Implementing the IEC 61850 Substation Automation Standard

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EnerNex

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ABSTRACT

This report documents the experiences and lessons learned from the deployments of the IEC 61850 Standard "Communication Networks and Systems for Power Utilities" at the New York Power Authority, Kansas City Power and Light, and Southern California Edison. Each utility implemented different parts of the standard, had different experiences and value achievement, and has different plans for future implementations. The report provides best practices for implementation of the standard and offers recommendations to industry groups including standards bodies and user communities for ways to minimize barriers for implementation. These recommendations may allow utilities to avoid problems and reduce the time required for implementation.

Keywords
Automation
Monitoring
Protection
Protocols
Standards
Substations

EXECUTIVE SUMMARY

This report presents a summary and analysis of deployments of the IEC 61850 Standard "Communication Networks and Systems for Power Utilities" at the New York Power Authority (NYPA), Kansas City Power and Light (KCP&L), and Southern California Edison (SCE). Each of these utilities began a journey investigating the application of the technologies, methodologies, and protocols that are part of the 61850 standards suite. This report is intended for anyone considering the implementation of 61850

61850 is not just a communications protocol, it is a holistic view for designing and managing utility substation and field device communication, automation systems, and applications. It is a collection of multiple protocols, concepts, and component standards. It can be considered a platform for designing, implementing and operating utility automation systems. 61850 provides a methodology for adding needed context and structure around what historically was simple, unformatted data. It is a "way of life" for utility automation.

Two of the utilities featured in this white paper – SCE and KCP&L – used funding from the American Recovery and Reinvestment Act (ARRA) of 2009 made available through the U.S. Department of Energy (DOE) for Smart Grid demonstration projects. SCE received nearly $40 million for the $80 million Irvine Smart Grid Demonstration (ISGD) project. The project had many facets but included the demonstration of the next generation of Substation Automation (SA-3) and an automation and control design based on the IEC-61850 standard. This is expected to provide measurable engineering, operations, and maintenance benefits through improved safety, security, and reliability. Prior to the ISGD project, SCE developed core knowledge on 61850 through their implementation of an IEC 61850 based Centralized Remedial Action Scheme (CRAS), which is highlighted in this report.

> **"It is hard to innovate if you are afraid to ever take any risk."**
> – Ed Hedges
> Mgr. Smart Grid Technology Planning, KCP&L

KCP&L is demonstrating an end-to-end Smart Grid - built around a major Smart Substation with a local distributed control system based on IEC 61850 and control processors — that includes advanced generation, distribution, and customer technologies.

NYPA's 61850 project had a specific technical driver and was initiated through their system protection group. They needed to upgrade the system protection in an existing station but in a smaller building. They chose to use 61850 to enable them to implement the new protection schemes in less space, using less copper, and with a technology that is more reliable, more capable, monitored, secure and much easier and faster to configure than traditional products and methods.

Each utility had very different experiences and value achievement in their respective implementations. They are also quite different in their plans for future implementations. NYPA for example sees themselves as an entity with a mission to blaze a trail for new technology implementation in the state of New York. When they have a new problem to solve, they will naturally tend to apply the latest technology so that others may learn from them. Their 61850 based substation project was no exception. NYPA sees 61850 as a clear new "way of life" for substation automation moving forward and chose to implement their substation project using it as a milestone toward developing a new standardized approach to substation automation. The project described later in this paper developed a series of best practices, identified new business processes and skill sets, and other learnings that will be used in all new substation automation projects moving forward.

SCE has been an early adopter of 61850 for some time before government funding was available – most notably using its high speed messaging capability to support sophisticated remedial action schemes on their transmission grid. Later, an ARRA funded project provided an opportunity to broaden their experience with 61850 to other substation automation tasks. For the ISGD project, they focused on integrating 61850 devices into their Common Cybersecurity Services (CCS) framework, took advantage of 61850 capabilities to automate device configuration management, and support a richer Human Machine Interface (HMI). The primary objective of the research was to increase understanding of how to use IEC 61850's configuration capabilities to reduce the levels of human intervention, reduce errors, and improve engineering time. This report describes the high speed messaging capability developed for their C-RAS project but includes lessons learned from both projects.

KCP&L also took advantage of ARRA funding to investigate the use of 61850 for a smart substation upgrade that features a local distributed control system. Four automation schemes were implemented:

1. Automatic load transfer on transformer lockout
2. Fast clearing of the bus upon feeder breaker failure
3. Backup over-current protection in the bus differential relay
4. Cross triggering of all devices for distribution system events

These schemes take advantage of 61850's object oriented approach to automation that simplifies implementing new automation applications. As a result, KCP&L would be able to implement schemes that reduce equipment stress, automatically restore service, and provide information about protection system operation events that could not be economically captured previously.

Of these three cases, NYPA and SCE are moving forward with using 61850 for additional projects. They have put in the necessary lab facilities, implemented training, and developed new processes to support the use of the technology in the utility. KCP&L in contrast has no plans to implement 61850 in future substations. Technically the project was a great success with all performance metrics achieved or exceeded. Institutional issues related to a desire to focus on one substation design and automation philosophy and technology rather than begin evolving to a next generation approach are preventing the technology from being rolled out operationally. Burns & McDonnel, KCP&L's engineering consulting partner on the project, has their own 61850 test lab in the area that can be used as a platform for training and design if and when KCP&L chooses to take a second look at adopting a new approach to substation and feeder automation technology.

All three utilities identified numerous lessons learned – almost all of which were common among them. These include:

Build a strong test-lab. One of the utilities interviewed for this report did not do this initially and it took a longer time to get personnel familiar with the new technology. They relied heavily on their vendor. SCE built extensive test labs for smart grid including a 61850 lab and a real time digital simulator (RTDS) that can be used for hardware in the loop (HIL) testing. KCP&L relied on their contractor's lab which limited the ability for their personnel to spend the time they needed to learn the new technology.

Need extensive training of the workforce. All agreed on this. A mix of old and new skills is required. Basic automation coupled with advanced network communications, 61850 design philosophy, automated testing and configuration tools, and new testing skills for site engineers and technicians are required.

Cross-vendor configuration is burdensome. This is another common point of agreement. Although 61850 is designed to provide multi-vendor interoperability, each vendor chooses to add their own value added capabilities that require using their own configuration tools. This limits the ability to utilize third party configuration tools to do vendor independent configuration, visualization, and management of the system as a whole.

Understand and specify standards compliance and interoperability testing. The IEC 61850 user community has formal processes for how products should be tested for standards compliance, interoperability as well as how test labs are certified and capable of issuing test certificates[1]. Specify in the procurement process that products be tested using an accredited lab.

Case studies and implementation profiles are needed. All three utilities interviewed said that they could have reduced their time to implement if they had known about and utilized example implementations that could serve as a starting point for some of their applications. This could be done through organizations such as the UCA International Users Group (UCAIug), EPRI, CEATI, the IEEE PSRC, IEC WG 10, the SGIP and others. It is recommended that these organizations significantly enhance the artifacts they do have to produce implementation guidelines that are in line with customer application requirements.

Participate more in the UCAIug 61850 User Group - SCE took particular advantage of the users group and one of their staff is an active member and sits on the UCAIug board of directors.

Take advantage of help from other utilities and entities –NYPA credited EPRI with helping them significantly through various 61850 related projects and activities and they took advantage of peer exchanges through the IEEE relay committee since their applications was very focused on protective relaying. It is advantageous to the entire industry to share cost benefit methodologies, design, procurement, commissioning, testing and operational best practices.

