21, rue d'Artois, F-75008 PARIS
http : //www.cigre.org

CIGRE US National Committee
2014 Grid of the Future Symposium

New Tools for Managing Smart Switching Devices

C.A. MCCARTHY
S&C Electric Company
USA

SUMMARY

Electric utilities have been accelerating the deployment of "smart" switching devices, featuring communicating controls, on medium-voltage distribution systems. Such controls perform measurements of power system voltage and current, and may take inputs from other devices or higher-level systems. The controls use onboard logic to determine if a switching action is required and, if so, implement the switching action and communicate the change back to the system operator.

The application of smart switching devices offers a wide range of benefits. For example, they can provide a higher level of electrical system efficiency and reliability to users than the traditional, labor-intensive procedure associated with service restoration after a fault. But as more and more smart switching devices are added to distribution systems, the balance can tip . . . improved electric system efficiency and reliability may come at the expense of utility operational efficiency. Communicating, decision-making controls need more frequent attention than non-communicating devices. New tools are thus required to manage the ever-increasing fleet of smart switching devices, from both Operations and Engineering points-of-view.

KEYWORDS

Smart Distribution, Data analytics, Reclosers, Pulseclosers, Self-Healing

christopher.mccarthy@sandc.com

1. Visual Aids for Operational Status

The grid of the future includes an abundance of smart switching devices on the medium-voltage distribution system. To fully realize the benefits of large numbers of these devices, utilities need tools that will permit them to better utilize the data offered by the devices, along with improved diagnostics. A great deal of data is available today, but isn't automatically correlated with multiple devices. And SCADA operation centers typically receive more data, via protocols such as DNP3, than the operators can fully absorb and utilize in real-time. Further, there are inefficiencies in how the data is presented, understood, and acted upon.

This paper describes a few scenarios in which a centralized remote monitoring and management tool can significantly improve a utility's operational efficiency by accessing more than the typical SCADA data from smart switching devices.

Figure 1 shows how the tool provided operations personnel with an easy-to-understand visualization of a 90-device, self-healing system, during an actual major storm event, as it unfolded over time. SCADA data points were available, providing the open/close status of each device, along with the ready/not status of each device's self-healing functionality. Although the operations personnel received this data, it was difficult for them to quickly assess the state of the system from the myriad of individual data points.

By contrast, the operations personnel could quickly assess the status of the devices from the stacked bar chart of the tool, built from the same data points. The chart shows the total number of devices that aren't ready for automatic operation, trended over time. At the beginning of the storm, a number of devices reported a "Faulted" condition as a result of a tree branch contact, a lightning strike, or some other problem that caused an outage for that section of line. In the second bar, some devices reported a "Communication Loss," indicating that the storm caused interference or damage to the communication system, or that the devices lost both ac and battery backup power. It took several hours for the storm to pass through, and the number of devices reporting a Faulted state continued to climb.

Although it isn't apparent in this chart, non-faulted devices performed automatic self-healing during the storm, to restore power to all non-faulted line sections. Line sections reported as Faulted likely suffered some physical damage that must be repaired. At the peak of the storm— shown in the fifth column—17 devices reporting a Faulted condition. Thereafter, as is apparent from the decreasing Faulted category, line crews are repairing damage and performing manual operations to return the system to its normal state.

