Reliable Protection Using a System Preservation Scheme

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Presented at the
47th Annual Western Protective Relay Conference
Virtual Format
October 20–22, 2020

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***Abstract*—Modern substation feeder systems use overcurrent-based protection, coordinated using time-overcurrent or definite-time overcurrent set points to ensure fast and reliable protection. The design of a standard coordination scheme ensures that the upstream backup protection is coordinated to handle system isolation if the primary protection fails. In islanded power systems, this coordinated tripping could easily result in a system blackout. With this danger, additional steps must be taken to section off the faulted area and preserve as much of the system as possible.**

The case discussed in this paper is a combination of three distinct buses, normally operating as one system, in extreme Northwest Alaska. During a fault, the priority is to ensure that there is no disruption of power to as much of the system as possible. However, the standard overcurrent coordination methods proved to be detrimental to the health of the whole system. Therefore, a special overcurrent protection scheme, called the system preservation scheme, was designed and implemented following nonstandard coordination methods. This paper discusses the development, design, and successful implementation of the system preservation scheme.

The system was modeled and tested using real-time digital simulation. During the factory acceptance test with a normal coordination scheme, the system kept going black for a close-in fault on any of the three buses. This was exactly what was meant to be avoided, as a blackout poses extreme safety risks by freezing up critical equipment and putting lives in danger. The proposed solution was to ignore coordination for the tie breakers and split the faulted bus from the rest of the system; the generators were located such that they could power their buses separately. This approach was tested to ensure that the rest of the system stayed online, allowing for rapid restoration of the faulted bus.

After the system preservation scheme was installed, an event occurred for an overload on the reactor connecting Buses 2 and 3. Bus 3 was islanded with too much load for its generation, and the expected loads tripped on underfrequency. Buses 1 and 2 stayed online, and Bus 3 was restored quickly.

The standard overcurrent coordination principles apply and work well in most situations. However, in a system like this where the cascading nature of the overcurrent scheme can be detrimental to life and critical equipment, it was considered necessary to deviate from standard principles. These intentional deviations from normal coordination practices work to make the system more resilient and keep as much of the power system intact as possible. This ensures that the system is easier to restore than it would be from a blackout condition.

This paper focuses on protection system design and testing, and the objective is to test the protective relay functionality.

I. Introduction

Red Dog Mine is a remote mine located in Northwest Alaska and is operated by Teck Alaska Inc. (TAK) and NANA Regional Corporation. Over a one-year period, the power system at the mine experienced three separate blackout incidents. During these incidents, the solid-state protection equipment provided minimal data—only targets with no time tagging—making it impossible to find a definitive root cause.

In addition to addressing these blackout concerns, TAK planned to extend the mine's operating life through better water processing and underground operations. These endeavors were of a magnitude that required more electric power than the mine had available. For these reasons, TAK decided to upgrade their protection and control systems for the next generation of operations.

The finished islanded system is a combination of three distinct buses, normally operating as one system, with no possible connection to any other system. The system voltage is 4,160 V, and the generators are directly connected at that same voltage.

Bus 1 is located within a standalone building with two generators, six feeders, one tie breaker, and one high-impedance ground current source that supplies 20 A primary ground current for a bolted single-line-to-ground (SLG) fault. Bus 1 also has one feeder with a remote contactor controlling a long cable to a remote camp load.

Buses 2 and 3 are both located in another building. There is a reactor separating these two buses. Bus 2 has one tie to Bus 1, one tie to the reactor that also ties to Bus 3, two generators, and two feeders. One feeder is bifurcated and has two variable-frequency drives (VFDs), which can each supply up to 1,900 kVAR to the system. The other feeder has one VFD, which can supply up to 1,250 kVAR to the system.

Bus 3 has one tie connected to the reactor that also ties to Bus 2, four generators, eight feeders, one station service fuse connection, and one high-impedance ground source that supplies 20 A primary ground current for a bolted SLG fault. One feeder has one VFD, which can supply up to 1,900 kVAR to the system. Two feeders have remote contactors controlling that remote load.

