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Abstract

Jackson Purchase Energy Corporation (JPEC), an electrical cooperative based in Kentucky, USA, has implemented a self-healing automation system to meet specific reliability improvement goals. The system includes 6 sources feeding 18 reclosers and switches, as well as integration with a central Distribution Management System (DMS). This type of automation solution works best when it preserves standard protection schemes and operating procedures, ties together diverse intelligent electronic devices (IED) and protocols, and allows non-scripted configuration and addition of new devices. Self healing automation systems that use sensors, controls, communications, and real-time distribution data to isolate faults and reconfigure feeders to minimize service disruption are an integral part of any Smart Grid vision.

Introduction

The first self-healing solutions used non-communicating devices coordinated with time delays and typically were installed in five-recloser loop scheme applications. Automation solutions sharing information between controls evolved using wireless communications. The first self-healing systems often used peer-to-peer communications and programmable logic to achieve an automated response to power system disturbances.^{[1][2][3]} The solution described uses fiber optic communications and configurable topology for easy implementation and future automation system expansion.

Location

Jackson Purchase Energy Corporation is a regional electric utility serving 29,000 member-owners in six counties of far western Kentucky (KY). The company owns and maintains more than 2,900 miles of line and 27 step-down substations. The Distribution Automation project is located in the commercial area surrounding and including a mall in Paducah, KY.

Existing System

The existing system was divided in 2 sections (Figure 1). The first section consisted of two motor-operated “dumb” switches that used voltage sensing to provide a backfeed for the mall. In the event a fault occurred on the primary feeder, one switch was designed to open and the other to close to pick up service to the mall from the secondary feeder. Each

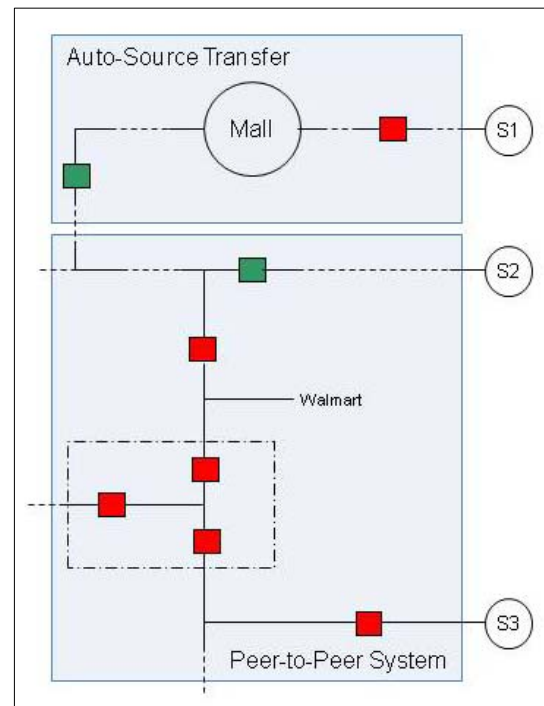


Figure 1: Existing System

switch was paired with a set of potential transformers (PT) to measure voltage. When the controls would sense a loss of voltage, the system would operate. The system would switch the load between two feeders on different substations.

The second element of the existing system consisted of three “smart” overhead switches and one “smart” pad-mounted switch using peer-to-peer communications to provide increased reliability to a few critical commercial accounts in the area of the mall. This system was designed for fault isolation and added reliability to just a few customers. The system used current transformers (CT) and PTs to sense faults and loss of voltage and then would switch the system to isolate faults and restore service to as many customers as possible. The controls communicated to each other using mesh network spread spectrum radios. This system was only good for switching loads between two sources and switched between two feeders on separate substations.

Why a new DA System?

Both of the existing systems were very unreliable. The switches in both systems operated correctly sometimes, but failed to operate correctly in most events. The line crews were often left trying to determine how to restore the system in addition to repairing a fault. Higher outage times were encountered — instead of the lower times the systems were designed to provide.

