Integrate or Not – A Comparison of Technological Advancement and Costs

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***Abstract*—Some utilities have not kept up with technology and believe money has been saved by keeping practices that have worked in the past. This paper compares two similar utilities who took two very different approaches on technology and competing in the ever-changing utility world. One chose to be on the very leading edge of technology while the other chose to keep things as they were and not change with the times.**

This paper describes how each utility chose to upgrade their systems in this day and age of smart devices. While their system loads are similar, the service territory of one utility is much larger. One has a legacy supervisory control and data acquisition (SCADA) system that has been in place for over 25 years. The second installed their SCADA system 11 years ago.

Overton Power District Number 5 (OPD5), a utility in southern Nevada, has a very progressive attitude toward technology. Early on, OPD5 partnered with companies to help OPD5 upgrade their system. Navopache Electric Cooperative (NEC), a utility in eastern Arizona, installed a SCADA system years before most cooperatives but has only recently upgraded some equipment. They have not partnered with any companies for assistance in this endeavor.

Staying on the leading edge does cost, but the costs go down as the technology becomes accepted and used. To produce an actual amount associated with this decision is difficult, so amounts spent on past projects are used. The idea of not updating a system to save money does not always work. OPD5 installed and then replaced some equipment within a couple of years; this decision was made by the policy of staying on the leading edge. NEC did not replace any equipment until 2011; as a result, NEC has seen an increase in expenses due to equipment limitations. Some of these expenses have been longer outages and increased labor hours.

The operational processes of different utilities are extremely diverse. Technology makes the utility operational process more efficient. Smart devices and smarter work practices go together. The ability to remotely gather information from protective relays causes outage time and labor hours to decrease; overtime can more than double without proper equipment and information.

Money cannot be saved without updating equipment. Examples are given where feeders could not be closed in because of limitations in old equipment. During the winter of 2010/2011, 2,890 customers had to wait hours for power to be restored because crews had to bring on the feeders in small sections. New relaying and information gathered by smart equipment can help expedite this.

Crews depend on information to do their job; if this information is not available, not only does it cost in resources, it also takes a toll on customer satisfaction. When a utility loses the support of the customer, nothing they do is good enough.

I. Introduction

Navopache Electric Cooperative (NEC) has approximately 38,000 metered customers with a service territory encompassing 10,000 square miles in the White Mountains of Arizona and New Mexico, about 200 miles northeast of Phoenix, Arizona. The service territory elevation ranges between 5,500 and 10,000 feet above sea level. NEC, a winter- peaking utility with a tourist-driven economy, has a peak load of 90 MW. Communities served by NEC include Pinetop-Lakeside, Heber/Overgaard, St. Johns, and Springerville in Arizona and Reserve and Glenwood in New Mexico.

Overton Power District Number 5 (OPD5) has approximately 12,000 metered customers with a service territory encompassing 2,025 square miles in the southern Nevada desert, about 60 miles northeast of Las Vegas. The service territory elevation is around 2,000 feet above sea level. OPD5, a summer-peaking utility with a tourist-driven economy, has a peak load of 100 MW. Communities served by OPD5 include Mesquite, Bunkerville, Overton, and Logandale [1].

These two utilities are very similar. In the early 1980s, NEC installed their supervisory control and data acquisition (SCADA) system, and OPD5 installed their SCADA system in 2000. Both systems were very progressive at the time of installation. Each utility partnered with a manufacturer who worked with their crews and utilized as much of the currently installed equipment as possible. Once installed, both utilities enjoyed demonstrating the capabilities of their SCADA systems to others. At this point, their paths diverged, with NEC deciding not to stay current with technology, and OPD5 continuing to stay current with technology.

II. Costs and Benefits Associated With Keeping Up With Technology

OPD5 commissioned their SCADA system in 2000 and, in 2002, upgraded relays that had been installed in 1995. The additional capabilities of these relays cost the utility about $2,500 per relay installed. These relays were upgraded because of the additional features offered, which included hot-line tagging, pushbutton control interfaces, additional logic programmability, and cold load pickup.

When a crew is dispatched to work on a line, the OPD5 operator can remotely enable or disable a hot-line tag on the line. This saves time and money, whether on the way to the job site or after the crew has finished for the day. Instead of having to send someone to the substation at the start or end of the day, they only need to call the operator.

Digital relays have evolved to the point where the SCADA capabilities of the modern relay are only limited by the imagination of the operator. To utilize these capabilities, utilities must constantly train employees on the features and functions the new relays contain.

When a fault occurs on the system, in addition to knowing which breaker operated, the OPD5 operator can determine from the information displayed whether to close the breaker or dispatch a trouble crew. Quite often, this decision has been made before the first customer calls to inform them that the power is out.