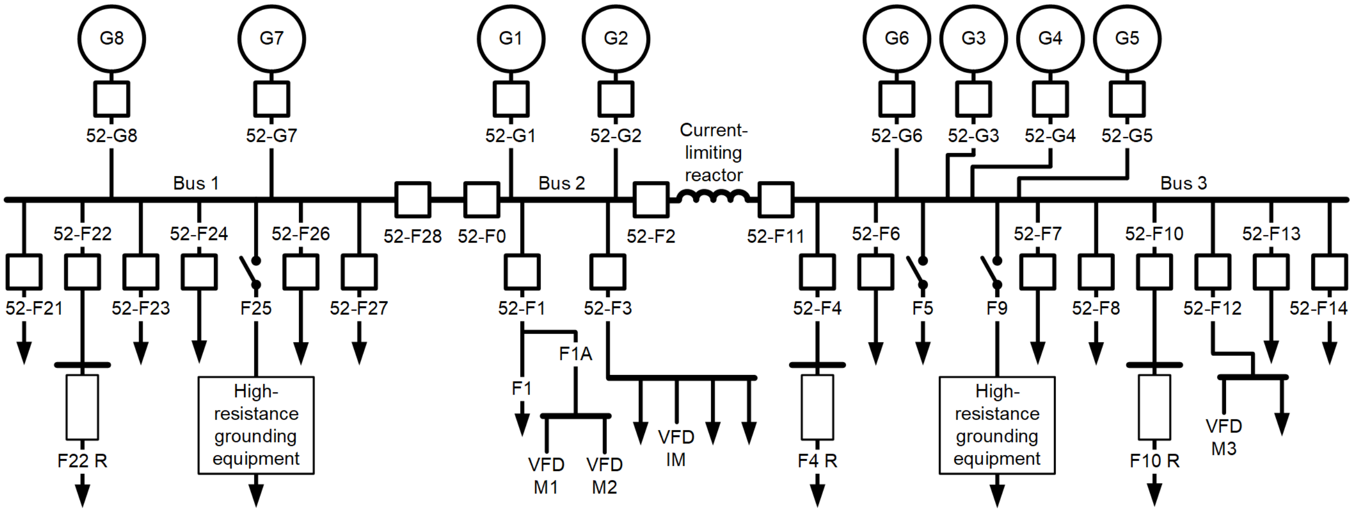

Fig. 1. Red Dog Mine load-shedding scheme

The system upgrades outfitted each of the ties, generators, feeders, remote feeders, and VFDs with microprocessor-based protective relays. These relays provide information back to a central supervisory control and data acquisition and human-machine interface (SCADA/HMI) system, which, in turn, provides operational visibility and control to the system operators. The data are also used by a new generator control system and load-shedding scheme, as shown in Fig. 1.

II. Coordination in Islanded Power Systems

The main goal of any protection system is to ensure the safety of personnel and equipment. The protection system must not encroach on the normal operation limits of the system and attempt to keep as much of the system energized as possible. Overreaching protection elements, such as distance and overcurrent protection, must be time- and pickup-coordinated to keep the isolation zone to a minimum [1]. To this end, the following four major criteria must be considered when setting these protection elements:

- Sensitivity
- Selectivity
- Speed of operation
- Security

Sensitivity refers to the ability of the protection element to detect faults. In a system with clearly defined zones of protection, the relay must be able to detect faults at the farthest ends of the system. Selectivity refers to the proper coordination of the system to detect and isolate faults within its protection zone on a selective basis. For example, in a radial system with a recloser and upstream relay, the upstream relay must wait for the recloser to clear the downstream fault. The upstream relay is time-coordinated with the recloser for this purpose.

Speed of operation refers to the clearing time of the relay for faults on the system. The critical fault clearing time (CFCT) must be considered when setting the operation time of the protection elements. A compromise may be needed between selectivity and speed of operation. Security refers to the ability of the system to maintain normal operation and allow transients when necessary. A protection system must be secure and not initiate isolation for normal operation or transient phenomena; this requirement means that security will conflict with sensitivity.

It is likely that the protection system for any given power system will not be perfectly sensitive, selective, fast, and secure. A unique compromise is needed to balance these traits, and that balance depends on the system under consideration. For grid-connected systems, speed of operation may not be critically important, allowing for greater flexibility with operation timing, which then directly allows greater selectivity. Additionally, fault current might be high enough to allow more flexibility in system sensitivity, which allows greater selectivity for more normal operation.

