-phase systems, phase-sequence is another important consideration. As synchronization may be accomplished on a three-phase system by monitoring only one phase, it is recommended to monitor the same phase from each source [1]. This practice can be extended to applications that synchronize across the generator step-up (GSU) by selecting that phase-phase LV voltage which is coupled magnetically to the corresponding HV phase voltage. Modern synchronizing systems can compensate for different source phases [2]; however, this may introduce complexity and possible errors into the scheme. Phase-sequence does not normally change from one synchronization to the next, except in portable generator applications.

To synchronize a generator to the power system, voltage transformers (VTs) are employed on the incoming (generator side) and running (system side) of the breaker. These VTs measure the generator and power system voltage, which can be used to calculate the voltage magnitude, phase, and frequency. In Figure 2 below, the VTs provide inputs to the autosynchronizer, IEEE Device Number 25A.

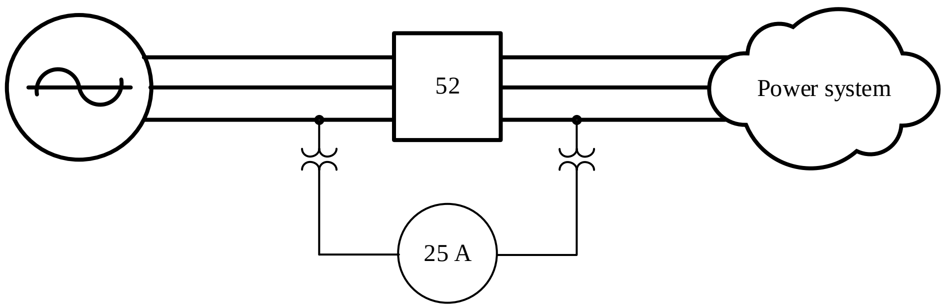

Figure 2: General Synchronizing Three-Line Diagram [1]

In actual practice, a combination of operators, autosynchronizers, synchronism-check relays, and other devices are employed as part of the synchronizing system. These are discussed in the following sections.

1.2 Synchronization ac Schematic

The voltage sources for two interconnecting systems are typically depicted on a three-line ac schematic. An example ac schematic is illustrated in Figure 3; VT selector switches for Running bus input are not shown; refer to Figure 32 for further detail. The synchronization ac circuit is typically made up of three buses. The incoming bus represents the voltage of the generator. The running bus depicts the interconnecting system voltage. This voltage typically comes from bus or line VTs. Finally, a neutral bus provides the common reference for the incoming and running voltage signals. Incandescent synchronizing lamps may be wired to these circuits for visual indication to operators/personnel. See Figure 32 in Section 7.2 for a depiction of these voltage sources.

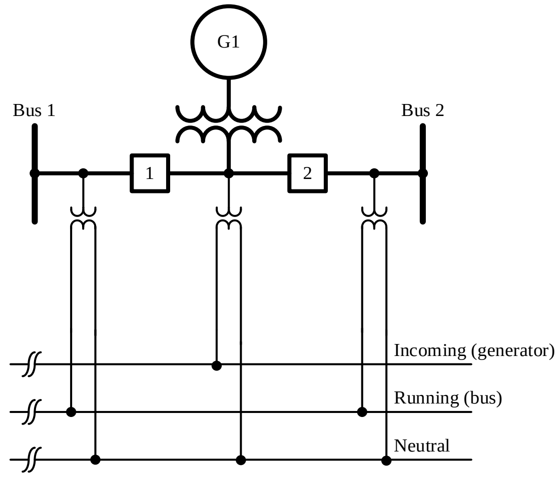

Figure 3: Synchronization System ac Schematic

1.3 General Synchronization Process

Figure 4 shows a sample generator with the associated voltage connections for a synchronizing operation.

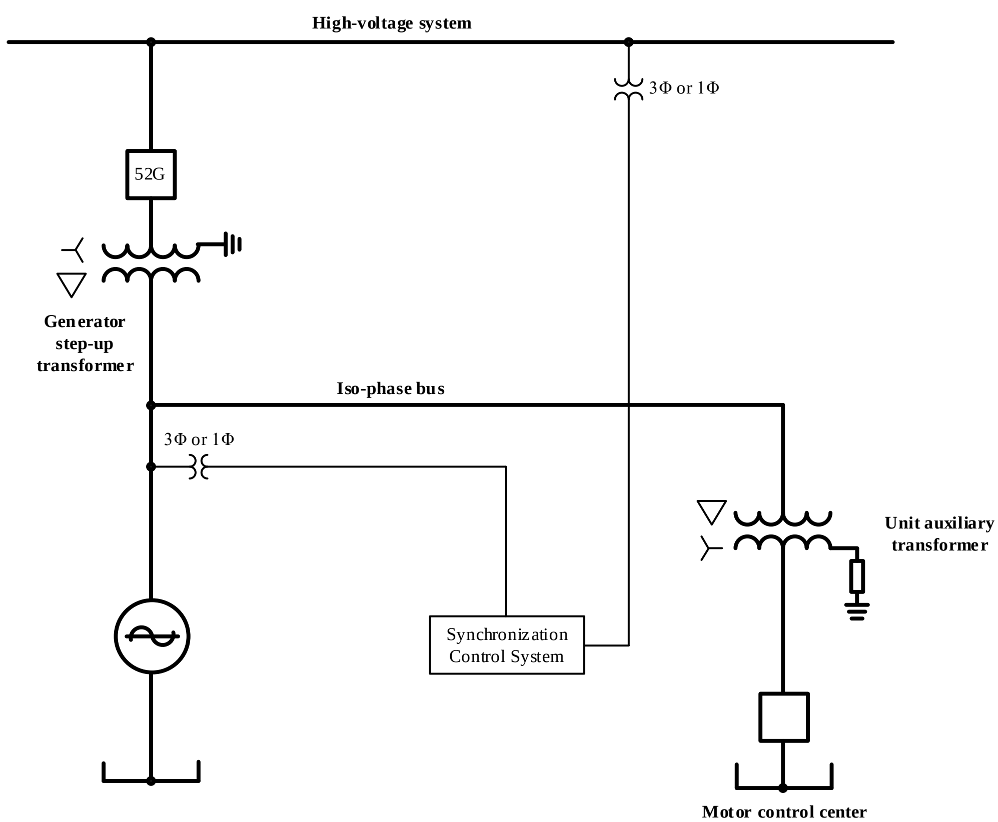

Figure 4: Example Generator Single-Line Diagram

A high-level overview of the synchronizing process is as follows:

1. Match generator speed to the interconnecting system speed.
2. Match the generator voltage, on the system side of the GSU transformer, to the interconnecting system voltage.

Initiate generator breaker closure when the generator voltage and the interconnecting system voltage phase angle approaches zero degree difference across the synchronizing circuit breaker. The synchronization system takes into account the turns ratio and fixed phase shift across the GSU transformer. Completing this process helps ensure a successful synchronization. See Section 6.1.1 for a more detailed synchronizing procedure.

1.4 Synchronization Failure Consequences

1.4.1 Electrical Transients

Electrical transients may result from voltage phase angle or frequency differences which can cause misoperation of differential, loss of field, or overcurrent protection. Transients expose generators to stress from electrical and mechanical torques. The specific type of transient determines what type of torques are imposed on the machine. During a synchronization transient, either accelerating or decelerating torque is produced to align the two systems in speed and angle.

Electrical transients on the grid, such as faults and switching events, result in mechanical forces on the stator and rotor windings. These forces are derived from the current magnitudes that flow through the windings during transients. Fundamental (e.g., 60 Hz) voltage and frequency excursions produce unidirectional and fundamental force components that interact with each other (see example in Section 9.4).

The transient current that results from a faulty synchronization depends on the voltage across the synchronizing breaker when it closes, which in turn depends on the synchronizing angle (δ_0)—the angle difference of the voltage between the generator and the interconnecting system [3]. Assuming matched generator and system voltage magnitudes of 1 p.u., the voltage across the breaker reaches a maximum of 2 p.u. when the synchronizing angle is 180 degrees. The current is limited by the sum of the generator subtransient reactance (X_d"), GSU transformer impedance (X_T), and system impedance (X_{SYS}), as shown in Figure 5 [4].

The generator stator and GSU transformer windings are braced for the maximum forces associated with a three-phase fault at the generator terminals [5] [6]; however, an out-of-phase synchronization (OPS) can exceed these forces and cause immediate or cumulative damage. The synchronization current can exceed that of a three-phase fault at the generator terminals when the synchronizing angle is near 180 degrees and the sum of the X_T and X_{SYS} is smaller than X_d". For example, if X_d" is 0.20 p.u., X_T is 0.10 p.u., and X_{SYS} is 0.033 p.u., a 180-degree OPS results in currents up to 2 p.u./0.333 p.u. = 6 p.u. The current for a three-phase fault at the generator terminals is 1 p.u./0.20 p.u. = 5 p.u., lower than that of the 180-degree OPS.

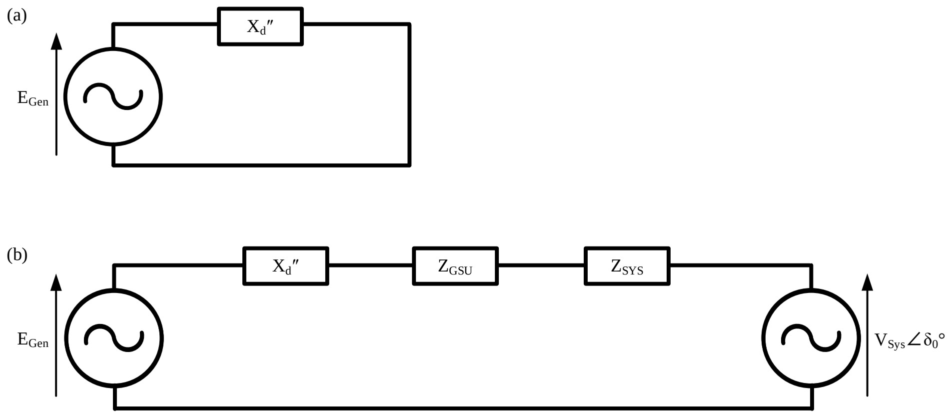

Figure 5: Simplified equivalent circuit for (a) three-phase fault and (b) OPS [4]

Faulty synchronization can also negatively impact the breaker. In the worst-case scenario, the ac component is fully offset such that the dc component of the current has a similar peak amplitude to the ac component. If the ac component decays faster than the dc component decays, current zero-crossings may be delayed for several cycles [7]. The ac component decays due to two mechanisms, each with its own time constant. The generator impedance transitions from subtransient to transient to synchronous and the driving voltage in the OPS circuit gets smaller as the generator voltage pulls into phase with the system. The decay rate of the dc component is based on the system X/R ratio. If current zero-crossings are delayed, the breaker may not interrupt the current for several cycles. It may also result in the loss of life of the breaker or catastrophic breaker damage [8].

Faulty synchronization because of significantly different voltage magnitudes between the generator and system can cause excessive var-flow between the generator and the system. This var-flow can impact the system voltage and possibly the generator's ability to remain synchronized.

Faulty synchronization can also subject the windings of the GSU transformer to stress, either immediately or eventually leading to failure. The authors are aware of one GSU that developed a phase-to-ground fault following a 180-degree OPS. The GSU was subsequently subjected to a second 180-degree OPS. The phase-to-ground fault evolved to a phase-to-phase-to-ground fault and destroyed the GSU, resulting in significant downtime and replacement cost.

1.4.2 Mechanical Transients

The generator and prime mover experience excessive mechanical torques if the angle or frequency differences are too large when the synchronizing breaker closes. This can result in immediate damage or fatigue damage (cumulative loss-of-life) to shaft-bearings, fillets and keyways, and turbine blade roots or other mechanical parts as the generator quickly accelerates or decelerates to match the system frequency and phase [9] [10] [11] [12]. Mechanical oscillations may also result in a trip of the prime mover. A synchronization failure event may go undetected; increasing the likelihood of cumulative damage (See Section 8).

Transients on the grid (electrical) or in the mechanical input system may generate transient mechanical torque components on the prime mover of a generator. The turbine shaft responds to these transients that cause mechanical torque stress. These mechanical transients experience a natural decaying component from the load of the system (system damping) when a generator is synchronized to the grid. Before the generator is synchronized to the grid, the prime mover typically feeds very little, if any, real load (no load condition) which translates to a long damping time constant. These pre-synchronization conditions can result in longer torsional oscillations once an OPS occurs.

The prime mover of a generator reacts to electrical transients and synchronization torque. The inertia of the machine determines the amount of time necessary to accelerate or decelerate the prime mover to match the system frequency upon synchronization. During an OPS, this component directly impacts how many torque oscillations are needed to pull the generator in synchronism with the grid [9]. Each torque transient adds an additional torque component to the prime mover shaft. These components add in a cumulative manner; with each torque transient contributing to the total mechanical stress imposed on the prime mover.

Faults on the system and reclosing operations generate electrical torques, which manifest as mechanical torques on the generator prime mover [13]. Single-line-to-ground faults on the grid result in minor turbine life fatigue. Multiphase faults impose a much greater impact on turbine fatigue due to the step-change in electrical power output, which creates a larger differential between mechanical input power and electrical output power. The machine experiences higher magnitudes of transient torque to counteract this disruption in output power. As shown in Figure 6, the most severe stress on a turbine emanates from either a faulty generator synchronization or an unsuccessful reclose due to a permanent three-phase line fault [14] [15]. Depending on the system topography, an unsuccessful reclose on a switchyard breaker can result in transient torques that are equivalent to an OPS. In applications where multiple lines leave a generating station, automatic reclosing (79[1]) schemes may be applied on the transmission line breakers located at a generating plant switchyard. To prevent the torques caused by reclosing into a fault, the reclosing scheme can be designed with leader/follower terminal reclosing logic. The remote terminal is set up with dead line permissive to re-energize the line. The generator terminal is set up with live/live synchronism check supervision only, such that the breaker does not automatically reclose unless the remote terminal reclose is successful. To prevent automatic reclosing causing an OPS event, parallel line automatic reclosing supervision can prevent reclosing in a case where the generator has lost synchronism with the grid. Alternatively, a synchronism check relay on the transmission line breaker, that monitors slip, is another alternative to prevent an OPS due to automatic reclosing.

[1] For ease of reference, relay device functions are assigned standard function numbers in IEEE Standard C37.2 and this report makes use of those IEEE device function numbers. Refer to IEEE Std C37.2-2022 IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations [16].

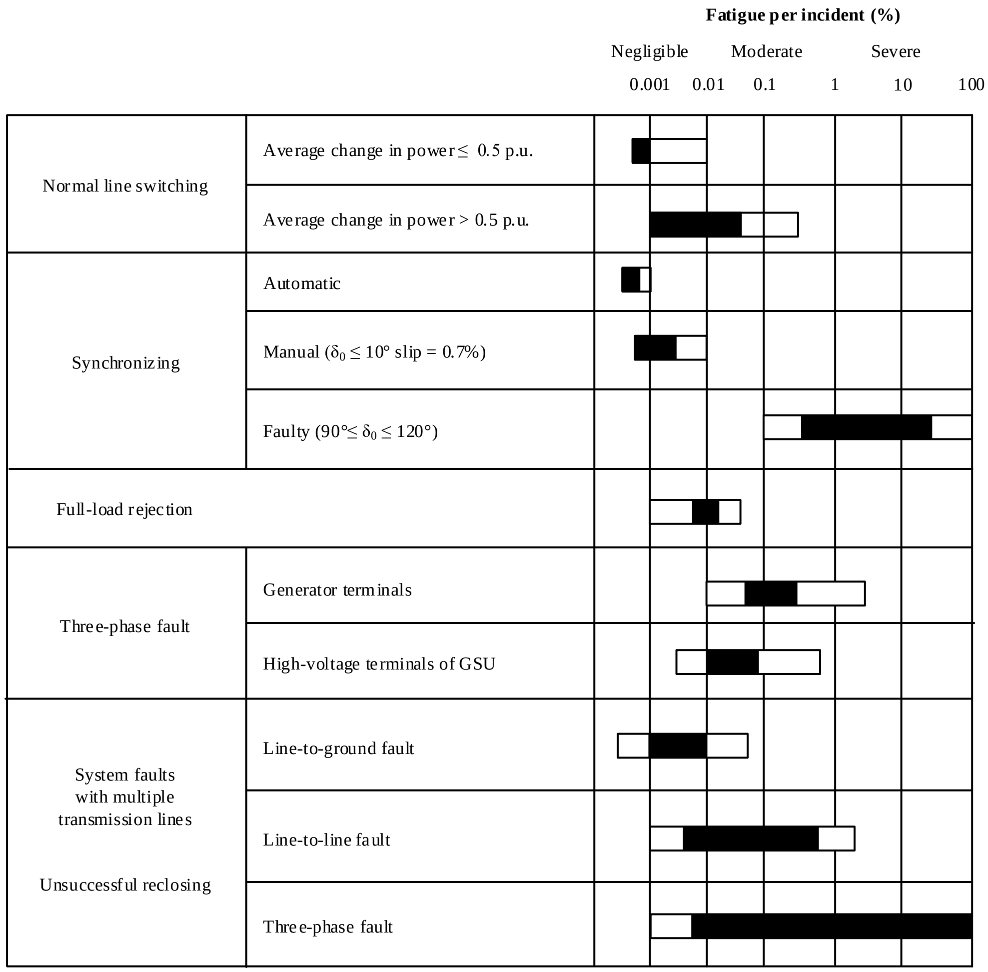

Figure 6: Turbine-generator shaft fatigue for switching and fault conditions [14] [15]

Though mechanical damage may not be significant, cumulative fatigue damage on the shaft ultimately reduces the life expectancy of the generator. This cumulative fatigue damage on the shaft is often expressed as a percentage loss-of-life value. Even when high torque limits are not exceeded, each torque cycle contributes to the cumulative fatigue damage on the shaft and adds to this percentage loss-of-life value [17].

A real-world consequence of an OPS was rotor damage on an 800 MVA steam turbine generator. The damage that occurred in December 2020 caused an outage of 98 days and incurred a total cost of about 16 million dollars [4].

2. Synchronizing Variables

Voltage and frequency are the variables used to prevent isolated systems from joining together in a destructive manner. The generator has an internal voltage coupled with the speed component from its prime mover. The system has a voltage and frequency component that is the aggregate of all the sources connected to it. These quantities can be used to establish satisfactory boundaries for tying the rotating systems together.

Synchronization occurs when two independently rotating systems are electrically joined. Synchronizing variables are measured on each side of the point of synchronization—the generator side and the system side. Voltage is provided by VTs and frequency is derived from the voltage measurement. A governor control system may measure frequency independently because it can directly measure the speed of the prime mover.

Synchronizing variables are typically measured by a synchronizing system (e.g., a relay or a control system). Since the goal is to synchronize with minimal variance, accuracy is an important variable within the scheme. The VTs that output secondary voltages have a degree of measurement error. Synchronizing systems also have a degree of error associated with their processing and algorithms. Minimizing these errors to a negligible level or compensating for them contributes to successful synchronizations.

Unit generator designs synchronize to the power system via a circuit breaker on the high-voltage side of the GSU transformer. When the running VT measures the interconnecting system voltage at the high side of the GSU transformer and the incoming VT measures the generator voltage on the low side of the GSU transformer, the change in voltage levels necessitates a voltage magnitude and angle compensation for proper comparison..

Due to the high voltage rating on the transmission system, it is generally more economical to use a capacitive voltage transformer (CVT) to measure the grid voltage. In this application (see Figure 7), voltage and angle compensation are not required for synchronization. CVTs may introduce additional steady-state errors compared to magnetic VTs [15] but this is typically negligible and not a problem for synchronizing generators.

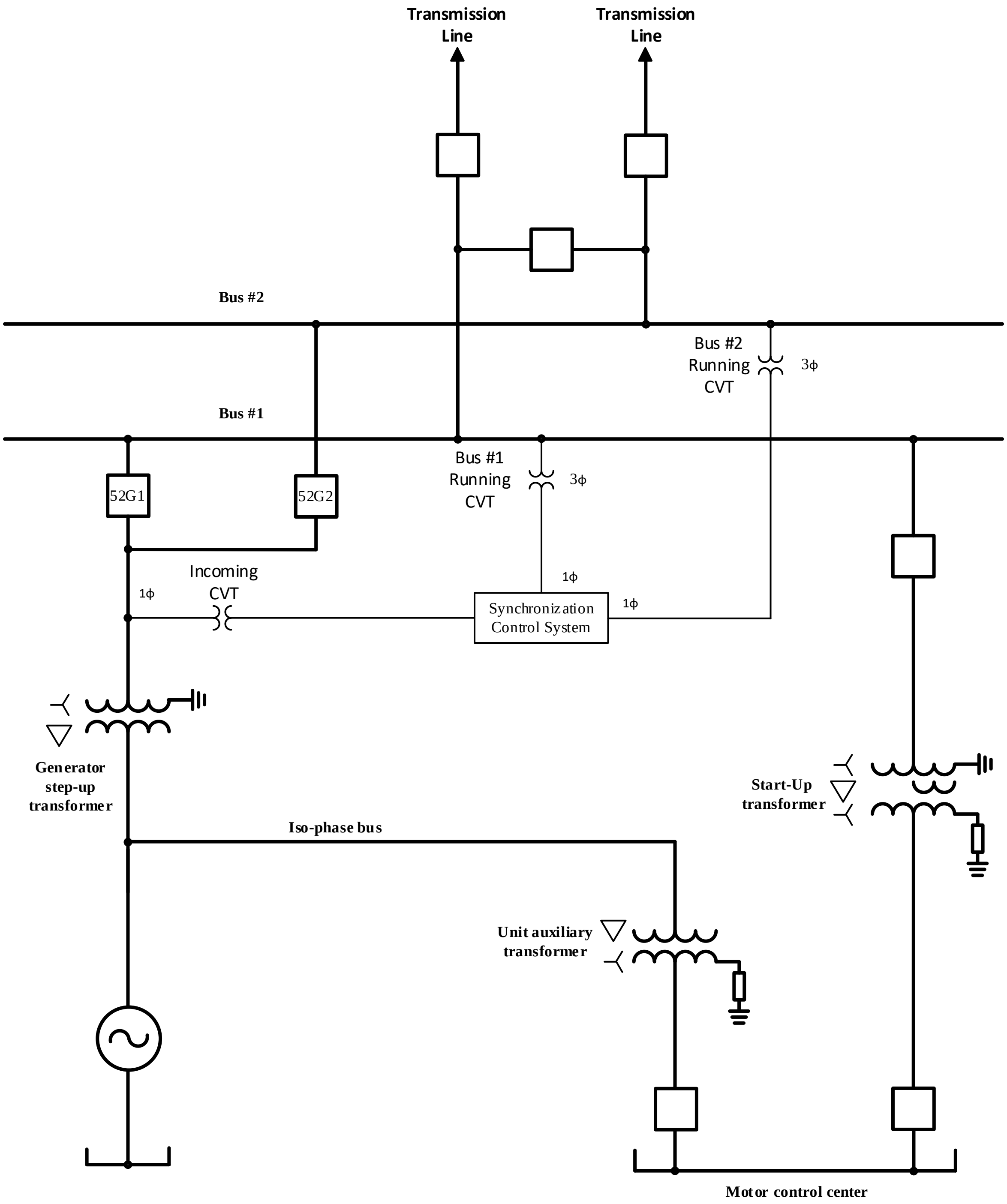

Figure 7: Example High-Side CVT Design

Unit generator designs also require consideration of the tap setting of the GSU transformer de-energized tap changer (DETC). Changes made to the GSU transformer high-voltage winding tap can trigger a review of the synchronizing scheme. Changes to the synchronizing scheme may be required to help ensure proper synchronization and avoid generator damage.

Synchronizing Parameter	Value
Breaker Closing Angle	± 10˚
Generator Side Voltage Difference Relative to System	0% to +5%
Frequency Difference	± 0.067 Hz

Figure 8: Synchronization Limitations for Salient-Pole [5] and Cylindrical Rotor Synchronous Generators [6]

2.1.1 Voltage Magnitude Difference

A voltage magnitude difference across the breaker just prior to closing results in a flow of reactive power after the breaker is closed. A generator per unit voltage less than the system per unit voltage results in a var absorption from the interconnecting system. This interaction may cause a voltage depression on the system that the generator is connecting to. If a large generator is synchronized to the system with significantly low voltage, the var import could trigger system voltage instability. The additional var demand can result in increased voltage drop on the lines connected to the switchyard bus, with the potential of progressing into uncontrollable voltage decline and eventual collapse. This is a particular concern in electrically weak systems or systems without local reactive power support.

IEEE Std C50.12 [5] and IEEE Std C50.13 [6] require that a generator be designed to withstand a voltage difference between 0% to 5% during synchronization. This rating uses the generator voltage as the reference. Therefore, the generator voltage is higher than the interconnecting system voltage for this rating to be met.

2.1.2 Voltage Phase Angle Difference

An excessive voltage phase angle variance between a generator and the interconnecting system results in a high-magnitude current through the location where the two systems are electrically joined. A synchronizing voltage phase angle less than 10 degrees is required so that the torsional and electrical stresses on the generator during synchronization are within its ratings [4] [5] [6]. Connecting to the system with an angle error greater than this specification may expose the generator to damaging transient torques.

To account for the total current contribution, Equation (1) may be used to calculate the rms current magnitude [15] [18]. Ideally, a generator is synchronized when there is a minimal angle difference between the generator internal voltage and the interconnecting system voltage.

$$\boldsymbol{I_{OPS\_rms}} = \frac{(\boldsymbol{E_{Gen}\angle\theta_{Gen}} - \boldsymbol{V_{Sys}\angle\theta_{Sys}}) \times \boldsymbol{K_{Asymmetrcial}}}{(\boldsymbol{X_d''} + \boldsymbol{Z_{GSU}} + \boldsymbol{Z_{Sys}})} \quad \textbf{(1)}$$

Where:

E_{Gen}: The internal voltage magnitude of the generator

V_{Sys}: The system voltage magnitude

θ_{Gen}: The generator internal voltage angle

θ_{Sys}: The system voltage angle

X''_d: Generator subtransient reactance

Z_{GSU}: The impedance of the generator step-up transformer

Z_{Sys}: The impedance of the interconnecting system

$K_{Asymmetrical}$: An asymmetrical factor to account for the dc component within the current

Equation (2) provides the ac current component through the synchronizing breaker [15]. This equation assumes that the generator voltage and system voltage are at the same frequency at the point of closure.

$$\boldsymbol{I_{Synchronization\_AC}} = \frac{\sqrt{V_{Sys}^2 + E_G^2 - (2V_{Sys}E_{Gen}\cos\delta)}}{(X''_d + Z_{GSU} + Z_{Sys})} \qquad \textbf{(2)}$$

Where:

δ: the instantaneous angle difference between the generator and system voltages

IEEE Std C57.12.00 provides Equation (3) to account for the dc current component during a synchronization [18]. The first cycle peak current for an OPS is a function of the current decay rate of the interconnecting system.

$$\boldsymbol{K_{Asymmetrial}} = \sqrt{2} \times \left\{1 + \left[e^{-(\phi+\frac{\pi}{2})\frac{R}{X}}\right]\sin\phi\right\} \qquad \textbf{(3)}$$

Where:

ϕ: The arctan(X/R)

R/X: The resistance-to-reactance ratio of the total impedance that limits fault current for connected transformer (transformer low side). This equates to the GSU transformer and system resistance and reactance magnitudes.

Any excessive phase angle across the synchronizing breaker, just prior to closing, causes an impulse torque on the rotor and stationary windings of the machine. High stator currents at large angle differences may also cause deformation of generator end-turns and lead to eventual winding failure. This failure mode can also occur due to the incremental damage from a number of previous impulse torques to the generator. It has been observed that closing at a static angle as low as 15 degrees can cause as large a power swing as closing at 0 degrees with an excessive slip frequency of 0.5 Hz [19], which is significantly higher than the frequency difference synchronizing limit of 0.067 Hz shown in Figure 8.

The relationship between the generator's electrical torque and the electrical synchronizing angle (δ_0) for the turbine model of Figure 9 is illustrated in Figure 10 [20]. The solid line in Figure 10 represents a simulation with no slip, i.e., the generator and system are operating at synchronous speed. A simulation for the unit running 2% faster than the system is characterized by the dotted line. The results demonstrate that the electrical torque generally increases for higher δ_0, reaching a maximum torque at 180 degrees. Figure 10 shows that there is not a significant impact of slip frequency on torque.