Several specific recommendations for industry groups including standards bodies and user communities were identified by the utilities participating in this case study report. Chief among these is the need for EPRI, the SGIP and 61850 user communities to do a better job communicating the projects underway, services they can provide, and tools/artifacts that are available to help new implementers. Neither NYPA nor KCP&L (directly or through their consultants) were aware of the user communities and services available.

Also, organized meetings and events to get multiple utilities in a room to share and develop common requirements and best practices. The SGIP Implementation Methods Committee (IMC)

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[1] UCAIug Testing and Certification - http://goo.gl/R4MnQx

has served in the past as a place to exchange information on 61850 but some additional outreach and marketing of this capability and the value associated with it is required. EPRI has multiple programs supporting utility implementations. Perhaps closer coordination between EPRI, the UCAIug, the SGIP IMC and PAP 23 will be useful.

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1
PARTICIPATING UTILITIES OVERVIEW

New York Power Authority[2]

Established in 1931 by Governor Franklin D. Roosevelt as New York's model for public power, the New York Power Authority (NYPA) is America's largest state power organization, with 16 generating facilities and more than 1,400 circuit-miles of transmission lines.

Figure 1-1
New York Power Authority Service Territory

State and federal regulations shape NYPA's diverse customer base, which includes large and small businesses, not-for-profit organizations, community-owned electric systems and rural electric cooperatives and government entities. 114 government entities in New York City and Westchester County received their electricity from NYPA. The customers include New York City government, the Metropolitan Transportation Authority, the Port Authority of New York

[2] http://www.nypa.gov

and New Jersey, the New York City Housing Authority, Westchester County government and most Westchester municipalities, school district and other public entities.

Kansas City Power & Light[3]

Founded in 1882, KCP&L is an investor-owned, regulated electric utility serving more than 800,000 customers in 47 northwest Missouri and eastern Kansas counties. With a service area of about 18,000 square miles, it takes more than 3,000 miles of transmission lines, 24,000 miles of distribution lines and more than 400 substations to deliver power to their customers.

Figure 1-2
Kansas City Power & Light Service Territory

Southern California Edison[4]

Southern California Edison (or SCE Corp), the largest subsidiary of Edison International (NYSE: EIX), is the primary electricity supply company for much of Southern California, USA. It provides 14 million people with electricity across a service territory of approximately 50,000 square miles.

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[3] http://www.kcpl.com/

[4] http:// www.sce.com/

Figure 1-3
Southern California Edison Service Territory

2
BUSINESS CHALLENGE

Before we examine the participating utilities implementations of the IEC 61850 standard, it is important to identify the business challenge the technology and associated standard is addressing. Generically, the business challenge is related to the purchase, construction, commissioning, and operation of substations. Substations house transformers, switches, breakers, and other equipment necessary to link bulk transmission lines with sub-transmission and distribution lines. The business challenge is to design, build, operate and maintain substations and the assets they contain at the lowest possible cost, with the highest safety and reliability possible.

Figure 2-1
Old KCP&L Control Room

Substations have been "automated" from their first implementation using mechanical controls and relays to ensure that abnormal situations – faults – are mitigated with the rapid opening of breakers to limit the amount of time that higher than normal currents are permitted to flow thus preventing catastrophic failure of the equipment. Power system and substation automation has continued to evolve over the industry's more than 100 year history. Technology has driven that evolution. Initially, innovation occurred with more intricate, sophisticated, and capable mechanical systems to better protect the expensive assets that are critical to the safe and reliable operation of the electric power system. Eventually electronic systems became more cost effective than some mechanical systems and were deployed “at the speed of value” that could be obtained from them. Soon it became possible to use emerging communications technology to remotely observe and control these critical assets thus eliminating the need to staff substations.

With communications came the realization that the expensive assets in the station could be monitored for proper operation and ensure that timely maintenance could be performed thus extending their useful life and minimizing the chance of unexpected and catastrophic failure. Numerous communications protocols were developed to support the rapid evolution of Supervisory Control and Data Acquisition (SCADA) resulting in a Tower of Babel like challenge to make everything work. The realization that standardized communications could enhance interoperability, allow best of breed technology to be deployed, and minimize the cost of integration and maintenance resulting in the transition from hundreds of proprietary communications methods and protocols in the 70‘s and 80’s to just the few we have today. The IEEE 1815 (DNP3) and IEC 61850 standards are just the latest evolution of communications technologies and methodologies as necessary tools to support the continued evolution of substation automation.

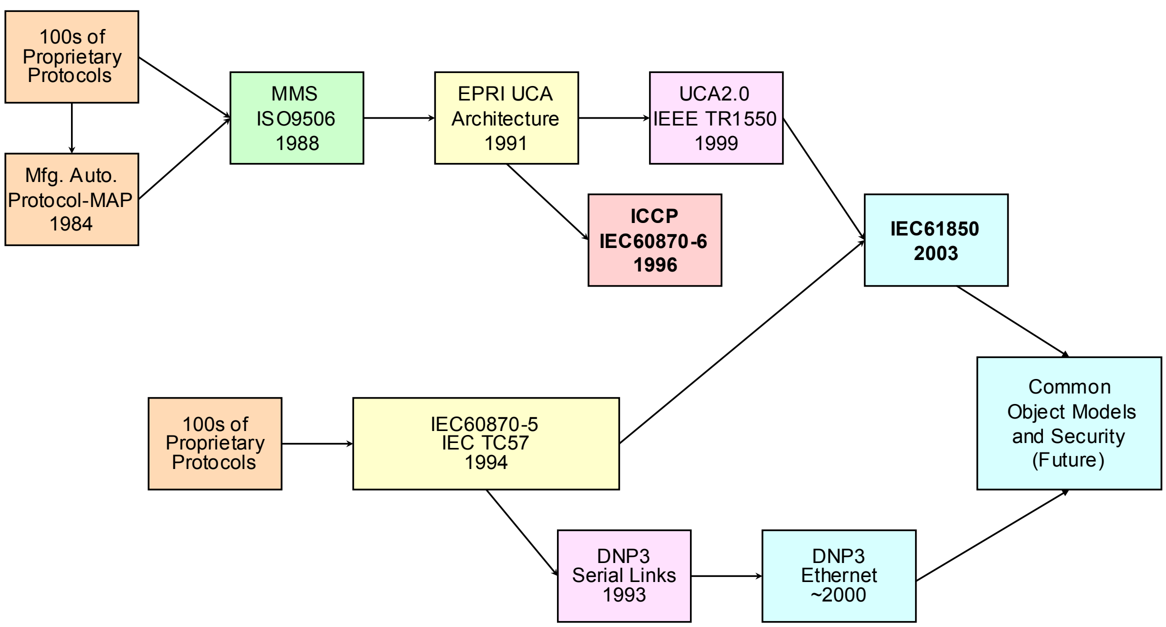

Figure 2-2
Utility Communications Evolution

In summary, substation automation addresses the business challenge of managing the cost of the purchase, construction, commissioning, and operation of substations by:

- Simplifying the specification and commissioning of substation assets
- Reducing the time to find and to fix problems
- Reducing equipment operation and maintenance costs
- Extracting higher performance through better situational awareness thereby increasing return on investment
- Improving worker safety
- Limiting impact to customers due to outages through automated control
- Providing better and faster operational decisions made with more timely data
- Improving power system flexibility, reliability, and resiliency

3

DESCRIPTIONS OF UTILITY IMPLEMENTATIONS

For this report, we will look at three different utility implementations of IEC 61850 as a solution to one or more aspects of the business challenge described earlier. Each utility – KCP&L, NYPA, and SCE – had different goals for their implementation but, ultimately, each must present a strong value case for the implementation to be permanently operationalized.