In islanded systems, the available fault current is restricted by the number and strength of sources available in the system. The CFCT is typically low, so speed of operation is the most critical trait. A fault that is not cleared quickly will result in the loss of the whole system. Therefore, selectivity is typically not of importance for islanded systems. Critical loads must be kept energized, which requires security as the second most important trait. It may be necessary to improve sensitivity by sectionalizing the system and adding protective devices with greater sensitivity and speed. However, this practice will cause selectivity issues.

III. Coordination in the Red Dog Mine

The Red Dog Mine is an islanded system that can have a maximum of seven generators in service at a time. The relays on the feeder mains were coordinated with the next downstream device, typically a fuse on the high side of a transformer. The pickup was chosen to allow maximum security to keep critical feeders supplied.

The initial coordination in the Red Dog Mine power system was performed using standard overcurrent coordination principles [1] [2] [3], including industry philosophies on overcurrent coordination in islanded systems [4]. The coordination was engineered to trip and isolate the faulted part of the system with the intention of keeping as much of the system online as possible.

Relay phase time-overcurrent pickup set points were calculated based on the full-load amperes and relevant equipment ratings of existing equipment. In most cases, the engineering team chose pickup set points at 125 percent of the feeder full-load amperes; this is a common practice with existing relay set points. Care was taken to ensure that the pickup conformed to the cable rating of the feeder or zone under protection.

The coordination time interval was calculated based on IEEE 242-2001 [3]. This standard is used to ensure that the relay operation allows enough time for the downstream device to operate. To ensure coordination, the time dial is adjusted when the timing is less than what the standard recommends.

Three feeders (F4, F10, and F22, in Fig. 1) have an additional downstream relay, and another three feeders (F1A, F3, and F12) have at least one VFD. All of these downstream relays are connected to a fused contactor, which provides overcurrent protection up to the rating of the contactor. Once this threshold is breached during an event, the relay blocks the TRIP/OPEN command and allows the fuse to clear the fault.

The relay phase and ground instantaneous overcurrent set points were calculated by configuring the system generators and grounding banks to provide the worst-case fault current at the bus in question. Three-phase and SLG faults were simulated at the remote bus. The phase instantaneous overcurrent pickup was set to 125 percent of the worst-case current, and the three-phase fault current and the ground instantaneous overcurrent were set to 50 percent of the maximum SLG fault current. The definite time on the ground instantaneous overcurrent elements was calculated to allow for a coordination time interval of 0.2 seconds between the local relay and the remote relay.

IV. Protection Scheme Testing Using an RTS

To test the system, the engineering team used a fully digital power system simulator capable of continuous real-time operations. This real-time simulator (RTS) performs electromagnetic power system transient simulations with a typical time-step of 50 µs using a combination of custom software and hardware. It supports a large number of digital and analog I/O as well as protection and control physical devices. These devices can be connected to the RTS and interact with the simulated power system for closed-loop testing [5].

The RTS power system model developed for the Red Dog Mine includes detailed generator, governor, automatic voltage regulator (AVR), VFD, and load models. The goal was to create a setup that tests and validates the load-shedding scheme, generator control system, and protection system design. The test setup, as shown in Fig. 2, includes governors, automatic voltage regulators, automation controllers, and protective relays interfaced with the RTS using hardware-in-the-loop (HIL) testing. The testing was carried out with one of each field device type HIL-interfaced with the RTS. Interfaced devices were carefully chosen to match the characteristics of the devices used in the field. This simulated testing mitigated the time and complexity that would render field testing impractical.

