Communications-Capable Fault Indicators Improve Outage Response for Coastal Oregon

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***Abstract*—Overhead fault indicators have long been vital tools for utility line crews, helping them to find a faulted line section on a distribution circuit by providing local annunciation for where the fault occurred. Traditionally, a mechanical flag or light-emitting diode (LED) indication shows that the fault was detected by the sensor. Line crews have to patrol the lines by following the tripped sensors until the fault is no longer indicated and then backtracking down the line to find the faulted line section. This process can be time-consuming, which significantly slows outage recovery times in the densely forested and mountainous terrain of the Oregon coastline. By adding communications capabilities to these fault indicators, a centralized effort can be made for dispatching line crews, while providing precise fault details that are possible because there are several sources of information. Central Lincoln People's Utility District (PUD) is in the process of installing such a system and is expecting to see improvements to outage recovery times, crew dispatch management, situational awareness during outages, and post-event analysis through supervisory control and data acquisition (SCADA) integration. This paper discusses how the information provided by the overhead fault indicators will improve Central Lincoln PUD operations and includes lessons learned by the engineers and operators while installing and using the system.**

Being able to monitor overhead fault indicators via SCADA allows Central Lincoln PUD to reduce customer outage times, improve safety, and reduce risk to patrolling troubleshooters. By having fault indicators communicating through SCADA, Central Lincoln PUD is able to isolate and sectionalize the problem area much faster. Central Lincoln PUD operators can see the faulted indicators on a map in the SCADA system, and they are also notified about the faulted indicators via cell phone text messages that are sent to operations personnel, including troubleshooters. This allows the troubleshooters to minimize the area of line that needs to be patrolled, which in turn reduces outage times. An additional benefit to using the fault indicator device is a load-logging function that is tied to a historian. This load-logging function has been useful within the Central Lincoln PUD systems engineering planning department when reconfiguring distribution systems.

A project of this magnitude does not come without its share of lessons learned. Central Lincoln PUD has grown from these lessons, which include design thoughts regarding proper configuration on all levels of installed devices, where and how to install not only the line sensors but also the radio links that provide the communications link between the field and SCADA, and other design lessons that are discussed in this paper.

***Index Terms*—Distribution automation, DNP3, faulted circuit indicators, outage response, radio communications, SCADA.**

I. Introduction

Central Lincoln People's Utility District (PUD) is a publicly owned electric utility that has been serving customers on the Oregon Coast since 1943. They have more than 38,000 residential, commercial, and industrial customers with a service territory extending 120 miles along the Oregon coastline and spanning an area of about 700 square miles. The coastal environment that Central Lincoln PUD resides in is beautiful, but it also presents significant operating and engineering challenges due to the weather (specifically, high wind and storms) and the corrosive sea-salt air. These challenges make it necessary for Central Lincoln PUD personnel to better strengthen the grid and undertake innovative engineering approaches to maintain a high degree of system reliability. Central Lincoln PUD is a winter-peaking utility with a high usage of electric heat among the residential customers. They purchase power from the Bonneville Power Administration (BPA) and participate in ongoing regional efforts to ensure an affordable and reliable power supply and to protect the beauty and resources of the Pacific Northwest environment.

Because of the rural nature of the service territory, more than half of the Central Lincoln PUD customers live in areas that do not have natural gas service for heating, cooking, or drying, thereby making electric service reliability not just important, but critical. Reliability is a key metric for assessing the effectiveness of distribution automation (DA) devices such as faulted circuit indicators (FCIs). Part of the Central Lincoln PUD Smart Grid Team 2020 project included the integration of DA devices. Central Lincoln PUD has knowledgeable engineering, information technology (IT), communications, networking, and meter relay departments, as well as few restrictions for proceeding with smart grid device integration throughout the district. This allowed them to move forward with the smart grid project from the beginning. The Central Lincoln PUD smart grid project is focused on implementing cutting-edge smart grid communications, monitoring, and control technologies. Used together, these initiatives will provide Central Lincoln PUD and their customers with true smart grid functionality and applications, which will provide measureable results and benefits that can be applied at other electric utilities. In addition to supporting Central Lincoln PUD operational and strategic objectives, these initiatives will also provide small, rural utilities serving low-density service territories with a model, technology roadmap, and operational results to draw upon when developing and implementing their own smart grid plans.

