Rapid Earth Fault Current Limiter (REFCL) Projects at Southern California Edison

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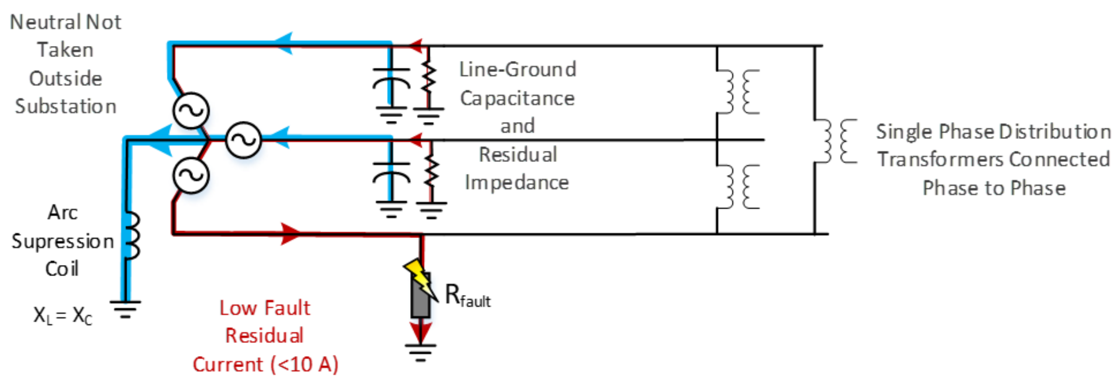

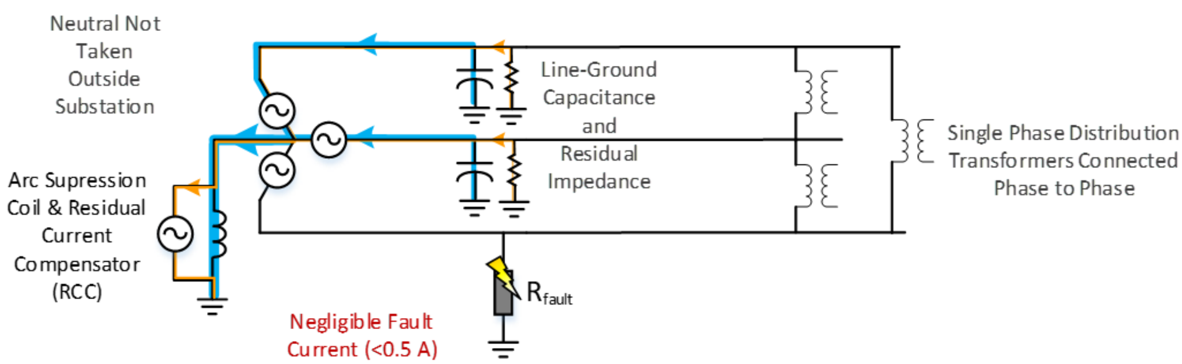

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2 Summary:

Rapid Earth Fault Current Limiter (REFCL) technology has been widely deployed in Europe and Asia for purposes of improving reliability and reducing shock hazards, as well as in the Australian state of Victoria for the purpose of wildfire mitigation. As part of the 2019 Southern California Edison (SCE) Wildfire Mitigation Plan (1), SCE evaluated the utility of REFCL technologies to reduce fire ignition risks associated with the electric system.

Multiple variations of REFCL technology were piloted to better understand how the available alternatives apply to the wide variety of circuit designs on the SCE system. The diversity of SCE circuit types means that no single variation is cost-effectively applicable across the entire SCE system. For example, for large substations feeding tens to hundreds of miles of high fire risk circuitry, Ground Fault Neutralizer projects modeled on the Australian REFCL program may be a good choice. However, the Ground Fault Neutralizer is neither economically viable nor necessary for fire risk reduction for smaller distribution systems. For these smaller facilities grounding conversion projects to unground or resonant ground them can achieve a similar reduction in risk at a much lower cost. The variations piloted are:

1. An overhead isolation transformer installed in 2020 covering 2.5 miles of the Calstate 12kV circuit.
2. A padmount isolation transformer covering 12 miles of the Stetson 12kV circuit installed in 2021.
3. An Arc Suppression Coil (ASC) to resonant ground Arrowhead substation installed in 2021 covering 40 miles of circuitry.
4. A Ground Fault Neutralizer (GFN) in Neenach substation installed in 2021 covering 169 miles of circuitry.

This paper describes the experiences and lessons learned from the installation and operation of these four facilities.

All four installations have demonstrated significantly higher ground fault sensitivity and reduced energy release from ground faults when compared to traditional system designs. Ground fault sensitivity increased from tens of ohms to kilo-ohms with all but the Arrowhead substation installation, already achieving the 14,400-ohm sensitivity allowing detection of a half ampere ground fault. Solidly grounded substations at SCE commonly have as low as 40-ohm ground fault sensitivity. The impact on total energy release was also reduced by approximately 99.9% when compared to typical SCE distribution systems.

Table 1: Comparison of sensitivity and energy release for ground faults on REFCL and solidly grounded systems

	Highest Impedance Ground Fault That can be Detected [Ohms]	Highest Impedance Ground Fault That can be Detected [Amperes]	Typical Energy Release from Ground Fault [Joules]
Typical 12.47kV Protection	40 to 300	25 to 180	10,000,000
Sensitive 12.47kV Protection with Fast Curve Enabled	300 to 1,440	5 to 25	2,000,000
REFCL GFN at 12.47kV	14,400	0.5	2,000

While the technology is promising, the pilots have helped identify several challenges that need to addressed to gain more confidence on this technology’s risk mitigation effectiveness. These include equipment reliability issues, time required to determine optimal operating procedures, more difficult fault locating, more complex circuit balancing, and single phase faults turning into multi-phase faults. Utilities outside the US have been able to realize benefits from this technology. Therefore, we recommend continuing to evaluate and pilot REFCL over the next few years to gain experience and resolve the challenges.

The path forward through 2024 is to build a North American supply chain as well as confirm best practices for design and operation of these systems. This will help SCE prepare for wider scale deployment starting in 2025 if the pilots are successful. Since the North American supply chain is new, SCE is working with both existing equipment suppliers to help them release products designed for this application and with new suppliers with experience in the international market. In addition, prior to wider-scale deployment, SCE will have to develop engineering, design construction and operations workforce who are conversant and trained in REFCL technology.

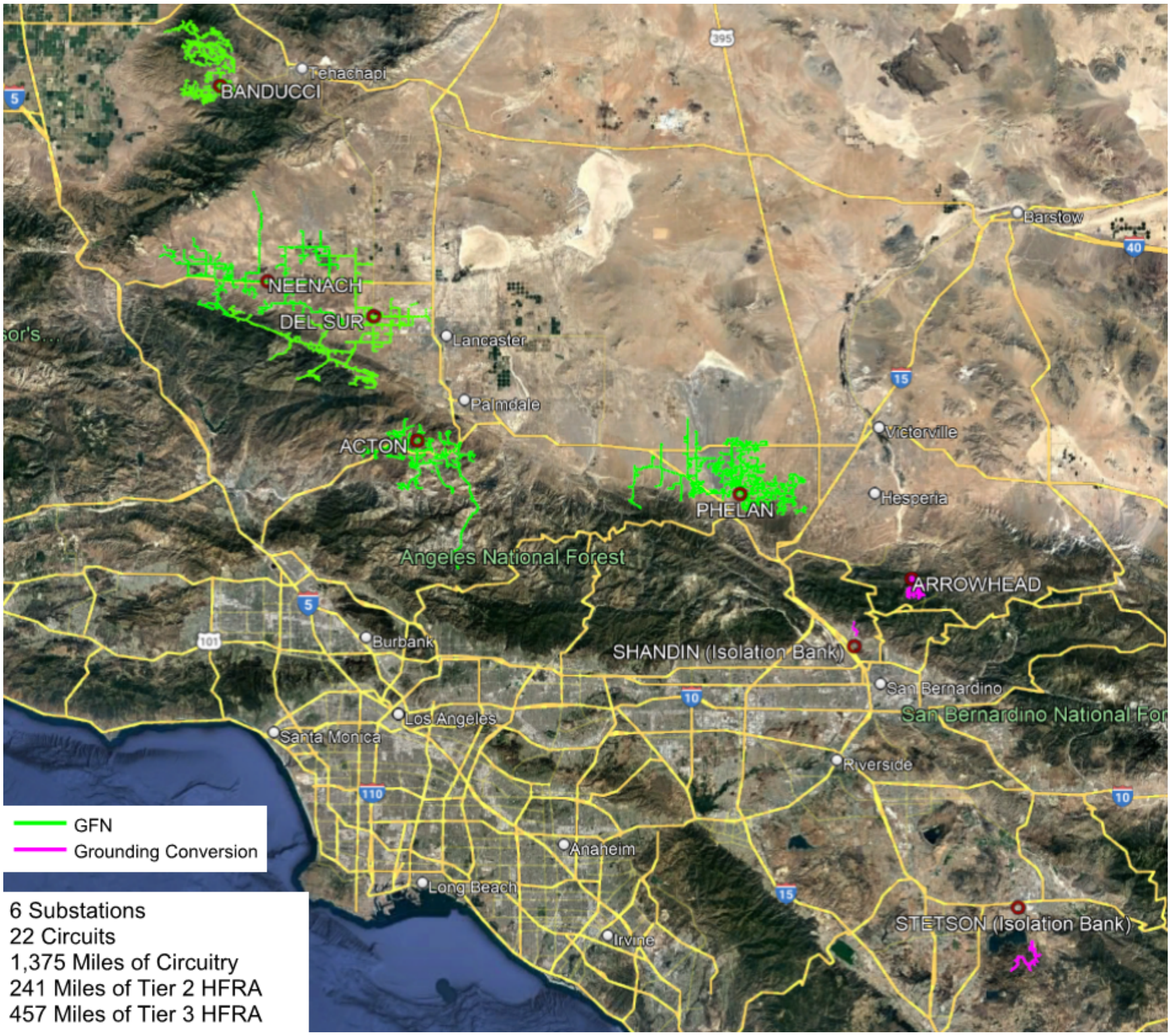


Figure 1: Active REFCL Projects At Southern California Edison

3 Background

3.1 Definitions

There is significant variation in the literature with the terminology used for these systems. This paper has settled on the following definitions, which follows the that used in most Australian investigations of the technology (2) (3)[1] and is also similar to the terminology in publications from New Zealand (4) and Brazil (5) (6) (7):

Arc Suppression Coil (ASC): An inductance which is connected to the neutral of a transformer to cancel out the current caused by the capacitance of the system. This device can be a fixed inductance, a variable inductance which is automatically adjusted with a plunger or a fixed inductance which is varied by the switching of capacitors. The terms Petersen Coil, Arc Suppression Reactor are synonyms.

Ground Fault Neutralizer (GFN): A combination of an Arc Suppression Coil and inverter (Residual Current Compensator) which can reduce the phase-to-neutral fault current to a significantly lower value than that on a resonant grounded system. The term Ground Fault Neutralizer is older than the Residual Current Compensation technology and some documents still use this term and Arc Suppression Coil synonymously. Many alternative terms have been used; one vendor uses the term Advanced Residual Current Compensation (8) to describe their product; the terms Dynamic Residual Current Compensation (DRCC) and Active Injection System (AIS) have also been used as vendor agnostic terms for this technology.

The term Ground Fault Neutralizer is used in this paper to refer to any product which combines an arc suppression coil and an inverter to minimize fault current. This was done as it is the most common term in the literature to refer to these systems (3) (4) (7) (9). Unlike other available terms, Ground Fault Neutralizer also clearly conveys what the technology does. While only one vendor refers to their product under that name, the term is not copyrighted and thus is available to describe the whole class of technology.

Rapid Earth Fault Current Limiter (REFCL): Any technology which significantly reduces the worst-case phase-to-ground fault current. This paper uses the term to describe technologies which can meet the voltage reduction targets after a ground fault followed by utilities in the Australian state of Victoria. The main technologies being investigated are Arc Suppression Coils and Ground Fault Neutralizers, but other technologies such as Faulted Phase Earthing were tested in Victoria Australia as part of their investigations and might be applied in future years. Some of the REFCL technologies are summarized in Figure 10.

[1] See section 8 for bibliography

Rapid Earth Fault Current Limiter (REFCL)

Resonant Grounded System

1. Arc Suppression Coil (ASC)

Ground Fault Neutralizer (GFN)

1. Arc Suppression Coil (ASC)
2. Residual Current Compensator (RCC)

Faulted Phase Earthing

1. Arc Suppression Coil (ASC)
2. Grounding switch on phases

Solid State Fault Current Limiter (SSFCL)

1. Transistor to open transformer neutral
2. Grounding switch on phases
3. Variation on Faulted Phase Earthing

Figure 2: Rapid Earth Fault Current Limiter Technology Tested in Australia

Residual Current Compensator (RCC): An inverter which is connected in parallel with the Arc Suppression Coil to cancel out any remaining fault current on a resonant grounded system.

Resonant Grounded System: A system grounded at the source transformer or a grounding transformer through an Arc Suppression Coil for the purposes of limiting the phase-to-neutral fault current. Synonyms include Compensated Neutral Systems and Frequency-Selective Grounded systems.

Ungrounded System: A system with no intentional connection to the source transformer neutral. A common synonym is an isolated neutral system.

3.2 SCE's Challenge

California's wildfire risk has increased in recent years due to climate change, drought, and other factors such as increased development in the wildland urban interface and significant build-up of fuel, including on federal and state forest lands. The full magnitude of the increased threat and the significance of its consequences did not become apparent until 2017, when California experienced five of the most destructive fires in its history. Thirteen of the 20 most destructive wildfires in California history occurred between 2017 and 2021, destroying more than 40,000 structures (three times the number consumed by the other seven). These catastrophic events emphasize that California's wildfire risk has increased to the point where the safety of our communities requires additional measures designed to address the higher level of wildfire risk. To this end, California Senate Bill 901 (SB 901), enacted in 2018, adopted new provisions of Public Utilities Code (PUC) Section 8386 requiring all California electric utilities to prepare, submit and implement annual wildfire mitigation plans that describe the utilities' plans to construct, operate and maintain their electrical lines and equipment in a manner that will help minimize the risk of catastrophic wildfires associated with those electrical lines and equipment.

For over a century, SCE has designed its electrical system with the primary goal of providing safe, reliable, and affordable power. This design includes many decades of engineering experience and the adoption of new technologies over time. SCE's design practices continue to advance with the addition of newer safety and reliability related technologies. As part of this advancement, it is important to understand and adapt to the "new normal" and the challenges that climate change brings. The greater intensity and year-round frequency of fire danger is driving the need for further evolution, hardening, and strengthening of the grid—particularly in High Fire Risk Areas (HFRA) in SCE's service area. As one of the nation's largest electric utilities, SCE's service area is approximately 50,000 square miles located in central, coastal, and Southern California. SCE's electrical system encompasses approximately 52,000 circuit miles of transmission and distribution overhead power lines, with more than 14,000 of those circuit miles traversing (HFRA). SCE is developing and implementing ways to further prevent, mitigate, and withstand the wildfire threat associated with its service area and HFRA.

Experts had predicted that decades from now climate change would increase the risk of these uncharacteristically large and severe wildfires, including a potential increase in the total area burned. These projected impacts are happening now, and regrettably much faster than some earlier climate forecasts. Shortly after the Mendocino Complex Fire in July of 2018, then Governor Brown explained that "[t]he more serious predictions of warming and fires to occur later in the century, 2040 or 2050, they're now occurring in real time." California's Fourth Climate Change Assessment—while acknowledging that projecting future wildfires is complicated—nonetheless notes the potential for greater fire risk in the future and particularly "mass fires" burning large areas simultaneously. Moreover, the California Department of Forestry and Fire Protection (CAL FIRE) has concluded that "[c]limate change has rendered the term 'fire season' obsolete, as wildfires now burn on a year-round basis across the State."

This recent increase in the size of, and destruction caused by, fires in the wildland urban interface, increased population density and development in the wildland urban interface, and the extremity of weather conditions, marks a significant change in the state's firefighting and fire prevention posture, and an increased need for comprehensive, year-round mitigation and preparedness efforts. The state's recent wildfires are proving that historical mitigation and preparedness efforts are not sufficient to adequately address the current hazards and risks associated with wildfires in California—it is therefore essential for all stakeholders to change the way we approach wildfire mitigation efforts. SCE agrees with Governor Newsom's statement that there should be "no greater emphasis, energy, and sense of urgency than on the issue of public safety."

Wildfires in the Southern California region in SCE's service area, and the damage they cause, are influenced by many factors including a dry and warm climate, Santa Ana winds, severe droughts, and extensive development in wildland urban interface. The Southern California region and the rest of SCE's service area is expected to continue to warm through this century. Climate studies also predict more severe droughts in California in future years. And although there is uncertainty in future predicted changes to Santa Ana wind events, in late 2017, Southern California was subjected to "unprecedented" strong winds that had the potential to carry palm fronds and other debris from long distances into utility lines. The projected increased climate warming, future prolonged periods of drought, and more potentially frequent extreme Santa Ana winds will continue to exacerbate wildfire risk conditions in Southern California. Given these projected conditions, SCE will continue to adapt its strategies and programs to mitigate wildfire risks.

Beginning in 2018, due to increasing risk factors that were driven in part by accelerating climate change, SCE significantly expanded its wildfire mitigation programs. In response to increased wildfire risk, SCE developed and has continued to refine a portfolio of programs and measures focused on mitigating the risk of wildfire ignitions associated with its electrical infrastructure. As part of its wildfire mitigation efforts, SCE has made significant investments in grid design and system-hardening mitigation activities. As explained in greater detail in its annual Wildfire Mitigation Plans, SCE's grid hardening activities focus on implementing grid infrastructure that mitigates the risks of ignitions associated with utility equipment. This includes several activities, such as deploying covered conductor, undergrounding of overhead lines, installing system automation equipment, remediating issues with long conductor spans, replacing old and potentially faulty equipment, and more.

SCE evaluates the optimal set of mitigations to reduce wildfire and Public Safety Power Shutoff (PSPS) risks most effectively throughout SCE's HFRA. Accordingly, SCE selected REFCL as a wildfire mitigation initiative because of its history of effectiveness in reducing energy from ground faults. It works by detecting ground faults on one phase in a three-phase powerline and almost instantly reducing the voltage on the faulted line while boosting the voltage on the two remaining phases, to maintain service for customers while extinguishing arcs. While REFCL is effective at reducing energy from a phase-to-ground fault, it does not mitigate phase-to-phase faults, which covered conductor is effective at. Thus, the two mitigations deployed together (where feasible) results in significantly increased mitigation effectiveness compared to either being deployed alone.

SCE's efforts to mitigate wildfire risks will continue to be informed by dynamic climate change risks as well as other factors that will be described in annual WMP filings with the Office of Energy Infrastructure Safety and the California Public Utilities Commission.

3.3 Transformer Grounding Alternatives

To understand why REFCL technologies are needed and how they work, understanding transformer neutral grounding can be helpful. Several different transformer grounding approaches including ungrounded, solidly grounded, resistance grounded, reactance grounded, and resonant grounded systems are utilized across the globe, and there is not wide international agreement for the best way to ground the neutral of a transformer supplying a distribution system. These designs come with tradeoffs in cost, safety, and reliability (2) (10) (11) (12) (13) (14).

Table 2 Tradeoffs from common styles of neutral grounding

	Solidly Grounded	Ungrounded	Inductance Grounded	Resistance Grounded	Resonant Grounded	Faulted Phase Earthing	Ground Fault Neutralizer
Equipment	Copper connection from ground grid to neutral bushing	No intentional connection to ground	Neutral reactor from the transformer or ground bank neutral bushing to ground grid	Neutral resistor from the transformer neutral bushing to ground grid	Arc Suppression Coil from the transformer neutral bushing to ground grid	Grounding switches connect phases to ground. Ungrounded or Resonant Grounded systems	Arc Suppression Coil and Residual Current Compensator from transformer neutral to ground grid
Example Countries where Widely Deployed for Distribution	Canada, South Korea, United States	Japan, Finland, Norway (14)		Australia, China (15), Ireland, Spain	Austria, China (15) (16), Croatia (17), Finland, France, Germany (18), Ireland (19), Italy (20), Norway (21), Poland (22), Russia (23), Switzerland, Sweden	Ireland (24)	Australia (25), Germany (26), New Zealand (4)
Permissible Load Transformer Connections	Phase-to-Phase (3 wire) and Phase-to-Neutral (4 wire)	Phase-to-Phase	Phase-to-Phase (if low inductance also Phase-to-Neutral)	Phase-to-Phase	Phase-to-Phase	Phase-to-Phase	Phase-to-Phase
Phase to Ground Fault Current	>5,000 A	1-200 A	>3,000 A	25-3,000 A	0.5-50 A	0.5-5 A	<0.5 A
Required Insulation Level	Phase-to-Neutral	Phase-to-phase	Phase-to-Neutral	Phase-to-phase	Phase-to-phase	Phase-to-phase	Phase-to-phase
Limitation of Transient Overvoltages	Good	Bad	Good	Average	Average	Average	Average
Equipment Thermal Stress	High	Low	High	Low	Extremely Low	Extremely Low	Extremely Low
Self-Extinguishing of Temporary Ground Faults	No	Not Always	No	Not Always	Almost Always	Almost Always	Almost Always
Cost	Low	Low	Medium	Medium	High	High	Extremely High
Ground Fault Protection Sensitivity	Low	Average	Low	High	Extremely High	Extremely High	Extremely High

3.3.1 Ungrounded Systems

In the late 1800s utilities started with ungrounded systems where there was no intentional grounding at the source transformers. These systems have some advantages as the design is simple and line to ground fault currents were only a few amperes. Electrical faults would often self-extinguish, and it was possible to continue supplying customers while a ground fault was present, which increased reliability. Energy release from ground faults were relatively low and limited the arc flash hazards from ground faults, although fault currents were still high enough to cause electrocution.

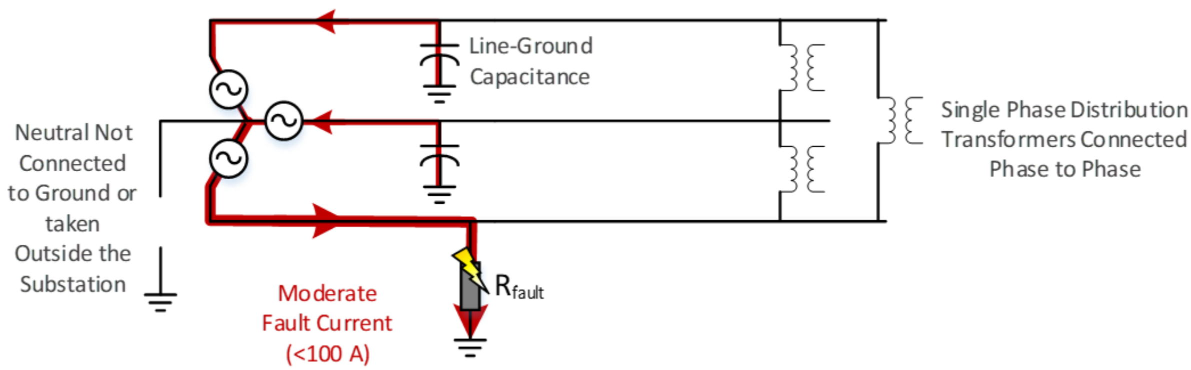


Figure 3: Overview of transformer connections and Fault Current Path for Ungrounded Systems

While they are a good option for small systems, ungrounded systems have limitations for larger systems, and therefore do not scale well. The ground fault current of an ungrounded system comes from charging current on the unfaulted phases summing and entering the fault (Figure 2). The fault current is thus proportional to the capacitance to ground of the system, which increases as networks expand or increase in voltage. As utility networks grew larger, fault currents became high enough that arcs no longer self-extinguished and instead continued until protection disconnected the source. These arcing ground faults also caused significant prolonged over-voltages which can cause apparatus on the system to fail.

Ungrounded distribution systems also had safety issues from downed wires. The systems would typically only alarm on ground faults rather than immediately de-energizing the lines. This increases customer reliability but sometimes leaves wires on the ground energized. This led many utilities to ground the wye point of the source transformers or install grounding transformers to increase fault current to a point that relays could detect the failure.

Ungrounded systems are still widely deployed today, but typically only for lower voltage applications. SCE uses ungrounded systems on generator buses, tertiary buses for large transformers as well as some small distribution systems. Examples of ungrounded systems exist at other North American utilities such as the Los Angeles Department of Water and Power's 4.8kV system, and internationally they are widely deployed for distribution circuits in many countries including Japan, Finland and Norway. On larger or higher voltage systems, where fault current exceeds 50 amperes even when ungrounded, other designs are typically used.

3.3.2 Solidly Grounded Systems

Most American Utilities, including SCE, moved to solidly grounded transmission, subtransmission and distribution systems. Solidly grounded systems have several advantages compared to the ungrounded systems: they have relatively straightforward protection to locate low impedance ground faults and relatively low transient overvoltages, which allows less expensive electrical equipment to be used. They also allow transformers at customer sites to be connected from phase-to-neutral rather than phase-to-phase, thereby reducing cost.

One of the biggest disadvantages of solidly grounded systems is the energy release from ground faults. When a ground fault occurs—such as a conductor falling on the ground or a tree or Mylar balloon contacting a conductor—very high currents are pushed into the fault. These currents can spark fires, create shock hazards for people or animals in the vicinity of the fault, and/or cause serious burns from arc flashes. This energy release also commonly turns temporary ground faults into permanent ground faults when the arc flash damages electrical equipment.

There are two styles of solidly grounded systems: (1) Unigrounded and (2) multi-grounded. In a unigrounded system, the load is connected phase to phase, just like in an ungrounded system (Figure 3). The only connection to ground is at the transformer neutral. In a multi-grounded system, the neutral extends out of the substation and is connected to many or all customer sited transformers (Figure 4).

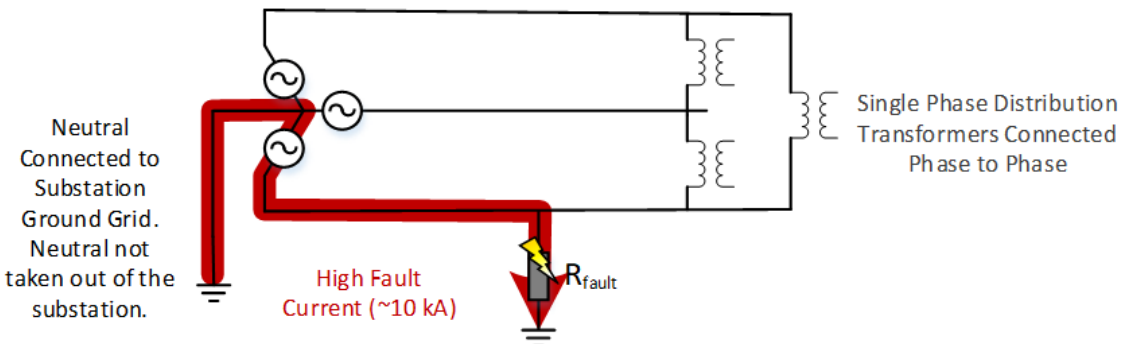


Figure 4: Overview of transformer connections and fault current paths for a solidly grounded source with a unigrounded neutral.

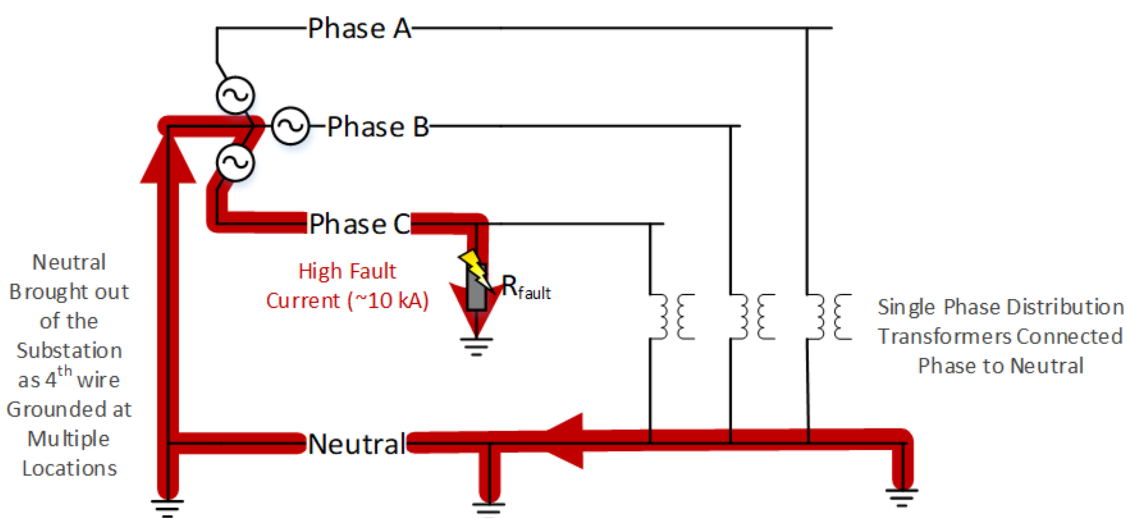


Figure 5: Overview of transformer connections and fault current paths for a solidly grounded source with a multi-grounded neutral.

All solidly grounded systems have high ground fault currents and low transient over-voltages. Multi-grounded systems are generally lower cost since the transformers only require one high voltage connection and one phase conductor. One downside, however, is that load current is released out of the phase conductors and into the grounded neutral. This ground current interferes with extremely sensitive ground fault protection and can cause stray voltages (27). Ungrounded systems can achieve higher sensitivity ground fault protection since all load is connected phase-to-phase so load current does not flow into the ground (11) (28).

In the early years of transitioning from ungrounded systems to solidly grounded systems, a safety advantage of solidly grounded systems was that they were often able to detect which circuit a ground fault was on and quickly disconnect the fault. The ungrounded systems which preceded these solidly grounded systems did not have this capability. Downed wires could remain energized for hours, increasing the risk someone would make contact. So, while the rate of energy release is much higher on a solidly grounded system, the time the hazard was present was thought to be lower due to the shorter duration of faults. However, ground fault detection for solidly grounded systems is not sensitive enough to detect all downed wires, and safety risks of contact with energized downed wires remain.

When using modern relays, solidly grounded systems have low ground fault detection sensitivity, especially for multi-grounded systems where load current traveling through the earth interferes with ground fault current. Other grounding systems described in the section below can offer more sensitive protection.

3.3.3 Impedance Grounded Systems

The neutral of a transformer can be connected to ground through a neutral resistor or reactor to create a system with a fault current between an ungrounded system and a solidly grounded system. This practice is very common at industrial facilities and in some parts of the world it is standard practice for distribution systems. Some distribution systems at SCE use neutral resistors or reactors. While SCE has some resistance grounded systems, use has been limited by additional complications to the protection design, higher transient overvoltages and the fact that load transformers cannot be connected from phase-to-neutral.

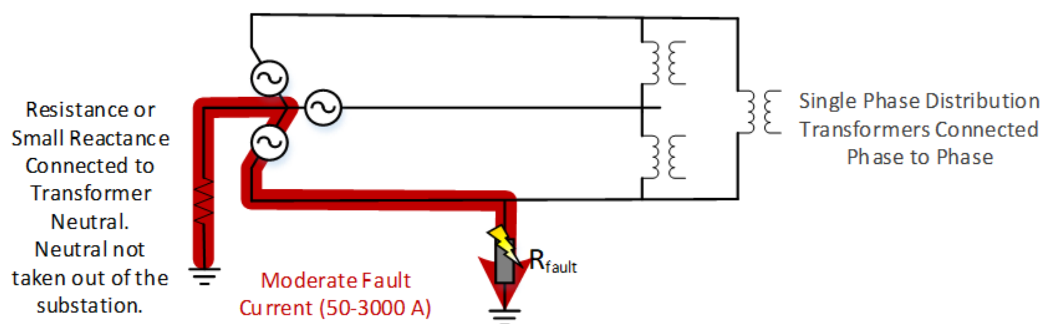


Figure 6: Overview of transformer connections and fault current paths for a resistance grounded source.

3.3.4 Resonant Grounded Systems

In much of the world, most notably Europe (14) (17) (18) (19) (20) (21) (22) (23) (29) (30) and China (14) (15) (16), resonant grounding is common for distribution and subtransmission systems. In a resonant grounded system, the transformer neutral is grounded through an inductance known as an Arc Suppression Coil (ASC). The reactance of this coil is matched to the capacitance to ground of the system, canceling out most of the fault current. With resonant grounding, the line to ground fault current can be reduced to a level between a tenth and a hundredth of the capacitive charging current of the circuit. This reduced current will be anywhere from a few hundred milliamperes to a few amperes depending on the size of the system.

The low fault current on resonant grounded systems means that equipment is unlikely to be damaged from ground faults. Some utilities that operate resonant grounded systems leave single line to ground faults on the system for hours while faults are located and repaired. This is particularly common in fully underground systems where other design practices can mitigate the public safety hazards of ground faults. Even when protection is installed to clear faults, clearing times are typically several seconds which is long enough for temporary faults to self-extinguish. That means that these resonant grounded networks are capable of very high levels of reliability.

