Distribution Digital Substation—Consolidated Protection and Digital Secondary Systems

Jason Byerly and Manish Thakur
American Electric Power

John Hostetler, Chris Burger, and Scott Wenke
Schweitzer Engineering Laboratories, Inc.

Presented at the
50th Annual Western Protective Relay Conference
Spokane, Washington
October 10–12, 2023

Distribution Digital Substation—Consolidated Protection and Digital Secondary Systems

Jason Byerly and Manish Thakur, *American Electric Power*
John Hostetler, Chris Burger, and Scott Wenke, *Schweitzer Engineering Laboratories, Inc.*

***Abstract*—A common strategy for substation protection has been to use an onsite control house containing a collection of relay panels. These panels often contain multifunctional relays or a wide combination of electromechanical relays aimed at protecting a single zone of the station (transformer, buswork, feeder, etc.). Incoming measurement signals, such as current transformers, potential transformers, or contact statuses, need to be wired from the yard back into the control house, whereas accompanying trip, close, and control outputs need to run the opposite direction. As the grid continues to expand, higher reliability is demanded, and the costs associated with owning and maintaining the electric infrastructure increase. In response to this challenge, alternative methods of substation design should be considered.**

Today, advancements in relaying capabilities offer several alternatives such as the centralization of protection and control and the digitization of secondary systems.

In this paper, we provide an overview of these technologies including expected benefits and challenges. Then we describe an upcoming pilot project being deployed by American Electric Power and share real-world data associated with this project, touching on key topics such as cost, usability, reliability, and safety.

I. Introduction

Protective relays were invented well over a century ago and relied on electromagnetic and mechanical principles to monitor analog signals and operate mechanical outputs when corrective actions were needed. Each of these devices was typically designed with a single function in mind, often requiring a multitude of devices with unique wiring and dedicated instrument transformers to meet the desired protection and control requirements. In addition, all communications took the form of mechanical contacts changing state. In these electromechanical protection systems, many individual single-function relays encompassed an entire panel and worked together to provide protection for a single protection zone. Redundancy for this protection zone required a second relay panel with similar electromechanical relays.

In the 1980s, when protective relaying started shifting to microprocessor-based technology, utilities were able to increase functionality through digitization. These devices could collect multiple analog signals, reducing the burden on instrument transformers to allow for shared wiring, and use onboard mathematical processing to combine signals and perform many different functions at once. Other benefits included advanced protective functions, self-diagnostics, data recording during system events, advanced communications for peer-to-peer or SCADA communications, and the use of flexible logic to replace physical wiring when performing AND/OR-type operations in dc control circuitry. In addition, redundant microprocessor relays are commonly contained in a single relay panel, reducing the panel requirements by half as compared to the earlier electromechanical relays. These changes have led to innovation in utility protection and control practices that improve efficiency and open new opportunities.

American Electric Power (AEP) owns and operates electrical transmission and distribution infrastructure across 11 states. Within this footprint, AEP owns 1,350 transmission substations with more than 40,000 miles of transmission line infrastructure. At the distribution level, it owns 1,800 substations and approximately 225,000 miles of distribution line coverage.

In 2003, North America experienced its worst blackout to date and, as a result, the creation of what is now known as the North American Electric Reliability Corporation (NERC) to oversee and mandate reliability and security standards for the bulk power grid. NERC mandates for electrical utilities are wide ranging, directly impacting how microprocessor relay systems are installed and maintained, with mandates such as Protection and Control and Critical Infrastructure Protection standards.

The overlap of NERC mandates with a relay inventory of more than 41,000 microprocessor relays is compelling AEP to look for strategies that both simplify and reduce relay systems. The strategy they are taking is twofold: 1) implement a digital secondary system (DSS) with simple merging unit distribution using fiber-optic communications to the microprocessor relays, and 2) consolidate relays into a centralized protection and control (CPC) device capable of providing complete protection for the distribution substation.

The following sections explain the standards and practices currently deployed by AEP, an introduction to DSS technologies, and an introduction to the concept of CPC. We then explore how these three concepts can be used to create a new design standard for AEP, identify the pertinent measures for the project to evaluate success, and discuss the preliminary results of the project.

II. AEP Standards Today

AEP's standards for a distribution substation typically consist of tapping a 69 to 138 kV transmission line with a two-winding, delta-wye-grounded transformer. This distribution step-down transformer will typically service three feeder circuits at the 12 kV level. The one-line diagram shown in Fig. 1 is an example of a typical distribution substation at AEP.

This design includes six microprocessor relays that provide protection and control for the substation assets.

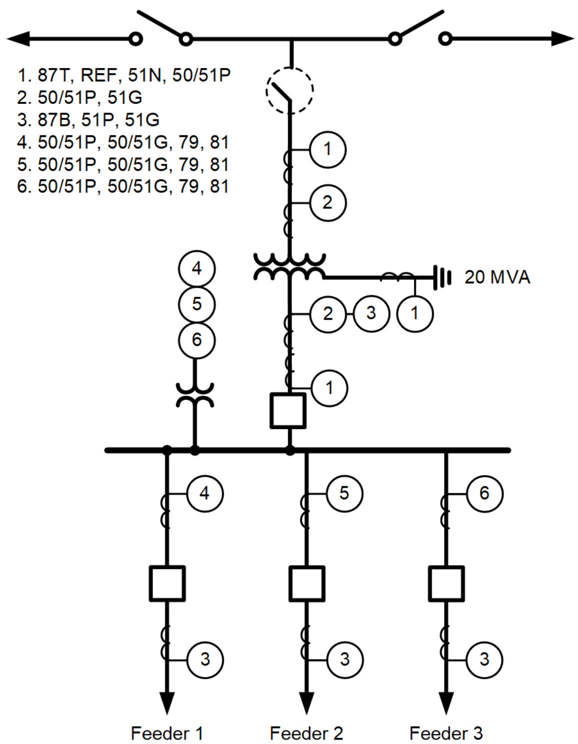

Fig. 1. Typical AEP distribution substation.

