Generator Power Swing Out-of-Step Protection and Analysis of Misoperation Events

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1.0 ABSTRACT

This paper details the Power Swing and Out-of-Step (OOS) protective element as applied for generator protection. Various element characteristics and styles are compared for performance during real-world conditions including failure to trip and false trip power swing events. Planning studies and setting verifications can be used to calculate settings and provide insight into system performance during events. Setting validation using event data is reviewed. Analysis of recent events involving generator out-of-sync conditions is presented, as well as a review of what protection may operate when the OOS element fails and conditions that could cause false OOS trips.

2.0 OUT-OF-STEP OR POWER SWING PROTECTION SCHEME FOR GENERATORS

Out-of-Step or Power Swing protection schemes for generators are used to detect loss of synchronism conditions between the connected generator and the power system where a pole slip can occur. An out-of-step or loss of synchronism condition can cause high currents, winding stresses, and other mechanical forces in the generator windings leading to high levels of transient shaft torques. These torques can be great enough to break the turbine generator shaft. With the risk of significant damage to the generator and generator step-up transformer, the out-of-step protection is depended upon to trip the generator before this level of damage can occur.

Other generator protection elements will not detect an out-of-step condition, so dedicated protection is needed. It is generally recommended for most larger generators, that tripping occur quickly before a pole is slipped to prevent generator damage and instability in other parts of the connected power system. Waiting too long to trip for these conditions could result in damage to the generator, generator step-up transformer, and generator breaker due to greater than 180° opening angle across the breaker. Generators can also go out-of-step during slow cleared transmission system faults and during loss of excitation events.

2.1 OOS PROTECTION SCHEMES

Various out-of-step protection schemes were examined from different protective relay manufacturers. The schemes that were looked at track positive sequence apparent impedance trajectory as seen from the generator terminals through the protection zone to detect an out-of-step condition. Blinders are used to detect when the apparent impedance enters and exits, along with associated timers to detect how long the apparent impedance takes to cross the characteristic. The common out-of-step protection schemes incorporate either single or double blinders.

During a fault, the apparent impedance trajectory will move through the element characteristic and the blinders almost instantaneously. For an unstable power swing, the apparent impedance trajectory would stay inside the element characteristic and the blinders for a time determined by a transient stability study, leading to a desirable out-of-step trip. It is important for these protection schemes to differentiate between a stable and unstable power swing. For a stable power swing, the generator should not trip offline.

When two systems are in phase with each other, the angular difference is zero. The voltage will be maximum and the current minimum. When the two systems are completely out of phase of each other, the angular difference will be 180° apart. The voltage at the terminal of the generator will be minimum and the current maximum. At 120° separation angle, it is unlikely that the generator can maintain stability and usually results in loss of synchronism. Out-of-step apparent impedance trajectories can move across the element characteristic from right to left or left to right. If the trajectory is moving from left to right this could mean that the unit is motoring. The out of step protection zone should cover from generator neutral to the high-side bushing of the generator step-up transformer.

2.2 SINGLE BLINDER SCHEME

The single blinder scheme uses one set of blinders with a supervisory mho element. A restricted pickup area is used and limited by the mho element and blinders. The apparent impedance trajectory of the power swing must start from outside the blinders and swing through the outer zone pickup area into the inner zone. Some schemes require the impedance to plot within the outer zone for a short time (<1 cyc) while others require the trajectory to enter from the outer zone. If the impedance then remains in the inner zone for a short or settable time, the condition is considered a power swing. These schemes often have an option to trip the breaker when the angle between the generator and system voltage is 90° or less. This option stresses the breaker less when tripping due to reduced current flow and less voltage difference at the breaker for this angle difference.

A pole slip counter can be used to trip after a specified number of pole slips. It should be noted that allowing a generator to slip more than one pole is primarily used outside of North America. For some hydro generators, it may be common practice to allow the unit to slip a certain number of poles before it is tripped. This is due to some hydro units having the possibility to still regain synchronism after a pole slip has occurred.

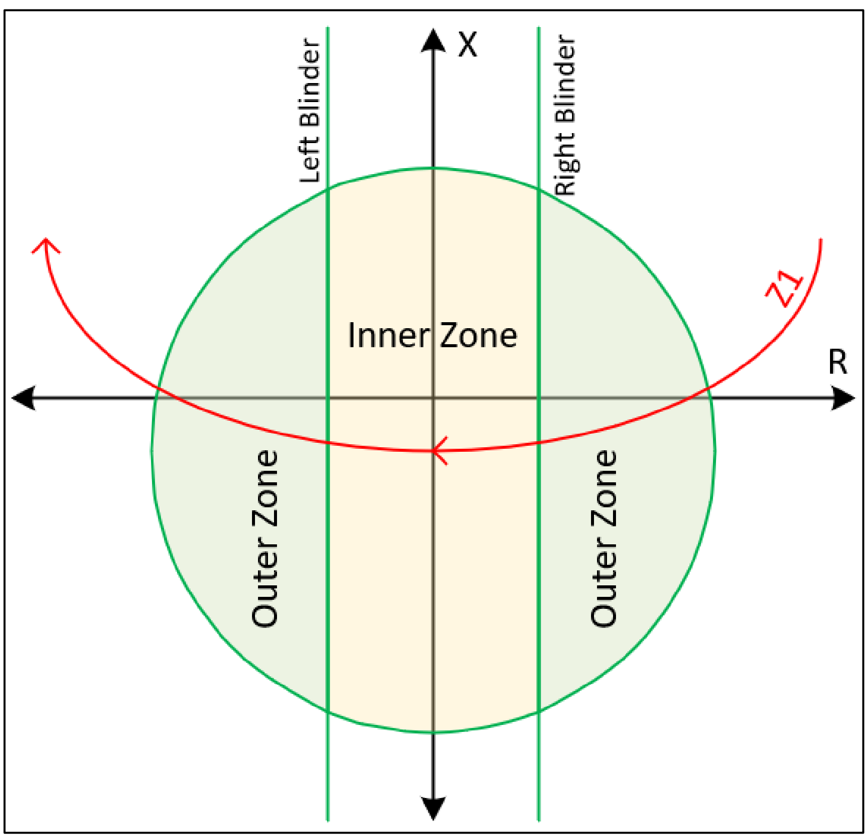

Figure 1: Single Blinder OOS Scheme

This scheme is considered easier to configure as it requires less analysis and system study to set as the impedance trajectory is the primary concern.

