

OOPS, Out-of-Phase Synchronization

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Abstract—Out-of-phase synchronization (OOPS) of a synchronous generator can damage the shaft and prime mover due to large transient torques. Additionally, stator and transformer windings are susceptible to damage from high currents during a faulty synchronization. Real-world OOPS events can result from voltage transformer wiring errors or synchronizing system failures. Protection elements typically applied to generating units cannot reliably detect poor synchronizing events and, consequently, do not reliably trip units for these potentially damaging events.

In this paper, we present an OOPS protection scheme that has been implemented to detect faulty generator synchronization and provide high-speed tripping. We share a real-world event of a steam turbine generator that was synchronized 180 degrees out of phase and demonstrate the performance of the scheme. Using simulations and analysis, we consider the transient torque due to out-of-phase synchronizing at other angles. We provide setting guidance and other tripping considerations for the OOPS scheme. The paper also includes a discussion of testing methods for verifying synchronizing circuits.

I. INTRODUCTION

An out-of-phase synchronization (OOPS) event results in a torque transient on the generator and prime mover. It exposes the generator, generator step-up (GSU) transformer, and system elements to a current transient that puts mechanical and thermal stresses on windings and other conductors. As shown in this paper, these transients can be significant. Depending on the machine, an OOPS event can excite torsional resonances in the drivetrain [1]. Since damage due to mechanical stresses tends to be cumulative in nature, it is important to detect these occurrences and clear the condition as quickly as possible.

A synchronizing system designed to be fault tolerant using guidelines in [2] that is properly installed and commissioned can significantly reduce the occurrence of OOPS events. But, the consequences of these events can be catastrophic, so providing a protection scheme for this low probability, high-impact event is recommended.

A wiring or design error is the most common cause of an OOPS event, although such an event can also originate from a voltage transformer (VT) problem, control system failure, or a setting error. A wiring error results in a significant angle (60 degrees or more) across the breaker at the instant of closing. Another cause of an OOPS event might be a sticky or slow synchronizing breaker. In this scenario, the synchronizing system works properly and energizes the breaker close coil at the moment of phase coincidence, but the breaker actually closes outside of the safe angle window.

In the authors' experience, OOPS events occur more often than some other events for which the generator is protected.

Nonetheless, a protection scheme to detect and trip for an OOPS event is not presently covered by industry guidelines [3]. Depending on the implementation, some inadvertent energization schemes may operate for an OOPS event. However, as we will see, the scheme requirements for an OOPS event are not onerous and, in the interest of accurate targeting, a dedicated scheme may be warranted.

For a slow-synchronizing-breaker scenario, IEEE C37.119-2016 includes a scheme for preventing an OOPS event [4]. But that scheme is limited to the specific circumstances of a properly functioning synchronizing system and a faulty breaker, so it will not be discussed further in this paper.

In this paper, we characterize the damage potential associated with an OOPS event in terms of instantaneous torque and current and compare it with acceptable synchronizing thresholds [5] [6], full-load current, and a three-phase fault. We present protection scheme logic and provide setting guidance. Finally, we consider approaches to ensure that an OOPS event does not occur in the first place via verification of the synchronizing circuits. We look at different approaches that energize VTs from a common source to prove that phase angles and voltage magnitudes match when the breaker is closed to avoid an OOPS event in the first place.

II. CASE STUDY: SYNCHRONIZING 180 DEGREES OUT-OF-PHASE ON A 373 MW GENERATOR

To understand the causes and behaviors of OOPS, we consider a real-world event. Fig. 1 shows a natural gas-fired combined-cycle power plant. The combustion turbine generators (CTGs) release heat as a byproduct of combustion, which is used to generate steam. The steam is then converted to electric power via the steam turbine generator (STG), making combined-cycle plants one of the most efficient types of fossil fuel generation.

This plant was on outage to modernize the line current differential protection (87L) on the 345 kV bus connecting the plant to the utility tie station. As is often done during plant outages, plant personnel took the opportunity to perform additional work, in this case replacing and relocating the 18 kV VT junction box on the STG that was severely corroded. The OOPS event happened during the first synchronization of the STG after the outage.

The startup process required first energizing the CTG main power transformers to restore auxiliary power to the station. Then, one of the CTGs was brought online to generate steam so that the STG could be brought online. Prior to the OOPS event, Breakers 2, 3, and 4 were closed with only CTG 1 online. Once

adequate steam pressure was built up, the STG was energized and ramped to nominal frequency and voltage to synchronize to the grid. Immediately on the closing of Breaker 1, the 87L relays tripped all five 345 kV breakers.