This paper focuses particularly on the FCIs that are part of the Central Lincoln PUD DA pilot project. This DA pilot project consists of a combination of Ethernet, radio frequency (RF) mesh, and serial communications technologies for the collection of supervisory control and data acquisition (SCADA) information from DA devices, such as line reclosers, fault indicators, vacuum fault interrupters (VFIs), and motor-operated switches. The primary objective for Central Lincoln PUD in implementing the DA pilot project is to eventually provide automated fault detection, isolation, reconfiguration, and restoration to reduce customer outage times, minimize outage areas, and improve overall system reliability. Another DA objective is to enhance situational awareness so that the system operator can better monitor and operate the distribution system during normal, abnormal, and emergency situations. The DA system will work to improve overall reliability, stability, and operational efficiency of the electrical distribution system.

The DA pilot project consists of the following three phases:

- Phase 1 – DA communications architecture design, development, testing, and implementation.
- Phase 2 – SCADA DA development and implementation.
- Phase 3 – design, development, testing, and implementation of automated fault detection (AFD), isolation, reconfiguration, and restoration schemes.

This paper is an expansion of [1] (which covered Phase 1 of the DA pilot project) and specifically discusses the FCIs that were part of Phase 2. Phase 3 is beyond the scope of this paper and will be covered in future endeavors.

II. System Architecture

This section discusses the physical hardware used in Phase 2 of the DA pilot project, the role that it plays in the system, and how it works.

A. System Design Overview

The system design incorporates various pieces of equipment located across several miles of distribution lines, substations, and the control center. Starting with a bottom-up view of the system, the communications-capable fault sensors are at the base. These sensors are located on the distribution lines at critical distances where there are human access points. These points are critical to the discussion because there are only a few points where a vehicle can access a view of the lines, thus limiting the number of human access points possible. This is because the Oregon Coast is fairly undeveloped and has rapidly changing elevations in heavily forested areas, making roads a rare commodity and access to lines very difficult. Presently, there are about 20 sensors integrated across the Central Lincoln PUD system, and approximately 30 sensors are ready for deployment.

The fault sensors each have an embedded mesh radio that connects to the next piece of equipment, which is the mesh router. There are several hundred of these routers installed across the Central Lincoln PUD system because they are also used in the Central Lincoln PUD advanced metering infrastructure (AMI) system. The routers communicate back to a head-end radio that has a hard link to the utility operations wide-area network (WAN). From this network connection, the real-time logic processor and data concentrator obtains the information from all of the faulted line sensors. Once the data are processed, the real-time logic processor and data concentrator provides all of the information to a SCADA master. The SCADA master then transmits messages via emails, text messages, and human-machine interface (HMI) indications announcing that fault sensor information has been received. This information is used by engineers, technicians, and operators to perform required system-restoration work. Fig. 1 provides a one-line diagram of the system architecture.