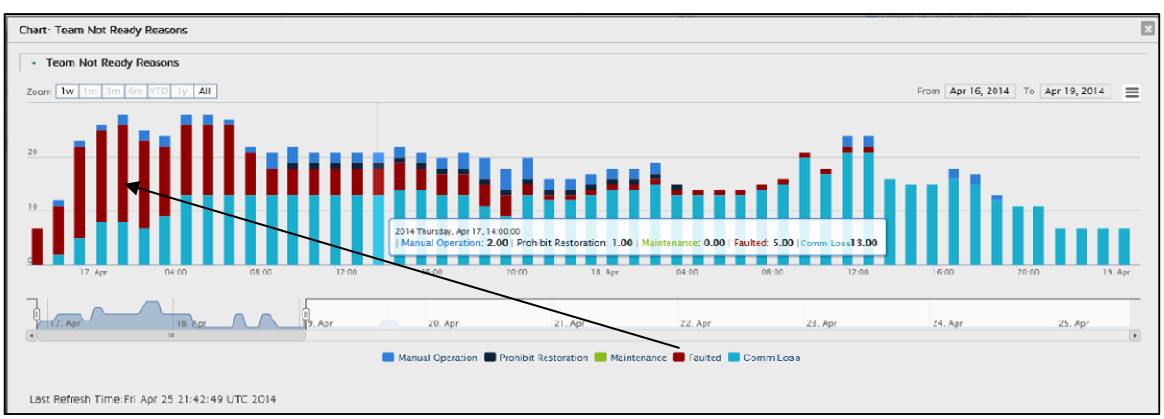

Figure 1. Status of 90-device, self-healing system during a major storm event.

From this single chart, which was updated throughout the storm event, operations personnel received a quick and useful indication of the status of the 90 devices. Additional charting capabilities allowed more detailed views showing, for example, all the devices reporting Faulted condition, their locations, and circuit numbers.

2. Remote Engineering Access

A common next step after service restoration has been completed is downloading of waveform capture and event files. These files are used in an engineering review of the performance of the system, as well as to attempt to understand the root causes of outages. But assessing the root causes of the outages and performance of the system becomes more and more difficult, as the volume of data increases greatly with the ever-increasing number of smart switching devices.

A remote monitoring and management tool can improve a utility's operational efficiency by providing a mechanism for remotely downloading waveform capture and event files. It eliminates the time delay and cost associated with rolling a vehicle to each device site to capture this data.

This tool offers an additional level of oversight too. Events that occur on multiple devices, including those that occur simultaneously on multiple feeders, can be correlated. Viewing the activity of multiple devices at the same time better completes the "big picture" of what happened. For example, if the waveform capture in Figure 2 is evaluated by itself, it appears to be a temporary fault that was cleared by this device, since the source-side voltages, Vx, were present throughout the event and the device was only open for a few seconds before closing and restoring service.

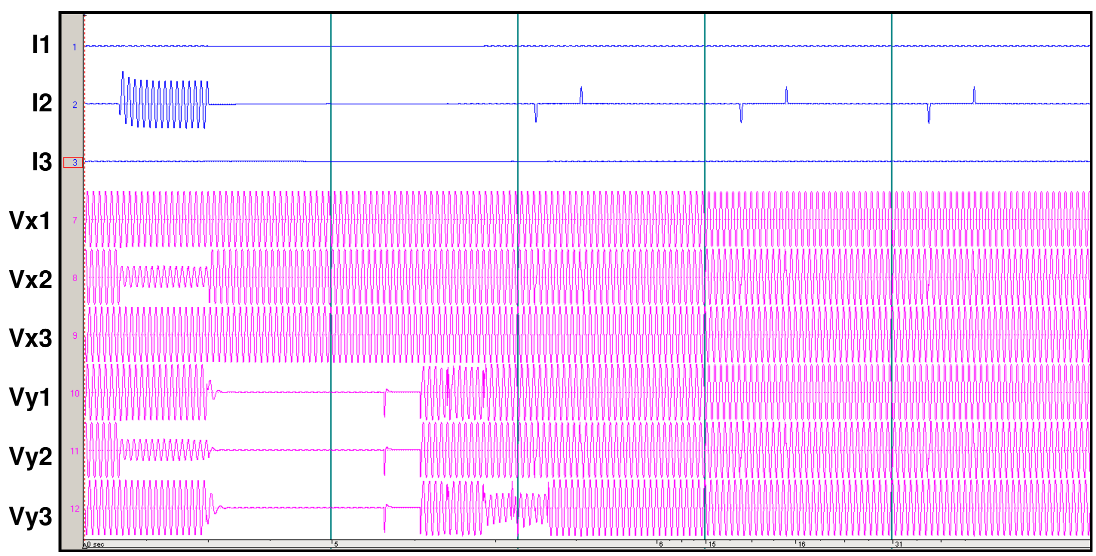

Figure 2. Waveform capture from upstream pulsecloser.