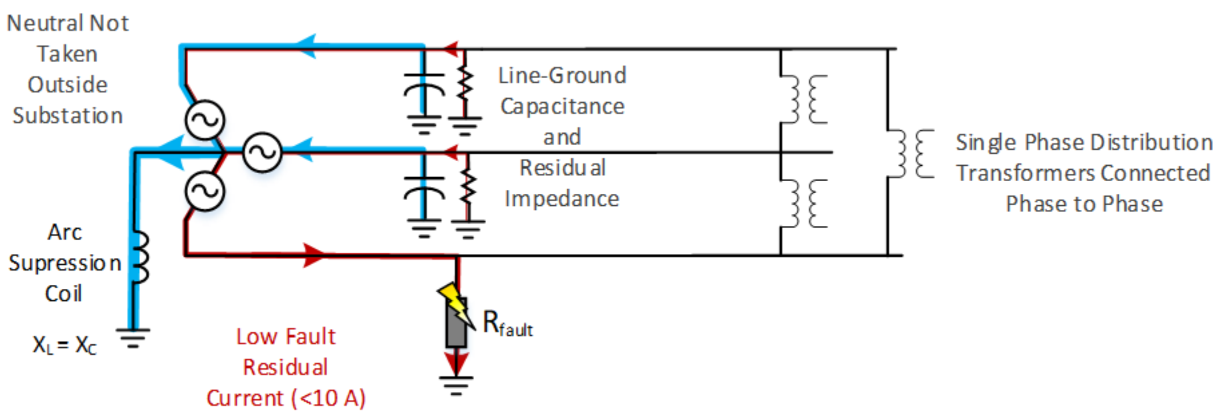


Figure 7: Overview of transformer connections and fault current paths for resonant grounding

While resonant grounding reduces the ground fault current, it cannot eliminate it. The remaining fault current is a result of the resistive losses of the circuits which cannot be canceled with the Arc Suppression Coil, as well as any difference between the inductance of the Arc Suppression Coil and the capacitance of the system.

3.3.4.1 Variations to Resonant Grounding

While fault currents with resonant grounding are much lower than with other methods of transformer grounding, it is sometimes desirable to get even lower fault currents. This is particularly true for large systems where even with resonant grounding the fault currents can be substantial or for applications like mines or wildfire prevention where even small fault currents are a safety hazard.

3.3.4.1.1 Faulted Phase Earthing

Fault current can be reduced further by closing a grounding switch on the faulted phase, connecting it to the substation ground grid. This redirects much of the remaining fault current away from the site of the fault. For faults near the substation, this technique can even get the voltage on the faulted phase under 50 volts once the switch has been closed. This method can be used on either an ungrounded or a resonant grounded system and has seen wide deployment in Ireland (24) as well as some installations in China and Switzerland (31) (32).

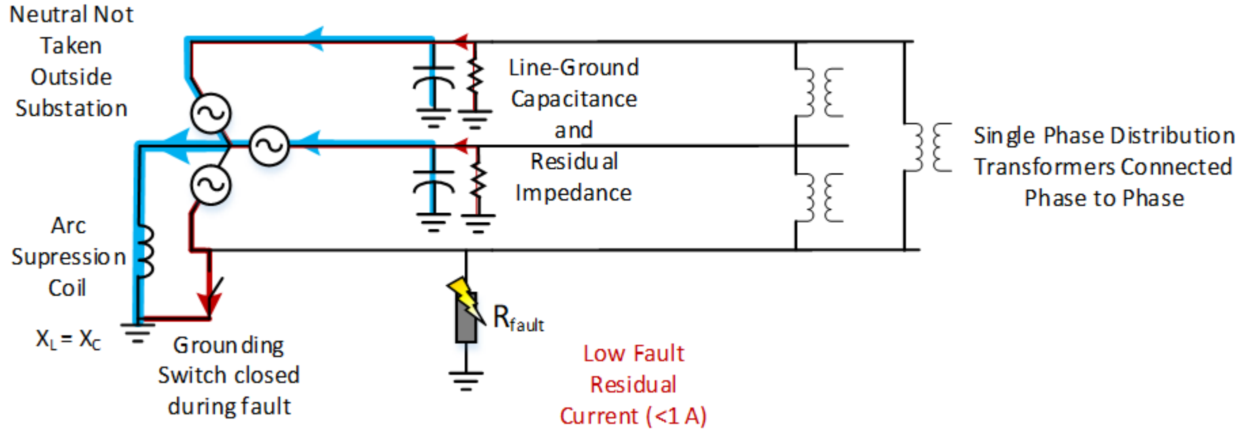


Figure 8: Overview of transformer connections and fault current paths for a resonant grounded source with faulted phase earthing.

3.3.4.2 Ground Fault Neutralizers

A similar effect to faulted phase earthing can be achieved by placing an inverter on the neutral of the transformer and using it to control the voltage on the faulted phase (33). The inverter injects current into the neutral of the transformer which allows it to set the voltage between the neutral and ground. This voltage is adjusted to minimize the voltage on the phase which has a fault. The neutral to ground voltage is set to be equal to and 180 degrees out of phase with the voltage on one of the phases, which cancels out the phase-to-ground voltage on a phase while leaving the phase-to-phase voltages unchanged.

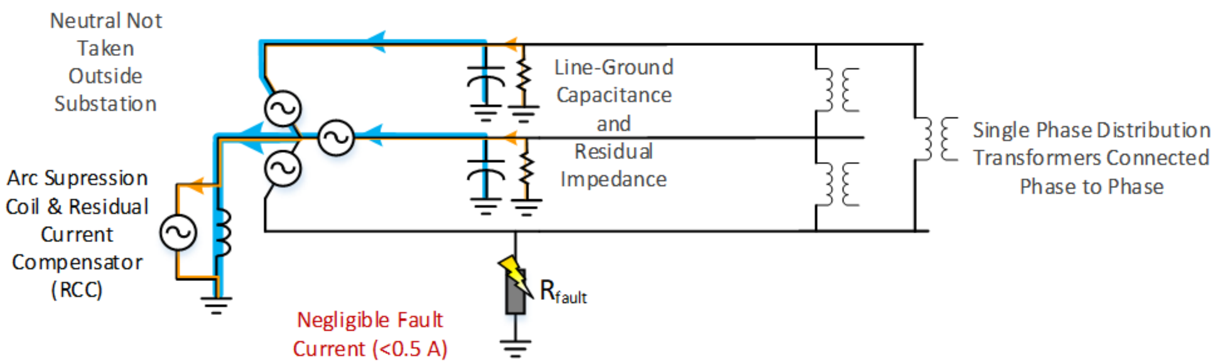
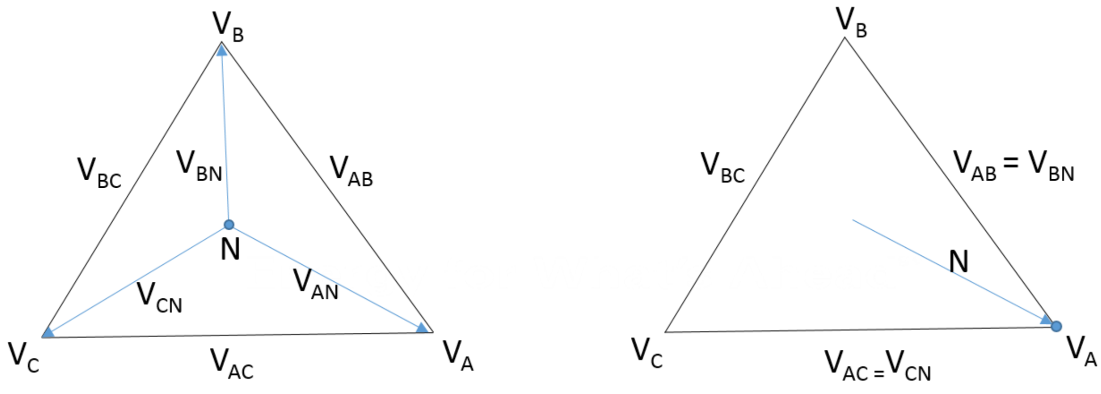


Figure 9: Overview of transformer connections and fault current paths for a Ground Fault Neutralizer



$$V_{AN} = V_{BN} = V_{CN} = \frac{V_{AB}}{\sqrt{3}} = \frac{V_{AC}}{\sqrt{3}} = \frac{V_{BC}}{\sqrt{3}}$$

Normal Operation

$$V_{AN} = 0$$
$$V_{BN} = V_{CN} = V_{AB} = V_{AC} = V_{BC}$$

A Phase Fault

Figure 10: Voltages produced during normal operation and a phase-to-ground fault

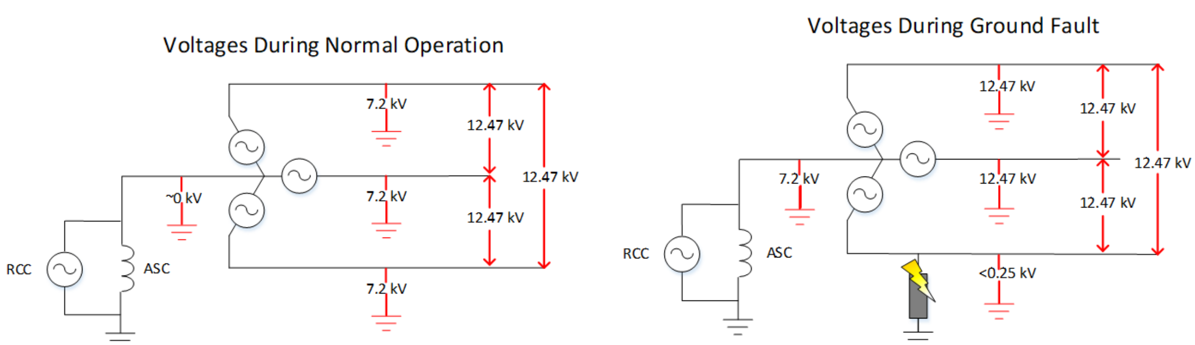


Figure 11: Voltages produced during normal operation and a phase-to-ground fault on a 12,470-volt system

The first Ground Fault Neutralizer was installed in 1992 on the Swedish Island of Gotland. The initial market was large underground distribution systems which had substantial fault currents even when resonant grounded, as well as mines and industrial facilities with special safety and reliability concerns. The Ground Fault Neutralizer allows these systems to continue to self-extinguish temporary faults and continue to feed load with faults still on the system (26) (33) (34).

Australian utilities determined that resonant grounding alone was not as effective at fire-risk reduction compared to a system with residual current compensation (2) (3) (35) (36) (37) (38) (39). The typical Australian 22kV network is several hundred kilometers with more than a hundred amperes of charging current. Even with resonant grounding, the fault current was high enough to cause ignition from a downed wire or tree branch contact. Based on that testing, this technology was scaled up as a fire mitigation program and is expected to be installed on 31,000km of circuitry by the end of 2023 (40) (41) (42).

4 Ground Fault Neutralizer at Neenach Substation

The Ground Fault Neutralizer installation at Neenach substation is the largest of the REFCL pilots at SCE. Because of the promise it shows, both SCE and PG&E (43) (44) are pursuing this technology as a part of their wildfire mitigation program. This technology has been widely deployed in Australia and proven effective, and as SCE scales up, is expected to have most applications across our HFRA.

Since GFN is installed in substations and helps reduce ignition risks for all downstream circuits, it is most cost-effective for large substations that feed many circuit miles with high fire risk. Space limitations at substations can impact costs if housing the GFN equipment requires an expansion or relocation of the substation or if the substation feeds substantial amounts of phase-to-neutral connected load which must be converted to phase-to-phase connected load.

4.1 Equipment Configuration

This pilot is one of the first two Ground Fault Neutralizer projects in North America and posed a learning curve in trying to develop effective ways to integrate the system into a substation and scale up. The initial configuration has been upgraded twice to incorporate lessons learned. The current design is expected to be ready for wider-scale deployments and its performance will be validated through upcoming projects at Acton, Banducci, Del Sur and Phelan substations in 2023 and 2024.

4.1.1 Initial Design

Neenach substation has one 66/12 kV transformer, three distribution lines and one capacitor bank, and is in an operating/transfer bus configuration where in normal operating mode all the lines and the transformer connect to the operating bus. An overview of this design is given in Figure 11 below (for simplicity, most disconnect switches, and the transfer bus are not shown).

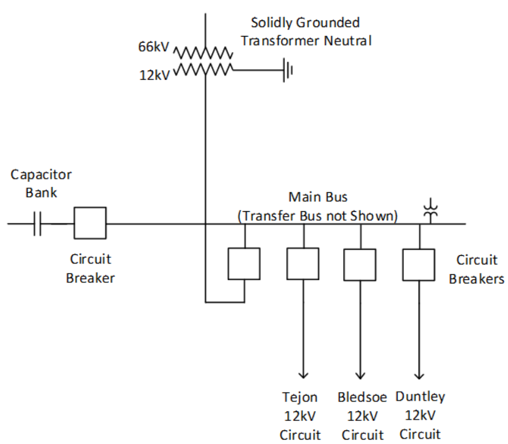


Figure 12 Simplified configuration of Neenach substation before the Ground Fault Neutralizer project

For the initial build in the spring of 2021, the installed Ground Fault Neutralizer was entirely pre-wired in a factory supplied enclosure. The enclosure included the arc suppression coil, residual current compensation inverter, voltage transformers and a grounding transformer. A 12.47kV three phase connection was made to the bus which supplied power to the equipment as well as provide a neutral for the Ground Fault Neutralizer to inject current into. A circuit breaker was installed on the neutral to allow the station to be solidly grounded if the Ground Fault Neutralizer needed to be taken out of service.

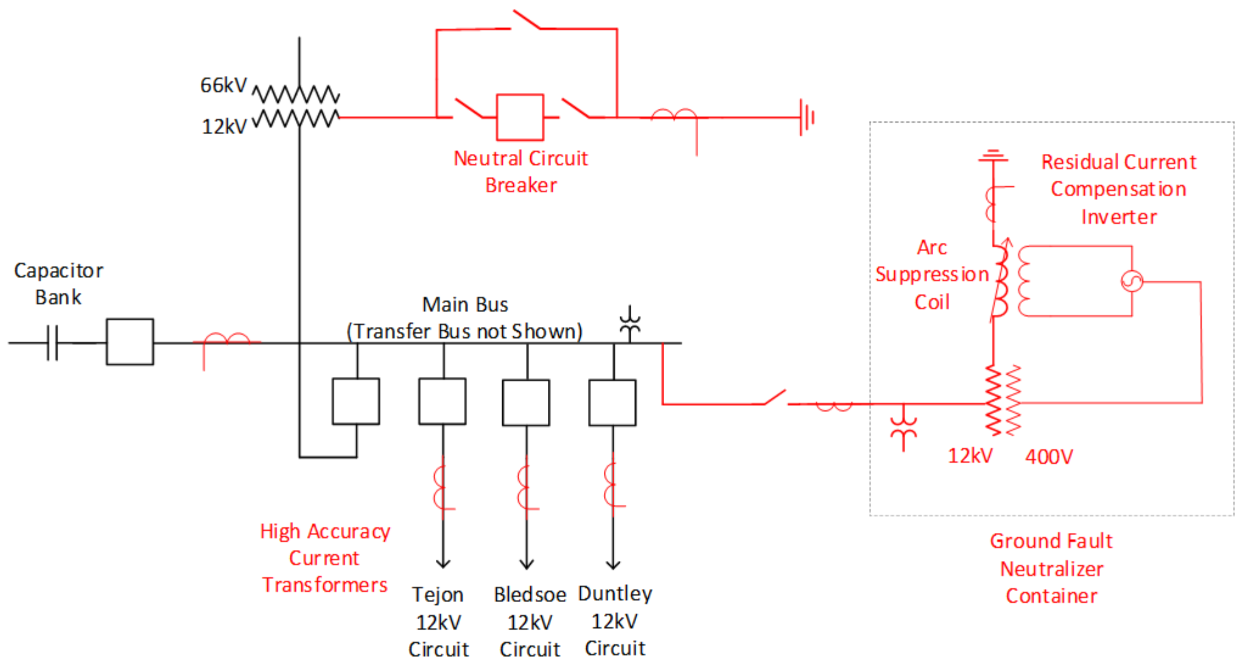


Figure 13: Neenach substation configuration for initial installation

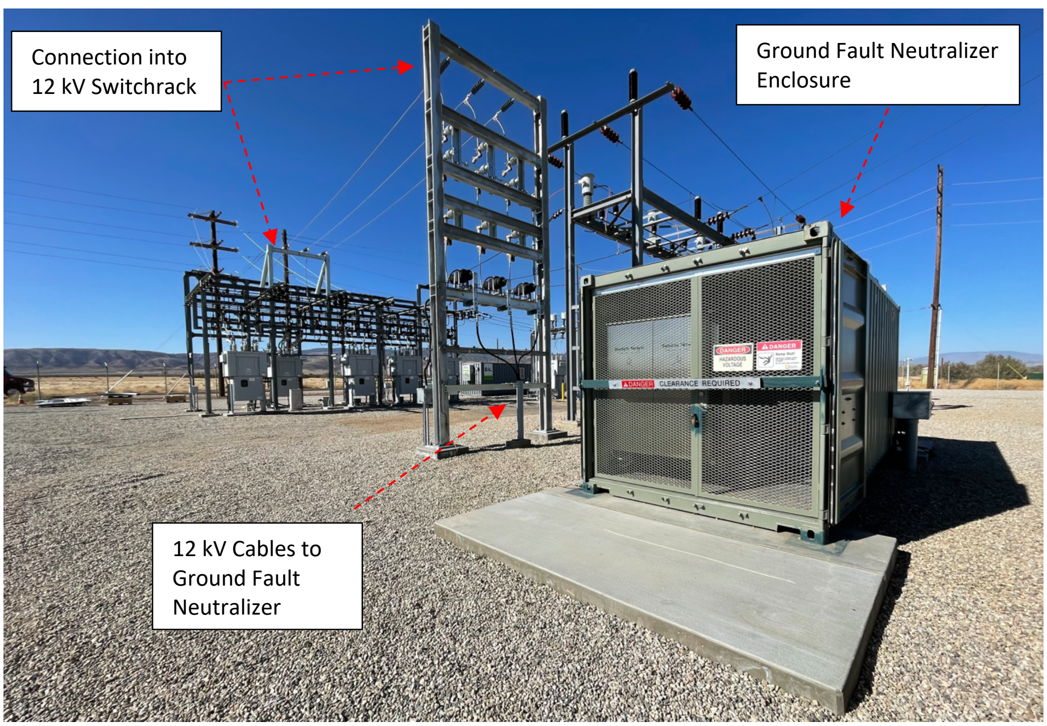


Figure 14: Overview of installation at Neenach substation in initial configuration.

Figure 15: Neutral Circuit Breaker for Ground Fault Neutralizer in Initial Configuration

4.1.2 September 2021 Reconfiguration

The Ground Fault Neutralizer was in its initial configuration for the fault testing and was briefly put in service in this configuration. However, shortly after it was put in service a failure of some equipment in the PG&E pilot installation called into question this design. Ferroresonance was suspected to cause problems when the Ground Fault Neutralizer is installed on a grounding transformer at the same time the station is solidly grounded at the source transformer.

In September 2021, once loading was low enough for the station to be removed from service, the Arc Suppression Coil was transferred to the neutral of the main 66/12.47kV transformer bank. The grounding transformer remained in service because it was required as a 400-volt power source for the Ground Fault Neutralizer controller. The location voltage was measured also remained the voltage transformers in the container. The station was put in service in this configuration and remained in this configuration until Q4 2022.

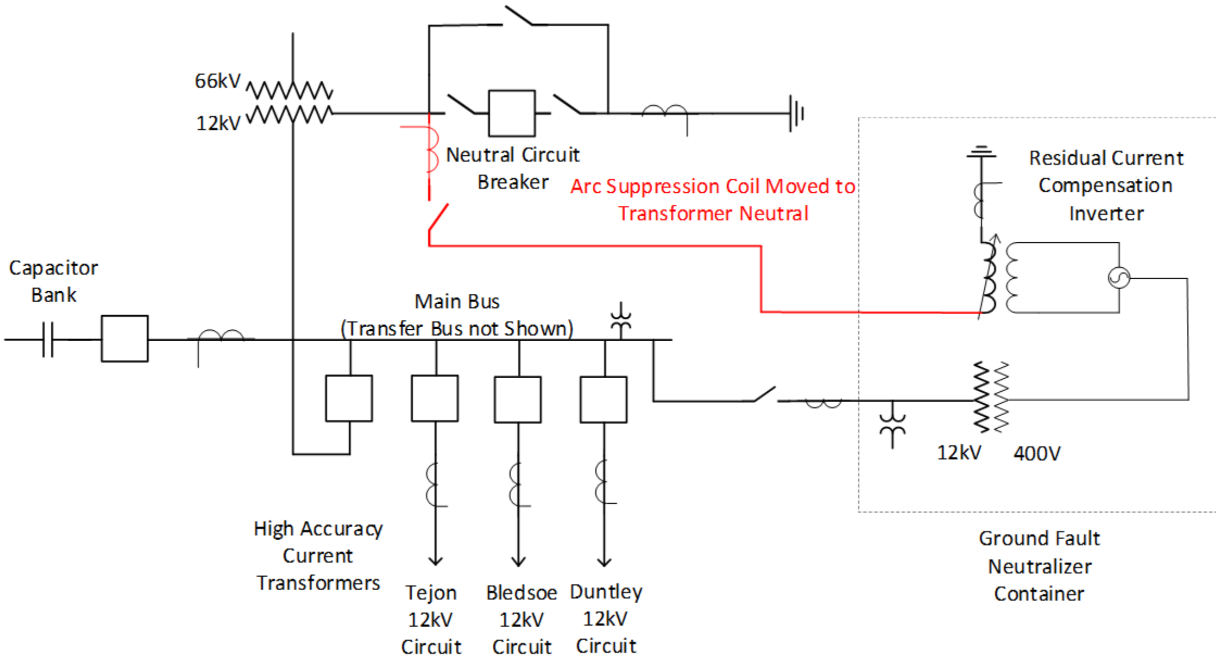


Figure 16: Neenach substation after arc suppression coil moved to main power transformer.

Figure 17: Ground Fault Neutralizer Connection Moved to Main 66/12kV Power Transformer Neutral

4.1.3 Q4 2022 Substation Rebuild

Once in service, the configuration installed at Neenach substation helped identify potential issues.

1. The connection of 12.47kV into the container is challenging to reproduce at substations with less available space. The switchrack structures required are large and difficult to site.
2. Having energized 12.47kV conductors in the container also means it is necessary to restrict access to the container due to exposed electrical components and increased the chances of an electrical fault damaging the Swedish Neutral equipment.
3. The grounding transformer was over-sized as it was only being used to provide 400-volt power to the inverter and no longer was used as a connection point for the arc suppression coil. It was also identified as a point of weakness in the design since it is not a typical part SCE uses and would be difficult to source after a failure.
4. The voltage transformers used by the Ground Fault Neutralizer voltage were non-standard parts for SCE.
5. The station lacked surge arresters on the 12kV bus, ultimately contributing to the failure of some of the equipment during a lightning storm which caused the equipment to go out of service for most of the second half of 2022.

To address these issues, the design was updated as shown in Figure 17. This new design eliminates the grounding transformer, eliminates a switchrack structure including the disconnect switches and current transformers on it, and it also uses standard voltage transformer ratios used elsewhere by SCE. It does require a larger station light and power transformer and a 240:400-volt transformer, but in net the quantity of equipment is reduced, and the number of standard SCE parts is increased. This reduces both the cost and probability of failure for the system and makes repairs easier. The new design is also easy to position in any vacant land which is available in a substation, only requiring a single high voltage connection to the main power bank transformer neutral. This made it substantially easier to site equipment in crowded substations.

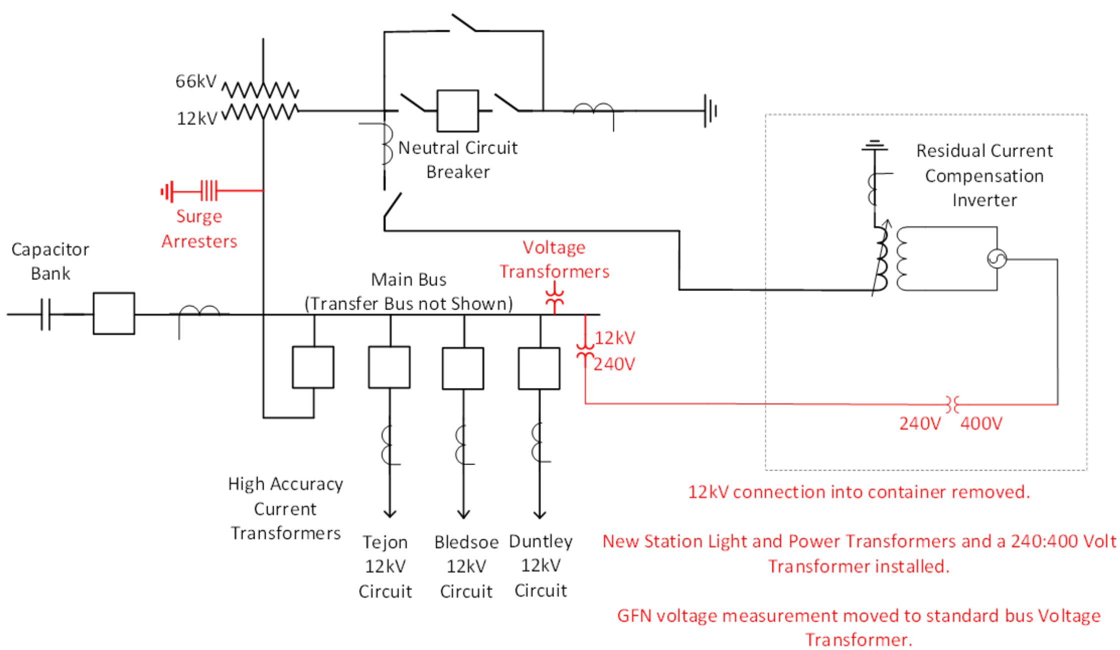


Figure 18: Latest configuration of Neenach substation removing 12kV from the GFN container

Figure 19: The 12kV Connection into Ground Fault Neutralizer removed in Q4 2022 rebuild

4.2 Commissioning Testing

The Ground Fault Neutralizer requires extensive testing before being put in service. This testing was further expanded to confirm the equipment was providing the expected risk reduction. The commissioning included balancing the circuits to the point that 0.5-ohm faults can be detected, a test of the insulation on all the circuits fed by the substation by raising the voltage on one phase at a time to 12 kV for ten minutes, and staged fault testing where 45 ground faults were placed onto the circuits.

4.2.1 Circuit Balancing

The Ground Fault Neutralizer detects extremely high impedance faults by reducing the level of background noise to be well below the target level of sensitivity. Since the Ground Fault Neutralizer is intended to detect ground faults down to 0.5 amperes, it was necessary to reduce the ground current noise on the network to a level substantially lower than 0.5 amperes. This is a big difference from many other advanced protection techniques which instead rely on detailed waveform analysis to increase sensitivity (45).

At the start of the project there was approximately 5 amperes of ground current returning to the substation which required mitigation. This reduction was accomplished by the installation of capacitive balancing units (CBUs), rephasing of two-phase tap lines, and removal of phase-to-neutral connected loads. This procedure was modeled off that used in the Australian REFCL Program (46) (41).

4.2.1.1 Methods to Reduce Ground Current Noise

To achieve a reduction in ground current noise, it is necessary to identify the sources of ground current on a distribution circuit and remove the largest sources of ground current until the targeted noise level is achieved. The main sources of this ground current noise are:

1. Transformers connected from a phase to a multi-grounded neutral.
2. Two phase tap lines.
3. Parallel transmission lines.
4. Transients and harmonics.

Multi-grounded neutrals allow load current to escape from phase conductors directly into the earth. They make sub-ampere ground fault sensitivity impossible with any existing technology. Neenach substation was chosen for this pilot in part because it did not have a multi-grounded neutral. At substations with a multi-grounded neutral it is necessary to either replace all transformers with phase-to-phase connected versions or install phase-to-phase connected isolation transformers which prevent the neutral current from coming back to the substation.

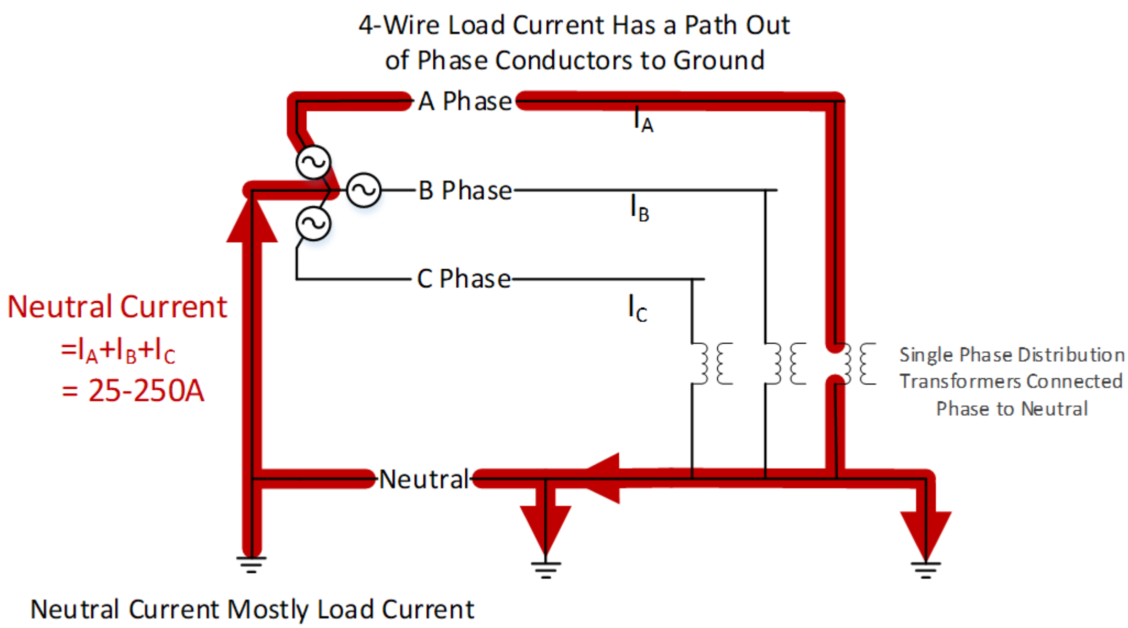


Figure 20: Load Current on a 4-Wire Multi-Grounded Neutral system has a Direct Metallic Path for Load Current to Escape to Ground.

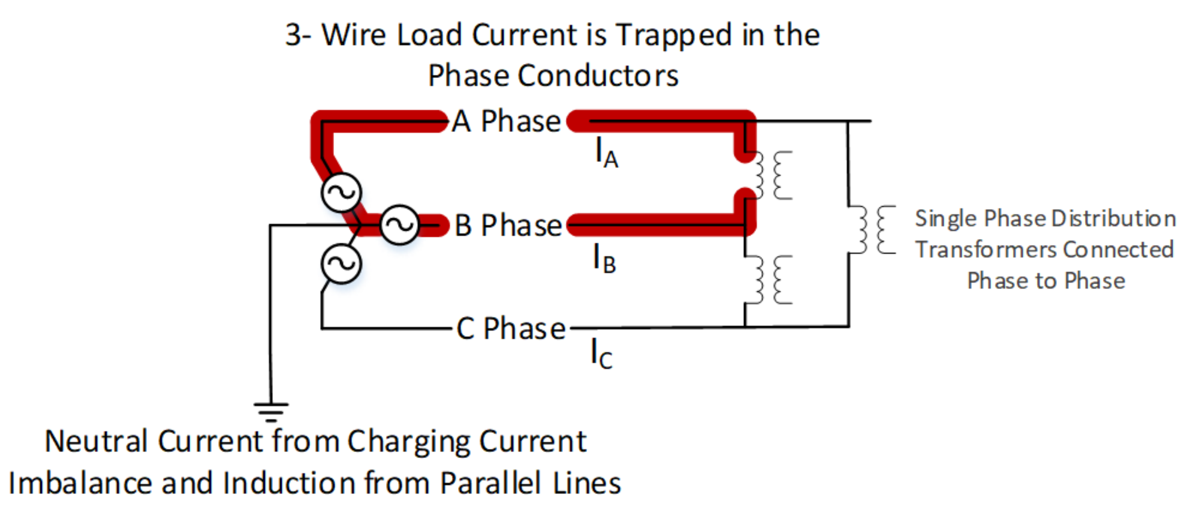


Figure 21: Load Current on a System Without Phase-to-Neutral Connected Transformers Does Not Produce Significant Ground Current Noise

Once the phase-to-neutral connected transformers are eliminated, two phase tap lines, particularly underground cables with two phases are the next largest source of noise. Since only two phases are present, the charging current does not sum to zero like it does on three phase lines (Figure 20). These tap lines are a steady state source of ground current which can be eliminated through the installation of Capacitive Balancing Units (CBUs). The balancing units should be placed as close as practical to the source of imbalance to ensure that routine switching or operation of reclosers does not separate the balancing unit from the tap line being balanced.