2.3 DUAL-BLINDER SCHEME

This scheme uses two pairs of impedance blinders, inner and outer, as well as a mho characteristic. An out-of-step declaration is made if the apparent impedance trajectory stays between the left two or right two blinders for a settable time delay and then advances further inside the inner blinder. An out-of-step trip is initiated when the fault impedance exits the mho characteristic. These schemes may also apply a positive sequence overcurrent supervisor. Additionally, OOS schemes may also be blocked with negative-sequence current as a power-swing event is often a balanced system condition.

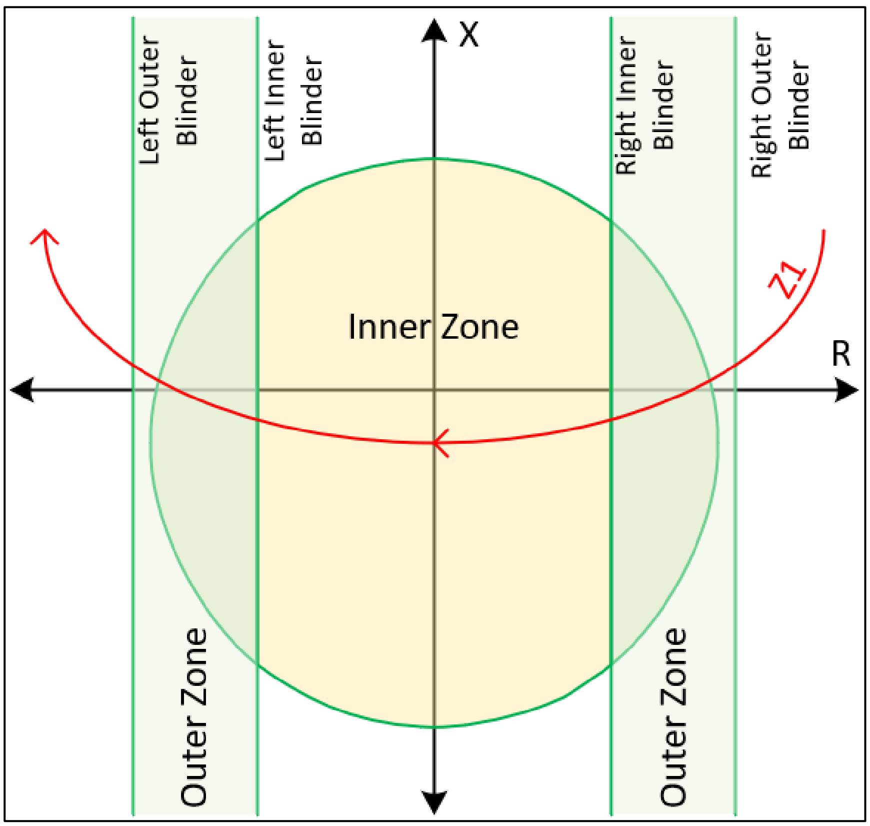

Figure 2: Double Blinder OOS Scheme

This scheme can be more involved to configure as the time delays between the inner and outer blinders is one of the defining characteristics of this element to detect a power swing.

2.4 IMPEDANCE ZONE SCHEME

These characteristics can be set as a lens, mho or quadrilateral zone with outer, middle, and inner zone characteristics. The apparent impedance trajectory is timed as it enters the zone characteristics via a selectable two- or three-zone configuration. These schemes can be configured to act similar to the single and double blinder schemes. One important distinction this scheme offers is the ability to have an upper zone area to determine power swing conditions. OOS tripping can occur once the swing is declared in the inner zone or for less stress on the breaker, once the apparent impedance continues past the outer zone. Additional time delays can also be used to reduce the stress to the breaker.

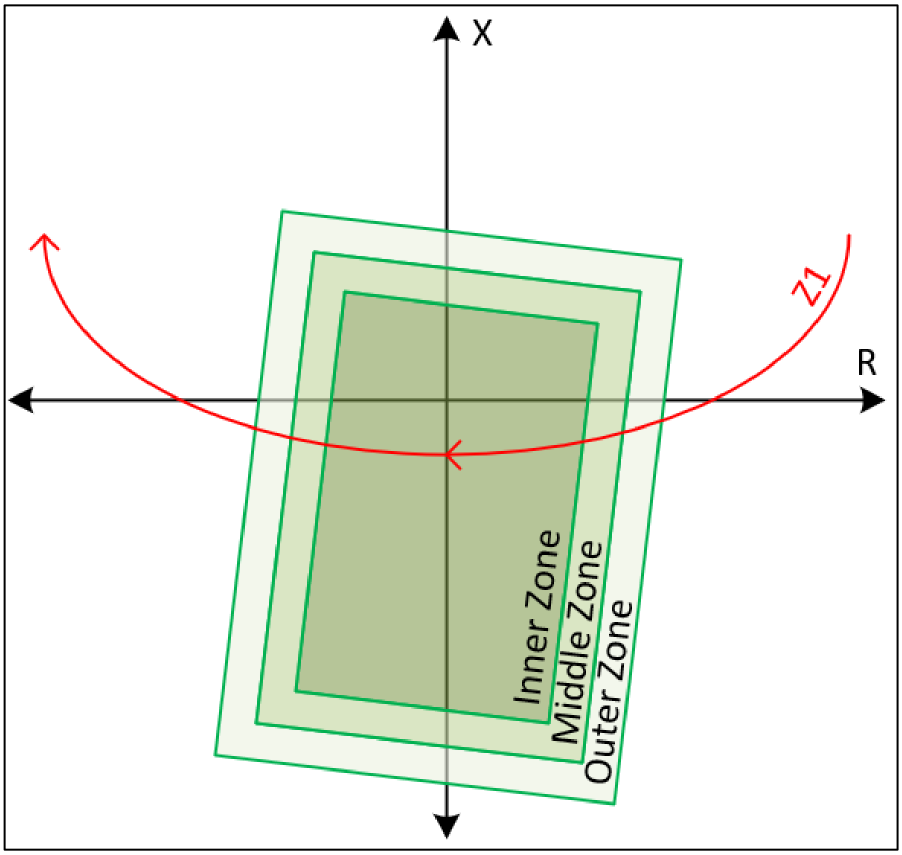

Figure 3: Impedance-Zone OOS Scheme

The two-zone characteristic uses the outer and inner zones to allow for more space in heavily loaded systems for separation between the zones. This method provides a single determination of the apparent impedance trajectory. To use the three-zone characteristic, there should be enough space between the maximum load impedances and the characteristic blinds. For this method, it is recommended to perform a transient stability study for the fastest expected power swings along with the settings of the power swing timers. Both of these methods can also apply an overcurrent supervisor for security.