> **What is 61850?**
>
> The IEC 61850 standard is not just a communications protocol - it describes a holistic view of designing and managing utility substation and field device communication, automation systems, and applications. It is:
>
> ***A comprehensive standard for the design of substation automation systems and applications***
>
> - ***A collection of multiple protocols, concepts and component standards***
> - ***A platform for designing, implementing, and operating utility automation systems***
> - ***A method for adding needed context and structure around what historically was simple, unformatted data***
> - ***A "way of life" for utility automation***

Kansas City Power and Light

KCP&L does not have SCADA at the distribution level and has very little communications in rural areas. The communications they do have are generally Plain Old Telephone Service (POTS) lines and dedicated low bandwidth (56-64kbps) serial lines with virtually no Internet Protocol (IP) based connectivity. They have been deploying fiber for years but primarily are using it for serial links because of NERC CIP compliance concerns. In the mid 2000's, KCP&L had a dedicated smart grid group which recognized the need to investigate advanced technologies and improve their overall approach to substation and feeder automation. When the American Recovery and Reinvestment Act (ARRA) of 2009 funding was announced, the smart grid group came up with a project idea to accelerate their research and trial implementations. The concept was to use the grant to investigate the recommendations being made by the National Institute of Standards and Technology (NIST) at the time to utilize modern interoperability standards such as IEC 61850 and the Common Information Model (CIM). They sought out and obtained executive support for the effort.

KCP&L received a $24 million grant which was matched by the utility and their partners. The KCP&L project implemented an end-to-end smart grid —built around the upgrade of a major smart substation with a local distributed control system based on IEC 61850 protocols and control processors—that includes advanced generation, distribution, and customer technologies. Co-located renewable energy sources, such as solar and other parallel generation, were placed in the demonstration area and fed into the grid. The demonstration area consists of ten circuits served by this one substation across two square miles with 14,000 commercial and residential customers. This area would potentially provide a "testbed" for technology evaluation including the possibility of a microgrid.

Once the grant was awarded and the project started, the project team faced several challenges: their sponsoring executive left the company and the new executive was understandably less invested in the effort, and the Director of Smart Grid moved elsewhere in the organization. These events resulted in the substation automation project no longer having a full-time, dedicated project team. The project was staffed using a time share process with resources spread around the organization. This approach made it nearly impossible for the team members to be truly invested in the effort and it fostered a perception (and eventual reality) of the project being a “one-off” activity. To mitigate staffing issues, heavy reliance was placed on utilizing the consulting engineering firm – Burns & McDonnell – to provide expertise and resources that would normally be handled by utility employees. The consulting engineering firm was highly skilled and qualified but this approach minimized the opportunity for skill building and internal technology transfer within the utility, Even with these administrative challenges, a solid technical solution was developed and significant lessons learned that are worthy of sharing with the industry.

Figure 3-1
Burns & McDonnell Smart Grid Lab

The technical vision was an IP-based substation – IP-based communications from the control center to the substation, IP within the substation, and IP out to field devices on the distribution system – with multiple aspects of the IEC 61850 standard (logical device modeling, MMS protocol over IP, and GOOSE messaging) being used for the information exchanges and control. Due to substation equipment product availability and other limitations, the distribution devices (fault current indicators and reclosers) utilized DNP3 over IP.

What is GOOSE?

GOOSE (Generic Object Oriented Substation Events) is a method for exchanging messages at high speed and reliability between devices in utility automation but most often associated with protective relaying applications. It is intended as a replacement for relay-to-relay copper wiring. Each device multi-casts (broadcasts) a selected set of data when a pre-configured event occurs.

To support high speed, the usual TCP/IP protocol layer that guarantees receipt of data is not used – instead GOOSE assumes the message will not get through. To counter this the protocol "shouts" the message many times backing off the repeats exponentially assuming that one of the messages will get through. This approach is based on IEEE 802 multicast addressing, uses hardware to filter out what is not needed, is very fast, highly reliable and works well even in congested network scenarios. GOOSE is ideal for relay interlocking applications.

It was also envisioned that one of KCP&L's vendor partners in the project (Siemens) would be leveraged to do all of the design work but, when it became apparent that they needed to implement other vendor equipment such as Schweitzer Engineering Labs (SEL) relays, Burns & McDonnell was chosen to take over the network and 61850 design aspects and much of the project execution responsibility.

For basic network communications, a redundant gigabit fiber based ring with 100mbps Ethernet interfaces to the relays was implemented in the substation (Figure 3-2) to carry 61850 protocol traffic (MMS over IP and GOOSE). Further redundancy was obtained by using Cisco products for one ring and RuggedCom for the other. KCP&L was one of the first implementers of the Cisco 61850 aware router. At KCP&L, all things IP are the responsibility of the Information Technology (IT) organization. Utility protection engineers were responsible for the relay protection specifications, and union technicians were responsible for making it all work. For design validation, staging and testing, the Burns & McDonnell 61850 lab was used.

Four protection applications were implemented in the substation 1) Automatic load transfer upon transformer lockout; 2) Fast clearing of the bus upon feeder breaker failure; 3) Backup overcurrent protection in the bus differential relay; 4) Cross triggering of all devices for distribution system events. Detailed information on the network design and protection functions implemented can be found in the April 2012 edition of T&D World Magazine[5].

A wide range of tools were utilized in the project. For the relay configuration, the SEL Architect was primarily used. SISCO's AXS4 was used for verifying device configuration, the OPC component of AXS4 product was used to create dashboards, XMLSpy and Programmers Notepad was used to inspect configuration files, Wireshark and other common networking tools were used for low level network analysis, and SEL Analytic Assistant was used for relay event analysis.

Numerous challenges were encountered and addressed during the implementation. A major challenge is the lack of a fully interoperable configuration capability such that a single configuration tool that could be used for all 61850 devices. Some of the vendor specific tools were tedious to use for configuration. Managing time synchronization is critical in these types of

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[5] "Wired for Success", April 2012, http://tdworld.com/distribution/wired-success, http://www.burnsmcd.com/Resource_/PressRelease/2535/FileUpload/article-TDWorld-Wired-for-Success-Olson.pdf

systems and some devices had issues with how they dealt with time stamping. It was not clear on the impact of time stamping differences in vendor equipment behavior. The Cisco equipment was not prepared to properly handle the GOOSE Ethernet frame type out of the box and required some time to get working properly. Numerous 61850 implementation issues were discovered where vendors interpreted some aspect of the standard differently than their peers. For example resets were handled differently between vendors. This highlighted the need for basic implementation profiles that an implementer can expect all vendors to implement.