AEP's standard approach to distribution substation protection and control is to install individual relays for each zone (e.g., transformer, bus, feeder) and provide backup protection using a combination of redundant, or adjacent, relay zones to mitigate relay and equipment failure contingencies. The scheme and methods used for primary and backup protection are outlined at a high level in the following sections.

A. Transformer Protection

The transformer zone has two relays that provide protection for the transformer and backup downstream zones.

The first relay (87T) provides percentage restraint differential, restricted earth fault protection, and inverse-time neutral overcurrent protection. It also provides backup instantaneous and inverse-time phase overcurrent elements for the high-voltage winding.

The second relay provides instantaneous and inverse-time phase overcurrent protection for the high-voltage winding (50P, 51P). In addition, it also provides both phase and ground inverse-time overcurrent protection for the low-voltage winding (51P/G).

The overcurrent elements in both Relay 1 and Relay 2 backup the bus and feeder protection zones.

B. Bus Protection

The bus zone relay (87B), Relay 3, provides an inverse-time based differential overcurrent coming from paralleled feeder and low-side breaker current transformers for high-speed protection. The 87B also provides sudden pressure relay tripping in addition to phase and ground inverse-time overcurrent elements that provide backup protection for all distribution feeder zones.

C. Feeder Protection

The feeder zone relays, Relays 4–6, provide instantaneous and inverse-time phase overcurrent protection for the given feeder using both phase and ground elements (50P/G, 51P/G). In addition, each feeder relay also provides underfrequency load shedding (81) and automatic reclosing (79).

III. Introduction to DSS Solutions

As digital technologies have expanded within the substation environment, additional focus has been placed on how these systems could be leveraged to simplify substation design and expansion, lower implementation costs, and improve overall system health monitoring. One such example is the development of several different high-speed, relay-to-relay communications protocols that allow for a digital alternative to copper wiring to share analog and digital information. This approach allows for a wide array of information to be transmitted over a single link with real-time health indications and the potential to be easily shared to numerous devices without the need for complex wiring. The potential to eliminate hundreds of feet of copper wire and associated terminations can be realized with digital secondary voltage and current signals being communicated between the control house and substation yard.

These concepts laid the groundwork for what is commonly defined today as a DSS, involving the conversion of protection and control information (current, voltage, and I/O status) out in the substation yard by the primary equipment via a digital device referred to in this paper as a merging unit and the communication of this information to one or more digital relays in the control house. These merging units are also capable of receiving digital binary signals from a relay and performing local initiation of a breaker trip or close via conventional contacts. Given that interrelay communications are necessary for schemes such as breaker failure or communicating breaker status, they could be easily communicated through the same digital link.

While specific DSS implementations can take many different forms depending on the application and user requirements, two approaches have become dominant. The first is a system that uses a switched network to traffic all the digitized signals between the merging units and relays. The second is a system that uses direct point-to-point connections between the merging units and relays. Both approaches have specific tradeoffs depending on how they are implemented. In general, a point-to-point system simplifies deployment at the cost of loss in flexibility, and the networked approach is the opposite and features increased flexibility in routing signals to any device at the cost of additional complexity.

Although these systems have several potential benefits, they also introduce a number of challenges. These will be discussed in greater detail in Section V. One consideration for such solutions is their effect on unavailability of the overall protection system. Because these systems use additional devices, the number of expected failures is increased. However, this issue can be mitigated by employing redundant devices for each zone of protection. This may be a desired scheme regardless of technology and can help to reduce unavailability back to approximately the same levels as traditional systems [1] while enjoying the additional benefits of DSS solutions.

IV. Introduction to CPC Solutions

The process of replacing numerous protective relays with limited functions into a few highly capable multifunction relays has naturally progressed as microprocessors have become more powerful. Today, an entire substation of relays can be replaced by a single device capable of collecting all necessary analog and digital signals from the substation. This concept is often referred to as CPC.

The movement toward consolidated protection has similar merits to the transition from electromechanical to digital relays nearly 40 years ago: reduced unavailability, reduced maintenance costs, reduced panel size requirements, and simplified applications. Each of these benefits is evaluated further within this section.

Although there are many different variations of CPC, this paper focuses on the use of a purpose-built, protection-focused CPC relay.

A. Reduced Unavailability

A benefit of consolidating protection into a single device is to reduce the overall cost of ownership. In simplified terms, the more devices in a system, the more often a device on the system will fail, which increases the number of service calls or repairs. While consolidated protection does reduce the number of service calls, any failure in a CPC system is more impactful to the protection of the power system. These competing ideas can be illustrated by using fault tree analysis [2], where we quantify different failure modes and assess the overall likelihood of a system failure.

Fault tree analysis is a systematic approach to understand and compare how system components influence a particular failure mode. For the example systems shown in Fig. 2 and Fig. 3, we will be calculating the unavailability of relay protection for a CPC configuration against a traditional relay configuration using discrete relays. Relay protection for this analysis will be defined as the relay hardware, relay firmware, and the associated current (CT) and voltage (PT) instrument transformers. It is important to note that this failure mode is strictly comparing the unavailability of relay protection elements and not the unavailability of clearing a fault, which would need to consider other system components such as circuit breaker unavailability. A deeper analysis of this failure mode is explored in [3]. To simplify our analysis, a failure of the DC system has been neglected since this component equally impacts systems with discrete relays or a CPC.