But when the waveform from a downstream device, shown in Figure 3, is included in the analysis, it is apparent that both devices tripped at the same time and, after a few seconds, the upstream device pulseclosed and restored service to that line segment. The downstream device also pulseclosed several times, to test the line for the presence of a fault. But since a fault was detected each time, the fault was considered persistent and that device locked out. On a typical distribution system, many events on feeders result in sympathetic voltage sags on adjacent feeders. A tool such as this, that can automatically correlate these events, will quicken the understanding of the simultaneous events.

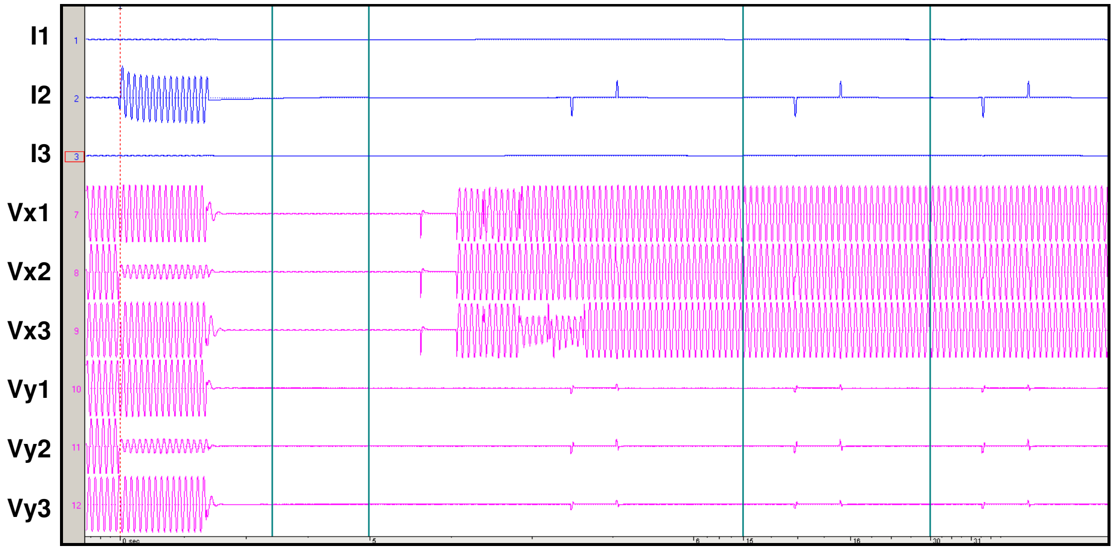

Figure 3. Waveform capture from downstream pulsecloser for the same event.

The ultimate benefit to utility engineers would be automated data collection after field events, coupled with software offering an assessment of the performance of the system. Such an arrangement would preclude the need to identify all the devices involved, collect and analyze the data, and form a conclusion. For example, were all the line sections that were not Faulted put back into service in less than one minute? If not, can the inability to achieve that objective be traced to intermittent communication? Or, were there loading constraints in place that prevented full restoration? The more automated the data collection process becomes, and the more hypotheses that the software can present based on the data, the more time engineers and technicians will have available to focus on system restoration and/or fine-tuning the application.

3. Beyond SCADA Data

Real-time operation of the electric utility distribution system is limited by the visibility of the smart switching devices, which is essentially the mapped SCADA points list. Each device type has a list of available information, and a utility can select the data they desire from that list. But if the manufacturer of the device did not expose a certain parameter or measurement in the points list, the utility has no easy means to acquire that piece of data.

Here's an example of the effort needed by a utility and a device manufacturer to add a new SCADA point, to gain visibility to a currently unavailable piece of data.

Let's say a normally-open device has voltage sensing on both sides, as shown in Figure 4. The utility has a practice of not closing a normally-open switch on a sub-transmission system when the voltage angle is more than 5 degrees out of phase across the switch. Local sync-check functions can be configured to block closing in this instance. But the utility would like to know ahead of time, for all their normally-open switches, which ones can be closed and which ones are outside the desired switching limits.