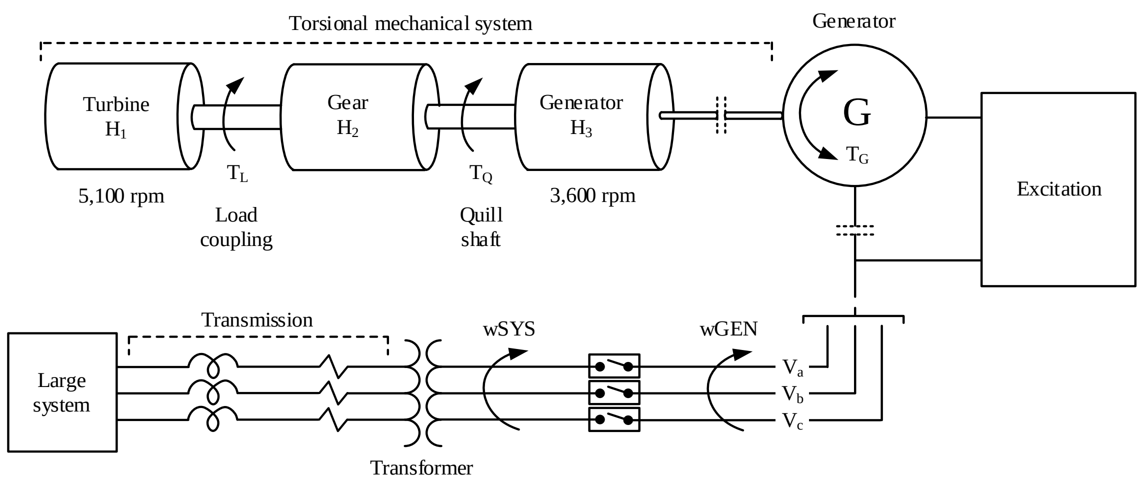

Figure 9: Schematic of the Generator/Turbine Model System [20]

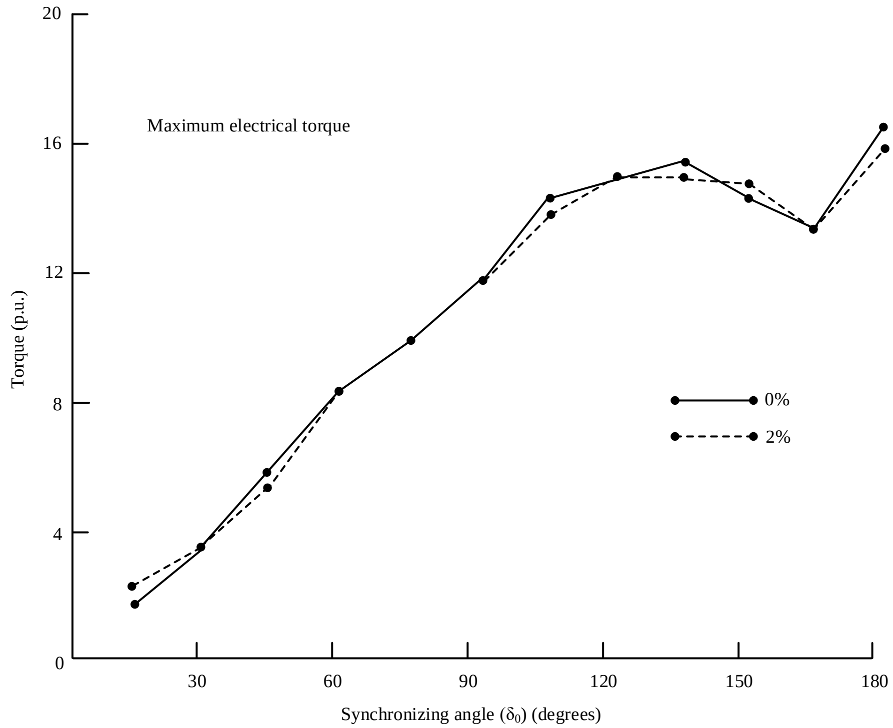

Figure 10: Electrical Torque vs Synchronizing Angle (δ_0) [20]

Figure 11 shows the relationship between the mechanical torque impressed upon the turbine and the electrical synchronizing angle (δ_0). In contrast with the electrical torque characteristic, the mechanical torque of a generator does not reach a maximum at 180 degrees. The mechanical torque of a generator has a maximum at δ_0 of 120 degrees and can exceed the maximum mechanical torques observed for a three-phase fault at the generator terminals. Reference [20] notes that δ_0 as low as 60 degrees results in calculated torques equivalent to a bolted fault. For a different system, reference [4] reports δ_0 between 70 degrees and 175 degrees to result in a higher torque than a three-phase fault at the generator terminals. The mechanical shock associated with a high δ_0 synchronization can excite one of the torsional modes of the combined generator-shaft-turbine system into an oscillation that lasts several seconds [21]. Also, the armature current increases with increases in δ_0, reaching a peak at 180 degrees.

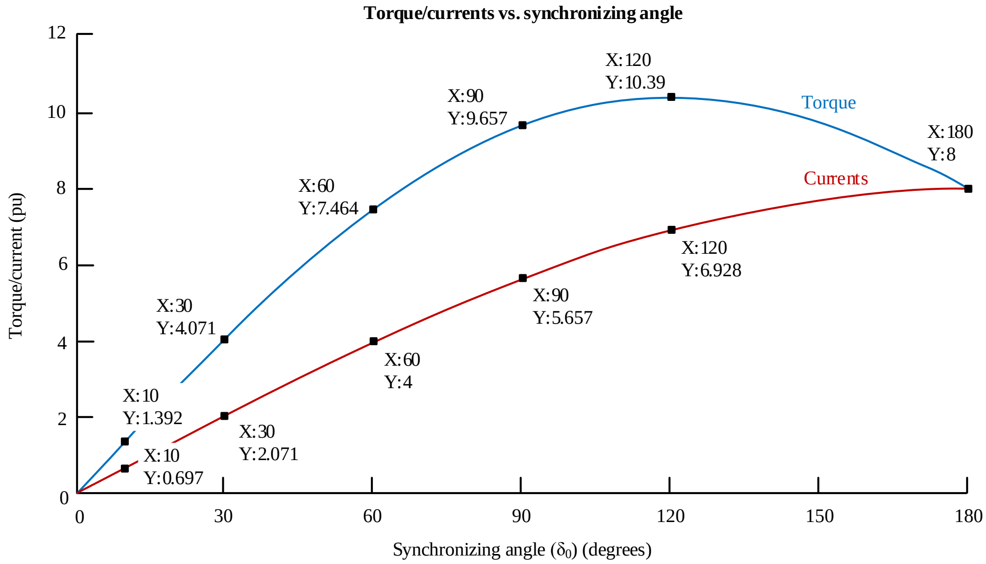

Figure 11: Mechanical Torque/Stator Current vs Synchronization Angle (δ_0)

Voltage phase angle difference is the most sensitive variable for torque stress from a faulty synchronization. It is also noted "that the torques due to faulty synchronization increase when the machine leads rather than lags the system" [20]. This phenomenon is due to the interaction of inertia and the resulting momentum. When leading, the electromagnetic forces tend to pull the rotor in synchronization in a braking action which opposes the rotating momentum. "Furthermore, faulty synchronization torques are apparently slightly increased if parallel machines are already online" [20]. This is because of the lower effective system impedance presented by the parallel machines.

2.1.3 Frequency Difference

Most actual synchronizing accidents occur with some frequency difference coincidental with the phase error. Although the mechanical shock from a phase error alone is worse than a frequency difference error alone, the speed difference at the time of angle error can have a marked effect on loss-of-life if the speed difference is significant enough to cause multiple slip cycles before the generator aligns its speed with that of the system. The oscillations excited may coincide with a mechanical resonant frequency of the machine and lead to shaft failure.

A high-slip synchronization requires more than one slip cycle to reach a state of equilibrium. Slip frequency (slip) is defined as the difference between the generator frequency and the system frequency. Each slip cycle imposes an out-of-phase current magnitude across the stator winding of the machine. However, this peak synchronization current is less than the maximum possible current because the dc component of the transient current would have decayed to a small value.

IEEE Std C50.12 and IEEE Std C50.13 require that generators be built to withstand a frequency difference of ±0.067 Hz between the generator and the interconnecting system.

This limit pertains to the electrical portion of the generator; the prime mover may have separate slip frequency ratings. The generator manufacturer may be consulted to verify the maximum allowable slip frequency that the generator is capable of withstanding. A synchronization that is within either of these specifications is expected to prevent damage from excessive frequency difference.

3. Synchronizing System

3.1 Generator Control Systems

Generator control systems regulate the output of a synchronous generator. The excitation control system regulates the internal voltage of the machine and its reactive power output. The governor control system adjusts the rotational speed of the prime mover and real power output. Both these systems are critical for proper synchronization to the grid.

3.1.1 Governor Control System

The governor control system monitors the mechanical speed of the prime mover. It may measure this component through a speed input or derive the frequency from the generator terminal voltage measurement. Using this information, the governor control system can also adjust the speed of the prime mover to match the system frequency. The generator breaker may be closed when the prime mover mechanical speed is rotating slightly faster than the system electrical speed—this is referred to as positive slip. Synchronizing in this manner creates an outward transient response in which the generator exports real power (watts) upon breaker closure.

When frequency measurement is established, decisions on how to adjust the speed for synchronizing can be determined. The synchronizing circuit, either manual or automatic, sends speed correction signals to the governor to raise or lower the speed. This change in speed comes from adjustment to the applicable process driving the prime mover, such as steam, combustion gas, or water.

3.1.2 Excitation Control System

Generator voltage is established by the excitation system before speed can be controlled. Synchronizing system devices also require a minimum generator voltage to calculate frequency. Furthermore, a healthy voltage level is required to determine that a viable generator and a viable bus exist before the synchronization process can begin. This voltage level varies among generator owner practices—a typical range is 70% to 80% of the rated voltage.

The initial terminal voltage of the generator is established by the excitation system prior to the synchronization process. Control provided by the autosynchronizer, manual voltage control, or automatic voltage regulator (AVR) can begin to control the voltage once the terminal voltage is above a sufficient level. If the generator voltage is lower than the system voltage, then it may have a detrimental effect on the system and/or generator (see Section 2.1.1). If the generator voltage is slightly higher than the system voltage, the machine produces a positive reactive power (var) flow into the system upon breaker closure. This prevents a system voltage depression because the machine does not absorb vars from the system—an important consideration for weak systems. Slightly higher generator voltage can be established either manually or by the autosynchronizer. Synchronizing system devices are often equipped with settings that require a slightly higher generator voltage before allowing breaker closure.

When voltage measurement is established, decisions on how to adjust the voltage for synchronization can be determined. The synchronizing circuit, either manual or automatic, sends voltage correction signals to the excitation controller to raise or lower the voltage. The excitation controller then adjusts the dc current to the field winding by controlling the applicable excitation circuit, such as power electronic firing angles.

Voltage naturally changes proportionally with changes to the prime mover speed. The response time for the excitation control system to make voltage changes is faster than changes to the prime mover speed because voltage changes are electrical in nature.

3.1.3 Prime Mover Automatic Speed Control

Automatic speed matching systems may be located in either the governor control system or an external relay. Modifications to the prime mover speed are slower than changes to the generator internal voltage due to the mechanical nature of the input power system. A critical aspect of this control is the ability to maintain stable prime mover speed as it attempts to match the frequency of the unloaded generator with that of the interconnecting system.

3.1.4 Overshoot and Hunting

A potential difficulty with speed control methods is the difficulty in settling at a desired prime mover speed, often referred to as control system hunting. A hunting behavior can be described as consistently overshooting a desired setpoint followed by undershooting the desired setpoint—this behavior is illustrated in Figure 12 [1]. As the prime mover speed approaches the desired speed, the control system overshoots the speed correction due to the miscoordination between the frequency of contact closures and the control system lag. These quick command pulses do not translate to quick changes in prime mover speed. This leads to oscillations centered around the speed setpoint as the control systems continue to correct the overshoot.

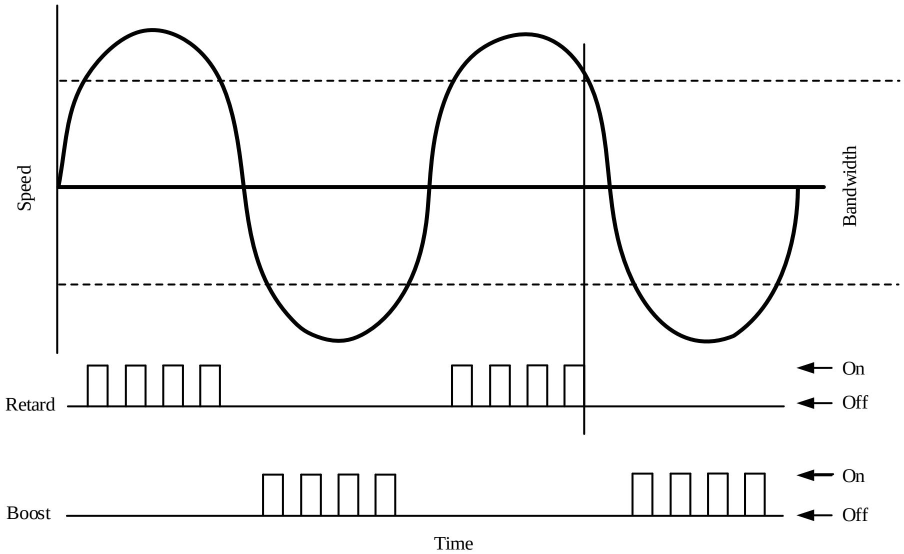

Figure 12: Hunting with frequency modulation [1] [15]

Hunting occurs when the autosynchronizer repeatedly overshoots the slip or voltage difference acceptance band and sends alternating raise and lower pulses. If the generator control responds to proportional correction pulses (see Section 3.1.5) and the pulse duration or slope is set too high, the controlled parameter overshoots the acceptance band. Similarly, if the autosynchronizer sends new correction pulses before the generator control can respond to the previous ones, the control can hunt as well.

For example, if a 60 Hz rated machine is at 95% speed when the speed matcher is energized, the slip frequency is 3 Hz with a pulse rate of 3 pulses per second. In 10 seconds, the governor would have received 30 of these pulses, yet the machine frequency would barely have begun responding to the first pulse (assuming a slow governor control). The pulses applied would result in a backlog of built-up mechanical energy that the control system has to disperse by adjusting the speed of the prime mover. Thus, even though the autosynchronizer has stopped issuing command pulses, the governor control system continues to adjust the speed resulting in overshooting. The autosynchronizer then tries to correct by issuing lower speed commands but this may lead to undershooting. When the hunting process has brought the frequency closer to a match, the pulses then may become too widely spaced. A slip frequency of 0.05 Hz requires a wait of 20 seconds between pulses (or even longer) if there are frequency fluctuations. This creates an extended delay for the synchronizing system to reach the desired prime mover speed equilibrium.

3.1.5 Modulation Techniques

These methods incorporate speed control into the governor control system by sending raise or lower contact pulses [1]. Two adjustments are used to form the control pulses—the pulse period (time between pulses) and the pulse width (the duration the associated contact is closed). The three modulation techniques are shown in Figure 13 and described in the following subsections.

Typically, the generator control systems either respond to fixed duration pulses or proportional duration pulses. The governor is the speed (frequency) control system. The automatic voltage regulator (AVR) is the voltage control system. If the generator control system adjusts the frequency or voltage by a fixed amount for each pulse, a fixed duration correction pulse characteristic is desirable.

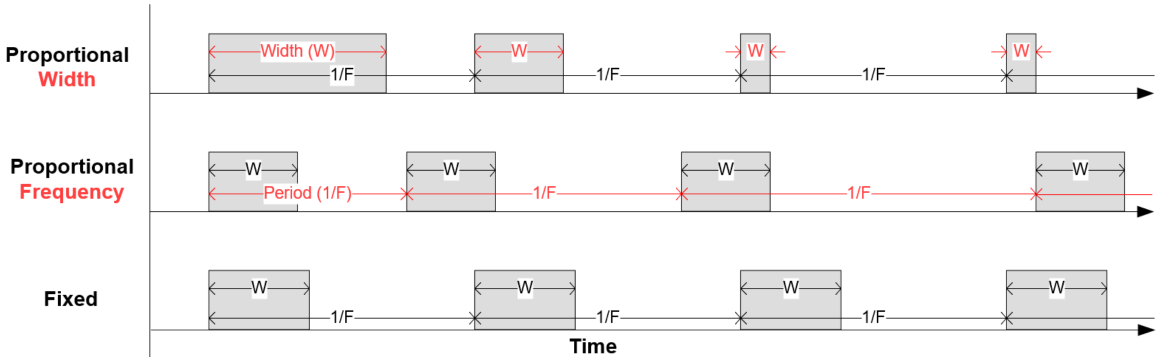

Figure 13: Prime Mover Speed Control Modulation Techniques

3.1.5.1 Proportional Pulse Width Modulation

For proportional pulse width modulation, the autosynchronizer maintains a fixed pulse period and varies the pulse width dynamically based on the slip frequency between the generator and the system (see Figure 14).

- Pulse width—For a high slip frequency, the pulse width is long; and as the slip frequency decreases, successive pulse widths become shorter. Based on a cycle-per-cycle determination of the slip frequency, the pulse width is automatically controlled to self-correct and lengthen or shorten as needed. The duration that the contact is closed determines the ramp rate of the governor speed correction. A proportional pulse width characteristic typically has a slope setting in Hz/second or seconds/Hz (Volts/second or seconds/volt for an AVR). The farther the generator frequency or voltage is from the synchronizing acceptance band, the greater the duration of the pulse.
- Pulse period—The pulse period may be set a little longer than the slowest machine response to a given pulse allowing the governor system time between command pulses to adjust the speed and establish a new equilibrium. The last pulse prior to match is just enough to nudge the machine into the acceptance window, thereby eliminating overshoot and hunting. In proportional pulse width systems, the interval is typically fixed.

Use of pulse width modulation leads to the most rapid convergence of the generator to system frequency.

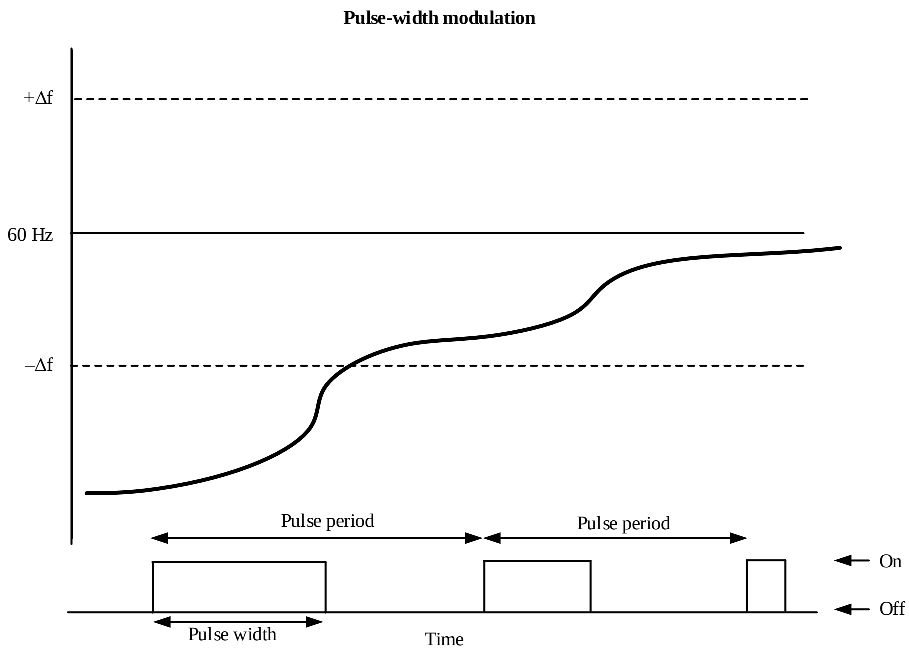

Figure 14: Pulse-Width Modulation [1] [15]

3.1.5.2 Proportional Pulse Frequency Modulation

In this control scheme implementation, the pulse width is fixed but pulse period can vary. In some implementations, the autosynchronizer applies a speed correction pulse to the governor for each slip cycle between the generator and system. Hence, the pulse period is inversely proportional to the frequency slip between the generator and the system. Multiple contact pulses may be issued in quick succession when the prime mover speed is far away from the desired setpoint. As the prime mover speed approaches the setpoint, the autosynchronizer issues fewer pulses.

3.1.5.3 Fixed Pulse Frequency and Fixed Pulse Width Modulation

In this control scheme, the pulse width and pulse period are both fixed. Command pulses are issued at a fixed rate until the prime mover speed is within the assigned control bandwidth. Subsequently, the generator is synchronized with the system.

3.1.6 Analog Bias Signal Method

Certain models of governors have provisions to accept an external analog voltage or current to bias the speed setpoint of the governor. The synchronizing device adjusts this speed bias for the governor to raise or lower the speed. Synchronizing devices can be equipped with an analog output for this purpose. The additive or subtractive bias allows a convenient tunable method to reduce control system error. In older machines, synchronizing circuits would control motor-operated potentiometers (rheostats) that would adjust the speed bias through a voltage divider. The analog bias is not needed in newer governor controls, which may be embedded into the distributed control systems (DCS), since the control loop configuration provides easily tunable parameters.

3.1.7 Control System Operation

Synchronizing a generator using a small positive slip and slightly higher voltage than the system helps ensure that the machine does not absorb any real or reactive power during the transient operation. This can help avoid protection scheme misoperation during startups [22]. An important final step in the synchronization process is the transfer of governor controls from isochronous to droop mode—these control modes are illustrated in Figure 15 [23].

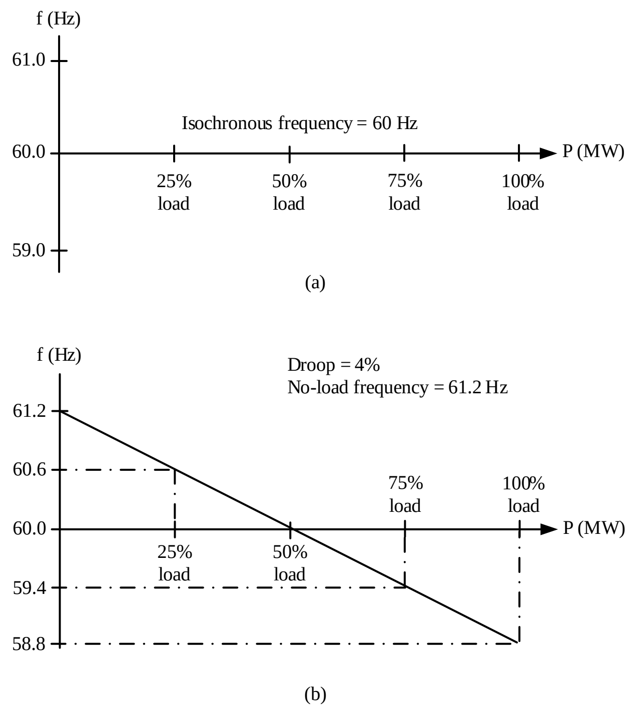

Figure 15: Governor control modes a) Isochronous b) Droop [23]

The isochronous control mode allows the governor control system to regulate the speed of the prime mover to a specified speed setpoint. As the megawatt loading on the prime mover varies, the governor control adjusts the mechanical input power to maintain the prime mover speed. After the generator is synchronized to the system, the generator no longer has independent control of the system voltage and speed. If the controls remain in isochronous mode, the generator moves to its operational limits when the system shifts from the reference setpoint. Transfer to droop mode is necessary for the prime mover speed to decrease proportionally as the megawatt loading increases. The dynamics of this control mode are dependent on the droop algorithm, percent droop, and no-load frequency. Generators intended to synchronize to the grid have both governor and excitation controls equipped with droop capabilities allowing stable operation when multiple generators are connected to the same system.

Transfer to droop mode is typically initiated by the change of generator breaker status or indication (e.g., valve position) that unit is slightly above full-speed no-load. Depending on the generator bus configuration, a combination of breaker status indications may be required to differentiate between islanded and synchronized conditions. This is especially true in medium-voltage applications where a generator may be connected to a switchgear with multiple main or tie breakers.

3.2 Synchronizing System Components

3.2.1 Synchroscope

An electromechanical scope, shown in Figure 16, displaying the angle difference between the generator and the system may be installed for local operator indication. The synchroscope indicates the angle between the generator and system voltage. The slip frequency can be judged based on the change in angle with respect to time (in revolutions per minute) at which the scope pointer rotates. Typically, a small slip is desired to reduce torque transients. However, if the slip is too low then it may take a very long time for the synchroscope to rotate into phase. Conversely, if the slip is very high the synchroscope may not be able to keep up and the indicating arrow will just quiver. When the arrow quivers, the synchroscope phase angle reading is not reliable.

The direction in which the scope pointer rotates reflects the relationship between the generator and system frequency. The reference point for the slip is the generator speed. The scope pointer rotates clockwise when the generator rotates faster than the electrical frequency of the system—indicating a positive slip. Conversely, the pointer rotates counterclockwise when the generator rotates slower than the electrical frequency of the system—indicating negative slip.

Figure 16: Electromechanical Synchroscope [2]

3.2.2 Synchronizing Lamps

A common feature of a synchronizing panel is two incandescent lamps connected in series between the incoming (generator) and running (bus) voltages. The lamps respond to the sum of the voltage across the two VT signals. When the voltages on each side of the breaker are in phase and of equal magnitude, the voltage across the two lamps is zero and the lamps are off. When the voltages on each side of the breaker are 180 degrees out-of-phase, the voltage is the sum of the magnitudes of the two voltages. That is why two lamps are connected in series. At this point, the lamps are at full brightness. This visual indication gives a composite indication of all three synchronizing variables—voltage magnitude difference, frequency difference, and phase angle difference.

Slip can be judged by how fast the lamps cycle between bright and dim. Voltage magnitude can be judged by whether the lamps go out completely. The angle difference can be judged by the point when the lamps are at their dimmest. While more sophisticated meters such as incoming and running voltmeters and a synchroscope are also used in a synchronizing panel, this simple indication can be very valuable. The synchronizing lamps generally provide indication of the synchronization process until the speed can be matched to the point that the synchroscope can start tracking the angle difference. Further, this strobing effect is easy for a human operator to interpret versus accurately reading information from several meters.

Note that, for extremely high slip, the thermal lag of the incandescent filaments may not show the expected pronounced strobe effect until the slip is reduced to reasonable levels. However, because the lamps never go out in that case, the indication that it is safe to close the breaker never occurs. Therefore, the indications provided by the synchronism lamps are quite fail-safe.

3.2.3 Manual Speed Matching Switch (15)

Speed control switches provide an operator the ability to manually control the speed of the prime mover. Contacts from the switch typically feed into the governor control system. If an autosynchronizer (25A) is used, these contacts are usually wired in parallel with the autosynchronizer’s speed matching contacts. Operators can manually issue raise or lower speed commands to modify the governor speed setpoint. The governor control system receives these commands and adjusts the prime mover speed, as appropriate. This switch is crucial for manual synchronization because it is the most fundamental technique for matching the prime mover speed with the system frequency.

Operator training can help ensure a successful operation when the need arises for a manual synchronization. Intimate knowledge of the speed control methodology can help prevent overshooting or hunting. The speed control methodologies are discussed in Section 3.1.

3.2.4 Manual Voltage Regulation Switch

Voltage control switches are typically implemented in a power plant to allow the operator to manually regulate the internal voltage of the machine. Contacts from this device typically interface with the excitation control system. If a 25A scheme is implemented, these contacts are usually wired in parallel with the autosynchronizer's voltage regulation contacts. Operators can manually issue raise or lower voltage commands to modify the voltage regulator setpoint. The voltage regulator uses these commands to adjust the magnitude of the dc current flowing through the field winding.

Operation of this device typically only occurs during a manual synchronization process. The operator issues voltage raise or lower commands to align the generator voltage with the system voltage based on the internal processes established by the generator owner.

3.2.5 Synchronization Enable Switch

A manually operated synchronizing switch (SS), sometimes called a 01 switch, may be used to activate the generators synchronization system within the synchronizing panel. It is also typically designed with an off position and a removable control handle. The removable handle helps ensure that more than one set of VT signals cannot be connected to the incoming and running buses of the synchronizing panel. This switch is to be left in the off position until the generator is ready to be synchronized. Closing the 01-switch energizes the voltage meter, synchroscope, and synchronizing lamps assigned to that specific generator. When the generator has a successful synchronization, the operator can place this switch in the off position and remove the handle to de-energize the synchronizing panel.

Generating facilities that have multiple generating units typically have duplicate and identical synchronizing systems. There may be multiple SS switches, one for each generator synchronizing breaker on the site. In this scenario, only one handle may be provided for the entire generating facility to allow only one unit to be synchronized at a given time. The single removable switch handle helps mitigate any human performance issues that may arise from manual control intervention.

3.2.6 Manual/Automatic Synchronization Switch (43M/A Switch)

A manual/automatic selector switch allows the operator to place the synchronizing breaker dc close circuit in the manual or automatic path. Close initiates on the synchronizing breaker may either come from an operator or the autosynchronizer. The operator would utilize the manual control path within the dc close circuit. The autosynchronizer close initiate is located within the automatic path of the dc close circuit. Design examples for synchronizing breaker dc close circuits are located in Section 5.

Some generating facilities may combine the synchronization enable switch (01) function with the manual/automatic switch (43M/A). This single switch will have an off/manual/automatic position. There are other configurations that may be used to accomplish these functions.

3.2.7 Generator Breaker Control Switch (01GCS)

This control switch allows the operator to manually control the generator breaker. Contacts from this switch are typically wired to the dc trip and close circuits of the generator breaker to initiate commands.

3.2.8 Synchronism-check Scheme (25)

A synchronism-check scheme can verify that the phase angle difference between two electrical systems are within an acceptable value. This function operates as a permissive device within the synchronization scheme; essentially acting as a last line of defense to prevent synchronization failure. The phase angle supervision creates an acceptable angle window centered around the 0 degrees (12 o'clock) position. This window defines the maximum closing angle for when the generator angle location is either leading (+) or lagging (–) the interconnecting system.

The voltage magnitude difference and slip frequency measurement are optional features that may be available in some protection/control systems.

Contacts from a 25 device may be wired to the close circuit of the generator breaker to act as a permissive function for both the manual and automatic synchronization operations (see Section 5.3).