The unavailability for each component in this analysis is shown in Table I [4]. Unavailability is defined as the fraction of time a device is unable to operate and is equal to the device's failure rate multiplied by the average downtime between repair, as shown in (1). An average downtime between repairs of 2 days was assumed for most components [2] when calculating unavailability, as well as factoring in the effectiveness of relay self-tests in notifying operators of a problem. Manufacturers often communicate a device's reliability in terms of mean time between failure (MTBF), which is the reciprocal of the failure rate. Component unavailability varies widely as function of each component's MTBF and how quickly a failed component can be repaired; however, the fault tree analysis shown in Fig. 4 and Fig. 5 remains unchanged.

$$q = \lambda T = \frac{T}{\text{MTBF}} \quad (1)$$

where:

q is unavailability

λ is the constant failure rate

T is the average downtime between repairs

MTBF is the mean time between failures (λ-1)

In a traditional system using discrete relays, it is common practice to use separate CTs for each relay. This provides the expected CT polarity for each relay's protection element and allows circuit breakers to be included in the zone of protection of two devices, as illustrated in Fig. 2.

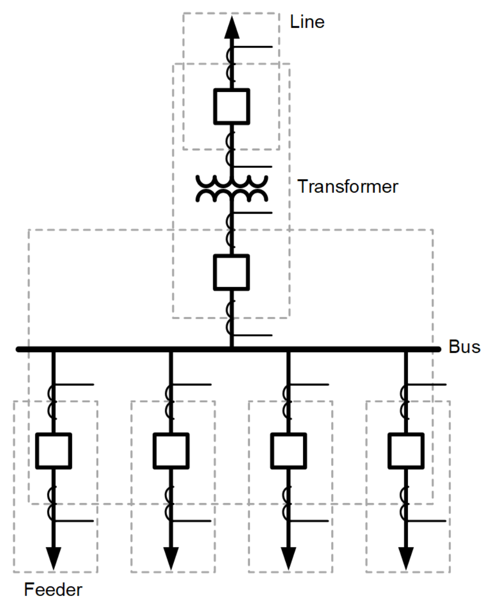

Fig. 2. Protection zones in a traditional system.

In the CPC system, shown in Fig. 3, the same CT is used for multiple protection zones, with polarity inverted digitally to ensure proper operation of individual elements. This results in half the amount of CTs required in a CPC system, reducing cabling and the chances of a CT failure. This approach does come at a cost, since each circuit breaker now is only being included in the zone of protection of a single relay. This can be mitigated when a redundant CPC relay is used with a second set of CTs. Due to the difference in instrument transformer practices between discrete devices and CPC, the component failures of CTs and PTs are included in the fault tree analysis in this paper.

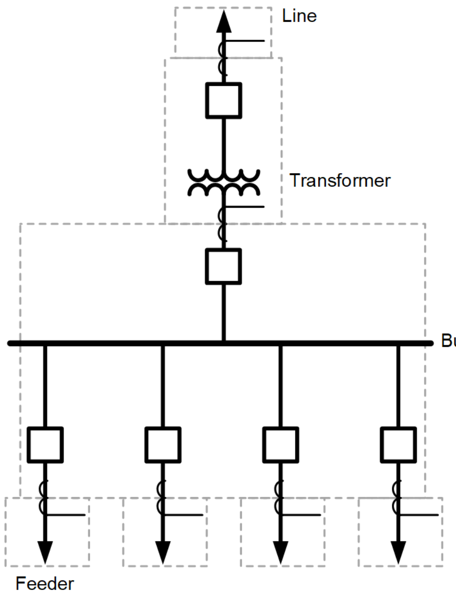

Fig. 3. Protection zones in a CPC system.

As relays increase in complexity, so does the possibility for coding errors. The work done in [4] was used to estimate firmware-caused unavailability based on code complexity. Using a base of unavailability of $100 \cdot 10^{-6}$, firmware unavailability grows at rate proportional to the square root of the lines of code, as shown in (2).

$$q_{FW} = \left(100 \cdot 10^{-6}\right) \cdot \sqrt{\mathrm{KLOC}/100} \qquad (2)$$

where:

q_{FW} is firmware unavailability.

KLOC is one thousand lines of code.

For this analysis 400 KLOC were estimated for discrete relays and 800 KLOC were estimated for a centralized protection relay which resulted in the firmware unavailability listed in Table I. A relay hardware unavailability of $100 \cdot 10^{-6}$ [2] was used for this example, which is extremely conservative for modern digital relays based on our field experience.

TABLE I
UNAVAILABILITY FOR EACH COMPONENT

Component	Unavailability (10^{-6})
Relay hardware	100
Discrete relay firmware	200
CPC relay firmware	282
Current transformer (3Φ)	30
Potential transformer (3Φ)	30

The fault tree shown in Fig. 4 calculates the protection unavailability for the system in Fig. 2. For a system using discrete relays, the unavailability of any single protection element is $2{,}490 \cdot 10^{-6}$, which is 8 times worse than the unavailability of a single relay. The unavailability of all protection simultaneously in this system is $691 \cdot 10^{-23}$, which is not a practical metric for this analysis and can be considered zero, which would be a practically impossible scenario.