3.0 TRANSIENT STABILITY AND PLANNING STUDIES

Transient stability studies provide important data needed for setting any of the out-of-step scheme elements that apply timers. A transient stability study is also needed to confirm blinder settings for double blinder schemes and to determine the out-of-step slip frequency since this is a system specific value. One of the most important values determined from the study is the shortest time that it takes the apparent impedance trajectory to cross the blinders during an out-of-step event. If the timer settings in the out-of-step scheme are not set appropriately, this can result in tripping the generator breaker while the angular difference is too large, stressing the breaker and possibly causing damage to the generator.

Transient stability studies consider the excitation and governor control systems responses during faults and other situations where the controls try to keep voltage and frequency steady. If the models of the equipment are detailed and accurate, faults that cause out of step conditions can be mimicked by simulations. An example occurred at Fort Patrick Henry, a Hydroelectric Dam with two generators on the 69 kV system. The two units were online when there was a slow to clear fault on a line a few miles away.

The generator relays showed a power swing from the fault, but both units stayed online as seen in Figure 4. Transient stability studies showed that the units should have gone out of step and tripped. Because of this event and conclusions, the unit's excitation systems were tested to validate the models. The existing models did not match the new test results, but the age of the excitation system prevented a valid model to be able to be developed from the test results.

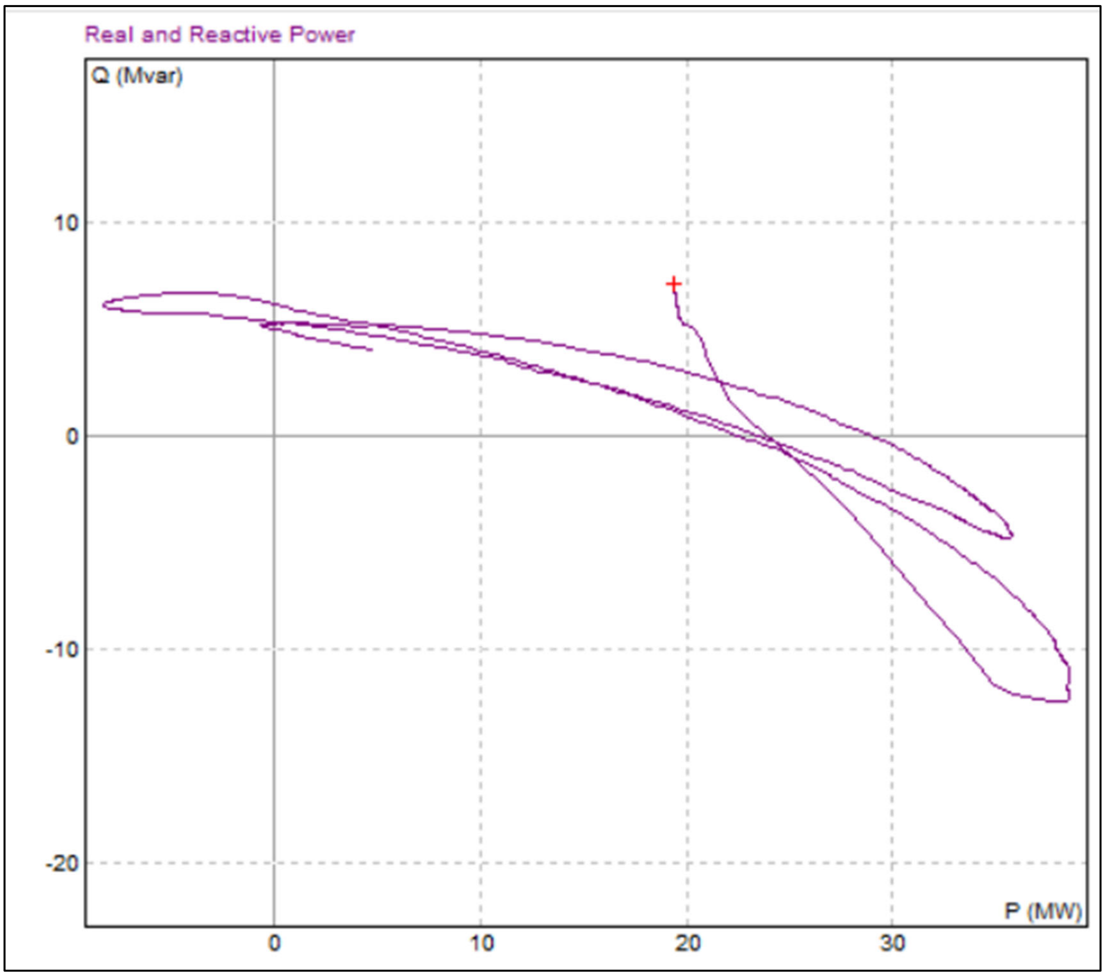

Figure 4: Fort Patrick Henry Event, MW vs MVAR

Another case of a nearby slow to clear fault at a Local Power Company line about 1 mile away caused an out of step condition on three generating units. Two of the generator's protective relays had out of step protection while the third did not have out of step protection. The two units that had OOS protection tripped. This event revealed lack of information in the models for the Local Power Company equipment.