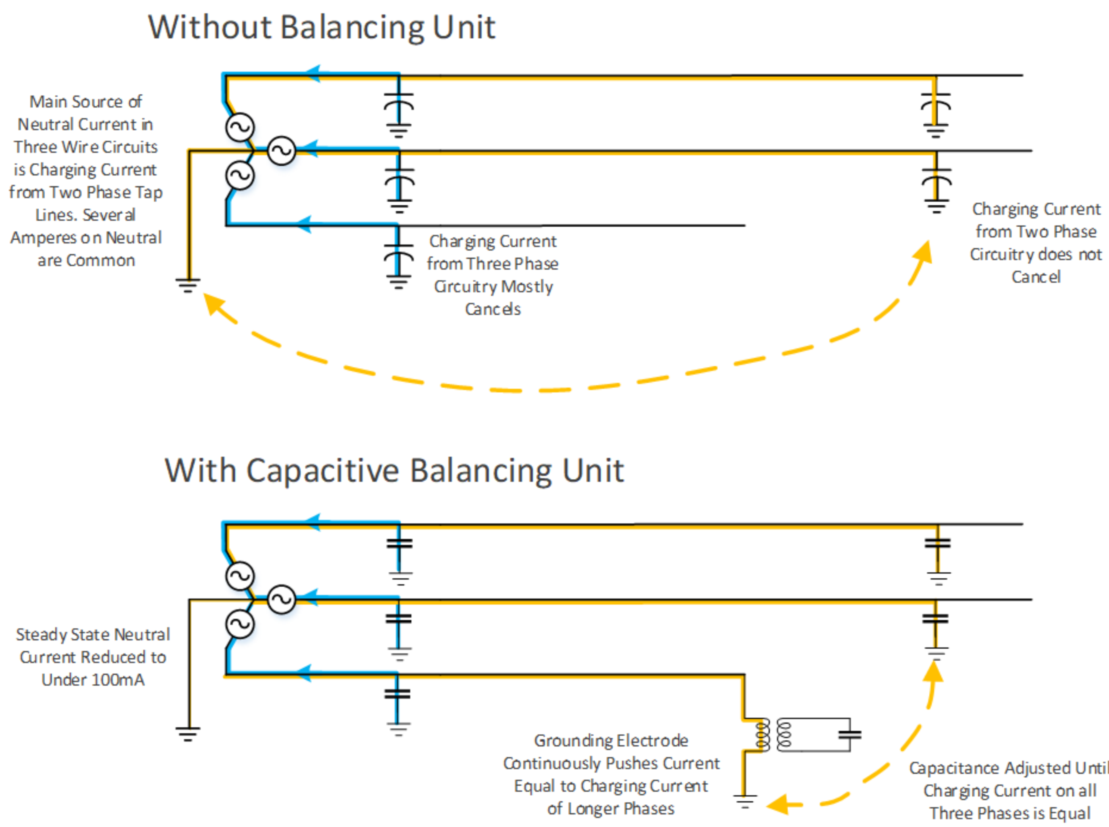


Figure 22: Current from Two Phase Cable Tap Lines with and Without Capacitive Balancing Units (CBUs)

Ground current noise can also come from parallel subtransmission or transmission lines. In these cases, induction off the parallel lines can push neutral current on the lines. This is typically a smaller source of noise than the other two sources but can be challenging to eliminate when there are long parallel circuits.

The previous three sources of noise are constantly present under the right conditions. Another class of noise is transient noise which is only present from milliseconds to seconds. Transient noise sources include switching or faults on parallel lines, faults on other buses in the same substation, and inrush current from energizing capacitors. In most cases transient noise is not a problem for the Ground Fault Neutralizer, it might see transient noise as a fault and briefly operate but the neutral shift it injects does not impact customers. The Ground Fault Neutralizer compensates for five seconds and confirms the fault is still present before any customers are dropped. In those five seconds the transient event is typically gone, and the Ground Fault Neutral returns the system to normal. This is an important reason the Ground Fault Neutralizer can be run with much more sensitive settings than traditional ground fault protection. Most protection interrupts customers for transient events if set too sensitive since it has no way to block fault current while maintaining load current.

Noise caused by temporary events longer than five seconds can result in customer outages even with the Ground Fault Neutralizer's ability to ride through shorter transients. The most important of these is single phase switching or switching which separates a balancing unit from the source of ground current it was balancing. This type of noise is only capable of being addressed by operating restrictions, good positioning of capacitive balancing units relative to the tap lines they are balancing and replacement of single-phase switching devices with three phase devices.

When unexpected noise is seen while attempting to balance circuits an additional possibility must be considered, that instead of noise being measured there is an actual high impedance fault allowing current to escape from a phase conductor. High impedance faults can stay on the system for many hours or even days before being reported as an issue or turning into low impedance faults and operating traditional protection.

4.2.1.2 Initial Circuit Balancing

On Thursday April 1st, 2021, the capacitive balancing units were set for the first time. The process followed was energizing a circuit up to the first open switch, neutral current was measured at Neenach substation and the settings on the capacitive balancing units were adjusted until the target values were achieved. Then the circuit was energized to the next open switch and the process was repeated until imbalance of each section was addressed.

Measurements were taken using extremely high accuracy metering current transformers installed at Neenach substation. On the secondary side the Ground Fault Neutralizer controller took the measurements, a Distribution Fault Recorder was also used, but on this date was unable to hit the required signal to noise ratio to measure milliamperes on the primary conductor.

Following this technique, the 60Hz neutral current on the Bledsoe and Duntley circuits was successfully reduced to well under 0.1A. The first half of the Tejon circuit was also balanced to under 0.1A. After a switch to the second half of the Tejon circuit was closed the noise level of the circuit amplified to the point it was not possible to balance much lower than one ampere.

Figure 23: Capacitive Balancing Units Installations

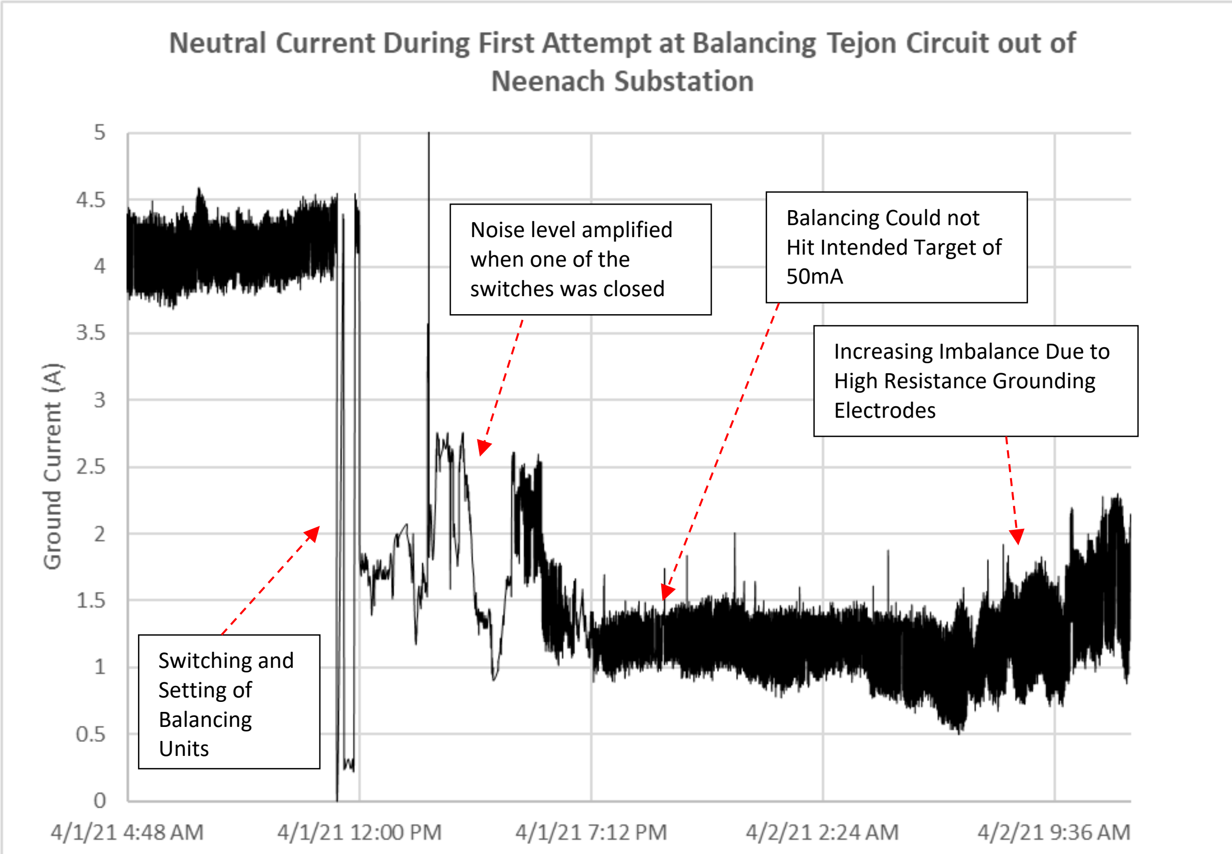


Figure 24: Ground Current for First Attempt Balancing Tejon Circuit, Includes Harmonics

Over the next few days, the circuits slowly became unbalanced. The reasons were initially unclear, and benchmarking with Australian utilities produced no examples of circuits becoming unbalanced. During the night of Tuesday April 6th, five days after entering service, a relatively small pole fire was reported at one of the capacitive balancing units. The next morning, a similar, contained pole fire was reported at a second balancing unit. Fire damage in both was limited to the base of the poles. A troubleman was dispatched to turn off all capacitive balancing units after the report of these ignitions. The cause of the circuit coming unbalanced was immediately apparent and corrected. The ground rods at the base of the pole, which were pushing from 0.55-0.75A into the earth, had heated up from the current. As the earth heated the sandy soil around the rods dried out increasing the resistance of the grounding electrodes and blocking some of the balancing unit current from entering the earth. Eventually this progressed to the point that the wood in the poles caught fire (47).

Even after all the capacitive balancing units were turned off the high level of background noise on the Tejon circuit continued for several days. Inspections were performed and plans were devised to find the noise source such as by installing Early Fault Detection (EFD) systems or switching to localize the noise to between two switches. Then, on April 8th the noise level on the Tejon circuit dropped dramatically. No source was ever found; however, a fuse blew on a transformer the morning of the noise reduction. A high impedance fault on that transformer, or possibly ferroresonance, remain credible sources of the noise. No similar source of noise has not returned since, but if it did return the Ground Fault Neutralizer would see it as a high impedance fault and operate since the magnitude was approximately a half ampere.

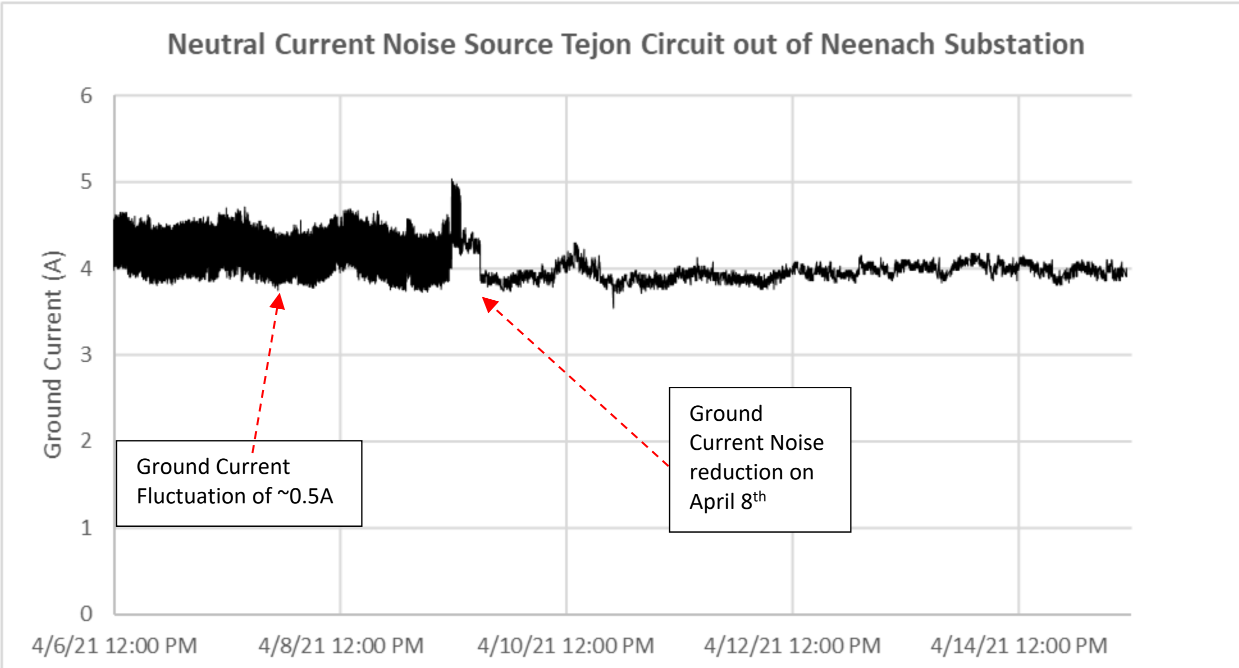


Figure 25: Ground Current Source on the Tejon Circuit Disappeared April 8th, Including Harmonics

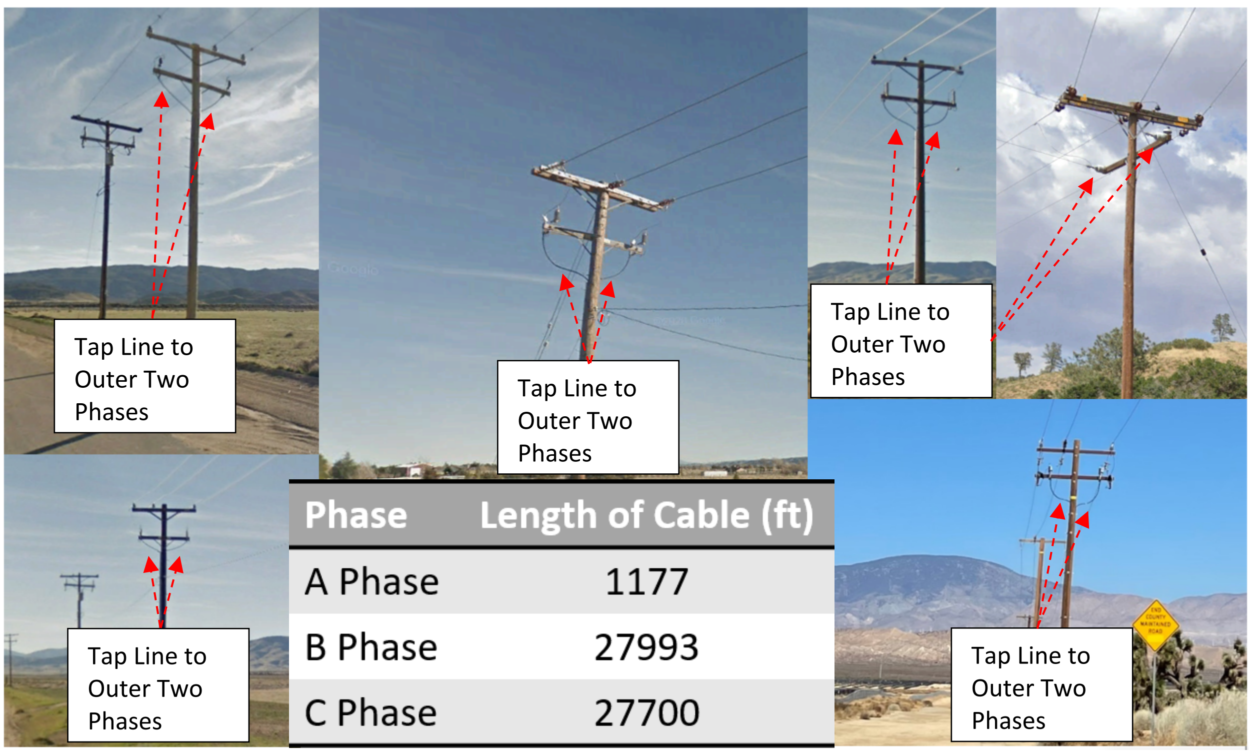
4.2.1.3 Updated Design for Balancing Unit Grounding

Since the grounding electrode design resulted in ignition when conducting 0.5-0.75 amperes of current into two-eight-foot ground rods, an updated version was required. The version moved to is a 40-foot-deep grounding electrode installed by drilling and lowering a conductor to the bottom of the hole. Two separate conductors were routed to opposite sides of the pole to give redundancy in case one is cut. The top ten feet was insulated by cable insulation and PVC conduit so that current is only injected into the earth at depth where any heating will not impact neighboring infrastructure.

Figure 26: Deep Grounding Electrode Installation

4.2.1.4 Second Attempt at Circuit Balancing

With the improvement of the balancing unit electrodes and elimination of the noise source, a second attempt at balancing the circuits was made. On further analysis it was found that most of the imbalance current resulted from cable tap lines being connected to the outer two phases, as shown in Figure 26. This practice results in a symmetrical cable riser so has been the preference of crews installing tap lines. Until the Ground Fault Neutralizer was installed this small amount of imbalance current did not represent a problem for typical SCE ground fault protection. To reduce the number of balancing units required, a round of rephasing was done to better balance the total amount of capacitance on each phase. This reduced the current on the transformer bank neutral from about 5 amperes to about 1.7 amperes.



Phase	Length of Cable (ft)
A Phase	1177
B Phase	27993
C Phase	27700

Figure 27: Most two-phase cable tap lines connected to outer two phases

Balancing units were then set and reduced the 60Hz current to around 100mA. However, the circuits came somewhat unbalanced at nights increasing to about 300mA. The reasons for this variation was later shown to be induction coming off parallel 66kV lines.

During this balancing the Digital Fault Recorder settings had also been updated to be able to measure with the required accuracy to see primary current to within a few milliamperes. The fault recorder had remote access and data easily formatted for analysis with python scripts so became the primary device used to confirm balance of the circuits. Measurements at this time were only made when the recorder was manually triggered which resulted in many measurements when actively working on the project and no measurements outside working hours. This was updated in subsequent months to automatically trigger at preset time intervals.

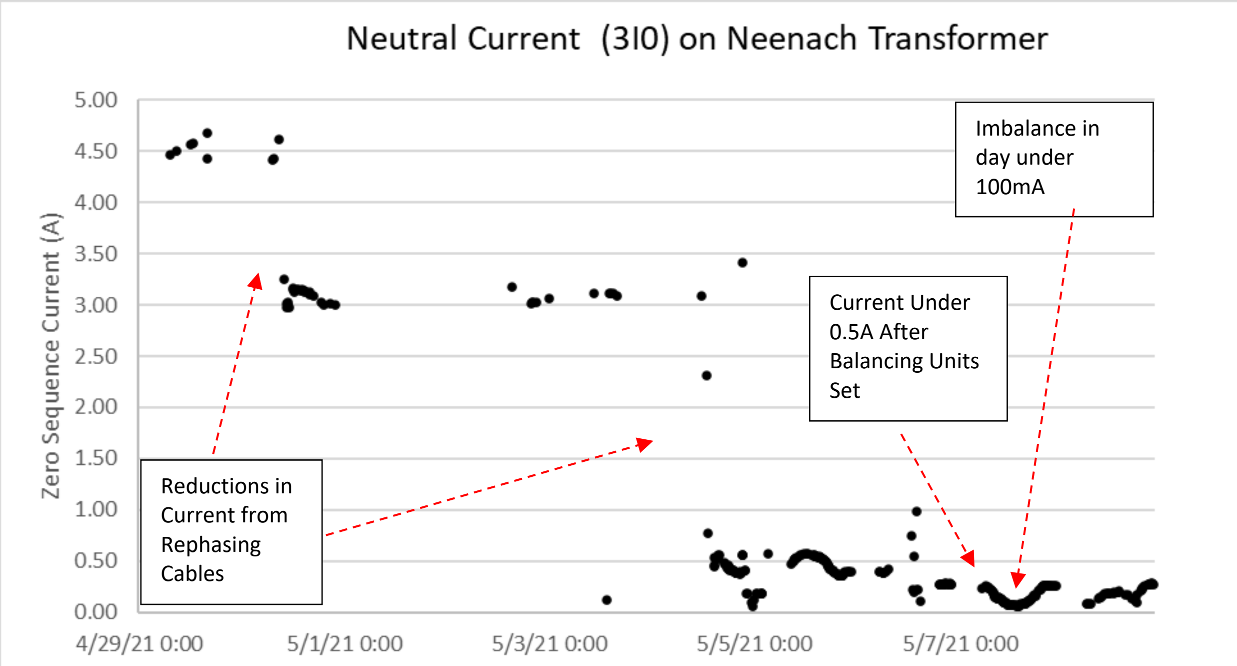


Figure 28: Neutral Current During Second Rebalancing, Harmonics Filtered Out

4.2.1.5 Fine Tuning of Balancing

At the conclusion of the second attempt at balancing, each circuit was balanced to the target values during the daytime but came somewhat more imbalanced than desired at night. Also, while every circuit was well balanced, there remained configurations which the circuits could get into by operating pole switches which would be too unbalanced to operate the Ground Fault Neutralizer. In subsequent months fine tuning of circuit configuration, capacitive balancing unit locations and capacitive balancing unit settings were performed to fine tune the balancing.

For the initial months of service, the circuit configurations which would imbalance the circuit were avoided with operational restrictions. The Ground Fault Neutralizer was removed from service when the circuit was put in an abnormal configuration by opening or closing switches on the circuit. In the rebuild at the end of 2023 additional measurements were given to Operators to allow them to determine if the existing configuration is balanced enough for the Ground Fault Neutralizer to enter service.

To reduce the daily variation of imbalance current, additional measurements on the imbalance was required. During this process, the Digital Fault Recorder became increasingly useful as the project team learned to schedule large number of measurements and create python scripts to analyze the large quantities of data it can produce. First it was confirmed in detail when the circuits came unbalanced and that almost all this variation came from one of the three distribution circuits, as shown in Figure 28 and Figure 29.

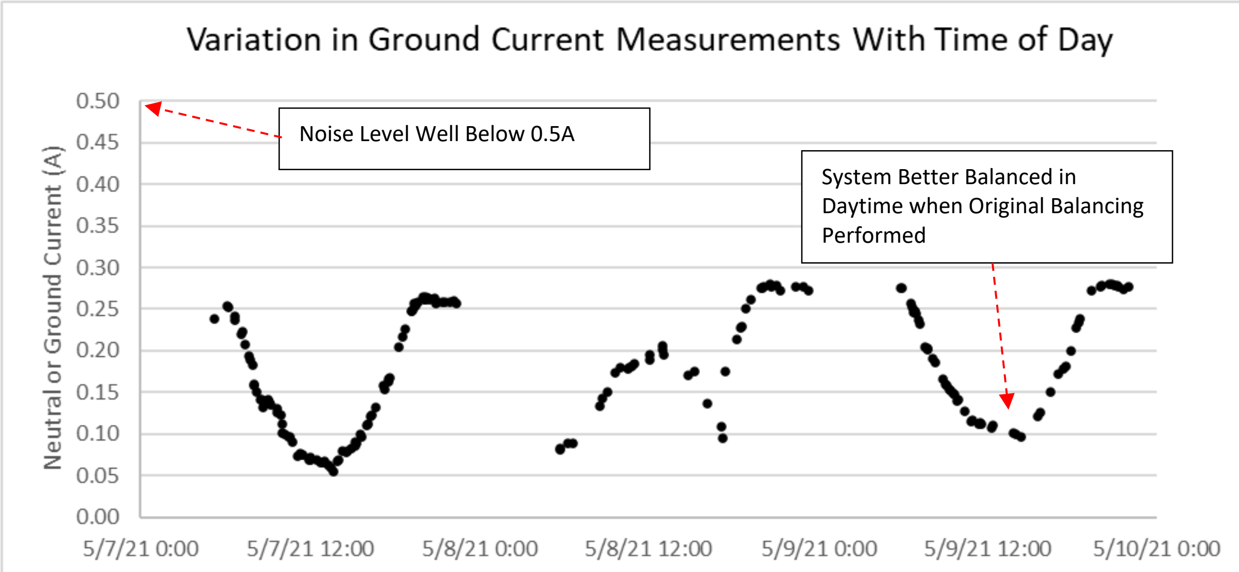


Figure 29: Neutral Current for Several Days After the Second Balancing Attempt of Neenach Substation

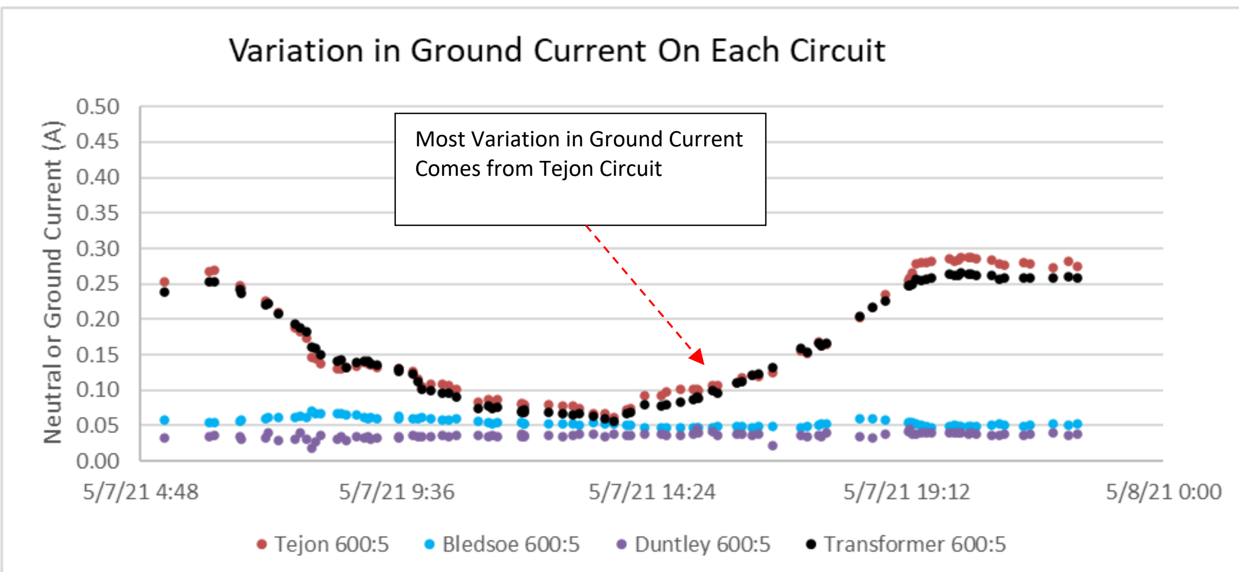


Figure 30: Neutral Current for Several Days After the Second Balancing Attempt of Neenach Substation

After confirming that the daily variation was consistent, the plan was developed to try balance to the midpoint of that variation rather than the conditions in the afternoon when the original measurements were made to balance. To determine correct settings, it was found that a graph converting the magnitude and angle of the imbalance current to an X and Y cartesian value was helpful. By graphing the level of imbalance along with the expected magnitude and direction which a one-step change of a Capacitive Balancing Unit would move that imbalance the current can be centered. For example, in Figure 29 the Bledsoe circuit could be better balanced by adding one step to C phase which would shift values up and to the left. The Tejon circuit can be better balanced by adding two or three steps to B phase.

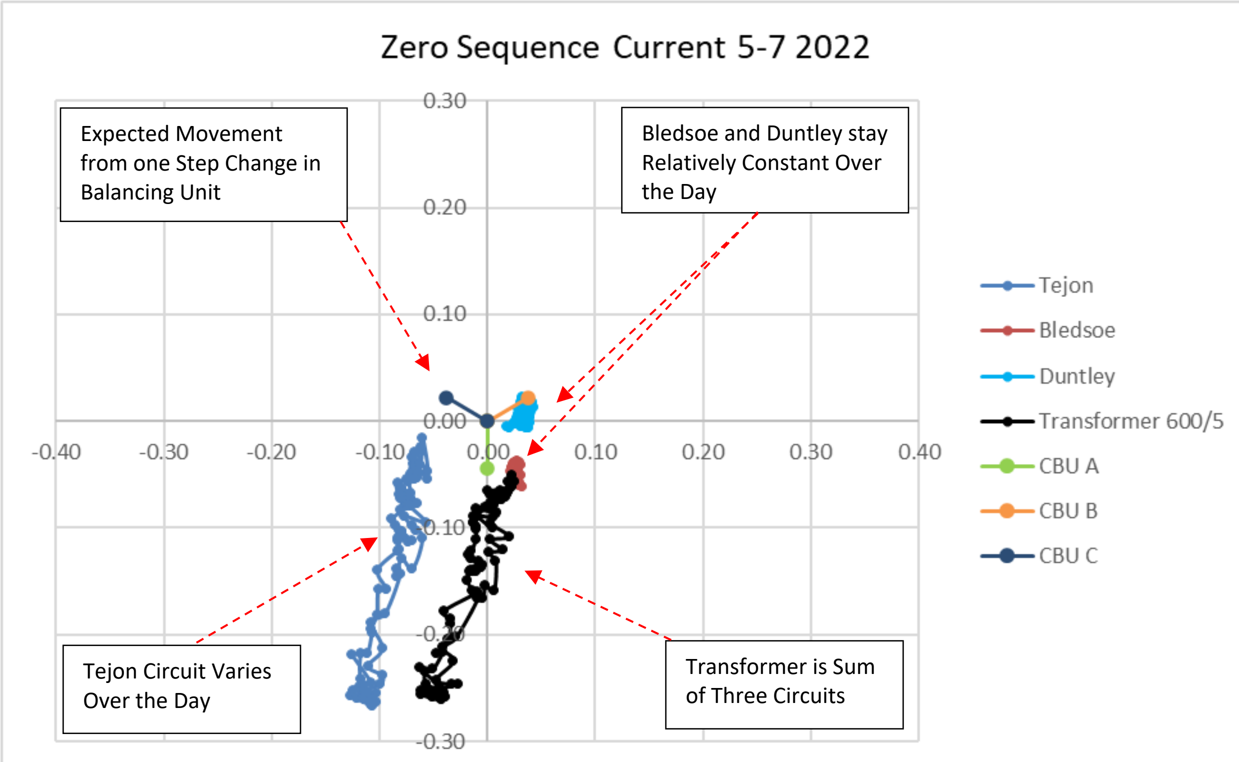


Figure 31: Measured Imbalance on May 7th, Converted to Cartesian Coordinates

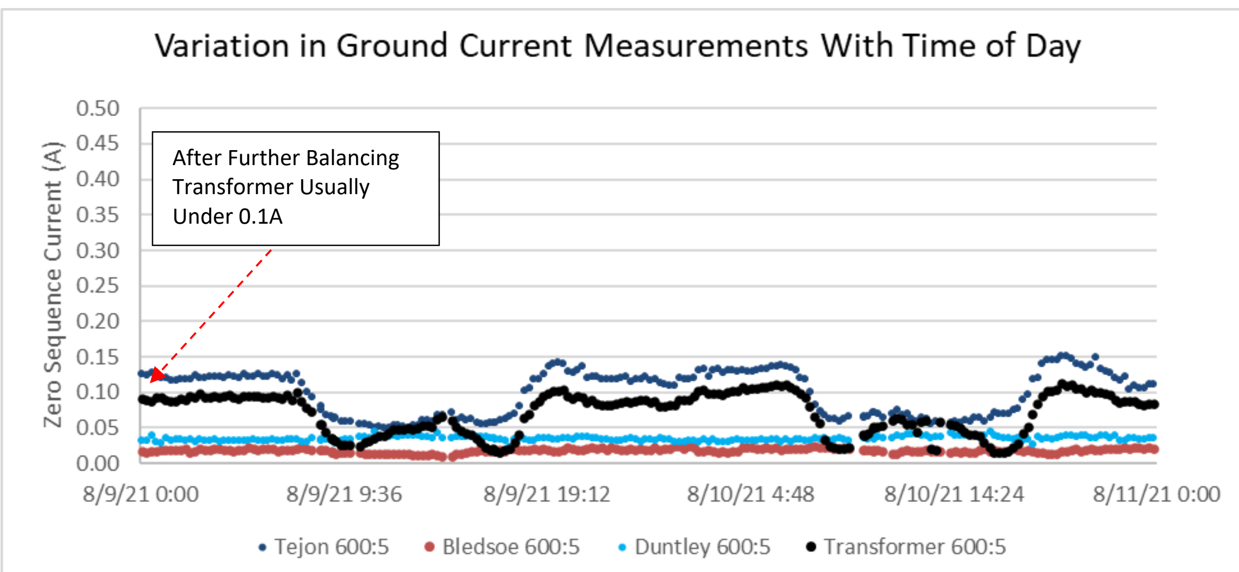


Figure 32: Neenach Imbalance in August After Better Centering Imbalance on Zero

After this procedure was followed imbalance was further reduced. The current on the main transformer bank at Neenach substation now spent most of the day well below the targeted 100mA as seen in Figure 30 and Figure 31, and throughout the day the signal to noise ratio was such that a 0.5A fault can reliably be detected. Additional fine tuning by this process was still possible but was not done as the noise level was low enough for the desired sensitive settings. Still, it was elected to make the smallest step on Capacitive Balancing Units on future projects 25mA instead of 50mA to give a tool to better fine tune circuits.

