# Designing Arc-Flash Mitigation of Medium-Voltage Substation Switchgear: Lessons Learned

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***Abstract* — Technology to detect arc-flash events in switchgear has been available for several years. Many questions arise during the design, installation, and commissioning of the arc-flash detection system. One of the primary questions is which scheme will provide the best arc-flash mitigation for a particular switchgear lineup. A novel approach of light sensors with overcurrent supervision was used to provide high-sensitivity to arc-flash light, built-in sensor spares for high system availability, and minimized the required changes and associated costs.**

**The use of microprocessor based relays provides additional functionality and monitoring that had not previously existed with electromechanical relays. This paper discusses the design, installation, and commissioning of an arc-flash detection system on Avista's Third & Hatch (3HT) 115/13kV substation. An example of the additional functionality is the improved tie-breaker failure protection. Examples of the monitoring improvements include SCADA communications and arc-flash sensor monitoring alarms. Avista's 3HT substation is a unique switchgear configuration consisting of three separate switchgear units with two tie breakers that caused several challenges during the design and installation. The paper also addresses lessons learned and provides suggestions for other utilities considering a similar design.**

## I. Background & Introduction

There have been many past papers detailing the hazards and possible methods to mitigate worker's exposure to arc flash hazards but most of these papers have been by vendors. Those papers have not addressed the challenges and questions that arise during the design, commissioning, and installation of an arc-flash mitigation system. This paper describes Avista's design, commissioning, and installation experiences so that other utilities might benefit from the knowledge gained and lessons learned.

The 115/13kV Third & Hatch (3HT) substation was targeted for relay upgrades as part of the Smart Grid Investment Grant (SGIG). Third & Hatch consists of three (3) transformers and switchgear lineups as shown in Figure 1. The three switchgear lineups are connected by tie breakers in only two of the switchgear units. Each transformer has a 115kV circuit switcher and a 13kV main bus breaker and three feeder breaker positions. All of the existing relaying was electromechanical with the exception of transformer # 3 which had older microprocessor relaying. This unique configuration presented several challenges for the design and installation of the arc flash mitigation scheme.

An earlier analysis of the arc flash hazards on the Avista system had identified 3HT as having an arc-flash exposure as high as 116 cal/cm$^2$. Since the feeder relaying was being upgraded, Avista took this opportunity to address the arc-flash hazards since 3HT still had remaining useful life and was not scheduled for a rebuild. One of the specific concerns was the elevated arc-flash exposure levels for someone operating the bus breakers from within the switch house.

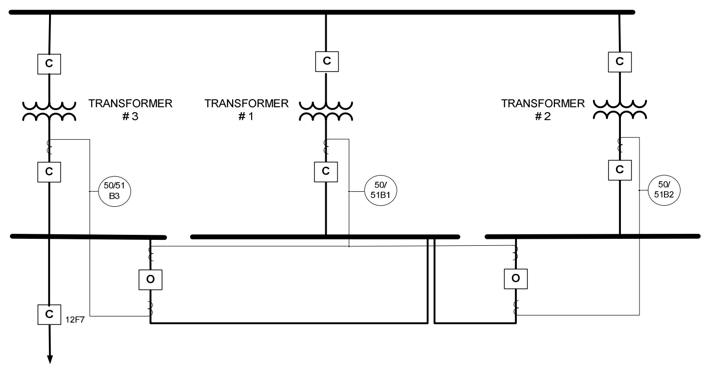


Fig. 1. Simplified Oneline

A Standard Operating Procedure (SOP) had been put into place for racking the metal-clad 13kV main circuit breakers. The SOP required de-energizing the transformer by opening the 115kV circuit switcher. The bus could still be energized through a bus tie to serve the customer load. Even with the SOP, the arc flash hazards were still in excess of 40 cal/cm$^2$. The NFPA 70E®: *Standard for Electrical Safety in the Workplace®* classifies levels above 40 cal/cm$^2$ as "dangerous."

Several protection scheme changes were made possible by using microprocessor relays. The Third & Hatch protection prior to this project was electromechanical relaying with the exception of transformer # 3 which had older microprocessor relaying. The transformer # 3 protection utilized a fast-trip blocking (FTB) scheme. The fast trip blocking scheme presented a "blocking" signal to the bus and transformer relays for faults that were on the feeders. This required delaying the bus and transformer protection using a timing relay. Since transformer #1 and #2 were electromechanical relaying the FTB scheme was not used on these switchgear lineups. We were able to maintain the FTB scheme and improve the functionality with the use of microprocessor relays. We also were able to improve the scheme for operations when the tie-breakers were closed.