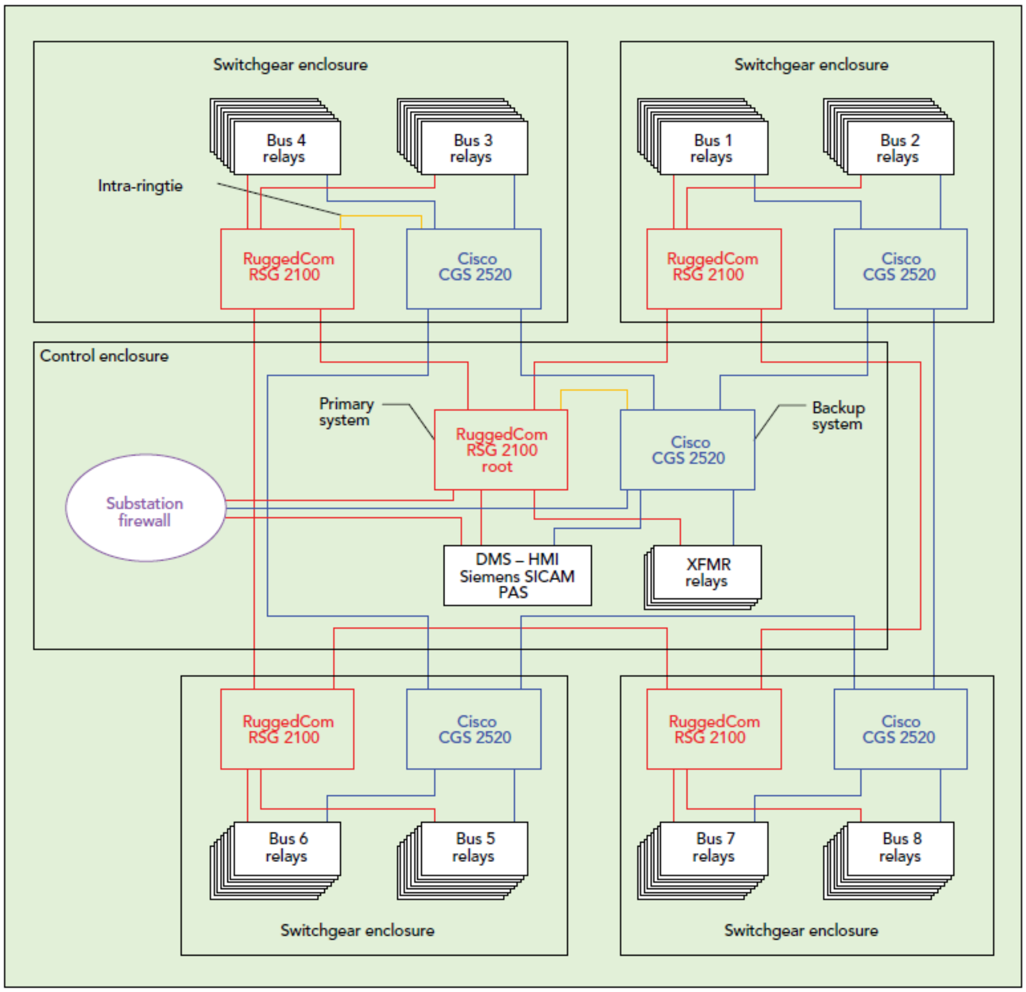

Figure 3-2
Substation Network Design

Even the physical Ethernet layer had challenges in the implementation of the redundant communications path – specifically in how port failover was handled in each relay. There was no way of easily observing which of the two redundant ports was active at any one time. Some relays always reported an error state for the inactive port.

Overall, once commissioned, the 61850 based solution exceeded its performance specifications and outperformed its non-61850 based equivalents. All project technical solution objectives were achieved and the lessons learned would streamline future implementations if operationalized.

Unfortunately, the substation automation approach and supporting technologies deployed for this project will not be operationalized at KCP&L. In fact, the high speed GOOSE messaging will revert to the copper wired interconnections that remained in place and future substations will revert to their existing standards for substation design. There are numerous institutional reasons for this. Fundamentally it comes down to making a clear business case for implementing new technology and design approaches. Developing such a business case was not part of the project scope. Without a well-documented business case, the perception within KCP&L is that the learning curve will outweigh the benefits and there is no appetite for supporting multiple substation automation approaches and associated support requirements (training, document, process change, etc.) during a technology transition. With the heavy reliance on vendors and contractors to implement the project, there was no way to transfer the knowledge and build buy-in to a new way of doing things even if there were clear benefits to be realized. The goal of using this station as a test bed for any new technology was not realized. There were numerous lessons learned in this project that can be used by KCP&L should they decide to revisit their substation automation design again in the future. These lessons and industry recommendations are useful now to others considering the implementation of 61850 and are documented later in this report.

Southern California Edison

SCE has been building expertise in IEC 61850 and investigating practical applications for many years – many of them prior to the ARRA funding opportunities. SCE personnel are very active in the development of the IEC 61850 standard suite and hold leadership positions in the 61850 user community (the Utility Communications Architecture International Users Group – UCAIug). SCE has implemented a 61850 lab, has invested significantly in training, and has a dedicated group focused in evaluating new applications and then operationalizing them in the organization.

The 61850 based application summarized here is for SCE's Centralized Remedial Action Scheme (C-RAS). Remedial action schemes (also known as a Special Protection Scheme – SPS) is an automated system focused on detecting very specific types of abnormal system conditions and quickly implementing actions beyond the usual fault isolation to maintain system stability. This is especially important in heavily loaded transmission networks where fault clearing operations might trigger cascading events and system collapse.

Figure 3-3
SCE Substation Automation Lab

SCE personnel have published several papers[6] about their C-RAS implementation since they first started investigating it ten years ago so we will only summarize the key points relevant to 61850 in this case study. In a recent publication[7], SCE wrote:

> "C-RAS uses protective relays installed in transmission substations across the SCE service territory to monitor critical transmission line flows and other electrical measurements, as well as relay or breaker operations that remove lines from service and might trigger rapid transmission system collapse. These monitoring relays transmit high speed data to a pair of redundant central controller arrays using IEC 61850 GOOSE messages over a wide area Ethernet network (WAN) comprised of dual-redundant T1 and Ethernet data links. The central controller arrays decide how to remediate a line loss within milliseconds of receiving the line trip message, and trip loads or generation to maintain system stability using WAN links, GOOSE messaging, and mitigation relays at shedding substation sites."

Like KCP&L, SCE's implementation is focused on system protection applications and uses 61850's GOOSE messaging protocol as its foundation. The reason for this is due to the ability to scale the deployment of RAS's in a timely and cost effective manner. As Figure 3-4 illustrates,

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[6] SCE Pilots the Next Level of Grid Protection, T&D World, Dec 2007, http://tdworld.com/overhead-transmission/sce-pilots-next-level-grid-protection; http://www.smartgridsharepoint.org/SCE-CRAS/Shared%20Documents/CRAS/C-RAS%20Pilot%20Article%20by%20Pat120307.pdf ; "A Real-world Implementation of Centralized RAS System", https://www.pacw.org/no-cache/issue/march_2014_issue/network_architecture/scalable_network_architecture_based_on_ip_multicast_for_synchrophasor_applications/complete_article/1/print.html

[7] Jun Wen et al, Wide-Area Ethernet Network Configuration for System Protection Messaging", Georgia Tech Protective Relay Conference, April 2012, http://quanta-technology.com/sites/default/files/doc-files/Wide-Area_Ethernet.pdf

SCE needs to implement a rapidly increasing number of RAS systems to keep up with system demands and to extract the most out of the system while ensuring system reliability and stability.