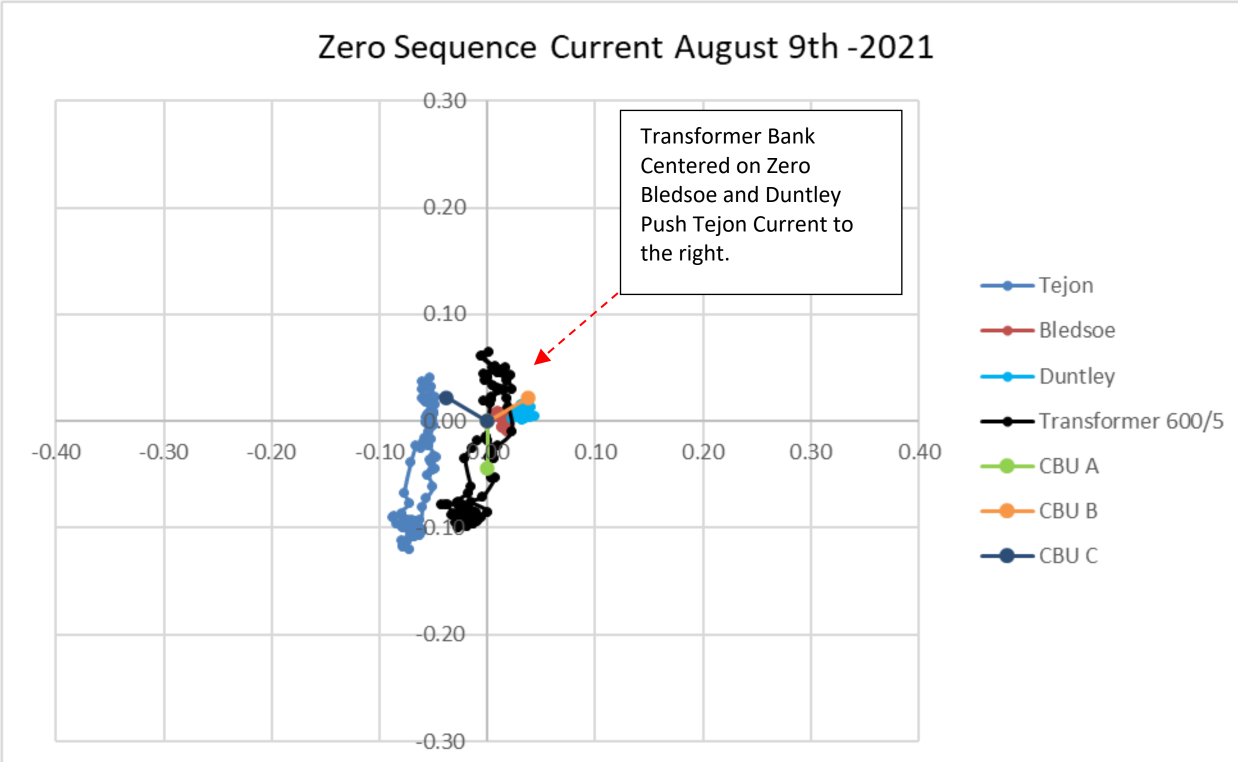


Figure 33: Measured Imbalance on August 9th, Converted to Cartesian Coordinates

Further investigations showed that the imbalance in the Tejon circuit has a strong connection to loading on a parallel subtransmission line, as shown in Figure 32. This line mostly carries solar power from nearby power plants, so it is lightly loaded at night but heavily loaded in the day. This subtransmission line is in parallel with the distribution for about ten miles. Other distribution lines are in parallel with subtransmission lines but the distances in parallel are much less. Consideration was given to installing subtransmission transpositions or parallel ground wires, but since the level of imbalance remained manageable, no further action was required at that time. It is possible that future projects will require work to manage this source of imbalance.

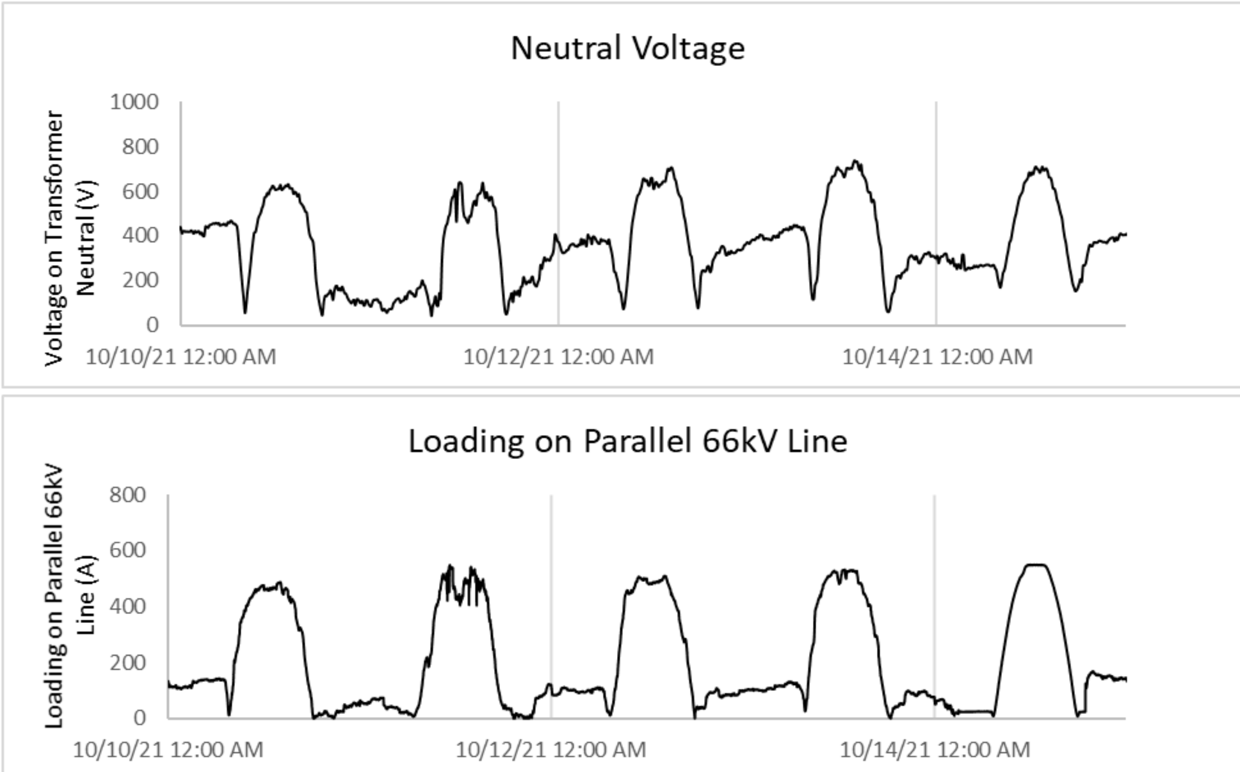


Figure 34: Imbalance at Neenach Substation Compared to Line Loading on Parallel 66kV Line

4.2.1.6 Results and Lessons Learned from Circuit Balancing

The circuit balancing process was ultimately successful at reducing the neutral current on the main power about 98%, from approximately 5 amperes down to 0.1 ampere. When the neutral breaker opens the current imbalance seen when solidly grounded converts to a voltage imbalance. The standing voltage on the neutral of the transformer was well under 1kV when at resonance, which is low enough to not cause serious stress on any equipment. This level of imbalance appears to be balanced enough to detect 0.5 ampere faults. This imbalance remained at low levels for the year and a half of the project with the only settings changes being made during continued attempts to balance for additional circuit configurations.

Going forward figuring out optimal numbers and locations of capacitive balancing units as well as incorporating greater automation into the balancing units will continue to be important design elements. At one extreme, circuits could be balanced only in their normal configuration and the Ground Fault Neutralizer could be removed from service whenever not in a normal configuration. At another extreme balancing units could be on each tap line with enough charging current that it might imbalance the station enough to look like a fault. SCE is moving forward with a strategy of balancing beyond every three-phase pole switch or recloser so that main line switching will always leave the station balanced. This strategy may be adjusted based on operational experiences going forward. For example, SCE may find balancing units are being installed for configurations which happen a few hours a decade or less. These balancing units might be better removed from the design.

Where significant parallel transmission and distribution exist, projects may be forced to make a choice between significant rebuilds of the distribution or transmission lines or accepting lower sensitivity. This is expected to be uncommon as similar lengths of parallel lines were not found on the 2023 projects.

4.2.2 Resonance Curve

To produce a resonance curve, the voltage across the arc suppression coil is measured as the inductance of the coil is varied. Voltage is expected to increase to a maximum, when resonance is reached, then reduce more after passing the resonant point. Many important characteristics of the system can be learned from the resonance curve including the charging current of the system, how well the system has been balanced and the damping of the system.

The inductance in resonance curves is typically measured in amperes of current that the arc suppression coil would inject into the system during a fault. This is a convenient way to measure inductance in this case because it matches the charging current of the system, for example if the arc suppression coil reaches resonance at 100 amperes it means that the sum of the charging current for all circuits is 100 amperes.

The resonance curve at Neenach substation was first measured in April 2021 after the first attempt at balancing. The peak voltage was reached when the coil was set to 55 amperes which shows that the sum of the charging current of all circuits is 55-amperes. This is close to values estimated before the equipment was purchased and shows that the 100-ampere coil was properly sized. The system can almost double in charging current, for example from load growth or underground conversions, before a larger coil would be needed.

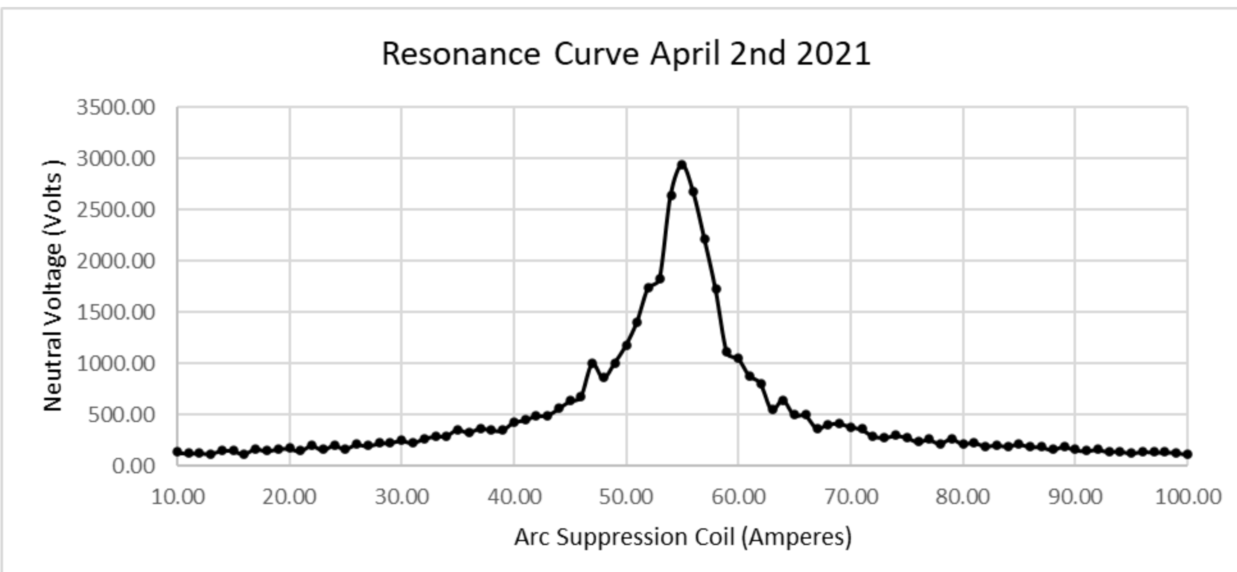


Figure 35: First Resonance Curve at Neenach Substation

One notable concern from this resonance curve comes from the fact that the voltage on the neutral at resonance is around 3,000 volts. This is a substantial neutral shift which results in high phase-to-ground voltage on at least one phase when in resonance. Also, the measurements were unstable, apparently from the same source of noise seen in Figure 24 which made balancing difficult in April 2021. Additional balancing work was required to reduce this standing imbalance.

After the balancing process was complete, additional resonance curves were measured. These showed that the balancing was successful at reducing the peak voltage to around 600 volts although it does vary by time of day as shown in Figure 32. That is a low enough value both to remove any concerns of over-voltage on a phase and is sufficiently low to be able to detect the voltage rise caused by a half ampere fault.

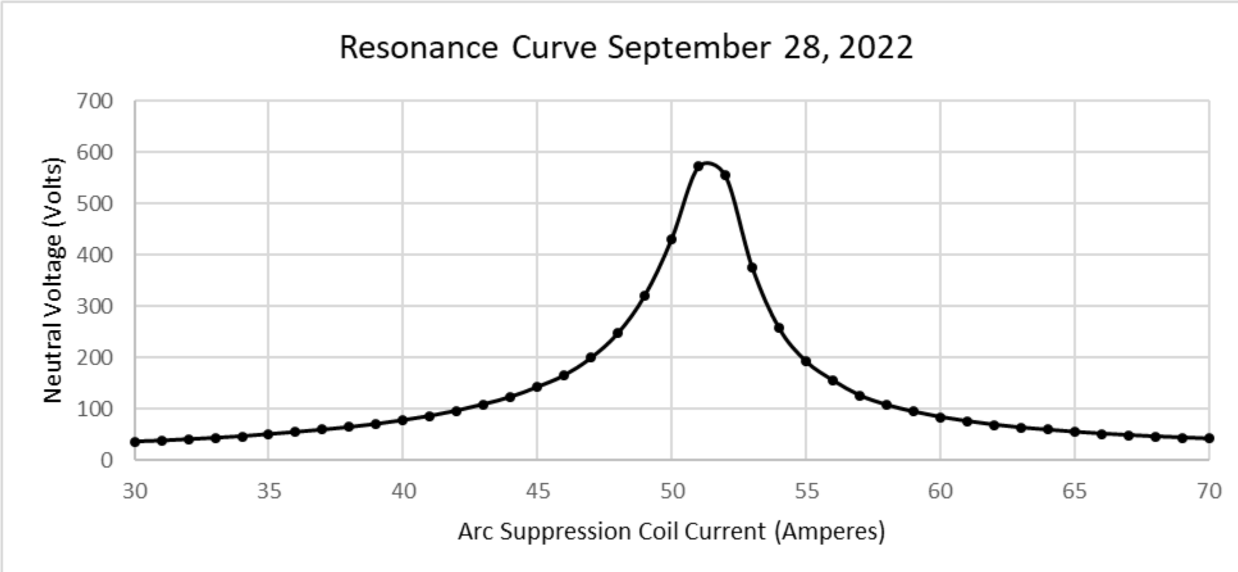


Figure 36: Resonance Curve at the Completion of the Balancing Process

4.2.3 Insulation Testing

4.2.3.1 Overview of Test Goals and Procedures

When it operates Ground Fault Neutralizer increases the voltage on the unfaulted phases from 7.2 kV to 12.47 kV. Most SCE distribution equipment is rated to this voltage with typical ratings on equipment exceeding 30kV for an hour. However, this rating is for new equipment. Sometimes aged equipment deteriorates over time to the point that it can no longer withstand this voltage.

Equipment with a known high risk of failure can be replaced as a part of the project construction. For example, in this project all porcelain lightning arresters were pre-emptively replaced because they were a known risk. Even after extensive preparations, some chance remains that equipment would fail the first time the Ground Fault Neutralizer displaces the neutral voltage. To reduce the impacts of such a potential failure, it was determined that before further testing the Ground Fault Neutralizer would be used to increase the voltage on each phase to 12kV for ten minutes. The testing was performed late at night and with distribution crews on site to minimize any risks to the public. This procedure was developed after benchmarking with Powercor in the Australian REFCL program showed they follow similar practices.

4.2.3.2 Results and Lessons Learned from Insulation Testing

No SCE owned equipment failed during the insulation test. This validated the desktop analysis that SCE equipment is rated for the voltages produced by a Ground Fault Neutralizer.

There were failures of several lightning arresters at solar facilities during the insulation test. Customers who owned primary voltage equipment had previously been informed installation of the Ground Fault Neutralizer and the possibility of arresters with a rating below 15kV failing was brought to them. However, the arresters were not shown on any of the drawings the customer shared with SCE. Future Ground Fault Neutralizer projects will need to improve the process of locating under-rated equipment at customer facilities.

4.2.4 Staged Fault Testing

Because of the cost and complexity of this project, it was decided to test it by placing faults on the circuits out of Neenach substation (9). This has been a standard process in the Australian Ground Fault Neutralizer projects (41) and has been performed on other Ground Fault Neutralizer projects such as the 110kV system powering the German rail network (26).

One advantage of the Ground Fault Neutralizer is that ground faults can be placed on the system without causing customer outages and with a relatively small release of energy. This allows staged fault testing to be more easily performed in a safe and controlled manner. Even for very low impedance faults it was possible to put a fuse in series limiting worst-case energy release if the Ground Fault Neutralizer failed to be as effective as expected.

Two resistance values were used for the faults 14,400 ohm and 225 ohms. These were based on criteria out of Victoria Australia for the target drop in voltage after initiation of a fault. Cable faults were also performed which allowed for proper setting of restriking settings. Cable faults also give waveforms for arcing faults across insulation which are expected for any phase-to-ground equipment faults.

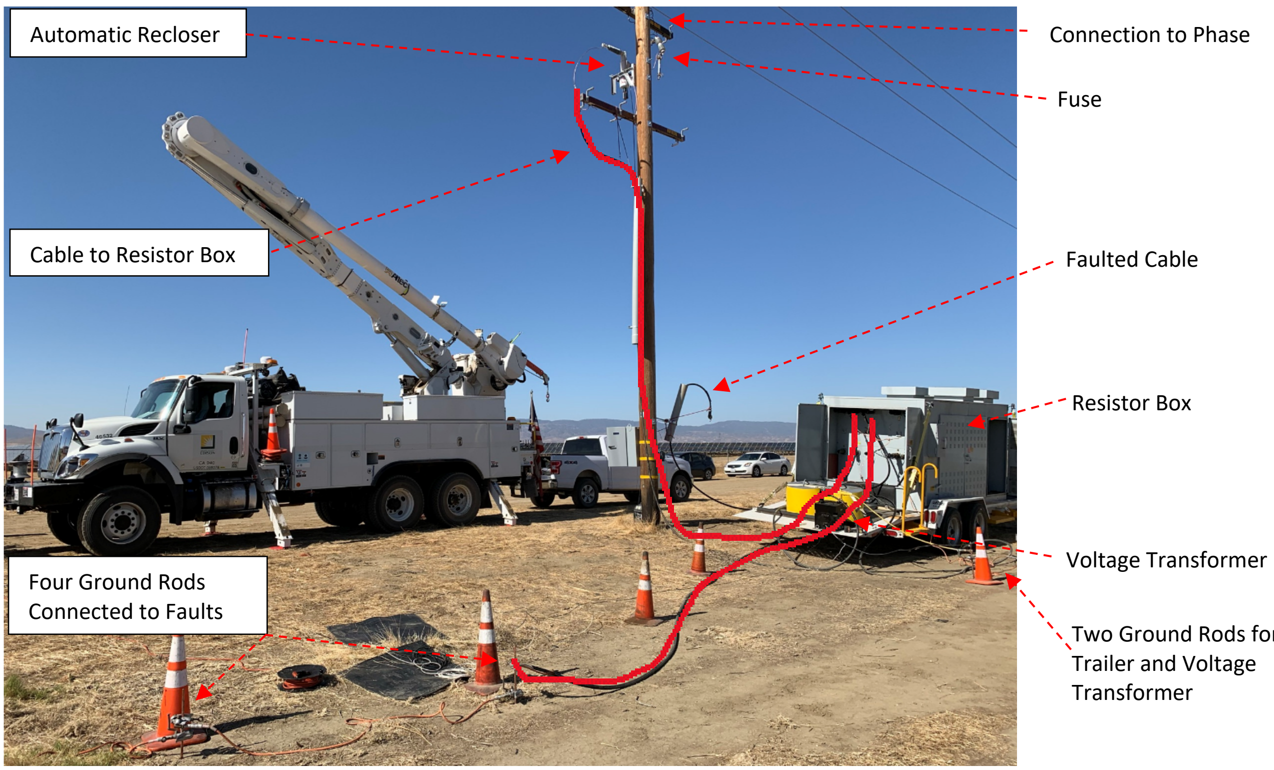


Figure 37: Fault Testing Setup

4.2.4.1 Resistor faults

The resistor faults demonstrated the system was working as anticipated. The system was able to act on ground faults faster than the traditional protection which was in service and operating normally during the testing. It was able to operate this quickly on ground faults with no impact on customer voltages.

The Ground Fault Neutralizer was able to detect half ampere faults both at the substation and end of line and act on them fast enough to meet the 250 volts after two seconds requirement. The fault confirmation requirement of achieving a i^2t of 0.1 A^2s was more challenging to achieve. The system often was borderline in meeting this criterion with many tests at 0.11 A^2s. Still, this represents a several order of magnitude improvement over the traditional methods of testing whether a fault is still present.

For the 225 ohm faults the performance of the Ground Fault Neutralizer was even better, meeting the desired voltage targets in every single test. The Ground Fault Neutralizer started reducing the voltage on the faulted phase from the very first cycle with each of the first few peaks reducing voltage compared to the previous by several thousand volts. In some tests, particularly those near the substation, voltage on the faulted phase dropped below 100-volts. The fault confirmation was able to confirm the presence of the fault with only an approximately 100-volt rise over this steady state value.

The lowest level of effectiveness was observed at the end of line faults on a heavily loaded circuit. For some of these tests the voltage on the faulted phase was only reduced to about 600 volts at the fault site even though it was under 150 volts measured at the substation bus. But even for these tests, energy release for ground faults was dramatically reduced and sensitivity increased to the 0.5 ampere level.

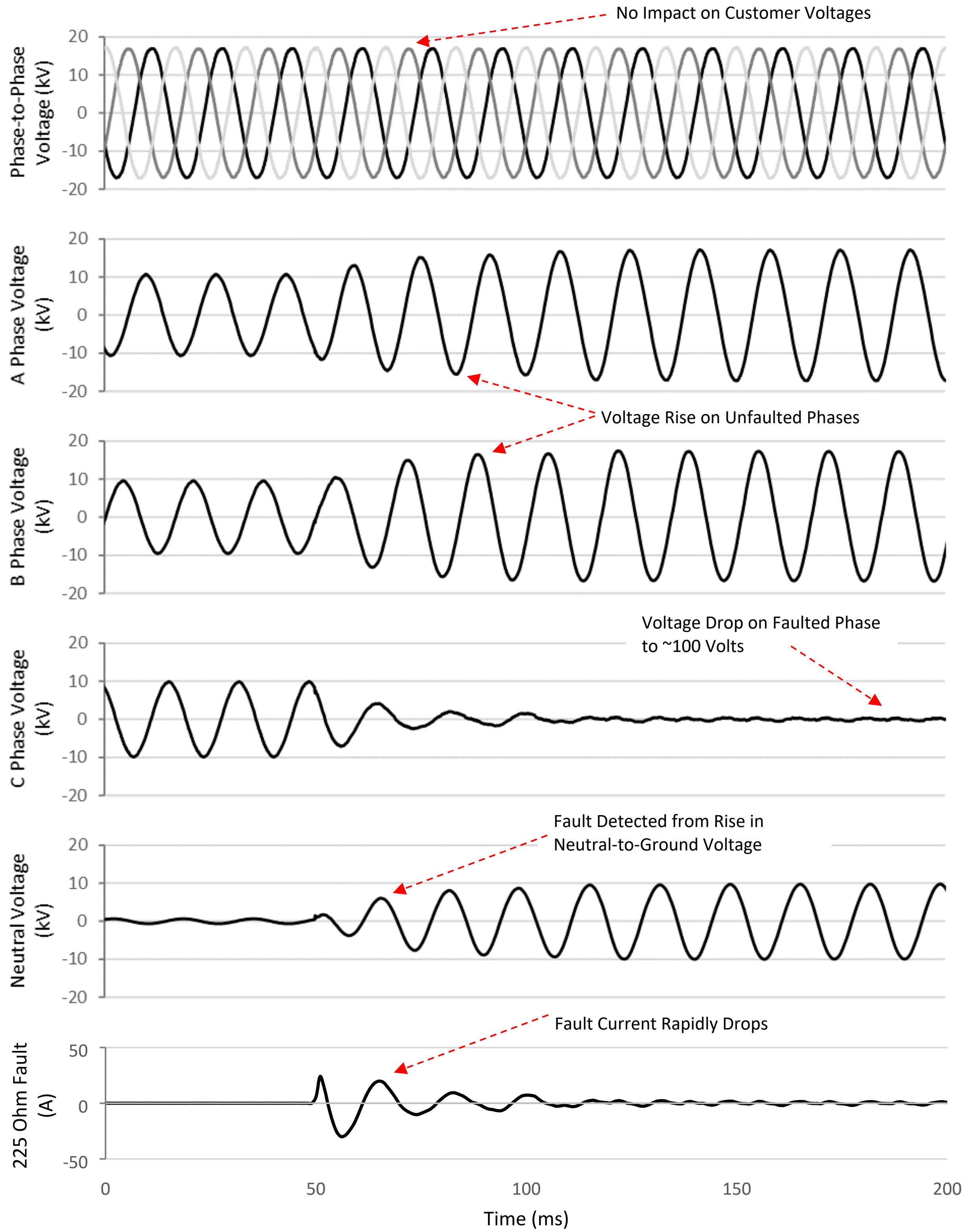


Figure 38: Waveforms for first 150ms of a 225-ohm, C phase, fault

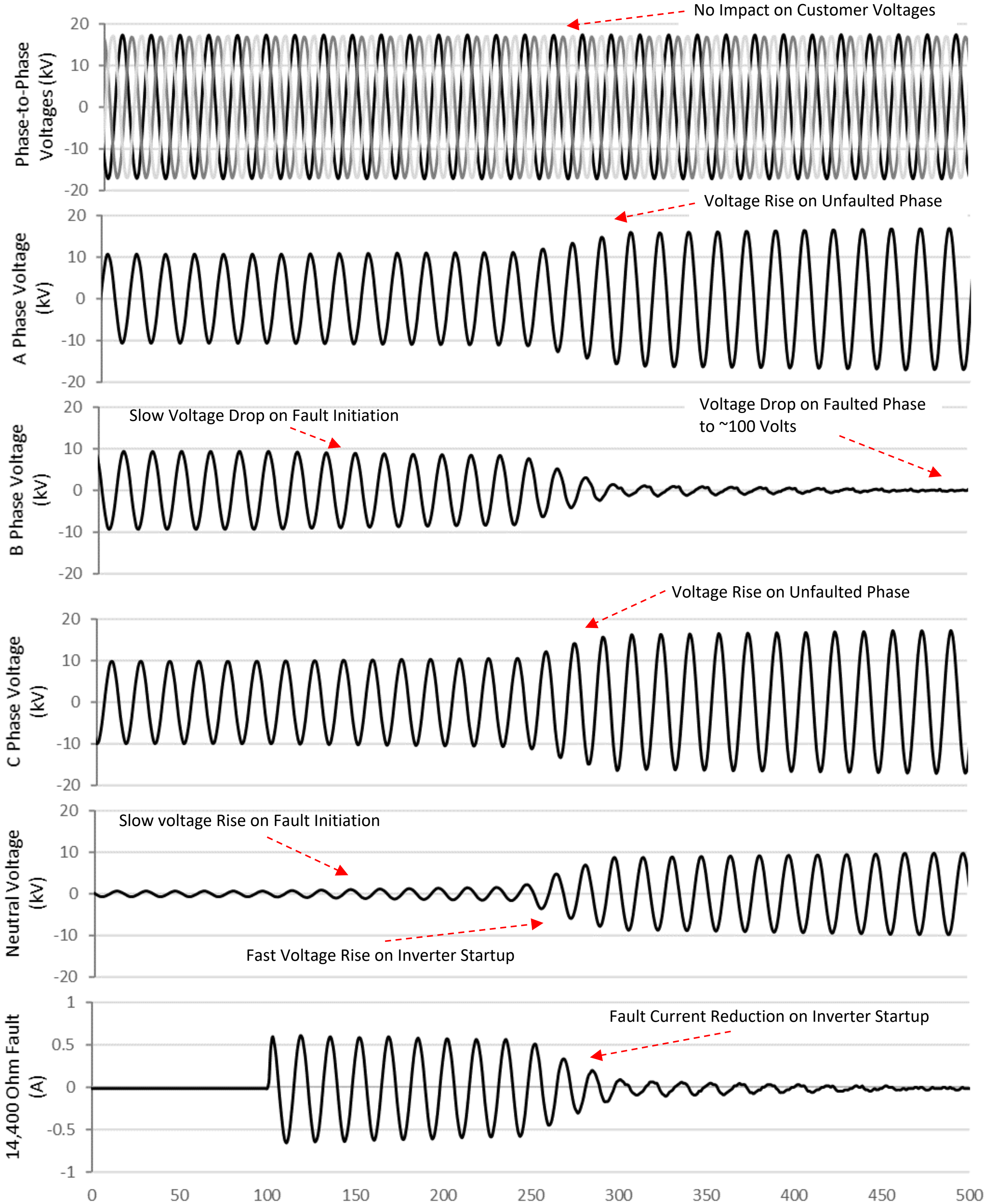


Figure 39: Waveforms for the first 400ms of a 14,400-ohm, B phase, fault.

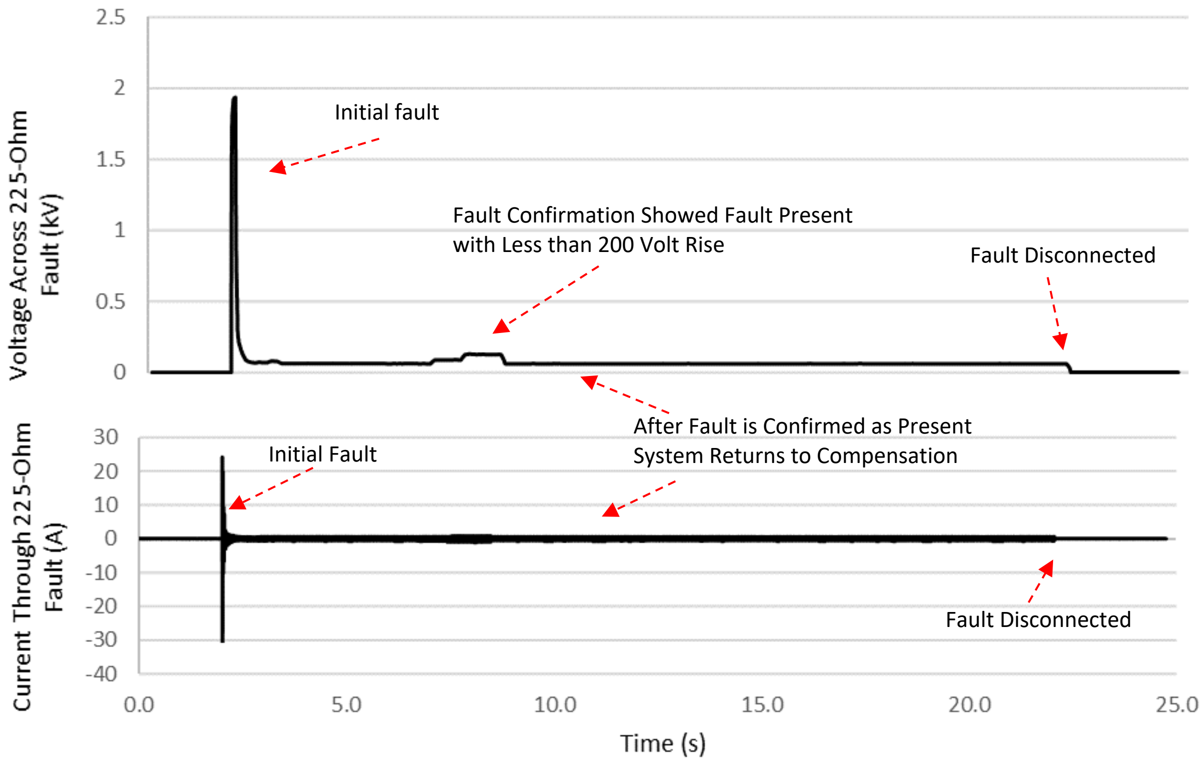


Figure 40: Waveforms for entire test for a 225-ohm fault

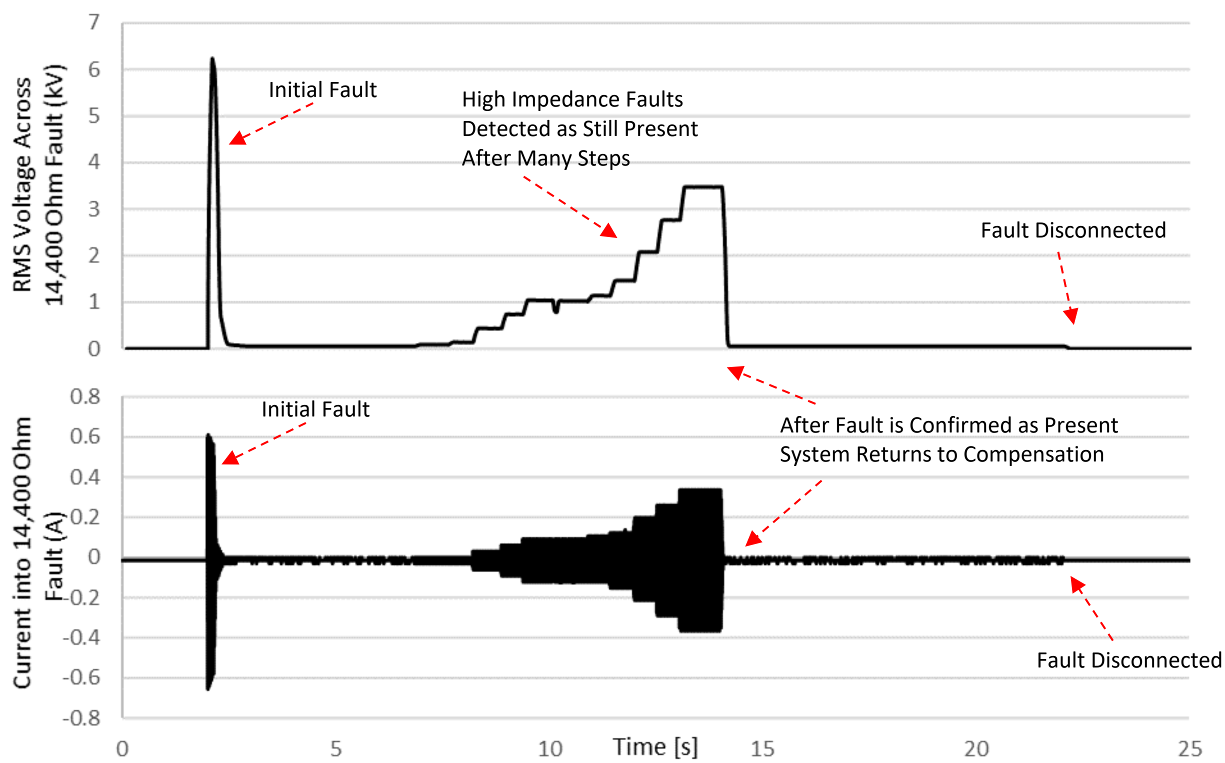


Figure 41: Waveforms for entire test for a 14,400-ohm fault

4.2.4.2 Cable faults

Cable faults saw an even larger reduction in energy release than resistor faults. The resistor faults are linear: if the voltage across the resistor is cut in half the current through the resistor is cut in half. Arcing faults such as faults across cable insulation are non-linear. The fault current across a cable insulation is nearly zero until a high enough voltage is achieved to arc across the air gap. Then the cable fault transitions from a very high impedance fault to a very low impedance fault. What this means for the Ground Fault Neutralizer is that it can reduce the steady state fault current to zero for cable faults or other faults which require arcing to reduce the impedance enough to conduct. This is of particular interest as most ignitions occur from arcing faults.