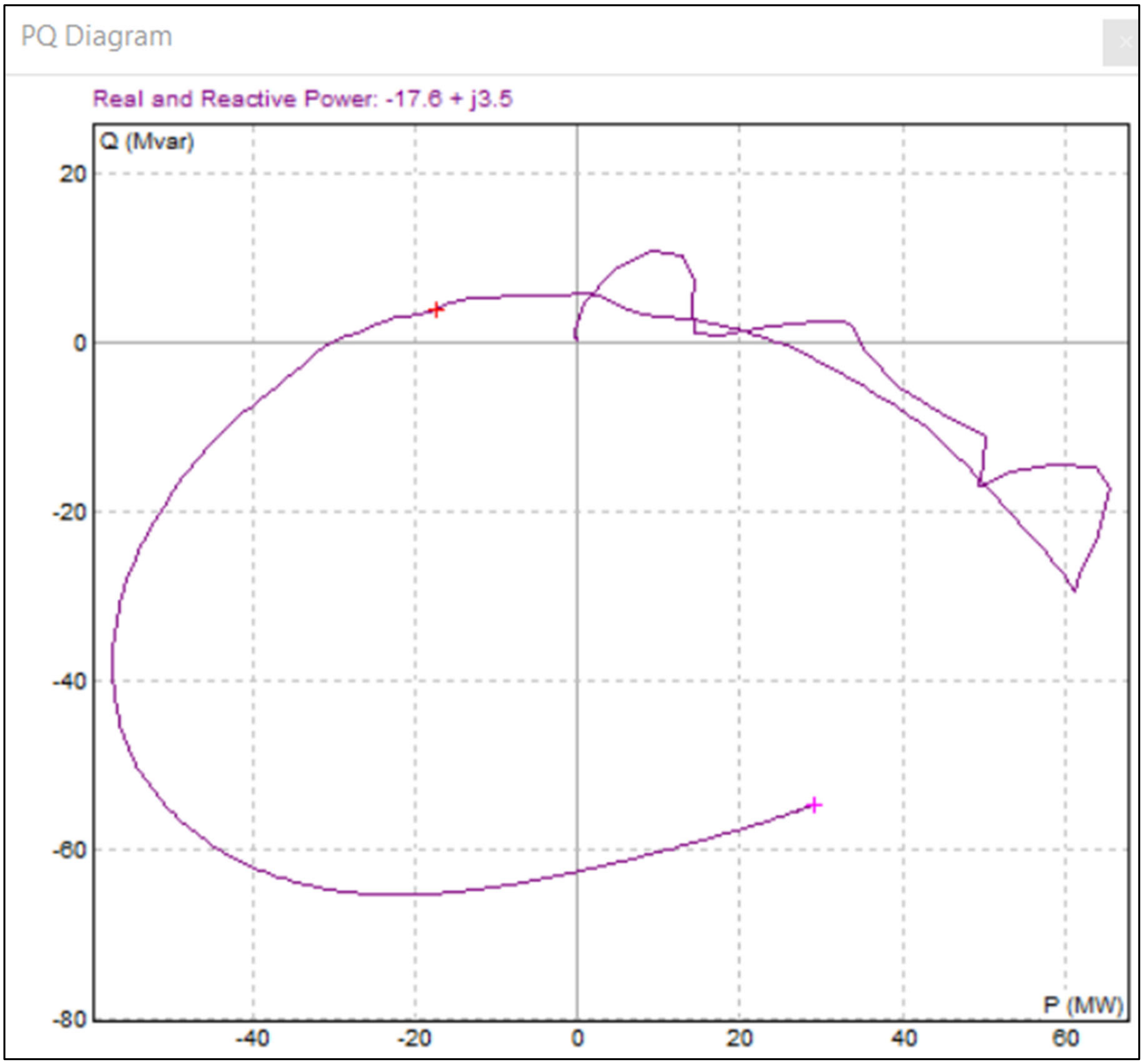

Figure 5: Out-of-Step Trip Event

4.0 EVENT ANAYLSIS

The generation site is a new combined-cycle natural gas plant with two combustion turbine generators (CTG1 and CTG2, 409MVA and 25kV) as well as a steam turbine generator (STG3, 561MVA and 19kV) that are connected to an existing fossil plant one half mile away. Figure 6 shows a simplified single line diagram of the combined-cycle plant and the fossil plant. Additional equipment is not shown on this diagram as it was disconnected or offline in order to simplify the overview.