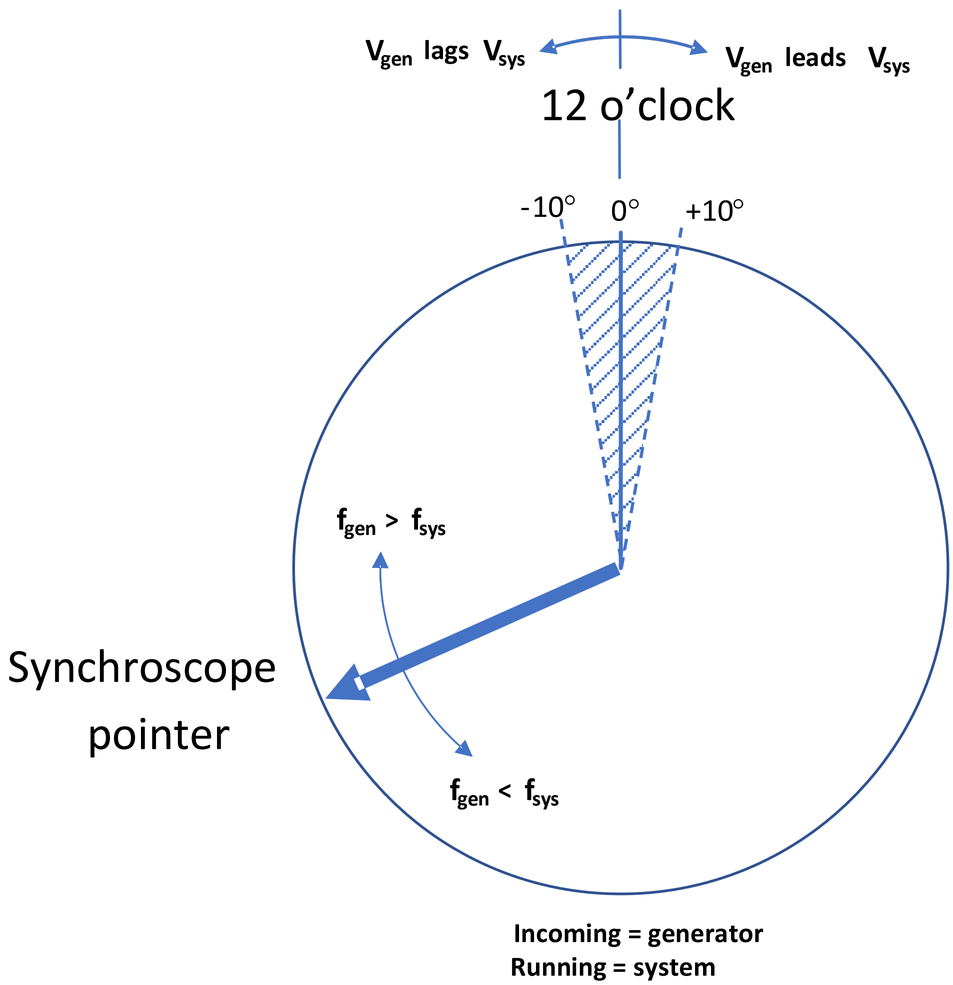

Figure 17: Synchroscope with Acceptable Synchronization Angle Window

Legacy synchronism-check schemes cannot directly measure slip frequency. Instead, these schemes check that the angle remains within the synchronism-check (25_{ANG}) window for some time to infer the slip frequency [2]. The maximum permissible time criteria (T_{25}) for these schemes is shown in Equation (4).

$$\boldsymbol{T_{25} = (25_{ANG} - \delta_{ANG}) \times \left(\frac{cycle}{360°}\right) \times \left(\frac{sec.}{F_{slip}}\right)} \quad \textbf{(4)}$$

The delay of the legacy synchronism-check scheme may be set less than the time criteria calculated using the maximum slip frequency.

Microprocessor relays are capable of directly measuring slip frequency, allowing them to directly account for changes in slip, with their internal algorithms. With this improvement, there is no need to widen the phase angle setting to overcome a deliberate time delay. This allows tighter synchronization angle settings for generator applications. Therefore, microprocessor relays do not require a time delay setpoint and provide higher quality synchronizations.

Legacy synchronism-check schemes are vulnerable to faulty synchronizations. It is advised to not implement legacy angle window/timer-based synchronism-check schemes. The use of a modern synchronism-check device that measures slip frequency directly is a more optimal engineering solution for synchronization.

3.2.9 Autosynchronizer System (25A)

An automatic synchronizing system may be implemented to augment the manual interactions of an operator. It can provide all the control functions necessary for successful synchronization. This system interfaces with both the excitation control system and governor control system. Voltage and frequency commands to the control systems are issued based on programming of the autosynchronizer. It also has the ability to initiate a breaker closure at an optimal time before phase angle zero, taking into account slip frequency and breaker closing time, resulting in reduced stress from a synchronization as described in Section 5.3.

3.2.9.1 Autosynchronizer Tuning

To properly tune the autosynchronizer correction pulse characteristic, it is desirable to understand both the generator control system’s response characteristics and the autosynchronizer’s control characteristics. Typically, the autosynchronizer control characteristic has adjustments for the interval between correction pulses and the duration of the correction pulses (see Section 3.1.5). The generator control typically requires a minimum pulse duration to detect the raise/lower command. Depending on the characteristics of the autosynchronizer, the interval can be fixed or proportional to how far out-of-band the controlled parameter is.

If possible, the generator governor control and exciter control engineers can be consulted to understand the generator control system’s characteristics. If this information is not available, the response characteristic of the generator control system can be discovered by test. The tuning procedure might include using test pulses of various duration and determining if longer pulses cause a greater change in the controlled parameter than shorter ones. If so, the generator control system will respond well with a proportional pulse duration characteristic. If the duration of the test pulses seems to have little effect on how much change in the controlled parameter (frequency or voltage) is observed, a fixed pulse duration characteristic is desirable. When taking these readings, it is important to understand that the generator control system will take some time to reach a new steady state after each adjustment.

When tuning the pulse characteristics, a balanced approach to adjusting both the interval and duration is best. Being too aggressive in either adjustment can cause hunting which will increase synchronizing times. Being too conservative with the correction pulse duration and interval settings can cause slow synchronizing as well because it takes a long time to adjust the frequency or voltage control setpoints into the synchronizing acceptance band. See APPENDIX B for examples of tuning the autosynchronizer correction pulse control characteristics.

3.2.9.2 Automatic Generator Breaker Closure

An essential function of the autosynchronizer is its ability to compensate for the breaker close mechanism inherent delay (i.e., breaker closing time). The autosynchronizer can use the measured slip frequency (F_{SLIP}) and the breaker closing time (T_{CL}) to determine the slip-compensated advanced angle (Θ_C) for a synchronization operation using equation (5). This allows the synchronizing breaker close command to be initiated early at the advance angle to compensate for breaker closing time. An autosynchronizer can compensate for breaker closing time more precisely and with higher consistency than a trained operator. Anticipating the closing time allows synchronization to occur when there is a near zero-degree difference between the generator and the interconnecting system. This helps minimize synchronizing torque transients.

$$\boldsymbol{\Theta_C\ (deg) = 360° \times F_{SLIP}(Hz) \times T_{CL}(seconds)} \qquad \textbf{(5)}$$

An output contact from the autosynchronizer system may be wired to the dc close circuit of the generator breaker for operational control.

3.3 Synchronization Logic

3.3.1 Permissive Synchronization Logic

The logic of Figure 18 may be used in a microprocessor relay or a control system to help prevent faulty synchronizations. The output of this logic represents a permissive control signal within the synchronization process.

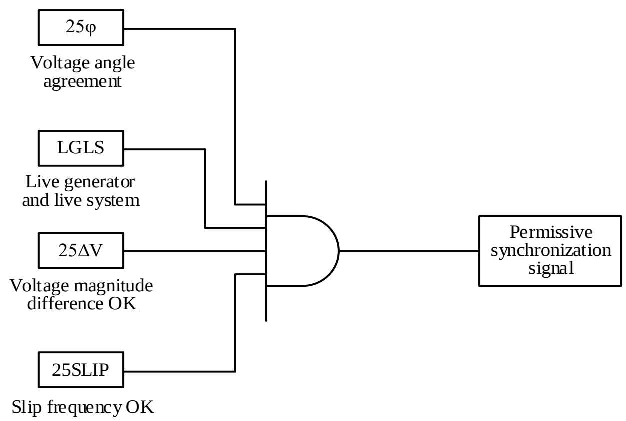

Figure 18: Synchronizing Permissive Operating Logic

The voltage angle agreement check (25φ in Figure 18) can have implementation variations. Historically, it has been implemented as a symmetrical window around zero degrees without any compensation associated with the breaker closing time. This is represented as $25\varphi_{SYMM}$ in Figure 19. Modern relays may optionally add either or both these features:

- The synchronizing angle can be compensated by the slip-compensated advanced angle (Θ_C) from Equation (5). The associated window is shown as $25\varphi_{COMP}$ in Figure 19, where the window is shifted counterclockwise by one degree to compensate a +50 mHz slip frequency ($f_{GEN} > f_{SYS}$) for a breaker with a 55.5 ms closing time.
- The 25φ window can be made asymmetrical. This is shown as $25\varphi_{ASYMM}$ in Figure 19, where for a positive slip frequency ($f_{GEN} > f_{SYS}$), the window only permits a closure between –10 degrees up to 0 degrees to help prevent a late closure.

These features are not necessary because the role of the permissive synchronization logic is to help prevent a faulty synchronization—it is not to aid an accurate synchronization, which is the role of the manual or automatic synchronizer. However, these features can be a refinement for supervising the primary manual or automatic synchronizing process in the event of a failure of the primary system.

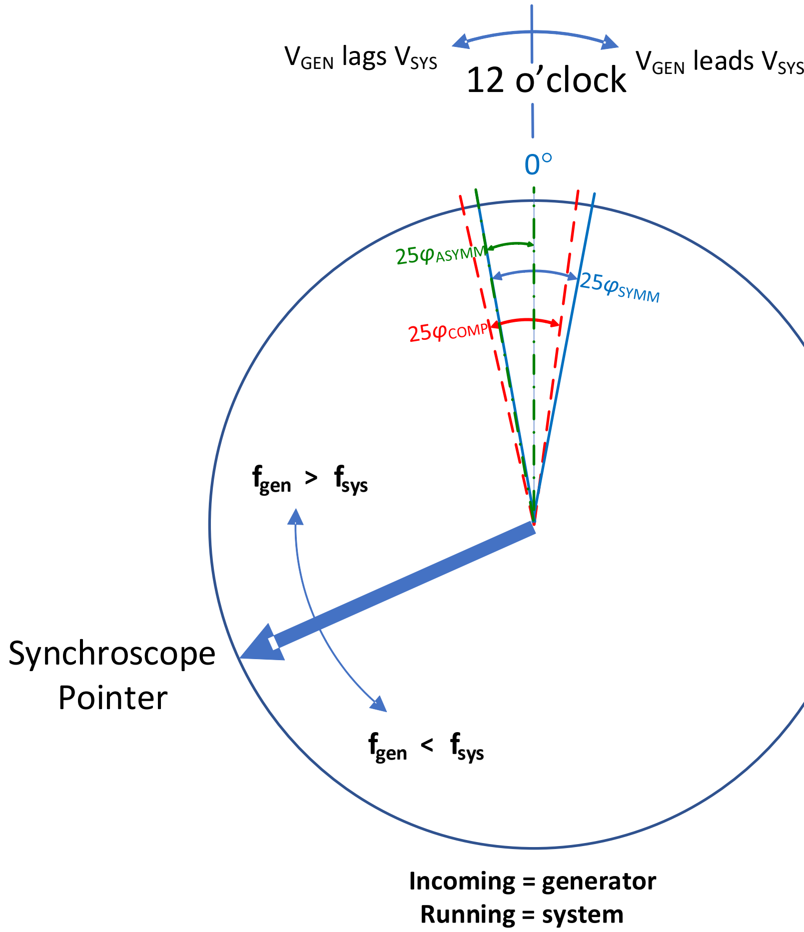

Figure 19: Different Implementations of the Voltage Angle Agreement Window

3.3.2 Dead Bus Close Permissive Logic

Generators designated for a black start operation may require additional synchronization logic. In a black start scenario, the system is dead, and generation is needed to start the re-energization sequence and grid restoration. Applying dead bus synchronization logic, as shown in Figure 20, allows a generator to provide black start support to the system in a secure manner.

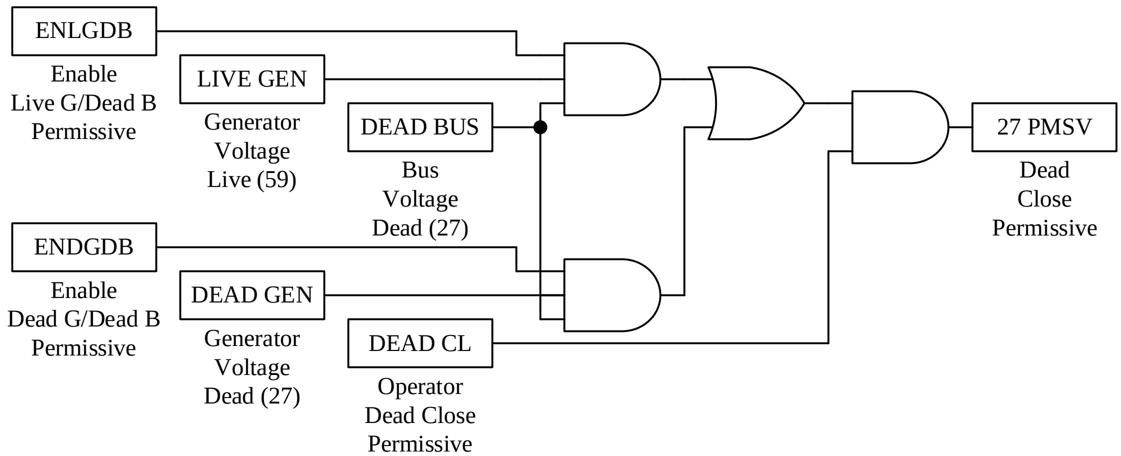

Figure 20: Black Start Synchronization Logic

Figure 20 shows two dead permissive paths, a live generator/dead bus path and a dead generator/dead bus path. In applications which require energization of a GSU transformer during the black start process, it may be desirable to close the low side breaker with both the generator and bus side dead. This is done to avoid transformer inrush currents. The GSU sees a steady buildup of voltage when the field is applied which effectively eliminates inrush current. The inputs ENLGDB and ENDGDB are set up parameters that would enable the path(s) that are needed for the application. In such an application, the low side breaker would be set up with ENDGDB enabled and the high side breaker would be set up with ENLGDB enabled.

Allowing the permission to close logic to assert based on sensing a dead voltage signal may result in a synchronization failure. The synchronism check device cannot reliably differentiate between a true dead condition and a problem in the VT circuit such as a blown fuse or an open circuit. If a dead permissive condition is enabled and the synchronism check device erroneously detects a dead bus, the permissive can assert, bypassing the expected synchronism check angle window and voltage window permissive conditions, allowing an OPS event to occur under non-black start scenarios. The solution to this problem is to include in the dead close permissive logic an input that is asserted by the operator to confirm that the intent is to close the synchronizing breaker to energize a dead bus. This input is designated DEAD CL in Fig. 20. If the system design requires that the dead close command come from an automatic synchronizer, the operator DEAD CL input would also be included in that device as well. This operator DEAD CL permissive may be in the form of a hardwired contact from the synchronizing panel or a communication bit from the generator control system to the synchronization device (s).

The synchronization device(s) monitor the generator voltage and the interconnecting system voltage to identify when the system is in a black start condition. Separate dead (27) and live (59) elements are used to determine the state of the generator and power system. A typical undervoltage threshold of 25% provides the criteria to establish a dead status. A typical overvoltage threshold of 75% may be used to establish a live status. If the voltage is above the undervoltage threshold but below the over voltage threshold, the state is indeterminant and neither live nor dead state is declared.

3.4 Digital Secondary Systems

The advent of digital secondary system (DSS) technology can solve many synchronization design challenges [24]. Digital secondary system technology uses devices located at the primary equipment to digitize instrument transformer analog sampled value data and primary equipment binary status signals and sends them across a digital communications link to protection and control devices in the control room. These same digital communications links carry control commands such as to energize a breaker close circuit from the protection and control devices to the primary power system apparatus. The communication links typically use fiberoptic cables between the digitizing devices (such as merging units and process interface units) and the protection and control devices. Digital secondary systems can be implemented using internationally standard technologies such as the IEC 61850 or using proprietary technologies.

Often, the synchronizing breakers and the generator controls are separated by great distances and/or ownership boundaries. Long VT runs and addition of isolation transformers may be required to address concerns with inductive coupling and ground potential rise in the VT circuits. The dc control circuit design also has its challenges. Often, the auxiliary dc supply in the generating plant is separate from the auxiliary dc supply in the substation and careful design helps ensure isolation of the two dc systems. Voltage drop in the breaker close circuits across a large distance is also a concern. Careful design to address such potential issues is required.

Further, in many applications, the generating plant and the transmission substation are owned by different entities leading to a desire to provide isolation between the protection and control equipment and circuits to simplify ownership, maintenance, and testing responsibilities.

Figure 21, Figure 22, and Figure 23 illustrate traditional technology and two types of DSS technology, respectively. The example is an application where the power plant and the switchyard are separated by ownership and/or distance and require isolation of circuits and equipment. The distance limitations of the communications channel may depend on the technology associated with the communications medium and/or equipment.

Figure 21 uses traditional hardwired synchronizing equipment. To implement these systems, a dedicated low-side (a) or high-side (b) synchronizing breaker in the power plant is required. While not shown in these figures, a synchronizing panel with synchroscope and other indications to allow manual synchronization in addition to automatic synchronization is possible.

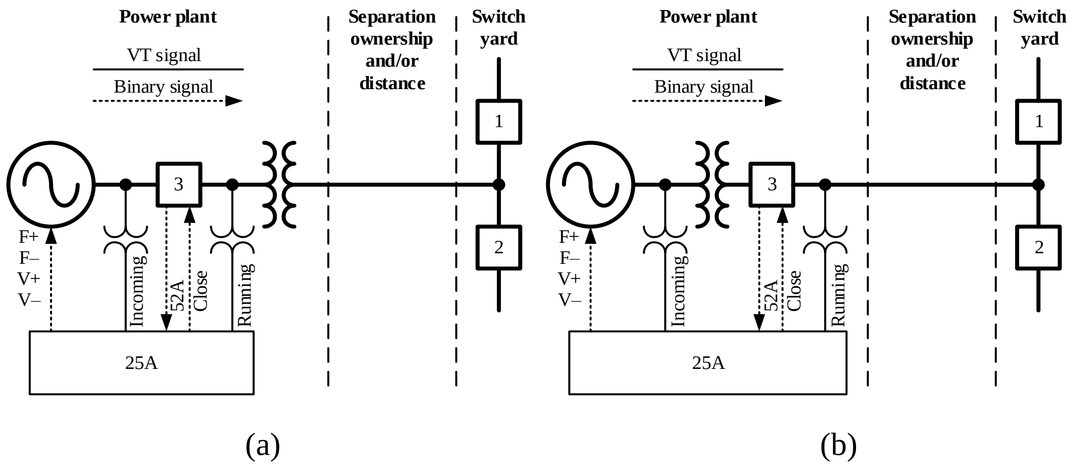

Figure 21: Example Synchronizing System for Applications Requiring Separation Using Traditional Technology a) low-side circuit breaker, b) high-side circuit breaker

In the following examples showing two types of DSS technology, the need for a local synchronizing breaker, as shown in Figure 21, is eliminated.

Figure 22 shows a DSS-based automatic synchronizer that requires only transfer of binary signals across the communications link. International standards such as IEC 61850 GOOSE protocol or other proprietary technologies can be used for this link. The advanced automatic synchronizer is located near the primary synchronizing breaker(s) and synchronizing VTs in the switchyard. A binary remote I/O module (RIO) is located in the generator control room to adjust the governor and AVR. Because manual synchronization requires a hard-wired synchronizing panel with synchroscope, the process to synchronize the generator manually requires that the operator go to the switchyard in the event that the automatic synchronizing system is not available.

Figure 23 shows a DSS-based automatic synchronizer that is capable of digitizing both analog sampled value data and binary signals for transfer across the communications link. In this case, the advanced automatic synchronizer can be located in the power plant. The only device located in the transmission owner's switchyard is the relatively simple merging unit. Notice also that this solution eliminates the need for a high-side synchronizing VT. The high-side synchronizing VT would only be required if a manual synchronizing panel is required in the switchyard for use in the event that the automatic system is not available.

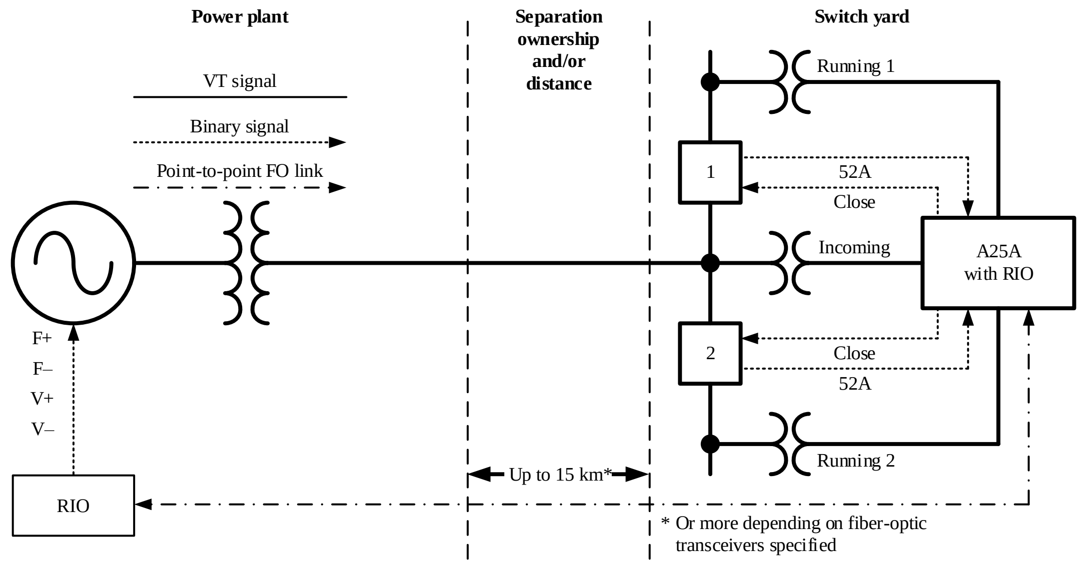

Figure 22: Example Synchronizing System for Applications Requiring Separation Using Binary DSS Technology

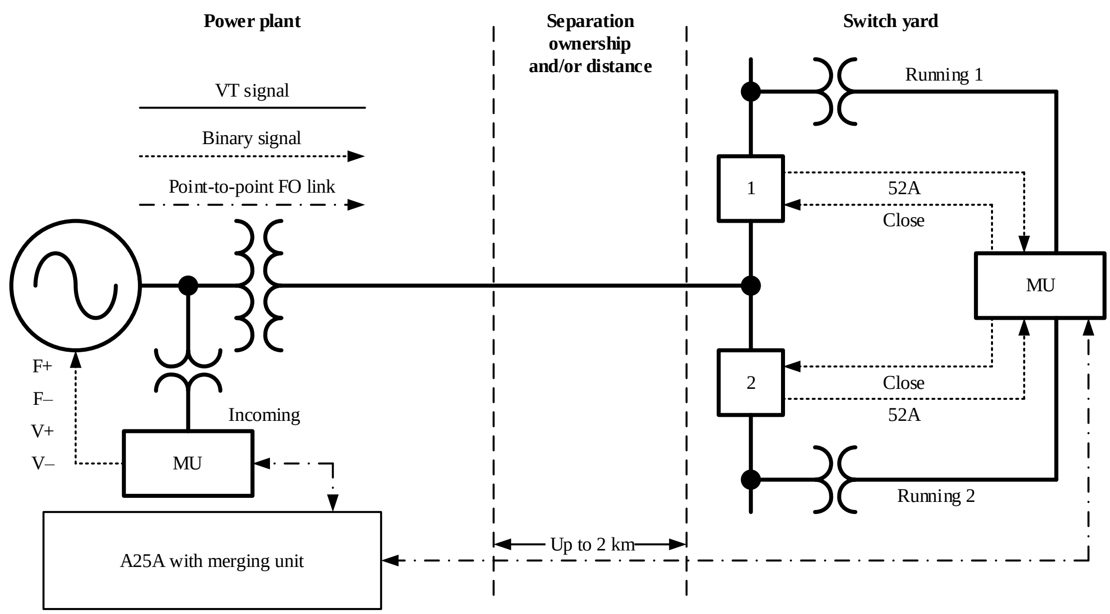

Figure 23: Example Synchronizing System for Applications Requiring Separation Using Analog Sampled Value Data and Binary Signal DSS Technology

This is just one typical example of applications using DSS technology. There are many other synchronizing challenges that can be solved or simplified using DSS technology.

4. Circuit Breaker Ratings

Currents in a generating plant due to a fault or an OPS can be high, reaching several hundreds of kilo-amperes at the generator voltage level on large units. Rating circuit breakers adequately to interrupt such large fault currents can help prevent a breaker failure.

The requirements for circuit breakers are standardized by IEEE Std C37.04 [25] and the associated breaker ratings are dependent on the system frequency, percent dc component in current, relay operate time, minimum opening time of the breaker, etc. In addition to these considerations, circuit breakers in generating plants face challenges such as higher voltage across breaker terminals, fault currents with high X/R ratios, and the possibility of delayed current zero-crossings [7] [26] [27].

4.1 Generator Circuit Breaker Requirements

The requirements for generator circuit breakers are standardized by IEC/IEEE Std 62271-37-013 [27] where it is generally accepted that a generator circuit breaker may be required to interrupt currents with delayed zero-crossings. A delay in zero-crossings occurs because of the time-variant nature of the fault current in a generating plant. For faults, the current changes over time due to the significant differences between sub-transient, transient, and synchronous reactance values of a generator. For an OPS, the primary reason for delayed current zero-crossings is the rapid reduction of the ac component when the rotor rapidly moves from the initial out-of-phase angle to an angle of zero [7] [26]. A comparison of a simulated three-phase fault and a simulated 60-degree OPS with the same initial maximum current amplitude is shown in Figure 24 [4]. Amongst synchronizing angles (δ_0) that result from common wiring errors, as shown in Figure 25, a 60-degree or 120-degree OPS can result in delayed current zero-crossings.

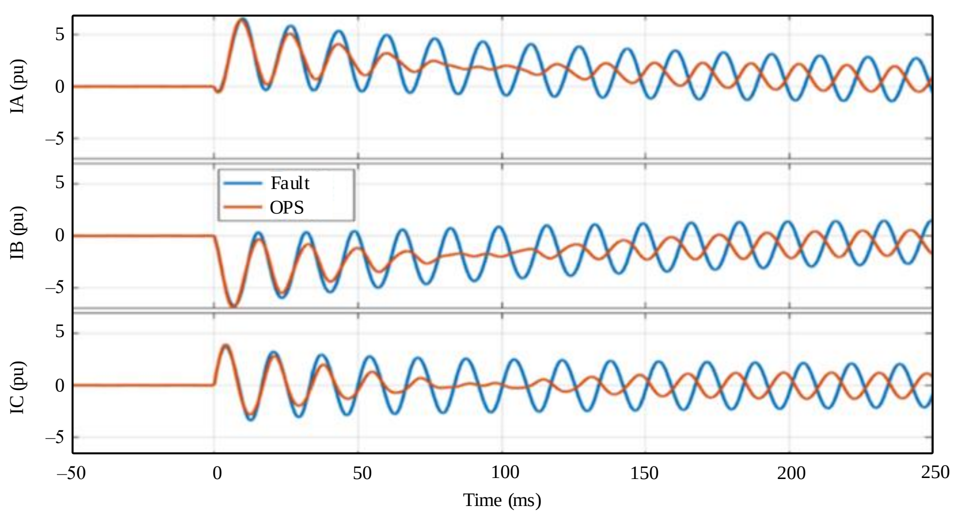

Figure 24: Behavior of Current Zero-Crossings During Fault and OPS [4]

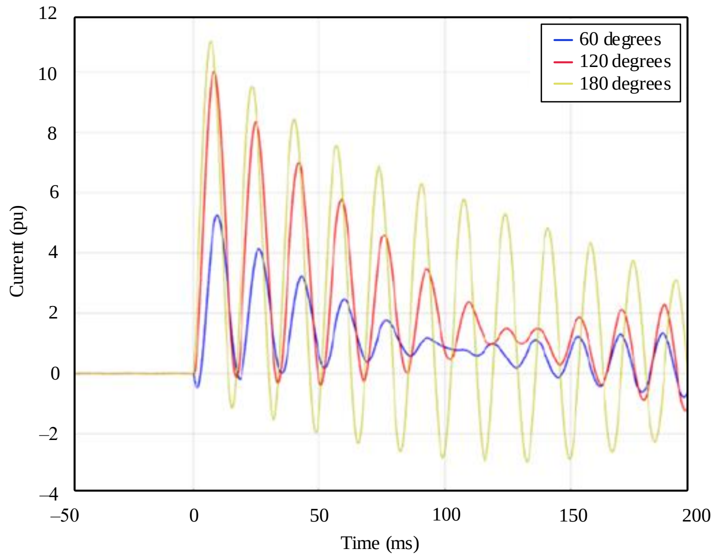

Figure 25: Impact of Synchronizing Angle on Delayed Current Zero-Crossings [26]

As stated previously (see Section 1.4), a generator breaker is likely to see greater than twice the system nominal voltage across its terminals prior to synchronization. For this reason, generator breakers are required to have a rated power-frequency withstand voltage greater than twice the rated breaker voltage [27].

4.2 Generator Breaker Technology and Arc-Voltage Considerations

Historically in North America, generator sizes outpaced the development of breakers. The currents on the low-voltage (LV) side of the GSU transformer is much higher than currents on the high-voltage (HV) side of the GSU transformer. Breakers with adequate interrupting capability on the LV side were neither available nor economical; consequently, unit breakers were applied on the HV side of the GSU transformer. However, there is an advantage of applying breakers on the LV rather than the HV due to the effect arc-voltage has on introducing current zero-crossings [7] [26] [27]. Breakers rely on a current zero-crossing to clear a fault, so obtaining a timely zero-crossing can make the difference between a successful current interruption or a breaker failure.

Breaker technology such as the older air-blast breakers or the newer SF_6 breakers have a relatively high arc-voltage in the vicinity of 3 kV to 4 kV compared to vacuum breakers with a 50 V arc-voltage. An arc-voltage is resistive in nature and acts in opposition to the voltage associated with a fault or an OPS. A fixed arc-voltage benefits an LV generator breaker significantly since the arc-voltage is a much greater percentage of the voltage level. Additionally, because the currents on the low-voltage side are higher, the relative arc-resistance is higher which reduces the X/R ratio resulting in a decay of any dc offset in the current and introduces current zero-crossings. Figure 26 shows the impact of a voltage arc on current zero-crossings depending on whether the breaker is located on the HV or the LV side of the GSU transformer. As evident from Figure 26, because of the arc-voltage, a

LV breaker introduces current zero-crossings on all phases and clears successfully. Whereas the HV breaker sees delayed current zero-crossings and clears much later.