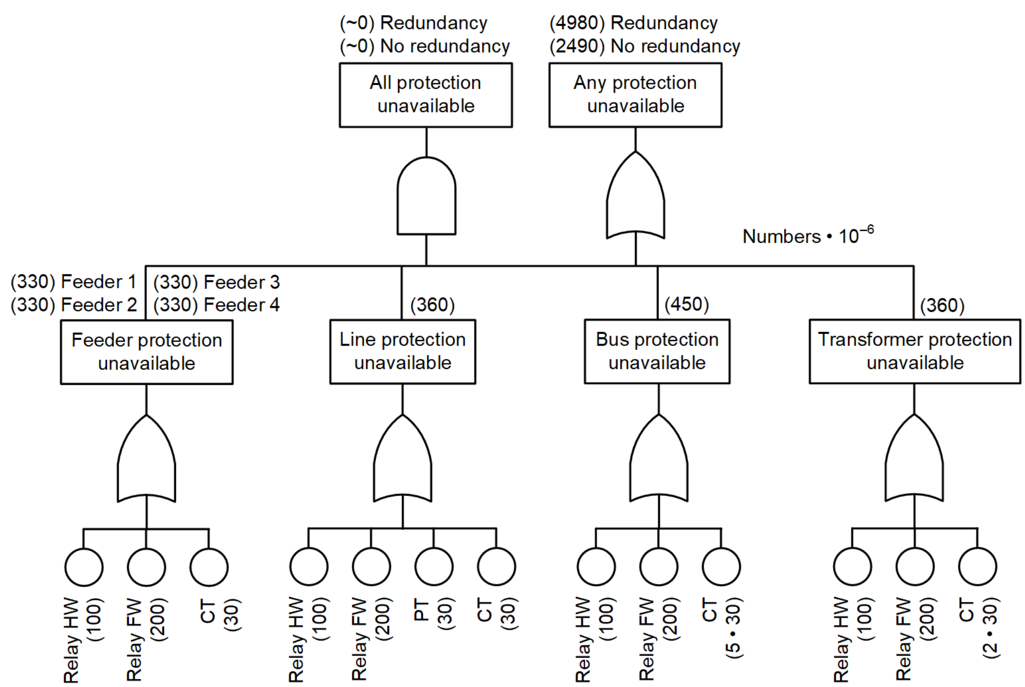

Fig. 4. Fault tree analysis for system with discrete relays.

The fault tree for a system using a centralized protection relay is much simpler to analyze. Any protection is unavailable when there is a failure of any system component. This calculates to 592 • 10^{-6}, which is 4 times better than in the discrete relay system (see Fig. 4). All protection is unavailable if a CPC relay has a hardware failure, firmware malfunction, or the impossible scenario that all CTs simultaneously fail (720 • 10^{-26}). The unavailability of all protection simultaneously for a CPC system is 382 • 10^{-6}, which is equal to the unavailability of a single relay. This is concerning considering the impact such a failure would have.

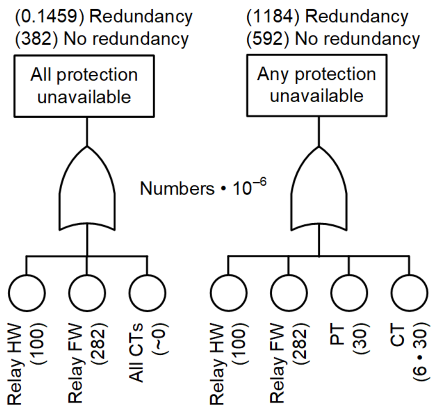

Fig. 5. Fault tree analysis for system with centralized protection.

To reduce the likelihood of losing all protection in a substation utilizing centralized protection, it is best practice to install a redundant centralized protection relay. To simplify our analysis, in this case, redundancy assumes a redundant relay and redundant instrument transformers. This analysis can be modified to fit any system configuration. When a redundant centralized protection system is installed, the unavailability of all protection drastically improves to $(382 \cdot 10^{-6})^2 = 0.1459 \cdot 10^{-6}$. While the unavailability of all protection is still much worse than in the discrete relay configuration, the likelihood of losing all protection simultaneously is still approximately 0 and will not be observed in the lifetime of any system, assuming prompt action is taken when a failure is detected.

While the addition of redundant relays will improve the failure mode of losing all protection, it also comes at a cost. The additional devices increase the likelihood of a service call. The chance of a service call due to a failed relay doubles when redundant relays are used. However, when a redundant relay is used in a centralized protection configuration, the unavailability of any relay protection is improved by a factor of 4 compared to traditional systems using discrete relays, and the unavailability all protection is approximately equal. See Table II.

TABLE II
FAULT TREE ANALYSIS SUMMARY

Failure mode	**Unavailability (10^{-6})**			
	Discrete relays		**Centralized relay**	
All protection	~0	✓	382	✗
Any protection	2,490	✗	592	✓
All protection with redundancy	~0	✓	0.1459	✓
Any protection with redundancy	4,980	✗	1,184	✓

Selecting equipment with higher reliability metrics is important to minimizing the cost of ownership; however, the best improvement to system cost of ownership is achieved through careful consideration of system configuration. The fault tree analysis summarized in Table II shows that when a redundant CPC relay is used, the chance of any relay or instrument transformer failure is reduced by a factor of 4, while the chance of all protection failing is negligible.

B. Reducing Maintenance Costs

To regulate and improve the reliability of the North American bulk electric system (BES), NERC created the PRC-005 standard. PRC-005 requires that all BES assert owners create a protection system maintenance program that complies with this standard. This maintenance program includes testing of relay communication systems, control circuitry, settings integrity, and measurement accuracy. Periodic maintenance and testing of these systems must be performed every 6 or 12 years, depending on the relay's self-monitoring capabilities.

In the example system shown in Fig. 2, 7 relays (line, bus, transformer, and 4 feeders) would be needed for a traditional discrete relay system. The same system can be protected by a single CPC relay, reducing PRC-005 maintenance activities for these devices by a factor of 7. This not only reduces the time training relay technicians, but also simplifies tracking relay firmware updates, settings files, cybersecurity patches, and service bulletins. In addition, a single relay model can now be stocked instead of managing several relay models.

C. Reduced Panel Sizes

As relays transitioned from many electromechanical devices that were purpose built to serve a single function to a few digital relays to serve a specific application, the panel size requirements reduced significantly. Today, several panels of relays that are designed for a specific application (e.g., line, feeder, or transformer) can be replaced with a single centralized protection relay. As panel requirements shrink, so does the footprint required of control houses, as illustrated in Fig. 6.