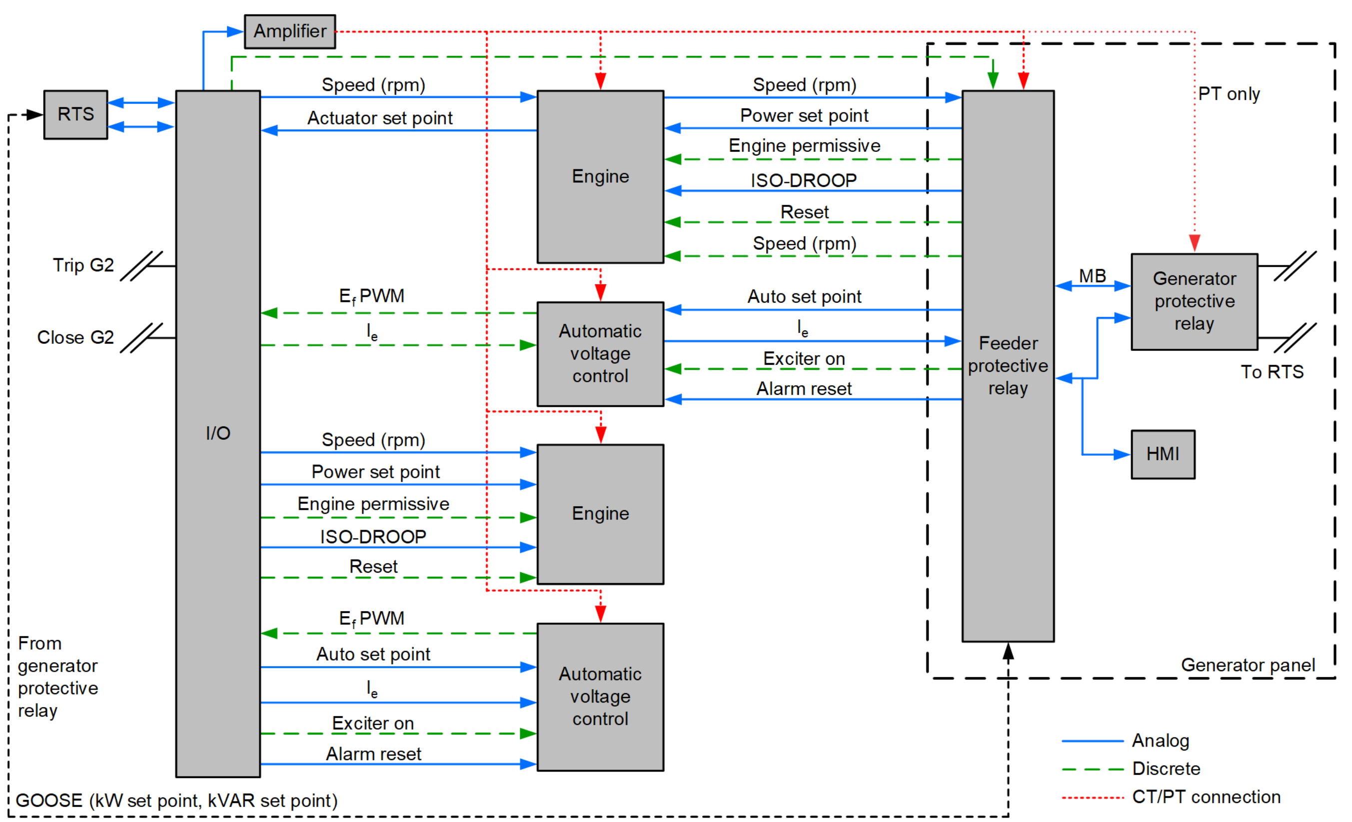

Fig. 2. RTS testing setup

V. Protection System Criteria

As discussed in Section II, the coordination goal in the Red Dog Mine system is to have as little of the system trip as is required to clear a fault. However, the CFCT also factors into the system design. The CFCT is defined as the maximum time taken to isolate the faulted part of the system before the system goes unstable and cannot be recovered, and it is always system-dependent. With very little empirical data available, the CFCT was not known for the Red Dog Mine power system.

With the initial coordination study completed for the Red Dog Mine power system, RTS modeling demonstrated how the system would operate with a generator control system and load-shedding scheme. The system was also tested for various faults at different fault locations.

The engineers tested many different scenarios and noticed a pattern: during any large fault relatively close to the bus and any bus fault, the system would go black. As expected, the CFCT was defined by the system. Further, large enough faults could not be conventionally cleared fast enough to prevent the whole system from collapsing.

For large-phase faults on any feeder, phase coordination is pointless—the system will go black, regardless of any mitigation measures. Since the system is high-impedance-grounded, ground faults were very small—around 40 A—and posed no setback to system stability. The ground instantaneous overcurrent coordination set points were considered valid for the system.