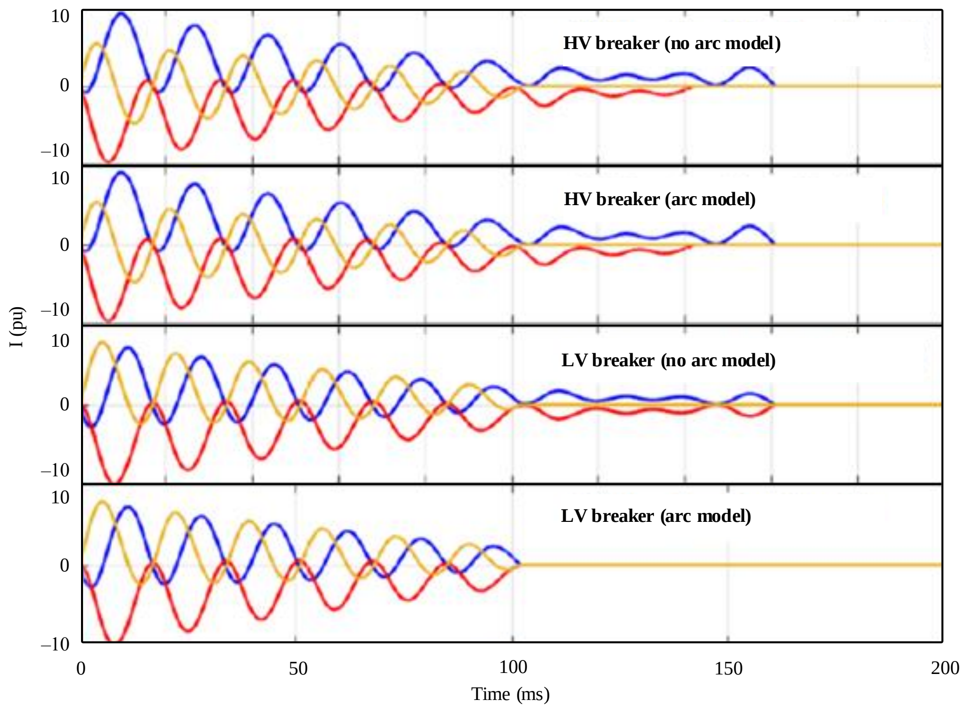

Figure 26: Impact of Breaker Arc-Voltage on Current Zero Crossings

In practice, delayed current zero-crossings can cause a failure to interrupt the current flow and an associated breaker failure trip may be required to clear the system condition. Several catastrophic failures of 500 kV SF_6 breakers have been experienced due to a decaying but persistent dc offset in the current and the associated lack of current zero-crossings [8]. IEC/IEEE Std 62271-37-013 [27] requires verification of a generator circuit breaker's capability to interrupt currents with delayed zero-crossings by use of computations that consider the effect of arc-voltage on the prospective currents resultant from a short-circuit or an OPS. As explained previously, the arc-voltage is expected to help induce a current zero-crossing within the maximum permissible breaker arcing time. If using stock inventory of transmission breakers for generator applications, IEC/IEEE Std 62271-37-013 [27] requirements need verification. The breaker manufacturer may be consulted to help verify a given application.

Generator breakers installed on the LV side are typically gang-operated with all poles closing within a few milliseconds of each other. In installations where the breaker is on the HV side of the GSU transformer, the breaker mechanism may allow independent pole operation, but the breaker poles are typically still operated together. For breakers that allow independent pole operation, the pole scatter may be larger. A pole scatter does not play a significant role during regular operation but can reduce generator torques and currents during an OPS [26].

4.3 Breaker Closure Timing

Breaker close time can impact synchronizing system performance (see Section 3.2.9.2). If the breaker close time is known within accuracy of ±0.030 s, then with a 0.067 Hz slip frequency, the error in Θ_C using (5) is less than 1 degree.

The breaker closing time can be determined by the methods discussed in Section 10.7. The low slip frequency requirement for synchronizing applications presents a more relaxed breaker closing time accuracy requirement than point-on-wave controlled switching applications [28].

The breaker mechanism may experience a slow closing time due to a lack of operation or from leaving a breaker open for a long time. The change in breaker closing time can have a detrimental impact on the quality of a synchronization. Manually operating the breaker multiple times, either during maintenance or before synchronization, can help prevent an increase in breaker operation time.

5. Synchronization Control Design

5.1 Manual Synchronization

The utilization of only a manual synchronizing scheme is the bare minimum system required for a synchronization. The breaker close circuit typically consists of a close contact from the manual breaker control switch (52GCS) wired in series with the synchronization enable switch (01). Figure 27 depicts a minimal manual synchronizing scheme design in a generator breaker close circuit.

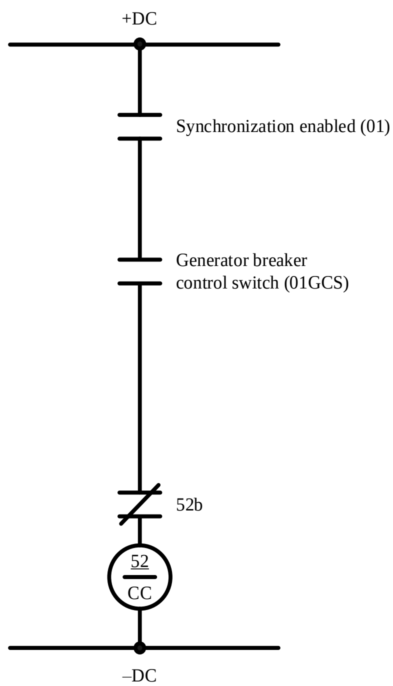

Figure 27: Simple Manual Synchronization Control Design

This is the least reliable synchronizing scheme design. The operator is required to match the generator voltage and frequency to the system through manual voltage regulator and prime mover speed control switches. The operator also has to initiate a breaker close command by visually observing the synchroscope and synchronism lamps. A well-trained operator can compensate for the delay associated with the breaker contact closure. They can judge the slip rate based on the synchroscope speed of rotation and initiate a breaker close at an advance angle before the pointer reaches the 12 o'clock position (0 degrees).

This synchronization practice requires adequate and consistent training to be successful. Operators need to be comfortable with the meter indicators and controls to help prevent human performance issues. They also need to be aware of conditions that may result in a synchronization failure and prevent breaker operation during these conditions.

There is nothing in place to prevent a faulty synchronization and this scheme is prone to human performance errors associated with generation operators. There is also little margin for error and the operation is susceptible to a synchronization failure.

5.2 Permissive Manual Synchronization

This scheme has the same design as the manual synchronization scheme with the addition of a synchronism-check (25) device. A contact from the 25 device is wired into the breaker control path of the close circuit to provide a permissive control function. Figure 28 depicts a typical permissive manual synchronization design in a generator breaker close circuit.

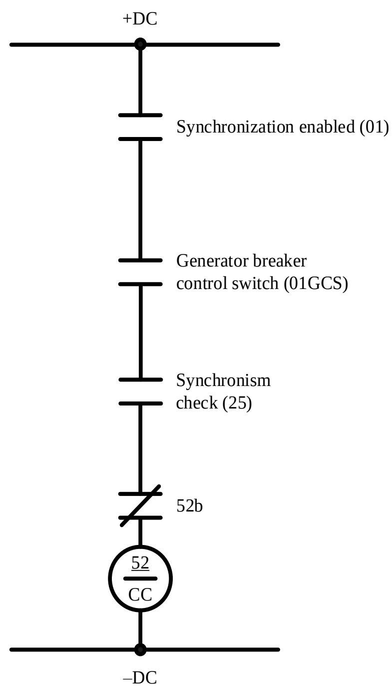

Figure 28: Permissive Manual Synchronization Control Design

This design improves the security of synchronizations compared to the scheme of Figure 27. The operator still has to perform the manual control of the generator and breaker closure. The improvement lies within the permissive contact of the 25 device, which prevents operations that are well outside of acceptable limits. However, this scheme can still be prone to human performance errors and possible errors associated with the 25 device (i.e., late closures).

5.3 Manual/Automatic Redundant Synchronization

A redundant approach to synchronizing in a generating station employs both a manual and an automatic control design. The breaker close circuit has independent close control paths manual and automatic operation. Figure 29 depicts a typical redundant synchronization control scheme design within a generator breaker close circuit [1].

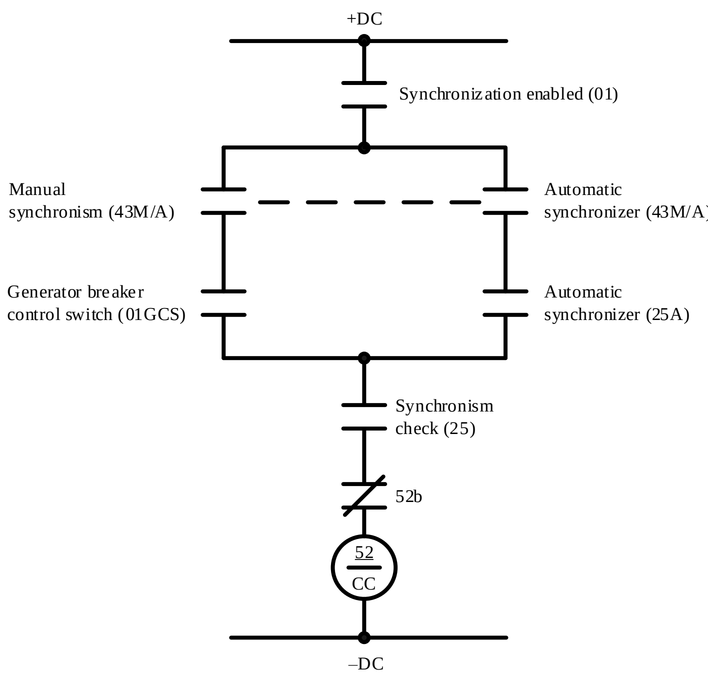

Figure 29: Redundant Synchronization Control Design [1]

This design provides a two-level system of supervision and improved reliability. The plant operator can select either the manual or the automatic control path for a synchronizing operation. In manual control mode, the operator is still required to perform the generator controls and initiate a breaker close command.

In the case that there is a failure in the automatic synchronizing system, the manual synchronization scheme is designed to operate in an independent manner. Once the selector switch is placed in the automatic position, the human element of breaker control is removed from the operation. Provisions may be made to bring the speed and voltage of the machine within the limits set on the autosynchronizer. The autosynchronizer issues commands to the generator control systems and issues a breaker close command at an optimal time.

A modern autosynchronizer typically compensates for breaker closing time and slip frequency, as discussed in Section 4.3. An autosynchronizer may also provide options to perform a synchronization when the generator's frequency and voltage are slightly higher than that of the system's, as discussed in Section 3.1.1 and Section 3.1.2, respectively.

A synchronism-check (25) device supervises both the manual and automatic synchronism paths to improve scheme reliability. It serves as the last line of defense for any failures in the synchronizing system.

5.3.1 Semi-Automatic Synchronization

A hybrid approach is to combine the best automation techniques with the capabilities that a human operator can add. A semi-automatic scheme, also referred to as a manual-supervised automatic synchronization, consists of a combination of human intervention and control system automation. This scheme employs the same redundant design covered in Section 5.3—however, the manual control close path is only used when there is a failure in the autosynchronizer system. Typically, generator operators are responsible for manually issuing voltage and frequency adjustments to the generator control system. They modify and try to match the generator voltage and frequency to that of the interconnecting system. After the operators have aligned the two electrical systems, the autosynchronizer initiates a close command to the synchronizing breaker.

5.3.2 Automatic Synchronizer with Operator Window Option

The automatic synchronizer may be connected in series with an operator close contact as shown in Figure 30. In this scheme, a plant operator holds the operator-controlled contact closed presenting a window for the autosynchronizer to issue the close command at the precise time. As with all manual/automatic schemes, a synchronism-check relay may be wired in series (not shown in Figure 30) to improve scheme reliability, resulting in three-level supervision [1] [2].

The disadvantage of this approach is that plant operators may be tempted to close their contact at angles far from the correct angle and hold the contact closed as the synchroscope rotates, eventually reaching the correct angle [1] [2]. This defeats the reason of having the operator in the circuit. For this approach, operator training is required to close within an acceptable angle that would not cause catastrophic damage even if closure occurred at that angle.

Alternatively, logic may be included that locks out the synchronization process if the manual close command is issued outside the correct angle window [1] [2]. This forces the operator to provide the manual close within the acceptable angle limits.

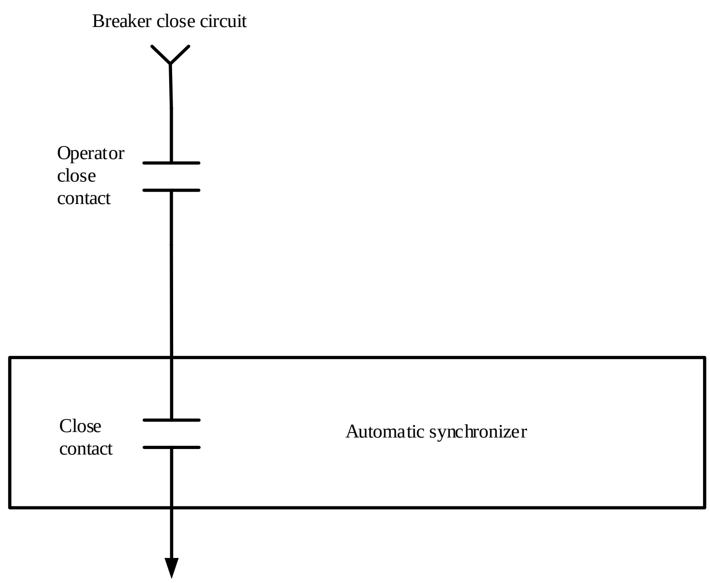

Figure 30: Manually Supervised Automatic Synchronization [1]

6. Generation Portfolio

Synchronizing systems are applied depending on the generator prime mover, the age of the unit, and its associated control system. With advancements in modern generator and prime mover control systems, a recent trend has been to move the autosynchronizer function inside the control system. When automatic synchronization is performed by the control system, it is advisable to have an external standalone synchronism-check device to supervise the control system close command. Some small generators, such as those used for emergency backup purposes, may not have an external synchronism-check relay installed.

6.1 Generation Type

6.1.1 Traditional Generators

Most traditional generators used for power generation are designed to be synchronized with the generator prime mover at full speed. Types of generator prime movers that often fall into this category include steam turbines, gas turbines, hydraulic turbines, and reciprocating engines.

A sample synchronizing procedure, with reference to Figure 31, is described as follows:

- The turbine is rolled to near-synchronous speed, say 95%.
- Excitation is applied to the field winding.
- The running system voltage is applied to one input to the synchroscope and the incoming generator voltage is applied to the other synchroscope input.
- The main generator breaker disconnects are closed.
- Turbine speed is increased to 100% of rated.
- Excitation is adjusted so that incoming generator voltage magnitude is just above running system voltage magnitude, as measured across the open generator breaker[2].
- The synchroscope is turned ON.
- Turbine speed is adjusted so the scope pointer rotates in the clockwise direction[3] and rotates slowly implying a low slip frequency.
- When the synchroscope is about 5 minutes to 12 o'clock, the generator breaker is closed.

The generator is suitable for operation upon successful completion of this process.

[2] This so that when the generator breaker is closed, there is no var import to the GSU/generator to avoid system abnormal conditions and possible relay misoperation (see Section 3.1.2 and Section 3.1.7).

[3] This so that when the generator breaker is closed, there is no watts import to the GSU/generator to avoid possible relay misoperation (see Section 3.1.1 and Section 3.1.7).

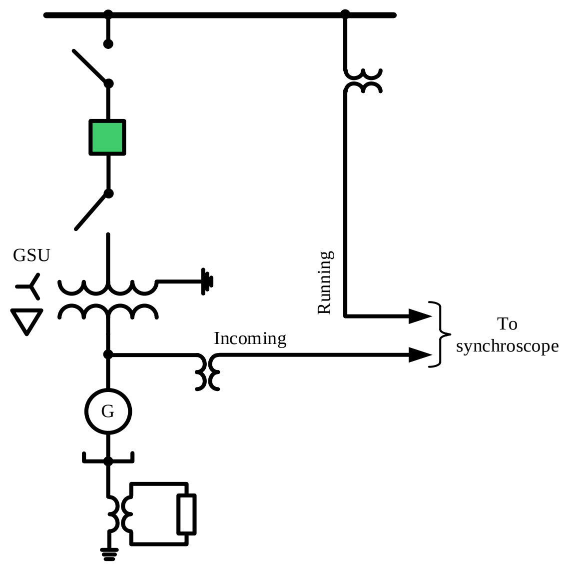

Figure 31: Sample Synchronization Procedure One-Line Diagram

6.1.2 Cross-Compound Generators

Cross-compound units consist of two generators, often driven by independent steam turbines, where both generator terminals share a common bus and use a single generator breaker to connect to the system. Cross-compound generators synchronize to each other before synchronizing to the system. There are two methods commonly applied to synchronize cross-compound generators to each other, both of which require equipment and controls beyond the scope of a traditional synchronizer.

The first method involves applying field current to each of the cross-compound generators at turning gear with very low speed. The steam valves are then cracked open to slowly accelerate the generators, allowing them to electrically synchronize at a low speed. Once the cross-compound generators are synchronized, they are accelerated together to synchronous speed. Note that the high-pressure turbine generates and the intermediate-pressure turbine motors during this period.

The second method involves accelerating both units to an intermediate speed before applying the field to each generator. In this case, a speed matching control valve is used to closely match the speed of each generator prior to applying the generator field current. Once the field current is applied to each unit, the generators synchronize together and are systematically accelerated to synchronous speed.

Once cross-compound generators reach synchronous speed, a traditional synchronizing system is utilized to connect the cross-compound generators to the system. It is important to note that each cross-compound generator typically has separate excitation and speed control systems. Therefore, voltage and speed adjustments made by the synchronizing system are simultaneously applied to each cross-compound generator.

6.1.3 Black Start or Emergency Backup Generators

Generators that are utilized for black start or emergency backup service have an additional feature in the synchronizing system that allows for the generator breaker to be closed on to a de-energized power system. Synchronizing schemes for black start generators may need modifications to permit closing with a live-generator/dead-system or dead-generator/dead-system scenario. See CIGRE TB 810 "Protection and Automation Issues of Islanded Systems During System Restoration/Black Start" [29] for further information on black start applications.

6.2 Local versus Remote Synchronization Initiation

Unmanned generation assets are now commonplace. As a result, many generation assets are set up so that they can be remotely controlled, started, and connected to the power grid. Automatic synchronizing systems are required when local operator intervention is not present. Unmanned sites typically use the autosynchronizer as the primary means for synchronization. Manual synchronizing systems cannot be the sole synchronizing system for an unmanned generating facility and may be implemented as a backup system to the automatic synchronizing system.

7. Synchronizing System Configurations

7.1 Dedicated Synchronizing System

A dedicated synchronizing system is the most common and straightforward synchronizing system. It may include a synchronism-check relay, an autosynchronizer, and a single (or dual) breaker arrangement to synchronize one generator. Manual synchronization operation requires the manual and visualization facilities (see Section 3.2) necessary for a successful synchronization operation. For dual synchronizing breaker arrangements, having a synchronism check function for each breaker eliminates a common mode failure between the synchronizing system and synchronism check function. Generating units that only allow automatic synchronization operation do not require a synchronization panel. This limits the design requirements for a synchronization system on this type of system.

7.2 Shared or Common Synchronizing System

It is sometimes the case that a single synchronizing system is shared for several generators, especially for older generators. This application is illustrated in Figure 32. The power plant control rooms have a single synchroscope (SS), a set of incoming and running voltage meters, and synchronizing lights. The operators select the generator and breaker desired for the synchronizing operation. The synchronizing selection switch or a control system relay then energizes the common synchronizing circuit with the desired generator and system voltages. The system is designed such that the breaker close command passes through a synchronism-check relay to the selected synchronizing breaker.

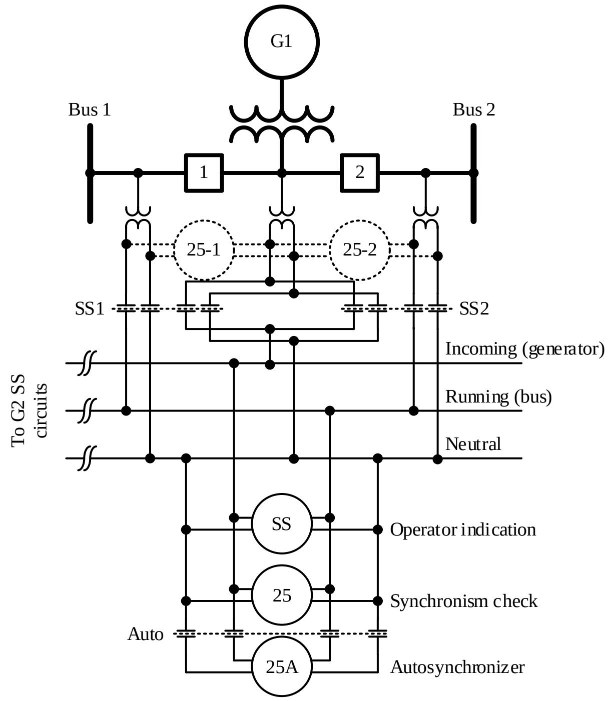

Figure 32: Synchronizing system ac Circuit

The circuits and interlocks can be complex and require attention to detail during commissioning. A disadvantage of this configuration is that if modifications are made to the common circuit, consideration may be given to recommissioning the synchronizing system for all generators.

When the synchronizing system is shared, one approach is to separate the series synchronism-check relay and install one dedicated/hard-wired synchronism-check relay per breaker. This approach guards against any errors in the switching, wiring or otherwise, that might contribute to a faulty synchronization.

7.3 Synchronizing Multiple Generators to a Single Bus

It is common to see multiple generators paralleled to a medium-voltage switchgear bus for the purpose of sharing a GSU transformer. When the generators are not acting as a black start resource, the shared bus is energized by the system. When the shared bus is energized by the system, if the generators have independent synchronizing systems, the generators may be synchronized simultaneously. If synchronized simultaneously, a consideration is to avoid an exchange of power amongst the generators to prevent an inadvertent operation of protective elements such as reverse power.

If the bus serves as a point to aggregate emergency backup generators for a facility, all of the generators may start simultaneously on loss of normal utility power. However, the synchronizing control system selects one generator as the lead generator and closes the lead generator breaker to re-energize the dead switchgear bus. The remaining generators subsequently synchronize to the lead generator in a traditional manner.

7.4 Synchronizing Across Delta-Wye Generator Step-Up Transformer

Some generator installations have electrical system configurations where there are no VTs between the synchronizing breaker and the delta-wye connected GSU transformer. In this application, as shown in Figure 33, a phase-to-neutral voltage in the switchyard is used to counteract the 30-degree phase-shift introduced by the GSU transformer. Auxiliary VTs that can compensate for the magnitude mismatch may be required in these applications when the running and incoming synchronizing VT secondary signals do not match and when analog instrumentation, such as a synchroscope and synchronizing lights, are used in a synchronizing scheme. The need for compensation is also dependent on whether the applied synchronizer and synchronism-check relays can provide internal compensation. These auxiliary VTs may compensate for magnitude differences between the generator and system secondary voltages. Synchronizing instruments such as synchroscopes, analog meters, and synchronizing lights can present a significant load. Hence, auxiliary VTs are sized accordingly. Auxiliary VTs may also be needed to provide isolation of the ground reference between the yard and the synchronizing panel.

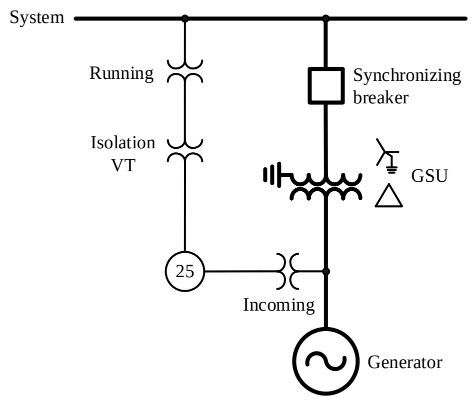

Figure 33: Synchronizing Across GSU Transformer with Isolation VT

8. Synchronization Failure Detection for Protection and Alarming

8.1 Slow-Close Detection Logic

The close mechanism of a circuit breaker may operate in a delayed manner during a synchronizing operation. In this case, the synchronizing scheme sends a close command at the correct instant, but the breaker closes slowly due to an internal problem. The slip causes the angle across the open breaker to increase to a potentially damaging value.

Some generator protection relays have logic to detect a slow close. An example of this logic is shown Figure 34 [30]. The logic monitors the angle from the instant that a close is initiated. If the angle reaches a set value and the breaker is still open, then the logic output asserts. If not available in the relay, this logic may be implemented as programmable logic in some relays. The output may be used to trip the breaker-failure zone to protect the generator or may be used to issue an alarm. See IEEE Std C37.119 [30] for more information on this scheme.

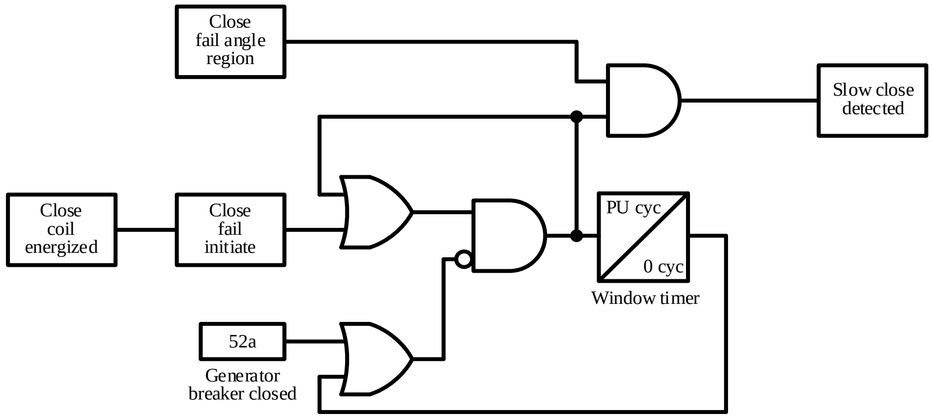

Figure 34: Slow Close Detection Logic [30]

8.2 Out-of-Phase Synchronization Detection Logic

An out-of-phase synchronization (OPS) occurs when a synchronizing scheme sends a close command at the wrong instant. The most common cause is a voltage circuit wiring error. The associated angle errors can be excessive (±60˚, ±120˚, or 180˚). For an OPS, the slow-close detection logic of Figure 34 cannot be relied upon. Commonly applied generator protection elements such as inadvertent energization, loss of field, out-of-step, reverse power, and differential, are not designed to detect this condition and also do not provide reliable protection for an OPS. In addition, dedicated OPS logic provides unambiguous targeting. It has been the case that a generator was subjected to multiple OPS events before the problem was discovered.

A scheme that has been used to detect an OPS is shown in Figure 35 [4] [26]. The scheme consists of an overcurrent element that can operate for a short duration following a breaker close. The output of this logic may be used to trip or alarm. If used to alarm, it may be set sensitively to remain dependable for OPS with low synchronizing angles (e.g., less than 60 degrees). If configured to trip, the consequences of delayed current zero-crossings require evaluation. For instance, if the breaker cannot interrupt currents without zero-crossings, the scheme may be set to trip only for a 180-degree synchronization but not a 60-degree or a 120-degree synchronization (see Section 4). This can be achieved by adjusting the overcurrent element's pickup setting using Equation (2) to trip for the desired synchronizing angle. If the breaker is not rated to handle the transient recovery voltage (TRV) following a 180-degree synchronization, then tripping may be delayed. This scheme only provides detection after an OPS has taken place and can reduce damage but not prevent it. Therefore, this scheme is not a replacement for the commissioning practices outlined in Section 10 that can be used to prevent an OPS. This scheme is also not a replacement for the slow-close detection logic discussed in Section 8.1, which can detect a problem before the breaker closes.

The OPS detection scheme of Figure 35 can be implemented using programmable logic available in many relays. Generator relays may also include the flexibility to implement this scheme as part of the inadvertent energization scheme by disabling the voltage supervision that is normally used to identify a de-energized generator.

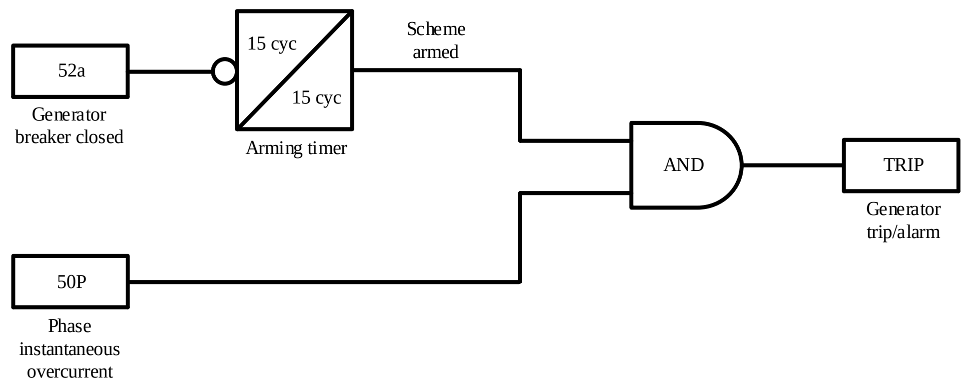

Figure 35: Dedicated Out-of-Phase Synchronization Detection Scheme

The scheme of Figure 35 can lose security in certain black start applications where closing the generator breaker energizes the GSU transformer and the resulting inrush current is higher than the pickup setting of the 50P element. In these applications, additional supervision using an operator-controlled dead-bus close permissive control, 43DB Figure 36 [2], improves scheme security and is shown in Figure 36 [26]. In this scheme, the human operator confirms the intention of closing the synchronizing breaker to energize a dead bus or GSU transformer (asserting 43DB), thereby providing security.