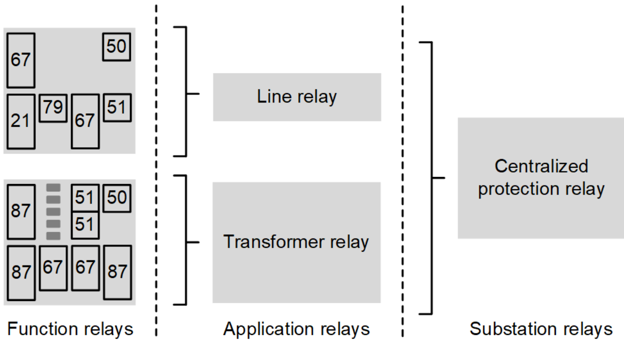

Fig. 6. The evolution of relay consolidation.

D. *Simplified Applications*

Another benefit of centralized protection and control systems is that functions that previously required coordination between discrete devices can be simplified and streamlined. For instance, when using discrete devices, some coordination time needs to be included in schemes like breaker failure protection. Because all the information is contained in the same device, some of the time required for devices to coordinate can be removed. In some applications, this can lead to time savings of nearly a cycle [3]. Additionally, because everything is in one device, we can eliminate interpanel wiring, which can be a source of error sometimes leading to misoperations [5] Similarly, functions like breaker lockout can also be simplified. One of the functional requirements for lockout is that it is coordinated among devices potentially operating the breaker so that there is a single point of contact to change the status of the lockout relay [6]. Since the same device is performing all the protection and control actions, lockout status only needs to be stored in a single device, which makes implementation of a digital lockout relay in logic much more practical.

These are just a couple of examples that are simplified by using a CPC architecture but any application that requires multiple devices to coordinate may be simplified.

V. Hybrid Design With CPC and DSS Technologies—Benefits Versus Challenges

AEP has chosen to explore a hybrid design that uses the technologies discussed in this paper, CPC and DSS, in an effort to address several common challenges utilities face with the use of conventional protection and control systems. For the purpose of the evaluation covered in this paper, the following criteria were identified as areas of interest. Some of these factors have been mentioned in previous sections at a high level. We will now discuss them in more detail and identify specific terms associated with these areas of interest.

- Asset management refers to the costs associated with deploying and maintaining a fleet of protection and control devices. These devices must undergo regularly scheduled testing and maintenance, and any identified vulnerabilities must be addressed in a timely manner.
- Engineering resources are involved with the design and documentation of a substation and its associated protection and control scheme. This can include items such as one- and three-line drawings, panel drawings, and control settings.
- Commissioning includes the resources required to install primary and secondary equipment, dig trenches, run cabling, land cabling, set program controls, and perform testing to validate protection and control system operation.
- Material cost not only covers the cost of primary equipment (transformers, breakers, disconnect switches, control houses, etc.) and secondary equipment (protection, automation, communications equipment, secondary cabling, etc.), but also substation land rights.
- Performance of the protection and control system is a vital part of any substation and, as such, the impact of alternative designs and new equipment needs to be evaluated. This can include criteria such as speed, selectivity, dependability, and security.
- Reliability of the protection and control system is of critical importance as utilities strive for fewer and fewer outages for customers.
- Safety refers to promoting the health and well-being of those working with (or around) substation equipment. Altering designs may allow for engineering controls to be implemented that reduce levels of risk for qualified workers.

Although CPC and DSS manufacturer solutions are becoming more popular in the industry, these are relatively new technologies that, in many cases, require different processes and technical expertise to deploy than conventional systems. Although these solutions may provide many theoretical benefits, they also may bring new challenges, which must be considered.

The following subsections provide a list of expected benefits and challenges that AEP considered when evaluating a hybrid system design, which would be evaluated throughout the process of the pilot project. Each item is associated with one or more areas of interest previously defined in this section.

A. *Expected Benefits of the Hybrid Solution*

1) *Asset Management*

A consolidated approach to relaying reduces the relay count for substation protection and control, whereas a DSS solution increases the total device count. However, it can be noted that DSS merging units can be designed not to have onboard settings or firmware. As a result, there are fewer devices to maintain, which each require periodic testing; documentation on device tracking, settings, regulatory compliance, and test results; and possibly firmware or security updates over time. Each of these items are directly associated with operations and maintenance costs.

2) *Engineering Resources*

Typical substation drawing packages include numerous drawings for each relaying panel and its associated wiring for many unique designs. With a hybrid scheme, the number of relaying panels, wiring connections, and unique devices is drastically decreased, which should result in fewer drawings with greater ability to reuse components from one design to another, saving drafting time. Other unique drawings, such as circuit breaker schematics that can be quite individualized depending on their interconnecting zones of protection, could be standardized to the same merging unit connections agnostic to the application.

As the demand for electric power increases, it is not uncommon for additional feeders or lines to be added to a substation. These changes typically involve significant efforts to add new panels and wiring associated with the new protection and control devices. Given a hybrid scheme, a certain ease of scalability is obtained by requiring only an additional fiber connection to the existing CPC device (which is only limited by the device's port count and programming) and digital mapping of the associated data.

SCADA design efforts for the station will likely be reduced due to a lower number of devices contributing to a smaller overall point map and fewer unique device addresses.

3) Commissioning

DSS solutions offer the advantage of being able to pre-engineer and test a component of the solution prior to reaching the substation site. Similar to how panel manufacturers purchase original equipment manufacturer devices, mount them into panels, run wiring, and conduct testing, DSS merging units offer the ability for breaker, transformer, or freestanding cabinet providers to integrate and test them within a controlled environment. This means the full system tests can be reduced to checking these precommissioning activities. This approach not only saves time onsite but, in some cases, can reduce the risk of human error.

A hybrid solution drastically reduces the amount of field wiring that must be pulled, terminated, tagged, landed, and tested in the field. Instead, limited fiber connections need to be made (often between a patch panel within the control house or in the substation yard) between the relay and the merging unit. Once the link is made, the DSS relay should be capable of confirming a healthy link and that the correct merging unit is connected in the correct location, which could significantly reduce commissioning time. Preterminated fiber can also be leveraged to further reduce commissioning times, the possibility for human error, and the need for specialized skill sets associated with fiber terminations.