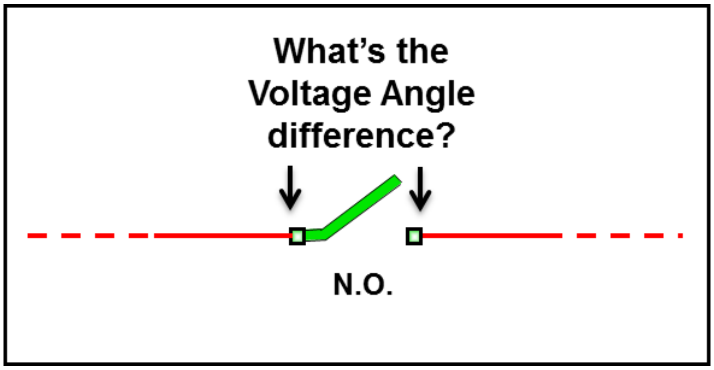

Figure 4. Depiction of the desired switch information.

Voltage sensing is presently provided on the device, so the fundamental measurements are already being made. In fact, the control is already calculating the voltage angle difference for use by the sync-check function. But this calculation is not currently exposed to the SCADA system.

For this scenario, let's assume that the utility asks the device manufacturer to add a new SCADA point providing the voltage angle across an open switch. The steps involved with this enhancement include:

1. Manufacturer needs to understand the request, accept it, and specify it
2. Manufacturer needs to add three new SCADA points for Δ Voltage Angle in firmware
3. Manufacturer needs to add support for the new SCADA points in the configuration software
4. Manufacturer needs to update and publish literature reflecting the new SCADA points
5. Manufacturer needs to wait for next software release cycle and then post the new SCADA points for customer use
6. Utility needs to download the updated software
7. Utility needs to install the updated software on appropriate users' PCs
8. Utility needs to install new firmware on all smart switching device controls
9. Utility needs to update control settings to add the new SCADA points
10. Utility needs to update the SCADA system to poll the new points
11. Utility needs to view SCADA points, one device at a time, to determine status

This effort, and the time required to effect it, can be greatly reduced if the remote monitoring and management software can access non-SCADA information from the smart switching devices. Replaying the same scenario with this technology has far fewer steps:

1. Manufacturer needs to understand the request, accept it, and specify it
2. Manufacturer needs to update the software to retrieve Δ Voltage Angle from device
3. Manufacturer needs to post the updated software
4. Utility needs to download and install the updated software (one instance)
5. Utility needs to go to updated dashboard display to view Δ Voltage Angle charts and graphs for all devices

The ability to access any additional SCADA points desired significantly reduces the number of computers, controls, and SCADA templates that need to be "touched" to add this functionality. In fact, a single software update accomplishes much more than a labor-intensive embedded firmware update, since it presents a visual aid for understanding the status of all devices at the same time.

This example could be effected even more quickly if the IEC 61850 protocol were used to publish local device data. There would be no waiting for the device manufacturer to update software. Instead, the utility could directly retrieve the relevant data points and perform the calculations in other real-time tools that make use of IEC 61850 data.

But ubiquitous use of electronic controls furnished with IEC 61850 protocol is a long way into the future. There is a need for advancements in remote monitoring and management tools right now, for better visibility of distribution system activity using protocols such as DNP.

The next advancements should include a means for tracking the benefits of deployed automation systems. Today, the major benefits of these systems—customer outages avoided, voltage sags avoided, and momentary outages avoided—are usually not tallied over time, or at least not in an automated manner. There is much knowledge to be gained by trending switching activity to understand how the system is actually performing, thereby highlighting the benefits of automation. Such knowledge will assist utilities in making the economic justification for deploying smart switching devices.

BIBLIOGRAPHY

[1] J.D. HUSS, Ameren Missouri, USA and C.A. MCCARTHY, S&C Electric Company, USA "Demonstration of Pulsecloser Applications and Benefits in Ameren's Distribution Automation Program" (CIGRE US National Committee 2012 Grid of the Future Symposium)