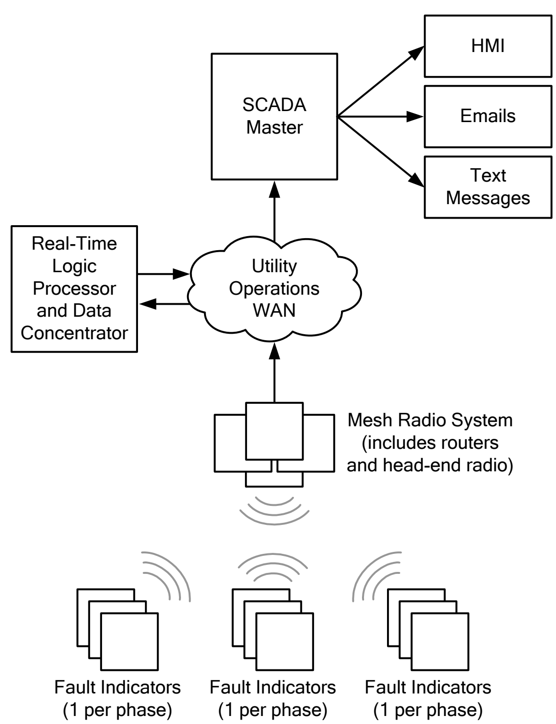

Fig. 1. System diagram showing key components and the communications paths used

B. Role of Fault Indicators

For a long time, the primary operation of a fault indicator was to trigger a visual flag or light after a certain level of current passed through the conductor where the sensor was hanging. Crews would need to visually inspect the fault indicators to identify the faulted line section, which was often very time-consuming, especially in the challenging terrain of the Oregon coastal region. Fig. 2 shows the type of fault indicator that Central Lincoln PUD installed on lines during the pilot project. Note that it has an antenna for wireless communications.

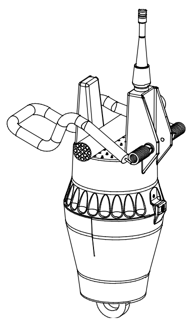

Fig. 2. Illustration of fault sensor installed by Central Lincoln PUD on conductors

Central Lincoln PUD chose communications-capable FCIs for the purpose of continuing the DA scheme discussed in [1]. The type of fault sensor that they chose has an internal battery with a shelf life of 20 years. This battery is used to provide a power source for an embedded mesh radio, which operates periodically (the radio is set to communicate once every 24 hours as well as after detecting a fault or outage). Once a fault is detected, the sensor turns on the radio, allowing it to find the mesh network. After a connection has been established, there is a transmission of DNP3 unsolicited traffic. In this unsolicited message, there is an abundance of information. This information includes measured current levels and temperatures for the previous 24 hours seen in one-hour increments, notification of communications status and failures, and indication of loss of current or fault events. DNP3 is the protocol of choice for several reasons and has the following key advantages [1]:

- DNP3 is an open protocol that is available for use by any manufacturer or user.
- DNP3 is specifically designed for the reliable communication of data and control information.
- DNP3 is widely supported by manufacturers of SCADA systems and software and by remote terminal units (RTUs) and intelligent electronic devices (IEDs).
- DNP3 allows for refined and concise messages that do not overwhelm bandwidth or require constant data links for multiple transmissions.

The transmitted data are sent to the mesh network routers. These routers communicate with terminal devices, such as the fault sensors or meters, as well as with other routers. The DNP3 datagram is passed from router to router until it reaches the mesh head-end radio. From the head-end radio, a connection is made to the Central Lincoln PUD operations WAN. Given the terrain of the Oregon Coast, this feature is very beneficial as compared with a direct-line-of-sight radio, which may never have an achievable clear path between radios with a straight path back to the operations WAN connection point. While the mesh radio network and the omnidirectional antennas that are required may not have the signal strength provided by a Yagi-type antenna, the ability to pick up connections from any router in the area provides the means to overcome the mountains and forests that line the coast. Other reasons, as detailed in [1], for using this type of radio network are as follows:

- The RF mesh network forms the communications backbone for several system solutions, allowing DA, AMI, and home-area network traffic to use a single communications network.
- Network radios are intelligent devices that can integrate with many different distribution devices, such as RTUs, switches, reclosers, capacitor banks, FCIs, and distribution transformers for advanced DA command and control applications.
- Radios use dynamic message packet routing and respond to changing network conditions; there are no static communications paths. Radios can prioritize individual messages to ensure dynamic routing through the network.
- Asynchronous, spread-spectrum frequency hopping allows multiple radios to use the same bandwidth, simultaneously transmitting multiple messages and ensuring scalability.

The real-time logic processor and data concentrator in this particular application is primarily used for collecting and concentrating unsolicited DNP3 messages, as well as consolidating messages from the fault sensors, IEDs, and other controllers found on the Central Lincoln PUD system. It then repackages the information, performing any required scaling, and provides a single, concise information map for the SCADA master to collect. The data concentrator is also able to provide diagnostic communications information based on the number of received messages or by viewing the incoming and outgoing traffic at a byte level. The currently unused IEC 61131-3 logic processing capabilities (refer to [2] for standard information) will allow Central Lincoln PUD to expand the capabilities in their DA system in conjunction with the communications-capable fault sensors in order to create a restoration scheme based around current line loading, known load capacity, precise fault location, and wide-area controls.