More phase fault simulations were run with varying feeder instantaneous set points. While the duration of the system's stability could be increased, eventually it would still go black. For example, when testing a three-phase fault on Bus 3 with a fault current of 45 kA, if the tie breaker did not open within 150 ms, then the generators on Buses 1 and 2 would become unstable. The engineering team noticed that Feeder F21, which had a large 1.65 MVA direct-on-line induction motor connected to it, dragged the system voltage down during a fault. The voltage on the bus could not recover from this voltage drain. This led to voltage collapse and the system going black.

One approach to correcting this issue was to trip Feeder F21 whenever any other feeder tripped. This helped prolong stability but did not solve the problem. Another idea was to trip the tie breakers when any feeder tripped. Again, this helped, but Bus 1 always collapsed for significant faults. No single solution could consistently keep much of the system intact.

The engineering team began successive tests of combining the following three most promising approaches:

- Lowering the instantaneous set points on the feeder relays and ignoring downstream coordination.
- Tripping Feeder F21 for any feeder instantaneous trip.
- Tripping the appropriate tie breakers to separate the fault from the rest of the system, as follows.
  - For a fault on Bus 1 or its feeders, trip Tie Breaker F28.
  - For a fault on Bus 2 or its feeders, trip Tie Breakers F0 and F2.
  - For a fault on Bus 3 or its feeders, trip Tie Breaker F11.

It took a combination of these approaches to keep the largest part of the system operating after the fault was cleared. The next step was determining the appropriate set points.

From the RTS simulations, any close-in fault resulted in a voltage collapse and the system going black at around 10 cycles. With Feeder F21 tripping and the appropriate tie breaker to isolate the fault, setting the feeder instantaneous tripping to 24,000 A kept the unfaulted buses working while the faulted feeder was cleared.

Extensive discussions about the appropriate instantaneous overcurrent level followed. While the RTS testing provided reasonable stability results, the solution could not be proved without data from the real-world system. Staged fault tests were not an option due to their difficulty and risk of damage, and accurate data would be difficult to gather in a timely manner. The exact location or magnitude of a close-in fault on the system cannot be known. Choosing a value close to the stability limit for one set of conditions might be too much for another set of conditions, resulting in a blackout. Considering the system tradeoffs, it was decided to choose 20,000 A as the instantaneous set point.

With the network in place as part of the HMI, generator control system, and load-shedding scheme operations, the engineering team decided to use Generic Object-Oriented Substation Event (GOOSE) messaging to direct trips as appropriate [6]. This decision meant direct tripping Feeder F21 and the appropriate tie or ties whenever feeder protection operated instantaneously. Table I describes the appropriate tripping for feeder faults. Time delays for GOOSE direct trips were included in the simulations, and all devices except the faulted feeder and its bus remained energized and operational.

Table I
Tripping Required for Instantaneous Elements

Instantaneous Faulted Feeders	F21 Trip	Tie Trip	De-Energized Bus	Energized Buses
F21, F22, F23, F24, F26, F27	Yes	F28	1	2 and 3
F1, F3	Yes	F0 and F2	2	1 and 3
F4, F6, F7, F8, F10, F12, F13, F14	Yes	F11	3	2 and 3

In the cases where an islanded bus did not have enough generation to carry its load, the load-shedding scheme would operate and shed the appropriate load as programmed, keeping the bus energized. When this process started, the control system would simultaneously balance each side of a tie for voltage and frequency and reconnect the isolated buses.

The bus preservation scheme is set up so that if any feeder detects a fault current over 6,000 A, it sends trips to its respective ties to isolate the bus. Once the ties receive this trip, or the feeder itself detects fault levels above a predetermined worst-case fault level, they isolate and clear Feeder F21. This approach requires the tie protection to isolate the buses for any possible feeder bus fault. The challenge, then, is that the Red Dog Mine power system typically runs six generators at a time, and at least five of those generators run for significantly long stretches of time. Any combination of active generators is possible, though which combination is active at a given time cannot be known.

A fault study was conducted to determine the appropriate set point at which the tie protection preservation could ensure the tie breakers tripped and isolated the fault appropriately. For this, the system was run at the worst-case operability, with five active generators and three-phase faults simulated at the end of each feeder in the system. The lowest observed fault contribution through the tie breakers was approximately 6,180 A.