A typical cable fault during this testing installed had several stages:

1. First, the stored capacitive energy of the system was released into the fault over the course of about 20ms. The peak currents for this stage were a few hundred amperes and the current was almost entirely harmonics.
2. Once the stored energy was released, the fault progressed to a restriking stage. In this stage fault current would be zero for a few milliseconds as the voltage on the phase slowly increased. Eventually the voltage on the phase would reach about 1,500 volts, then the insulation would flash over producing a restrike. The restrike discharged the stored energy of the system reducing the fault current again to zero. Then the process repeated. No over-voltages were observed during this stage despite the restriking.
3. After about 60ms the inverter contactor closed. The inverter held the voltage on the faulted phase too low to arc across the insulation. Fault current in this stage is zero.
4. Five seconds later the fault confirmation started to raise voltage on the faulted phase. The first few steps the fault current was zero as the voltage was too low to arc across the insulation, so no fault was detected. Once the voltage on the phase rose above about 1,500 volts restriking resumed. Once the restriking was detected, the inverter again reduced voltage on the faulted phase and the fault current returned to zero.

The pattern of the Ground Fault Neutralizer rapidly reducing fault current to zero is likely to be seen with any arcing fault since the voltage to produce an arc is above the voltage seen during these tests.

The Ground Fault Neutralizer was more consistent on the initial fault than the fault confirmation. It took several tests, adjusting the settings between tests to get the level of performance on the restriking seen in Figure 42. It is likely that at least some restriking faults will need to be performed on future installations to confirm these settings.

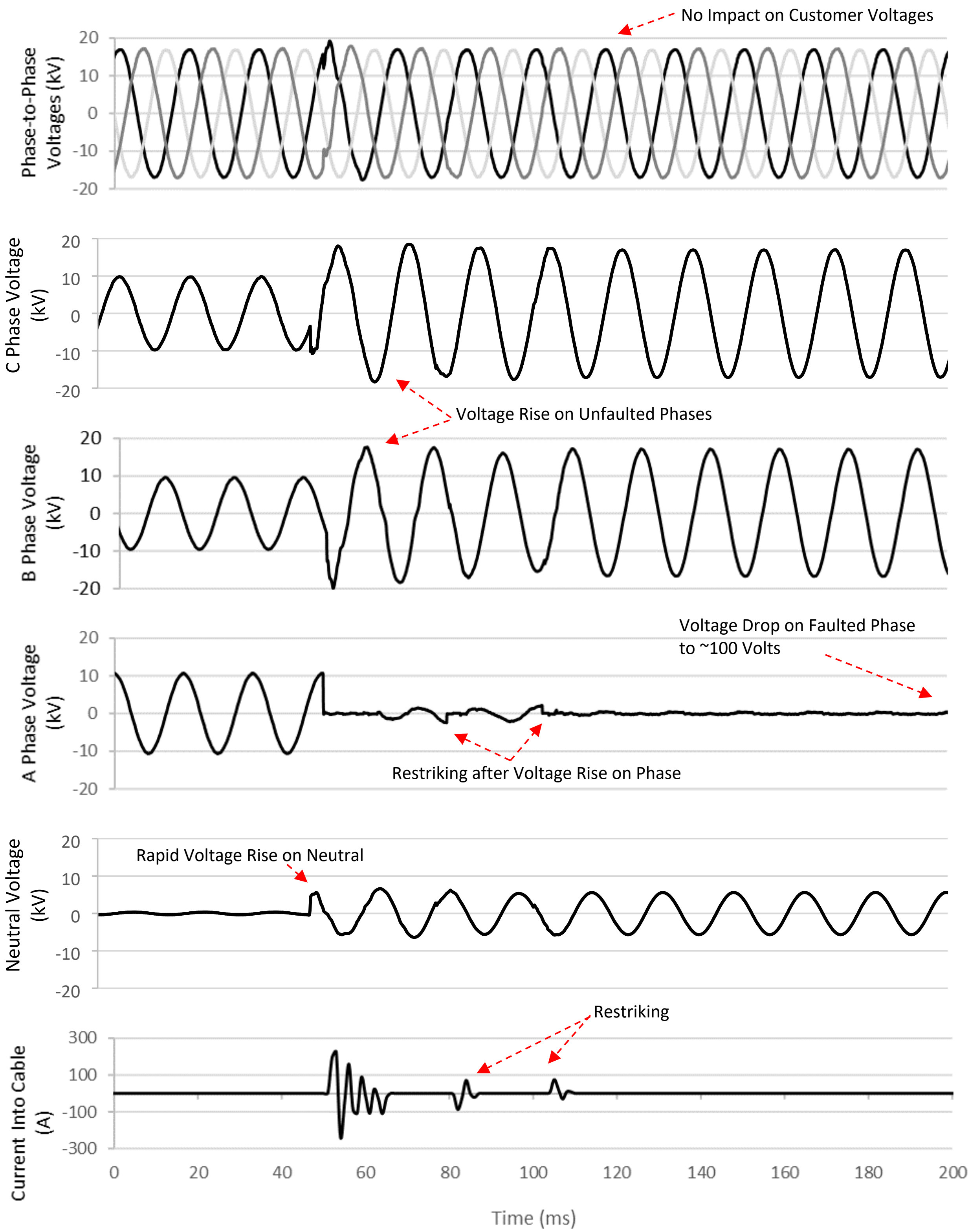


Figure 42: Waveforms for initial 150ms of a cable fault

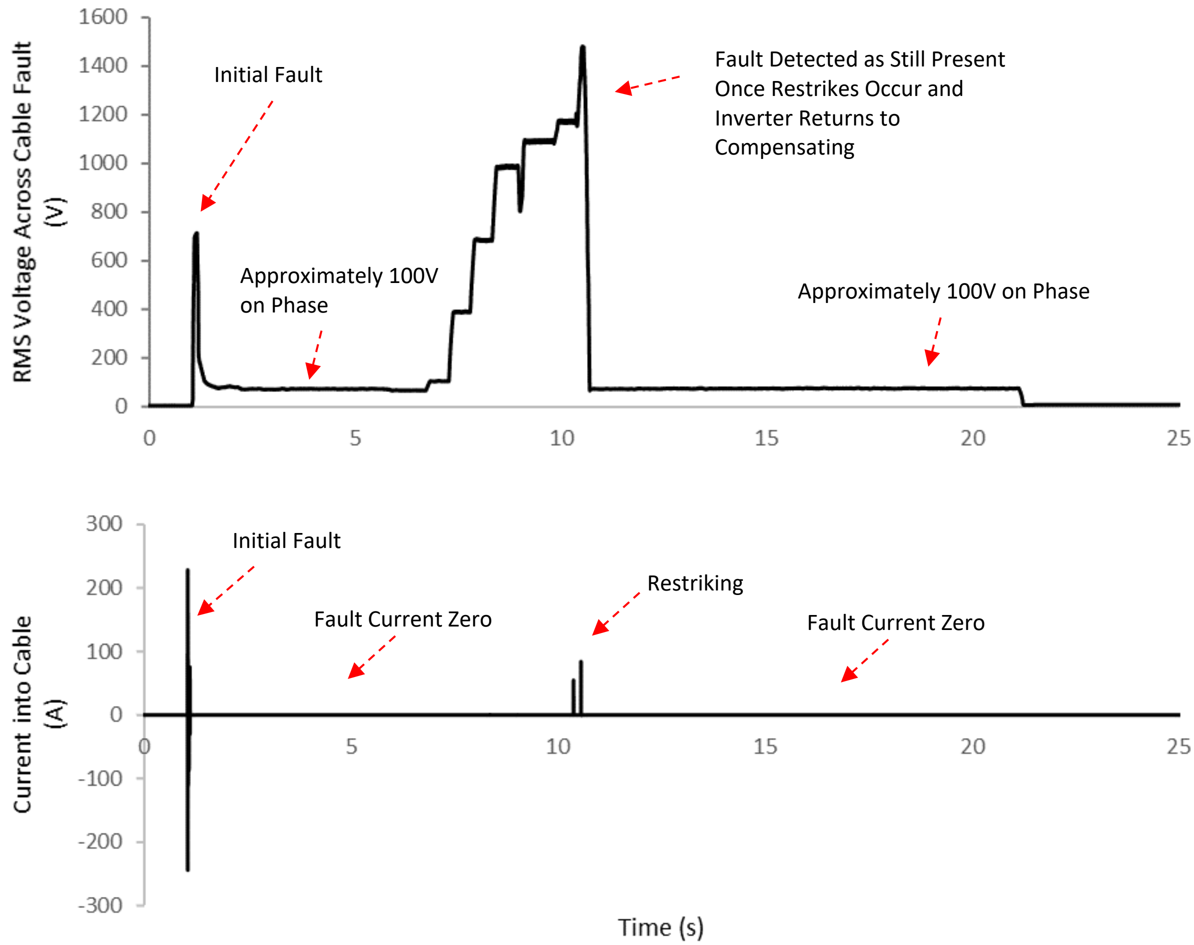


Figure 43: Voltage across cable fault and current into cable fault for entire duration of test

4.2.5 Fault Testing Summary and Lessons Learned

The performance of the Ground Fault Neutralizer in fault testing was superior to any traditional over-current protection. The sensitivity of ground faults was increased to 0.5 amperes from as little as 80 amperes and the reduction in energy release in cable faults was approximately 99.9%, a couple kilojoules down from more than a megajoule. The ability to put low impedance faults on the system for as long as twenty seconds without impacting customers is also an advantage compared to over-current protection where customers must be disconnected from power even for temporary faults.

Table 3 Summary of Fault Test Results

					Measured at Bus			Calculated	Measured at Fault		
Test	Fault Duration [s]	Location	Scenario	Phase	RMS Voltage 85ms after fault [V]	RMS Voltage 500ms after Fault [V]	RMS Voltage 2s after fault [V]	Fault Confirmation i^2t [A^2s]	Peak Fault Current [A]	Steady State RMS Fault Current [mA]	Steady State RMS Fault Voltage [V]
1	2	Duntley End of Line	225 ohms	C	549	102	66	NA	31.4	250	57
2	20	Duntley End of Line	14,400 ohms	C	90	92	70	NA	0.67	10	65
2.1	20	Duntley End of Line	14,400 ohms	C	6350	118	74	**0.77**	30.7	430	99
3	2	Duntley End of Line	225 ohms	A	191	102	123	NA	0.67	9	135
5	20	Duntley End of Line	14,400 ohms	A	6750	173	100	**0.8**	31.5	540	120
6	20	Duntley End of Line	225 ohms	B	660	74	70	0.58	0.64	21	83
7	20	Duntley End of Line	14,400 ohms	B	6300	125	96	0.1	0.61	10	90
8	2	Duntley End of Line	Cable	B	295	83	82	NA	267	0	136
9	2	Bledsoe End of Line	225 ohms	A	1100	178	46	NA	30.8	2410	545
10	20	Bledsoe End of Line	14,400 ohms	A	6150	144	65	NA	NA	NA	NA
10.1	20	Bledsoe End of Line	14,400 ohms	A	6050	100	77	0.051	0.73	38	583
11	2	Bledsoe End of Line	225 ohms	B	395	178	83	NA	30.2	2800	630
12	20	Bledsoe End of Line	14,400 ohms	B	6820	145	99	0.056	0.67	50	615
13	20	Bledsoe End of Line	225 ohms	C	970	183	110	5.8	31.2	2800	629
14	20	Bledsoe End of Line	14,400 ohms	C	6700	200	103	0.052	0.72	45	570
15	2	Bledsoe End of Line	Cable	C	290	123	100	NA	233.7	0	572
16	2	Tejon End of Line	225 ohms	B	650	122	102	NA	28.8	1000	240
17	20	Tejon End of Line	14,400 ohms	B	6280	93	67	0.097	0.7	25	283
18	2	Tejon End of Line	225 ohms	C	335	102	95	NA	29.6	980	235
19	20	Tejon End of Line	14,400 ohms	C	6290	177	103	0.072	0.7	25	250
20	20	Tejon End of Line	225 ohms	A	1038	118	93	0.61	30.42	600	145
21	20	Tejon End of Line	14,400 ohms	A	6756	169	79	0.055	0.7	15	158
22	20	Tejon End of Line	Cable	A	856	106	80	551	160	0	165
23	2	Tejon Substation	225 ohms	A	230	106	91	NA	26.9	310	70
24	20	Tejon Substation	14,400 ohms	A	6930	159	97	0.064	0.7	5	52
25	2	Tejon Substation	225 ohms	B	590	106	94	NA	31.1	260	57
26	20	Tejon Substation	14,400 ohms	B	6170	99	126	0.11	0.64	11	59
27	20	Tejon Substation	225 ohms	C	735	88	80	0.62	31	290	65
28	20	Tejon Substation	14,400 ohms	C	6550	172	75	0.07	0.67	7	70
29	2	Tejon Substation	Cable	C	122	108	84	NA	397	0	79
29.1	20	Tejon Substation	Cable	C	665	145	101	1401	235	0	65
31	2	Bledsoe Substation	225 ohms	A	272	129	87	NA	31.5	350	79
32	20	Bledsoe Substation	14,400 ohms	A	7030	110	81	**0.11**	0.75	9	73
33	2	Bledsoe Substation	225 ohms	C	362	135	92	NA	31.4	350	78
34	20	Bledsoe Substation	14,400 ohms	C	6800	138	137	**1**	0.75	24	70
35	2	Bledsoe Substation	225 ohms	B	632	117	95	NA	29	310	69
36	20	Bledsoe Substation	14,400 ohms	B	6130	111	81	**0.11**	0.66	15	53
37	20	Bledsoe Substation	Cable	B	254	125	82	3.3	280	0	52
38	2	Duntley Substation	225 ohms	A	288	91	114	NA	NA	NA	NA

					Measured at Bus			Calculated	Measured at Fault		
Test	Fault Duration [s]	Location	Scenario	Phase	RMS Voltage 85ms after fault [V]	RMS Voltage 500ms after Fault [V]	RMS Voltage 2s after fault [V]	Fault Confirmation i^2t [A^2s]	Peak Fault Current [A]	Steady State RMS Fault Current [mA]	Steady State RMS Fault Voltage [V]
39	20	Duntley Substation	14,400 ohms	A	7020	352	89	0.11	0.76	9	65
40	2	Duntley Substation	225 ohms	B	428	108	76	NA	30.3	231	51
41	20	Duntley Substation	14,400 ohms	B	6200	109	102	0.11	0.67	35	55
42	20	Duntley Substation	225 ohms	C	397	105	82	0.43	30	275	61
43	20	Duntley Substation	14,400 ohms	C	6410	108	119	0.12	0.72	36	63
44	20	Duntley Substation	Cable	A	283	132	101	12.5	236	0	73

The most widely used criteria for when REFCL installations are adequate for preventing ignition are those defined in the regulations in the Australian state of Victoria. When converted to the voltages used in California these would require a reduction of the voltage on the faulted phase during a 225-ohm fault to 1900-volts rms after 85ms, 750-volts rms after 500ms, and 250 volts rms after 2 seconds. For a 14,400-ohm fault it would require a reduction to 250ms in 2 seconds and an i^2t of 0.1 A^2s for the fault confirmation. An example of these targets compared to a voltage waveform can be seen in Figure 43. The test values were compared to these target criteria in Table 2, all cells meeting a criterion are highlighted in green, and text for cells which missed the criterion are in red.

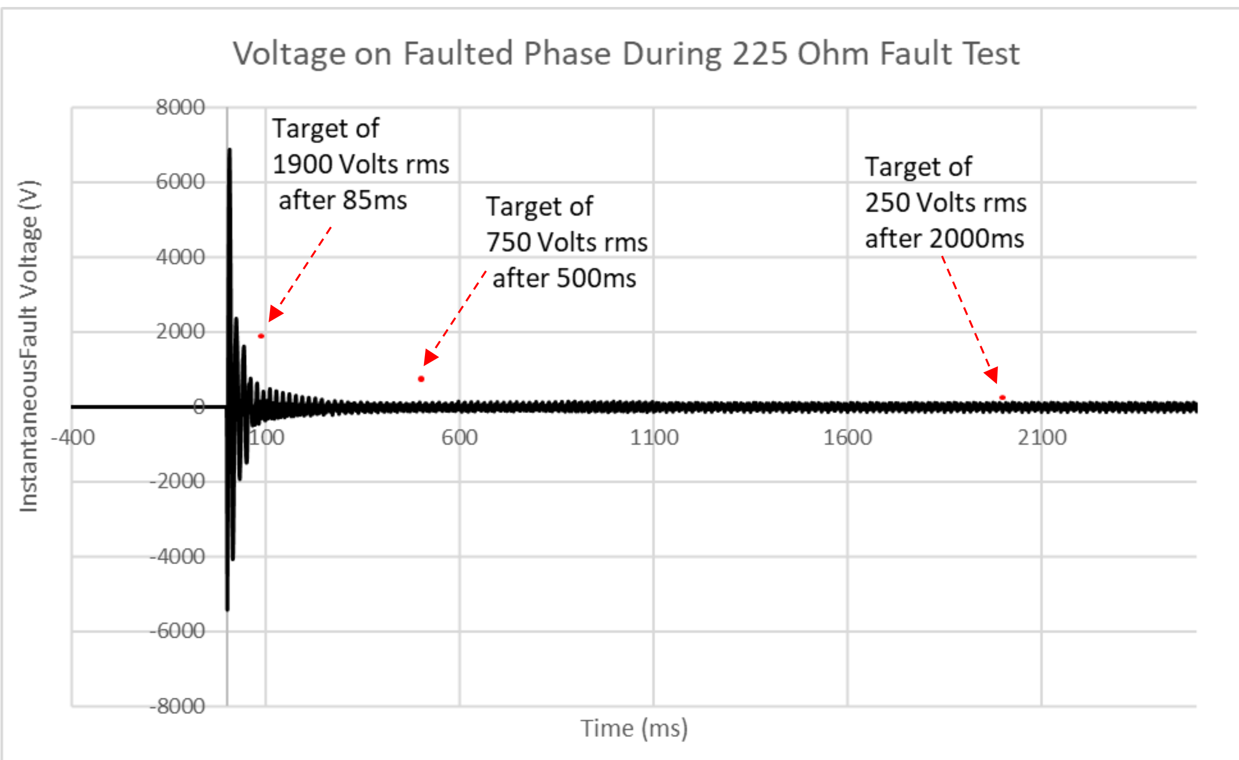


Figure 44: Voltage from a 225-ohm fault test compared to Victorian ignition targets

The tests were consistently able to meet all criteria for 225-ohm faults and the initial target for a 14,400-ohm fault. The target for the i^2t of the fault confirmation was more challenging. Although several of the tests initially missed this target by a large margin, the cause of the misses was found to be a problem with settings which were corrected. With the corrected settings several more tests missed the target by a small amount such as Test 32, which had an i^2t of 0.11 A^2s compared to a target of 0.1A^2s. With final settings typical energy release from high impedance faults was 0.5kJ for the initial fault and 1.5kJ for the fault confirmation. Even while settings were still being adjusted the worst faults had a total energy release around 15kJ about a thousandth of the worst-case energy release from a ground fault on a solidly grounded system.

Whether the Australian criteria will be used on future SCE projects will depend on the circumstances. Where they are low cost to achieve, they will likely continue to be followed. However, even if the Ground Fault Neutralizer misses these targets, it is still an improvement over existing SCE systems. In some cases, changes costing several million dollars are expected to be required to meet these targets, which may not always be practical or feasible. For example, if a future project includes $5M in added costs to increase ground fault sensitivity from 0.7 amperes to 0.5 amperes, the money may be better spent on installing a Ground Fault Neutralizer in a substation that does not already have one. The 0.7 ampere ground fault sensitivity achieved would still be more than a 100X improvement over typical substation overcurrent protection.

4.3 Operating Modes

The Ground Fault Neutralizer can be run in many different modes with some modes prioritizing increasing reliability and other modes prioritizing reduction in fault energy and sensitivity. SCE is likely to continue making minor changes to operating modes for the first few years that this technology is used, since understanding of the safety and reliability tradeoffs continues to improve.

4.3.1 Operating Modes Alternatives for Ground Fault Neutralizer

4.3.1.1 Load Remains Online During Ground Faults

With the Ground Fault Neutralizer, fault current can be reduced to the point that load can still stay in service during ground faults. While similar operating modes are commonly used on ungrounded or resonant grounded systems, restriking remains at the site of the fault which can damage equipment or lead to safety hazards. The RCC inverter stops this restriking by reducing the voltage on the faulted phase to below that needed to arc across insulation failures.

This mode maximizes reliability and is thus the most common mode among industrial users of the Ground Fault Neutralizer as well as utilities with fully underground networks. This mode is also sometimes used by operators of overhead networks but is less common as there is still some risk from energized downed wires. There is also risk of a second ground fault occurring on another phase when faults are left for extended periods of time. This causes a cross country fault, where current is circulated between the two fault locations. The Ground Fault Neutralizer still blocks most fault current returning to the source transformer, reducing the fault current somewhat compared to a solidly grounded system, but the fault current is high enough to come with electrical safety risks.

4.3.1.2 Immediate Disconnection of Faults at Substation

Instead of leaving faults on the system, another common practice is to automatically open the circuit breaker at the substation on permanent faults. The Ground Fault Neutralizer has the capability of detecting which circuit the fault is on even for very high impedance faults. This information can be used to determine which circuit breaker to open.

The Ground Fault Neutralizer operates with no intentional delay and on very low fault currents. Therefore, it typically does not have enough information from the initial fault to determine which circuit it is on. It then comes back several seconds later and performs a fault confirmation which injects a small amount of current into the system and monitors where that current goes. After this process is complete the circuit breaker supplying the fault is known and can be opened.

Because the whole process takes several seconds, this blocks the operation on temporary system disturbances or faults which self-clear. The ability to remove temporary ground faults without disconnecting any customers partially makes up for the loss in reliability from opening a circuit breaker on faults which would otherwise be cleared with a downstream fuse.

This operating mode maximizes the safety improvements of the Ground Fault Neutralizer. It is thus the mode preferred by Australian utilities during high fire conditions to reduce the risk of ignition. It however can reduce system reliability, particularly in high fire conditions when it is necessary to patrol the entire circuit after every circuit breaker operation.

A big opportunity to improve this operating mode exists by incorporating fault pass indicators and reclosers which can see these low magnitude current faults. This would allow only the section of circuitry with the fault to be opened, rather than the entire circuit. Australian utilities have had success in doing this, but to date the products are not well developed for the American market.

4.3.1.3 Bypassing on Permanent Faults

Another operating mode is to only use the Ground Fault Neutralizer for temporary faults and to use traditional protection for permanent faults. The cost-benefit ratio of using the Ground Fault Neutralizer instead of traditional protection is at its greatest for temporary ground faults. A temporary ground fault can be entirely cleared without an impact on customer reliability. The ability to clear temporary faults improves reliability and safety at the same time. Temporary ground faults often turn into permanent ground faults due to the damage caused by the energy release of the fault, so in many cases lengthy outages can be entirely prevented.

This operating mode functions the same as the mode which trips the circuit the fault is on, except the neutral circuit breaker is closed on permanent faults instead of opening the circuit breaker.

4.3.1.4 Lessons Learned and Future Plans

For the time the Ground Fault Neutralizer was in service before the end of June 2022, it was running with operators manually clearing faults by opening switches. This level of manual intervention proved challenging because of the level of training required for operators and their level of comfort manually de-energizing lines. Operator intervention was also slower than desired, in one case a fault resulted in a failed arrester and a cross country fault after about 35 seconds. An automated system would be able to clear the fault before this happened, but an operator takes longer to clear such a fault, increasing the probability of a cross country fault.

Additional automation was added into the system in Q4 of 2022 which better matches the operating modes used in Australia. One mode was introduced which automatically opens the line circuit breaker for permanent faults. This is expected to be used in high fire season but might be used all year if reliability can be maintained. This is particularly likely once reclosers on the circuit have been upgraded to see faults with the Ground Fault Neutralizer in service.

A second operating mode uses the Ground Fault Neutralizer to extinguish temporary faults but bypasses on permanent faults. This mode is expected to be used mostly outside high fire risk conditions to increase reliability. It might sometimes also be used in high fire conditions if the reliability impact of operating with full sensitivity and circuit breakers at the substation operating is too great.

4.4 Availability

One of the biggest challenges in the first year and a half of service was the relatively low percentage of time the Ground Fault Neutralizer was in service. Since it was first commissioned, the Ground Fault Neutralizer was only in service around half of the time. This remains the largest challenge with getting the anticipated risk reduction from the technology. There have been improvements to spare parts policies and increases in operator visibility into how balanced the circuits are, but the impact of these improvements will not be clear until the projects have been in service longer.

4.4.1 Summary of time in and out of service

The Ground Fault Neutralizer was in service for a total of 5,730 hours between first energization in June 2021 and September 2022. A summary of the time in and out of service for every month since it first entered service is provided below:

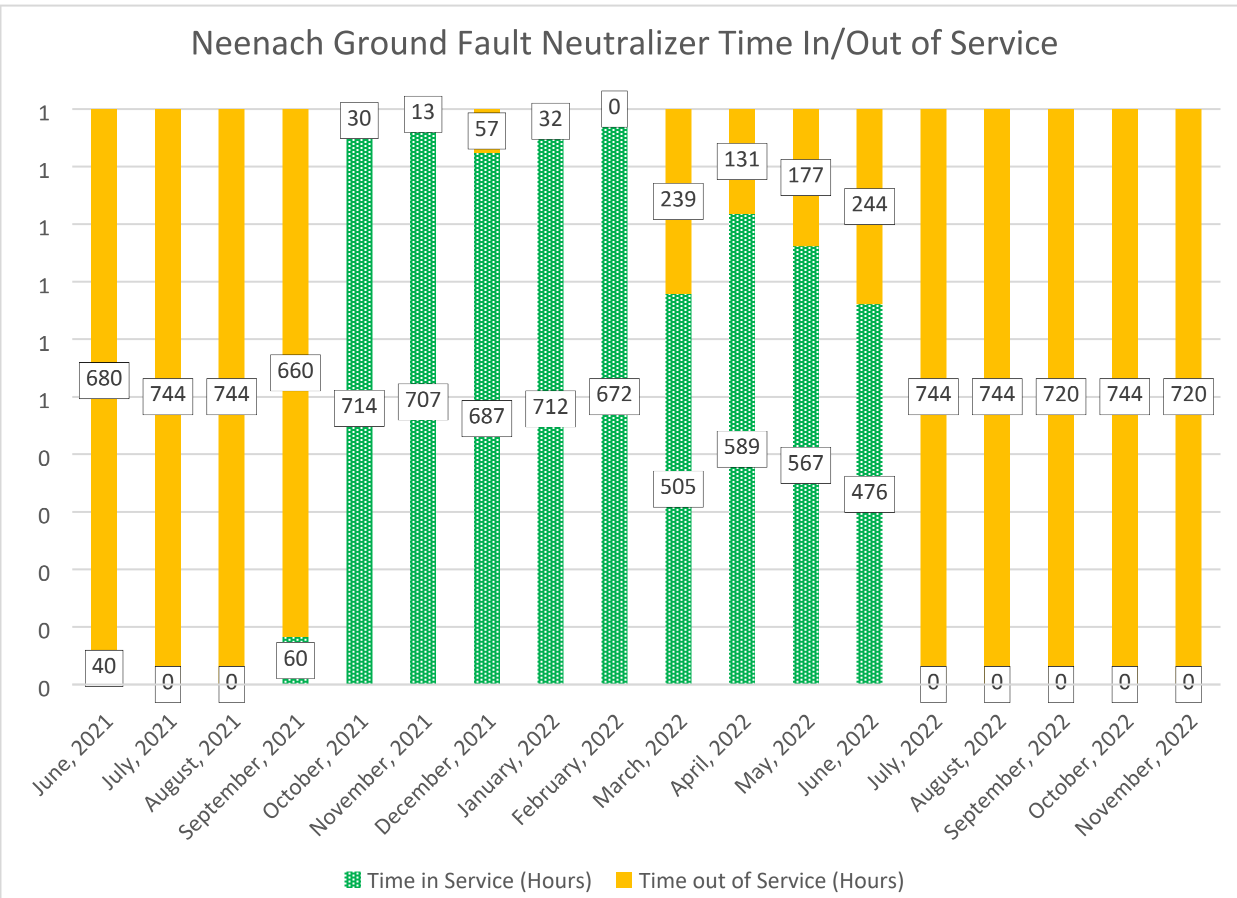


Figure 45: Availability of Ground Fault Neutralizer in first months after it entered service

The initial period it was out of service from June 2021 through September 2021 first resulted from an air conditioner failure. The air conditioner was under-sized and a model not readily available in the United States. Therefore, it needed to be redesigned to use an appropriately sized and locally available unit. While the equipment was out of service, lessons learned from PG&E showed that the Ground Fault Neutralizer needed to move from a grounding transformer to the neutral of the main 66/12 kV power transformer. The equipment was thus kept out of service until late September when loading was low enough to return it to service.

In the subsequent five months availability was much higher, ranging from 92-100%. The Ground Fault Neutralizer was only taken out of service whenever the circuit was in an abnormal configuration due to concerns that the circuits might not be balanced enough for it to remain in service.

In March through May availability reduced to 68-82%. This was largely because the circuit was so often in an abnormal configuration in those months. In particular, large amounts of covered conductor was installed and the Ground Fault Neutralizer was taken out of service during this work. It also was taken out of service for several days as capacitive balancing units were moved to improve circuit balancing and to investigate a time it did not operate as expected due to an incorrect setting.

In June of 2022 a lightning storm damaged a current transformer and three voltage transformers which were used by the Ground Fault Neutralizer. No spares were immediately available for the voltage transformers as they were a specialized model which plans had been made to remove from the design. The Ground Fault Neutralizer was left out of service until an already planned rebuild in Q4 which was intended to incorporate various lessons learned during the project.

4.4.2 Activities to Improve Availability

The time the Ground Fault Neutralizer is out of service can be divided into two categories: (1) time where it is out of service because of equipment reliability issues, and (2) time where it needs to be out because of system conditions.

4.4.2.1 Equipment Reliability Issues

Three equipment reliability issues resulted in the Ground Fault Neutralizer being out of service:

1. An air conditioner failure in the Ground Fault Neutralizer container.
2. An incorrect setting which caused the Ground Fault Neutralizer to see a fault as a substation fault instead of a line fault; and
3. Failure of a current transformer and three voltage transformers due to a lightning strike.

In the first and last failure the cause of the Ground Fault Neutralizer not being available for an extended time was the same—the use of non-SCE standard parts and lack of a spare parts program. Neither item was a high percentage of the cost of the system, but both are necessary to its function. Where it could, such as for the air conditioner, SCE moved to standard parts which are used on other similar projects. For current transformers this was not possible because the Ground Fault Neutralizer requires higher accuracy class current transformers than other SCE programs. So, improvements were made for the storage of spare parts near where they are needed.

There remain some higher cost components where SCE does not have a spare, but as the size of the program grows and higher confidence is gained that equipment designs are locked in, additional spares can be purchased.

The outage for incorrect settings resulted from inexperience with the system. Moving the arc suppression coil from the grounding transformer to the main power transformer was not a common activity for either SCE or the manufacturer. Both parties were unaware of the impact it would have on a particular setting. This is not anticipated to be an ongoing issue but due to how new the system is to SCE, similar problems may occur occasionally, particularly in the first few years the equipment is in use. In most cases setting change issues are expected to be resolved without lengthy outages.

4.4.2.2 Reducing Need to Remove from Service for Abnormal Circuit Configurations

The Ground Fault Neutralizer requires a high level of balance of capacitance to ground in the network. This was not something SCE had previous experience with. Initial balancing did a good job of balancing the normal configuration of the substation, but there remain some switches that if opened would imbalance the station enough to look like a fault to the Ground Fault Neutralizer. Therefore, it was decided to take the Ground Fault Neutralizer out of service every time the circuit was in a non-standard configuration. Most commonly this happened during circuit work such as installation of covered conductor. This did not have a big availability impact during fire season, when less planned work is performed, but in the Spring, it resulted in the Ground Fault Neutralizer being out of service for extended periods of time.

When a detailed analysis of the time the Ground Fault Neutralizer was out of service was made, it was found that in most cases the circuits remained balanced enough for it to remain in service. The design however lacked any operator feedback to know that the circuits remained balanced. This feature was added into the design in Q4 2022, so it is expected that going forward the requirement to remove the Ground Fault Neutralizer due to system configuration can be reduced to a few minutes while single phase switching is performed. There will still be some cases which necessitate the Ground Fault Neutralizer be out of service, most notably when supplying circuitry normally fed out of other substations which may not have been balanced.