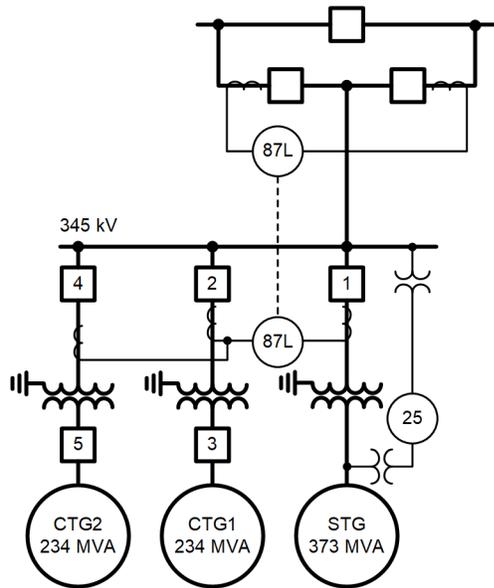


Fig. 1. Combined-Cycle Plant With Strain Bus Tie Line

The first hypothesis was that the current transformer (CT) connections were not phased correctly to the new 87L relays, resulting in the 87L trip when the STG picked up load. Looking at the currents from available oscillography (Fig. 2a), the plant personnel observed that there was an extremely high three-phase current magnitude of 55 kA (4.7 pu) produced by the generator. Was it possible that the cause was a three-phase fault simultaneous to the synchronization? This was unlikely given that both sides of Breaker 1 were energized prior to synchronization. Furthermore, 345 kV SF₆ breakers have three separate tanks; if a breaker mechanism had failed, it likely would not have caused a three-phase fault.

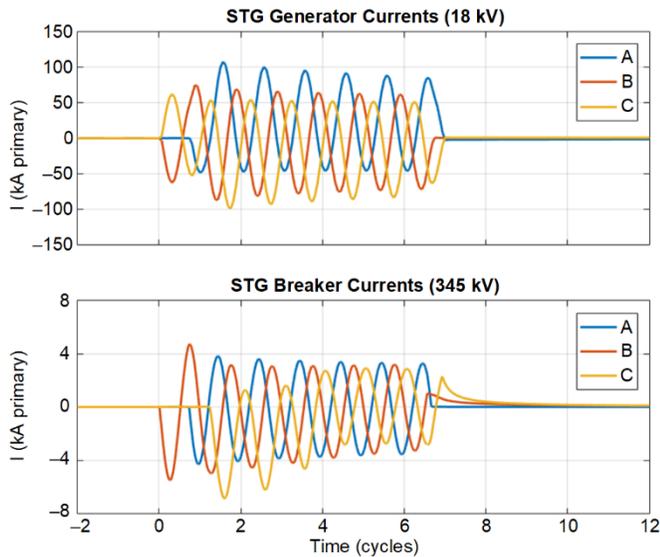


Fig. 2. Currents From Oscillography at the Time of the OOPS Event

The next hypothesis was poor synchronizing. The 18 kV VT cables that had been replaced were tested to verify the synchronizing circuits. After further investigation, it was confirmed that the polarities of the VTs were connected backward, resulting in a 180-degree OOPS event, despite an ideal synchronizing indication from the synchroscope. Because the VT junction box replacement and relocation was tacked-on work for this outage, the work plan had not included steps to verify the primary phasing of the VT circuits during startup.

The plant personnel who replaced the VT junction box did not understand the risk they had caused the plant. They performed no tests to verify the phasing to the relays and synchronizing circuits after replacing nearly all the VT wiring and cables. Methods to verify synchronizing circuits are discussed in Section V.

Inspection of Fig. 2 shows that the bus was cleared in about 7 cycles by the 87L relays. The cause of this sympathetic trip was CT saturation due to the high currents from the 180-degree OOPS event. Further discussion of the sympathetic trip is beyond the scope of this paper. However, the opening of the tie to the grid in only seven cycles was a fortuitous event.

To understand the severity of a 180-degree OOPS event, we used the recordings from the generator relay (Fig. 3) to calculate the instantaneous air-gap torque (T_{em}) using the method presented in [7].

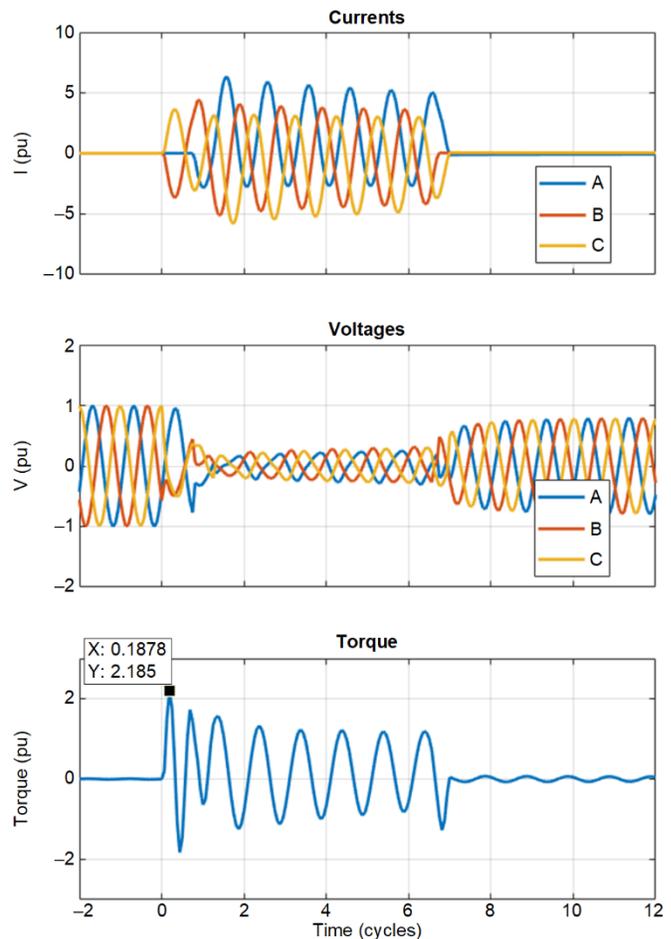


Fig. 3. Currents, Voltages, and Calculated Torque From Field Event

In this method, T_{em} is given by (1) using the quantities calculated in (2) and (3).