From this fault study, a value of 6,000 A was chosen for tie tripping. This amount could result in more isolation than is actually required, but the system responded better to more islands than it did attempting to retain stability during large faults. With the generator control scheme and load-shedding scheme in place, it was much easier to restore the system and lost load with a generator running than starting from a blackout.

VI. RTS Test Case

The system preservation scheme's logic is validated by simulating multiple scenarios using the RTS simulator. As discussed in Section V, tripping Feeder F21 along with the associated bus ties isolates the faulted bus and prevents a system blackout. Fig. 3 and Fig. 4 show two cases, one with Feeder F21 not tripped (Case 1) and another with Feeder F21 tripped (Case 2), wherein both scenarios are simulated by applying a three-phase fault on Bus 3 for 10 cycles. In Case 1, the voltage collapses and the system blacks out, even though Buses 1 and 2 are isolated from Bus 3. In Case 2, however, the system voltage recovers, as shown in Fig. 4.

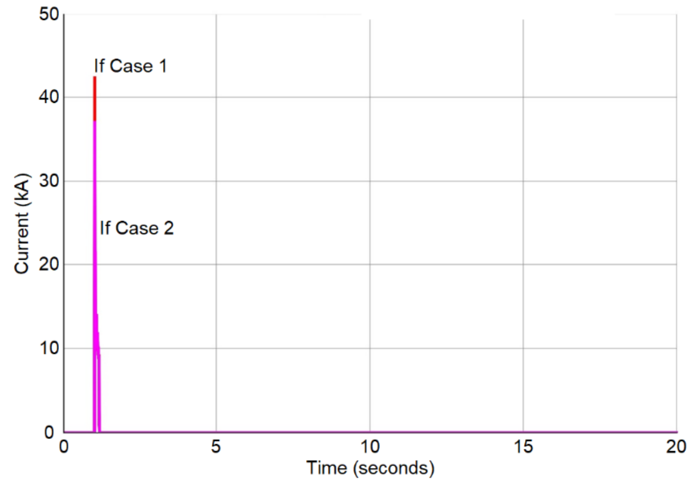

Fig. 3. Fault current profile

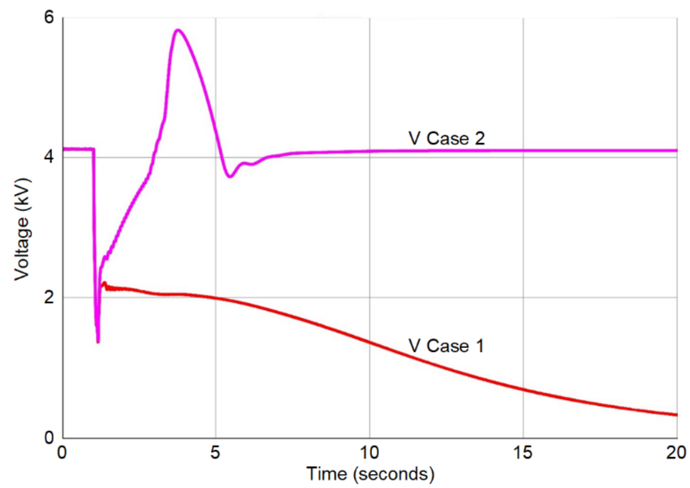

Fig. 4. System voltage profile

Feeder F21 feeds large direct-on-line induction motors that drag the system voltage even after the fault is cleared in Case 1. The islanded generators at Buses 1 and 2 cannot support the system voltage, and eventually, the system goes dark due to the voltage collapse. In Case 2, the scheme correctly trips Tie Breakers F2 and F11 and isolates the faulted bus from the rest of the system. An initial unbalance is observed due to VFD interactions on Buses 2 and 1. However, the voltage on Bus 2 recovers after an initial unbalance and stays steady, keeping the islanded system voltage healthy.

VII. Conclusion

The Red Dog Mine's system topology shows that it is possible to run the system as three separate islands, depending on the generators online at any given time. The RTS test case shows that with appropriate load balancing, it is possible to run the system sectionalized. After the system preservation scheme was installed, an event occurred for an overload on the reactor connecting Buses 2 and 3. Bus 3 was islanded with too much load for its generation, and the expected loads tripped on underfrequency. Buses 1 and 2 stayed online, and Bus 3 was quickly restored.