Part of the unreliability of the previous system was that it used spread spectrum radios that required line-of-site for communication between the switch controls. In the years since the original system was installed, commercial growth in the area has caused the line-of-site radios to become less efficient. In the past year, optical fiber was installed in this area and could be used to communicate between the switches in the DA system. This provided faster, more reliable communications for the overall system.

The programming of the peer-to-peer system was also complicated and cumbersome. Engineers would invest hours of time for every misoperation of the system, trying to understand and modify the programming (to avoid recurring problems).

In the end, very few customers in the area of the mall benefitted from the existing systems. JPEC wanted to consolidate the systems and expand the benefits to a wider group of customers. Prior to the upgrade, approximately 30 customers benefitted from the peer-to-peer system and approximately 120 customers benefitted from the voltage-sensing switches at the mall. With the upgrade, more than 800 customers will benefit (Figure 2). Included in the customer base benefitting from the upgraded system are several hotels, restaurants, gas stations, and other commercial businesses. Many of these businesses are important to JPEC in emergency situations (such as the 2009 ice storm), so a mutual benefit to the cooperative was realized with this upgrade by increasing the ability to keep these facilities operational.

New Automation Solution

The upgraded system provides reliability for three circuits on each of two substations to completely back each other up. This allows for one of the two substations to have complete backup. One substation has a fourth circuit that is not currently tied into the system. To increase reliability, the two stations are fed from separate transmission lines.

The feeder automation system that was chosen by JPEC utilizes a decentralized architecture (Figure 3). The decentralized architecture consists of redundant substation processors (one active, one standby) communicating with the field devices and also sending information to the DMS system. The DMS sends commands to the automation system by communicating directly with the active substation processor. The substation processor pushes any commands for field devices from the DMS directly to the

respective IEDs. This architecture has many advantages over a peer-to-peer system or a centralized architecture.

In addition to the flexibility of the field devices, the new automation system can also utilize multiple communications media. The recently installed optical fiber network can be utilized for