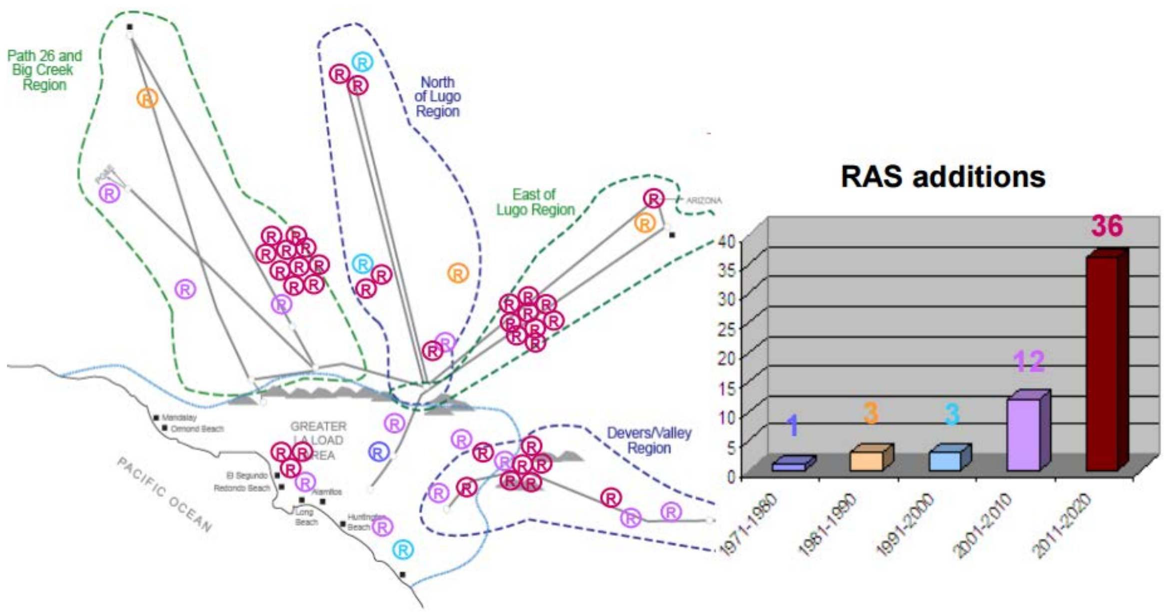

Figure 3-4
RAS Scheme Additions

Prior to the 61850 based C-RAS architecture, their RAS implementations had a limited situational view with highly local, preselected inputs; had limited actions available with pre-selected mitigation approaches; no information could be shared among different RAS implementations; the large number of RAS's had a high risk of uncoordinated responses and misoperation; no equipment sharing between RAS's was possible; and the time and effort to manage and update remote RAS's was not tenable when scaled up. SCE determined that a centrally managed system could be more rapidly deployed and maintained using a standards based approach (61850) that leverages their high speed wide area optical network. This architecture allows for a holistic approach to protecting the system, supports implementing new RAS's quickly to meet rapidly changing system demands, better controls equipment, labor and engineering costs, scales well, and is practical to manage and maintain with minimal staffing. Information can be shared across the entire system and supporting equipment can be shared.

The C-RAS application runs on SCE's extensive SONET based optical fiber wide area network ring. Details can be found in the aforementioned references. The key to the success of the C-RAS system is ensuring that the network architecture can support the requirements for GOOSE messaging in general and scale to the number of RAS enabled substations (more than 100). This requires careful traffic analysis and design by experienced network designers who understand the application requirements. All aspects of the system are highly redundant including the control center architecture as depicted in Figure 3-5.

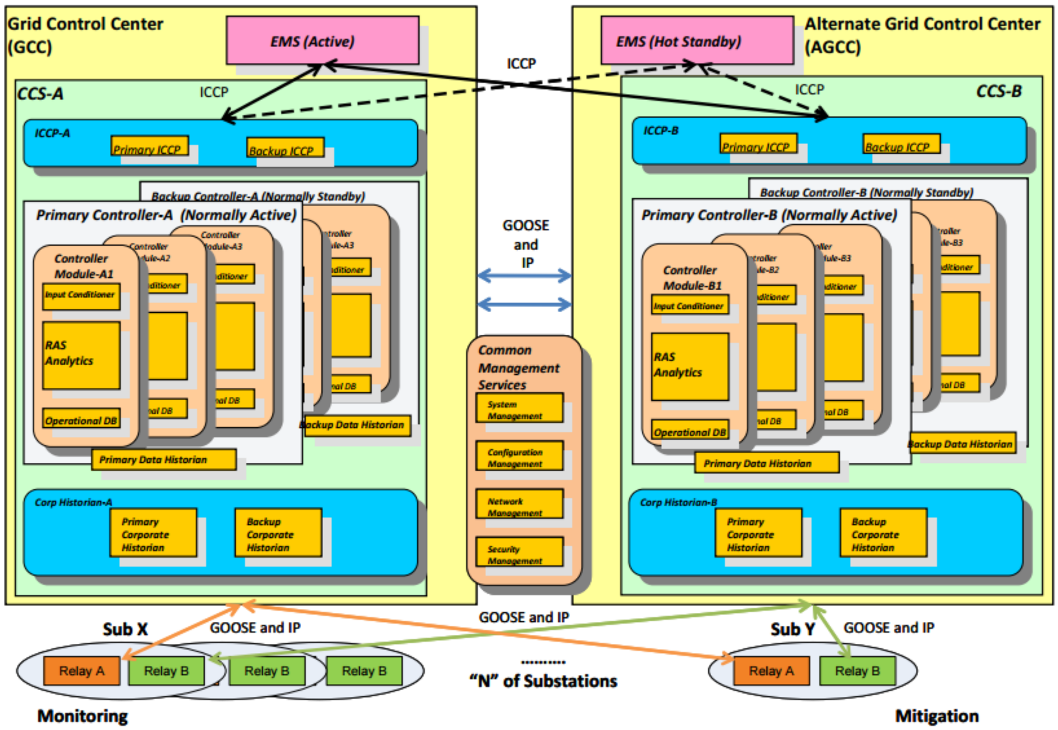

Figure 3-5
Control Center Network Environment

SCE had to evaluate their requirements for an enhanced RAS capability and determined that the IEC 61850 GOOSE protocol was best suited to the task. Their reasoning for selecting GOOSE included:[8]?

- Single international standard power system protocol.
- Focused on pervasive Ethernet networking technology
- Configure relays, controllers, IEDs with automated system engineering & configuration tools per IEC 61850-6 system configuration language (SCL)
- Layer 2 LAN multicast GOOSE message is fast for mission critical tripping uses.
- Publisher-subscriber communications are efficient for sharing status and values with any number of users in Ethernet network environment.
- Easily meets requirement for under 38 ms round trip time to achieve 50 ms maximum from line trip to load shed trip.

A key differentiator for SCE's GOOSE application is the fact that the messaging is occurring over a wide area between geographically distant facilities. GOOSE was originally designed to be confined to a single substations local area network and, as such, is designed around a Layer 2 multicast pack that has no routing information. IEC technical report 61850-90-1 describes how to use 61850 between substations or any separated LAN locations via Layer 2 GOOSE tunneling.

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[8] "Wide-Area Ethernet Network Configuration for System Protection Messaging",Texas A&M Conference for Relay Protection Engineers, April 2012, http://prorelay.tamu.edu/12_powerpoints/TuesdayAM/5%204-3%20AM%20Udren%20Wide%20Area%20Ethernet%20TAM%20V1%20040312.pdf

The future of GOOSE in wide area applications is the new IEC technical report 61850-90-5. This update to the standard uses Layer 3 transport via UDP/IP unicast or multicast. A key feature of this approach, beyond being inherently routable, is that it supports end-to-end authentication of data packets to support today's high security demands in critical infrastructure systems.