Typical coordination studies prioritizing selectivity and sensitivity are not of use in islanded systems if critical clearing times are not considered or met. A well-coordinated system does not equate a stable power system. A coordination study is just one piece of the puzzle in setting up a protection scheme that is both reliable and secure. For islanded systems, selectivity will need to be sacrificed to make sure that there is a stable, operational system following the clearance of the disturbance. The standard overcurrent coordination principles apply and work well in most situations. However, in a system like this, where the cascading nature of the overcurrent scheme can be detrimental to life and critical equipment, it was considered necessary to deviate from standard principles. These intentional deviations from normal coordination practices work to make the system more resilient and keep as much of the power system intact as possible. This ensures that the system is easier to restore than it would be from a blackout condition.

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IX. Biographies

Mehul Joshi received his Diploma in Electrical Engineering in 1988, his BS degree from Gujarat University, India, in 1995, and his MS degree in electrical power systems from the University of Detroit Mercy in 2004. Mehul worked for Gujarat Electricity Board in Gujarat, India, as a junior engineer for 13 years before joining Fording River Operations, an operation of Teck Resources Ltd, in 2006. He is currently a senior electrical engineer at Red Dog Mine, an operation of Teck Alaska Inc. Mehul has experience in ac/dc drives, generator protection and excitation, power system protection design and commissioning, short-circuit and coordination studies, arc-flash studies, and electric shovels, drills, and haul trucks. He is a P.Eng. certified by APEGBC.

Scott L. Barndt received his BS degree in electrical engineering from Rose-Hulman Institute of Technology in 1990 and his MS degree in electrical engineering from the University of Colorado Boulder in 1991. Scott worked for Western Area Power Administration for 8 years at various locations before joining Bonneville Power Administration in 1999, where he worked for 16 years. He is currently a project engineer in protection in SEL Engineering Services, Inc. Scott has a wide variety of experience in protection, ranging from single-pole protection on 500 kV systems to 480 V protection on motors. His experience includes power system protection design and commissioning, short-circuit and coordination studies, arc-flash studies, and remedial action schemes. He is registered as a PE in Washington, Wyoming, Montana, Oregon, Idaho, Alaska, and the US Virgin Islands.

Alaap Anujan received his BS degree from Cochin University of Science and Technology, India, in 2010 and his MS degree in electrical power systems from the University of Idaho in 2015. Alaap worked as a project engineer for 3 years in the Hotels division of ITC, Ltd, in India before joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2015. He is currently a project engineer in SEL Engineering Services, Inc. Alaap has experience in power system protection design and commissioning, short-circuit and coordination studies, arc-flash studies, and power system modeling and testing using control and power hardware-in-the-loop testing with a real-time digital simulator. He has been an executive member of IEEE Region 6, Palouse Section, since 2015 and is actively involved in various IEEE initiatives in the region.

Ceeman B. Vellaithurai received the BE degree in electrical and electronics engineering from Anna University Tiruchirappalli, India, in 2011 and his MS degree in electrical engineering with specialization in power systems from Washington State University in 2013. Ceeman received the Best Outgoing Student Award from Anna University Tiruchirappalli for his academic achievements. He is currently working with Schweitzer Engineering Laboratories Inc. as a protection engineer. His research interests include real-time simulation of cyber power systems and protection systems.

Mahipathi R. Appannagari, PE, received his MS in electrical power systems from the University of Idaho in 2012. He is presently working as a project engineer at Schweitzer Engineering Laboratories, Inc. His areas of expertise include power management system design and studies, power system modeling for dynamic and protection studies, microgrid and renewable applications, power electronics, and power system drive modeling. Mahipathi is a registered PE in California.

Brandon Nafsinger received his BS degree in electrical engineering from the University of Idaho in 2017. Brandon started as an intern in SEL Engineering Services, Inc. (SEL ES) at the completion of his sophomore year in the summer of 2015. He is currently a project engineer in protection in SEL ES. Brandon has experience in power system protection design and commissioning, short-circuit and coordination studies, logic design, and relay settings.

20200902 • TP6984-01