Due to DSSs using a single fiber connection to communicate analog and digital information rather than several copper wires, trench size can be reduced, offering the potential for quicker installation times with less material.

4) Material Cost

DSS solutions use a single fiber connection to communicate analog and digital information rather than several copper wires. This results in a drastic reduction in the amount of copper cabling used between the control house and the substation primary equipment, opening up the opportunity for saving hundreds or thousands of feet of copper wiring.

A hybrid solution not only reduces the number of protection and control devices within the control house, but also moves the analog-to-digital conversion and I/O of relaying devices elsewhere. This results in a potential to greatly reduce the number of panels and the overall control house footprint, which often add significant cost to substation projects.

5) Performance

Current transformer performance (the ability to recreate a secondary signal that accurately represents the primary current) is negatively impacted by the amount of burden placed on the secondary. In conventional microprocessor-based relay applications, the majority of current transformer burden is due to copper cabling connecting it to the relay. In DSS applications, the merging unit is typically located near the current transformer, effectively eliminating a large portion of the current transformer burden. As a result, DSS applications provide an opportunity for improved current transformer performance and/or the potential to use lower-rated current transformers to achieve the same performance.

In some cases, electromagnetic coupling between secondary conductors has resulted in false I/O assertions or phantom analog signals.

DSS applications tend to be more resilient to this behavior due to the reduced length and exposure of copper cabling and alternative use of fiber.

In conventional applications with copper secondary wiring, relays are not able to detect if secondary cabling has been compromised until a misoperation occurs. A DSS solution offers the ability for both the relay and merging unit to provide active channel monitoring and for users to develop contingency behavior, such as protection disabling or alarming.

6) Safety

With conventional substation designs, personnel working within the control house are exposed to secondary cabling that has the potential to carry high levels of energy. In addition, it is common for workers who must interact with the relays to perform device isolation. If current transformers and potential transformers are not terminated properly, extremely hazardous conditions can result. With a DSS application, secondary cabling is left outside the control house and relay isolation can be achieved via fiber removal or digital settings, leading to safer working conditions inside of the control house.

B. Expected Challenges of the Hybrid Solution

1) Asset Management

DSS solutions introduce more devices (merging units) than traditional systems. They have associated part and serial numbers, which may require additional documentation. However, to help address this, merging unit manufacturers have designed these devices to be non-programmable and to have a universal design capable of handling a wide array of applications.

2) *Engineering Resources*

Due to all protective relaying functions being consolidated into a single device, the complexity of developing settings for that device likely increases.

Documentation for previous relay-to-relay schemes, such as breaker failure, virtual lockouts, or fast bus tripping schemes, need to be designed to clearly indicate supervisory conditions.

Oftentimes, microprocessor relays feature front panel pushbuttons and LEDs that can be programmed to allow for local control and/or visualization of particular protection zones. A CPC design requires new or supplemental methods for local user control and visualization, such as a separate HMI.

3) *Commissioning*

Some components of the proposed hybrid design differ drastically from conventional designs. These differences will likely drive the need for new processes and the development of new skills amongst workers. These may include tasks such as terminating fiber, verifying connection health, or validating connections from the relay to each merging unit. As a result, initial projects often have higher costs.

Conventional relay testing consists of isolating the relay and connecting a test set to the relay via a test switch. This is followed by performing various current and voltage simulations and observing relay behavior. When using a DSS application, the protective relay and merging units are located in different places. Therefore, new test strategies need to be developed.

4) *Reliability*

When a DSS solution is deployed, additional device counts detract from overall reliability. However, this can be addressed by incorporating centralized protection to reduce the number of protective relays. Choosing simple, robust, and purpose-built merging units also helps maximize system reliability.

The following sections of this paper explore the hybrid pilot project that AEP is pursuing and review how the project aligns or conflicts with the expected benefits and challenges evaluated in this section.

VI. Pilot Project Design

AEP is currently in the engineering and design phase for a new greenfield substation in Ohio. This substation will be their first to implement CPC plus DSS for a distribution substation. This substation is planned to be energized and placed into service in April 2024. This project is a step to help realize cost savings associated with substation protection and control systems.

This project is being treated as a pilot for a new distribution standard and a learning opportunity to validate cost savings and benefits. Provided that benefits are realized and challenges can be addressed, AEP intends to design more hybrid design projects in the next few years.

The protection and control system will comprise merging units, a CPC relay, and a data gateway. Fig. 7 and Fig. 8 show a simplified overview of the hybrid design and the proposed protection and control panel, respectively.

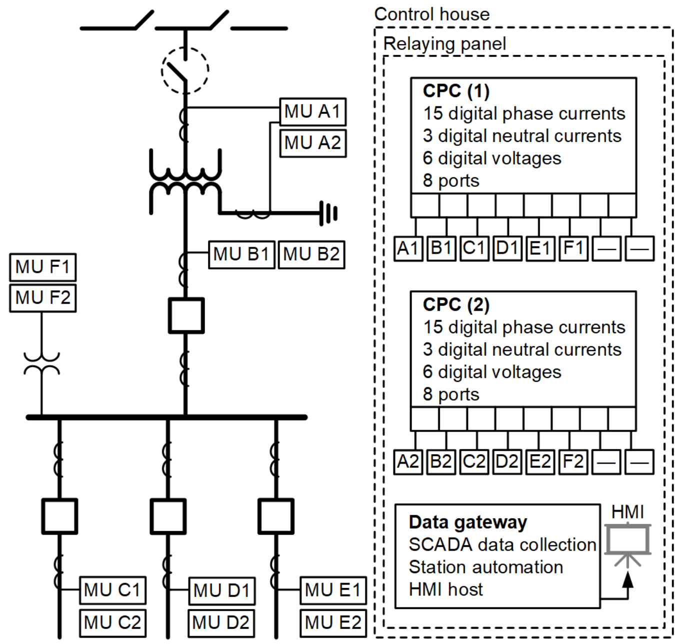

Fig. 7. The hybrid substation design of a CPC using a DSS.