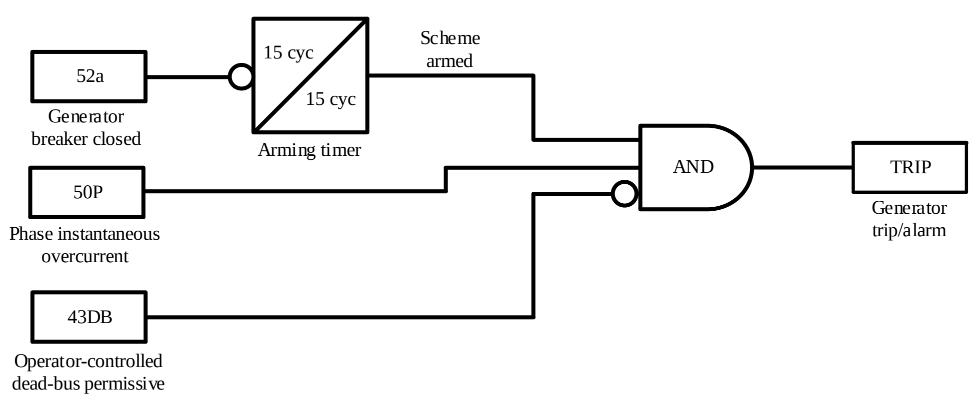

Figure 36: Out-of-Phase Synchronization Detection for Black Start Applications

The scheme of Figure 35 works well in applications with a LV generator breaker. However, in dual-breaker bus configurations (see Figure 32), there is a possibility of closing either Breaker 1 or Breaker 2 to synchronize the generator. If Breaker 1 is already closed and Breaker 2 is subsequently closed, a high bus current through Breaker 2 might flow that does not correspond to the generator current and the scheme of Figure 35 could lose security. In such applications, verifying the status of both breakers and using the partial differential current of the two breakers, as shown in Figure 37, improves scheme security [4]. The partial differential current is shown as the magnitude of the phasor sum of the two breaker phase currents.

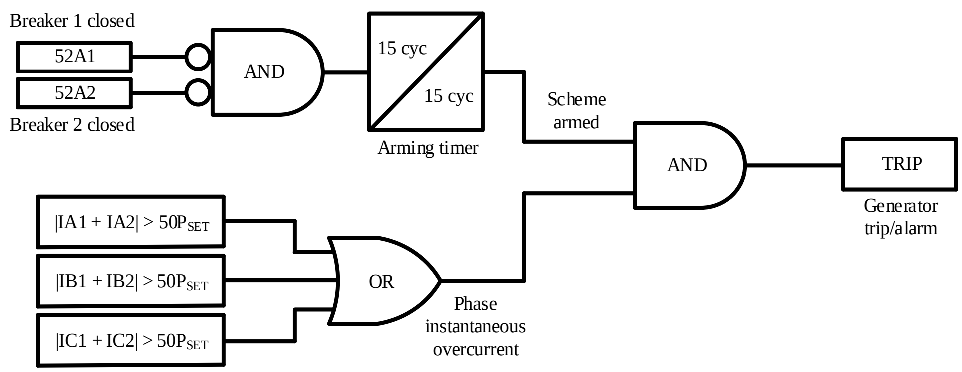

Figure 37: Out-of-Phase Synchronization Detection for Dual-Breaker Bus Applications

Bus configurations in some generating plants can provide additional operational flexibility using disconnect switches, as shown in Figure 38. For example, if 5D7 and 5D8 are open, 5D3 and 5D4 are closed, and 5D9 and 5D10 are open, then Breakers 5CB6 and 5CB7 may synchronize Generators G3 and G4. If the position of these switches were reversed, then Breakers 5CB6 and 5CB7 no longer synchronize Generators G3 and G4.

Because of the additional operational flexibility where closure of a breaker does not imply synchronizing a particular generator, the scheme of Figure 37 requires additional security considerations. One proposed solution is for the HV OPS detection relays to send the trip to each generator relay. The generator relay only trips the LV generator breaker if the generator is energized with no load current. Generators, even those operating in condensing mode, typically carry measurable reactive load. Therefore, a lack of load current is indicative of the generator that is being synchronized.

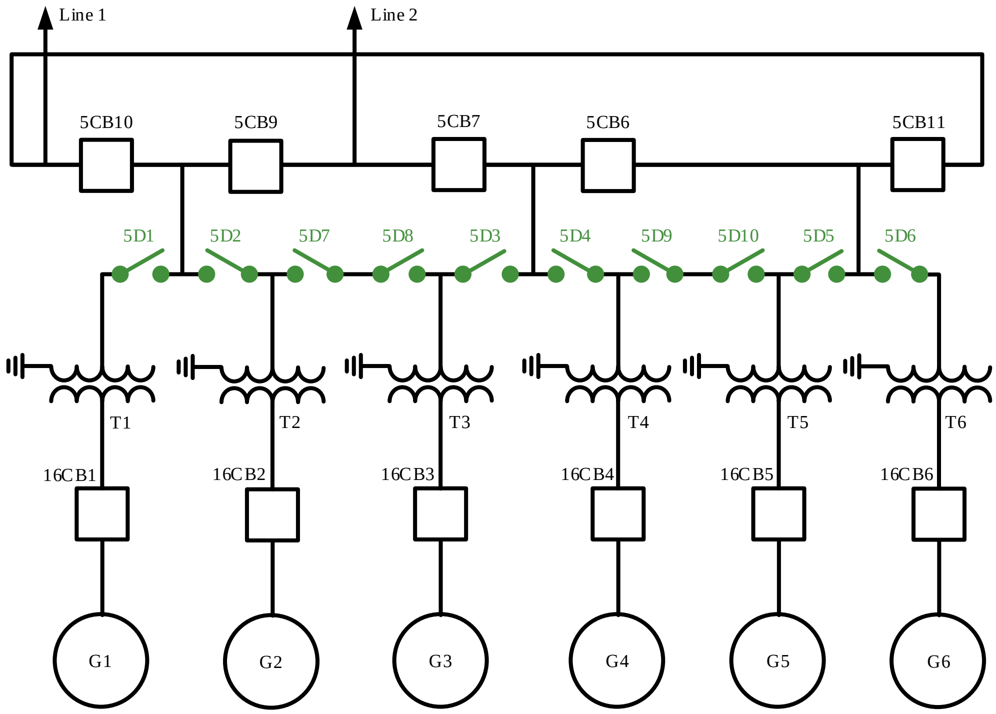

Figure 38: Use of Disconnect Switches to add Operational Flexibility [4]

An alternative to the scheme of Figure 35 that does not rely on breaker statuses to facilitate various types of applications is shown in Figure 39 [4]. The scheme is armed by a low-set overcurrent element (50L). Set the dis-arming element above GSU magnetizing current and below the minimum current associated with an online generator—typically in the range of 2% to 8% of generator rating. A lower setting will minimize the chances of a generator being online with the scheme armed. Additional security relative to the scheme of Figure 35 is provided by shortening the arming duration to two to three cycles and by use of a rising-edge trigger for the 50P element. The dropout of the arming timer can be set in the range of two to three cycles to provide a short window of opportunity for the 50P element to assert. For black start applications, similar enhancements as Figure 36 are applicable to the scheme of Figure 39.

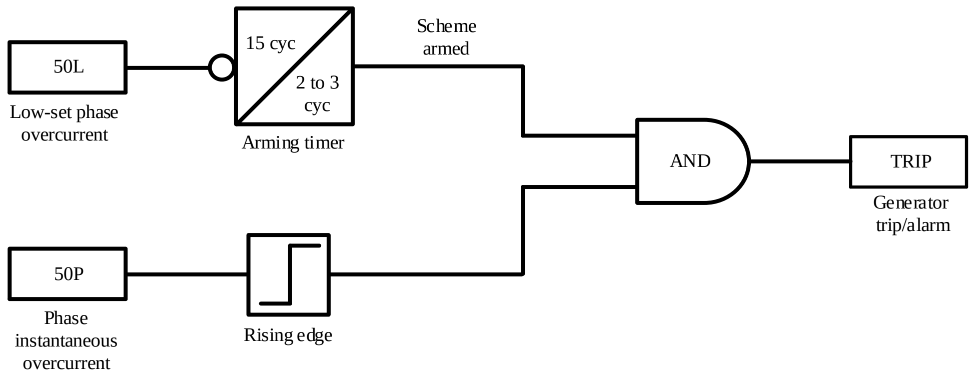

Figure 39: Out-of-Phase Synchronization Detection Scheme Without Reliance on Breaker Status

8.3 Reverse Power (32)

The reverse power element, although not designed for this purpose, can sometimes pickup for a faulty synchronization. The intent of the reverse power element is to provide protection for scenarios where the generator has lost the mechanical input energy from the prime mover, such as motoring or a controlled unit shutdown. In these scenarios, the generator begins to absorb real power from the system in an attempt to operate as a motor [22].

Faulty synchronization as a result of an OPS or a high-slip synchronization can also cause a transient power flow. However, the protective element time delays are typically too long for the element to operate for this condition. Real power may be absorbed by the generator in an attempt to change the speed of the prime mover to bring it in alignment with the system frequency. Typically, reverse power elements pickup during the transient power flow but do not trip. The generator power and the performance of the reverse power element (32P1) for a 180-degree OPS is shown in Figure 40 [4]. The reverse power element was set with a real power (P3Φ) pickup of –3.8 percent and to alarm after 20 seconds and trip after 140 seconds. The reverse power condition lasts for less than 0.5 seconds and does not trip.

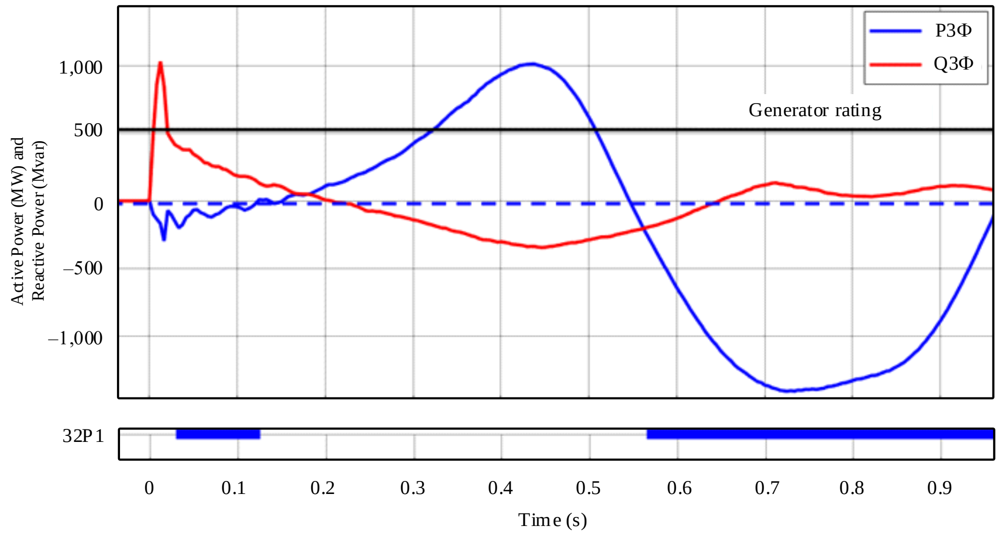

Figure 40: Reverse Power Element Response for an Out-of-Phase Synchronization

The reverse power element may also trip if the VTs wired to the generator relay are inverted in polarity and the machine starts generating. However, the reverse power element is not designed to detect wiring errors or a faulty synchronization and is therefore not used for this purpose.

8.4 Loss-of-Field (40)

A loss of field element is designed to protect a generator when it loses the field excitation current within the generator. This abnormal operating condition causes the generator to absorb reactive power from the system in an attempt to maintain synchronism with the grid and operate as an induction motor [22].

The large voltage magnitude variance during an OPS can cause a transient reactive power flow. The machine absorbs reactive power from the system as the synchronizing torque drives the two systems into a state of equilibrium. This reaction may trigger the loss of field element to operate when it is set sensitively and with a short time delay.

This protection scheme may be able to provide partial protection for an OPS. However, the loss of field element is not designed to detect fault synchronizations and is therefore not used for this purpose.

9. Post Out-of-Phase Synchronization Analysis

9.1 Electrical Torque Stress

Generator turbines are typically expressed or modeled as a single unit. Investigating further, the turbine is made up of a shaft interconnecting multiple shaft sections. Steam turbines shaft sections typically consist of high-pressure, intermediate-pressure, and low-pressure sections; however, other arrangements exist. Gas turbines are typically simpler arrangements. Turbines connect to the generator and the exciter (if it is a rotating exciter). Each of these rotating elements have a unique mass—these have a direct impact on the natural frequencies of the turbine shaft system.

The maximum electromagnetic torque generated from an OPS can be expressed by the following equation [26]:

$$\boldsymbol{T_{em}} = \frac{\boldsymbol{V^2}}{(\boldsymbol{X_d''}+\boldsymbol{Z_{GSU}}+\boldsymbol{Z_{Sys}})} \times \left[\sin(\boldsymbol{\delta_0}) + 2\sin\left(\frac{\boldsymbol{\delta_0}}{2}\right)\right] \tag{6}$$

Where:

V: The generator and system voltage magnitude (typically assumed to be 1 pu with both the generator and system voltages at nominal)

δ_0: the angle difference between the generator and system at the point of closure

The instantaneous electromagnetic torque the machine experiences during the event can be expressed by the following equation with respect to the synchronizing angle (δ_0) [3]:

$$\boldsymbol{T_E} = \frac{\boldsymbol{V^2}}{(\boldsymbol{X_d''}+\boldsymbol{Z_{GSU}}+\boldsymbol{Z_{Sys}})} \times \left[\sin(\boldsymbol{\delta_0}) - 2\sin\left(\frac{\boldsymbol{\delta_0}}{2}\right)\cos\left(\boldsymbol{\omega t} + \frac{\boldsymbol{\delta_0}}{2}\right)\right] \tag{7}$$

Faulty synchronizations are transient in nature requiring some time before equilibrium can be established. This transient may result in multiple torque components being applied to the generator. Consequences of a synchronization failure are discussed in Section 1.4.

9.2 Damage Assessment

The electromagnetic forces that occur during a faulty synchronization are impressed onto the stator windings, the winding support structure, the winding slot wedges, the stator core, rotor body, and into the rotor field windings. The winding supports are designed to endure small transients during a successful synchronization. However, the larger transients during an OPS can result in significant damage.

The mechanical torques impressed upon the turbine are the result of a large difference in the mechanical input power that is driving the prime mover and the electrical output power that is removed from the shaft (produced by the generator). There are several OPS scenarios that can occur. As stated in Section 2.1.2, the most extreme scenario is when the generator leads the system voltage. The shaft transient torque during this condition is the highest and can be higher than a three-phase fault shaft transient torque. Thus, the actual shaft transient torques are not directly related to the measured transient stator currents (see Section 2.1.2).

Under synchronizing conditions, the turbine is rotating at synchronous speed with little torque through the rotating turbine shaft and the connected body elements because the unit is at “full-speed no-load”. The resultant transient torque magnitude during an OPS can increase with higher total turbine inertia. The torsional stress is typically concentrated through the generator journal to the generator/turbine coupling and then into the turbine journal. If the transient torque is extreme, the coupling and rotor elements can yield which can result in high coupling and journal runouts[4]. If the runouts exceed manufacturer's recommendations, the rotors may need to be removed and inspected thoroughly to determine repair alternatives.

It is also possible to incur damage in the exciter coupling and rotor elements—see real-world example in Section 1.4.2 where an 800 MVA generator had rotor damage. During the transient torque event, the generator rotor can move enough to cause a rub in a seal which can result in high exciter vibration. If the vibration is above the automatic trip point or deemed by operators to be extreme, the unit is shutdown to limit further damage. In the case where damage has occurred in the generator or on turbine elements, the exciter components require thorough inspection, and the rotor runouts measured.

If an OPS has occurred on the unit, then it is advisable to remove the links (as shown in Section 10.4.2) and fully test the generator to check that it was not damaged by the OPS. The corrected synchronizing circuits can be tested using a backfeed test before returning the plant to service. Removing and reinstalling the links of a large generator can take nearly a day, which needs to be planned for.

Areas to inspect include:

- Stator end-winding supports for movement or gaps in winding filler blocking
- Loose brackets or bolting
- Loose ties or blocking
- Cracked insulation components
- Indications of movement of stator-core components
- Rotor under retaining ring for winding or insulation element movement
- Rotor retaining ring movement
- Rotor runouts at coupling and near journal
- Damaged coupling bolts
- Housing seals rubbed or damaged
- Damaged coupling hubs
- Movement of coupling on shrink hub or pins[5]
- Bearing damage
- Exciter winding, collector rings, lead connections, and excitation components
- Generator breaker for damage connections or controls
- Generator iso-phase or phase lead damage
- Generator step-up transformer oil sample analysis and internal winding inspection

Inspection of shaft and coupling components may require non-destructive examination techniques to check for cracks or material deformation. For hollow bore shafts this may

[4] Further information on journal runouts can be located in reference [31].
[5] Further information on shrink hubs or pins can be located in reference [31].

require the removal of the bore plug and an internal bore inspection for indications of material deformation or cracks.

If the OPS was severe, electrical tests can be made on the generator stator windings, generator rotor, exciter windings, excitation components, and the GSU transformer to determine if damage has occurred. These tests may include:

- Generator dc overpotential and/or very low frequency (VLF) tests (stator windings)
- Generator rotor pole balance or recurrent surge oscillograph tests (rotor windings)
- Exciter winding insulation and pole balance tests
- Generator step-up transformer sweep frequency response, dissolved gas analysis (DGA), and insulation tests

9.3 Evaluating Damage Extent

The transient torque (moment) due to an OPS results in rotor torsional stress which is cumulative damage if allowed to re-occur. This mechanical stress may cause eventual material fatigue. While starts, stops, and full-load rejections, have different stress concentrations compared to OPS transient torques, they all contribute to the loss-of-life of the rotating forgings, shafts, and couplings. Therefore, the percentage of life a turbine has lost due to a faulty synchronization requires consideration of the entire turbine history, i.e., any previous loss-of-life events are added to the faulty synchronization.

Figure 41 shows an example typical relationship of cyclic damage to a material. Note that this example does not include any factors for temperature. Turbine rotors operate at temperatures near to the inlet steam temperatures for each element. While synchronizations occur at startups, the turbines are prewarmed to prevent any rotating component interference. In addition, startups are typically classified as cold, warm, and hot, to distinguish the starting scenarios.

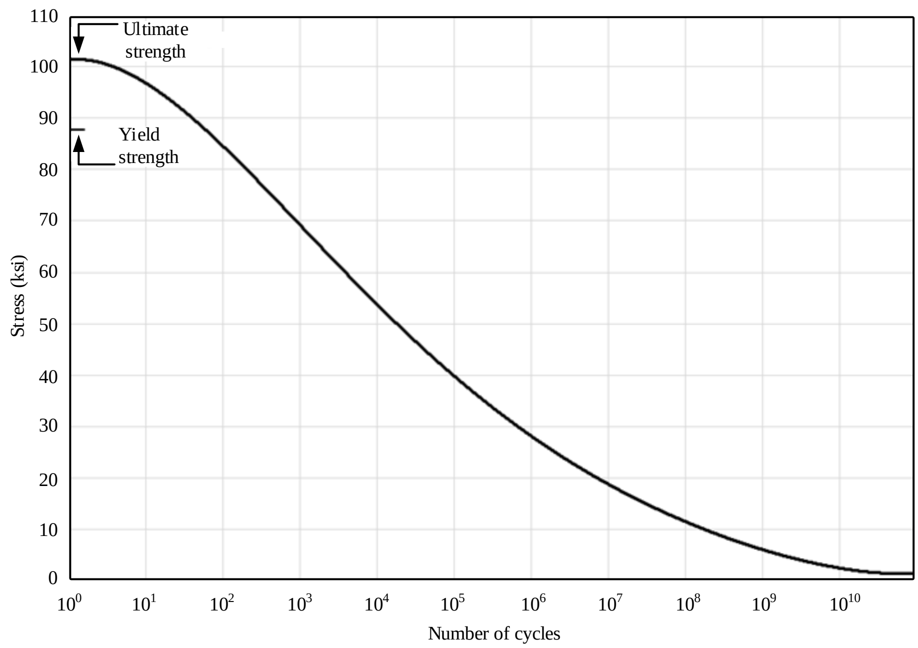

Figure 41: Typical Stress to Number of Cycles to Failure Relationship

Loss of shaft life is a function of the mechanical stress magnitudes and the duration the turbine was exposed to the stress. The duration of the stress exposure is typically referred to as the number of stress cycles. Analysis of each OPS can help determine the torque stress and potential loss-of-life [13]. To account for the number of stress cycles, the torque is summed/integrated until the oscillations dampen and the magnitudes decay to a level below the turbine fatigue limit.

9.4 Electromagnetic Torque from Event Report Data

There are no transient torque requirements for a generator other than the IEEE Std C50.12 [5] and IEEE Std C50.13 [6] requirements to withstand a three-phase fault at its terminals. The transient torque from an OPS event/transient record can be calculated and compared to that of a three-phase fault at the generator's terminals. A similar torque calculation may be performed to compare the transient torque from an OPS to external faults that a generator has experienced in its lifetime.

Several methods to calculate electromagnetic torque have been presented [32]. The method that uses the generator terminal voltages and currents is most suitable to evaluate severity of an OPS because these quantities are commonly available from event report data. The method to calculate the electromagnetic torque using event report data is detailed in [33] and is illustrated in this section using 60 Hz system 180-degree OPS [4].

Our starting point is the event report data—the phase currents and phase voltages measured at 16 samples-per-cycle (960 Hz)—as illustrated in Figure 42.

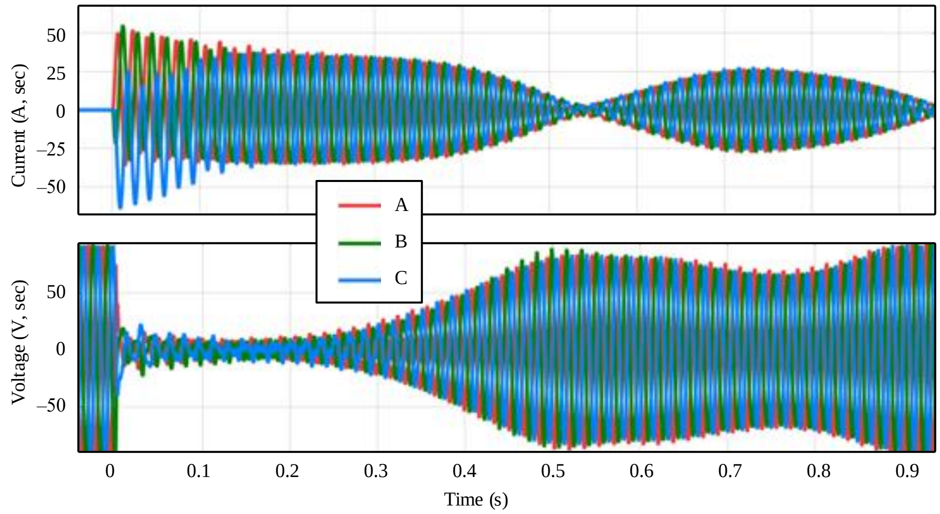

Figure 42: Phase currents and voltages for a 180-degree OPS [4]

The phase currents and phase voltages are then used to calculate phase-to-phase voltages that have been compensated (*$VABcomp_k$ and $VCAcomp_k$*) for the stator winding resistance (R_S), as shown in Equations (8) through (13). The subscript *k* in these equations represents the present sample; likewise, *k–1* would represent the previous sample.

$$\boldsymbol{IAB_k = IA_k - IB_k} \quad \textbf{(8)}$$

$$\boldsymbol{ICA_k = IC_k - IA_k} \quad \textbf{(9)}$$

$$\boldsymbol{VAB_k = VA_k - VB_k} \quad \textbf{(10)}$$

$$\boldsymbol{VCA_k = VCA_k - VA_k} \quad \textbf{(11)}$$

$$\boldsymbol{VABcomp_k = VAB_k - IAB_k \bullet R_S} \quad \textbf{(12)}$$

$$\boldsymbol{VCAcomp_k = VCA_k - ICA_k \bullet R_S} \quad \textbf{(13)}$$

The compensated phase-to-phase voltages are then integrated using the trapezoidal rule using Equations (14) and (15). They are subsequently multiplied by the base angular frequency (ω_b) in Equations (16) and (17) to obtain the phase-to-phase flux quantities (*φAB and φCA*).

$$\boldsymbol{intVAB_k = \frac{h}{2} \bullet (VABcomp_k - VABcomp_{k-1}) + intVAB_{k-1}} \quad \textbf{(14)}$$

$$\boldsymbol{intVCA_k = \frac{h}{2} \bullet (VCAcomp_k - VCAcomp_{k-1}) + intVCA_{k-1}} \quad \textbf{(15)}$$

$$\boldsymbol{\varphi AB_k = \omega_b \bullet intVAB_k} \quad \textbf{(16)}$$

$$\boldsymbol{\varphi CA_k = \omega_b \bullet intVCA_k} \quad \textbf{(17)}$$

Event reports may be triggered at a non-deterministic time where the calculated flux has a dc component that requires removal [33]. The dc component of the flux in the first three cycles of the event report, assuming it contains steady-state/pre-synchronization data, is calculated using Equations (18) and (19) and removed to calculate the modified flux values (*φABm and φCAm*) as shown in Equations (20) and (21).

$$\boldsymbol{DCAB = \frac{1}{3 \bullet SPC} \sum_{j=0}^{3 \bullet SPC-1} \varphi AB_j} \tag{18}$$

$$\boldsymbol{DCCA = \frac{1}{3 \bullet SPC} \sum_{j=0}^{3 \bullet SPC-1} \varphi CA_j} \tag{19}$$

$$\boldsymbol{\varphi ABm_k = \varphi AB_k - DCAB_k} \tag{20}$$

$$\boldsymbol{\varphi CAm_k = \varphi CA_k - DCCA_k} \tag{21}$$

The modified flux values and the phase-to-phase currents are then used to calculate the electromagnetic torque (Tem) as shown in (22). To aid analysis, this torque may be plotted as a per-unit quantity, as illustrated in Figure 43. The maximum electromagnetic torque in Figure 43 is 3.65 p.u.

$$\boldsymbol{Tem_k = \frac{2}{\sqrt{3}} \bullet (\varphi CAm_k \bullet IAB_k - \varphi ABm_k \bullet ICA_k)} \tag{22}$$

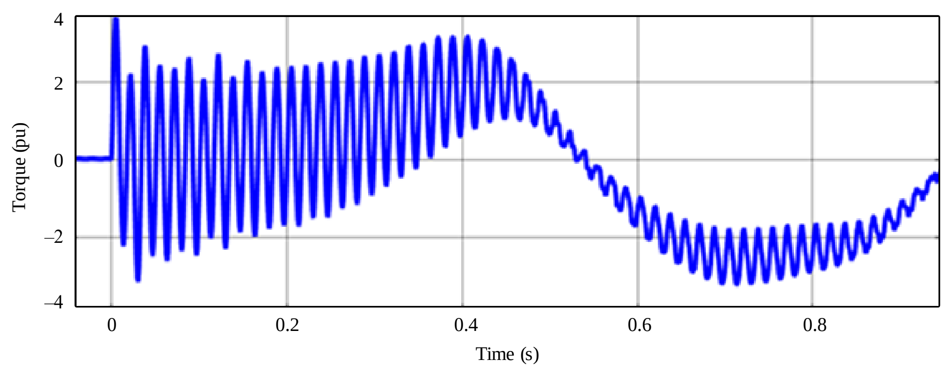

Figure 43: Instantaneous Electromagnetic Torque during a 180-degree OPS [4]

This maximum OPS torque can be compared with the theoretical maximum electromagnetic torque for a three-phase fault ($T_{3\Phi}$) at the generator terminals as calculated in (23) [1]. The generator associated with the OPS of Figure 43 had an X_d" of 0.180 p.u.—therefore, $T_{3\Phi}$ evaluates to 5.55 p.u., higher than the 180-degree OPS torque of 3.65 p.u.

$$\boldsymbol{T_{3\Phi} \cong \frac{V^2}{X_d''}} \tag{23}$$

If data is available from previous external faults, the same approach outlined in this section can be used to calculate the electromagnetic torque. The torque for an external fault on the transmission system is shown in Figure 44. External faults typically result in significantly lower torque and last for a shorter duration than an OPS.

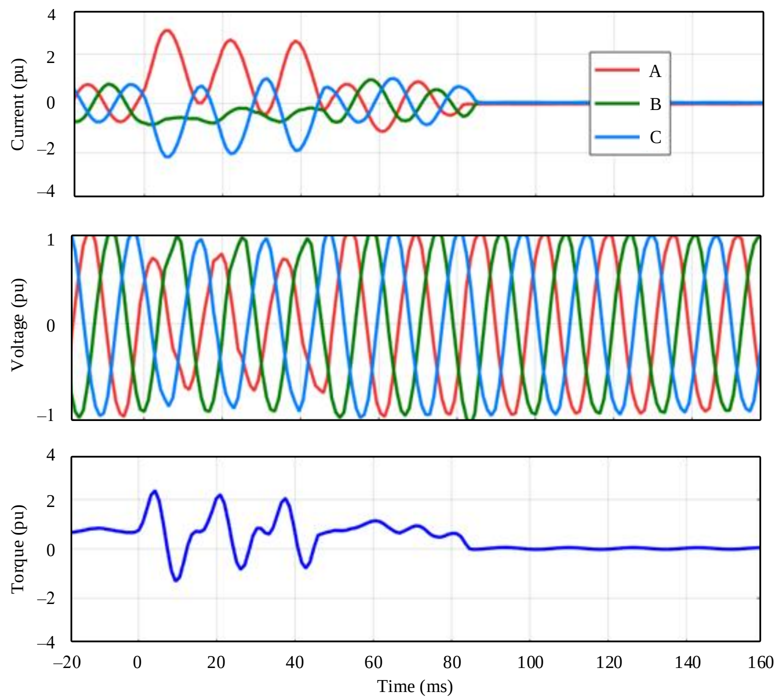

Figure 44: Currents, Voltages, and Torque for an External Fault [4]

9.5 Time-Overcurrent from Event Report Data

As noted in Section 1.4, the overcurrent from an OPS can also stress the GSU transformer windings, leading to failure. The time-overcurrent due to an OPS can be compared to the transformer withstand characteristics from IEEE Std C57.109 [34]. The approach is to plot the overcurrent magnitude (in per-unit of rated GSU transformer current) and its associated duration throughout the OPS, as illustrated for a 180-degree OPS in Figure 45 [4]. The time-overcurrent for the external fault of Figure 44 is also plotted in Figure 45. The transformer withstand characteristic (14.7% impedance) is also used for reference. The torque for this 180-degree OPS was lower than the transformers withstand characteristic but much higher than the time-overcurrent for the external fault.