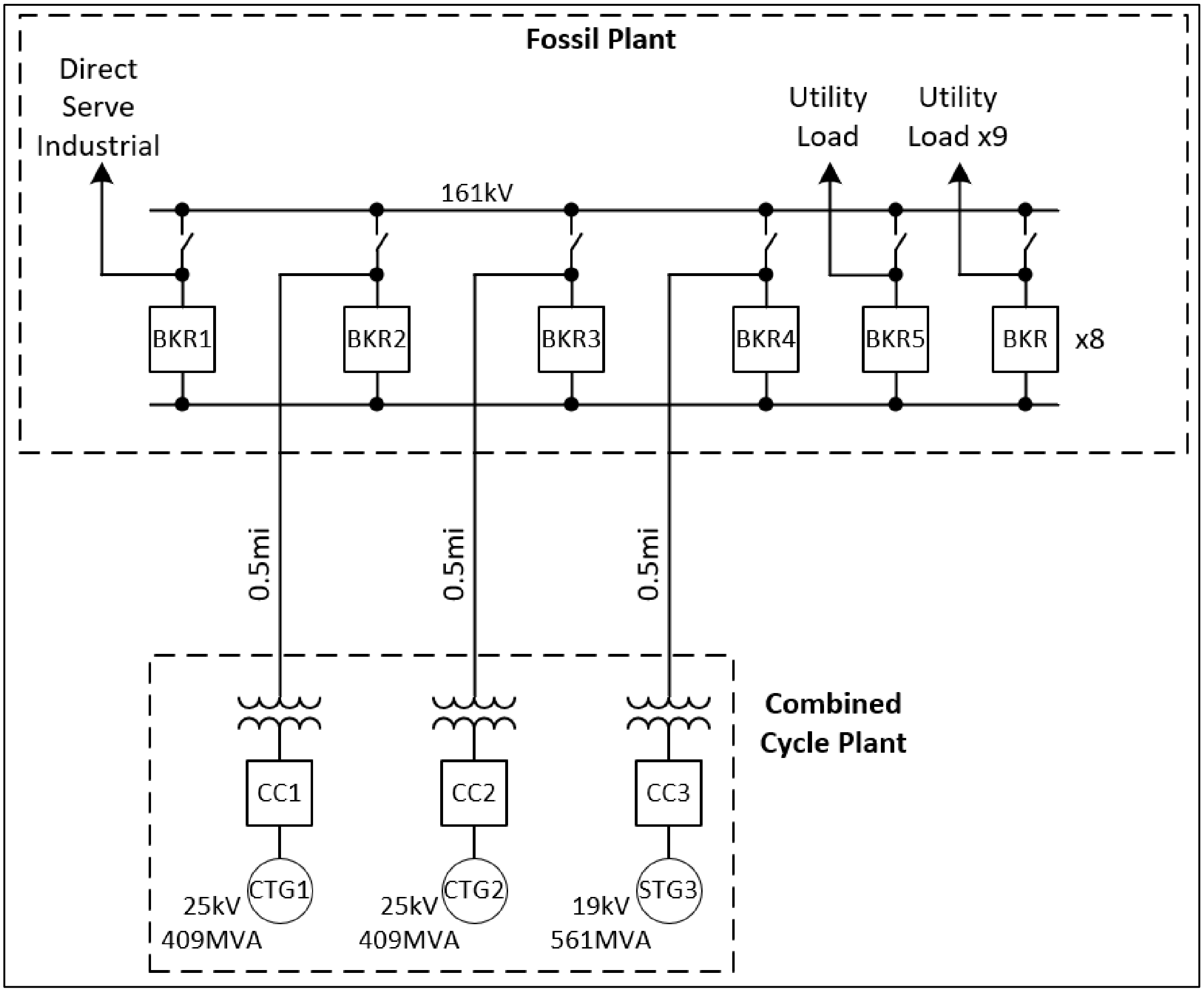

Figure 6: Simplified Single Line Diagram

The OOS element for the combined cycle units was configured for a dual-impedance characteristic with an inner and outer zone to track the impedance locus of the generator during a swing event. The inner zone left and right reach is set to determine when the generator and system are 120° and 240° apart. The outer zone detects stable swings as well as assures that the difference between the generator and system angle is less than 60° when tripped to reduce stress on the breaker. The forward reach for both the inner and outer zones is set to 1.5x the GSU impedance while the reverse reach is set to twice the generator transient reactance. A transient stability study showed the critical clearing time for a three-phase fault on the high side of the GSU is 16 cycles. At 17 cycles the generator would go unstable and take 0.132s to shift 60° and 0.288s to shift 120°. Based on NERC recommendations [4], a 100ms time is used as the threshold for a power swing entering the outer zone and passing to the inner zone, as well as across the inner zone. Similarly, a 50ms timer is used for power swings leaving the inner zone and crossing the outer zone. Figure 7 shows the OOS characteristic and the backup distance elements in the CTG1 protection.

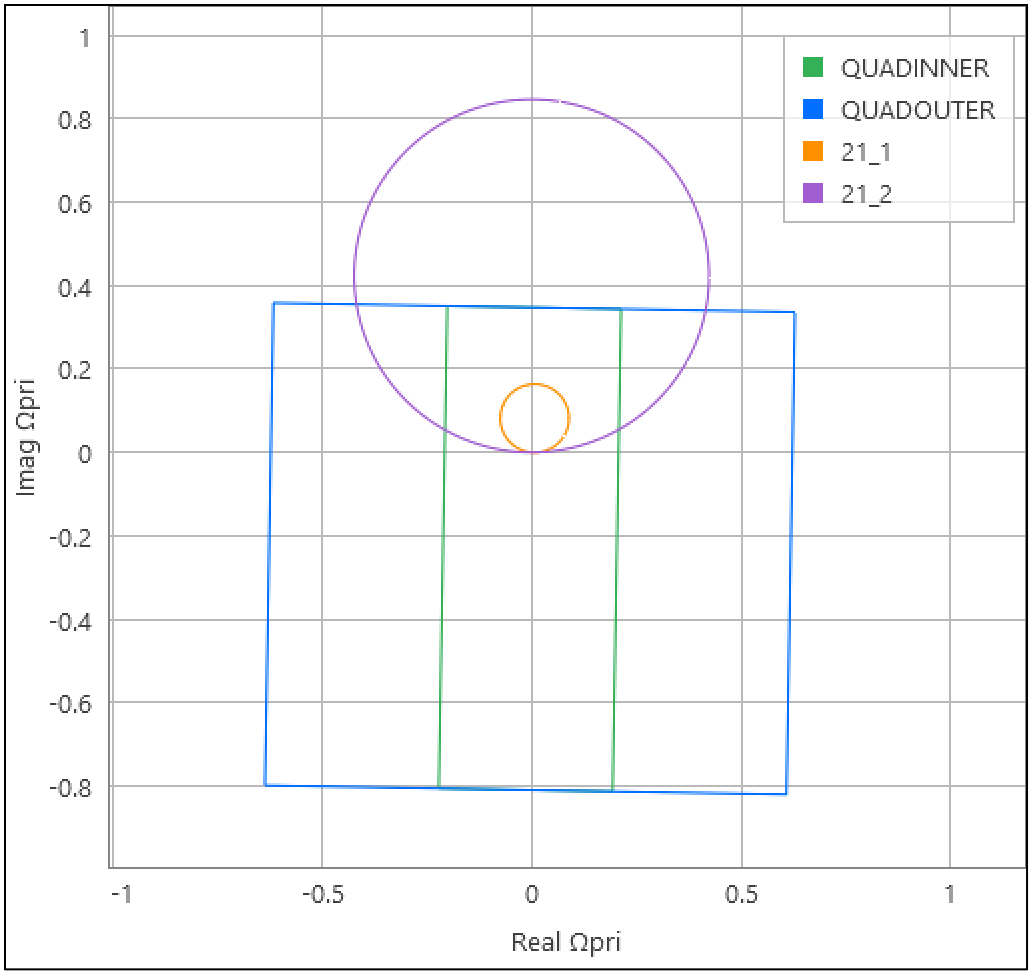

Figure 7: CTG1 Out-of-Step and Backup Distance Elements

A downstream utility fed by BKR5 experienced a slow-clearing evolving multi-phase fault on a transformer. The fault evolved from BC to BCG to ABC. As a three-phase fault, it persisted 28 cycles and sagged the voltage at the generator bus to 20% of nominal on all three phases. In addition to event data from the generator protection system, a Digital Fault Recorder (DFR) at the generating station on the 161kV bus recorded fault data over a longer time period and provided additional insight into the event. Figure 8 shows the CTG1, STG3, and combined CTG1/STG3 contribution to the fault, as well as the 161kV bus voltage. The data shows the system pre-fault, during the evolving system fault, the power swing after the transmission system breakers cleared the fault, and post trip of CTG1.