In addition to the GOOSE based C-RAS effort, Southern California Edison (SCE) engineers designed and demonstrated an IEC 61850-based substation automation system at MacArthur Substation in Irvine, California using American Recovery and Reinvestment Act funding as part of its Irvine Smart Grid Demonstration (ISGD). This project was put in service on November 2013 and it is SCE's third generation network-based Substation Automation System (SA-3). The system's primary components are SCE's IEC 61850 Substation Configuration Tool, Central Management Services (CMS), Cyber Secured Substation Gateway, and Human Machine Interface (HMI). This new system was designed to take advantage of IEC 61850's standardized data structures, configuration files, and portability to newer technologies. The new system has been tested in 2014 and 2015 and when proven successful will be standardized going forward.

The primary objective of the research was to increase understanding of how to use IEC 61850's configuration capabilities to reduce the levels of human intervention and reduce errors and improvements in engineering time.

MacArthur Substation is one of the first field deployments of SCE's Common Cybersecurity Services (CCS) platform. SCE's smart grid demonstration uses this platform, which provides military-grade cyber security for substation devices and communications between the various field devices and ISGD back office systems. EPRI has written a separate case study on this initiative[9]. The lessons learned from both the CRAS and ISGD projects are summarized later in the Lessons Learned section of this report.

New York Power Authority

NYPA's 61850 project had a specific technical driver and was initiated through their system protection group. They needed to upgrade the system protection in an existing substation but in a smaller building. They chose to use 61850 to enable them to implement the new protection schemes in less space, using less copper, and with a technology that is more reliable, more capable, monitored, secure and much easier and faster to configure than traditional products and methods. This was designed to be an operational system from the beginning.

NYPA, as a state government public power entity, has a mission to blaze a trail for new technology implementation in the state of New York. When they have a new problem to solve, they will naturally tend to apply the latest technology so that others may learn from them. Their 61850 based substation project was no exception. NYPA sees 61850 as a clear new "way of life" for substation automation moving forward and used the substation project as a template for their new design standard. The project developed a series of best practices, identified new business processes and skill sets, and other learnings that will be used in all new substation automation projects moving forward.

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[9] EPRI Report 3002004613, Gale Horst, "A Case Study on Southern California Edison Substation Automation – Irvine Smart Grid Demonstration", April 2015

NYPA's project is a major, comprehensive 61850 based substation automation implementation in both 230kv and 115kv sides of the substation. The devices involved include:

- 214 Relays (157 Primary + 57 Secondary)
- Multiple vendors - Siemens + GE + Schweitzer
- 14 Transmission Line Terminals
- 4 Autotransformers
- 6 Buses (breaker and half scheme)
- 45 Breakers
- 5 Capacitor Banks w/Circuit Switchers
- 2 Capacitor Banks w/Breakers
- No hardware lockouts or Mode/Selector Switches

Key drivers for basing their new substation automation design on IEC 61850 was reduced wiring, fewer devices (no RTU's or dedicated disturbance recording devices), reduced footprint, centralized remote device access and maintenance, and being based on new technology with the promise of being more capable, more reliable, monitored, and secure.

NYPA issued an RFP for a turnkey solution – design, furnish, deliver, install, test and commission the system. The scope included all protection systems, the substation LAN, HMI and integration of SCADA and other devices such as PMU's, and training. A lot of responsibility was placed on a single contractor – Siemens. NYPA had little or no 61850 expertise and no awareness or interaction with the 61850 standards and user communities. They relied on Siemens to fill that gap. The decision time to go from idea to contract was only one year but it took four years to finalize the design.

As noted earlier and in the sidebar, 61850 is a suite of protocols – not just one. The figure below illustrates the protocols that constitute 61850. For the NYPA project, the GOOSE and MMS Protocol Suite were implemented on a single Ethernet network know in 61850 as the Station-Bus. It is envisioned that the Sampled Values (SV) protocol which uses a separate LAN bus (known as the Process-Bus) to share digitized voltage and current data from instrument transformers will be implemented in a future project.

The initial project was based on Edition 1 of the IEC 61850 standard but they are committed to upgrading to Edition 2 of the standard in this and future station implementations[10]. One consequence of being an Edition 1 implementation is that many functional capabilities were implemented using a 61850 logical component known as General Input Output (GIO). This is a catch all for device capabilities and applications functions that cannot be modeled in a more standardized way using 61850 logical nodes and functional components. The use of GIO limits multi-vendor interoperability and adds some maintenance complexity. New logical nodes and

[10] Edition 1 of the IEC 61850 standard was published between 2003 and 2005. Edition 2 of the standard began to be published in 2010. In addition to resolving various shortcomings that were identified during the initial implementations of the standard, Edition 2 also expands the range of applications outside of the substation, as reflected in the standard's title being changed from "Communication Networks and Systems in Substations" to "Communication Networks and Systems for Power Utilities".

other aspects of Edition 2 allow more functionality to be implemented in standard ways across vendor implementations.

Since this was an existing station with existing protection systems in the old control building and the 61850 based systems in the new relay building, the cut-over process had to be well planned and executed sequentially by bus and circuit bay over a 4-5 year time frame in accordance with NYPA's breaker replacement program. During installation and commissioning of each circuit, temporary 61850 I/O devices need to be instantiated to facilitate interfacing the old devices and transitioning to the new 61850 devices for various protection schemes.