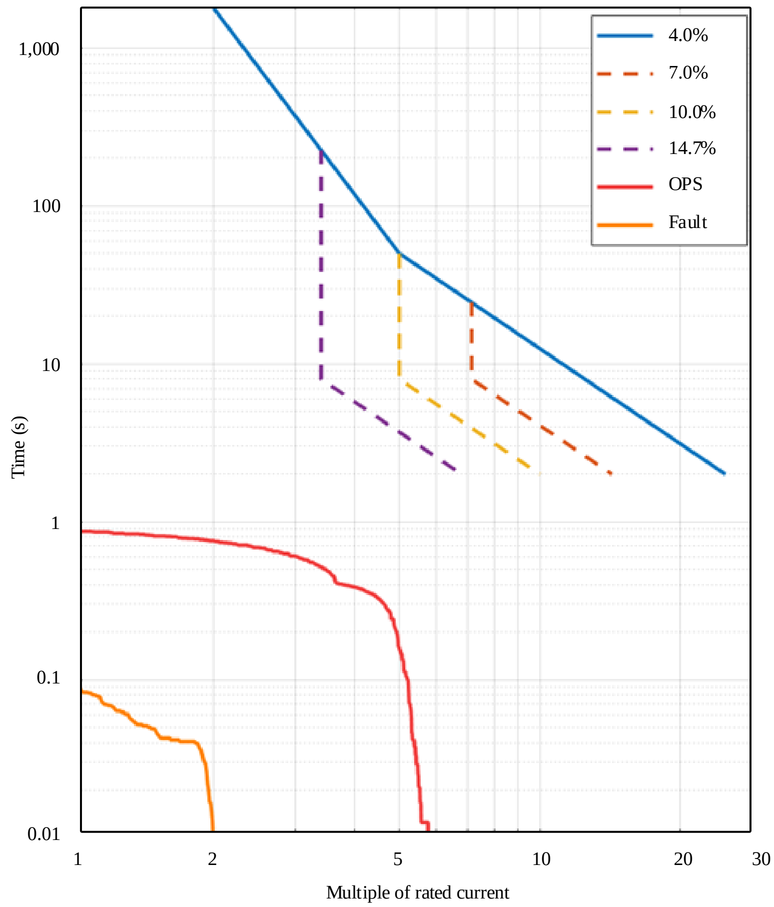

Figure 45: Time-Overcurrent During a 180-degree OPS [4]

9.6 Corrective Action Plans

In the event of an OPS, the generator owner may perform a thorough root cause analysis. The goal of this analysis is to determine the exact cause for the faulty synchronization. The root cause may be due to one or more of the following reasons:

- Inadequate commissioning
- Human performance errors
- Or equipment malfunction

Determining the root cause helps improve the quality of future synchronizations. The most common cause for an OPS is inadequate commissioning of the synchronization system.

The following activities, in no particular order, help provide insight for a synchronization failure:

- Retrieve event reports/oscillography from devices that are connected to the VTs associated with the synchronizing scheme—this includes the VTs on the system side and generator side of the location where synchronization occurs.

- Perform a point-to-point check of the synchronizing system ac and breaker close path dc circuits. A meter can be used to check impedance continuity between the local and remote end of wire terminations. This wiring verification helps ensure the quality of the input measurements of the synchronizing system.
- Verify that the settings of the synchronizing relay and/or control system match the latest as-left settings.
- Perform phasing tests across the location where synchronization occurred. Verify that the voltage angles of each phase between the system and the generator match.

Wiring errors necessitate a design verification and field modification. A setting error may be reviewed by the original settings developer and tested in the field. Providing training to generation personnel might prevent a future OPS. In addition, improvements to processes and engineering quality may be implemented as a future safeguard.

10. Commissioning Practices

A complete verification of the synchronizing system is required to guarantee that the synchronizing system performs successful synchronizations. The verification process is composed of the following activities:

- Verification of the programming and functionality for the devices within the synchronization system
- Verification of the dc control circuitry
- Verification of the ac secondary sensing circuits
- Primary phase tests
- Control tuning test

10.1 Programming/Functionality Verification

There are two functions to verify in the synchronizing system, the permissive functions and the matching control functions.

10.1.1 Permissive Function Verification

Verify the proper operation of the synchronizer and synchronism-check relay with a relay test set. The relay test set is configured to inject secondary voltage into the devices to verify the following functionality:

- Pick-up and drop-out of the phase angle window
- Pick-up and drop-out of the voltage difference window

- Pick-up of black start permissive element (if applicable) as discussed in Section 6.1.3
- Pick-up and drop-out of the slip window

10.1.2 Control Function Verification

As covered in this report, there are various means for matching the incoming generator frequency and voltage to the running bus including raise and lower pulses between the synchronizer and the generator controls, analog bias signals between the synchronizer and the generator controls, and matching features built into the generator controls themselves. Communicating with the generator controls engineers (governor and AVR) can help confirm that the matching control functions are configured correctly.

If the control function interface is via raise and lower pulses, tests can be made to verify that the pulse outputs of the synchronizer are connected to the proper inputs on the generator controls and that the generator controls respond correctly to the pulses (raise pulses cause raises, etc.). This verification can also include verification of whether the generator control system responds to proportional or fixed duration pulses (see Section 3.1.5).

If the control function interface is via analog bias signals, tests can be made to verify that the bias signals are connected to the proper inputs on the generator controls and that the generator controls respond correctly to the bias signals (scaling and polarity is appropriate, etc.). The scaling of the bias signals and the gain of the generator control response can be verified by test.

If the generator controls have matching features built in, determine if the best performance can be obtained by using the matching function in the generator control or in the synchronizer. Verify that only one control system is performing the frequency or voltage matching control function.

These tests do not replace the need for tuning the controls. But they can help facilitate success when it is time to do final control system tuning.

10.2 AC Secondary Sensing Verification

The next step of verifying the primary voltage phasing is equally important. Without completing this critical step, an OPS is possible even if the synchronizer and synchronism-check relays are operating properly (see Section 10.4).

There are a multitude of pitfalls where mismatched secondary voltage phasing and magnitude may not provide an accurate representation of the primary voltage phasing and magnitude. Although there are numerous root causes, some examples are provided below:

- Secondary wiring mistakes
- Accidentally selecting VTs on the wrong phase

- Connection errors on the primary and/or secondary VTs
- Incorrect or mismatched VT ratios

The key to finding these errors before an actual synchronization is verification using the same primary voltage on both sets of synchronizing VTs. The verification method depends on the configuration of the electrical system and the auxiliary system. For all methods, the synchronizing breaker is closed with power applied on one side and a dead bus on the other side. To avoid an inadvertent energization, if the system is used as the power source, the generator is isolated. This process requires careful planning as it often requires coordination with multiple entities. Section 10.4 provides further guidance on these techniques.

10.3 DC Control Circuitry Verification

The close logic and closing circuit dc schematic requires verification using both go (things happen as expected) and no-go (unexpected things do not happen) tests. A useful test to include during the startup procedure is the mock close test [26]. In a mock close test, everything is ready for first synchronization except that at least one of the breaker isolation disconnect switches is left open such that when the breaker closes, the generator is not actually connected to the grid. During the mock close test, the operator first tries to close the breaker when the synchroscope is at 6 o'clock. This safely verifies that there are no sneak circuits that might bypass the permissive contact. This test can also verify that a polarity-sensitive hybrid synchronism-check permissive contact is wired correctly and provides proper blocking action. Other interlocks can also be safely tested during the mock close test. While the dc circuits can be tested during the outage, this test can help confirm that everything is in its final configuration and using live signals.

The operator then initiates a close at 12 o'clock on the synchroscope to verify that the breaker closes as expected. The mock close has the added advantage of exercising the breaker once before the first actual synchronization. Once the mock close tests are completed, the breaker is opened, the isolation disconnect is closed, and the first synchronization can occur.

Prior to performing a mock close test, remember to disable the automatic loading logic described in Section 10.9. This logic may be returned to service when the mock close test is complete.

10.4 Primary Phasing Tests

Use of proper testing methods, as described in this section, can completely verify the synchronizing circuits and associated equipment [26]. Secondary injection is usually done at the time of commissioning. Voltage signals are injected at the VT local terminal box to verify the correct wiring, polarity, and grounding of the VT secondary circuits in the AVR, generator relay panel, and synchronizing panel. Secondary injection also verifies the measurements of the generator protection relay. However, this injection does not determine if there are any issues in the primary circuits.

The preferred method is a primary voltage test with the generator and system VTs energized from the same source. These procedures change based on whether it is a first-time commissioning or commissioning after modifying VT circuits. Before putting primary voltage on the equipment to perform these tests, it is important to verify that the equipment protection is functional and in-service.

10.4.1 Forward-Feed Test

One method of primary testing is to use the generator to energize the VTs used for synchronization via a forward-feed test. This is accomplished by first isolating the system side of the synchronizing breaker from the utility system and bringing the generator to speed with no load and field applied. The interlocks are then bypassed to allow the synchronizing breakers to close such that both the generator VT and the synchronizing VT are energized from the generator. However, there are challenges associated with a forward feed test.

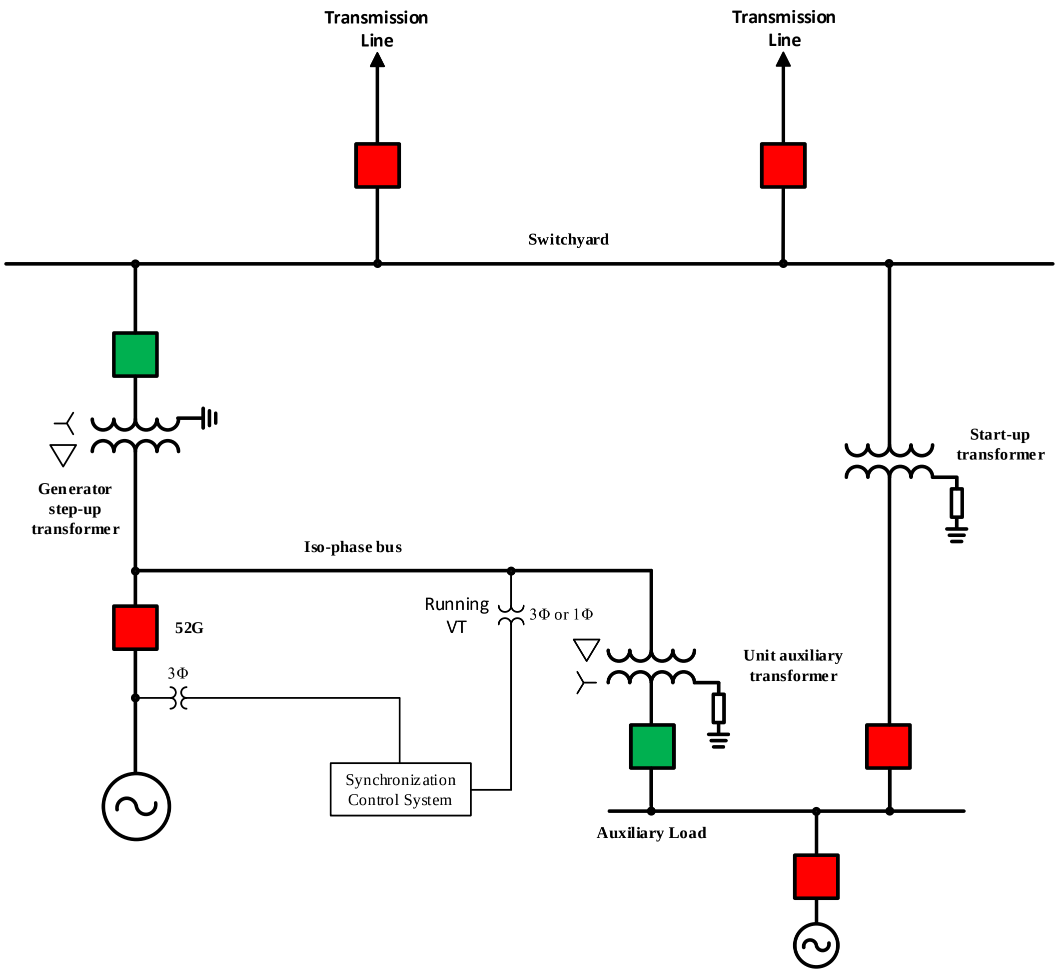

Figure 46: Generator Terminal Breaker Test

The ability to isolate the system is dependent on the generator design and/or the transmission design. The location of the running VT determines the system side isolation clearance needed for this test. This request will have to be coordinated with system operations to help ensure it is possible to achieve the clearance necessary for this test. Taking a bus outage is typically required to isolate the running VT. A generator with a breaker connected to its terminal (Figure 46) may allow for easier isolation of the system side since the clearance points for the test are located within the generation facility. It may be possible to obtain this clearance in a switchyard with a breaker-and-a-half (Figure 47) or ring bus design. However, a straight bus design (Figure 48) makes it almost impossible to isolate the running VT since the start up transformer will have to be de-energized as a part of the bus outage.

For a breaker-and-a-half switchyard design, the following example sequence may be used to perform this test. Depending upon the configuration other means of isolating one of the running VTs are possible.

1. Isolate Bus #2 by opening and tagging out breakers 52L2, 52L4, 52G1, and 52G2.
2. Open breaker 52A1 and close breakers 52ST and 52A2 to energize the auxiliary load from the transmission system and start the generator up.
3. Close the generator breaker (52G2) to energize bus 2. This may require temporarily jumpering the interlocks to close breaker 52G2.
4. Verify that the bus #2 running VT and incoming VT to the synchronizing panel are in phase.
5. Open breaker 52G2 to begin restoring the switchyard to normal.
6. Restore the switchyard by closing 52L2 and 52L4.
7. Verify that the bus #1 running VT and bus #2 running VT are in phase. This indirectly verifies that bus #1 running VT is also in phase with the incoming VT.

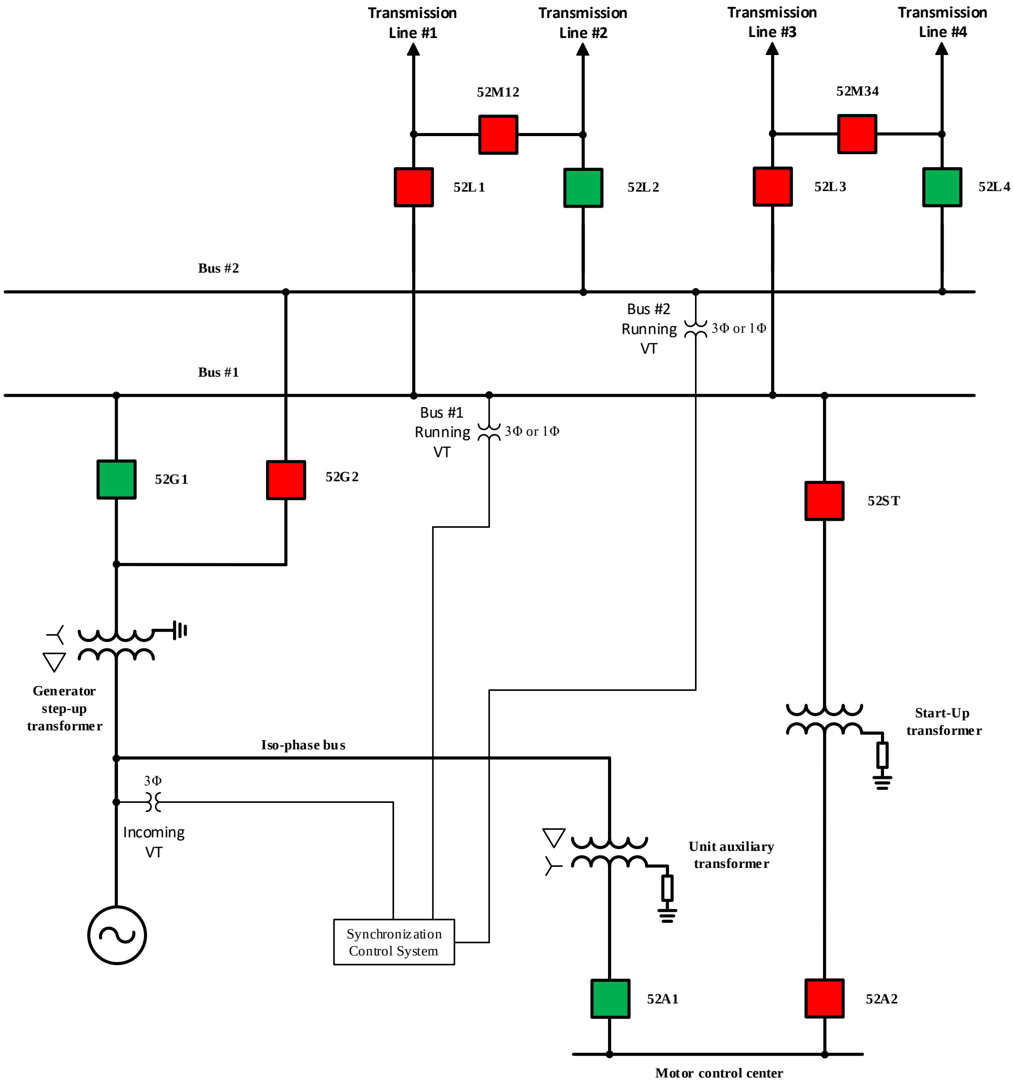

Figure 47: Breaker and Half Test

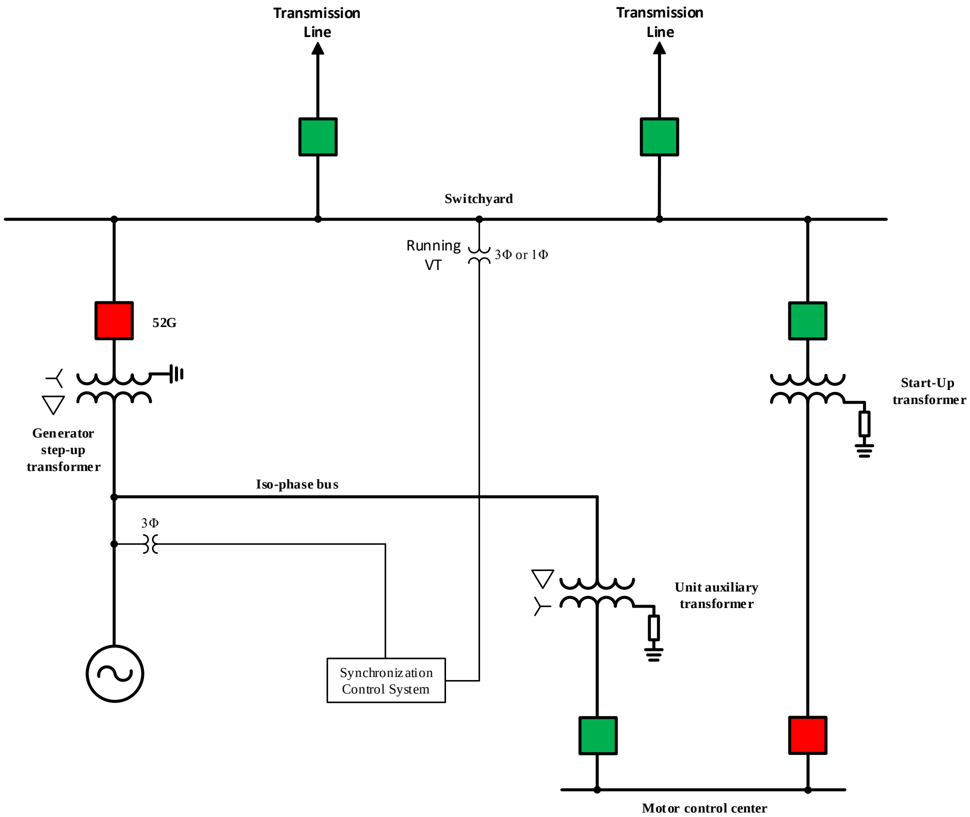

Figure 48: Straight Bus Application Challenge

When disconnecting the generator terminals is impractical, generators that are capable of starting quickly and that have their auxiliaries powered from a startup source, such as hydro or simple-cycle combustion turbines, can be disconnected from the utility system by a disconnect. They can then be started in black-start mode to energize the VTs used for synchronizing to test the synchronizing circuits. A forward-feed test may also be impractical due to the station arrangement, as shown in an example from [26] and as shown in Figure 49. For this system, the bus has to be hot to start and run a combustion turbine generator to generate steam before the steam turbine generator can be brought up to speed. There is no way to isolate the high-voltage synchronizing VT to energize it from the steam turbine generator. As a result, the backfeed test is the only viable option.

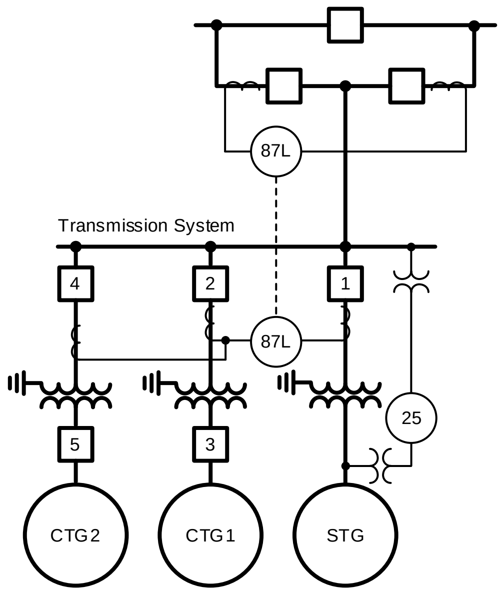

Figure 49: Impractical Forward-Feed Design [26]

10.4.2 Backfeed Test

The backfeed test is conducted by placing the unit into its normal configuration, disconnecting the generator terminals (either by removing connecting links or opening disconnects, see Figure 50), and then bypassing the interlocks to close the synchronizing breaker. Once the synchronizing breaker is closed, the synchronizing devices can be verified to show synchronism.

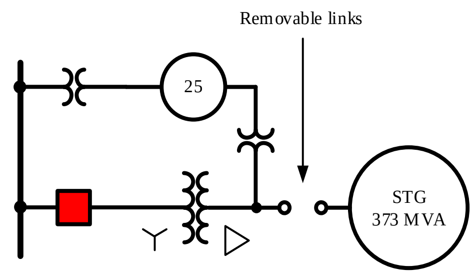

Figure 50: Verifying the Synchronizing Circuits Using a Backfeed Test [26]

After the VTs are energized from the same source, the rotation check of the generator also follows a backfeed test in the event where the primary conductors connected to the generator terminals have been disturbed and cannot be restored with certainty, such as with smaller units where the primary conductors are cables. This is accomplished by simply connecting the generator in its normal configuration, blocking output breaker closure, and bringing the generator to a full-speed no-load condition with field applied. At this point, a rotation check of the secondary side of the generator VTs can verify that the rotation matches that of the backfeed test.

Ferroresonance can be a concern during a backfeed test when the generator bus is energized by the system. The high-impedance grounded generator is disconnected leaving the generator bus ungrounded. Energizing the generator bus, while ungrounded, leaves the bus VTs vulnerable to ferroresonance. If wye-wye connected VTs exist on the generator bus, a load may be connected to the VT secondary to dampen any electrical transients that occur and prevent ferroresonance. Typically, a set of incandescent light bulbs or power resistors have been connected to the generator VT secondary. The resistive loads are connected to the VT secondary A-phase-to-ground, B-phase-to-ground, and C-phase-to-ground. If the VT secondary winding configuration is a broken delta with a loading resistor, then no extra precautions are warranted. This design is already implemented to prevent ferroresonance when a ground fault occurs.

10.4.3 Phase Sticks

Phase sticks are test instruments that are used to determine the phase angle difference between two electrical conductors. Typically, phase sticks are used to check whether the two conductors are of the same constant electrical phase. Phase sticks are sometimes also applied to verify primary phasing, which varies dynamically during synchronization. Wireless phase sticks have also been considered for primary phasing tests. However, they may have excessive measurement delays that cause erroneous readings when there is a significant slip frequency. This may cause the phase stick angle measurement to not align with the generator synchroscope.

Some level of personal protective equipment (PPE) is typically required when phase sticks are used. Due to safety concerns, the previously mentioned methods are better suited for primary phase testing.

10.5 Control Tuning

During the commissioning process, monitoring the performance of the synchronizing system and tuning to adjust performance can help avoid overshoot and hunting (see Section 3.2.9). Synchronizer system tuning may also be required any time that elements of the prime mover speed control system or excitation control system are modified.

10.6 Routine Testing

Routine testing may be performed by verifying that the voltage magnitudes, frequency, and phase angle from the generator VTs (measured at the incoming bus) and the system VTs (measured at the running bus) are equal when the synchronizing breaker is closed. Using this approach prevents any modifications to the synchronizing system and reducing the possibility of a possible failure introduced by testing.

10.7 Breaker Testing

The generator breaker is critical to the protection of the generator and benefits from periodic maintenance and testing. To use the automatic synchronizer’s slip-compensated closure feature effectively, obtaining the breaker closing time is required, either from a breaker timing test or from a relay oscillography record. The breaker closing time corresponds to the elapsed time from the moment a synchronizer sends the close command to the moment the breaker contacts touch. While a breaker timing test is preferred to verify the coherence between the auxiliary contacts and the main breaker contacts, using the breaker auxiliary contact status reported in a relay oscillography or sequence-of-event data is suitable to estimate the breaker closing time for synchronizing purposes (see Section 4.3).

Accurate breaker closing times can be determined with a breaker timing test device. The test set is connected to the primary bushings, the trip/close coils, and the auxiliary status contacts. The test set then measures resistance of the primary contacts, and the closing time is determined as the time between energization of the close coil and the resistance between the primary contacts becoming zero.

10.8 Design Verification

A new or revised synchronizing system design requires verification, to the maximum extent possible, prior to conducting primary phasing checks. The secondary wiring of the synchronizing system is tested by utilizing point-to-point, secondary voltage injection, and loop-check testing strategies. The goal is to identify and correct any issues so that the primary phasing test simply confirms that the synchronizing system is wired correctly.

10.9 Testing Considerations

After using the primary phasing tests of Section 10.4 to verify that the synchronizing panel and the synchronism-check relays indicate an in-phase condition, the breaker can be opened to restore the system to normal. The methods of Section 10.4 allow the entire synchronizing circuit to be tested at once and minimize the potential for errors. A piecemeal approach to final testing of essential protection schemes can be successful, but it introduces the opportunity for errors and is generally considered inadequate, especially for synchronizing circuits [26].

This type of testing is highly unusual for generating facilities and occurs infrequently. These tests typically occur at the end of an outage, and care is required to help ensure that all normal protection is enabled and functional, such as differential and overcurrent elements. This is especially true when backfeeding from the utility system or black-starting the generator. The authors of this report are aware of at least one fault that has occurred during a backfeed procedure. While the actual cause of the fault was the result of a lockout–tagout oversight, significant damage to equipment was avoided because the protective relay system was in service as described above.

Some protective elements may operate unexpectedly due to the abnormal power system configuration utilized for the test. Reverse current flow caused by the inrush current of GSU, auxiliary, and excitation transformers may cause unanticipated operation of impedance, and directional power elements. Additionally, inadvertent energization protection, differential element, and third-harmonic stator ground fault protection [35] may require review as part of the primary phasing test procedure planning process.

When the generating unit is in a startup condition, it is important to consider that there is often logic that automatically begins applying load to the generator when the generator breaker closes. Under a normal operating condition, this prevents a reverse power condition after the generator breaker closes. However, during this test there is no load available, and the control system may unexpectedly overspeed the prime mover. Examining the prime mover control system logic can help prevent an overspeed event during this test. Additionally, closing the generator breaker for this test may require manually bypassing interlocks designed to prevent accidental closure.

Testing may require equipment to remain at full-speed no-load for an extended period of time. Some types of prime movers, such as steam turbines, have restrictions on the time duration that the unit can remain at full-speed no-load. Equipment limitations require consideration during the test procedure planning process.

Testing may be required any time any part of a synchronizing circuit is disturbed. This includes the primary conductors, VTs, VT secondary circuits, automatic synchronizer, synchroscope, and synchronism-check relay. It is easy to be overconfident when dealing with the secondary circuits of the VTs used for synchronizing. However, a problem can be introduced by simply disconnecting two wires on the secondary side of a VT used for synchronizing. Once disconnected, the only sure method of ensuring the correct configuration is to perform a primary phasing test.

10.10 Special Considerations for Programmable Synchronizing Systems

Modern numerical synchronism-check elements introduce additional complications to the primary phasing tests. These elements often include phase and magnitude compensation settings that require verification during the primary phasing tests of Section 10.4. Simply checking that the incoming (generator) and running (bus) signals are in-phase and of equal magnitude when fed from the same source may not be possible if these features are being used. An incorrect compensation setting could fool the permissive relay into allowing an OPS, so it is necessary to verify that the compensated signals are in-phase and of equal magnitude and that the synchronism-check element asserts during the primary phasing tests [26].

11. Synchronization Performance Monitoring

Engineering infrastructure allows monitoring synchronizing system performance and the quality of synchronizations. A digital device may be used to monitor system conditions and initiate a generator breaker closure. This device may be a digital relay or be a part of the generator control system. To evaluate performance of the synchronizing system, records with relatively low sampling rates may be adequate. To calculate electromagnetic torque after synchronization (see Section 9.4), event reports with 16 samples-per-cycle data (or higher) with durations of 2 seconds (or longer) may be adequate.