$$T_{em} = \psi_d \cdot i_q - \psi_q \cdot i_d \quad (1)$$

$$\psi_d = \omega_b \cdot \int (v_d - r_s \cdot i_d) \quad (2)$$

$$\psi_q = \omega_b \cdot \int (v_q - r_s \cdot i_q) \quad (3)$$

The subscripts d and q refer to direct and quadrature quantities. The quantity r_s is stator resistance, and ω_b is the nominal angular frequency. The instantaneous values for v_d , v_q , i_d , and i_q are calculated directly from event report voltages and currents. A numerical integration method is used to calculate ψ_d and ψ_q , the d and q components of flux. The maximum torque is 2.2 pu and the current magnitude is 4.7 pu for this 180-degree OOPS event, normalized to generator ratings.

There was significant pole scatter (20 ms between the first and last pole closing) during the close of the STG synchronizing breaker (Fig. 2b). During the pole scatter period, the CTG 1 GSU transformer supplied substantial zero-sequence current (shown by the Breaker 2 currents in Fig. 4), similar to a ground fault. Once the last pole closed, the currents became balanced but were trapped with significant offset and no zero crossings. If the CTG breakers had to interrupt such currents, the interrupters could be damaged. Fortunately, all of the other breakers around the bus tripped due to the sympathetic 87L trip. The other breakers did not experience missing current zero crossings. Current zero crossings may also disappear during an OOPS event [8] via a different mechanism (see Section III).

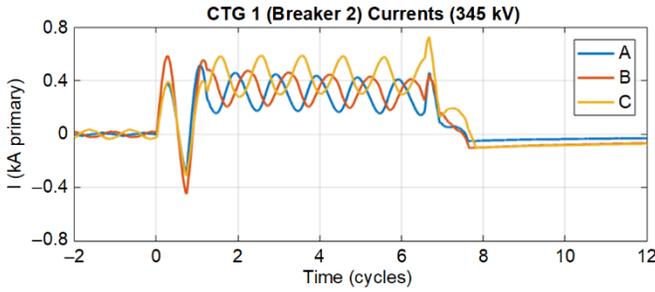


Fig. 4. Missing Zero Crossings in CTG Currents

OOPS events often occur after work is performed on synchronizing equipment and circuits. Wiring errors may lead to OOPS events at $\delta_0 = \pm 60$ degrees, ± 120 degrees, or 180 degrees. Pole scatter also has an effect on generator torque and currents. The effect of synchronizing angle and pole scatter are discussed in Section III.

III. CHARACTERISTICS OF AN OOPS EVENT

A. Simplified System Model, Parameters, and Validation

The breaker close corresponding to the event of Fig. 2 had significant pole scatter, which affects the current and torque magnitudes. To better understand the characteristics of an OOPS event, we modeled the system of Fig. 1 without the CTG units. The simplified system of Fig. 5, with the parameters in Table I, was used to better understand the phenomenon. The MVA base for all the parameters is 373 MVA.

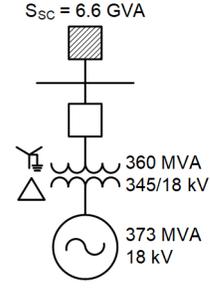


Fig. 5. Simplified System Simulation Model (S_{sc} is the system short-circuit MVA rating)

TABLE I
PARAMETERS FOR THE SYSTEM OF FIG. 5

Parameter	Data
$X_d, X_d',$ and X_d''	2.276 pu, 0.294 pu, and 0.214 pu
$X_q, X_q',$ and X_q''	2.238 pu, 0.614 pu, and 0.195 pu
X_l	0.122 pu
R_s	0.004 pu
T_d' and T_d''	0.530 s and 0.023 s
T_q' and T_q''	0.409 s and 0.023 s
H (inertia constant of generator and turbine)	2.92 s
GSU impedance (X_T)	0.0446 pu, X/R = 84.4
System equivalent (X_s)	6,600 MVA, X/R = 11 (0.0288 pu)

To validate the system of Fig. 5, we applied the same breaker pole scatter to obtain the simulated signals of Fig. 6.