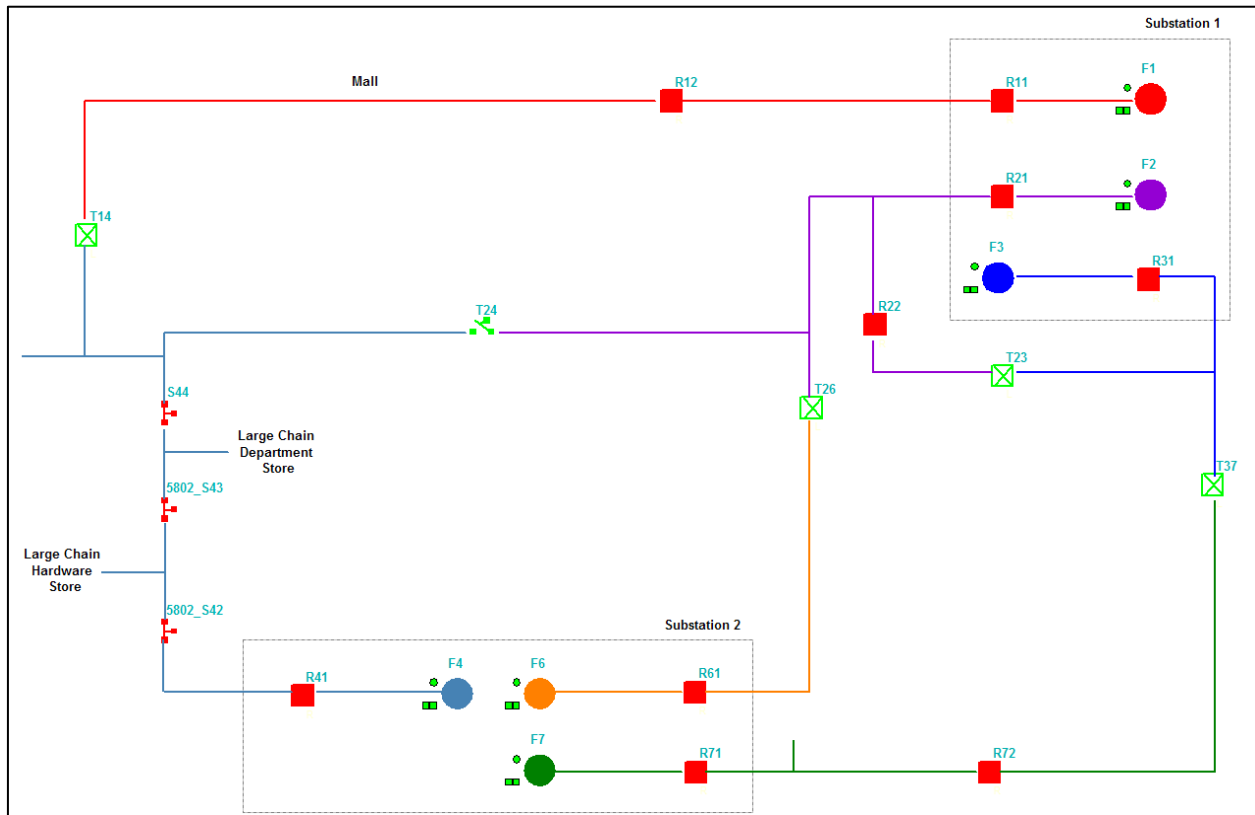


Figure 2: New DA System

Peer-to-peer systems typically require the utilization of only one vendor for all protective line devices or the purchasing of a separate piece of hardware to interface with alternate vendor equipment. One benefit of the chosen solution is the ability to incorporate multiple vendors' equipment. While the previous system did not always work, JPEC still had a large investment in the equipment. The chosen solution allowed for incorporation of the existing equipment into the expanded DA system. This allowed for an initial cost savings by not having to replace the existing switches immediately. Also, using equipment already familiar to operations personnel meant little training was required for them to feel comfortable working on feeders tied into this system.

the new controls while maintaining the spread spectrum radio network for the existing hardware. This can be accomplished because the substation processor communicating with all the field devices has multiple connections available.

The substation processor handles any protocol conversion that might be needed from using multiple vendor IEDs. It also normalizes all the data from the field devices into a central database for use by the Feeder Automation (FA) Engine. The FA Engine monitors changes in the database that trigger the automation logic.^[4] When automation is needed, commands are sent through the database and out to the specific controls. This means the FA Engine is separate from the communication server and

does not require any specific protocol or communications media information.

Since all the automation logic is handled in one central location, diagnosing what occurred is easier than with a peer-to-peer system. The FA Engine records all automation logic and system events in a single log on the substation processor that can be used as a comprehensive sequence of events and diagnostic tool.

Another advantage to the decentralized architecture over the peer-to-peer system is the scalability. A smaller system can be easily expanded without having to reprogram several devices. Two other substations with ties into the two stations currently utilizing the system will be included in a future expansion of the DA system. A new high school and hundreds of residential customers may benefit from this future expansion.

One of the common arguments against a decentralized or centralized system is the single point of failure. This problem is mitigated by implementing redundant substation processors. JPEC has installed two substation processors, one in each substation associated with the automation system, which communicate with each other over the fiber network. If the active substation processor fails for any reason, the standby substation processor will take over the communications and control of the automation system. The failover is transparent to the field devices because both substation

processors are configured with the same communications settings. The failover is also transparent to the SCADA system due to the use of a shared virtual IP (internet protocol) address that is only active on the active substation processor.