## II. Challenges

One problem quickly identified with the existing scheme was not all of the relays knew the status of the 13kV main breakers and the tie breakers. When the scheme had originally been installed with electromechanical relays, this was expensive and unnecessary. However, with the installation of the microprocessor relays, this now could be accomplished inexpensively and allowed for scheme improvements.

Another issue identified for improvement was the FTB scheme itself. For instances when a 13kV main breaker was open and a tie breaker was closed, there was a possible misoperation for close-in feeder faults. Consider the case, referring to Figure 2, of transformer # 3 being out-of-service for maintenance.

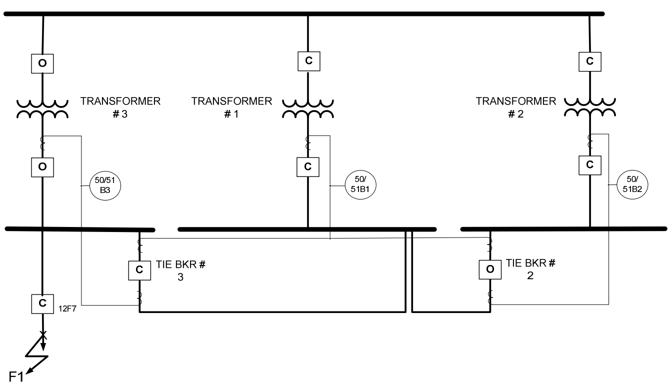


Fig. 2. Simple Oneline with Transformer # 3 Out-of-Service

For the F1 fault, the 12F7 protective relays would need to send a fast transfer block signal to the 50/51B3 relay and to the 50/51B1 relay. The FTB scheme uses a 4-cycle delay to allow the ‘block’ signal to be transmitted and received. The 50/51B1 relay protective elements would not pickup for the fault since the currents would cancel in the differential relay 50/51B1. However, the transformer # 1 protective relaying could operate for the fault if it was not blocked by the FTB scheme. This would result in a “race condition” between the transformer overcurrent and the feeder overcurrent relaying unless a FTB signal is received from 50/51B3. The transformer # 1 tripping would clear the fault, but would not meet the desired selectivity requirements. This was a major concern since the 3HT substation has critical large loads. Avista wished to maintain the FTB scheme philosophy and the availability of relay-to-relay communications provided an inexpensive method to supply the FTB signal for this configuration.

Also, consider the case where the fault F1 is actually in the 12F7 breaker compartment due to a racking-in of a closed breaker. Most switchgear provides mechanical measures to prevent racking-in closed breakers but several known arc-flash events have been caused by this situation. If the fault is in the 12F7 breaker, then the 50/51B3 relay needs to ignore the FTB signal and trip the bus lockout 86B3, Bus 3 main 13kV breakers, and the Tie Breaker # 3 to clear the fault. This led us to ask several questions:

1. Why would we want to wait 4-cycles if this was an arc-flash event?
2. How would 50/51B3 know to ignore the FTB signal?

A decision was made to upgrade the transformer protection to microprocessor relays as well to gain the many benefits such as relay-to-relay communications, event reporting, and self-monitoring.

## III. Design Considerations

Like most substations, installation of the scheme was complicated by system operational requirements. Table 1 shows a comparison of the methods that we considered.

TABLE I
BUS DIFFERENTIAL OPTIONS

| Scheme Description | Advantages | Disadvantages |
|---|---|---|
| High-impedance bus differential | Fast and secure for all fault types, easy to set | Requires additional relay, dedicated CTs, Expense to purchase CTs, testing more complex |
| Low-impedance bus differential | Fast and secure for all fault types | Requires additional relays, Expenses to wire CTs, testing/setting more complex |
| Fast bus trip | Use of new main and feeder overcurrent relays. Faster than TOC, secure, communications channel monitors integrity of scheme, relatively low cost to install fiber and transceivers | Settings more complex, CTs on bus side of breaker would result in delayed tripping for faults in the feeder breaker |
| Arc-flash relay | Independent of existing protection scheme | New technology concerns |

We recognized that there were several traditional bus differential methods that might work but also faced challenges in a switchgear design. For instance, high-/low-impedance bus differential schemes would require additional CT’s which could be difficult to fit into the existing switchgear. The FTB scheme also had issues in that if the arc-flash was on the load side of the feeder breaker, a ‘block’ would be sent to the block the bus protection from tripping the 13kV main breaker quickly. We were concerned with the possible racking in of a closed breaker that could result in an arc-flash event and the ‘block’ being sent and delaying clearing of the fault. This would jeopardize the personnel even further. Even though the arc-flash would be in a different compartment, the shutter doors would be open exposing the personnel to the arc-flash and possible harm from the breaker being pushed into them.