Monitoring and recording system and generator voltages allows evaluation of synchronization voltage bandwidth. The monitoring device can be set up to trigger recording during synchronization operation and capturing an adequate pre trigger and post trigger duration to allow evaluation of the synchronization performance. The system voltage may be obtained from two separate buses in a unit generator design—in which case, the monitoring device measures both bus voltages. For system voltages on the high-side of the GSU transformer, the monitoring device requires capability to account for possible phase-shifts through the GSU transformer to compare with generator voltages. By measuring generator voltage, the system can derive generator frequency. The generator frequency and system frequency at the moment of generator breaker closure can be used to calculate the slip frequency of a synchronization. The measurement of these variables can be used to plot a synchronization event on the generator synchronization scope or window.

Measuring generator current can help evaluate the stress imposed on a generator and the GSU transformer due to a synchronization (see Section 9.4 and Section 9.5). For multiple generators connected to the same bus, it is beneficial to monitor GSU transformer current independently because the GSU transformer may be exposed to higher current magnitudes than an individual generator.

The status of the generator breaker is typically used to initiate transient event recording. If the system design consists of dual generator breakers, each breaker status is monitored because either breaker may be used to synchronize to the grid. It is important to record pre-synchronization variables, i.e., the voltage and frequency before the generator breaker closes, for analysis.

When synchronization is performed manually by an operator or by a non-digital auto-synchronizing system, a synchronism-check function in a microprocessor relay can be used to supervise the synchronization. The microprocessor relay that provides the synchronism-check function can also gather and report information on slip frequency, voltage difference, phase angle on breaker close, and breaker closing time for evaluation of the synchronizing performance and to trend degradation of equipment due to synchronizing error over time.

11.1 Synchronization Monitoring Ecosystem

A phasor data concentrator (PDC) may be used to monitor and store synchronizing events. This device might interface with the generator facility relays, switchyard relays, and the generator control systems. This interface typically uses a communications medium (serial cables, ethernet cables, etc.) and may be implemented using an established ethernet network through a network switch. The synchronization ecosystem may be programmed to measure the appropriate quantities and transmit them to the PDC. These quantities are measured at electrical points of interest within the generating facility (e.g., the terminal of the generator, etc.). The device data sampling rates and sampling time require time alignment to aid event analysis.

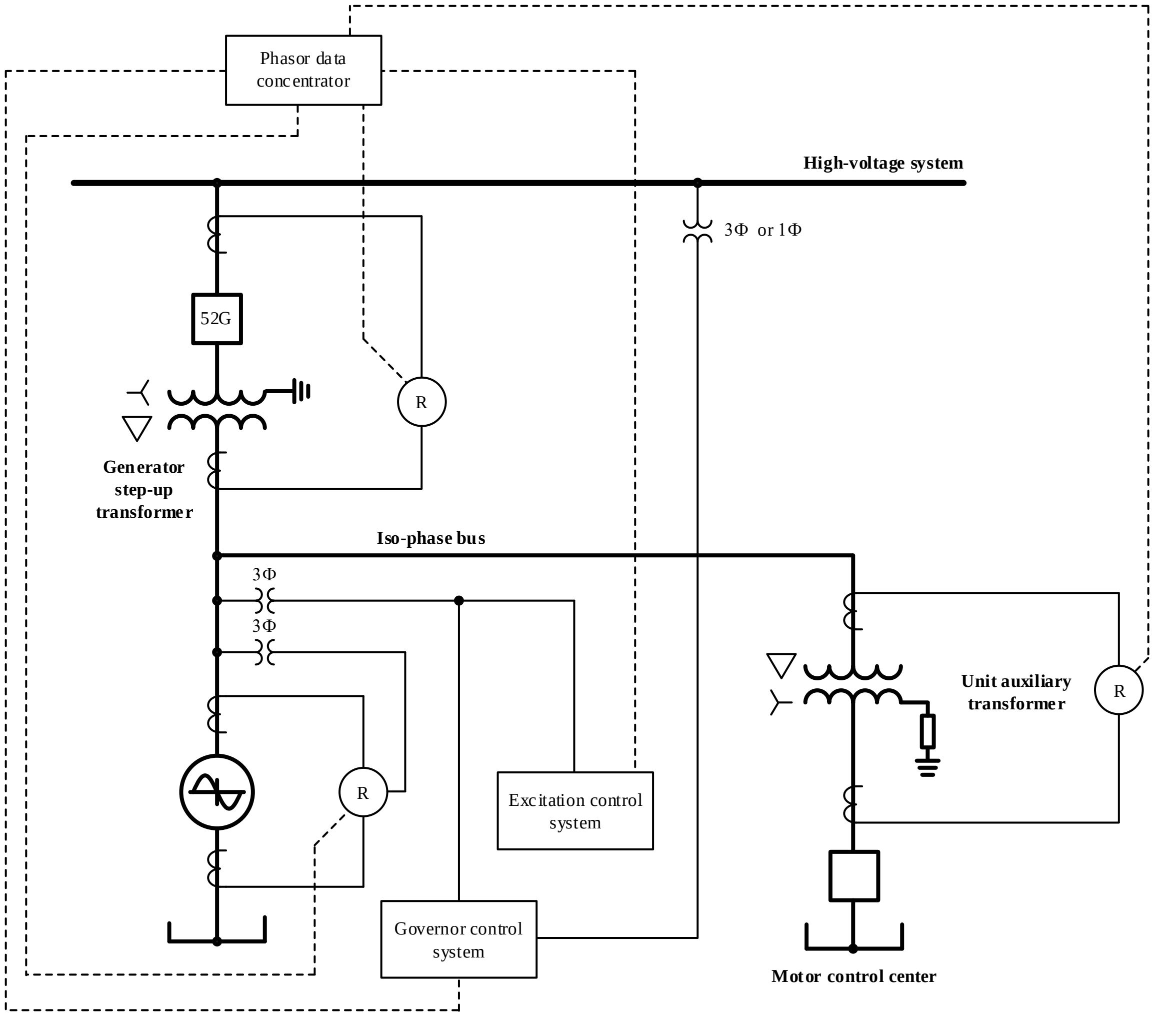

Figure 51: PDC One-Line Design

11.2 Cumulative stress over time to prime mover

Data from synchronizing events may be stored in a database for the lifetime of a generator. This data may be aggregated to monitor the mechanical stress on the prime mover over the generator's lifetime. This approach helps provide an accurate health evaluation of the electromechanical system because the stress (torque, vibration, etc.) imposed on a turbine is cumulative in nature and may lead to damage over time. As a generator ages, the data can be referenced whenever there is a question about the life or health of its prime mover.

12. Communications-based Synchronization

Advanced synchronism-check relays have the capability to interface with other devices via communication protocols. These communications bits can be used to implement permissive and synchronism-check functions in a relay's logic instead of the generator breaker's close circuit. This option can simplify applications where a lot of copper-wire runs are required to communicate with all synchronizing system devices.

The communications protocol IEC-61850 (GOOSE) may be used with an ethernet-based communication network to coordinate with devices throughout the generating facility. The use of an ethernet-switch allows for multiple devices to gain access to the network. Once on the network, devices can be programmed to send and receive logical nodes through the ethernet network. Relays that are highly dispersed can communicate with each other to help ensure a successful synchronization.

The use of DSS technology enabled by IEC-61850 (Sampled Values) and similar protocols have also improved modern synchronizing practices by providing reliable and economical solutions to many design challenges. See discussion in Section 3.4.

13. Aurora

Avoiding Unwanted Reclosing on Rotating Apparatus (Aurora) refers to a malicious attack on a power system where a generator breaker is intentionally opened and closed out of synchronism to damage the generator. An attacker requires either physical or remote access to the control equipment and the means to bypass or disable the normal synchronization logic [36].

The following multi-layered approach provides the best defense:

- Restrict access to information about the generation system including the strength of the power system and interconnections with the power system.
- Restrict access to protection, control, and communication system designs.
- Remove unnecessary external communications connections and secure those that are necessary.
- Follow best physical and cybersecure practices.

Several methods to further secure the protection and control systems are listed in the PSRC AURORA report [36]. These devices ideally have no external communications connection [36].

Anti-islanding detection and wide-area synchrophasor schemes have also been proposed for Aurora mitigation [37].

14. Conclusion

Synchronizing systems are critical components that help ensure proper operation and maximize life of a generator. An entity goes through a process to synchronize a generator to the grid. The synchronizing system helps ensure that the generator's voltage magnitude, voltage phase angle, and frequency are within an acceptable bandwidth. When a synchronizing system failure occurs, a generator may be exposed to severe electrical and mechanical torque and current transients. These transients may damage or reduce the life of a generator.

Permissive control schemes can be used to prevent a faulty synchronization. Prevention of a faulty synchronization is the first line of defense for a generator. In the event of an out-of-phase synchronization, protection schemes can reduce potential damage to a generator. Some generator protection schemes may inadvertently detect an OPS; however, these elements cannot be relied upon for protection during a synchronization. Dedicated out-of-phase synchronization detection schemes provide optimal protection and alarming for the generator and prime mover systems.

Commissioning of a synchronizing system using primary phasing tests is a crucial step for generator synchronization. Applying a high-degree of attention to detail and thorough testing can negate human performance errors that lead to faulty synchronizations. From point-to-point checks to meticulous maintenance processes, all the pieces matter. Understanding how every component of the synchronizing system impacts generator operation helps improve quality of synchronizations— preventing generator damage and potentially prolonging generator life.

APPENDIX A Synchronizing System Application Example

An application example of the permissive synchronism-check configuration of synchronizing systems for a unit generator-transformer configuration is provided in this appendix. The single-line diagram of Figure 52 depicts the unit generator-transformer design that can synchronize to the 345 kV power system by closing either Breaker 52G1 or Breaker 52G2.

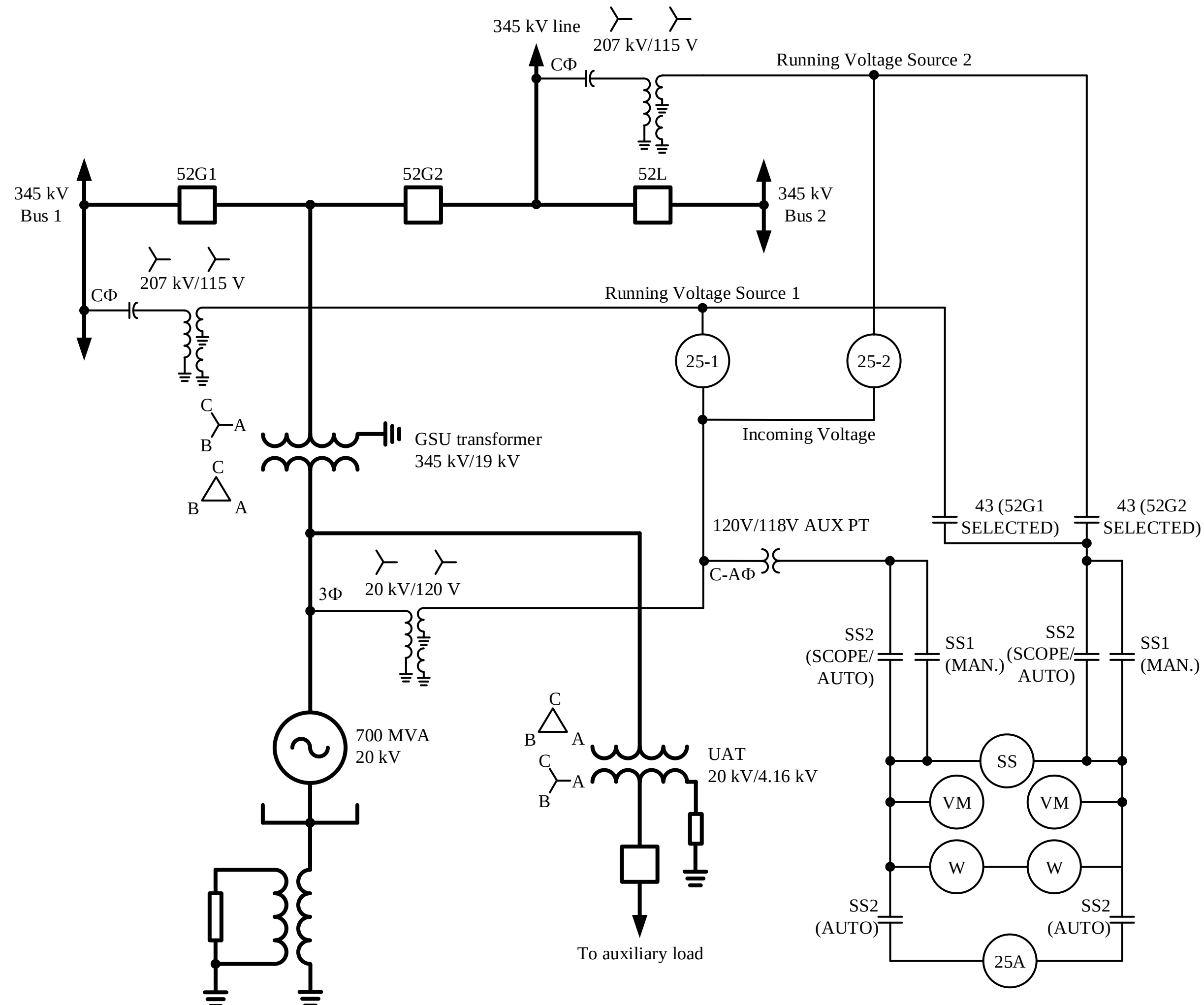

Figure 52: Unit generator system with dual high-voltage synchronizing breakers

A.1 System Data

The generator, GSU transformer, and interconnecting system data for the system of Figure 52 are provided in Table 1, Table 2, and Table 3, respectively. The automatic synchronizer (25A) is built into the turbine controls and its parameters are provided in Table 4.

For this example, the 25A is not a modern automatic synchronizer and cannot compensate for mismatched voltage ratios. The automatic synchronizer settings are set per the generator manufacturer's recommendations and/or company operating philosophy. It is important that the automatic synchronizer $25HIGH_{25A}$ and $25LOW_{25A}$ voltage window limits do not prevent the generator from being synchronized to the system under stressed or normal operating conditions. The GSU turns ratio and voltage schedule may be considered in determining the $25HIGH_{25A}$ and $25LOW_{25A}$ voltage window limits.

Table 1: Generator Data

Parameter	Data
Rated voltage (kV_G)	20 kV
Rated frequency	60 Hz
Generator Terminal VT Ratio (VTR_{Gen})	20 kV/120 V = 166.67
VT Connection	YNyn0

Table 2: GSU Transformer Data

Parameter	Data
Rated HV winding voltage (kV_{TH})	348.5 kV
Rated LV winding voltage (kV_{TL})	19 kV
Connection	YNd1/YDAC
GSU Turns Ratio (GSU_{RATIO})	348.5 kV/19 kV = 10.59

Table 3: Interconnecting System Data

Parameter	Data
Interconnecting System Rated Voltage (V_{SYS})	345 kV
Synchronism Potential #1 VT Ratio (VTR_{Synch1})	207 kV/115 V = 1800
Synchronism Potential #2 VT Ratio (VTR_{Synch2})	207 kV/115 V = 1800

Table 4: 25A Automatic Synchronizing Parameters

Parameter	Data
Upper Voltage Limit ($25HIGH_{25A}$)	130 V
Lower Voltage Limit ($25LOW_{25A}$)	106 V

Delta Voltage Limit ($DELTAV_{25A}$)	2.5 V
Maximum Slip ($MAXSLIP_{25A}$)	0.1 Hz
Minimum Slip ($MINSLIP_{25A}$)	0.02 Hz

A.2 Synchronizing Control System AC Schematic

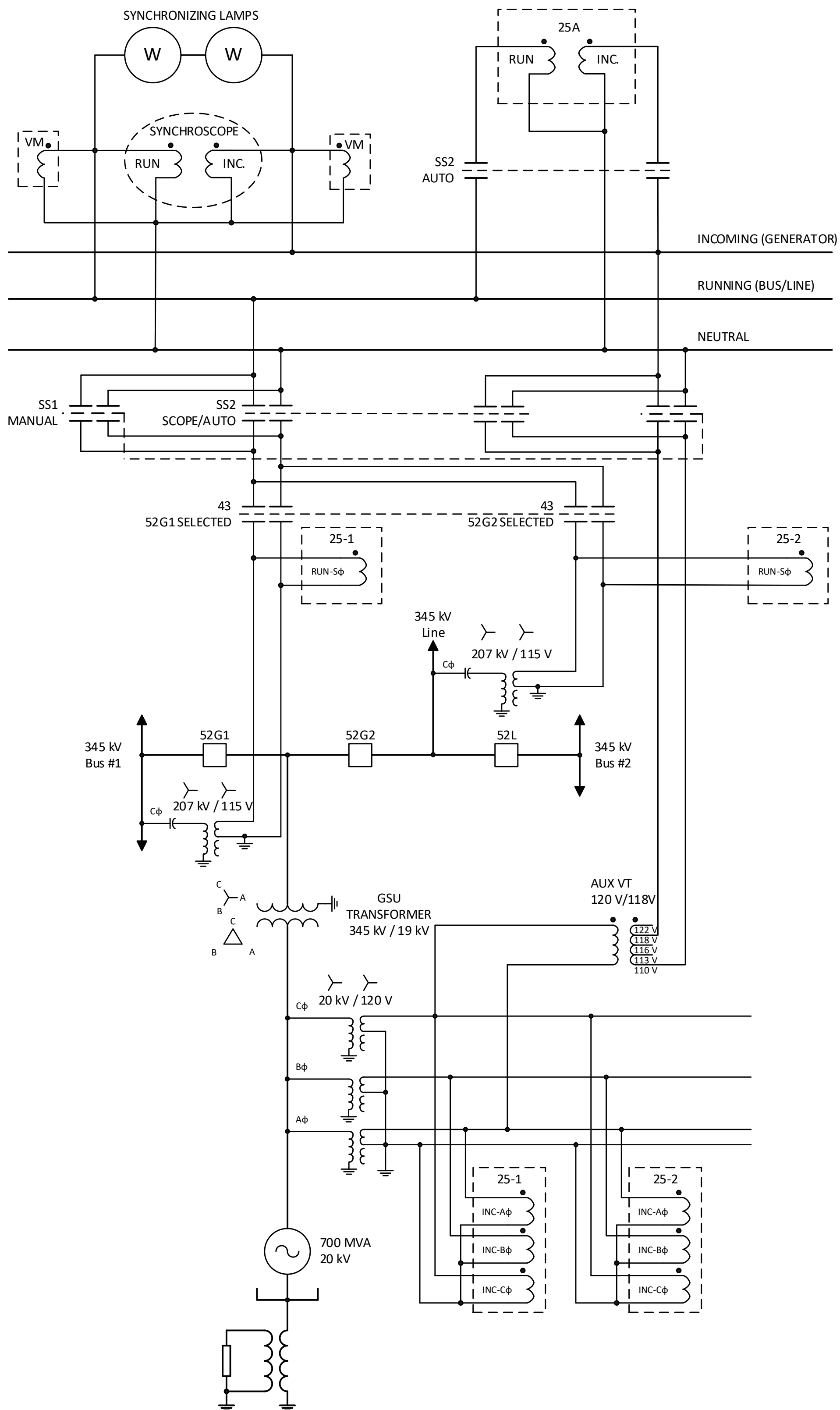

Figure 53: Synchronizing System Control Design

A.3 Synchronizing Breaker Control Design

The dc schematic for the 52G1 close circuit and associated control/selector switch contact development tables are shown in Figure 54. The dc schematic for the 52G2 close circuit is shown in Figure 55. The three close strings are discussed as follows:

1) Close String #1:
   - Parallel Close Supervision: Following synchronizing of one generator breaker, the slip of the generator with respect to the system is ~0 Hz. The phase angle difference across the open generator breaker is static. A wide-angle setting is typically used in case the open breaker is tying two systems together whose phase angles have separated by more than 10°. As a result, the synchronism-check permissive relay has a synchronism-check angle set with a wider angle to allow the remaining generator breaker to close. It is important to check that the relay allows a parallel close with ~0 Hz slip. If the relay does not include zero slip in the permissive window, then additional measures are taken such as including a synchronism bypass switch. For this application, zero slip is included in the permissive window by relay design.
2) Close String #2 & #3:
   - Close strings #2 & #3 implement redundant synchronization control design as previously discussed in Section 5.3. All close strings are supervised by field breaker status as additional security to prevent an inadvertent energization. The 41Xa field breaker status can also be wired as a digital input in the 25-1 & 25-2 relays rather than the breaker close circuit to simplify wiring.

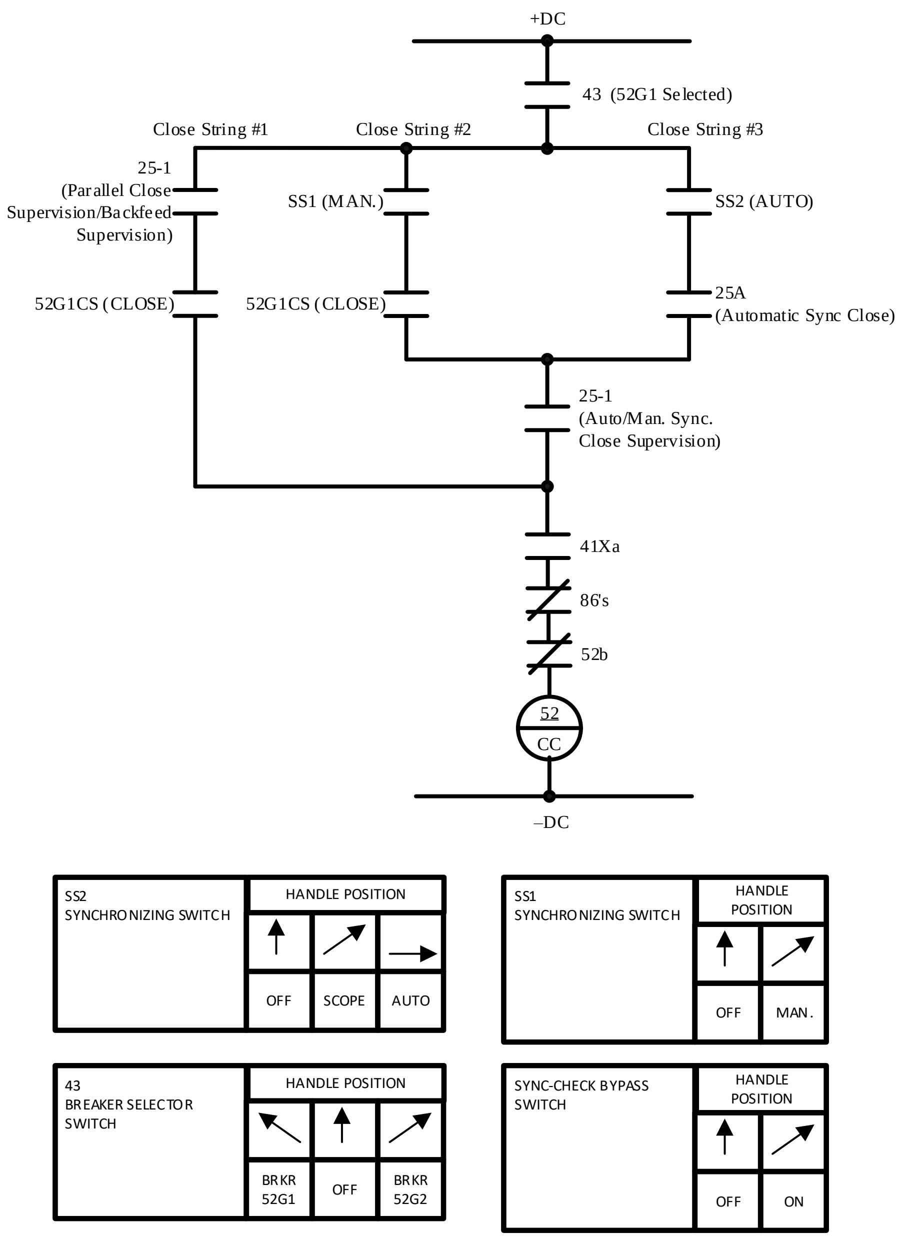

Figure 54: Synchronizing Breaker 52G1 Control Design

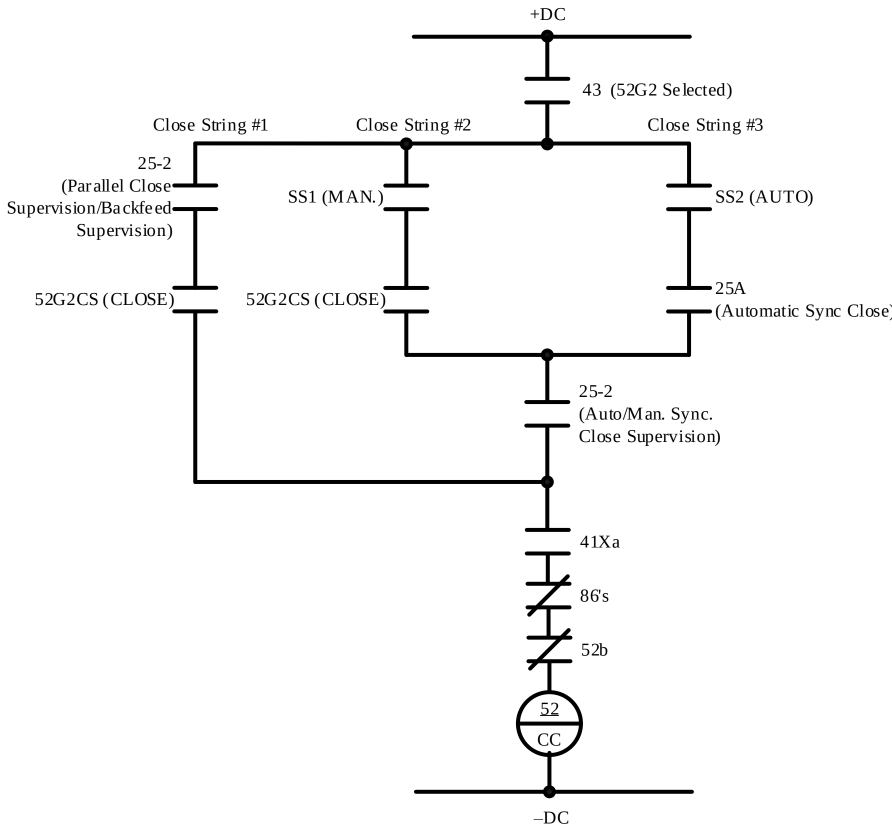

Figure 55: Synchronizing Breaker 52G2 Control Design

The 25-1 & 25-2 input/outputs are tabulated in **Table 5** and **Table 6**.

Table 5: 25-1 Digital Input & Output Table

Input/Output	Description
IN1	52G1a
IN2	52G2a
IN3	43 (52G1 Selected)
OUT1	Parallel Close Supervision
OUT2	Automatic/Manual Synchronism Close Supervision

Table 6: 25-2 Digital Input & Output Table

Input/Output	Description
IN1	52G2a
IN2	52G1a
IN3	43 (52G2 Selected)
OUT1	Parallel Close Supervision
OUT2	Automatic/Manual Synchronism Close Supervision

A.4 Operator Indication Design & Auxiliary VT Ratio Selection

The operator uses synchronizing lights (W), synchroscope (SS) and voltmeters (VM) to manually synchronize the generator to the system. Once the generator has been synchronized to the system, the operator will close in the remaining breaker once they have verified the synchroscope is no longer rotating, the scope arrow is roughly at the 12'O clock position, voltages are withing acceptable limits and the synchronism-check relay provides operator indication that a close is permitted. The GSU transformer is delta-wye connected. A VT connected C-phase-to-ground is used at the switchyard and the generator has phase-to-ground VTs installed. The generator CA-phase-to-phase voltage is in phase with the C-phase-to-ground voltage of the switchyard. Due to the 30° phase shift introduced by the GSU, the difference in voltage ratios and the GSU off-nominal turns ratio; an auxiliary VT is used to correct the ratio mismatch and provide correct indication to the operator. If a DETC is applied, it is considered.

The auxiliary VT is connected CA-phase-to-phase on the primary side. The secondary side of the auxiliary VT has taps available to match the incoming voltage to the running voltages. The generator nominal voltage is chosen as the base for calculating $VINC_{NOM\_LL}$ and $VRUN_{NOM\_LG}$. The GSU turns ratio is accounted for and the ratio of the auxiliary VT ($VTRAux_{Ideal}$) is calculated as follows [1]:

$$\boldsymbol{GSU_{RATIO} = \frac{kV_{TH}/\sqrt{3}}{kVTL} = \frac{348.5kV/\sqrt{3}}{19kV} = 10.59} \quad \textbf{(24)}$$

$$\boldsymbol{VINC_{NOM\_LL} = \frac{kVG}{VTRGen} = \frac{20kV}{166.67} = 120.00\,V} \quad \textbf{(25)}$$

$$\boldsymbol{VRUN_{NOM\_LG} = \frac{kVG * GSU_{RATIO}}{VTRSynch1} = \frac{20kV * 10.59}{1800.00} = 117.66\,V} \quad \textbf{(26)}$$

$$\boldsymbol{VTRAux_{Ideal} = \frac{VINC_{NOM\_LL}}{VRUN_{NOM\_LG}} = \frac{120.00V}{117.66V} = 1.02} \quad \textbf{(27)}$$

However, per the auxiliary VT data sheet, a 120 V/118 V is the closest available tap, so the actual auxiliary VT ratio (VTRAux) is:

$$\boldsymbol{VTRAux = \frac{120.00\,V}{118.00\,V} = 1.017} \quad \textbf{(28)}$$

A.5 Permissive Synchronism-check (25-1 & 25-2 relays)

The 25-1 & 25-2 relays are microprocessor-based relays that measure slip directly and compensate for breaker closing time when the measured slip is outside of ±0.005Hz and less than the maximum slip limit as defined by the relay (zero slip is included in the permissive window). They also utilize an uncompensated static synchronism-check element if the relay measures that the slip is within ±0.005 Hz. The incoming voltage is connected to the 3-phase voltage input at the generator terminals. The single-phase running voltage input is connected to the switchyard VT.