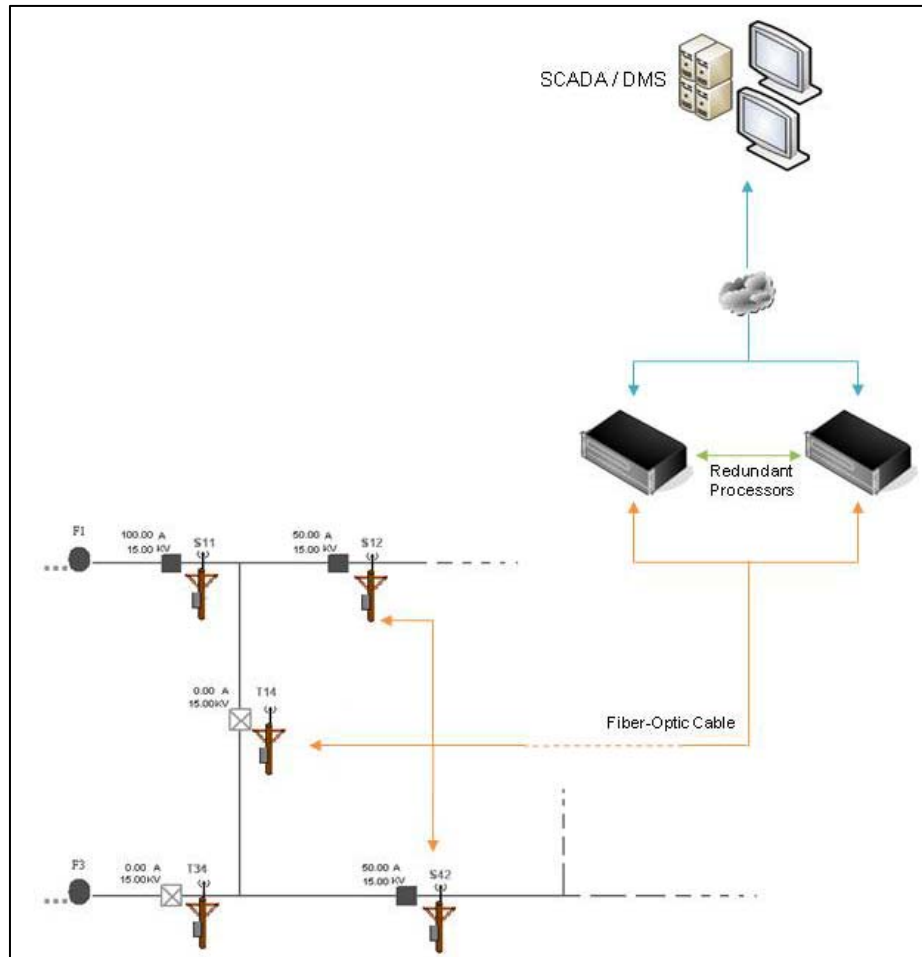


Figure 3: System Architecture

Automation Functionality

The FA Engine supports four different base management algorithms that control or respond to devices opening on a feeder: Fault Management, Voltage Management, Load Management, and System Fault Management. Fault Management is triggered by a fault condition that must be isolated before power can be restored to other zones. Voltage management is triggered by a loss of voltage

and implies that only reconfiguration of the system is required and that no zone must be isolated. Load management is responsible for load transfers and shedding. System Fault Management is a no-response routine reserved for notifying the feeder automation that no response is required (such as during frequency load-shedding).

The core of the self-healing distribution automation system is the ability to isolate faulted line segments and reconfigure resulting de-energized zones to alternate sources to restore power. The fault management algorithm is responsible for the isolation of faulted zones. This goal is achieved in the Feeder Automation software using a standard set of rules that are applied with only system topology input from the user. No scripted programming is needed which would add complexity. The FA Engine compensates for miscoordination, missing information, and devices on the system that do not trip for faults (such as automated load-break switches).

The fault isolation algorithm is triggered when a lockout point is received from the device, creating a new disconnected link, and a fault target is received. The FA Engine will then use information from all the devices on that link to determine the fault location. The devices surrounding the faulted section are sent a command to open (to isolate the fault).

When the faulted section has been isolated, the FA Engine can begin the reconfiguration algorithm to restore power to as many unfaulted zones as possible. Upon reconfiguration, the system will evaluate all possible connection points for the link. By default, the link will be moved to the tie switch with the greatest amount of capacity. It will also ensure that no devices on the new link will become overloaded by adding the unpowered link. Alternatively, the automation system can be configured with preferred alternate sources. The FA Engine will attempt to move the entire link to any feeder with available capacity as a whole before it considers fragmenting the link into individual zones.