Once the data have been concentrated in the field to as few real-time data concentrators as possible, the SCADA master makes the final collection, allowing for the operations headquarters to store, analyze, and leverage the information from the system to perform work and ensuring that Central Lincoln PUD customers have safe and reliable electric power service. The human-facing system peripherals are controlled and messages are generated with data collected by the SCADA master. These peripherals include the HMI, email servers, and text messaging services, all of which provide critical information to the operators of the Central Lincoln PUD system so that action can be taken quickly and efficiently to restore any lost service.

III. Benefits of the System

Prior to the start of the Central Lincoln PUD Smart Grid Team 2020 DA project, there were only a couple dozen noncommunicating FCIs on their 12.47 kV electrical distribution system. The FCIs were mostly located on very rural distribution lines that were not usually along roads and that were often difficult to patrol during a faulted system condition. While these noncommunicating FCIs were beneficial to crews, it was time-consuming to find the faulted circuit, which led to longer outage times for customers. With the introduction of the communications-capable FCIs, line crews no longer have to patrol by foot and drastically reduce the safety risks they encounter during storms or at night, both conditions which make traversing the already unwieldy Oregon coastline even more dangerous. Without the need to take extra precautions for foot patrols, the speed with which power is returned to the customer base can now be increased.

Central Lincoln PUD already had a fiber-optic and microwave link network in place between all of the 25 substations in their system. However, they did not have any dedicated communications links downstream of the substation feeder breakers. In 2013, when Central Lincoln PUD was wrapping up the implementation of their new AMI system using a 900 MHz mesh radio network, the ability to communicate to more devices over radio throughout the district increased. Not only had Central Lincoln PUD established communications to the industrial, commercial, and residential digital AMI devices, but they advanced the communications out to an additional array of DA devices without having to create an entirely new network. These devices included regulator banks, three-phase and single-phase reclosers, VFIs, motor-operated sulfur hexafluoride (SF6) switches, and FCIs. Now, with the ability to communicate to the DA devices via radio, Central Lincoln PUD is able to bring any binary or analog data points that IEDs can provide back to their SCADA system. This new benefit of seeing devices between the substation and the endpoint meter data opens the door to having an outage management system that shows real-time system data on the SCADA HMI.

During the investigation of integrating DA devices into the SCADA system, systems engineering planning became aware of a new FCI device that communicates over the same radio network that was being used for the AMI devices. By having one 900 MHz radio network, Central Lincoln PUD would only need to configure, maintain, and operate a single radio network. Additionally, both in-house personnel experience in using the network and the ability to easily maintain one network rather than having to manage multiple radio networks is obtained. These were all added benefits from an engineering design and system management perspective. However, the main benefit was to the district operator and operations, which now have near real-time fault circuit monitors showing when and where a faulted circuit occurred on the system.

An additional advantage of having communications-capable fault location information coming into the SCADA system via FCIs is the feature of load logging on the feeder. Central Lincoln PUD has found that the load-logging feature is a key planning consideration during distribution feeder examination when feeder reconfiguration is desired. System engineering planning uses the load-logging data when planning to reconfigure the system.

IV. Lessons Learned

The biggest lesson learned from the wireless FCI deployment at Central Lincoln PUD was to properly plan ahead by choosing the FCI locations, making a test plan, and integrating the data. Planning, especially the testing phase, is much more imperative for wireless FCIs compared with traditional FCIs. Adequate planning ensures that wireless fault indicator deployment will work correctly the first time.

Each deployment location for the wireless FCIs was carefully evaluated and selected to provide the most benefit when trying to find a fault. Applying fault indicators at every span would provide the most data about the system, but because of the high associated cost, this was not a practical approach. To minimize cost while still providing necessary fault information, only ideal installation sites were chosen to optimize the wireless FCI benefits. Central Lincoln PUD chose installation locations in inaccessible areas that were difficult for line crews to patrol. The wireless FCIs provide the most benefit when the time to find a fault is minimal, so strategic placement of the sensors is a key factor in reducing the fault-finding time.