An alternative to taking the Ground Fault Neutralizer out of service is taking a larger customer outage so that the circuit stays in a balanced configuration. In the long run, SCE might move to this practice, but it is more likely that additional balancing would be performed on any circuitry which regularly results in the Ground Fault Neutralizer being removed from service.

4.5 Electrical Faults with Ground Fault Neutralizer in Service

Most of the faults which this system has seen was from the staged fault testing. (9) The success of this testing and the success of the utilities in Australia (25) remains the key evidence of effectiveness. In the time it was in service, the Ground Fault Neutralizer operated on three permanent ground faults and two temporary ground faults. Also, two ungrounded faults occurred while it was in service, which the Ground Fault Neutralizer took no action on because the technology only acts on ground faults.

4.5.1 Phase-to-Phase Ungrounded Faults

The Ground Fault Neutralizer took no action on the two ungrounded faults, which was expected as it can only act on ground faults. One of the two ungrounded faults resulted in an ignition and an approximately 2-acre fire. A mylar balloon bridged the gap between two phase conductors in November 2021 resulting in a pair of 1,350A, 6 cycle faults. Falling incandescent particles from the fault caught dry grass below the line on fire. This case provides an example of why covered conductor, when deployed together with REFCL (where feasible), would increase mitigation effectiveness compared to REFCL being deployed alone.

4.5.2 Temporary Ground Faults

The benefit of the Ground Fault Neutralizer is at its greatest for temporary ground faults since it can prevent them from progressing to permanent ground faults due to the energy release. Without the Ground Fault Neutralizer these temporary ground faults would at least require a brief customer outage as arcing continues after the object falls away from the lines on a solidly grounded system. There were two temporary ground faults which the Ground Fault Neutralizer prevented from impacting customers.

The first temporary fault was a substation fault in January 2022 which the Ground Fault Neutralizer was able to extinguish entirely. The fault confirmation process showed that the fault was gone within five seconds. It is unknown where in the substation this fault occurred, but at certain locations in the substation all customers supplied from the substation would have been de-energized because of this fault.

The second temporary fault was during a lightning storm in June 2022. The Ground Fault Neutralizer operated, extinguished the fault, then found that the fault was gone during the fault confirmation process. Lightning is a noted area where resonant grounding improves reliability because much of the damage done after a lightning strike comes from the power system pushing energy into the flashover. Without this additional energy release the equipment is often undamaged and can remain in service after a lightning caused flashover.

4.5.3 Permanent Ground Faults

All three permanent ground faults progressed to being multi-phase faults before the Ground Fault Neutralizer could eliminate them. The first started as a ground fault when loose molding from a car contacted a phase and ground, it remained a ground fault for around one second before the molding contacted a second phase and fuses cleared the fault. The Ground Fault Neutralizer demonstrated its capability of operating faster than fuses and block the ground fault portion of the current but was unable to prevent the arcing after the second phase was contacted.

The second permanent ground fault was a downed wire. Again, the Ground Fault Neutralizer proved that it was faster than almost any other protective device by keeping the energy release too low to blow an 18-ampere current limiting fuse. After approximately 35 seconds of compensation an arrester at a customer facility failed resulting in a cross-country fault. Cross-country faults are where two separate faults on different phases occur at different parts of the system (48). Since two phases are involved the Ground Fault Neutralizer can only block any ground current when they occur. The current limiting fuse blew and the fault on the customer arrester was cleared with the Ground Fault Neutralizer in service by an operator manually opening switches.

The third permanent ground fault was a major lightning strike that failed equipment in the substation on all three phases. As it involved three phases from the start, and the failed equipment included instrument transformers used by the Ground Fault Neutralizer the Ground Fault Neutralizer was unable to take any action.

4.5.4 Summary of Ground Fault Neutralizer Lessons Learned

The Ground Fault Neutralizer demonstrated that it could be run with a very high level of ground fault sensitivity without excessive numbers of operations. It also demonstrated that it is capable of extinguishing temporary ground faults with no impact on customers.

Ground Faults progressing to multi-phase faults prevented the system from blocking the fault current in some cases. The frequency of these events will continue to be monitored. With the new settings, permanent faults will be automatically cleared after the conclusion of the fault confirmation process, which should reduce the probability of faults progressing to multi-phase faults. If faults progressing to multiphase faults continues to be a challenge at these shorter times, the time the faults are left on the system may be further reduced. This is not expected to be required long term as any equipment not rated for the over-voltage will be removed relatively quickly after installation.

The project at Neenach substation went through several design iterations. It is anticipated that the substation part of the design has been optimized to the point that it can scale up and remain mostly unchanged. The only major unmet need on the substation side is a second supplier to limit the dependence on a sole source of equipment. This will be addressed with the ongoing project at Del Sur substation.

The distribution part of the scope is more likely to be updated in future years as best practices are better understood over time and new technology becomes available. The project at Neenach substation does not include fault pass indication or the ability for automatic reclosers to detect ground faults when the Ground Fault Neutralizer is in service. It also includes many fuses which if they operate could look like a fault. Designs replacing these fuses with three-phase devices will be explored.

5 Grounding Conversion Projects

When comparing the SCE system designs to those where the Ground Fault Neutralizer was being installed in Australia, it became clear that SCE typically runs lower voltage distribution, 12.47 and 16kV compared to the Australian 22kV designs. At lower voltages system sizes are typically smaller due to limitations in how far power can be sent. On the smallest of these systems, testing confirmed it is possible to convert from solid grounding and reduce worst case fault current to get the energy release down low enough to meet the performance requirements followed in the Australian state of Victoria (49) (50).

For most of these installations resonant grounding was used, however on the smallest of these systems ungrounding the system can be sufficient to meet the target reduction in energy release and increase in ground fault sensitivity.

5.1 Resonant Grounding at Arrowhead Substation

The largest grounding conversion project was performed at Arrowhead substation as a project under the EPIC program. This project was intended to address both wildfire concerns and employee and public safety from ground faults. Most of the market for Arc Suppression Coils is for improving safety and reliability which would be equally of interest outside of HFRA. While a few hundred arc suppression coils are in service worldwide as a part of Ground Fault Neutralizer projects, tens of thousands are in service for the purposes of reducing, underground equipment explosions, step and touch voltages, arc flash hazards, and improving reliability by extinguishing temporary faults with no impact on customers.

Despite this international popularity, very few Arc Suppression Coils are in service in North America. The only active installation SCE could identify at the start of this project was a pair of coils operated on a 41kV subtransmission system in Minnesota. This lack of use for Arc Suppression Coils appears to have resulted from poor understanding of the state of the technology internationally. Most notably, there is a lack of knowledge for how to design a protection system to properly detect and clear faults, as well as little understanding in the function and design of the Arc Suppression Coils themselves. An additional barrier is widespread adoption of phase-to-neutral connected distribution transformers which increase the cost of conversion at most North American utilities, although it is less of a problem in California where phase-to-phase connected load is more common.

To better position SCE to make future expansion of this technology—either in small substations to address fire risk or in dense urban networks for improved reliability and safety—a demonstration was performed at Arrowhead substation. This is a small substation where it might be possible to achieve the ignition benefits of the Ground Fault Neutralizer without the cost and complexity of the inverter. Arrowhead substation also has two circuits which makes it a good test location for protection systems which can detect which circuit the fault is on.

5.1.1 Equipment Configuration

The equipment was installed in a configuration where the Arc Suppression Coil acts only on temporary ground faults. For permanent ground faults the system will be bypassed with a resistor and the fault cleared with the protection which was already present at the substation. This is a common way to operate arc suppression coils since the greatest benefit is for temporary faults, and it also provides experience which will be necessary to move to a system which trips lines without bypassing.

A simplified version of the station configuration before the project is given in Figure 45 and after the project in Figure 46. The neutral circuit breaker was installed so it can be closed into the neutral resistor and return the substation to the initial type of grounding.

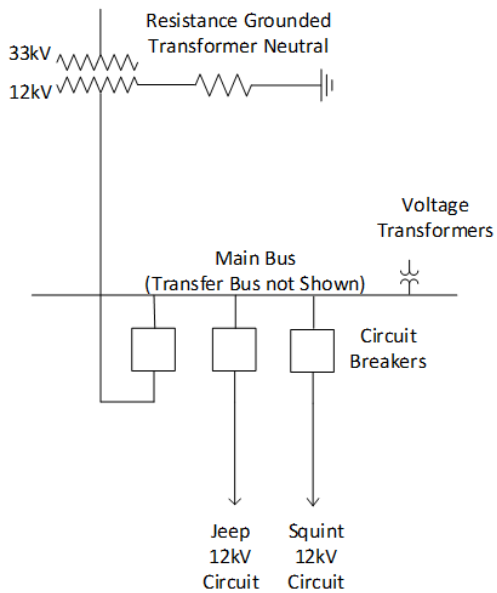


Figure 46: Simplified configuration of Arrowhead Substation before the project

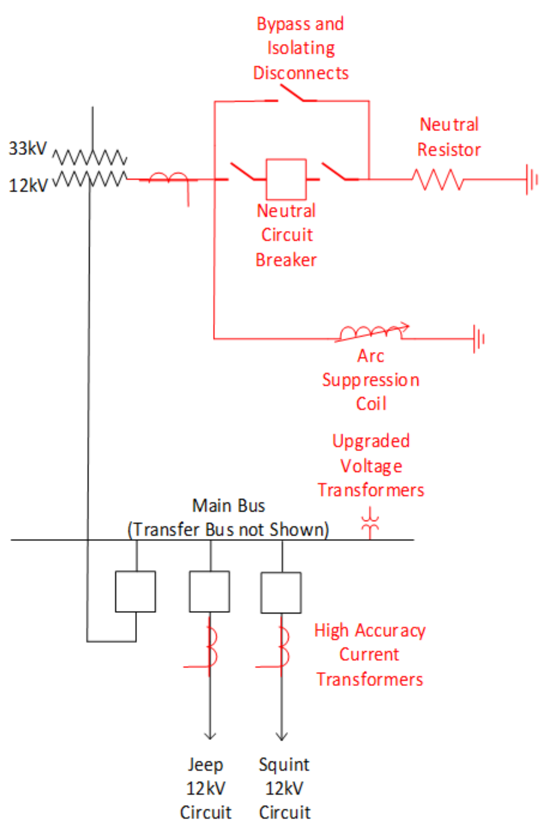


Figure 47: Simplified equipment configuration of Arrowhead Substation after conversion to resonant grounding

5.1.2 Equipment Designs

Most of the equipment for this project was based on typical SCE equipment standards. However, two equipment types were new designs for this project: The Arc Suppression Coil, and the Current Transformers.

5.1.2.1 Arc Suppression Coil

An arc suppression coil can be produced from any variable inductance. Examples include coils with taps which can be manually adjusted, small coils which can be switched in and out, a fixed coil with capacitors on an auxiliary winding which can be switched in and out, and coils with an adjustable air gap which tunes the inductance (49) (51).

For the project at Arrowhead substation a coil with an adjustable air gap was chosen. To alter the inductance a motor on the top of the coil moves a transformer steel plunger. If the air gap gets smaller than the inductance increases and if the air gap gets larger the inductance decreases.

Figure 48: Overview of arc suppression coil at Arrowhead substation

To stay at the correct point on the resonance curve, voltage is measured while the coil is adjusted. The coil is on resonance when the neutral voltage is at a maximum. In some substations the coil is set exactly to resonance while other substations keep it several amperes off resonance. This is typically done to reduce the sensitivity of the system or the standing voltage when at resonance.

5.1.2.2 Instrument Transformers:

To achieve extremely high ground fault sensitivity, it is necessary to have very accurate measurements of the current which escapes from powerlines and returns to the substation through the earth. This neutral current or zero sequence current can be measured one of three ways:

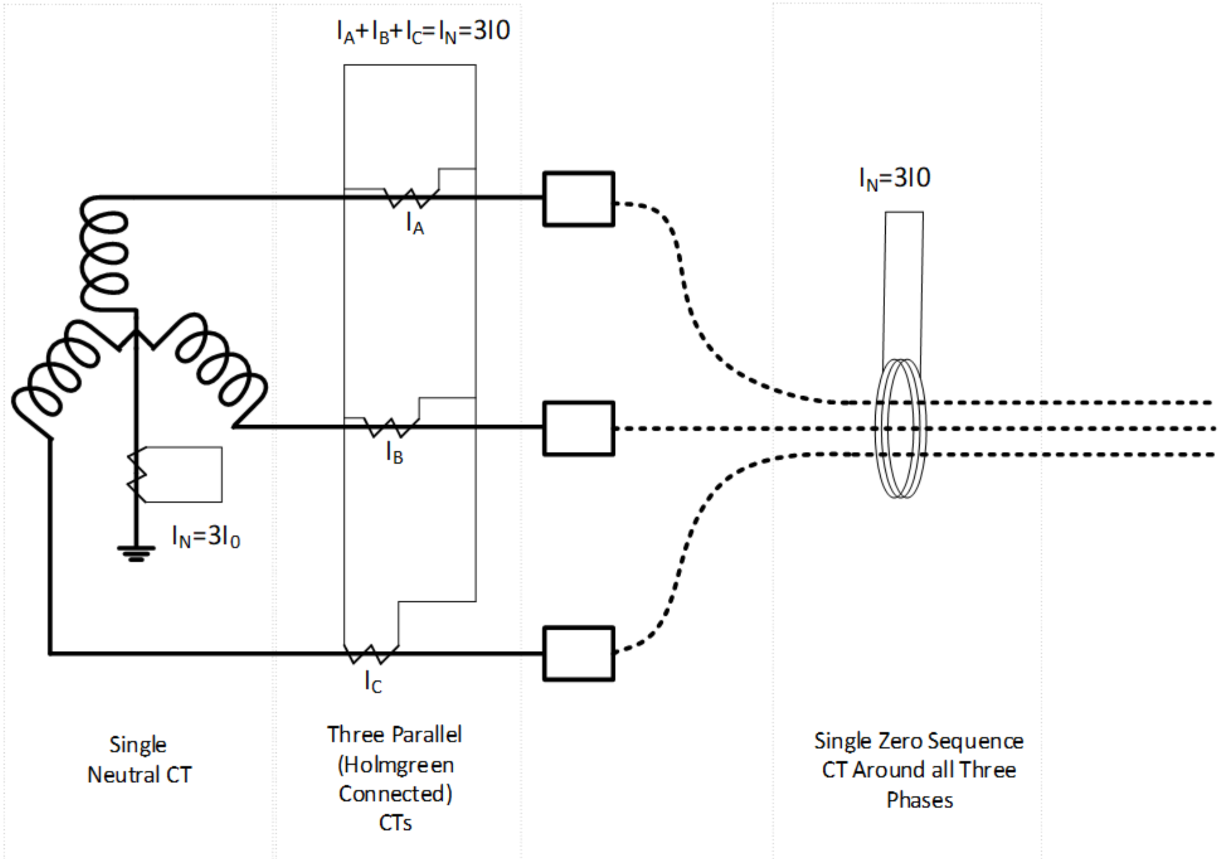


Figure 49: Neutral Current Transformers (CTs), Holmgreen Connected Current Transformers and Zero Sequence Current Transformers are three ways to measure the neutral current

1. Neutral current can be measured with a current transformer on the neutral of the substation transformer. This is typically the most accurate way of measuring as load current from phase-to-phase connected transformers cannot interfere with the measurements.

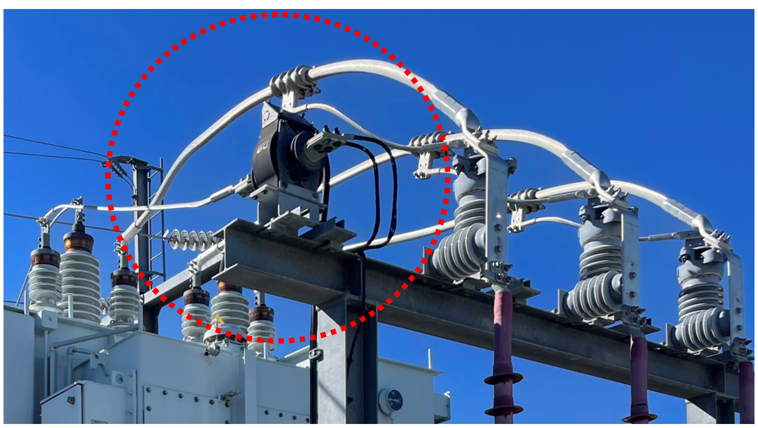


Figure 50: Typical Current Transformer on the neutral of a substation transformer

2. Neutral current can be measured with a window current transformer which goes around all three phases. This can achieve nearly as good of accuracy as a neutral current transformer because the balanced

current in the three phases sums to zero. They can also be purchased with low ratios since they are not measuring load current. Current transformers with a 50 to 5 ratio, where fifty amperes of primary current produce five amperes of secondary current, or lower are available.

Turns ratios which produce a lot of secondary current can be important because total measurement error comes from both primary and secondary side measurement error. For some devices relatively high secondary currents are needed for good measurement accuracy. This is somewhat countered by the fact that at these ratios the current transformer accuracy, particularly its phase angle accuracy, can be reduced.

While window current transformers are not able to be as accurate as the neutral current transformer at the substation source transformer, they have the advantage that they can make measurements elsewhere on the system. A common practice is to install one current transformer per distribution circuit when the circuits leave the substation in underground cables.

Figure 51: A zero sequence current transformer around all three phases of a distribution line

3. Neutral current can be measured with a current transformer on each phase, where the secondaries in parallel with a Holmgreen connection. In this case the current of the three phases is summed. Load current should sum to zero when it is all connected phase-to-phase. Therefore, the output current is the same neutral current measured with a window current transformer.

   Holmgren connected current transformers are the most challenging of the three to apply. They require very well-matched current transformers. If the transformers have somewhat different accuracy and ratio error, load current differences between the phases will not properly sum up to zero. Load current which is contained to the phases will then be measured as being ground current.

Making this more challenging, current transformer standards only address the single-phase ratings of a current transformer. Even relatively low accuracy class current transformers can perform quite well as Holmgreen connected current transformers if their errors are identical. However, given the present state of industry standards it is preferable to buy higher accuracy metering transformers or do significant testing on a larger batch of current transformers to put them in sets of three matched units. REFCL projects at SCE have settled on using 0.15S metering class current transformers which is the highest accuracy class commonly available. By using high accuracy current transformers, the maximum possible difference between any two units in the set of three is reduced to a manageable level.

5.1.3 Protection

One of the biggest challenges in converting to resonant grounding in North America is the lack of local knowledge of how to configure and install ground fault protection when resonant grounded. The European market has had a century to develop dozens of products. This means that engineers are faced with deciding between many different products which may be unfamiliar, and which can be utilized as part of the safe operation of the power system (11) (24).

Some of the protection functions available on the market are:

1. Delta Admittance: There are a wide variety of methods based on analyzing the zero-sequence admittance of the circuits. some inject a small current into the fault location and the change in admittance on all circuits. Others compare admittance of each circuit to what it previously was to see which circuit had a change in admittance at the time of fault (52) (53).
2. Multifrequency Admittance: Admittance of the circuits at frequencies other than 60Hz can also be used to detect which circuit the fault is on. (54)
3. Incremental Conductance: The zero-sequence conductance of a circuit is the resistive part of the zero-sequence admittance. Incremental conductance is a variation on the admittance method where only the real part of the admittance is looked for. This can help the protection distinguish switching from faults.
4. Fault Inception Transient: When a fault occurs, there is a brief transient period where the stored energy of the charging current is discharged through the fault. This transient current is in an opposite direction on a faulted and unfaulted circuits.
5. Wattmetric or IcosΦ: By analyzing the zero-sequence voltage and the angle between the zero-sequence voltage and zero sequence current the wattmetric method the resistive losses on each circuit can be monitored. The zero-sequence voltage.
6. Neutral Voltage Displacement: Whenever a ground fault occurs on a resonant grounded system the voltage from the neutral to ground (zero-sequence voltage) increase. The presence of a fault, although not the location of the fault, can be detected with this method. This is often used for backup protection or to supervise methods which are likely to detect other system disturbances as a fault.

While many products exist, they are not all well-tuned for the wildfire market. Typical European utilities are reducing ground fault current to the 10 amperes to 50 amperes range while for wildfire applications the preference is to get the ground fault current below 0.5 amperes. While vendors involved in the Australian REFCL program have achieved this level of sensitivity, that was typically only done through use of the inverter slowly injecting current into the circuit and observing the impact on feeder admittances. At Arrowhead substation it was necessary to achieve this sensitivity either through passive measurements or with a much smaller source injecting small currents into the neutral of the transformer.

After review of these methods, it was decided that Arrowhead substation would have admittance, transient, wattmetric and neutral voltage displacement method all monitoring the circuits. These have only been running in monitoring mode. For permanent faults the neutral voltage displacement is detected, and the arc suppression coil is bypassed with a neutral earthing resistor to operate the previously installed protection. Operation of the resonant grounding protection continues to be monitored. If it performs satisfactorily it may be enabled to open circuit breakers on permanent faults at a future date.

A Digital Fault Recorder (DFR) is recording waveforms of all events at the substation. This gives SCE the capability of replaying records from faults, switching, or other system events to determine whether the protection will operate correctly.

5.1.4 Commissioning Testing

The commissioning testing procedure for Arrowhead was limited to testing all the sub-components were in good working order including the settings of the relays. Then a resonance curve is performed which measures that the arc suppression coil was working properly.

No circuit balancing was performed as it was desired to see the maximum performance which could be achieved without it. The balancing of circuits adds significant cost and complexity to REFCL projects, so this project was used as a test bed to see if the desired voltage reductions could be achieved without balancing.

No insulation testing of the circuits was possible due to the lack of an inverter. This was not a concern since the substation had previously been high resistance grounded and thus had been exposed to similar over-voltages during ground faults for decades. This might be a bigger limitation if this technology is applied to larger circuits which were previously solidly grounded.

5.1.4.1 Resonant Curve

A resonance curve is a typical commissioning test on a resonant grounded system. The coil inductance is adjusted until the voltage on the neutral is at a maximum. This is the resonant point, when the coil is at this setting fault current will be at a minimum.

When the resonance test was performed at Arrowhead substation it was not possible to set right at the resonant point. The standing neutral voltage was estimated to be about 9kV which is too high for the distribution equipment to continuously withstand. It was possible to confirm with this test that the arc suppression coil was adequately sized though. The resonant point is approximately 21 amperes which is comfortably below the 35-ampere rating of the coil.

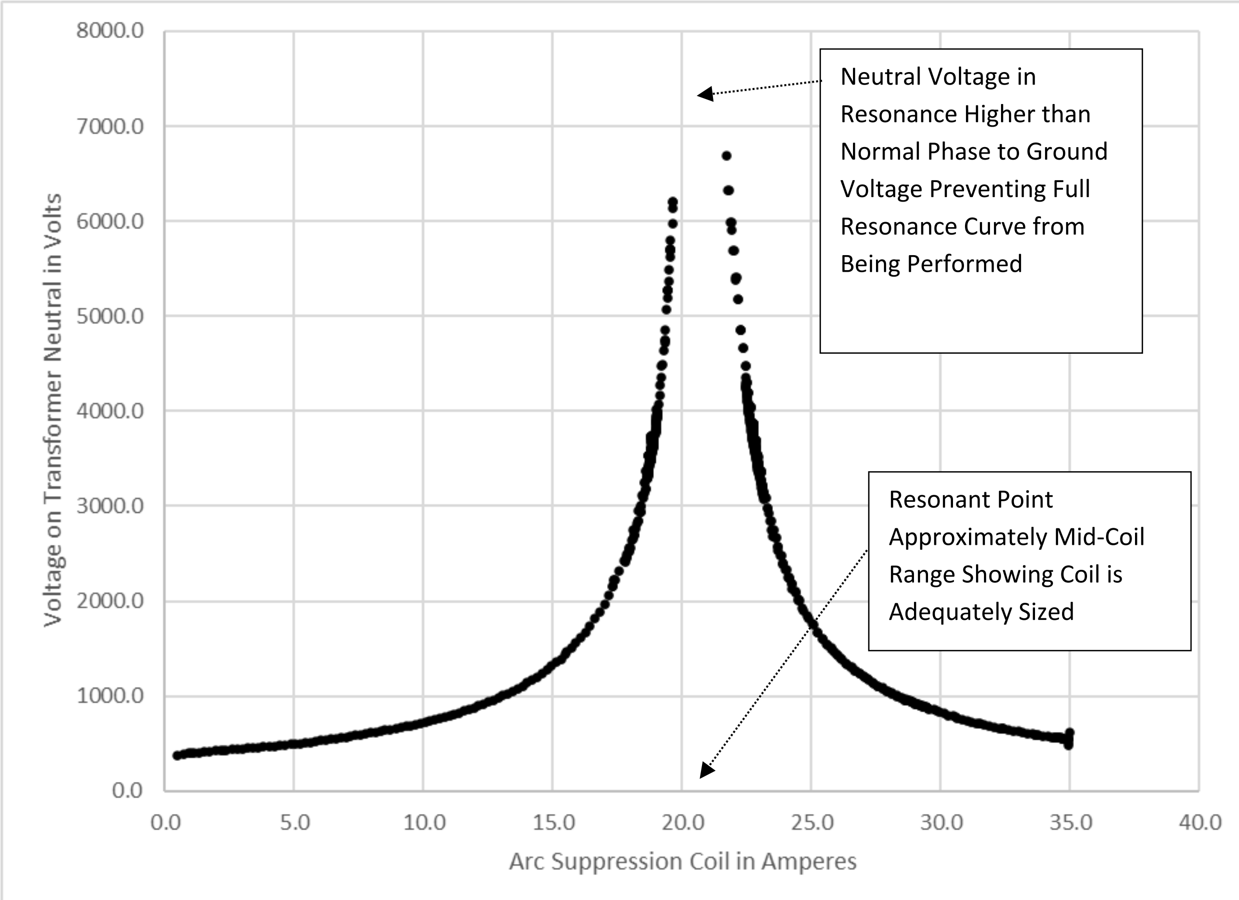


Figure 52: Resonance Curve at Arrowhead Substation December 21, 2021

5.1.5 Neutral Voltage Displacement

Continuous neutral voltage became one of the greatest challenges in this demonstration. The arc suppression coil can be thought of as a RLC circuit near resonance. The standing voltage is decided by the driving current and damping resistance. It is possible for this standing voltage to exceed normal phase-to-ground voltage on the neutral which could damage equipment on the circuits.

This standing voltage on the neutral is decided by the resistance to ground of the system which dampens the voltage, the imbalance of the system which provides the driving current, and how close the capacitance and inductance are to resonance. The high neutral voltage can be solved by addressing any of these three causes.

5.1.5.1 Running off Resonance

The method now being used to reduce this standing voltage is to run off resonance. Rather than running exactly on resonance, the coil can be programmed to stay several amperes away from resonance. As shown in Figure 51, being at about 13 amperes results in a standing voltage of only 1,000 volts. An advantage of this method is it is easy to implement, requiring no additional equipment.

There are however some downsides of running off resonance. Every additional ampere that the fault current is off resonance increases maximum ground fault current by an additional ampere. So, if the system could be run at resonance it would have a maximum ground fault current of 0.5 amperes, but if set to 13 amperes, the fault current would be (21 – 13) = 8 amperes. Since the energy released by a fault is proportional to current squared, an

8 ampere fault releases 256 times as much energy as a 0.5 ampere fault of the same duration. Also, it is possible that switching on the circuit accidently puts the system right at resonance. In this case it is necessary to have over-voltage protection to quickly take the arc suppression coil out of service and arresters sized to protect all equipment.

5.1.5.2 Damping Resistor

Another common way the standing neutral voltage can be lowered is the installation of a damping resistor. This resistor typically goes on an auxiliary winding of the arc suppression coil. It reduces the resistance to ground of the resonance circuit and thus lowers the standing imbalance voltage. It has the advantage that it can result in a robust and easy to operate system. Unlike running off resonance there is no risk of switching putting the network in a configuration which will have high voltage on the neutral. Also, increases in imbalance current from changes in network configuration are unlikely to look like faults. This has successfully been adopted by utilities with networks similar to SCE such as utilities in Ireland.

This method comes with the same disadvantage as running off resonance, ground fault current is increased. The installation of a resistor which pushed 5A through the arc suppression coil will increase the fault current by 5 amperes. Depending on the size of the resistor it is typical to have a fault current from 5-50 amperes when using a damping resistor. Unlike running off resonance, additional equipment must be installed.

5.1.5.3 Fully Three Phase Systems

Three phase cables and overhead lines send little neutral current back to the source substation. The charging current on each phase is equal and opposite so they sum to near zero. Some utilities have installed only three phase cables on their distribution networks. This is done primarily to supply three phase power to all customers but has an added benefit that these systems have very little standing neutral voltage when resonant grounded. This is typical practice in some central European countries such as Germany.

This method is extremely difficult to apply to an existing system. Adding an additional phase often requires a complete rebuild of the infrastructure. However, it might be used as a method to maintain balance in the future. If future tap lines and rebuilds are installed as three-phase than the networks will slowly become more balanced. The downside of this method is the added infrastructure costs of installing a third phase which is not required to supply the loads and associated safety risks such as downed wire which result from another wire in the air.

5.1.5.4 Isolation Transformers

Where a section of network is extremely imbalanced it can sometimes be desirable to remove it from scope for resonant grounding. This can be accomplished by the installation of a delta-wye transformer which does not change the voltage but does change the source grounding scheme. Everything to the source side remains resonant grounded but the wye point on the load side is solidly grounded or resistance grounded. The isolation transformer now becomes the source for this imbalance which no longer goes to the substation.

This method is most attractive for underground sections of circuitry which is fused. These systems already have extremely low public safety risks and the costs of balancing a large underground network can be extremely high. Installation of isolation transformers was sometimes used by Australian utilities to reduce the total charging current supplied by the Arc Suppression Coil. That allowed their systems to achieve higher ground fault sensitivity. The most likely place SCE will use this method is when the underground circuitry is connected phase-to-neutral. In these cases, an isolation transformer can remove the need to replace all the distribution transformers and upgrade the sections of single-phase cable to two-phase. To use isolation transformers as a method of reducing neutral voltage, it would be necessary to install one on many, and possibly all, of the longest two-phase cables. In most cases this will prove impractical on a large network, but it might be considered where one or two tap lines are most of the source.

5.1.5.5 Capacitive Balancing Units

Capacitive Balancing Units inject current into the earth which is out of phase with the currents created by other sources of imbalance. Typical installations will put a capacitive balancing unit near the end of long two-phase cables to inject a current into the earth which makes the system behave as if it were a three-phase system.

The advantage of capacitive balancing units is that they can solve the problem of high standing neutral voltage without increasing damping or running off resonance. This allows systems which use them to have extremely high ground fault sensitivity. They are the preferred method of lowering standing neutral voltage for the Australian REFCL program which can detect half ampere faults.

The disadvantage comes mostly in cost and complexity. The sources of imbalance must all be located, and balancing units must be installed as close as possible to each source. These systems also have additional requirements around single phase switching and picking up of unbalanced circuitry with are normally supplied by another substation.

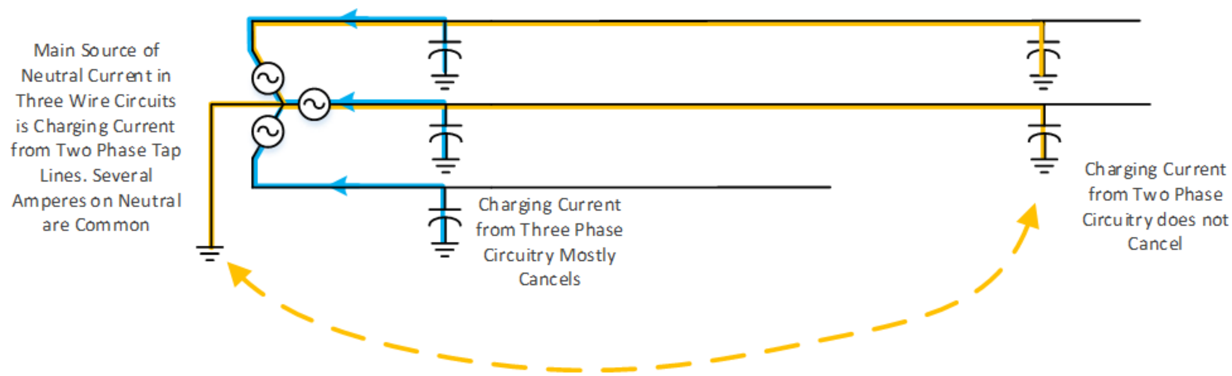


Figure 53: Path of ground current from a two-phase cable without balancing units

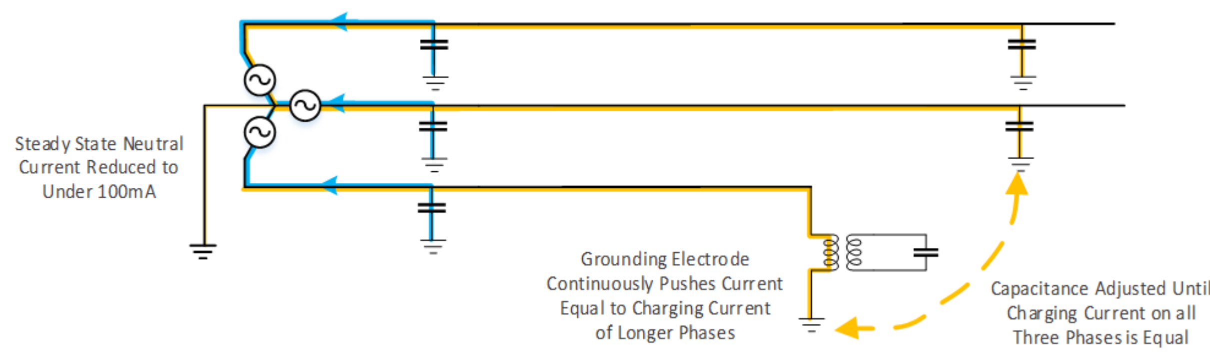


Figure 54: Path of ground current from a two-phase cable with balancing units

5.1.5.6 Active Current Injection

It should be possible to actively inject current into the neutral of the transformer to reduce the neutral voltage displacement. This could be achieved by using an inverter connected to an auxiliary winding on the arc suppression coil to inject current that actively reduces the standing neutral voltage. Alternatively, an automatically controlled capacitive balancing unit could be used inside the substation. The device could be programmed to either simulate a damping resistor or a capacitive balancing unit at the substation. If reliable methods of separating a fault from imbalance can be developed it might be possible to achieve extremely high ground fault sensitivity without the requirement to balance circuits.