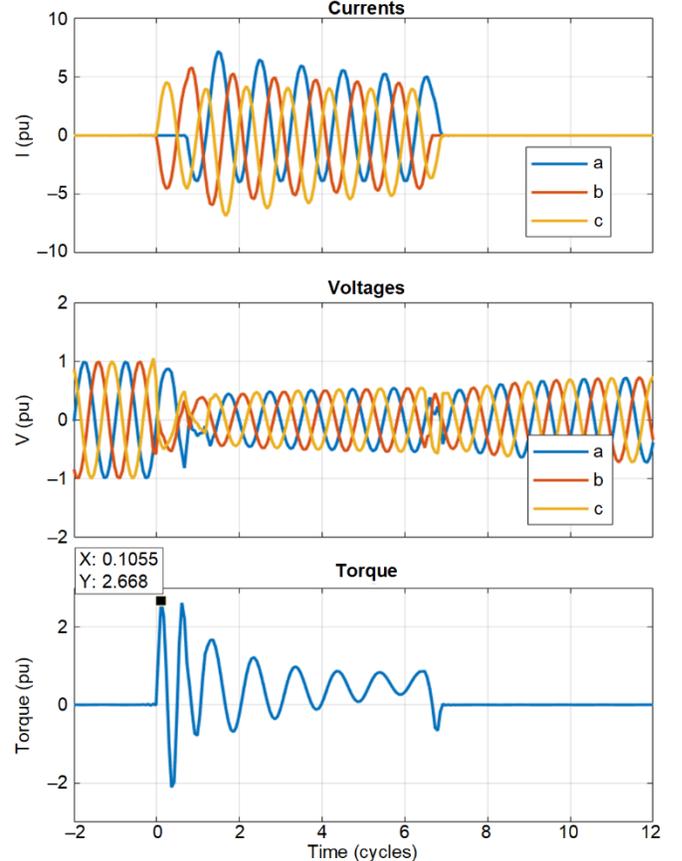


Fig. 6. Simulated Currents, Voltages, and Torque

The signals look very similar to the event in Fig. 3, indicating that the model is sufficiently accurate. The minor differences, such as the voltage magnitude differences during the OOPS event, may be attributed to the omitted CTGs.

B. Current and Torque Magnitudes During OOPS Events

Using the model, we simulated out-of-phase close events from 0 to 180 degrees. The peak torque and current magnitudes the generator was exposed to are shown in Fig. 7. The peak torque is an instantaneous value obtained from simulation, whereas the current magnitude corresponds to a filtered signal from a relay with the dc offset removed. If the generator voltage is equal to the system voltage, then the current can be represented using (4), similar to what is shown in [8].

$$I_{AC} \approx \frac{V \cdot |1 - \angle \delta_0|}{X_{total}} = \frac{2 \cdot V}{X_{total}} \sin\left(\frac{\delta_0}{2}\right) \quad (4)$$

where:

I_{AC} is the maximum ac current magnitude.

V is the generator and system voltage magnitude (typically 1 pu).

X_{total} is the sum of X_d'' , X_T , and X_S .

δ_0 is the synchronizing angle (the initial angle difference across the breaker).

The maximum torque on the generator shaft can be represented via (5), a simplified form of what is shown in [1].

$$T_{em} \approx \frac{V^2}{X_{total}} \left(\sin(\delta_0) + 2 \sin\left(\frac{\delta_0}{2}\right) \right) \quad (5)$$

Equations (4) and (5) were used to create Fig. 7. The theoretical torque is higher because the simulation numbers have delays and filters. For reference, we simulated a three-phase fault at the generator terminals and obtained a peak torque of 4.5 pu and a current magnitude of 4.4 pu.

For our system, the torque imposed on the generator for a 10-degree close is nearly 1 pu and the current is 0.5 pu. This informs us that the >10-degree limit to declare a faulty close specified in [5] and [6] may limit the forces during synchronizing to close to the generator ratings.

The torque and current magnitudes in Fig. 6 are lower than those for the 180-degree close in Fig. 7 because Fig. 6 has pole scatter identical to the event of Fig. 3 whereas Fig. 7 has no pole scatter. During a pole scatter, when the first pole is closed while the other poles are open, the effective system strength is lower, which substantially lowers the generator torque and currents as calculated in (4) and (5). Furthermore, the synchronizing angles for the subsequent poles change due to the closed poles changing δ , making the behavior quite complex. The lower currents available due to pole scatter influence protection element margins, as discussed in Section IV.

Equations (4) and (5) are conservative (worst-case) approximations and do not account for the decay associated with the various system time-constants. The system of Fig. 5 was quite strong, which is not uncommon in the modern power system; higher system impedances reduce the current and torque the generator is exposed to proportionally.