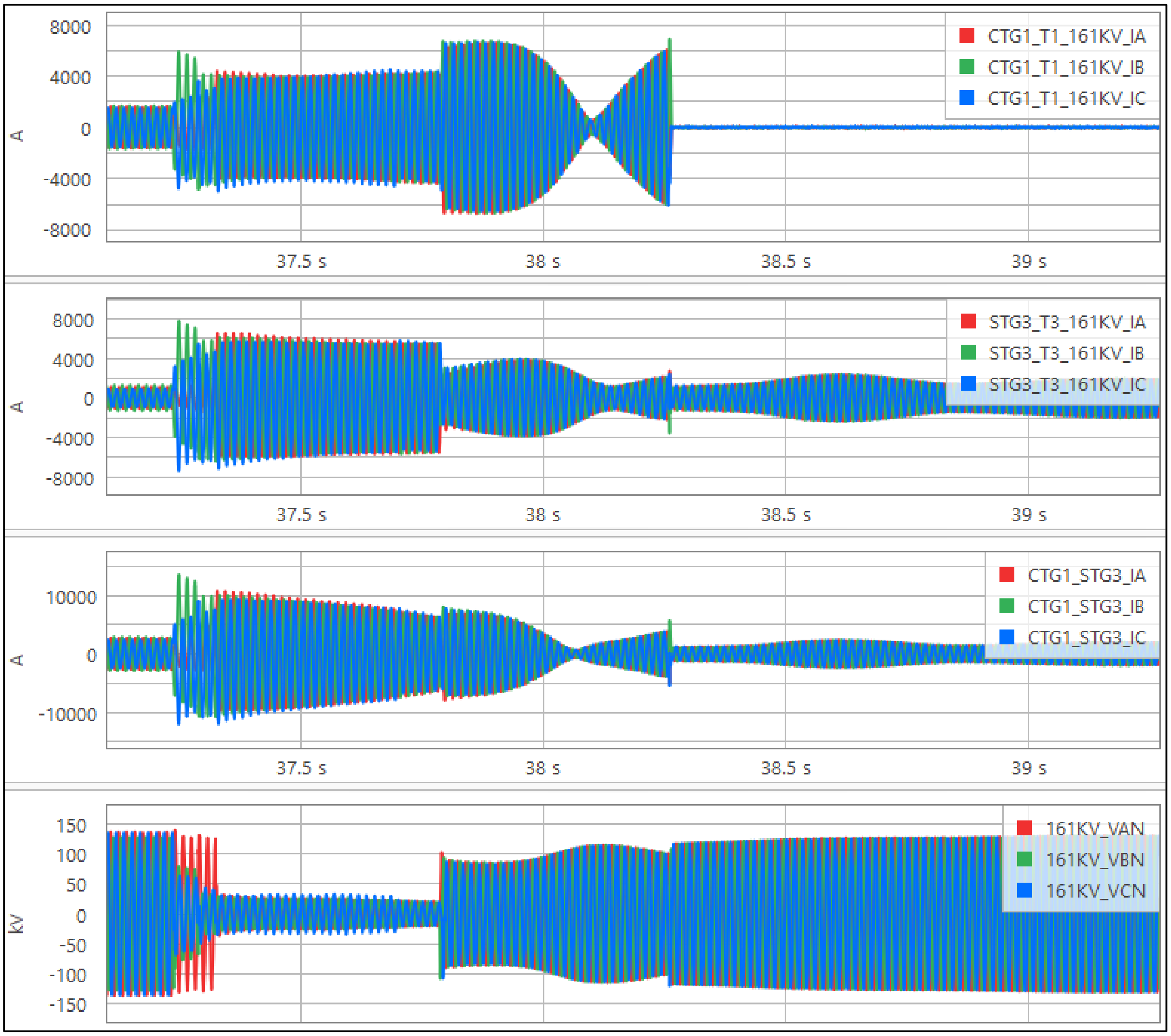

Figure 8: DFR Event Data

CTG2 was offline at the time while CTG1 and STG3 were online. The generator protection system was intended to trip on an OOS condition prior to slipping a pole but did not operate. CTG1 tripped due to the turbine control system sensing a rate-based acceleration overspeed condition of 16% per second. The control system had a communication loss and was not able to directly trip the unit or excitation system but did send a breaker failure initiate (BFI) signal to the generator protection relays. The breaker failure initiate signal immediately tripped the generator breaker through the generator protective relays as a re-trip condition. The BFI signal also acted as the trigger for event data in the generator protective relays. Due to the event trigger from BFI and not the OOS element operation, the initial fault inception and three-phase fault portion of the fault were not captured by the generator relays but was captured by the GSU relays. Additionally, due to the communication equipment power loss and failure, the CTG1 excitation system remained online for four minutes after the unit tripped, causing concern for heating and damage.

After CTG1 tripped, STG3 remained online for about two additional seconds before tripping on a reverse power element from operating in a low current motoring condition. It is believed that the turbine control system was also in the process of removing STG3 from service when the reverse power permissive signal was supplied to the STG3 generator relays but has not been confirmed.

The path of the CTG1 positive sequence impedance during the event is shown in Figure 9. The three-phase fault persisted for 28 cycles inside of the backup zone-2 distance element in the generator relays but did not trip as the time delay is configured for 75 cycles to coordinate with system protection relaying. It is assumed that a system breaker opened to clear the fault downstream to start the pole slip event. This allowed for a significant voltage recovery and possibly a power flow issue with both CTG1 and STG3 online with the loss of load. Due to the length of the three-phase fault, the generators sped up and lost sync with the system. The CTG1 phase relationship between positive sequence current and voltage shifted about 95° from the initial three-phase fault condition up the start of the pole-slip condition.