The location of network repeaters and routers also plays a crucial role when selecting wireless FCI installation locations. Network repeaters transmit the data from the FCI back to the substation or takeout point. Installing an FCI within close proximity to these repeaters makes the FCI communicate data more reliably. In Central Lincoln PUD areas that had no repeaters or marginal network coverage, the network reliability was significantly increased by the addition of repeaters.

Bench testing of the wireless fault indicators and communications links turned out to be one of the most vital steps to ensuring a successful deployment. Traditional noncommunicating FCIs are relatively easy to deploy and require no or minimal predeployment testing and validation, but wireless FCIs offer much more complex functionality. As with any new technology, testing prior to deployment is critical. Central Lincoln PUD worked with the FCI manufacturer to create a repeatable and comprehensive plan to fully test FCI functionality, including testing permanent and momentary faults, loss of current, load current, and other wireless FCI functionalities. This testing plan establishes a best-known deployment method that will be used for future deployments. In addition, the entire system (consisting of the FCIs, the head-end radios, and the real-time logic processor and data concentrator) was also tested in the laboratory prior to deployment. This test phase ensured that the wireless FCI data were properly routed to the RTU and SCADA system for all endpoints. Fully testing the entire system in the laboratory also provided the confidence needed before deploying units in the field.

Using a systematic approach to integrate the data into SCADA paid dividends down the road. Having a systematic procedure for integrating the data ensured that no data points were duplicated or missing. An integration procedure was developed, documented, and implemented for every wireless FCI. This gave Central Lincoln PUD consistency throughout all endpoints on the system. Having the data integrated correctly the first time prevented the need to go back and revise data mapping later.

V. Conclusion

Easily integrated and fully featured devices, along with careful planning ahead for FCI site locations and router locations within the radio network, made the difference in successfully deploying wireless FCIs across the Central Lincoln PUD system. Carefully selecting wireless FCI locations achieved the most benefits from the FCIs and minimized cost, while also leaving room to grow the system as the Central Lincoln Smart Grid Team 2020 project progresses. The testing phase identified any issues, which were corrected before the field installations.

By taking a systematic approach to integrating the wireless FCI data points, Central Lincoln PUD accomplished three main things. First, they ensured system-wide consistency. Second, they now collect only the most important pieces of information by eliminating redundant or missing data. Finally, they reduced overhead across the system (e.g., increased FCI battery life, improved data packaging for a quicker integration process, and preserved mesh network bandwidth). Doing these three things allows for efficient operation, especially in areas with harsh terrain and weather conditions and when reliable service is critical.

VI. References

[1] S. Gamache, J. Monsanto, R. Baldevia Jr., and D. Booth, “Central Lincoln DA Pilot Communication Architecture,” proceedings of the Power and Energy Automation Conference, Spokane, WA, March 2013.

[2] IEC 61131-3, Programmable Controllers – Part 3: Programming Languages.

VII. Biographies

JW Knapek received a B.E.E.E. from Vanderbilt University. JW went to work for a consulting company in Nashville, Tennessee, where he focused on substation and control system design. He now works for Schweitzer Engineering Laboratories, Inc. (SEL) as an application engineer in automation. JW assists customers with their integration and communications needs using SEL products. He is a licensed PE in the state of Tennessee.

Shamus Gamache received his B.S. degree in electrical and electronics engineering from Oregon State University. Shamus is an IEEE member in the Power and Energy Society and is also a member of the NSPE. Shamus is a senior systems engineer in the systems engineering department at Central Lincoln People’s Utility District (PUD) in Newport, Oregon, where he has been employed for the past eight years. Shamus is also the distribution automation manager under the smart grid projects at Central Lincoln PUD. Shamus is a registered PE in the state of Oregon.

Jakob Fowler graduated from Northern Illinois University in 2011 with a degree in electrical engineering. He was an electrical engineer intern for Falex Corporation from 2009 to 2011 and worked designing electrical systems for new tribology test machines. Jakob joined Schweitzer Engineering Laboratories, Inc. in 2011 as an associate field application engineer in the fault indicator and sensor division. He focused primarily on support for faulted circuit indicators used on distribution circuits. In 2014, Jakob transferred to the research and development division to work on the development of faulted circuit indicators and sensors.

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