OPD5 added software to their system that automatically retrieves event reports from their smart relays. This information is then used when analyzing power system operations. A single mistake in a switching procedure can cost upwards of $15,000, but the data available from smart relays can be used to prove that the equipment functioned correctly.

When OPD5 issues a switching order to reroute power for maintenance, they can easily change the settings group in the affected relays to properly protect the lines and coordinate with other protection devices. This settings group change is done remotely by the system operator.

III. Costs and Benefits Associated With Not Staying Current With Technology

Unlike OPD5, NEC has not incurred any associated costs for upgrades of field equipment and their crews have not needed training.

In late 2009 and early 2010, NEC had four outages after business hours. The crews had to bring the feeders up in pieces because of the lack of cold load pickup capabilities in the relays. This added about 2 hours of crew overtime to the restoration of each fault. If newer relays with cold load pickup capabilities had been installed, this extra time and money would not have needed to be spent and power to the affected customers would have been restored sooner. The overtime costs incurred for each of these outages was approximately $2,450, which would have paid for the relay upgrades.

During the winter of 2010/2011, heavy snow loads caused several outages on the NEC system. Once the lines had been repaired, load diversity had been lost and cutouts had to be installed during the restoration efforts. This added an estimated 8 hours to the restoration time. After the cutouts were installed, the lines were brought back up in sections, requiring additional crew time for line patrols and switching operations. This resulted in 32 hours of overtime pay.

NEC started out installing SCADA-capable devices on their system, but replacements have removed those devices. During a recent storm, one of these areas lost power and required dispatching a lineman to attempt a reclose. The breaker held, and power was restored. The costs to NEC were loss of revenue on the feeder for an hour and a half and a 2-hour callout for the lineman.

Without modern relays, the available data are very limited and the collection takes much longer. In order to determine if a relay operated correctly, a crew must be dispatched to collect the data for analysis. A committee looking at curbing outages in an area required certain relay data each week. To collect these data, a substation journeyman had to spend 1 day each week driving to the substation to manually retrieve the reports.

In 2011, NEC started to modernize some equipment. Newer technology was installed in one substation that had experienced 45 outages, five caused by equipment misoperation. They are hopeful that the new equipment will decrease the number of outages and misoperations. In another substation with SCADA control, the equipment would malfunction and open the breakers. Special procedures were implemented after this had happened three times. With the installation of the new equipment, the special procedures have been eliminated and the substation is running normally.

Because many of the NEC protective relays are electromechanical, a switching order to reroute power for maintenance will cause loss of protection coordination, so the relays could cause an unnecessary outage by picking up for load instead of a fault.

IV. Anatomy of an Outage

NEC and OPD5 both experience outages, but the actions and durations are much different.

A. *NEC Outage*

For NEC, a recent winter storm outage looked something like this.

At 7:30 p.m., a fault on the 69 kV system causes a line breaker to lock out and a downstream circuit switcher to operate. The line feeds four substations and 3,200 customers. The breaker, set to nonreclose, closes and holds. The circuit switcher then closes, which causes the breaker to reopen. At this point, the customers have been without power for about 8 minutes.

The crew opens the circuit switcher, and the breaker closes. This restores power to 1,600 customers. The control on the breaker fails and remains in nonreclose. During the storm, the breaker operates three more times, and dispatch is able to remotely close the breaker each time. If the control had not failed, high-speed reclosing would have saved approximately 10 minutes of outage time for these 1,600 customers.

The crew then opens an air switch beyond the circuit switcher and requests a close from dispatch. The circuit switcher fails to close, and the crew has to manually close the circuit switcher. Approximately 450 customers are without power for an additional 30 to 40 minutes while the crew returns to the circuit switcher.

At 11:30 p.m., the crew starts line patrols to find the fault. Because fault location data are not available at dispatch, the crew starts patrolling from the circuit switcher. Because of the ruggedness of the terrain, it can take 30 to 45 minutes to patrol

700 feet of line. Three hours later, the crew finds the fault and starts repairs. There are still 1,150 customers without power.

The failure of the control causes confusion with the crew and dispatch, which adds time to the outage. Two days later, the substation foreman is dispatched to these sites to collect relay data. Because of the snow from the storm, a snowcat must be sent to reach the circuit switcher. This takes about 10 hours and costs NEC almost $2,000. If any relay settings changes need to be made, this process must be repeated in a couple of days to install the new settings.

B. OPD5 Outage

An OPD5 outage looks something like this.

At 7:30 p.m., a fault on the OPD5 138 kV system causes a line breaker to operate. Dispatch receives the fault location data from the relay. The upstream circuit switcher is opened from SCADA, and the line breaker closed. The crew is dispatched to the location of the fault to start repairs.

V. Conclusions

Customer service is the key to any business. In the past, many utilities did not consider the customer in this equation. Both OPD5 and NEC are concerned with customer service.

