Power System Engineering, Inc.

Improve Outage Handling and Protection

Four Ways Automation Can Improve How You Do Things Today

By Power System Engineering, Inc. (PSE)

Sometimes using the same process for many years can mean missed opportunities for improvement.

Introduction

Many utilities address outages using processes they have developed over years. The benefit of this approach is that these tried and true methods are well understood by everyone involved during an outage event. However, sometimes using the same process for many years can mean missed opportunities for improvement. And many utility engineers are not fully aware of what other options are available.

This article will review four different ways to improve outage handling and protection through automation currently available. Today, utilities are making improvements in how they:

- **Detect Outages and Locate Faults**
- **Recreate What Happened During a Fault**
- **Improve Restoration Time**
- **Reduce Miscoordination**

Some of these improvements are very straight forward to implement and use much of the equipment and software your utility likely has in place today. Other improvements rely on new software and systems. In those situations, it is helpful to understand the benefits to help determine what new software and hardware would be most advantageous for you.

While OMS systems are helpful in using customer reported outages to trace fault locations, other systems can also be used to detect and locate outages sooner.

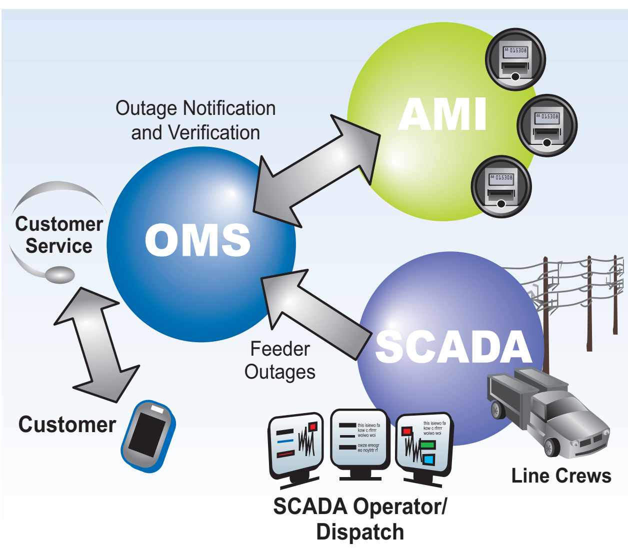
Outage Detection and Location

Many utilities become aware of outages when customers call to report that their power went out. And line crews are often dispatched to drive the lines looking for a fault based on which customers have called. While utility OMS systems are very helpful in using customer reported outages to trace possible fault locations, other existing systems can also be used to detect the outages sooner and improve the utility crew's knowledge when attempting to locate a fault.

All of the essential items needed to realize these improvements may already be in place at your utility:

- **SCADA:** Many utilities have SCADA systems in place and use them at least to monitor the status of substation breakers.
- **Relays:** Most utilities also have microprocessor based (Intelligent Electronic Device – IED) relays for protecting feeders.
- **AMI:** Many utilities have invested in automated metering (AMI) systems to improve how they get information from customer meters.

What utilities often lack, however, is integration. These systems can be integrated—with little expense—to great advantage. The graphic shows a typical process for performing outage detection with all of these systems integrated and working together.



Typical Outage Detection Process

1. Relays trip or detect overcurrent sending fault information to SCADA.
2. SCADA displays fault information to the dispatcher.
3. SCADA sends fault distance and type to OMS.
4. OMS requests meter status from AMI in possible affected areas.
5. AMI pings meters and determines outages.
6. AMI sends meter status to OMS.
7. OMS and SCADA information available to customer service and line crews.

While this information sharing may not save enormous amounts of time or money, it allows your utility to operate more efficiently and smartly. In addition, being proactive to an outage situation, rather than reactive, provides your customers and members with greater comfort that they are being well taken care of.

It is helpful to your engineers to be able to easily obtain detailed relay forensics about what fault type occurred and when.

Recreating Faults

Beyond the initial urgency in detecting a fault and restoring power, it is often helpful to understand what caused the fault in the first place. It could be that miscoordination occurred and engineering wants to go back and look at what happened on each phase to understand how they should adjust their time-current curves or overcurrent thresholds.

In these instances, it is helpful to be able to easily obtain detailed forensics from the relay about what fault type occurred and when, as well as to be able to view each of the 3-phase current waveforms to understand how the trip occurred.

Most relays provide two levels of event reports. The basic relay event report contains the time the event was triggered, type of fault, fault current magnitude, distance to the fault, recloser shot count, and frequency when the fault occurred. Bringing this basic information back to your SCADA system is very beneficial so operators can access information such as whether the fault type is a single phase-to-ground fault, phase-to-phase fault, or 3-phase fault.

Beyond this, it is possible to bring back much more sophisticated data easily. Most relays provide a second level of event reporting that includes ¼ cycle waveform data for all voltages and currents for multiple cycles before and after a fault event occurs. However, many engineers do not have this data easily available in their current system. Instead, they have to drive to substations and feeder reclosers to extract the data from the IEDs. Having a system that is properly configured so that time synchronization via a GPS clock is set up in each device as well as having devices configured so the software can easily extract the data remotely allows engineers to be efficient in investigating potential problems.

Improving Restoration Time

Fault Detection, Isolation and Restoration (FDIR) systems are increasingly being explored by utilities. FDIR automation can significantly reduce customer outage time around a faulted line segment. However, when considering FDIR, it is critical to understand that there are many different ways of implementing it. Understanding what you want to achieve and how the different technologies can work with your existing technology is critical to determining what is most appropriate for you.