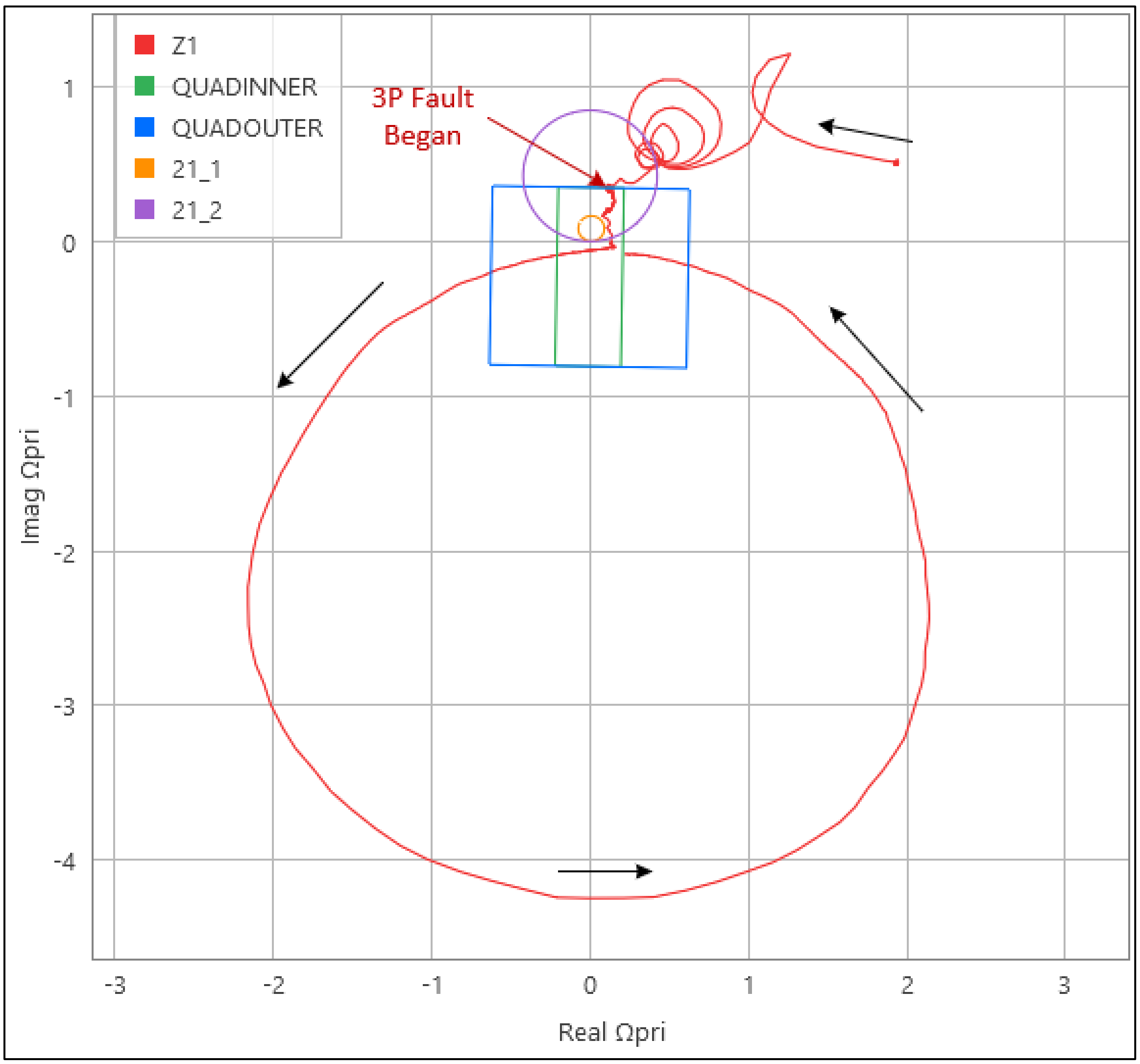

Figure 9: Z1 Impedance During Fault

As the fault entered the top of the OOS impedance zones, there was no differentiation between the inner and outer blinders. The relay event data showed both blinders asserting at the same time, so the relay considered this a fault condition and not a power swing. If the generator control system had not tripped the unit, it is unlikely that the OOS element would have detected the swing after the first pole-slip as it proceeded through the impedance zones a second time. Z1 was between the outer and inner right blinders for about 80ms (shown in Figure 10 between the orange and purple cursors), short of the 100ms delay required to arm the power swing element for tripping.

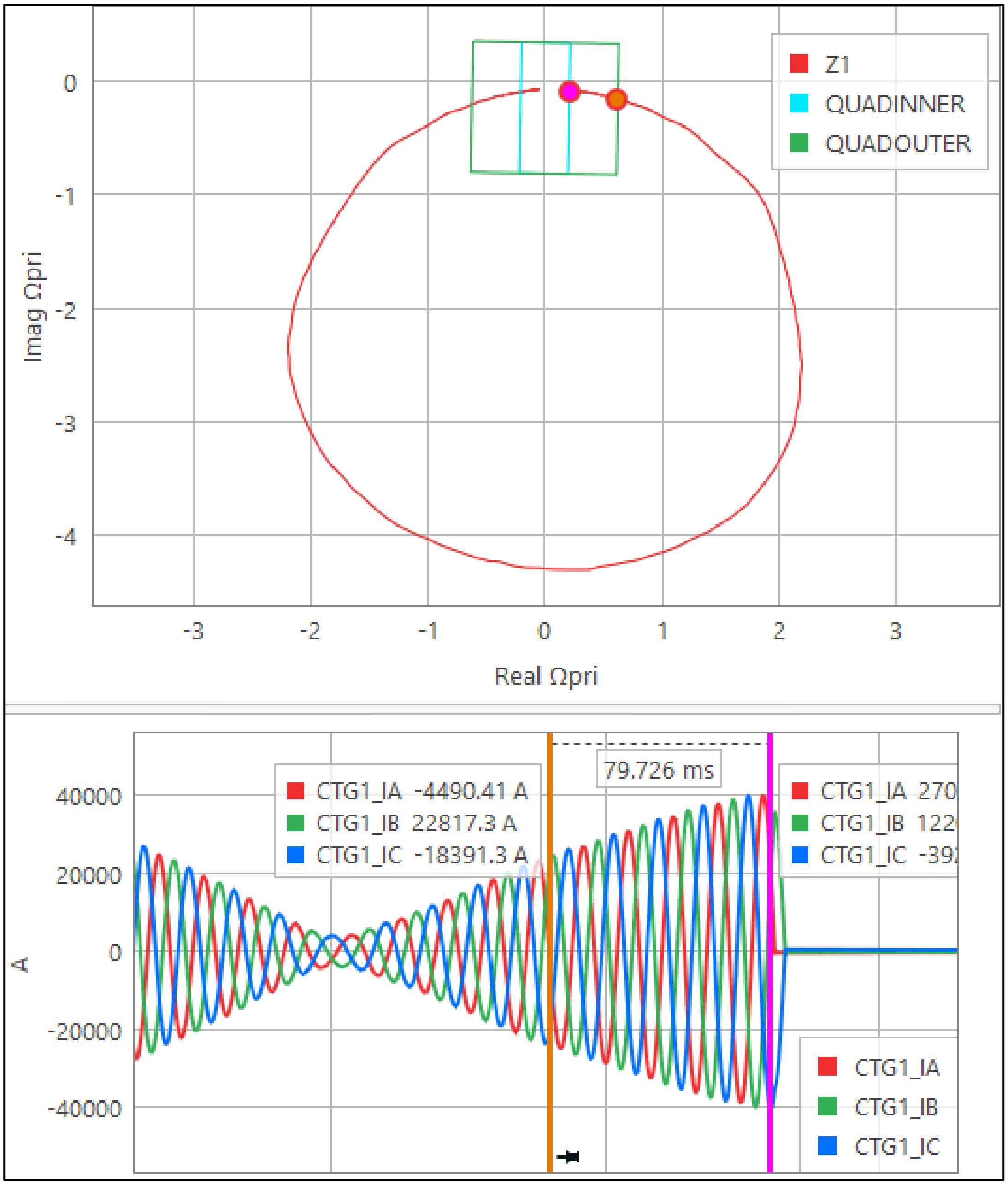

Figure 10: CTG1 Relay Event Data Showing Z1 and Power Swing Element

Using the DFR event data, one full slip cycle took 453.6ms. This translates to 1 / 0.4536s = 2.205 slip cycles per second, or 360° * 2.205 / 60Hz = 13.2° of travel per 60Hz cycle. With an outer to inner blinder separation of 120° - 60° = 60°, this results in a Z1 travel time of 60° / 13.2°per cycle = 4.536 cycles or 76ms between the two blinders. To detect this condition in the future with the same blinder impedances the OOS outer blinder delay would need to decrease from 100ms down to 70ms.