After researching the methods, we chose a combined light and overcurrent detection method available in an arc-flash relay. This method has been successfully implemented by other utilities and it allowed for only minor changes to the existing protection scheme. This method is published as having a response time of 1-7 ms [1]. Our analysis showed that this operating time was sufficient to reduce the arc-flash hazards to within acceptable levels of less than 40 cal/cm$^2$. It also provided improved protection for the racking in of a closed breaker discussed above and the standard 50/51B functionality.

Since the light and overcurrent method only required minor changes to the existing scheme, we believe it also saved cost and time in the design, installation, and commissioning.

The use of microprocessor relays also allowed for relay-to-relay communications as shown in Figure 3.

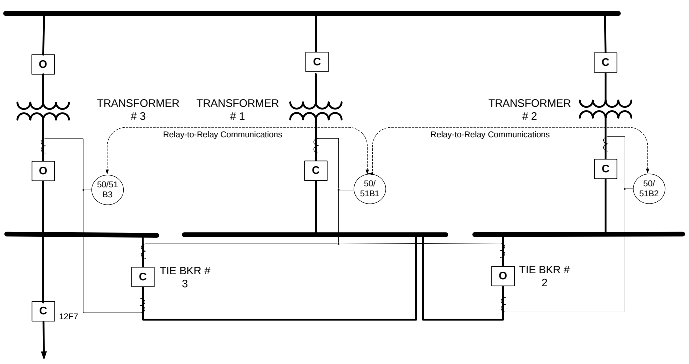


Fig. 3. Simple Oneline with Relay-to-Relay Communications

The relay-to-relay communications provided several protection scheme improvements. The use of communications allowed for breaker status to be shared with the Bus 1 protective relay for use by the arc-flash mitigation logic, the breaker failure logic, and the slow close/trip logic. The relay-to-relay communications also allowed for the FTB signal to be transmitted to the other buses when a tie breaker was closed without the need of 43T switches. We used a communications enable/disable input into the microprocessor relays to facilitate testing. We also provided an arc-flash detection communications alarm and relay indication to warn operators if the scheme was not fully functional.

With the abnormal system configuration in Figure 2, if a fault were to occur on Bus 3, then the 50/51B3 relay would try to trip the tie breaker. Assuming that the tie breaker fails to trip, then the 50/51B3 relay would then trip the feeder breakers on the Bus 3 and send a BFT (breaker-failure trip) signal to the 50/51B1 relay via the communications channel. As previously mentioned, the 50/51B1 relay would normally not trip for this fault since the fault is external from the zone of protection. When the BFT signal is received in the 50/51B1 relay, the relay then trips the 86B1 relay to trip the Bus 1 13kV main breaker and the feeder breakers. Avista made the decision to trip the feeder breakers since our system is beginning to have a lot of distributed generation and possible back-feed sources due to the SGIG.

Figure 4 shows a partial of the zones of arc-flash protection for the 3HT substation.

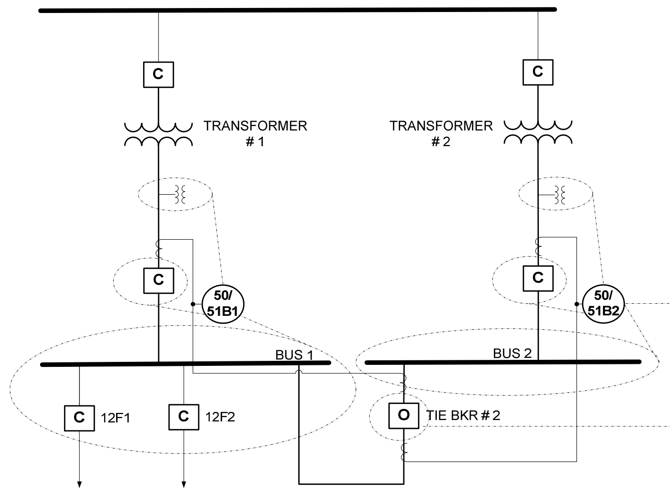


Fig. 4. Partial Oneline with Arc-Flash Detection Zones

The relay-to-relay communications were also necessary to facilitate the arc-flash detection scheme. For a fault on Bus 1 in Figure 4, the remote tie breaker is tripped via both hardwiring and by the relay – to – relay communications. The relay uses high-speed (50 µs), trip-duty output contacts to trip the tie breaker to clear the fault as fast as possible. Similar logic was used for the arc-flash detection scheme of the tie-breaker itself. The difference between the two zones was the tripping of the bus lockout relays.