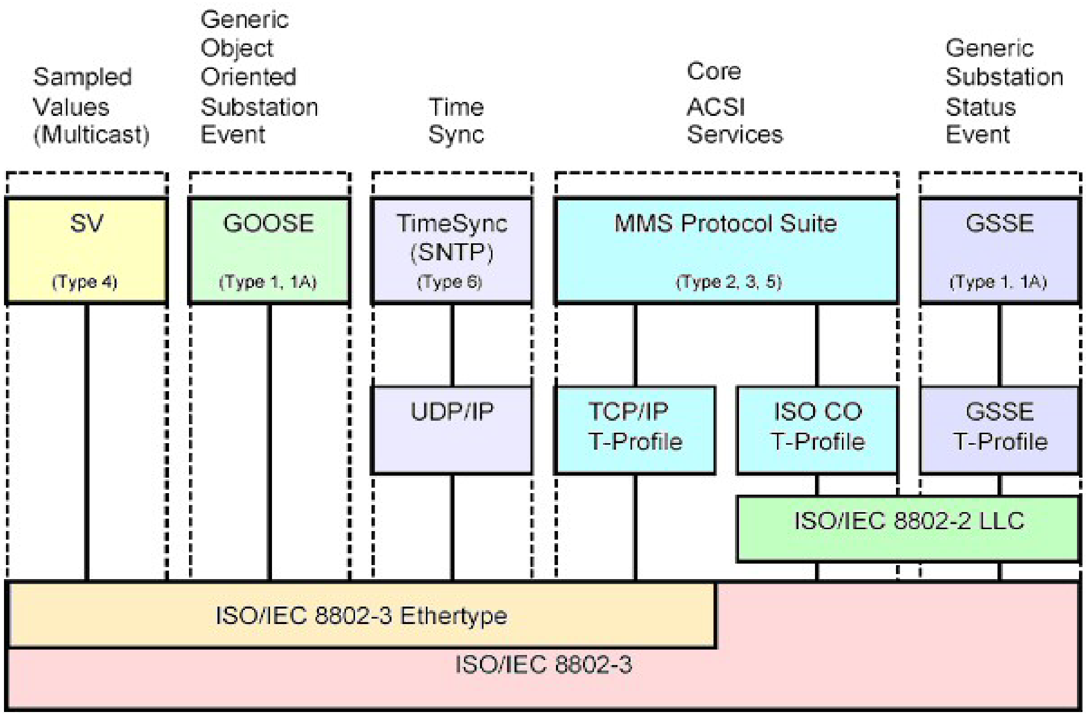

Figure 3-6
61850 Protocols

There we numerous delays during the effort through configuration and field acceptance testing. Unexpected complexities due to limitations in Edition 1 of the standard contributed to this. One example is related to how test modes are implemented – this is custom for each vendors equipment in Edition 1. Edition 2 is an entirely new design with a more well thought out approach to how test modes are implemented. Challenges with naming conventions were encountered and limitations in 61850 device models resulted in extensive custom logic using the previously mentioned GIO work around contributed to cost overruns and delays. For a mature, highly interoperable standard, vendor software limitations and cross vendor integration was still burdensome and needs more work in the standards and user communities to mitigate. Some aspects of 61850 related to efficient configuration of devices and their connectivity (IID, CID, ICD, etc.) is not supported by all vendors. This needs to be mitigated through standardized basic application profiles and well documented best practices.

Initially only the contractor made use of vendor provided and third party 61850 tools. As NYPA staff became more familiar with the technology they were able to use the tools for device configuration, monitoring, and maintenance. In general, NYPA staff report that third party tools still need work to be useful especially in multi-vendor environments.

Based on the experience with initial project, NYPA intends to implement 61850 in future projects. This includes a Special Protection Scheme (SPS) at Niagara in 2015 and the Plattsburgh Substation in 2015-2017. The Plattsburgh project will include an A System that implements a 61850 station bus similar to the first project and a B System that will be hardwired but with 61850 capability. A Process-Bus will be evaluated as well as non-conventional instrumentation transformers that utilize the Sampled Values protocol over the process bus. Other projects include small hydro facilities and two green-field substations. To better support design, GOOSE and SV evaluation and test plan development in their lab, NYPA will implement Real Time Digital Simulator (RTDS) based testing using the RTDS Technologies and/or Opal-RT systems.

NYPA discovered that moving toward a 61850 based “way of life” for substation automation does mean that the way you design and manage the systems are different. Processes have to change, training is required, lab facilities are needed to test and evaluate designs and products, and new operational and maintenance guidelines need to be developed. Working closely with experienced vendors and independent engineering consulting firms and integrators can lessen the immediate impact and give the organization time to adapt to the technology change.

4
SOLUTION BENEFITS

This portion of the report summarizes the benefits realized by the utility solution implementations described above. There are many common themes as well as unique benefits realized in these examples.

Common benefits expected and/or realized in all projects include:

- Simplification of integration. 61850's logical node based information models are independent of the underlying communication protocol. Standard names for standard things simplify multi-vendor integration.
- Multi-vendor integration support minimizes the potential for vendor lock-in and allows for best of breed vendor selection for a given device function or application.
- Simplified engineering, implementation and operation with cost savings in configuration, commissioning and maintenance once the organization is matured to support and take advantage of the new technology.
- Less risk of human error by minimizing custom, complex, and manually configured logic.
- Capital cost reduction – significant reduction in space required, copper control wiring, mechanical control switches, signaling devices and meters. Potentially extensive and costly CT and VT wiring can be reduced if a process bus is implemented.
- Enhanced reliability, lower cost, and enhanced security through the use of commodity Ethernet and IP based communications infrastructure for all data exchanges in real time.
- GOOSE messaging protocol is uniquely qualified to support complex but necessary protection schemes not previously practical inside a substation or across a wide area.

Other benefits realized by one or more of the utility projects described here include:

- Enabling a distributed intelligent network that provides new service opportunities not previously envisioned or possible
- Allows existing transmission lines, transformers and other assets to be more fully loaded and utilized by mitigating the risk of system instability during line and generation trip scenarios and other system faults.
- Supports improved grid security through enhanced situational awareness, secure end-to-end communications, and better data availability for after event analysis.
- Enhanced protection of physical assets from damage in substations during fault events through ease of implementing interlocking protection schemes[11].

[11] Siemens Switchgear Interlocking - http://www.energy.siemens.com/hq/pool/hq/energy-topics/standards/iec-61850/Application_examples_en.pdf

5
LESSONS LEARNED

All three utilities identified numerous lessons learned – almost all of which were common among them. These include:

Build a strong test-lab. One of the utilities interviewed for this report did not do this initially and it took a longer time to get personnel familiar with the new technology. They relied heavily on their vendor. SCE built extensive test labs for smart grid including a 61850 lab and a real time digital simulator (RTDS) that can be used for hardware in the loop (HIL) testing. KCP&L relied on their contractor's lab which limited the ability for their personnel to spend the time they needed to learn the new technology.

Need extensive training of the workforce. All agreed on this. A mix of old and new skills is required. Basic automation coupled with advanced network communications, 61850 design philosophy, automated testing and configuration tools, and new testing skills for site engineers and technicians are required.

Cross-vendor configuration is burdensome. This is another common point of agreement. Although 61850 is designed to provide multi-vendor interoperability, each vendor chooses to add their own value added capabilities that require using their own configuration tools. This limits the ability to utilize third party configuration tools to do vendor independent configuration, visualization, and management of the system as a whole.

Understand and specify standards compliance and interoperability testing. The IEC 61850 user community has formal processes for how products should be tested for standards compliance, interoperability as well as how test labs are certified and capable of issuing test certificates[12]. Specify in the procurement process that products be tested using an accredited lab.

Case studies and implementation profiles are needed. All three utilities interviewed said that they could have reduced their time to implement if they had known about and utilized example implementations that could serve as a starting point for some of their applications. This could be done through organizations such as the UCA International Users Group (UCAIug), EPRI, CEATI, the IEEE PSRC, IEC WG 10, the SGIP and others. It is recommended that these organizations significantly enhance the artifacts they do have to produce implementation guidelines that are in line with customer application requirements.

Participate more in the UCAIug 61850 User Group - SCE took particular advantage of the users group and one of their staff is an active member and sits on the UCAIug board of directors.

Take advantage of help from other utilities and entities –NYPA credited EPRI with helping them significantly through various 61850 related projects and activities and they took advantage of peer exchanges through the IEEE relay committee since their applications was very focused

[12] UCAIug Testing and Certification - http://goo.gl/R4MnQx

on protective relaying. It is advantageous to the entire industry to share cost benefit methodologies, design, procurement, commissioning, testing and operational best practices.