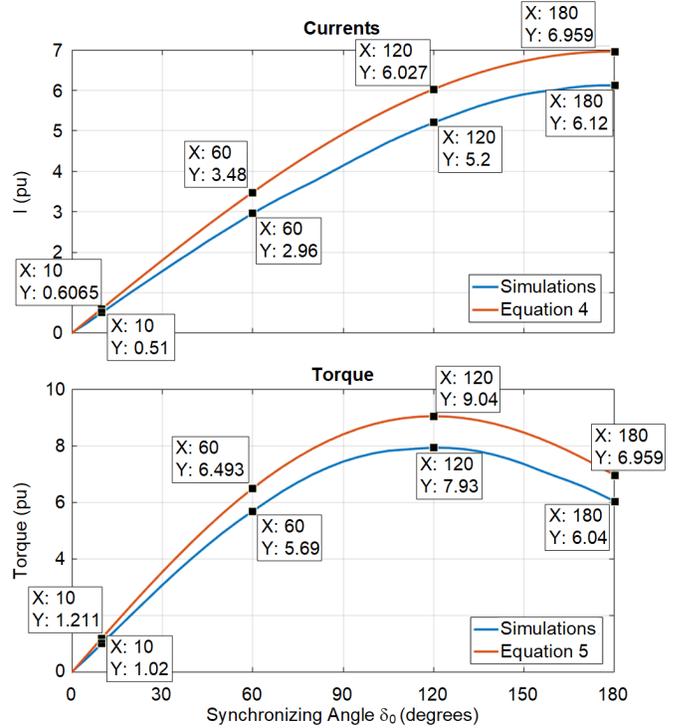


Fig. 7. Currents and Torque as a Function of Synchronizing Angle δ_0

C. Loss of Current Zero Crossings

An OOPS event creates a power system transient due to the synchronizing angle (δ_0) across the breaker. The current waveforms can exhibit a loss of zero crossings during the transient as the rotor is pulled from δ_0 to closer to the system angle. This phenomenon is covered in detail in [8]. The voltage driving the initial current is the difference in voltage between the rotor voltage and the system voltage. As the rotor angle gets closer to the system angle, the driving voltage gets smaller and the magnitude of the ac current becomes smaller. The time constant of the reduction of ac current magnitude is a function of how fast the rotor angle moves and the time constant of the transition from subtransient to synchronous impedance. On the other hand, the magnitude of the dc transient is a function of the initial ac magnitude and the point-on-wave at which the contacts close. The time constant of the dc transient (τ) is a function of the X/R ratio (X_{total}). If the ac component collapses faster than the dc component, zero crossings can be lost for a time. Fig. 8 illustrates the effect.

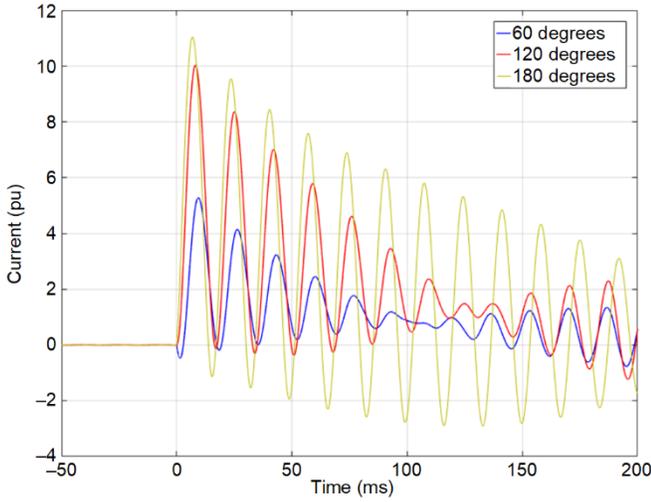


Fig. 8. Impact of δ_0 on Delayed Current Zero Crossings (Phase B shown)

The ac part is provided by (6) and the dc part corresponds to (7). Interrupting the current during the period where there are no zero crossings places additional burden on the breaker contacts [9].

$$i_{ac} \approx \frac{2V_s}{X_{ac}} \sin\left(\frac{\delta}{2}\right) \quad (6)$$

$$i_{dc} \approx \frac{2V}{X_{total}} \sin\left(\frac{\delta_0}{2}\right) e^{-\frac{t}{\tau}} \quad (7)$$

X_{ac} is the sum of X_d' , X_T , and X_S , as the time frames under consideration for a loss of zero crossings generally occur in the transient period, which is longer than T_d'' . Note also that i_{ac} is a function of δ and is defined by the well-known swing equation shown in (8).

$$\frac{2H}{\omega_0} \cdot \frac{d^2\delta}{dt^2} \approx \frac{2V^2}{X_{ac}} \sin(\delta) + T_{br} \quad (8)$$

T_{br} is the braking torque and is responsible for the difference in response when an OOPS event occurs at a negative versus a positive δ_0 . Equation (8) is a second-order, nonlinear differential equation that can only be accurately solved using numerical methods.

The initial angle (δ_0) has a significant impact on the time required for δ to reach zero, which in turn dictates the onset of delayed current zero crossings, as shown in Fig. 8. In this figure, OOPS events are simulated at angles of 60 degrees, 120 degrees, and 180 degrees using the example system of Fig. 5. A 180-degree value results from a polarity error (e.g., comparing A with $-A$); a 120-degree value results from a transposition error (e.g., comparing A with B); and a 60-degree value results from a setting error or a polarity-and-transposition error (e.g., comparing A with $-B$). The 60-degree value is less likely than the others but not impossible. Note that a larger δ_0 provides more time for dc decay and, in the 180-degree case, there is no loss of current zero crossings. The worst case is at 60 degrees, where the loss of current zero crossings begins after approximately two cycles. Section IV addresses the 60-degree case for setting OOPS protection.

The closing point-on-wave has a minor impact on the time to a delayed current zero crossing (when any of the three phases loses zero crossings) and varies by approximately $\pm\frac{1}{2}$ cycle during a close without any pole scatter.

Examination of (6), (7), and (8) reveals additional dependencies. DC decay is strongly influenced by the X/R ratio. Furthermore, the magnitudes of i_{dc} and i_{ac} are each a function of the system impedances, which are a function of the stiffness ratio (SR) defined by (9) [10] where S_{SC-SYS} is the short-circuit MVA of the system, and S_{SC-GEN} is the short-circuit MVA of the generator.

$$SR = 1 + \frac{S_{SC-SYS}}{S_{SC-GEN}} \quad (9)$$

Finally, the inertia constant (H) dictates how quickly the rotor can move and, therefore, how long it takes for δ to reduce from δ_0 to a low value.

The example system of Fig. 5 was used to quantify the impact of X/R, SR, and H on the time to a delayed current crossing. Each of these three parameters was varied with the rest of the parameters held constant. The time of the last zero crossing was measured and the minimum for the three phases was recorded in Fig. 9. Note that a loss of current zero crossings does not occur in the region to the right of the plotted data.

The results of Fig. 9 apply specifically to the example system of Fig. 5 but also provide some general insight. Examination of this figure shows that it is prudent to trip for an OOPS event with no intentional delay. Delayed current zero crossings could be an issue in cases where the system X/R ratio is unusually high.