Reference Phase Selection

The single-phase running voltage input is connected to phase C-phase-to-ground of the switchyard VT. The relay will compare the C-phase-to-A-phase incoming voltage to the running voltage. The pertinent setting is shown below:

$$\boldsymbol{SYNCP_{INC} = VCA\ (Options\ are\ VA, VB, VC, VAB, VBC, VCA)} \tag{29}$$

Note: The use of line-to-ground voltages for synchronizing on a high-impedance or ungrounded system is often avoided. In a high-impedance or ungrounded system, the neutral reference can be offset from ground, making the phase-to-ground signal unreliable for synchronizing [1].

Magnitude & Angle Compensation

Angle correction factor (ACF) is available to compensate for incoming and running voltages that may not be in phase.

For this application, the running voltage is in phase with the incoming voltage. The ACF is set as follows.

$$\boldsymbol{ACF = 0°} \tag{30}$$

The nominal running voltage is 117.66V line-to-ground. The nominal incoming voltage is 120V line-to-line. The 25-1 & 25-2 relays are measuring line-to-ground voltages. The Ratio Correction Factor (RCF) is used to match the incoming voltage to the running voltage.

$$\boldsymbol{RCF = \frac{VRUN_{NOM\_LG}}{VINC_{NOM\_LL}} = \frac{117.66\ V}{120\ V} = 0.98} \tag{31}$$

Voltage Window Acceptance Criteria

The compensated running and incoming voltages are compared to an accepted voltage window that has a lower and upper boundary. The synchronism check element is enabled if the compensated incoming voltage and running voltage are within the boundary. Two approaches of setting the voltage window are considered and discussed.

1) The 25-1 & 25-2 voltage window may be set to match the 25A. This may be acceptable if the voltage of the system remains within the voltage schedule as determined by the transmission planner. The voltage schedule for this example is 1 to 1.06 pu or 345 kV to 365.7 kV. With the 25A voltage window settings set wider than the voltage schedule, the 25-1 & 25-2 relays will not get in the way of an automatic synchronization if they are matched to the 25A voltage window. However, at system voltages outside of the voltage schedule, it is possible that an automatic synchronization would be blocked by the 25-1 or 25-2.
2) To overcome the disadvantage of Option #1 above. Set the voltage window wider than the 25A voltage window settings. A 5% margin is used in this example. The margin accounts for the relay's measurement accuracy.

$$\mathbf{25LOW = 0.95 * 25LOW_{25A} = 0.95 * 106\ V = 100.7\ V} \quad \textbf{(32)}$$

$$\mathbf{25HIGH = 1.05 * 25HIGH_{25A} = 1.05 * 130\ V = 136.5\ V} \quad \textbf{(33)}$$

Voltage Difference Acceptance Criteria

Per IEEE Std C50.13 [6], a 0 to 5% voltage difference may be used as a maximum threshold for synchronization. This setting is configured to be slightly larger than the 25A % voltage difference with margin. The 25A voltage difference threshold is in secondary volts; however, the 25-1 & 25-2 voltage difference threshold is in percent. The margin accounts for measurement error. A margin of 5% was used.

$$\mathbf{25VDIF = \frac{DELTAV_{25A} * 1.05}{VRUN_{NOM\_LG}} * 100\% = \frac{2.5\ V * 1.05}{117.66\ V} * 100\% = 2.2\%} \quad \textbf{(34)}$$

An additional check is enabled to confirm the incoming voltage is greater than the running voltage.

$$\mathbf{25INCV_{HIGH} = Enabled} \quad \textbf{(35)}$$

Maximum/Minimum Slip Considerations

Per IEEE Std C50.13 [6], if a generator is synchronized with a slip of 0.067 Hz or less, maintenance does not need to be performed on the generator. However, in practice the prime mover control may not be fine enough to achieve a slip this low. For this example, the 25A is set with a maximum slip of 0.1 Hz. The 25-1 or 25-2 relay maximum slip setting is set to 110% of the 25A setting so they do not block an automatic synchronization. The margin accounts for measurement error. For this case, the relay has a slip measurement error of ±0.003 Hz.

$$\mathbf{MAXSLIP = MAXSLIP_{25A} * 1.1 = 0.11\ Hz} \quad \textit{\textbf{(36)}}$$

The above calculated setting will allow a synchronism check to pass if the slip is within ±0.11 Hz. The manual synchronizing procedure indicates that the operator is trained to adjust the slip of the generator so that the synchroscope rotates clockwise at a speed rotating slightly faster than the second hand of a clock. This results in an approximate slip of 7.2° per second (MINSLIPMANUAL = 0.02 Hz). The 25A also has a minimum allowable slip set to 0.02 Hz. The 25A has logic enabled to check that the generator is rotating faster than the system. The minimum slip setting is configured so it does not prevent an automatic or manual synchronization. The margin accounts for measurement error.

$$\boldsymbol{MINSLIP = 0.75 * MIN(MINSLIP_{MANUAL}, MINSLIP_{25A}) = 0.015\ Hz} \quad \textbf{(37)}$$

Automatic/Manual Synchronism Check Angle Setting

Per IEEE Std C50.13 [6], if a generator is synchronized with a phase angle difference of 10° or less, maintenance does not need to be performed on the generator. This element is operational when the measured slip is within the MAXSLIP and MINSLIP setpoints. The 25ANG1 setting defines the maximum & minimum angle difference between the incoming and running voltages. It measures slip directly and accounts for the breaker close time. The phase angle limit setting in the 25-1 & 25-2 relays can be set to 25ANG1 = 10°.

Parallel Close Check Angle Setting

This element is enabled to allow 52G2 to be closed in to restore the line if 52L is out of service. It is torque controlled with indication that the generator has been synchronized to the system using breaker status. Standard transmission/distribution line synchronism-check angle limit can be used. Per IEEE Std C37.104 [38], this angle limit is typically set between 20° and 30°. A wide-angle setting is typically used in case the open breaker is tying two systems together whose phase angles have separated by more than 10°. For this application, the parallel close angle check setting is set to match the transmission companies' standard. In this case $25ANG2_{BK} = 20°$.

Synchronism Check Operation & Breaker Close Timers

Based on a breaker timing test, the 52G1 circuit breaker used for this scheme has a 116.7 milliseconds close time.

$$\boldsymbol{TCLSBK1 = 116.7\ ms \times \frac{1\ cycle}{16.67\ ms} = 7\ cycles} \quad \textbf{(38)}$$

$$\boldsymbol{Slip\_Angle_{BK1} = SF_{BK1} \times \left(\frac{360\frac{deg}{cycles}}{60\ Hz}\right) \times TCLSBK1} \quad \textbf{(39)}$$

$$\boldsymbol{Slip\_Angle_{BK1} = 0.1\ Hz \times \left(\frac{360\frac{deg}{cycles}}{60\ Hz}\right) \times 7\ cycles = 4.2°} \quad \textbf{(40)}$$

The automatic synchronizer will issue a close command at 4.2 degrees approaching 0° (12'o clock) on the synchroscope. At maximum slip, the 25-1 & 25-2 relays will issue a close permissive at 14.2° approaching 0° on the synchroscope. See synchronism coordination plot for 52G1 in Figure 56.

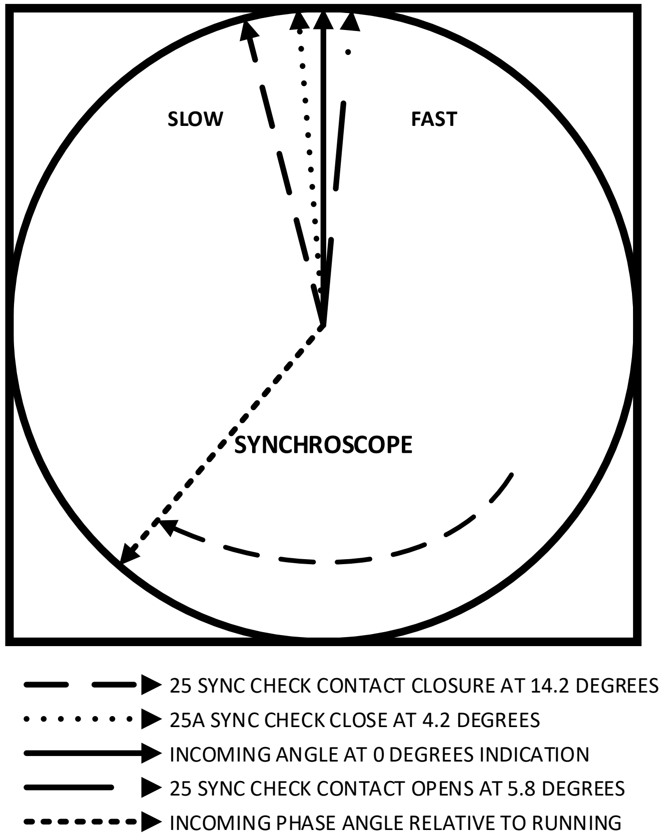

Figure 56: 52G1 Synchronism Coordination Plot at Maximum Slip

Based on a breaker timing test, the 52G2 circuit breaker used for this scheme has an 83.3 millisecond close time.

$$\boldsymbol{TCLSBK2 = 83.3\ ms\ \times \frac{1\ cycle}{16.67\ ms} = 5\ cycles} \quad \textbf{(41)}$$

$$\boldsymbol{Slip\_Angle_{BK2} = SF_{BK2} \times \left(\frac{360\frac{deg}{cycles}}{60\ Hz}\right) \times TCLSBK2} \quad \textbf{(42)}$$

$$\boldsymbol{Slip\_Angle_{BK2} = \ 0.1\ Hz \times \left(\frac{360\frac{deg}{cycles}}{60\ Hz}\right) \times 5\ cycles = 3°} \quad \textbf{(43)}$$

See synchronism coordination plot for 52G2 in Figure 57.

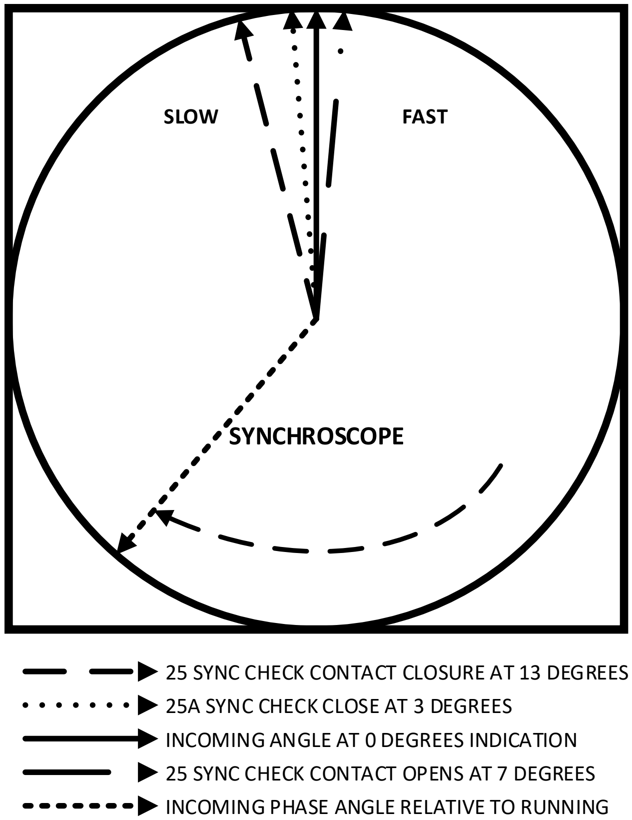

Figure 57: 52G2 Synchronism Coordination Plot at Maximum Slip

Summary of 25-1 & 25-2 Parameters

Table 7: 25-1 Settings

Setting	Value	Description
$SYNCP_{INC}$	VCA	Synchronism phase reference
ACF	0°	Angle Correction Factor
RCF	0.98	Ratio Correction Factor
25LOW	100.7 V	Running/Incoming voltages low supervision
25HIGH	136.5 V	Running/Incoming voltages high supervision
25VDIF	2.2%	Running/incoming voltage difference in %
$25INCV_{HIGH}$	Enabled	Allow closure if incoming voltage is greater than running voltage
MAXSLIP	0.110 Hz	Maximum slip to enable 25ANG1
MINSLIP	0.015 Hz	Minimum slip to enabled 25ANG1

25ANG1	10°	Slip-compensated synchronism check angle
25ANG2	20°	Slip-compensated synchronism check angle #2
TCLSBK1	7 cycles	Breaker close time
25SE	!IN1*IN3	Synchronism enable
OUT1	25A2*IN2	Parallel close
OUT2	25A1	Automatic/Manual synchronism check supervision

Table 8: 25-2 Parameters

Setting	Value	Description
$SYNCP_{INC}$	VCA	Synchronism phase reference
ACF	0°	Angle Correction Factor
RCF	0.98	Ratio Correction Factor
25LOW	100.7 V	Running/Incoming voltages low supervision
25HIGH	136.5 V	Running/Incoming voltages high supervision
25VDIF	2.2%	Running/incoming voltage difference in %
$25INCV_{HIGH}$	Enabled	Allow closure if incoming voltage is greater than running voltage
MAXSLIP	0.110 Hz	Maximum slip to enable 25ANG1
MINSLIP	0.015 Hz	Minimum slip to enabled 25ANG1
25ANG1	10°	Slip-compensated synchronism check angle
25ANG2	20°	Slip-compensated synchronism check angle
TCLSBK2	5 cycles	Breaker close time
25SE	!IN1*IN3	Synchronism enable
OUT1	25A2*IN2	Parallel close
OUT2	25A1	Automatic/Manual synchronism check supervision

APPENDIX B Autosynchronizer Tuning Field Experience

B.1 Legacy Autosynchronizer Example

Field experience with autosynchronizer tuning in several installations has shown a significant reduction in the time taken to synchronize a generator. The early applications were small hydro generators where the water turbulence and low inertia made the speed-match especially difficult. These tests were performed at a hydroelectric station in the North Eastern United States with small generators, which can be quite challenging.

The test results for Generator #1 are shown in Figure 58 with the frequency difference between the generator and the system shown on the y-axis. The results show the generators homing in on the system frequency in three to four precisely-controlled steps.

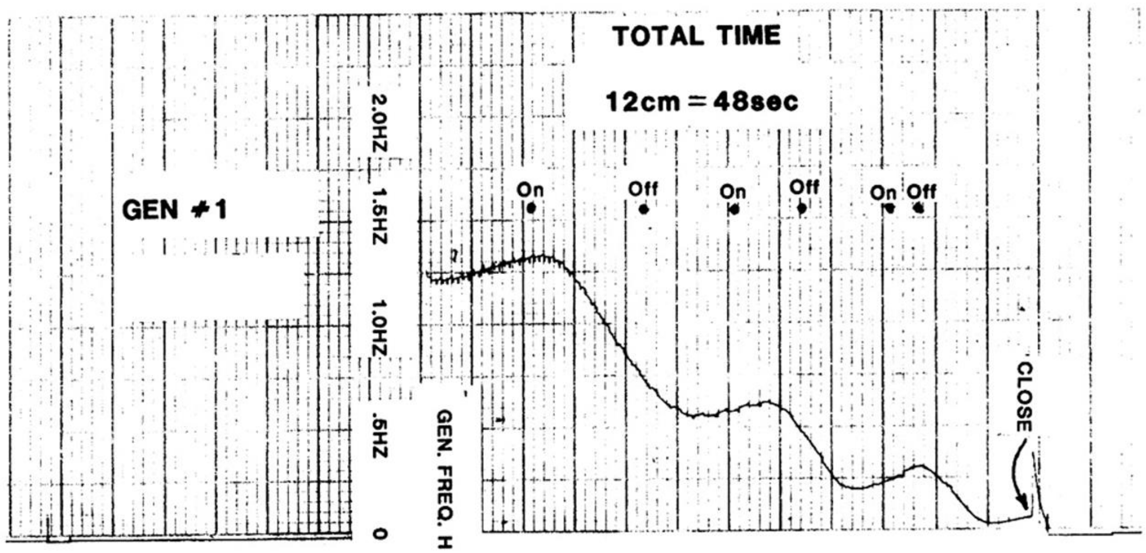

Figure 58: Hydro Station Test Results for Speed-Match of Gen #1

Three generators, two rated at 6,250 kVA and one at 7,500 kVA, driven by Francis turbines, were individually tripped offline and then automatically restarted. A final test was run with two units tripped and restarted in sequence. The Generator Control Unit, which was switched to all three generators, supplied control pulses to Woodward Type A actuators that, in turn, controlled hydraulic servomotors to move the wicket gates. These pulses are indicated by the "On" and "Off" marks on the recordings of Figure 59 and Figure 60. The frequency difference acceptance limit on the automatic synchronizer was set at 0.15 Hz (three small divisions on the chart). Once the frequency and the voltage difference limits were met, the breaker closed on the next pass through zero degrees.

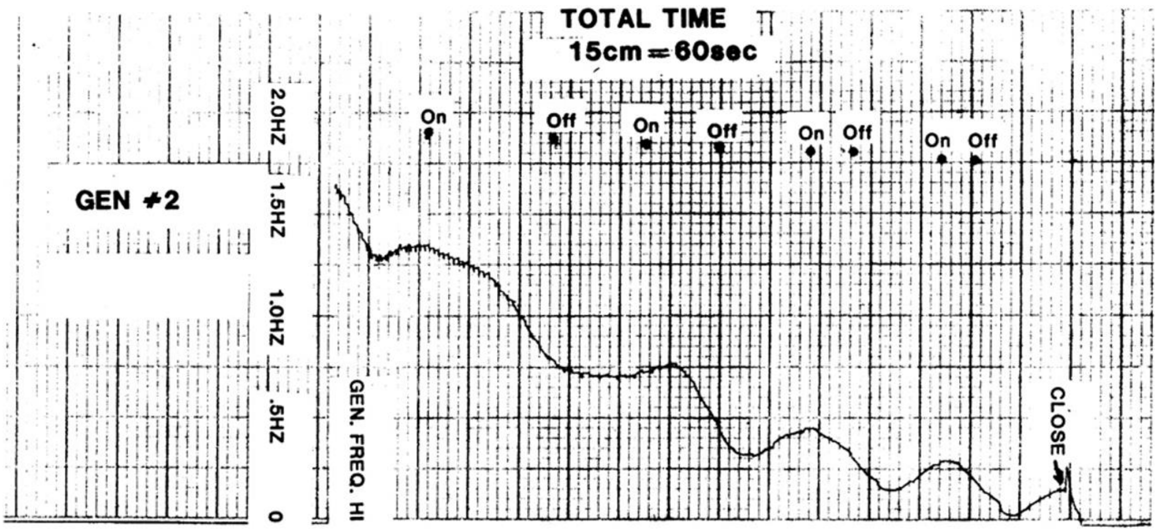

Figure 59: Hydro Station Test Results for Speed-Match of Gen #2

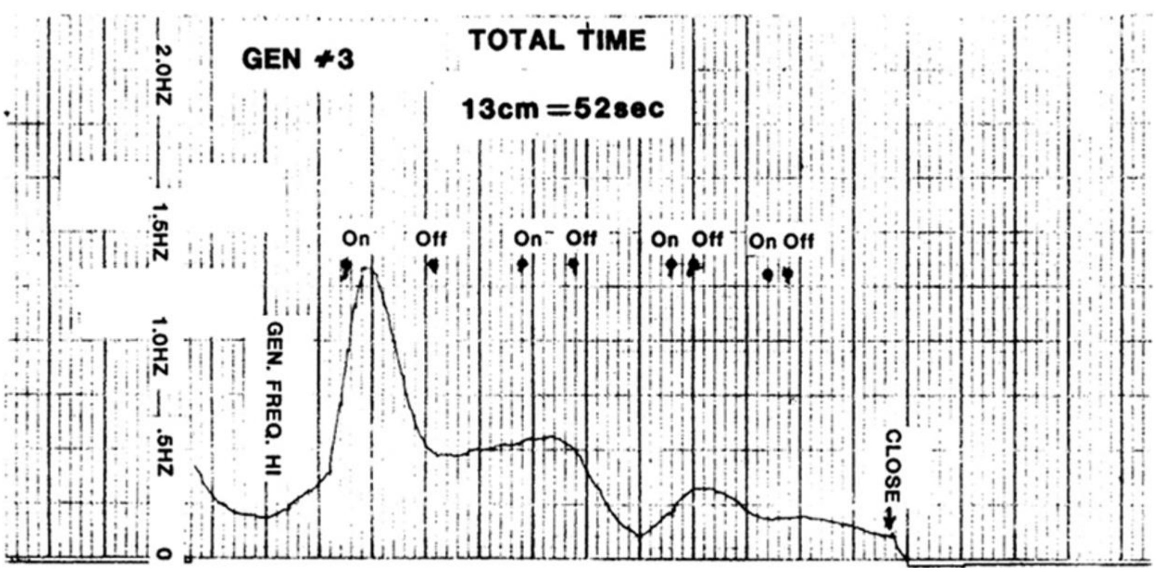

Figure 60: Hydro Station Test Results for Speed-Match of Gen #3

One unexpected result from the tests was observed when comparing the test results of Figure 58, Figure 59, and Figure 60 with tests run earlier that day. The morning tests were performed with a pulse width setting of 5 seconds/Hz and a pulse period of 10 seconds. For the afternoon tests, the pulse width setting was doubled to 10 seconds/Hz and the pulse period was halved to 5 seconds. The total time to synchronize the generators is summarized in Table 9.

It was expected that increasing the pulse width setting and decreasing the pulse period would reduce the time to synchronize. However, the nearly two-to-one difference in the time it took Generator #2 to synchronize compared to the two other generators (148 seconds versus 82 or 92 seconds) was practically eliminated by the new settings.

The results indicate that multiple generators with widely varying response times can be controlled with a single shared automatic synchronizer by utilizing pulse width modulation. It is also apparent that the proportional pulse width modulation (see Section 3.1.5) is especially effective for hydro plants by automatically compensating for large changes in net head and torque that would otherwise cause the starting characteristics to vary drastically.

Table 9: Time-to-Synchronize Compared for Two Sets of Control Parameters

Generator	Morning Time-to-Synchronize (Pulse Width = 5 seconds/Hz; Pulse Period = 10 seconds)	Afternoon Time-to-Synchronize (Pulse Width = 10 seconds/Hz; Pulse Period = 5 seconds)
Gen #1	82 seconds	48 seconds
Gen #2	148 seconds	60 seconds
Gen #3	92 seconds	52 seconds

B.2 Microprocessor Autosynchronizer Example

An automatic synchronizer that provides a synchronizing recording function can be very useful in optimizing tuning of the control functions. This example is from a new automatic synchronizer installed on an existing hydroelectric generator during a protection and control system modernization project. The recordings shown in Figure 61 and Figure 62 were provided to the design engineer by the commissioning technicians for review. No attempt had been made to tune the control characteristics prior to synchronizing the unit for the first time.

All control parameters were left at default. The automatic synchronizer uses a proportional pulse duration characteristic for both frequency and voltage correction. Each function has an interval setting in seconds and an adjustment rate setting (proportional slope) in Hz/seconds or volts/seconds.

From the time axis in Figure 61, we can see that the unit took approximately 1 minute to synchronize.

B.2.1 Frequency Matching

Figure 61 shows the slip frequency and the slip frequency permissive window. The window is set to allow synchronizing between 0.05 Hz and 0.10 Hz fast. We can immediately observe that the frequency matching control is hunting. The control issues five frequency raise pulses and six frequency lower pulses. We can see that the frequency overshoots the permissive band in both directions. SLIPOK asserts only intermittently.

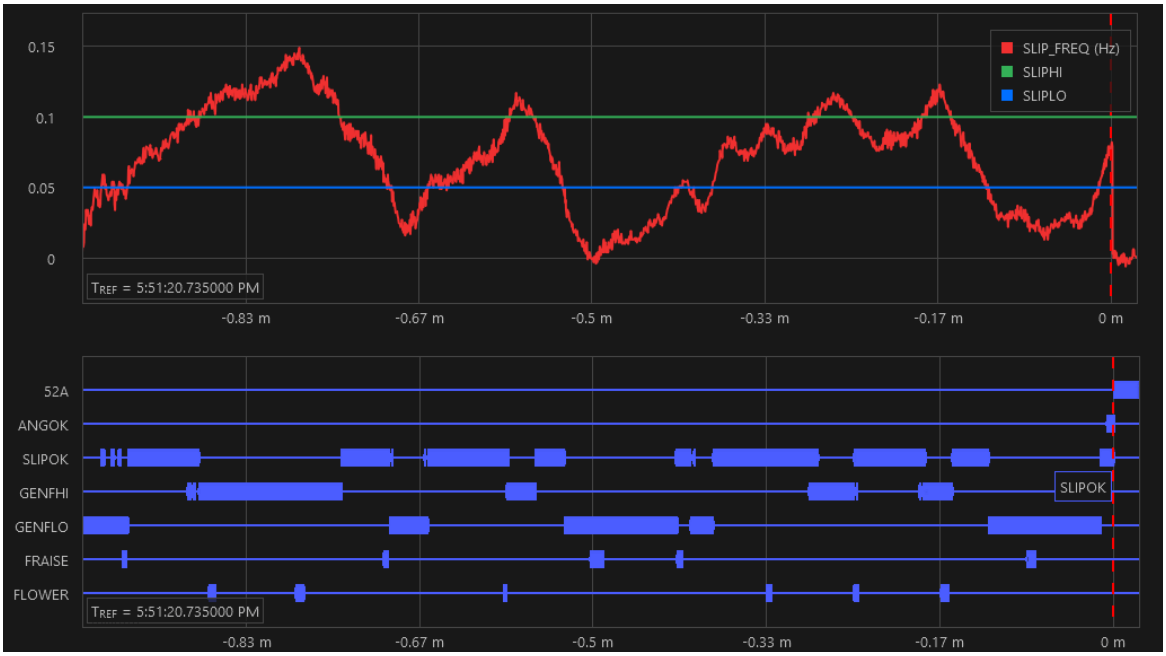

Figure 61: Frequency Correction Pulse Response

It appears that the generator was synchronized after only one minute due to the fortunate coincidence of the slip being in the permissive band (SLIPOK asserted) when the angle passed through zero degrees (ANGOK asserted).

Based on this recording, the design engineer recommended that the Hz/Seconds setting be increased by a factor of three to five. Increasing the Hz/Seconds setting in this device tells the control to expect a larger change of frequency for each pulse which effectively reduces the duration of the pulse compared to how far the frequency is from the center of the permissive band. The pulse interval was left at the default setting of five seconds between pulses because the governor appears to respond very quickly to each correction pulse.

B.2.2 Voltage Matching

Figure 62 shows the voltage difference (DELTA_VOLT) and the voltage difference permissive window. The window is set to allow synchronizing between 0.0 and 1.9 volts secondary high. We can immediately observe that the voltage matching control needs to be set more aggressively. The control issues eight voltage raise pulses. We can see that the voltage moves very little with each pulse.

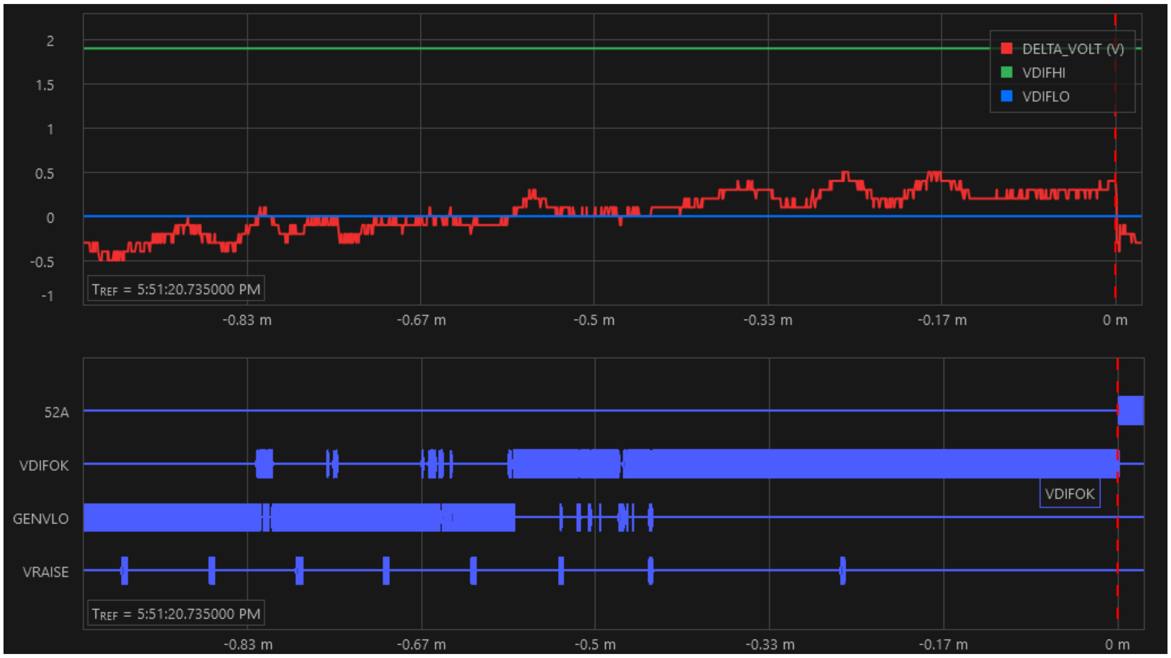

Figure 62: Voltage Correction Pulse Response

VDIFOK asserts fairly early because the voltage was fairly closely matched prior to initiation of the synchronizing operation.

Based on this recording, the design engineer recommended that the V/Seconds setting be decreased by a factor of three to five. Increasing the V/Seconds setting in this device tells the control to expect a larger change of voltage for each pulse which effectively reduces the duration of the pulse compared to how far the voltage is from the center of the permissive band. The pulse interval was left at the default setting of five seconds between pulses because the AVR appears to respond very quickly to each correction pulse.

The commissioning technicians were then instructed to analyze the recording after the next synchronizing operation and further refine the control settings to get good performance.

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