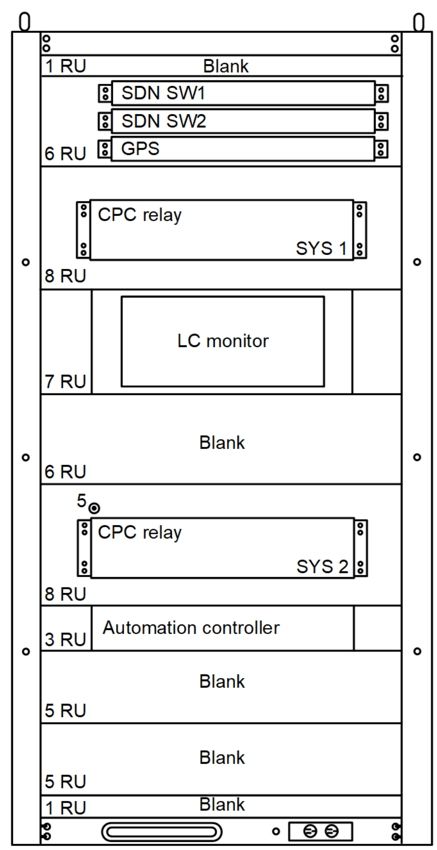

Fig. 8. Panel design based on DSS-capable relays.

A. *Merging Units*

Merging units will be installed within the substation switchyard with primary equipment. They will be installed in sets of two for redundancy purposes; the first merging unit will be connected to CPC System 1, and the second will be connected to CPC System 2.

Merging units contain contact I/Os for measurements, alarms, and controls as well as analog inputs for power system measurements from conventional current transformers and potential transformers. They provide the capability of keeping copper wiring in the switchyard and connecting a communications link directly to the CPC through fiber-optic based communications.

The communications of the merging units to the CPC use a simplified communications architecture and protocol to align data and communicate without external clock signals or Ethernet switch infrastructure. This approach simplifies the protection and control system by reducing the points of failure that would otherwise need more complicated engineering processes to provide communications and time-source redundancy.

The merging units use a nonroutable protocol to communicate to the CPC with a sampling rate of 10 kHz. Data consumed by the CPC from various merging units are time-aligned, and this is achieved in a straightforward manner within the nonroutable protocol.

The merging units are nonconfigurable and do not require settings or firmware maintenance. This simplicity is advantageous because it reduces engineering and maintenance times for these systems and the overall cost of ownership. Fewer files to manage is also an advantage by simplifying the configuration management process associated with the project.

B. CPC

The consolidated protection and control for the distribution substation will consist of two fully redundant devices for the protection of the substation. Automation and control is shared between the two CPC relays and the data gateway.

The CPC relays will be installed in the control house in a single panel, potentially reducing the control building size. The CPC substation eliminates four relays from the existing standards, which leads to simplified engineering and maintenance. In addition to the elimination of four microprocessor relays, the CPC also implements a virtual lockout relay, further reducing the number of relays in the station by two devices.

Each of the CPC relays provides complete substation protection for a transformer, bus, and up to three feeders, with the following elements, summarized in Table III.

TABLE III
CPC PROTECTION ZONES

Zone	Function
Transformer	Percent restraint differential
	Restricted earth fault
	Phase and ground time overcurrent
Bus	Low-impedance differential
Feeder	Phase and ground instantaneous overcurrent
	Phase and ground time overcurrent
	Underfrequency load shedding

The CPC provides an individual reclosing 79 function for each of the distribution feeder breakers. In addition, the CPC is programmed to use the transmission line motorized switches to sectionalize for line faults and remove the faulted section when required. The CPC also has backup controls for the station breakers and switches for situations when the data gateway is out of service.

C. Data Gateway

The data gateway supports three primary roles: HMI, SCADA, and data aggregation.

The HMI serves as the primary location to display the substation one-line, real-time power flows and situational awareness. The controls to operate all the primary equipment are virtualized in a graphical user interface to replicate existing functionality. The HMI presents all station alarms for asset monitoring, including communications and CPC health, and provides a central repository for Sequence-of-Events (SOE) data.

In substations, AEP installs a remote terminal unit to consolidate relay communications for SCADA. The data gateway will serve this role and communicate to the two CPC relays using IEC 61850 MMS/GOOSE for monitoring, alarms, and controls. Operation centers will communicate to the substation using the DNP3 protocol and interface only to the data gateway.

The last role of the data gateway is to aggregate substation data for centralization and postprocessing purposes. COMTRADE, SOE, and other files will be collected from the CPC relays and moved to remote servers for data analysis. The data gateway will perform routine network audits of substation assets connected to the network. It will also be used for running packet captures and analyzing communications problems.

VII. EVALUATION OF HYBRID DESIGN

AEP is pursuing this new design for distribution as a cost savings initiative. Because the project is still being designed and implemented as of the writing of this paper, a full set of data on actual cost savings is not available. However, because the project is in process, some data can be measured or estimated with some degree of confidence. It is also worth noting that while not every topic identified earlier in the paper will be discussed because data may not be available, we felt it was important to identify these topics so that success or challenges in the project can be determined.

Preliminary analyses suggest the new design reduces construction labor costs by 12 percent and future material costs associated with protection and control by up to 13 percent. Pre-engineering cost analysis estimates cost savings approaching $600,000 for a substation when factoring in optimization efforts for building size, trench, conduits, and cabling. As outlined previously, utilizing a CPC design should reduce the number of field failures and, therefore, reduce maintenance costs, but field data will not be available until the project has been deployed for some time.