The microprocessor relay chosen provides high-speed output contacts that operate in under 50µs, providing fast tripping of circuit breakers. In contrast, conventional electromechanical output contacts can take as long as 8 ms to operate. This was important in the other schemes from Table 1 since it was not available and would add time to the arc-flash clearing time.

## IV. Installation

The arc-flash microprocessor relay allowed for the use of either four point sensors or loop sensors to detect the light from an arc-flash event as shown in Figure 5.

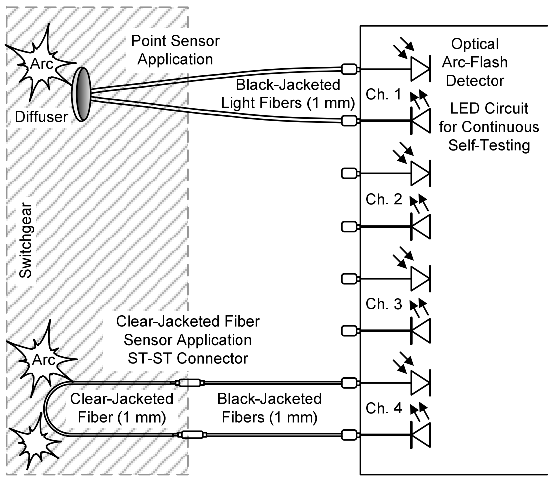


Fig. 5. Microprocessor Relay Arc-Flash Detection System

Our design used only the loop sensors which are made of 1 mm plastic fiber-optic cables that are routed in the switchgear. The black-jacketed fibers were used to route the fiber to the ‘zone of protection’ and then the clear-jacketed fiber was used. This prevented the possibility of a misoperation by the light entering the clear-jacketed fiber in the wrong switchgear compartments.

The clear-jacketed fiber was routed into the switchgear breaker compartments from the 13kV bus compartment for the zone that covers the feeder breakers. When we began to route the fiber, our crews asked several questions:

1. What happens if the fiber comes into contact with the 13kV bus?
2. How far away can the fiber be from the arc-flash and detect a sufficient amount of light?
3. What are the bending radius requirements of the fiber loop sensors?
4. What would happen if someone took a picture (camera flash)?
5. Will the opening and closing of the breaker for normal operations pick-up the light sensing element in the relay?

The all-plastic, fiber-optic sensors are inherently nonconductive, but are not intended for direct contact with energized bus. Accordingly, we installed the fiber sensors on the sheet metal walls of the switchgear, attaching them with nonconductive plastic fasteners.

[2] recommends that “Loop sensors should be installed within 2 m of the anticipated arc-flash light source, with a minimum of 0.5 m of bare fiber exposed, allowing a maximum loop length of 70 m, including the bare and jacketed fiber sections.” Our crews found that the 1 mm plastic fiber-optic cables were easy to route and it was easy to meet the manufacturer’s recommendations.

If a camera flash was to occur, the relay would not operate since the microprocessor relay uses a combined light and overcurrent detection method and is recommended to be set above load current. Similarly for an overcurrent condition without the light-flash event, the relay will not operate.

We reviewed the sequence-of-event reports for several months after the scheme was installed to observe the operation. We were able to determine that we never received the light measurements above the detection level for normal breaker opening/closing. The 3HT 13kV breakers are vacuum breakers so we believe this is to be expected.

The relay allows for an arc-flash sensor diagnostic to be performed to ensure integrity of the clear-jacketed fiber. Figure 6 shows the results of the diagnostic test after the installation of the bare-light fiber loops.

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=>>AFT
Arc Flash Diagnostic in progress . . . . .