This has apparently not been done to date except for short periods during Ground Fault Neutralizer commissioning. The added complexity of such a system has not made it an appealing option as a balancing choice. With continued development it might make it substantially easier to resonant ground systems which include large numbers of two-phase tap lines.

5.1.5.7 Paths to Reduce the Standing Imbalance at Arrowhead Substation

To date, the only method used to reduce the standing imbalance has been to run off resonance by about five amperes. This was an attractive solution as this problem was discovered at the energization of the arc suppression coil and did not require any configuration changes. This is a sub-optimal method of running the station, though, so it is likely that changes will be made in the future.

5.1.6 Availability

The Arc Suppression Coil has spent most of the time since install in service, including at least 95% of the time in every month from February 2022 through October 2022. It has been in service more than 7,500 hours which exceeded the time in service of the Ground Fault Neutralizer despite first entering service six months later. Some of this might be because of the less components required to install a system without an inverter or capacitive balancing units. Some of it is also that less reconfigurations requiring it to be bypassed happen in a smaller substation. It also appears that some is simply luck as the components which failed on the Ground Fault Neutralizer during the lightning storm are components used in both projects.

The main reasons it is taken out of service are to pick up load out of adjacent substations. The most notable time this happened was from December 30th, 2021 to January 5th, 2022. A storm came through and damaged equipment out of an adjacent substation. This required the substation to pick up some circuitry with higher imbalance than the circuitry out of Arrowhead substation. The Arc Suppression Coil had to be bypassed for six days until repairs were made and the system returned to normal. This type of incident can be expected to happen less in a wide-scale rollout where adjacent substations have had imbalance of circuits reduced.

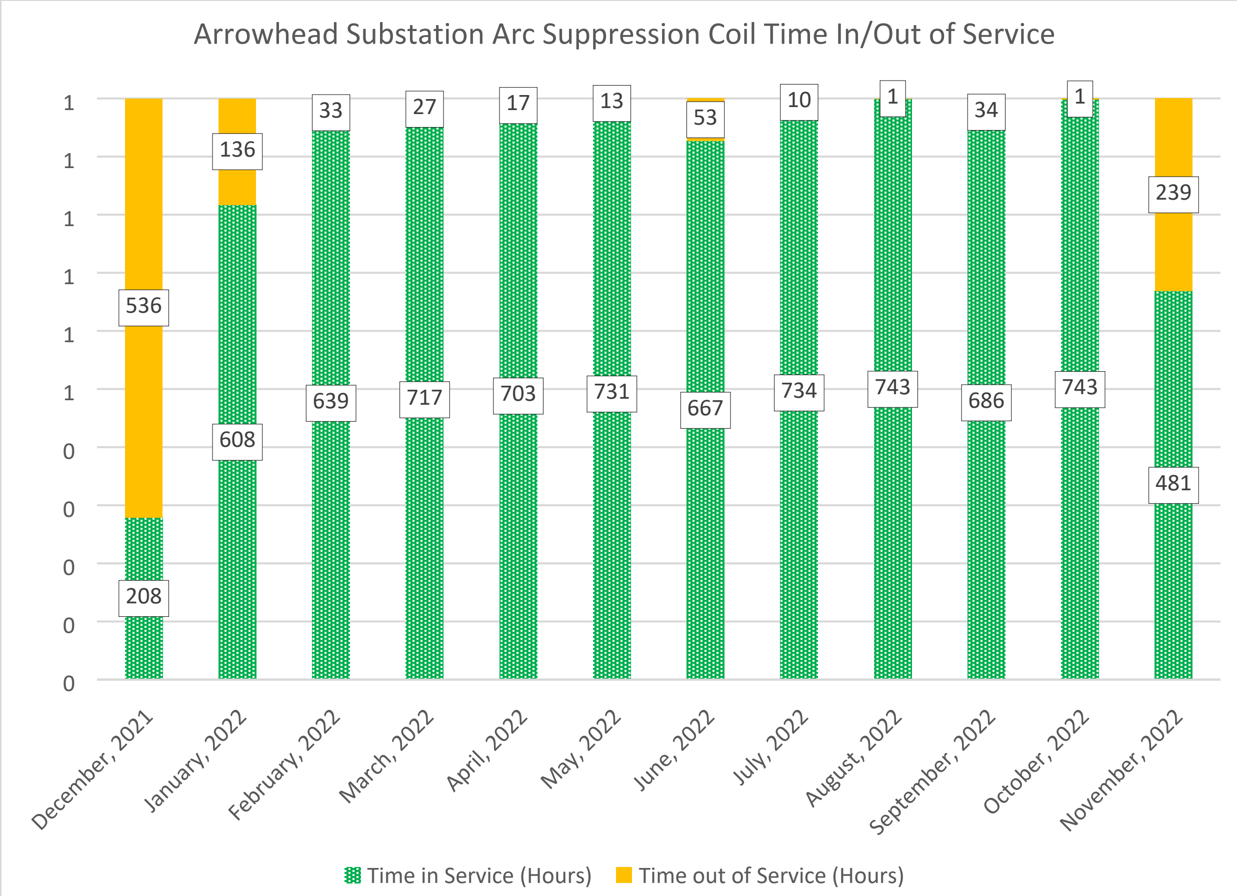


Figure 55: Availability of Arc Suppression Coil in first months after it entered service

The Arc Suppression Coil was also taken out of service for a week in November 2022 to investigate its operation for the first permanent ground fault to occur on the system. This length of an outage is not expected to be typical, but since it was the first operation, it was taken out to give time to confirm everything was ready to re-enter service.

Unlike the Ground Fault Neutralizer, this level of unavailability does not appear to justify additional effort to improve the amount of time in service. The times it is out of service are generally because the circuit is too unbalanced to allow it to enter service, so there is little room for improvement until adjacent circuits are balanced as part of REFCL projects.

5.1.7 Electrical Faults with Arc Suppression Coil in Service

Arc suppression coils have commonly been used by international utilities to improve electric system reliability, by self-extinguishing temporary faults and in some cases allowing systems to continue to supply customers even with a ground fault. SCE is intending to make use of the self-extinguishing capability but does not intend to operate with the presence of faulted circuitry. In the time it was in service there was one permanent ground fault and one permanent ungrounded fault. There were also many ambiguous events where the fault recorder saw circuit activity, but it was uncertain if the activity was a temporary fault or other system disturbance.

5.1.7.1 Phase-to-Phase Ungrounded Faults

The Arc Suppression Coil took no action on the one ungrounded fault, which was expected as it can only act on ground faults.

5.1.7.2 Temporary Ground Faults

The benefit of the Arc Suppression Coil is at its greatest for temporary ground faults since it can prevent them from progressing to permanent ground faults due to the energy release. Without the Arc Suppression Coil temporary ground faults would at least require a brief customer outage because arcing continues after the object falls away from the lines on a solidly grounded system.

There were several system disturbances that appear to have been temporary ground faults which were self-extinguished by the Arc Suppression Coil. The lowest impedance of these was recorded on October 12, 2022 when the Digital Fault Recorder measured multiple disturbances between 10:50 and 15:50. Example waveforms are shown in Figure 54. Three spikes of current were measured on each circuit, one with a peak of 155 amperes. This was the stored energy from the capacitance of the circuit discharging into the ground fault. The voltage on C phase collapsed while A and B phase voltage increase. The neutral voltage also increased to a peak of 15kV. The rapidity of the drop in voltage on the faulted phase is expected only for a low impedance ground fault.

Analysis of the waveform showed that this fault was on the Jeep circuit but no other information about the location of the fault was apparent. Because of the low energy release of these faults, they are not expected to be possible to locate by patrol. The only likely way they can be located is by technology such as Early Fault Detection which can find the location of arcing.

Similar waveforms were captured on six other days although it is unclear of all disturbance captured were temporary ground faults on the distribution circuits or whether other system disturbances such as faults on parallel lines explain some of these waveforms.

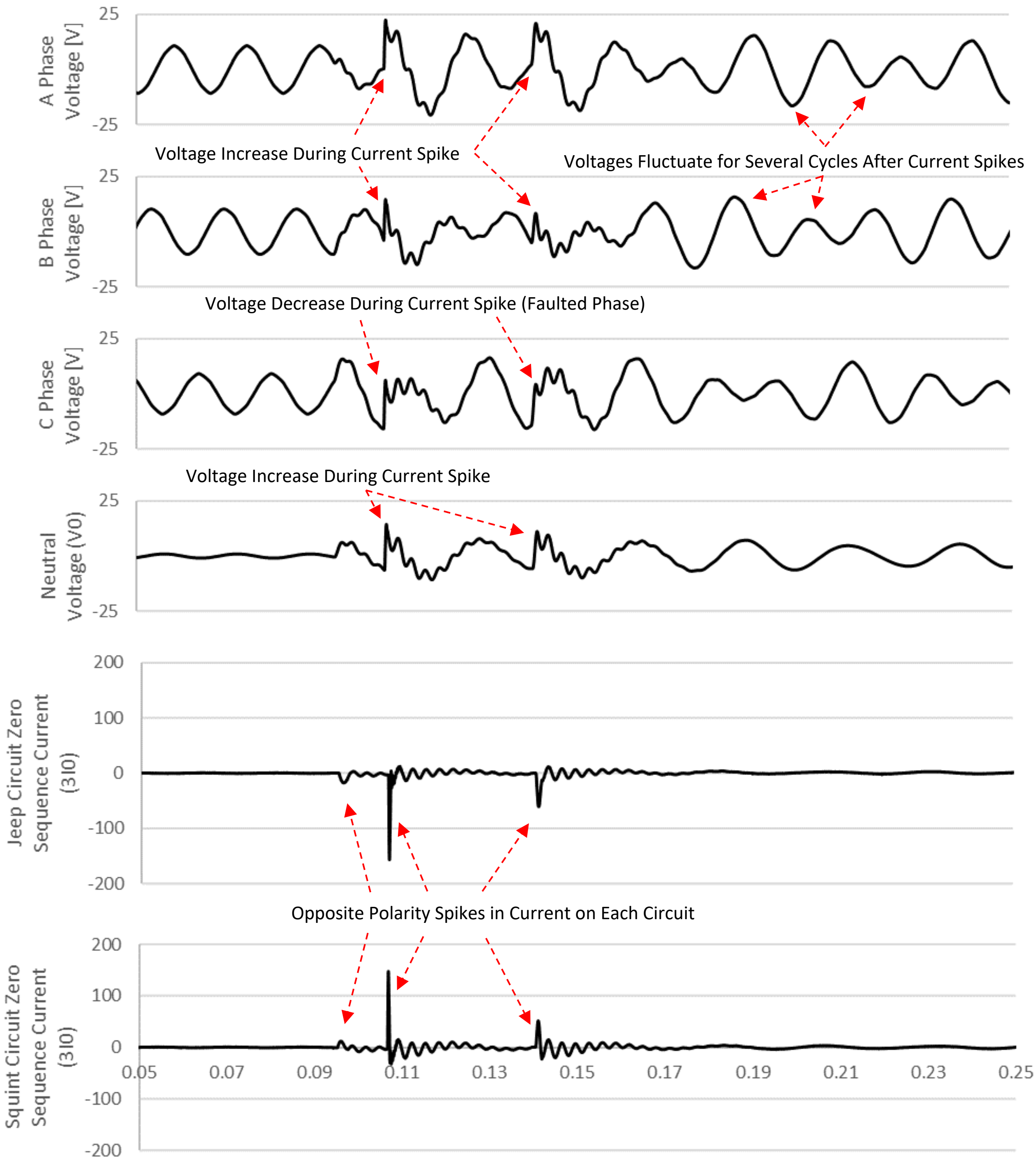


Figure 56: Temporary Ground Fault Seen at 11:37AM on October 12, 2022

5.1.7.3 Permanent Ground Faults

The only permanent ground fault occurred on November 5, 2022. The Arc Suppression Coil bypassed after about 350ms of high voltage on the neutral. It was expected that traditional protection would immediately operate when the coil was bypassed. However, instead of immediately operating a circuit breaker, fuse, or recloser, the circuit returned to normal. Starting at this time small current spikes started to be detected by the Digital Fault Recorder and the Recloser halfway down the Jeep Circuit. They started with a frequency of one record every few hours but within two days the rate increased with 17 such current spikes being measured by the recloser two days later on November 7th. This arcing eventually turned into a phase to ground fault of about 30 amperes which opened the recloser.

Further investigation showed the cause to be a failed distribution transformer. Why the Arc Suppression Coil protection saw a problem two days before the traditional protection remains unclear. The resistance grounding was set to a similar level of sensitivity.

Figure 57: Failed Transformer was the first Permanent Ground Fault at Arrowhead

Unlike the fault testing on the Ground Fault Neutralizer over-voltages were seen on the unfaulted phases because of this restriking. The highest voltage was seen on A phase which briefly reached a peak voltage of almost 24kV. This is about the highest voltage which is expected to be possible on this system due to operation of arresters. This is a lower magnitude transient than is seen in ungrounded systems but is still substantially higher than what was seen in the Ground Fault Neutralizer faults since the inverter prevents restriking. No equipment failed due to these voltages, which is not surprising as SCE equipment is rated for ungrounded systems. However, this will continue to be monitored. Should these voltages cause problems with equipment, it might result in SCE using more Ground Fault Neutralizers instead of Grounding Conversions since the Ground Fault Neutralizer limits the overvoltage.

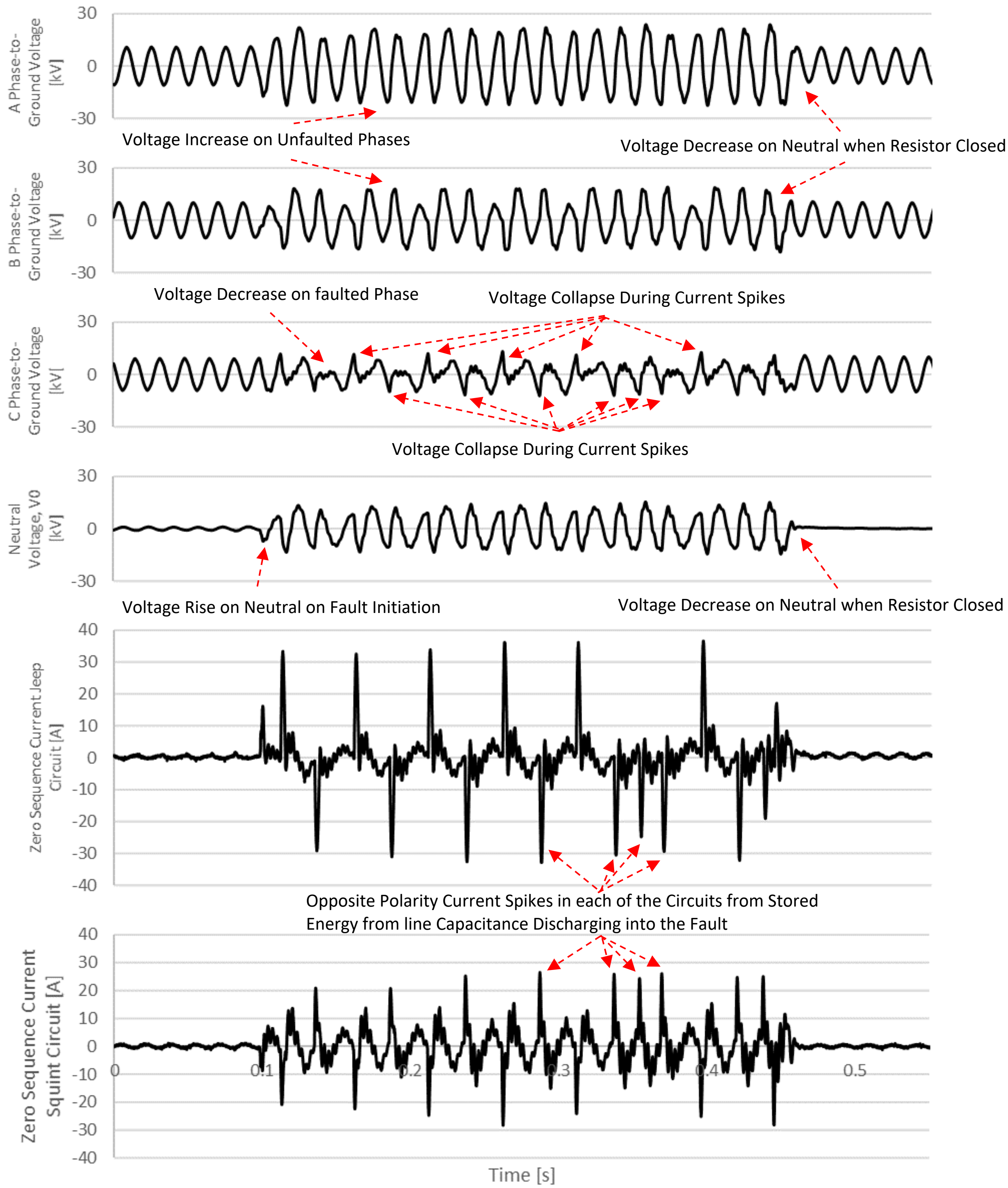


Figure 58: Permanent Ground Fault November 5, 2022

5.1.8 Lab Testing

5.1.8.1 RTDS Testing

Hardware-in-the-loop testing was performed utilizing a power system model of two feeder circuits, Jeep and Squint, out of Arrowhead substation. Hardware-in-the-loop testing is used to evaluate the performance of a device by simulating part of the power system while sending and receiving inputs and outputs between the device and the simulation in real time. This allows for testing of scenarios that are not feasible to replicate in the field for evaluation. The implementation of a Hardware-in-the-loop test environment also enables the project team to play back actual events from the field in a controlled lab environment.

Two relay manufacturers (referred to as relay Vendor A and relay Vendor B) each provided a Real Time Digital Simulator (RTDS) RSCAD model (referred to as Model A and Model B, respectively) for hardware-in-the-loop testing to evaluate new protection functions that can detect phase to ground faults on compensated systems. Each vendor provided a report of their testing with recommended settings (47) (48). Initially, the project team re-created the hardware-in-the-loop environment at the Grid Technology Innovation lab and reproduced the test results provided by each vendor. Verifying the results demonstrated that test environment was successfully replicated, and that the relay performance was in line with the reports provided by each vendor.

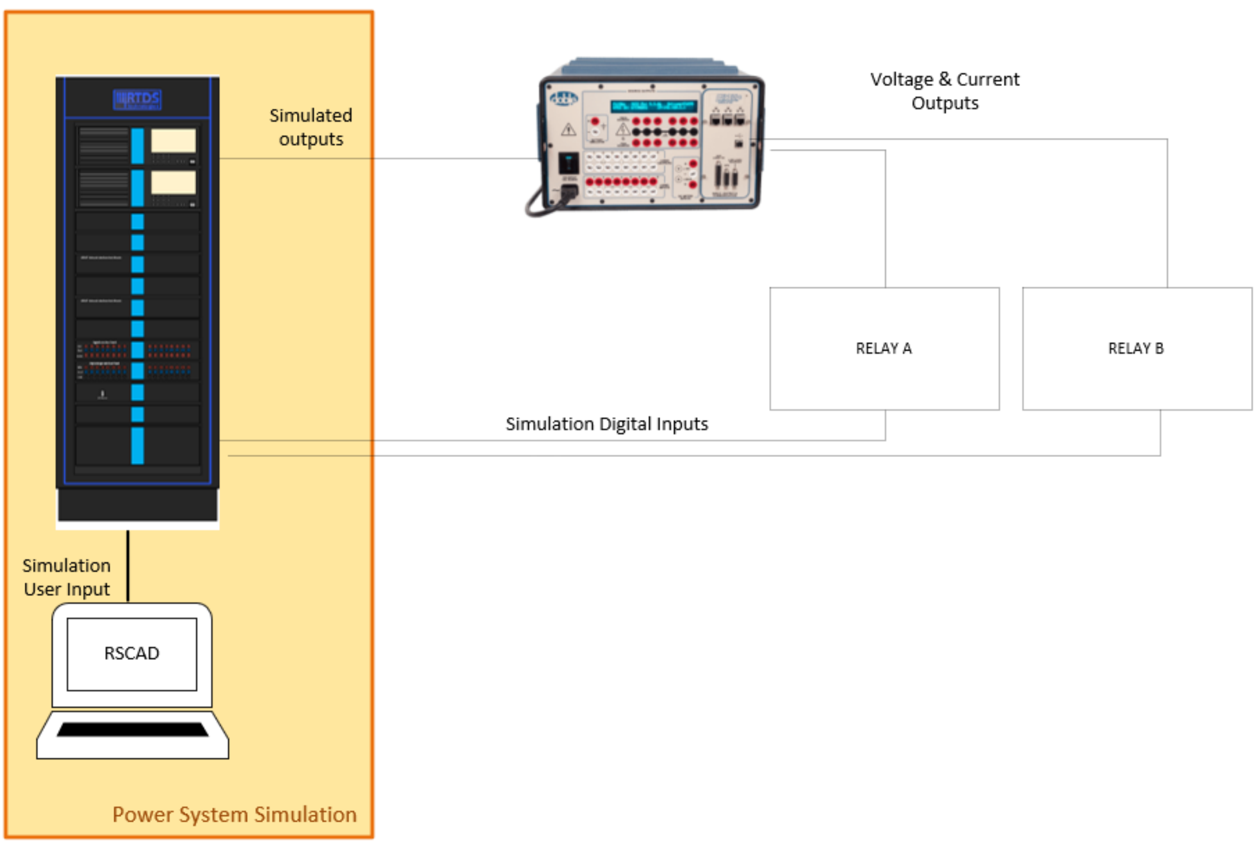


Figure 59 RTDS Hardware-In-The-Loop Test Environment

After confirming the original test cases, the project team began updating Model A and Model B to reflect the system as-is. Each model was 'tuned' so that the resonance curve, charging current on each phase of each circuit, and the system damping would align more closely with measurements taken in the field at the ASC installation site.

Additionally, the two models were expanded to include capacitive balancing units which the project team intends to incorporate in the field sometime in the future. The hardware-in-the-loop testing performed in the lab with both relays allowed the project team to perform rigorous testing of different types of faults along the system and to observe how each relay's protection algorithms would perform in those scenarios.

To summarize findings from the test results, Relay A was able to detect fault direction and operate correctly for all tested scenarios. Relay B frequently mis-identified fault direction, and in many cases operated in both the forward and reverse directions for forward faults. For a more direct comparison, Relay B was also tested using Model A. Use of Model A improved the performance of relay B somewhat; however, Relay B still mis-operated the directional element for some faults.

Table 4 RTDS HIL Test Results with Capacitive Balancing Units

Relay Vendor	RSCAD Model	Fault Duration [Cycles]	Fault Direction	Fault Impedance [Ohms]	Results
A	A	20	Forward & Reverse	0.01	Can detect correctly in forward and reverse direction. Operations times vary between 0.1674s - 0.2527s
				500	
				1000	
				1500	
				2400	
				7200	
				12000	
				14400	
B	B	10 cycles*	Forward	0.01	Frequently mis-identified fault direction. Operates at approximately 0.11s
				500	Occasionally mis-identifies fault direction. Operation times approximately 0.12-0.13s
				1000	Correctly detects fault direction (forward only) for all cases. Operation times approximately 0.12-0.13s
				1500	Correctly detects fault direction (forward only) for all cases. Operation times approximately 0.12-0.13s
				7000	Consistently detects fault in both directions for forward faults. Forward directional element operates correctly between approximately 0.14-0.16s. Reverse directional element operates incorrectly at approximately 0.62s. Wattmetric element operates approximately between 0.147-0.167s.
				8000	Consistently detects fault in both directions for forward faults. Forward directional element operates correctly between approximately 0.15-0.177s. Reverse directional element operates incorrectly at approximately between 0.62-0.635s. Wattmetric element operates approximately between 0.15-0.169s.
				10000	Consistently detects fault in both directions for forward faults. Forward directional element operates correctly between approximately 0.177-0.21s. Reverse directional element operates incorrectly between approximately 0.62-0.64s. Wattmetric element operates approximately between 0.157-0.183s.

Relay Vendor	RSCAD Model	Fault Duration [Cycles]	Fault Direction	Fault Impedance [Ohms]	Results
B**	A	20 cycles	Forward & Reverse	0.01	Correctly identifies fault direction. Directional element operates at approximately 0.0089-0.01339s. Wattmetric element operates between 0.01755-0.3611s for all cases except reverse direction C phase fault.
				500	Correctly identifies fault direction. Directional element operates at approximately 0.01-0.013s. Wattmetric element operates between 0.01759-0.35394s.
				1000	Correctly identifies fault direction. Directional element operates at approximately 0.0139-0.028s. Wattmetric element operates between 0.01759-0.3541s for all cases except reverse direction C phase faults.
				1500	Frequently detects fault in both directions. Forward direction element operates correctly between 0.01741-0.0329s and reverse operates incorrectly at up to 0.524s. Wattmetric operates between 0.01769-0.361s for all cases except reverse direction C phase faults.
				2400	Frequently detects fault in both directions. Forward direction element operates correctly between 0.0196-0.0412s and reverse operates incorrectly at up to 0.532s. Wattmetric operates between 0.017553 -0.361s for all cases except the reverse direction C phase faults.
				7200	Frequently detects faults in both directions. Forward direction element operates correctly between 0.0424-0.1027s and reverse operates incorrectly at up to 0.5721s. Wattmetric operates between 0.0176-0.361s for all cases except reverse direction C phase faults.
				12000	Consistently detects faults in the wrong direction. Reverse direction element operates in all cases between 0.509-0.634s. Wattmetric operates between 0.0177-0.147s for all cases except reverse direction C phase faults.
				14400	Consistently detects faults in wrong direction. Reverse direction element operates in most cases between 0.511-0.649s. Wattmetric operates between 0.026-0.2059s for all cases except reverse direction C phase faults.

*Note – Relay B with Model B was tested at fault durations of 10 cycles. Tests performed at 20 cycles revealed that Relay B forward and reverse directional elements will **both** operate. The oscillography for a 20-cycle fault was captured during this test for further review.

**Note – results detailed in this test are for relay settings using calculated neutral voltage

5.1.8.2 Comtrade File Playback Testing

In addition to RTDS hardware-in-the-loop testing, the project team also performed testing using the comtrade playback feature of the lab equipment. The comtrade files were pulled from a DFR (Digital Fault Recorded) installed in the field. This testing allowed the team to observe how each of the relays would have operated for events that occurred in the field.

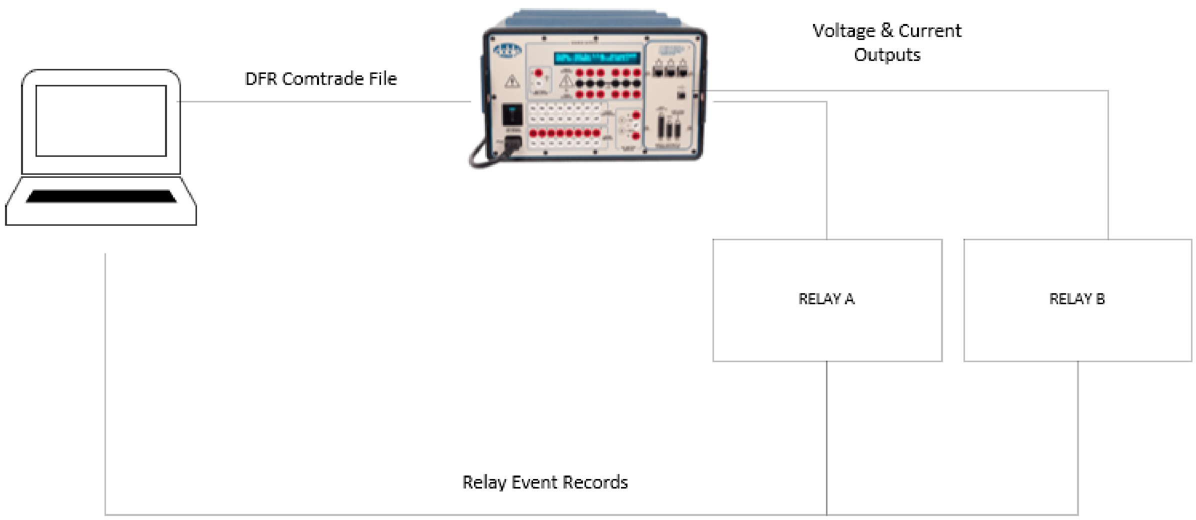


Figure 60 Comtrade File Playback Test Environment

In early November 2022, a phase to ground fault occurred on the system where the Arc Suppression Coil is installed (see Figure 56). The project team obtained the comtrade files from this event and played the event back in the lab using both relays. When played back, each relay should identify one comtrade file as a fault in the forward direction, and the second file in the reverse direction.

The following results were observed:

1. Relay A correctly identifies the fault in the forward and reverse direction for the corresponding comtrade file
2. Relay B results varied depending on whether the elements used a calculated V0 or measured Vx.

Overall, the operations were not consistent with the expected outcome. Based on the findings from both the comtrade file playback and the RTDS testing performed at the lab, Relay A performed more favorably, and Relay B will require additional testing and vendor support to reliably detect faults on this system.

This demonstrates one of the greatest challenges with adopting resonant grounding. While many products are on the market and are being successfully used internationally, experience in North America with proper setting of such systems is lacking.

5.1.9 Summary of Arrowhead Substation Resonant Grounding Lessons Learned

The project at Arrowhead substation demonstrated that a resonant grounding system which only operates on temporary faults can be reliably operated at a much lower level of cost and complexity than the Ground Fault Neutralizer projects. The availability of this system was much higher, probably due to that reduction in complexity.

To achieve the full risk reduction benefit matching a Ground Fault Neutralizer on a larger substation, it will be required to upgrade this system to run on resonance and rapidly determine which circuit the fault is on. Both will require significant upgrades. In its existing configuration though it has the capability of self-extinguishing temporary faults with no impact on customers and much less total energy release than typical SCE designs.

To be able to run on resonance, there are two paths forward: installation of balancing units or installation of damping resistors. While damping resistors are the much lower cost solution, they increase the energy release from ground faults. Therefore, it is anticipated that balancing units will ultimately be installed on the system.

The level of complexity of Arrowhead substation can be greatly reduced at substations which only supply one circuit. In those locations, it is not necessary to determine which circuit the fault is on, just detect the presence of a fault. This can easily be done by measuring neutral voltage. When a fault is present, the line breaker can be opened within two seconds meeting the voltage reduction targets for prevention of ignition. Based on this lesson learned through the Arrowhead project, the next few grounding conversion projects will target single circuit facilities. Small multiple circuit substations will likely be delayed until additional operational experience with the Arrowhead substation project has upgraded the protection to reliably detect which circuit ground faults are on.

5.2 Calstate Circuit Ungrounded Overhead Isolation Transformer

The smallest of the grounding conversion projects was performed by breaking off a small part of the Calstate 12.47kV distribution circuit with an isolation transformer. Because this system is so small, about 2.5 miles, the voltage reduction targets can be met by ungrounding the load side of the transformer resonant grounding was not required.

5.2.1 Equipment Configuration

Three transformers were used to make a delta-wye connected isolation transformer which leaves the load side voltages at 12.47kV but allows for different source grounding on each side of the transformer. Faults are detected with a voltage transformer which measures the voltage on the neutral of the transformer. When voltage is above a threshold a recloser opens after one second clearing the fault. Zero sequence voltage is able to be applied for ground fault detection in the small systems which only have a single circuit, which avoids the need to discriminate the faulted circuit. Single circuits with multiple series devices can also be coordinated with sequential time delays.