The table below provides five different methods by which a utility can automate the process of isolating a fault and restoring power from unaffected areas. Each option is very different in terms of the objective it attempts to achieve. When implementing an FDIR system, many utilities are simply trying to reduce restoration time below the time required for a line crew to drive a line to find a fault, isolate it, and close tie points manually before beginning the work of repairing a faulted section of line.

Method		Procedure	Timeframe
1	Operator Activated Restoration	Operator detects trip with SCADA alarm, determines switching steps, coordinates with line crews, perform isolation and restoration	5 minutes
2	Standard Automated Restoration	Software determines most likely fault location, isolation and restoration strategy	30 seconds - 2 minutes
3	High-Speed Automated Restoration	Products operating over high-speed communications perform rapid isolation and restoration	1 - 2 seconds
4	Automatic Source Transfer	Localized critical load source switching	~100ms (6 - 10 cycles)
5	Direct Transfer Trip	Transmission line protection between separate substations	~100ms (6 cycles)

The simplest means of accomplishing FDIR is by implementing a SCADA system in which an operator can work in conjunction with line crews and issue trip and close commands to substation and feeder reclosers when they see that a breaker has tripped. If a utility has an operator on duty, they can isolate the fault and restore power to many customers in as little as 5 minutes. Even if the utility does not have a

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manned operation center, isolating and restoring power to customers by manually performing operations via SCADA can still mean significant time and cost savings over performing isolation and switching solely with line crews. This first step of automation can greatly reduce outage time if operators are available to monitor the SCADA system.

Methods 2 and 3 from the table on the previous page describe centralized and decentralized FDIR solutions in which software and hardware automatically detect an outage and determine appropriate isolation and restoration across multiple substations and feeders. The offerings in these categories vary in terms of the level of control operators have over the restoration and the amount of system modeling that is done as a part of calculating the restoration solution. Methods 4 and 5 describe solutions specific to restoration for a single critical load or for a specific section or transmission line.

Below is a list of several factors that should be considered when investigating an FDIR solution via methods 2 and 3.

- **Load Flow Modeling:** Should the FDIR system attempt to predict feeder voltage and available capacity before offering a restoration solution?
- **Visualization:** Do the operators want to view the system geographically or through a system-level one-line?
- **Configuration and Maintenance:** How complex is the data that goes into the FDIR automation, and how will you maintain this system as it grows?
- **Integration:** How should the FDIR system be integrated with your AMI and OMS?
- **Load Management:** How does the system handle changes in loads, and how well can it balance load?
- **Communications Tolerance:** How well does the system handle communication system limitations?

While each vendor's solution has unique benefits, the speed of restoration obtained via centralized and decentralized FDIR solutions is most significantly impacted by the speed of communications to the substation and feeder reclosers. Some systems are tolerant of communications over slow networks, but others require high-speed networks in order to operate properly. Selecting the communications network appropriate for your terrain and territory size will have the single biggest impact on the restoration speed.

Reducing Miscoordination

Beyond FDIR systems, which assist with automating restoration, several vendors offer products that can help utilities avoid miscoordination issues between multiple reclosers in close proximity. Some utilities are faced with miscoordination challenges within cities, or any situation in which distances between reclosers is limited. Others face challenges as they attempt to increase the number of reclosers to improve the ability to isolate a fault.

Several vendors have designed unique capabilities into their reclosers and recloser controls that mitigate some of these issues. Some vendors have built into their devices the ability to reclose for a very short period of time in order to simply to check whether a fault is still present. This allows multiple reclosers to sequentially test for a fault which has been seen by a series of units. Testing for a fault in this manner can allow the reclosers to use similar or identical time-current curves and resolve miscoordination afterward.

Another solution relies on high-speed communication between reclosers to indicate which recloser is closest to a fault so that only the closest recloser opens. This type of solution allows multiple reclosers to use identical time-current curves and simultaneously select only one of them to operate on a fault.

Yet another miscoordination solution uses high-speed communications to share instantaneous current information between reclosers so that the reclosers can analyze the differential current between the devices and determine, based on current flow, the location of the fault and how to properly isolate it. This type of solution also relies on the high-speed communications to begin the isolation of a fault and restoration of power to unaffected areas even while upstream reclosers are executing reclose operations to clear the fault.

Understanding automation solutions from recloser vendors and whether you can implement these practically over the communications options available to you can improve your overall coordination.

There are many ways automation can improve upon the tried and true processes your utility has been using for years.

Summary

There are many ways in which automation can improve upon the tried and true processes your utility has been using for years. The key is to understand several important factors when making your decisions:

- **Technology Fit**
  Understand what technology will help you address your unique situation while adhering to your protection and safety principles.
- **Protection**
  Understand how the protection principles you are currently using are impacted during faults and restoration.
- **Operations**
  Understand how your operation procedures determine how you apply automation and how automation will impact those procedures.
- **Communications**
  Understand how communication impacts the performance you receive from your automation program and set expectations for whether the technology you are considering will perform as you hope it will.

PSE has experience in implementing many different automation systems and would be glad to assist you in designing an automation system that fits your needs.

About the Author

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Jim has BS degree in Electrical Engineering from Milwaukee School of Engineering, Milwaukee, WI and a Master's degree in Business from Edgewood College, Madison, WI. He has over 20 years of engineering experience and leads the SCADA, Substation Modernization and DA focus areas for PSE. Jim assists utilities with plans for upgrading substations, accounting for security based on NERC CIP requirements. He also leads procurement, design, and deployment of SCADA systems for cooperatives as well as municipalities. In addition, he has a strong background in communications systems for monitoring and control based on spread-spectrum, licensed, cellular, and Wi-Fi technologies.

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