Beyond the cost savings, there are additional benefits with this solution. AEP anticipates being able to build and commission protection and control systems faster and with better quality. Merging units will be factory-installed and built in a controlled environment. This will make it much easier to make corrections to errant wiring and can reduce field labor significantly. The labor-intensive job of landing hundreds of wires in the switchyard will be simplified to terminating fiber optics, speeding up the building process with an estimated 83 percent reduction in total field cable count and terminations and an 87 percent reduction in total cable footage with the new design. Only spot checks will need to be done in the field, and self-reporting by the CPC relay can help identify any errors that make it out of the panel factory. By speeding up these projects, AEP expects to better utilize existing personnel to maintain existing systems and build new substations in the future.

The control house will be limited to a home for the battery system and a single CPC relay panel. This represents a significant reduction in panels since traditional designs often use several panels to house all protection and control devices. This should lead to fewer errors in panel construction because of the reduction in context-switching between designs while building a panel [7]. Second, the reduction in number of panels means the floor space requirement of the control house is reduced and the footprint needed for a substation can be reduced as well. An additional benefit to the reduction in devices is fewer system settings and assets to manage and maintain. The DSS technology chosen does not introduce complicated configuration and file management requirements. It also does not require firmware patching and other remote management because of the simplified nature of the merging units. Other solutions with more complex merging units could be used in the future but may erode some of the cost savings because of the additional settings and configuration.

As the project is implemented, we expect to get more concrete data to support and expand on this analysis, especially as it relates to the parameters identified in earlier sections. But the initial estimates support the deployment of the hybrid design.

VIII. Conclusion

Both DSS and CPC technologies present interesting new opportunities for innovation in AEP protection and control space. By applying these concepts to distribution standards, AEP is looking to both see cost savings and improve the efficiency of commissioning and maintenance. This paper shows how the existing distribution standard at AEP can be adapted using a highly featured protective relay in a CPC application. While the project is not implemented yet, we have identified metrics that can be used to measure the success of the project, and early estimates indicate savings will be realized.

IX. References

[1] S. B. Ladd, E. Haithcox, K. Perren, R. Koch, K. Slattery, M. Weaver, M. Zahn, A. Shrestha, S. K. Mutha, and L. Booth, "Point-to-Point Digital Secondary System Design for a Transmission Substation at Duke Energy: Challenges and Solutions," presented at the 49th Annual Western Protective Relay Conference, Spokane, WA, October 2022. Available: selinc.com/api/download/137358/?lang=en.

[2] E. O. Schweitzer, III, B. Fleming, and T. J. Lee, "Reliability Analysis of Transmission Protection Using Fault Tree Methods," presented at the 24th Annual Western Protective Relay Conference, Spokane, WA, October 1997. Available: selinc.com/api/download/2465/?lang=en.

[3] A. Shrestha, A. Chatterjee, P. Nadkar, J. Fultz, S. B. Ladd, T. I. Raffield, and E. Haithcox, "Case Study: Designing Centralized Protection and Control Systems for a Distribution Substation at Duke Energy," to be presented at the 50th Annual Western Protective Relay Conference, Spokane, WA, October 2023.

[4] E. O. Schweitzer, III, and D. Whitehead, "Resetting Protection System Complexity," proceedings of the 46th Annual Western Protective Relay Conference, Spokane, WA, October 2019.

[5] Y. Xue, M. Thakhar, J. C. Theron, and D. P. Erwin, "Review of The Breaker Failure Protection Practices in Utilities," presented at the 38th Annual Western Protective Relay Conference, Spokane, WA, October 2011. Available: na.eventscloud.com/file_uploads/08459e40feec142e648207fe237f9108_xue_pap.pdf.

[6] D. McGinn, P. Myrda, B. Kasztenny, and D. Finney, "Implementing Lockout Function with IEC 61850 Communications Based P&C Systems," GE Grid Solutions. Available: www.gegridsolutions.com/multilin/journals/issues/winter09/9th-implementing%20lockout%20function%20with%20iec61850.pdf.

[7] R. J. Schonberger, *World Class Manufacturing*, The Free Press, New York, 1986.

X. Biographies

Jason Byerly received his BS degree from the Ohio State University in 2004 and is currently pursuing his MSEE from the University of Idaho. He joined American Electric Power (AEP) in 2004 and has supported several roles in protection and control engineering. Jason is a registered PE in Ohio, a senior member of IEEE, contributor to IEEE PSRC, and member of IEC 61850 WG.

Manish Thakur is director of protection and control engineering at American Electrical Power (AEP) with 26 years of experience in protection and control (P&C). His current responsibilities at AEP include system protection and control specifically, compliance and relay misoperation investigations of transmission systems up to 765 kV. His areas of expertise include high-impedance (HiZ) fault detection, series compensation application on extra-high-voltage (EHV) systems, transient and real-time simulations, standardization, and digital substations. Prior to joining AEP, Manish worked with ABB and General Electric as a P&C application and consulting engineer. Manish received his Bachelor of Science in India and Master of Science from University of Manitoba, Canada. Manish is a member of IEEE and is a PE registered in Ohio.

John Hostetler received his BS from Washington State University in 2011 and his Master of Engineering degree from the University of Idaho in 2020. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2011, where he works as a lead product engineer in the research and development division.

Chris Burger received his BS degree in electrical engineering from Virginia Polytechnic Institute and State University in 2015 and his Master of Engineering degree in electrical engineering from the University of Idaho in 2022. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2015, where he works as a protection application engineer in the sales and customer service division. Chris also obtained his PE certification in the state of Ohio in 2021.

Scott Wenke received his BS degree in electrical engineering with a power emphasis from Washington State University. Prior to joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2013, Scott worked at Itron. At SEL, he is a product manager in the power systems group of research and development and is responsible for transmission and substation product lines.

20230911 • TP7135-01