KCP&L Specific Lessons Learned

- C-Suite level support not dependent on any one executive for implementing new technology and all it entails is critical to long term success and benefit realization
- A dedicated design and implementation team of respected thought leaders and technical experts drawn from multiple departments within the organization is critical to develop, spread and maintain the buy in for technology and organizational change.
- A strong business case built on a well socialized and accepted framework is needed to properly assess and communicate value throughout the entire organization
- Use external resources to ease the new technology transition but don't outsource too much and attempt technology transfer too late.
- Build time into the project to build trust in the new technology
- Use of an experienced, vendor independent consulting engineer or firm experienced in all aspects of 61850, communications and the power engineering specific applications is helpful to oversee multi-vendor implementations and mitigate integration problems

SCE Specific Lessons Learned

- Vendor interpretations of the standard are inconsistent. This created longer engineering and design times when testing the system in the Factory Acceptance Testing (FAT) and Accepting Testing Procedure (ATP).
- Back office integration was challenging. There were integration challenges at the start of the project. Specifically, operational systems such as the Energy Management System were impacted by the additional data provided by the substation automation system. Other systems such the Data Historian and Central Management Services also required new interfaces for new sub- station automation applications. Utilities considering a similar automation system should establish key requirements and deter- mine which existing systems will be affected.
- Utilities planning to adopt a substation automation system should obtain "stakeholder buy-in" early in the process. They should also obtain support from the training departments. Instituting a substation automation system not only affects systems, it also affects the operational processes associated with these systems. As SA-3 integrates with or replaces operational systems, it will lead to procedural changes. Although such procedural changes may seem trivial, the ramifications across system operations can be significant. SA-3 impacts back office processes as well as processes within the substation.
- Hands-on training proved to be critically important. While there are various resources that can provide basic overviews of the standard, this training does not readily translate into practical knowledge. Hands-on training with the utility-specific relays and testing tools are needed to speed up the development process. It may also be necessary to have customized in-depth training on specific areas of the standard not normally covered in broad trainings, such as the details of MMS.
- Generic object oriented substation events (GOOSE) messaging was used in the ISGD project for a bus-protection scheme. GOOSE messaging can have many potential benefits if

implemented properly, however, it does have limitations. One of the most challenging aspects is finding ways to safely isolate and test digital wires. This also requires a shift in mindset on how testing must be done. IEC 61850 does provide a simulation bit that is intended for this purpose, however, during the SA-3 development this feature was not implemented in any of the chosen relays. In addition, GOOSE messaging works very well on a one-to-many communications application where one publishes a GOOSE message and many on the network subscribe to the same message, but there are applications in SCE's current practices where a many-to-many relationship is required. This results in a GOOSE configuration where every participating IED publishes a GOOSE message that all other IEDs subscribe to. This is not an issue unless the IEDs in use have a limit of how many GOOSE messages they can subscribe to. The major issue arises when a new device needs to be added to the scheme at a later time. This requires all existing IEDs to be configured to subscribe to the new device. Depending on current testing practices, this might require re-testing every participating IED. The hardwire equivalent of this is a bus where every participating IED can read and energize the bus independently.

- Standardization of GOOSE message configuration tools is required. Ideally a single tool would be able to configure GOOSE messages on multiple devices. However, multivendor implementation of GOOSE messaging can be cumbersome to implement since each vendor's configuration tool works differently and it might require going back and forth, importing and exporting CID files between the multiple vendor tools.
- IEC 61850 allows for many optional parameters to be implemented. There is a need for more consistent adoption of optional fields between vendors to be able to take full advantage of the standard. This led to mixed results during interoperability testing. The design engineer should keep in mind that options implemented by one vendor are not necessarily implemented by another vendor, leaving interoperability between conformance tested devices to be at only a very basic level.
- System and device information available for automatic capture and transfer to the CMS lowered the importance for user remote access. However, it quickly became apparent that it was still valuable for troubleshooting issues the team encountered on the Substation Gateway.

The IEC 61850 standards suite and associated technologies can bring significant value to a utility automation project but like any new technology brought into an organization the consequences of technology change must be anticipated and managed.

6
RECOMMENDATIONS TO INDUSTRY

Several specific recommendations for industry groups including standards bodies and user communities were identified by the utilities participating in this case study white paper. Chief among these is the need for organizations such as EPRI, the Smart Grid Interoperability Panel (SGIP) and the 61850 user communities to do a better job of communicating information on the projects that they have underway, services they can provide, and tools/artifacts that are available to help new implementers. Neither NYPA nor KCP&L (directly or through their consultants) were aware of the user communities and services available.

Other recommendations include:

1. Develop better vendor-specific and third party tools for configuration, monitoring and maintenance
2. Develop basic application profiles to simplify specifications for common applications.

    Note that the SGIP has a new Priority Action Plan (PAP 23) focused on developing a Basic Application Profile (BAP) for distribution feeder monitoring[13]. In California, the Smart Inverter Working Group (SIWG) chose to use the device information modeling portion of the 61850 standard to describe the information expected to be exchanged with a Smart Inverter[14].
3. User communities should implement a better set of collaboration tools (adhoc list servers, SharePoint, Web meeting accounts) for information exchange.
4. Facilitate better access to the IEC standards community to ensure that technical issues and potential solutions identified by vendors, utilities and implementers are vetted, implemented in revisions to the standards, and then fed back to the implementing utilities.
5. Organize physical meetings and events to get multiple utilities in a room to develop and share common requirements, use cases, case studies, business value frameworks and performance metrics, methods and targets.
6. Facilitate utility participation as observers at vendor interoperability testing events

[13] PAP-23 – Testing Profile for IEC 61850, Communication Networks and Systems in Substations - http://www.sgip.org/Testing_Profile_IEC61850

[14] California Rule 21 Smart Inverter Working Group Technicla Reference Materials - http://www.energy.ca.gov/electricity_analysis/rule21/

7 GETTING STARTED

If you have a substation automation project on the horizon and want to know how to get started using 61850, here are a few key starting points:

- Develop a vision of how you want to approach utility automation in the future and identify an executive sponsor.
- Organize a working group of your best thought leaders, communications gurus, and protection engineers to communicate the vision and develop a disciplined set of requirements that a new approach must address.
- Engage an outside expert at least temporarily to help bring you up to speed quickly on the industry state of the art and best practices, facilitate your initial working group meetings, and act as an honest broker to get you on the right track.
- Download and study the documents listed in the Resources section of this report
- Join the UCAIug 61850 Users Group to avail yourself of all of the tutorial information available to members and attend a meeting or interoperability event to understand how others are approaching 61850 implementation.
- Using the UCAIug, EPRI, SGIP, and other collaboration organizations and venues, build and maintain relationships with your peers in other organizations who have either implemented or are considering implementing 61850.
- Communicate and publish your successes, failures, and lessons learned through users groups, industry publications and other venues.

8
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"Technical Overview and Benefits of the IEC 61850 Standard for Substation Automation", Ralph Mackiewicz SISCO, Inc. - http://www.sisconet.com/downloads/IEC61850_Overview_and_Benefits_Paper_General.pdf

61850 Fundamentals – ABB
http://www.youtube.com/embed/D194LwtKtjA

Video Based Resources

Siemens:
IEC-61850 Fundamentals – 5:02
https://youtu.be/D194LwtKtjA

Modernizing the Grid in Orangeburg, SC with Distribution Feeder Automation – 3:47
61850 never mentioned – use of the standard is entirely transparent to the utility. See separate white paper.
https://youtu.be/WC_L63jqaEI

ABB:
IEC 61850 and Substation Automation (2011) – 51:31
https://youtu.be/abOt8iKpPVk

Introduction to IEC 61850 (2011) – 1:57:43
https://youtu.be/zB4-mBQPd7k

Introduction to IEC 61850 (2012) – 1:24:29
https://youtu.be/0ZGv1vz43Gg

Schweitzer (SEL):
IEC 61850 Substation Modernization and Wire Reduction – 3:27
https://youtu.be/ylyIrLL0qL0

EnerNex:
Smart Grid, Utilities, and Internet Protocols – 1:18:27
https://youtu.be/zB4-mBQPd7k

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