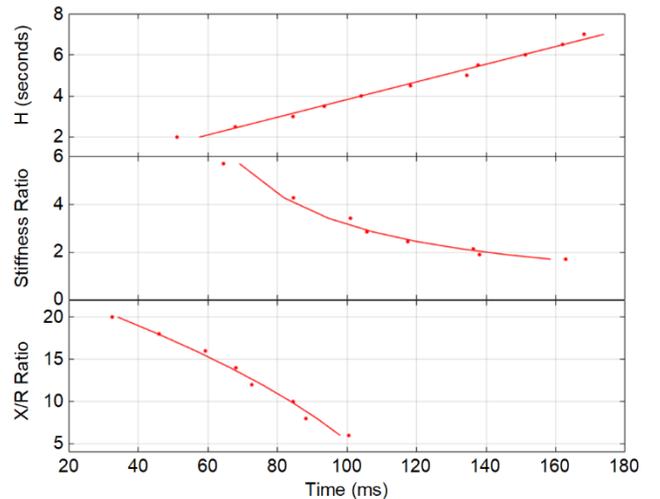


Fig. 9. Impact of H, SR, and the X/R Ratio on the Time to a Delayed Current Zero Crossing at $\delta_0 = 120^\circ$

In these simulations, the breaker was not tripped following the OOPS event. Breaker arc resistance can provide significant additional damping. To illustrate, we implemented an arc model using (10), provided from [8], which was obtained from numerous interrupting tests with SF₆ breakers.

$$V_{arc} \approx \text{sign}(i) \cdot 3,500 \cdot |i|^{-\frac{1}{6}} \quad (10)$$

The arc model was implemented in breakers on both sides of the GSU. The low-voltage (LV) breaker carries a higher magnitude current during the OOPS event due to the lower voltage. In addition, the resulting LV breaker arc voltage is in opposition to the much lower generator voltage. The results are shown Fig. 10. Either the high-voltage (HV) or LV breaker is used to clear the OOPS event after 100 ms. Results are shown with and without the arc model. It is evident that breaker arcing has virtually no impact when opening the HV breaker but a significant impact when opening the LV breaker. Therefore, a loss of current zero crossings should not be a concern for LV breaker applications [8]. This may be a protective consideration, as discussed in Section IV.

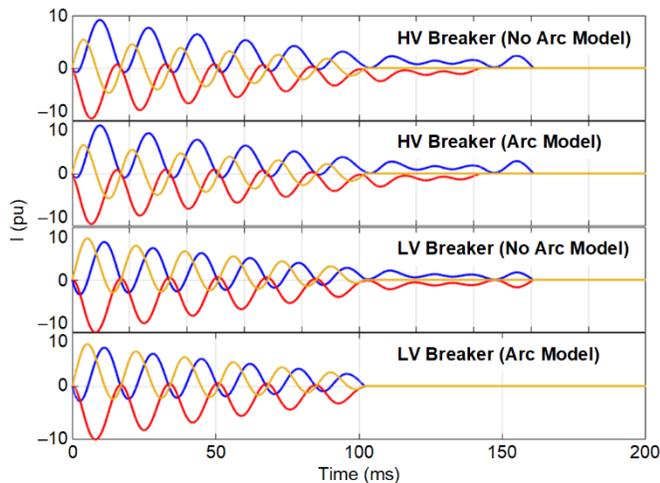


Fig. 10. Impact of Breaker Arc Voltage

IV. OOPS PROTECTION ELEMENT

Traditional generator protection cannot typically detect OOPS events. Generally, most elements that might be responsive to the high currents during an OOPS event are time-delayed, and high-speed differential elements are blind to this event. The inadvertent energization element is typically disabled by the presence of voltage and/or the field breaker closed status, thus disabling the element during an OOPS event [11]. Furthermore, an OOPS event can continue to occur every time a generator is synchronized until the underlying cause is addressed.

Duke Energy engineers have also had experiences with OOPS events in the past. To detect and trip for OOPS events, they implemented an additional protective element by modifying the inadvertent energization function. This element consists of an instantaneous overcurrent (50) that is enabled for 15 cycles immediately after the breaker closes, as shown in Fig. 11. The use of a current-only scheme ensures that voltages that may be compromised due to synchronizing circuit issues do not affect the scheme.

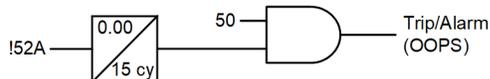


Fig. 11. OOPS Protection Scheme

A. Overcurrent (50) Pickup

The pickup set point of this protective element should be sensitive enough to detect an OOPS event but should also be high enough that it does not inadvertently operate on an acceptable synchronization. The magnitude of the synchronizing current can be calculated via (4).

The angle δ_0 used for (4) may require consideration of the synchronizing breaker location. If the breaker is on the LV side, arc resistance typically helps introduce zero crossings that allow the breaker to clear the OOPS condition (Fig. 10d). If the breaker is on the HV side, breaker design plays a key role. Generator breakers are often specifically designed to produce enough arc voltage to deal with a loss of zero crossings [9]. If not, additional security may be considered.

The scheme must also be dependable for cases where the breaker has pole scatter. An adequate dependability margin is required to ensure that the relay detects an OOPS event. Later in this section we provide an example.