50/51B2/20120103                        Date: 02/02/2012   Time: 07:36:48.549
3HT/R-10651                             Time Source: Internal

Channel #    Sensor  Test Light Limits  Measured       Sensor      Excess Ambient
             Type     Min(%)   Max(%)   Test Light(%)  Diagnostic  Light

AF Input 1   Fiber    10.00    100.00   100.00         Pass        OK
AF Input 2   Fiber    10.00    100.00   100.00         Pass        OK
AF Input 3   Fiber    10.00    100.00   100.00         Pass        OK
AF Input 4   Fiber    10.00    100.00   100.00         Pass        OK
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Fig. 6. Relay Diagnostics of Bare-Light Fiber Loops for Bus 2

We were surprised to discover that the clear-jacketed fiber is very forgiving in the installation and that if installed per the manufacturer’s recommendations there is little to no light loss.

We were fortunate to have the relay manufacturer’s on-site support during our installation. One recommendation that we had not considered was to install a spare for each of the loops in Figure 4. This will allow us to replace any damaged loops without having to take an outage on the switchgear.

## V. Commissioning

When we began to route the fiber, several questions were asked:

1. How do we test the arc-flash fiber/sensors?
2. What would the appropriate light-sensing settings be?

We tested the arc flash detection system by using a test set that incorporated an arc-flash simulator. The simulator generates “an arc” by a high intensity, surface mounted LED that is connected to the test set. The test set is used to inject current into the relay and this allows for accurate timing of the relay operation. We found that the best light measurements were achieved when the sensor was placed approximately 3-6” with a reflector from the clear-jacketed fiber.

We used the relay’s metering command to obtain the light metering data for the installed clear-jacketed fiber loops. This is necessary so that the arc-flash detection settings are above the ambient light levels. We tested the system with a 13kV breaker removed, two cubicle doors open, and a flood-light directed into one cubicle to represent normal maintenance conditions. These conditions produced only 0.4% light intensity so we set the relay at 1% light intensity.

## VI. Conclusions

An arc-flash detection relay provides a significant reduction to the hazards presented to personnel. For instance at 3HT, we were able to reduce the exposure from 116 cal/cm$^2$ to 13 cal/cm$^2$ representing a significant improvement in safety both to personnel and equipment.

The authors hoped to share our experience with other utilities considering an installation of an arc-flash detection scheme.

Below are recommendations, thoughts, and lessons learned from the design, installation, and commissioning of Avista's 3HT substation:

- Careful analysis of the switchgear arrangement and current transformer locations is critical in the choice of the arc-flash mitigation scheme selected.

- Install an additional fiber loop in each case. This will allow for replacing a damaged bare-fiber loop or point sensor without needing to take an additional outage. Since some loops include the bus, this is important since getting the outage scheduled can be difficult to impossible.

- The installation never goes exactly as planned, expect changes when you actually have access to the switchgear. Even though you will have drawings of the switchgear, it is best to plan out the installation as you get access to the switchgear. We were able to use gaps and other switchgear features that we had not planned on using that allowed for a faster installation and less splices in the fiber loops.

- Bench testing should be performed to become acquainted with the relay and logic prior to installing in the switchgear to reduce outage duration.

- Detailed logic diagrams are essential since this is an unfamiliar (and often new) design. The logic diagrams were invaluable as we commissioned the system for both the relay technician to understand and for Operations to later use.

- Ensure that the fiber is not covered when the breaker shutters are open.

## VII. References

[1] W. Knapek and M. Zeller, "Verifying Performance and Safety of Arc-Flash Detection Systems," in 2011 38th Annual Western Protective Relay Conference Proceedings.

[2] B. Hughes, V. Skendzic, D. Das, and J. Carver, "High-Current Qualification Testing of an Arc-Flash Detection System," in 2011 38th Annual Western Protective Relay Conference Proceedings.

## I. Biographies

**Kevin Damron** received his BS in electrical engineering from the University of Kentucky in 2001 and a 'Power Systems Protection and Relaying' certificate from the University of Idaho in 2009. Kevin has broad experience in the field of power system operations, maintenance, and protection. Upon graduating, he joined Schweitzer Engineering Laboratories, Inc. as a power engineer in the research and development division. Prior to joining Avista Utilities in 2010, he was employed by Eta Engineering Consultants, PSC providing engineering and consulting services. Kevin is a registered professional engineer in Washington State and is a member of IEEE.

**Bob Hughes** received his B.S. in electrical engineering from Montana State University in 1985. He is a senior marketing engineer in the protection systems department at Schweitzer Engineering Laboratories, Inc. Bob has over 20 years experience in electric power system automation, including SCADA/EMS, distribution automation, power plant controls, and automated meter reading. He is a registered professional engineer in Washington State and a member of IEEE.