Another consideration would be to reduce the forward reach of the inner impedance zone. For this event, reducing the forward inner zone reach from 0.35Ωpri to 0.27Ωpri would have allowed Z1 to plot between the inner and outer zone for 0.16s, arming the OOS power swing element. This would likely have allowed an OOS trip prior to the pole slip.

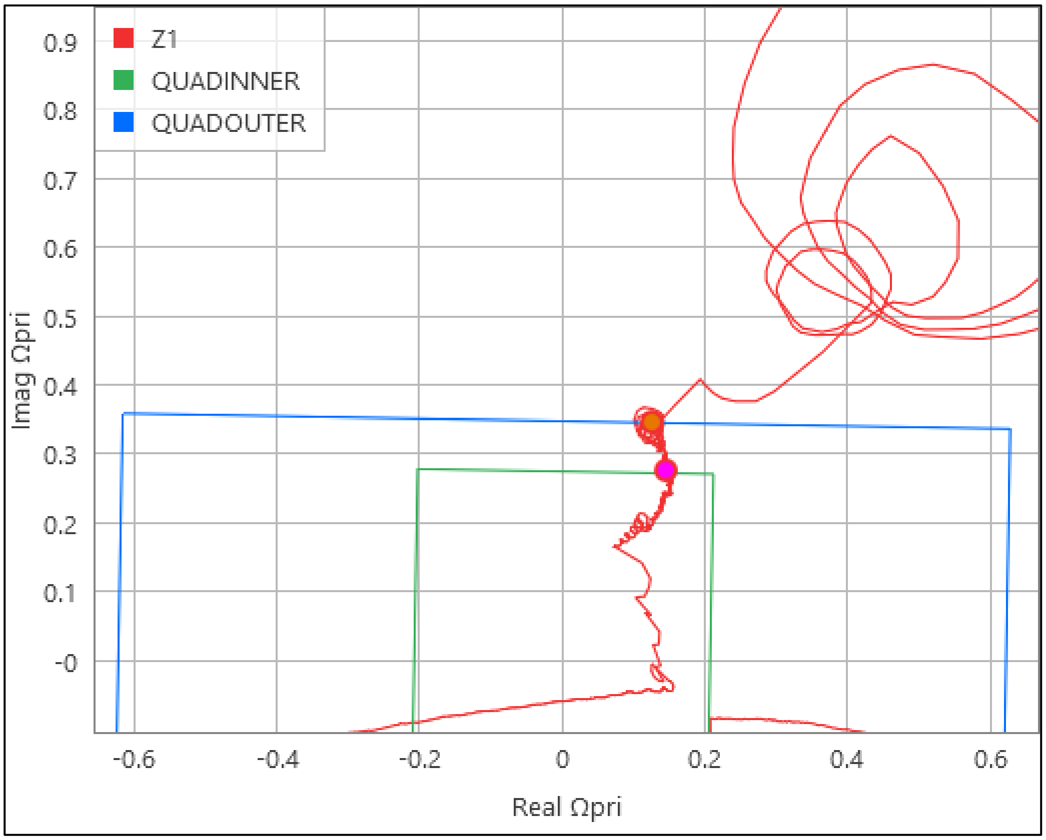

Figure 11: CTG1 Relay with Inner Reach Reduced

CONCLUSIONS

Accurate modelling of the system is important to be able to perform studies that define the OOS power swing element characteristics. These models may require information from external systems or verification of the model through test to ensure the OOS element operates effectively. Additionally, the relay setter should consider all fault types and select which style OOS element characteristic is most effective for the system at hand rather than assuming the faster or easier setting methods will work for all cases. This paper has shown one misoperation event where additional analysis is required to ensure dependability for all swing events. The authors encourage the readers to perform analysis of OOS element performance for all events to confirm the model and assumptions made are correct.

REFERENCES

[1] Application of Out-Of-Step Protection Schemes For Generators, PSRC Report of WG J5 of the Rotating Machinery Protection Subcommittee

[2] IEEE Tutorial On The Protection Of Synchronous Generators, Second Edition

[3] NERC Power Plant and Transmission System Protection Coordination, Rev 1.

BIOGRAPHICAL SKETCH

Seth Barnes graduated from The University of Mississippi in 2010 with a B.S.E.E. and a M.S.E.E. from The University of Tennessee at Chattanooga in 2020. Upon graduation, he worked as a contract Telecomm Engineer for AT&T in Mississippi. Seth joined the Tennessee Valley Authority in 2013 and worked as a Telecomm Field Engineer and later a System Engineer in the North Alabama area. In 2017, he joined the System Protection & Analysis group, developing relay settings and performing post fault event analysis for the TVA power system. Seth is a member of IEEE.

Laurel Brandt is an Electric Engineer for the Tennessee Valley Authority (TVA) in Chattanooga, Tennessee. She has worked in primarily with Generating plants, performing duties in design, project management, protection and control system ownership, and operations support. Her current responsibilities are to support relay maintenance specialists for testing and troubleshooting, improving reliability of the generating fleet by identifying and correcting protection system misoperations and supporting plant operations and project implementation. She has also worked in Transmission Operations NERC Reliability and on a Battery Storage Research Project for TVA. She has a B.S.E.E from Georgia Institute of Technology. She is a member of the IEEE/PES Power System Relaying and Control Committee, Chair of the NERC Failure Modes and Mechanism Working Group, and a registered Professional Engineer in the state of Tennessee.

Joshua Hughes graduated from Tennessee Technological University with a B.S.E.E focused on digital signals. He initially worked as a System Engineer at Tennessee Valley Authority nuclear substations providing commissioning services, root cause analysis, and system data trending to predict equipment failures. Later, Joshua joined Schweitzer Engineering Laboratories, where he served as a project engineer and senior application engineer where his work included providing application and product support and technical training for protective relay users. Joshua now works for Qualus as a Lead Engineer to provide system studies, field system protection services, event root cause analysis, and technical training. Joshua is a member of the IEEE and is a registered professional engineer in the state of Tennessee.