B. Arming/Tripping Logic

The 50 element should not be enabled on the machines while they are online due to the inability to coordinate the element with other protective systems. An OOPS event, however, results in a high current magnitude at the instant of breaker closure. We can use a 52A status signal, in conjunction with a timer with a 15-cycle dropout delay, to disable the overcurrent element 15 cycles after the breaker closes. As noted in Section III, this condition must be cleared immediately because zero crossings may stop if the condition persists. Hence, no additional time delay should be provided and the element should trip instantly.

This scheme also detects and trips high-speed for the slow-breaker-close OOPS scenario, which may mitigate the need for the breaker-failure-based slow synchronizing scheme described in [4]. Another consideration may be to alarm for a poor synchronization exceeding 10 degrees [5] [6].

C. Field Experience and Scheme Validation

Duke Energy has used this protective element on over 75 units since 2011. The element has never misoperated, and it correctly operated once during a breaker flashover event. Although Duke has not yet experienced an OOPS event on a unit where this protection has been implemented, the element has been proven to work in a lab environment.

We confirmed the scheme dependability for the event of Fig. 3, as shown in Fig. 12. The overcurrent threshold was set based on the assumption of an HV breaker that was not designed to produce enough arc voltage to handle a loss of zero crossings, which occurs quite quickly in the 60-degree case (Fig. 8). Therefore, we set our overcurrent element to the theoretical maximum of 3.5 pu using (4) with $\delta_0 = 60$ degrees.

For our 180-degree field event, we used a margin of 35 percent (4.73 pu versus a setting of 3.5 pu). If we had a 120-degree event with the same level of pole scatter, we might expect a current of 4 pu based on the ratio of currents in Fig. 7. This is about 15 percent higher than the 3.5 pu setting, demonstrating scheme dependability.

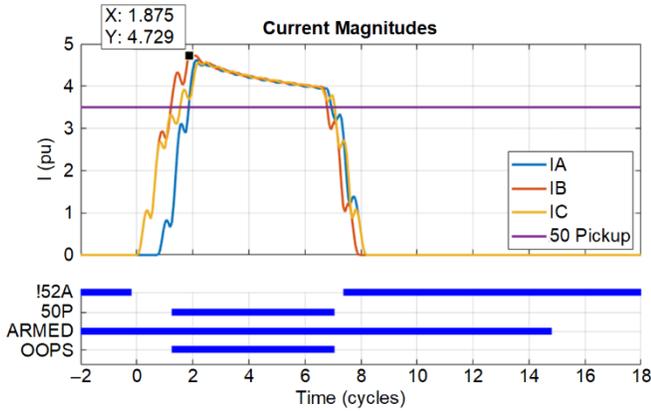


Fig. 12. OOPS Protection Scheme Validation Using Field Event

If we had a 60-degree event with no pole scatter, we might expect a current, as measured by a relay, of 2.96 pu (Fig. 7). Our pickup setting is 18 percent above this value, demonstrating scheme security.

As noted earlier, generator breakers are often designed to produce enough arc voltage to resolve the issue of a loss of zero crossings [9]. In such cases, an additional dependability margin may be added. A setting of 1.5 pu is significantly above the currents observed from an acceptable synchronization of 0.5 pu (Fig. 7). It is also 50 percent of a realistic 60-degree OOPS event of 2.96 pu.

D. Application Considerations for Generators Designed for Black-Start

Black-start generators are designed to be able to start when normal grid-supplied auxiliary power is not available. They are grid reliability assets used to recover from a wide-area system blackout. A black-start generator is used to pick up loads and allow other generators to be started in the planned grid restoration sequence. Thus, a black-start generator will often include a permissive path in the synchronizing breaker closing circuit to allow closing under a hot-generator/dead-bus scenario. In many black-start scenarios, closing the synchronizing breaker will energize a transformer. The resulting inrush currents may be higher than the pickup setting of the OOPS scheme and therefore prevent the grid restoration sequence from continuing. Thus, the OOPS scheme for a black-start generator may require additional supervision.

The closing circuit for a generator synchronizing breaker that must allow a permissive path for a dead-bus scenario has to be designed with care. The bus-side voltage sensing relay cannot tell the difference between a dead bus and a blown VT fuse. For this reason, we recommend including an operator-controlled dead-bus close permissive control, 43DB [2]. The human operator is required to confirm that the intention is to close the synchronizing breaker to energize a dead bus or step-up transformer before this path is asserted. If the breaker closing circuit does not have this feature, a faulty synchronization is possible if there is a problem with the bus-side voltage sensing circuit and the protection provided by the OOPS scheme should not be disabled.

The application of the OOPS protection scheme to a black-start generator should be assessed. If the black-start sequence

can result in inrush currents above the pickup setting of the OOPS scheme when the synchronizing breaker is closed, the hot-generator/dead-bus close permissive path should include the previously mentioned 43DB control. The scheme is then modified as shown in Fig. 13 to use this control to prevent the OOPS scheme from misoperating during a black-start operation.

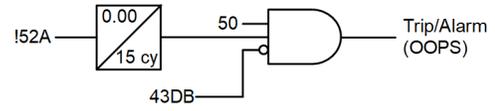


Fig. 13. OOPS Protection Scheme for Black-Start Applications

E. Synchronism-Check Element Supervision Using Sequence Voltages

Wiring errors can be detected by checking for abnormal levels of sequence voltages from each VT. This approach is similar to that used in many loss-of-potential schemes. The checks can be implemented in existing relays by using a combination of positive- and negative-sequence voltage elements via programmable logic. The logic output is used to supervise the synchronism-check element. These checks cannot detect 100 percent of wiring errors, but when used in combination with the OOPS protection scheme, they provide an extra measure of reliability.