The Feeder Automation system is designed so that it will not interfere with manual operations initiated by field personnel or SCADA operators. The system does not take any control action when it sees any device close because of some external request (external to an automation-initiated request).

The FA system supports voltage management at any device location. A voltage management event may be driven by undervoltage tripping from the device itself or initiated by the FA Engine detecting a loss-of-voltage condition and initiating a control action. In a voltage management event only a single device needs to open at the first location with a loss of voltage to prevent backfeeding. The reconfiguration algorithm then restores power to the de-energized zones.

All load management functions are triggered when the FA Engine calculated demand current exceeds the configured limit. The system can transfer zone segments from one feeder to another to relieve overloading without intentionally dropping customers. Alternatively, if load levels rise too high, the Automation Engine can de-energize zone segments after load transfers have failed to relieve critical overloading.

DMS Integration

The most common source of error in any automation system is in the communications setup. The decentralized architecture simplifies the communications setup by having only one master for all the field devices and one slave to the Distribution Management System. The substation processor is configured to communicate with the field devices using their native protocol (DNP3) and this communication setup is transparent to the DMS. The DMS is configured to talk to one device, the substation processor, which contains all the data from the field devices.

Having a DMS system communicating with the substation processor allows JPEC to monitor the

devices in the field as well as the automation system on a real-time basis. This allows for faster response times to events on the system. As soon as an event occurs, the dispatch center can notify operation personnel so they can begin any necessary repairs.

The DMS system also allows for faster restoration after repairs have been completed. The automation system has a single command to return the system to the normal state. When operations personnel verify that repairs are complete, the dispatch center can send the command to the Feeder Automation Engine to return the system to normal (without an interruption of service to any other customers). The FA Engine accomplishes this by first closing in any open devices, and then opening the tie device. With this single command, restoration can be accomplished very quickly.

Conclusion

JPEC's implementation of self healing automation software will improve reliability on critical distribution circuits, while preserving traditional feeder protection schemes and operational practices. Diverse IEDs have been integrated into a common automation system with real-time visibility via an interface to the central DMS system. The automation system hardware and software platform provides capacity for future expansion. The configurable structure of the software algorithms will allow easy addition of new IEDs or modification of the current schemes. The simulator module provides a tool for creation and testing of new schemes, as well as for training personnel. Detailed logs of automation logic, commands, and events are used for detailed analysis of faults and possible system improvements. Reliability of the automation hardware has been enhanced by the installation of redundant automation processors in separate substations. All these features combine to minimize disruption of customer service and make self-healing feeder automation an integral part of JPEC's Smart Grid vision.

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Author Biographies

Tracy Bensley is Vice President of Engineering and Operations at Jackson Purchase Energy Corporation in Paducah, KY, USA. Prior positions include Sr. Vice President of Electric Operations at Lumbee River EMC, President at Electrical Consulting Engineers, Inc., and Estimator/Project Manager at R.H. Bouligny, Inc./Vanderpool, Inc. Tracy received an A.S. in Pre-Engineering at Pensacola Junior College and a B.S. in Electrical Engineering from Florida State University. He is a member of the Institute of Electrical and Electronics Engineers (IEEE), a Tennessee Valley Public Power Association Certified Power Executive, and a licensed Professional Engineer.

Charlene Grommesh is an engineer at Cooper Power Systems, a division of Cooper Industries. She received a BS in Computer Engineering from Marquette University in Milwaukee, WI, USA. Charlene joined Cooper Power Systems in 2004 and her experience includes communications, training, customer support, marketing, and protection software scheme development. She's been working in distribution automation since 2005. Charlene has authored several technical application manuals and co-authored a paper presented at DistribuTECH in 2009.

Peter Stenborg is a Project Manager for self healing automation software applied with reclosers and switches to improve reliability of medium voltage distribution circuits. In more than 25 years with Cooper Power Systems (RTE Corp.) his experience has included the application of transformers, overcurrent protection, automatic step voltage regulators, and the testing, processing and application of dielectric coolants. He earned a BS in Mechanical Engineering and MBA from the University of Wisconsin – Madison, USA, and is a licensed Professional Engineer.