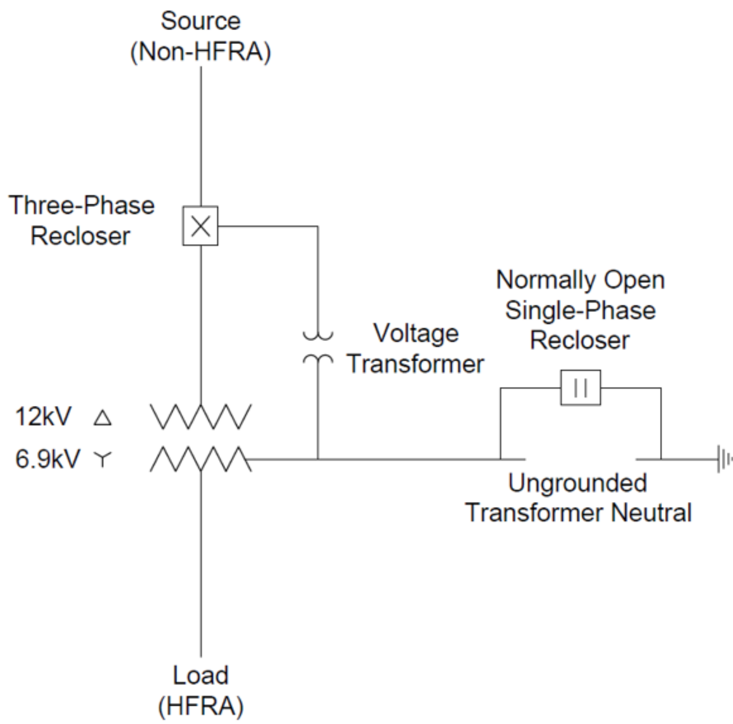


Figure 61: Equipment Configuration for Ungrounded Isolation Transformer used on Calstate Circuit

Figure 62 Isolation Transformer Installed on the Calstate Circuit

No balancing units were required, although some two-phase tap lines were rephased to minimize the charging current imbalance of the circuits. Balancing units would have been required if any two-phase tap lines were present.

5.2.2 Availability

The system has remained in service continuously since installation. While it is built to be solidly grounded for short times to blow fuses, that has not yet been necessary. This high availability compared to substation projects comes from the fact that there is less circuitry behind the transformer and no ties to other circuits. Therefore, the system does not need to be turned off to pick up non-normal load which has not been balanced.

5.2.3 Summary of Calstate Isolation Transformer Lessons Learned

The project successfully was put in service and remains in service after two years. The sensitivity for ground faults is approximately 100,000 ohms yet it has only operated once since energization when an open phase unbalanced the circuits.

Despite this success, the form it takes is not a widely scalable solution. Several concerns needed to be worked out before a deployment in certain areas:

1. Using an overhead transformer both limits the maximum size and limits its use in areas where aesthetic concerns do not prevent installation.
2. A delta-wye transformer has a thirty-degree phase angle shift which means it cannot parallel with other circuits unless those circuits also have a similar isolation transformer.
3. Ungrounded transformers can meet the voltage reduction targets on very small systems, possibly as large as 3.3 amperes charging current, but will not be able to achieve them on larger systems. In some cases, this will still be the best available practice, and it could still be expected to reduce wildfire risk (54), but a solution like resonant grounding or faulted phase earthing to reduce the fault current further is desirable.

5.3 Stetson Circuit Resonant Grounded Padmount Isolation Transformer

The isolation transformer install at Stetson substation was designed to be a more scalable solution than the Calstate isolation transformer. Instead of an overhead, ungrounded, delta-wye transformer, a padmounted, resonant grounded, delta-zig zag transformer was used. This was the first installation of the technology described in U.S. Pat. No. 10,605,795 (57). The size of the transformer was also increased from 1,000 kVA to 1,500 kVA. This results in a design which can be widely applied on the SCE system, although the design is still too small for some sections of circuitry which have extremely long lines or large amounts of cable.

5.3.1 Equipment Configuration

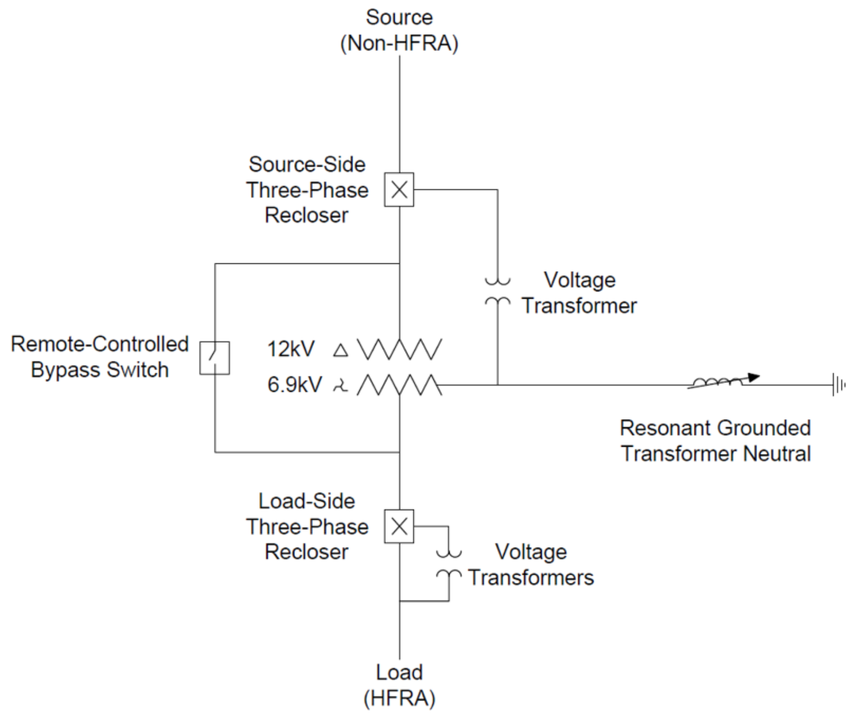


Figure 63: Equipment Configuration for Resonant Grounded Isolation Transformer used on Stetson Circuit

5.3.2 Availability

For similar reasons to the Calstate isolation transformer, the one on the Stetson circuit has been in service continuously since construction, a little more than a year.

5.3.3 Summary of Stetson Resonant Grounded Isolation Transformer Lessons Learned

The isolation transformer on the Stetson circuit was successfully installed and resonant grounded. The design is applicable to a much wider variety of circuits than the Calstate circuit.

The main challenge of this design has been the amount of space required to install the isolation transformer, particularly if a larger sized transformer is required to carry the load. While some sites have the required space, the amount of space required often makes installation impossible. Several space saving options are being considered—most notably the use of wye-wye transformers which are somewhat smaller than delta-zig zag transformers.

Challenges have been experiences with sourcing of Arc Suppression Coils. Most Arc Suppression Coils on the market are sized for large European networks with hundreds of amperes of charging current. The installation on the Corsair circuit used 240-volt inductors which were easier to source than 7,200-volt inductors but increase size by the requirement to have a step-down transformer and larger inductors sized to withstand relatively high currents. Many different alternatives are being considered such as a 7,200-volt inductor with an auxiliary winding using switched capacitors, a scaled down version of an inductor with a variable air gap, or even distributed arc suppression coils (58) (59) connected to cables or internal to padmounted transformers.

6 REFCL Program Status at SCE

SCE continues to evaluate performance of the different REFCL pilots and may shift resources between them as their strengths and challenges are better understood. Ground Fault Neutralizer pilot has progressed the most as there is information available from wide deployment in Australia along with the results from SCE's project. Most of the miles covered in 2023-2025 will come from Ground Fault Neutralizer projects.

The Grounding Conversion projects are continuing to make improvements to designs and are expected to start to scale up by 2024. Total number of miles covered by these projects will likely remain less than the Ground Fault Neutralizer, but the circuit miles converted will be better targeted to HFRA circuitry with less coverage of non-HFRA circuitry. In the short-term grounding conversions will be applied in single circuit applications as the designs for protection systems with multiple circuit systems is not far enough along.

Initial projects will all be at 12.47 kV and 16kV projects are likely to follow shortly behind them. SCE 4kV systems are not good candidates and will only be installed as a part of a conversion to a higher voltage installation. Higher voltage 33, 55, and 66kV projects remain technically credible, but will not be undertaken until SCE has additional experience with the technology. Projects at 115kV or above are not considered technically credible, worldwide few installations operate at above 110 kV due to the high costs.

6.1 Future Ground Fault Neutralizer Projects

Based on the performance seen from the Ground Fault Neutralizer, four additional projects have been initiated. Two of these projects, Acton, and Phelan substations, are targeting a 2023 energization and two, Banducci and Del Sur, are targeting a 2024 installation. One of the risks SCE faced with this technology was from a single vendor supplying the Ground Fault Neutralizer equipment. Onboarding a second supplier was a high priority to mitigate supply chain risks and better accommodate any future scale up. Therefore, one of the substations targeting 2024 energization will be done with a second vendor.

There are operational advantages to building out the best candidate substations in one region of the SCE system before moving to the next region. This ensures that crews working on them have a high level of familiarity with the equipment. It also reduces the time the Ground Fault Neutralizer is out while the substation picks up neighboring circuitry which has not been balanced. The area being prioritized for the initial years of the project is the northern end of the Angeles National Forest and Tehachapi. This is an area which has many high fire risk circuits and is relatively easy to convert due to the small number of phase-to-neutral connected transformers and a voltage of 12.47kV which has equipment rated for the over-voltages.

It is anticipated that the projects in 2020 through 2024 will be sufficient to build up both suppliers and internal SCE knowledge of this technology. A larger scale up would be possible in 2025 if continued performance is observed for the pilots. If a wider scale up is delayed, continuing to deploy in at least two substations a year is recommended so the supply chain can be maintained to be able to support a larger expansion when appropriate.

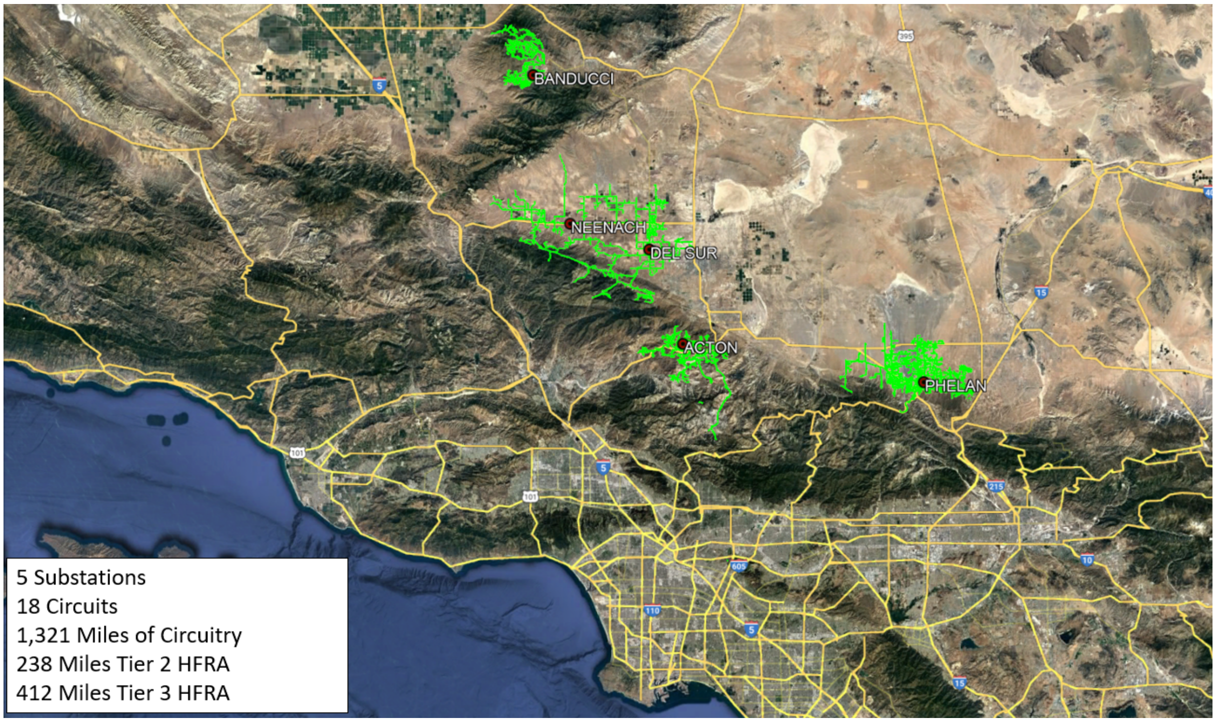


Figure 64: Active Ground Fault Neutralizer Projects

6.2 Future Grounding Conversion Projects

The next few years of grounding conversion projects will be focused on upgrades to single circuit facilities and improved practices for the creation of single circuit facilities by installation of isolation transformers. Once the Arrowhead Substation project has been upgraded to meet the desired energy reduction targets and protection sensitivity additional multiple circuit projects might be performed. It is also possible that longer term grounding conversions could be performed outside High Fire Risk Areas to improve safety and reliability.

6.2.1 Future Upgrades for Arrowhead Substation

The project at Arrowhead has been successful in reducing the ground fault current of temporary ground faults to around 5-7 amperes. This represents a big improvement over typical North American utility design. To date though it has not been able to meet the desired wildfire targets. In the immediate future the project will be left in the existing configuration. In the time it has been in service no ground faults have occurred so leaving it for a few more years will give good information which can be used to test proposed line protection. Any faults which happen are being recorded in a digital fault recorder which can be replayed to test different protection algorithms.

Once sufficient data can be collected to confirm the best protection to select the line with a fault, protection upgrades may be made to allow the system to clear permanent faults. This step would likely be taken before a scale up of this design to additional substations, although a system which only acts on temporary faults might be preferred in some cases.

It still appears possible to achieve the desired reduction in energy release from ground faults for wildfire purposes if Capacitive Balancing Units are installed on the circuits. These should allow the coil to run right on resonance which should reduce the worst-case fault current to around 0.5 amperes. Additional investigations are ongoing to whether to take that step.

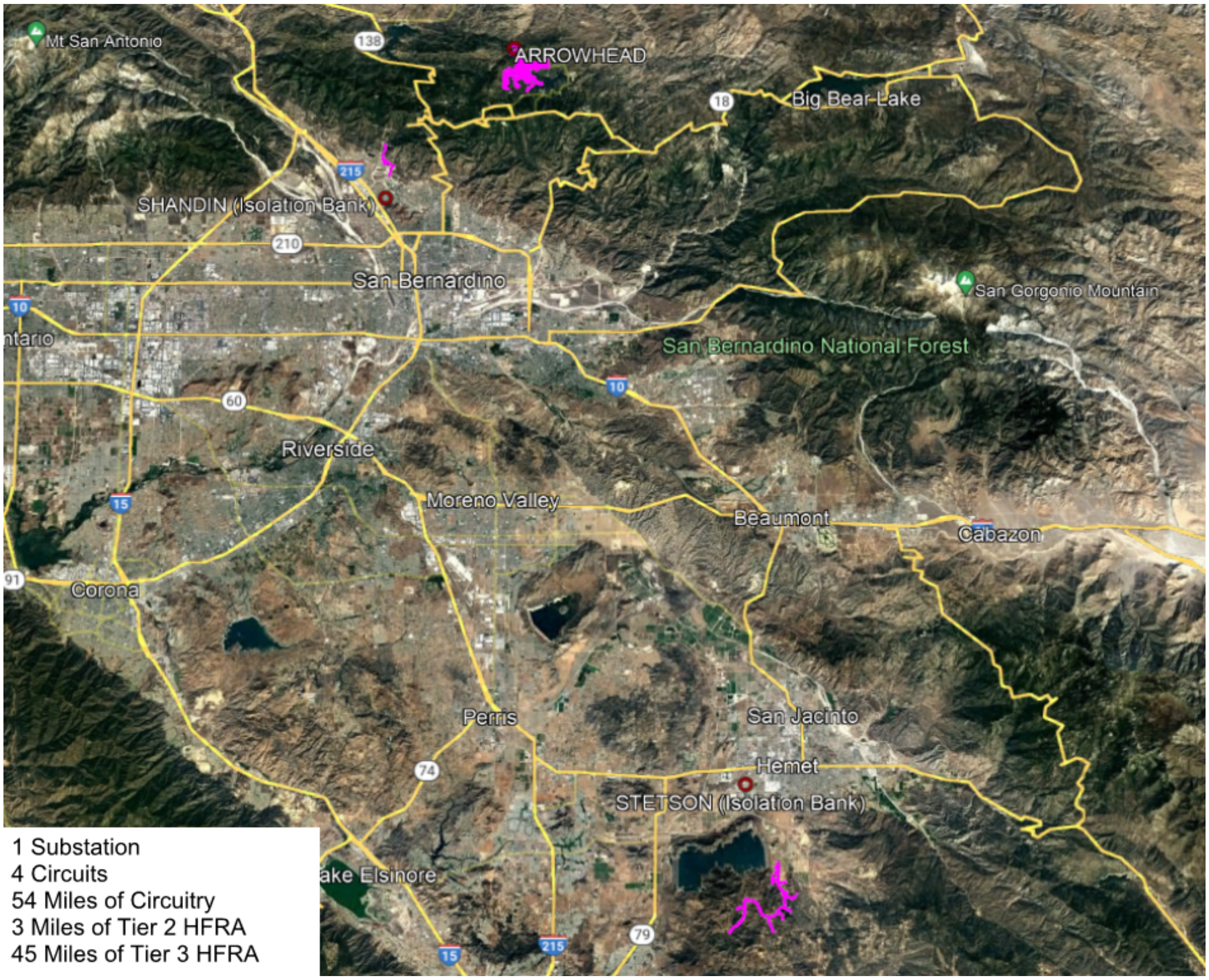


Figure 65: Existing Grounding Conversion Installations

If this form of resonant grounding gets scaled up from Arrowhead substation to a larger rollout, the project at Arrowhead substation will probably get retrofits to be the first substation match the final design. The major components at Arrowhead are all expected to stay as is but there may be modifications in the protection or a particular component which is found to have problems.

Another possibility is that it could be converted to a Ground Fault Neutralizer. This would require the addition of an inverter but in several years the cost of that might have reduced to the point that it is a reasonable alternative for a substation the size of Arrowhead.

6.2.2 Grounding Conversions of Existing Single Circuit Facilities

Single circuit facilities have been more successful for grounding conversions because of the simpler designs, particularly for protection. SCE has some existing single circuit transformers which can be converted to be ungrounded or resonant grounded to reduce the energy release from ground faults. These are a high priority for conversion because unlike the isolation transformer installs, they do not require a new transformer and unlike multiple circuit substations do not require protection which can determine which circuit the fault is on. Efforts are ongoing but the first conversion is expected in 2023.

6.2.3 Grounding Conversions with new Isolation Transformers

Efforts continue to improve the design for ungrounded and resonant grounded isolation transformers. The biggest target for design improvements is to reduce the size of the installations so they fit into existing easements and increase maximum rated load to install on more heavily loaded circuitry. The next installation is expected in 2024.

7 Appendix A: SCE Equipment Upgrades to Install REFCL Systems

In many cases the cost of REFCL systems is driven more by the costs of replacing equipment not rated for the technology than by the actual costs of the new equipment. The following section summarizes the equipment which needs to be replaced to convert different SCE systems.

7.1.1 Upgrades Required Due to Phase-to-Neutral Connected Equipment

Since resonant and GFN grounded systems cannot have phase-to-neutral connected load, many of the devices SCE installs are not compatible with this system. However, SCE already has significant phase-to-phase connected load meaning that the impact of moving to resonant or GFN grounding is likely to be less than for most North American utilities.

7.1.1.1 Distribution Transformers

SCE owns several different style of distribution circuits some with many phase-to-neutral connected transformers and some with none.

7.1.1.1.1 4 kV Overhead and Underground Systems

All load on the SCE 4 kV overhead and underground systems is connected phase to neutral. As a result of this fact 4 kV substations are not credible candidates for resonant grounding or GFN. Should the system be desired it would be implemented as a part of a project to convert to 12 or 16 kV.

7.1.1.1.2 12 and 16 kV Underground Systems

The underground 12 and 16 kV systems contain both phase-to-phase and phase-to-neutral connected transformers. Therefore, some substations can be upgraded with few customer transformers requiring replacement and some will require replacement of every single distribution transformer.

The actual cost of the transformers in many cases will be a small percentage of the costs required to convert a circuit to phase-to-phase connected transformers. Where conduits are in good shape it might be reasonable to replace all transformers. However, when conduits are too small to fit a second cable or where conduits otherwise require replacement the civil costs will quickly balloon.

7.1.1.1.3 12 and 16 kV Three Wire Overhead Systems

All transformers on 12 and 16 kV three wire overhead systems are already connected phase-to-phase. This fact makes the three wire overhead systems dramatically easier to convert than any other SCE system.

7.1.1.1.4 12 and 16 kV Four Wire Overhead Systems

Where underground phase-to-neutral connected transformers are being fed by overhead lines, SCE uses 4 wire systems that include a neutral. These systems are a mix of phase-to-neutral connected transformers on the underground part of the system and phase-to-phase connected transformers on the overhead system. They will typically require fewer upgrades than fully underground systems but will vary considerably from one circuit to the next.

Single phase load installed since around 2002 will be installed in duct so the cables and transformers can be removed and replaced without substantial civil work. More challenging are older systems which often used cable in conduit (CIC). For these installations the underground may need to be entirely rebuilt, although isolation transformers can often be installed at a lower cost. Costs can therefore be extremely high if there is a lot of older single-phase load on the circuits.

7.1.1.2 Instrument Transformers

Unlike other phase-to-ground connected load the fault current contribution from phase-to-ground voltage transformers is typically small. Therefore, in GFN systems the inverter can cancel out any contribution to fault current from these transformers. However, it still sometimes may be desirable to change phase-to-neutral connected voltage transformers to phase-to-phase connections particularly where more sensitive transformers would be required anyways.

Due to the relatively small number of phase-to-ground connected voltage transformers this is not expected to be a significant contributor to cost below 115-kV. At 115-kV and above there exists a significant population of phase to ground voltage transformers which are not rated for the overvoltage and thus would require replacement.

7.1.2 Upgrades Required Due to Overvoltages on a Resonant or GFN Grounded System

Whenever a line to ground fault occurs on an ungrounded, resonant grounded, or GFN grounded system any equipment connected to the other two phases sees an overvoltage of ~1.7 times the normal voltage. Some equipment is not rated for this value and will thus be required to be replaced. This is a significant driver of cost and makes cost comparisons for upgrades between utilities difficult. Each utility must evaluate how much of its equipment can survive the overvoltage and replace any components which are not rated for it.

SCE has a serious advantage over many utilities on its 12.47 kV system. This comes from the fact that much equipment is shared between the 12.47 and 16 kV system. This shared equipment can withstand a significant overvoltage and will not need to be replaced. However, there are a few components on the 12.47 kV system such as surge arresters which are not shared and thus may require replacement. A similar benefit is sometimes seen on the 16 kV system since 25 kV equipment has often been installed due to it being an industry standard rating.

There is a risk that some equipment exists which has deteriorated to the point that it would have already failed if it were not on a solidly grounded system. This means that soon after conversion to resonant or GFN grounding reliability might drop as this equipment fails, leading to unplanned outages for replacement. It expected that this equipment will fail within the first year and that it will not impact long-term reliability. Commissioning testing should be performed to minimize this risk by including a commissioning test that operates the system with a sustained overvoltage. This should force failure of any deteriorated equipment in a controlled environment and with resources mobilized for quick replacement.

7.1.2.1 Transformers

Transformers are one of the highest cost pieces of equipment on a utility system and one of the most susceptible to failure during an overvoltage. However, most transformers SCE purchases are rated for use on a resonant or GFN grounded system, so few transformer replacements are required.

7.1.2.1.1 Distribution Transformers

Because of how common ungrounded systems are at distribution voltages, standard transformers are rated for use on ungrounded systems. Distribution transformers are all tested to 34kV phase-to-ground per C57.12.00 Table 3 (60). This means that even at 16 kV where a phase might see 17kV phase-to-ground voltage it is still at only half the value it was tested for.

7.1.2.1.2 Substation Transformers

7.1.2.1.2.1 12 and 16 kV Transformer Windings

At 12 and 16 kV the substation transformers are rated for use on a resonant or GFN grounded system, but test reports should be examined on transformers older than 2009. These transformers with 12 kV windings are tested at 34 kV and those with 16 kV windings are tested at 50 kV. So, the rating of the transformer will not be exceeded. When examining test reports on older transformers particular attention should be paid to whether the neutral is rated for the same voltage as the other bushings. The neutral voltage will see line to ground voltage during a fault so needs to be rated for it.

7.1.2.1.2.2 33kV through 66 kV Transformer Windings

Most windings from 33kV to 66 kV are delta connected. These windings are rated for use on a resonant or ungrounded system. Per C57.12.00 (60) transformer windings rated for 33 kV are tested to 70 kV for two minutes and transformer windings rated for 66 kV are tested to 140 kV. Therefore, the overvoltages produced on a resonant or GFN grounded system stay far below what the transformers were tested to.

Particular attention should be paid to transformers that have a grounded wye connection. These transformers are more likely to not be rated for use on a resonant or GFN grounded system. For example, most ground banks will require replacement due to under-rated neutral bushings.

7.1.2.1.2.3 115 kV Transformer Windings

Most windings at 115 kV are wye connected but they may not be solidly grounded. Per C57.12.00 (60) transformer windings are tested at 173 kV for two minutes. Therefore, the overvoltages produced on a resonant or GFN grounded system stay far below what the transformers were tested to. The neutral bushings for these transformers are rated for full insulation on transformers newer than 2009 but older transformers require additional review of test reports.

Particular attention should be paid which have a grounded wye connection. These transformers are more likely to not be rated for use on a resonant or GFN grounded system. For example, most ground banks will require replacement due to under-rated neutral bushings. SCE uses more wye connected transformers at 115kV than 33 or 66kV, in most cases this means that at 115kV the upgrade costs will be extremely high.

7.1.2.2 Power Cables

Cables represent one of the largest cost risks on the SCE system for a resonant or GFN grounding installation. Cables today are tested at twice the nominal voltage for one hour as a commissioning test. Therefore, cables have experienced higher overvoltages than would be expected from this system. However, the margin is significantly less than the margin for most other equipment. Also, old cables may have degraded to the point that an overvoltage will cause failure.

A significant number of power cables required replacement when the GFN devices were installed in Australia. SCE has not experienced any power cable failures to date on any of the REFCL installations, but it remains a risk.

7.1.2.3 Surge Arresters

Surge arresters are one of the pieces of equipment most likely to require replacement when shifting to resonant or GFN grounding. However, many arresters are already rated for this system provided the periods of higher-than-normal voltage in fault events do not significantly exceed ten seconds.

7.1.2.3.1 Substation Surge Arresters

SCE standards require different arresters depending on how well a system source is grounded. One surge arrester is required for an effectively grounded system, another if the system is not effectively grounded. For example, a 60 kV Maximum Continuous Operating Voltage (MCOV) arrester is used if a 66 kV substation is effectively grounded and a 72kV MCOV arrester if it is not.

Table 5 SCE standard of arresters to use in substations

Nominal System Voltage (kV)	Grounded[a] (G) Ungrounded (UG) System	Apparatus BIL (kV)	Arrester Rating (kV)
12	G	110	12
12	UG	110	15
16	G	150	15
16	UG	150	21
33	G	200	30
33	UG	200	45
55	G or UG	350	60
66	G	350	60
66	UG	350	72
115	G	450	96

a. A system is effectively grounded when X_0/X_1, obtained from System Operation — Protection Division, is less than 3.0.

To get an idea of the scale of replacements which will be required, the arresters purchased in 2009-2019 for 66 kV were checked. About 85% of these arresters were the 72kV arresters rated for an ungrounded system. Therefore, it is expected that most arresters will not require replacement. However, all arresters should be inspected to ensure they are rated. Also, there remains a question as to whether 90kV arresters which can operate at the higher voltage continuously would be more appropriate.

7.1.2.3.2 Distribution Arresters

At 12 kV, 15kV class, 12.7 Maximum Continuous Operating Voltage (MCOV), arresters are installed per SCE standards. Provided the system is not left for hours in a faulted state, these arresters do not require replacement. Older arresters, particularly porcelain ones, are being replaced due to the higher risk and higher consequences of their failure.

At 16 kV 15.3 kV MCOV arresters are installed. These may be left in service provided the duration of the voltage displacement remains less than 10 seconds. However, it may make sense to replace these arresters so that longer clearing times can be tolerated.

Table 6: SCE standard which specifies which arresters to use in substations

Standard Distribution Arresters		
Circuit Voltage (kV)	**Nominal Arrester Rating (kV)**	**MCOV Arrester Rating (kV)**
2.4 & 4.16/2.4	3	2.6
4.8	6	5.1
7.2	9	7.7
12/6.9 & 12	15	12.7
16/9.5 & 16 & 24.9/14.4	18	15.3
33	36	29.0

7.1.2.4 Circuit Breakers

The line to ground voltage rating of circuit breakers per industry standards does not change based on the system grounding. A typical circuit breaker was tested to a voltage more than twice what it will see during a fault on a resonant or GFN grounded system. The ratings of the circuit breakers SCE has been purchasing are given in Table 3.

Table 7 Voltage ratings of circuit breakers SCE installs, based on C37.06, Table 15 (61)

Nominal Voltage (kV)	Voltage of Type Test kV, 60hz	Voltage of Commissioning Test kV. 60hz	BIL, kV
12	50 kV dry, 45 kV wet	50 kV dry, 45 kV wet	110
16	50 kV dry, 45 kV wet	50 kV dry, 45 kV wet	110
33	80 kV dry, 75 kV wet	80 kV dry, 75 kV wet	200
66	160 kV dry, 140 kV wet	160 kV dry, 140 kV wet	350
115	310 kV dry, 275 kV wet	310 kV dry, 275 kV wet	650

Circuit breakers on a resonant or GFN grounded system are required to interrupt current with a somewhat higher Transient Recovery Voltage (TRV). These circuit breakers are given a first pole to clear factor of 1.5 rather than 1.3. SCE has been purchasing circuit breakers with a 1.5 rating for decades, so few replacements of circuit breakers are expected.

7.1.2.5 Disconnect switches

Disconnect switches are rated for use on either a grounded or ungrounded system and have enough margin that none are expected to require replacement. The rating of disconnect switches SCE has been purchasing is based on C37.30.1 (62) and is given in Table 4.

Table 8 Voltage ratings of circuit breakers SCE installs

Nominal Voltage (kV)	Voltage of Type Test kV, 60hz	BIL, kV
12	45	110
16	45	110
33	80	200
66	140	350
115	275	650

7.1.2.6 Insulators

Insulators are typically rated substantially higher than other electrical equipment and are thus not anticipated to be a great concern when upgrading to resonant or GFN grounding. For example, 66 kV line insulators are tested to 208 kV wet and 248 kV dry. These values are nearly 50% higher than the test values for circuit breakers and more than three times the overvoltage they will see after an upgrade.

7.1.2.7 Capacitors

While many capacitor banks were required to be upgraded as a part of GFN installation in Australia, SCE capacitors are not anticipated to need serious upgrades to meet these overvoltages.

7.1.2.7.1 Substation Capacitors

From 12-66 kV capacitor banks are connected as ungrounded wye. These capacitor banks are insulated from ground with insulators rated for the line voltage. Therefore, no upgrades are required.

At 115 kV wye grounded banks are used. Also, the neutral rating is significantly below the line to ground voltage so the neutrals cannot be simply disconnected from ground. These capacitor banks require complete replacement to be able to withstand the overvoltages from a resonant or GFN system which would add significant cost to any projects at that voltage.

7.1.2.7.2 Distribution Capacitors

Distribution capacitors at 4 through 16 kV are delta or ungrounded wye. The phase-to-ground voltage rating is sufficient for use on a resonant or GFN grounded system.

7.1.3 Primary Connected Customers

The same equipment challenges which are described in clause 9.1 will be required for primary connected customers (63). Because of the multiple companies involved and huge variety of connected equipment this represents one of the largest challenges in implementing resonant and GFN grounding.

7.1.4 Other Equipment Requiring Upgrades

7.1.4.1 Voltage Regulators

Voltage regulators are rated for the overvoltages may require upgrades even where they are phase-to-phase connected and rated for the overvoltages. (64)

It is necessary that the charging current on the three phases be balanced. Voltage regulators can cause voltage imbalance if the three phases are being set to different voltages. This can occur either from open delta connections where only two regulators are used or from settings which allow independent operation of the three phases. Open delta voltage regulators therefore require upgrade to closed delta with all three phases controlled by a single controller.

7.1.5 Summary of Equipment Requiring Upgrades

Table 9 Summary of Equipment Requiring Upgrades

Equipment Type	4 kV	12 kV	16 kV	33 kV	55/66 kV	115 kV
Substation Transformers	Keep	Keep	Keep	Keep	Keep	Keep
Grounding Transformers	Keep	Keep	Keep	Keep	Replace	Replace
Distribution Overhead Transformers	Replace	Keep	Keep	Keep	NA	NA
Distribution Underground Phase-to-Phase Transformers	Keep	Keep	Keep	Keep	NA	NA
Distribution Underground Phase-to-Neutral Transformers	Replace	Replace	Replace	NA	NA	NA
Open Delta Voltage Regulators	NA	Upgrade	Upgrade	Upgrade	NA	NA
Circuit Breakers	Keep	Keep	Keep	Keep	Keep	Keep
Disconnect Switches	Keep	Keep	Keep	Keep	Keep	Keep
Voltage Transformers Phase to Phase	Keep	Keep	Keep	Keep	Keep	NA
Voltage Transformers Phase to Ground	Keep	Replace Some	Keep	Keep	Keep	Replace
Current Transformers	Replace Some	Replace Some	Replace Some	Replace Some	Replace Some	Replace Some
Metering Units	Keep	Keep	Keep	Keep	Keep	Replace
Line Arresters	Keep	Keep	Keep	Keep	Keep	Keep
Substation Arresters	Replace Some	Replace Some	Replace Some	Replace Some	Replace Some	Replace Some
Insulators	Keep	Keep	Keep	Keep	Keep	Keep
Capacitor Banks	Keep	Keep	Keep	Keep	Keep	Replace
Cable	Replace Some	Replace Some	Replace Some	Replace Some	Replace Some	Replace Some
Automatic Reclosers	Replace Some	Replace Some	Replace Some	NA	NA	NA
Primary Connected Customer Equipment	Replace Some	Replace Some	Replace Some	Replace Some	Replace Some	Replace Some

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