V. VERIFYING SYNCHRONIZING CIRCUITS

While the element of Section IV is a protection upgrade that is easy to implement, the primary line of defense against OOPS events is to take steps to avoid their occurrence in the first place.

A. Primary Phasing Tests

Synchronizing circuits and associated equipment can be verified with 100 percent certainty, as long as the correct testing methods are followed. The preferred method is a primary voltage test with the generator and system VTs energized from the same source.

1) Black-Start (Forward-Feed) Test

One method of primary testing is to use the generator to energize the VTs used for syncing via a black-start 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 can then be bypassed to allow the synchronizing breakers to close such that both the generator VT and the synchronizing VT are energized from the generator. This can often be done by isolating a bus or line using disconnect switches.

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 black-started to energize the VTs used for synchronizing to test the synchronizing circuits. A black-start may also be impractical due to the station arrangement as shown in the next subsection.

2) Backfeed Test

For Fig. 1, the bus has to be hot to start and run a CTG to generate steam before the STG can be brought up to speed. There is no way to isolate the 345 kV synchronizing VT to energize it from the STG. In such cases, the connected utility system may be used to “backfeed” or “back charge” the primary conductors, thus energizing the VTs and associated circuits. This backfeed test is conducted by placing the unit into its normal configuration, disconnecting the generator terminals (either by removing connecting links or opening disconnects), 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.

After the VTs are energized from the same source, the rotation check of the generator must also follow 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 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.

For Fig. 1, the links had to be removed (as shown in Fig. 14) to fully test the generator to ensure that it was not damaged by the OOPS event after the fact. The corrected synchronizing circuits were tested using a backfeed test before returning the plant to service. On a generator this size, removing and reinstalling the links can each take nearly a day, which had to be planned for.

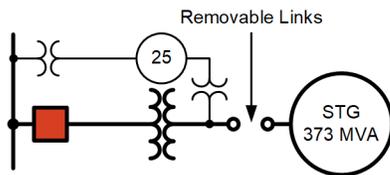


Fig. 14. Verifying the Synchronizing Circuits Using a Backfeed Test

3) Primary Injection Test

Primary injection tests are a third option in some cases with the use of appropriate equipment. Synchronizing circuits on unit-connected machines that use generator-side VTs and a GSU high-side VT usually cannot be properly verified using typical test equipment for primary injection, but it may be an option in some cases.

B. Testing Considerations

The synchronizing panel and the synchronism-check relays must be verified to indicate an in-phase condition; then the breaker can be opened to restore the bus to normal. These methods 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.

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 must be taken to ensure that all normal protection is enabled and functional, such as differentials and overcurrent elements. This is especially true when back feeding from the utility system or black-starting the generator.

This testing must be conducted 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.

C. 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 must be verified during the primary phasing tests. 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 OOPS event, 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.

D. Mock Close Test

The dc schematic logic in the closing circuit should be verified 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 so-called mock close test. 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 ensures 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. This 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.

VI. CONCLUSION

OOPS events can cause severe damage to a machine and must be avoided. Examination of Fig. 7 shows that the worst-case transient torque on the shaft occurs for an OOPS event at 120 degrees and that the worst-case high-current forces on the stator and transformer windings occur for an OOPS event at 180 degrees.

We evaluated the damage that a generator experiences during an OOPS event by comparing generator torque and current to those of acceptable synchronization, full-load, and a three-phase terminal fault. The damage to a generator due to an OOPS event may be catastrophic.

Conventional generator protection provides little protection for OOPS events, and there is no commonly available guidance to address this issue. The protection scheme proposed in this paper is simple and inexpensive. It consists of an instantaneous overcurrent function armed by a breaker status indication. To maximize possibility of a successful trip, the element should not be time-delayed. The overcurrent threshold may be set based on breaker location. Duke Energy has used this scheme successfully for years.

The complete synchronizing system must be fully tested whenever any part of the system is disturbed using the methods discussed. The choice of methods depends on the system configuration. Energizing both the incoming and running VTs from the same source is necessary to have complete confidence in the synchronizing circuits.

In the case study, the focus of the outage was the replacement of the utility tie protection. The subject matter experts for the plant owner were not aware that the generator VT circuits were being rewired, and testing was not included in the outage plan. In this case, the only method to verify the synchronizing circuits would have been to do a backfeed test by isolating the generator from the isophase bus by removing the links as shown in Fig. 14 and energizing the 18 kV VTs from the grid. This is no small task considering that the isophase bus is rated to at least 12,000 A. Removing and reinstalling the links can each take nearly a day and had to be planned for.

Fast tripping for an OOPS event using the protection system described in this paper can limit damage. In the case study event, the generator was synchronized at 180 degrees. The sympathetic tripping by the 87L relays removed the transient torques and high currents from the generator after only seven cycles. The shock to the generator was limited to the point that the plant personnel did not notice anything unusual except that the new 87L relays tripped. The generator and GSU transformer were fully tested after the event; no damage was found, and the generator was returned to service later that week.

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VIII. BIOGRAPHIES

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