In 1981, NEC justified their SCADA system based on a new type of customer who was less tolerant of poor service and long outages. As time passed, the NEC focus shifted to new construction and cost savings. In 2000, OPD5 used much the same reasoning to justify their SCADA system.

Safety and reliability improve when infrastructure is improved. The replacement of old devices with new smart devices increases the System Average Interruption Index (SAIDI) and Customer Average Interruption Index (CAIDI) numbers of a utility.

Any piece of equipment can fail, but the frequency and possibility of failure increase with age. Also, older equipment is more costly to maintain because of obsolescence and the resulting lack of repair parts. Some repair parts can be salvaged from failed equipment, but more often than not, failures occur in the same subassemblies, thus negating the use of salvaged parts.

If we look at the costs of a prolonged outage versus the cost of relay upgrades, a single outage can pay for an upgrade. By comparing the costs of the OPD5 relay upgrade and the NEC 2010 outage, we see that the labor to install the cutouts would pay for the upgrade.

As the utility workforce ages and the number of young people willing to work in the utility industry decreases [2], we must find methods to utilize crew time more effectively. During major outages, having data in the hands of the operator to use in dispatching trouble crews is paramount.

The cause of many outages cannot be predicted, but the outage time can be reduced by gathering information from smart devices connected to the power system. The closer to real time this information is collected, the faster power can be restored to the affected customers. Knowledge of the location and other information for a power system fault can be used to determine where to send the trouble crew and thus reduce outage time.

By using the communications capabilities of modern relays to gather operational and nonoperational data, crew time can be used for system maintenance and upgrades instead of data collection. Analysis of the data to determine proper operation can start at almost the same time the relay operates.

Keeping customers happy means informing them of the steps taken to increase system reliability and reduce the frequency and length of outages.

Newer safety requirements for personnel protection from arc-flash incidents have increased the need for upgraded protective relays.

OPD5 had several utilities look at what they had done after the installation of their SCADA system. During these tours and demonstrations, a question would be asked of the visitors: Are you going to incorporate parts of this system that would fit your system? Most of the answers were “no.” Some of the reasons given were: too big or small, no resources, and budget restraints. It was always felt that most of these utilities could have done anything if they would just work towards a goal.

Now, after looking at the comparison between OPD5 and NEC, it is obvious that change is hard. Converting processes and procedures that have been in place for many years will take almost as long as they did to evolve. Management and labor must be willing to work on this change together for anything to get done. The facts show that it is much better to integrate, but many utilities still do things the way they always have.

VI. Future Options for NEC

NEC has communications to all their substations and a few line locations. With the addition of a communications processor in each substation, they could provide enhanced SCADA capabilities and access to nonoperational data. Their current SCADA system has the capability of speaking DNP3 to field devices, so the communications processor could collect operational data from the installed digital relays and provide the data to their remote terminal unit. A second connection to the communications processor could then provide engineering access to event data.

With the addition of a few more intelligent electronic devices, NEC could dramatically decrease crew times in responding to interruptions and restoring power. This would increase customer confidence and reduce overtime charges.

A typical NEC substation would require a communications processor and four relays. The cost for the communications processor is about $4,500, and each relay is about $3,000. Labor to install, test, and commission each relay or communications processor is $2,000. The total cost to upgrade the substation is between $25,000 and $30,000.

If we expand this to the 16 major substations NEC has, the total cost for relays and communications processors would be between $400,000 and $480,000.

VII. References

[1] K. Streett, K. Leech, and G. Rauch, "Power Delivery System Integration and Automation at Overton Power District No. 5 Overton, Nevada," proceedings of the 4th Annual Western Power Delivery Automation Conference, Spokane, WA, April 2002.

[2] A. Grice, J. M. Peer, and G. T. Morris, "Today's Aging Workforce – Who Will Fill Their Shoes?," proceedings of the 64th Annual Conference for Protective Relay Engineers, College Station, TX, April 2011.

VIII. Biographies

Kevin Streett majored in Construction Management at Boise State University. He has broad experience in the field of power system operations and construction. Prior to joining Navopache Electric Cooperative (NEC) in 2007, he was involved in the construction of substations, transmission lines, and distribution systems in the United States and overseas. He was also involved in the development of the Overton Power District SCADA system. He is currently the Operations Manager at NEC, responsible for power system operations, maintenance, and construction.

Kevin Leech received his BSEE from the University of Wyoming in 1994. He has broad experience in the field of industrial and power system control and automation. Upon graduating, he worked as a design engineer/project manager in industrial automation and control. In 1998, he joined Schweitzer Engineering Laboratories, Inc. as a system integration engineer, working on power system automation and control projects. He is now an integration application engineer/team leader. He is a member of IEEE and has authored and presented papers on power system integration topics.

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