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CIGRE US National Committee
2015 Grid of the Future Symposium

Challenges and Lessons Learned from the Design and Implementation of an IEC61850-90-5 Synchrophasor System

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SUMMARY

Synchronized phasor measurements (synchrophasors) can provide sub-cycle data rates and thus enable a series of new applications and analytics. Example applications include measurement of voltage phase angle differences across the system, fault location, Small Signal Oscillation Detection, and Linear State Estimation. Future concepts include backup line current differential and Dynamic Contingency Analysis.

The synchrophasor system, described in this paper is in operation. The production infrastructure is engineered per the IEC 61850-90-5 Technical Report [1] and provides a total of 432 PMU output streams from 176 multi-function devices distributed across numerous key substations. The system includes several aggregate Phasor Data Concentrators (PDCs) spread throughout the service territory which connect to multiple Super PDCs through Multicast communication. The real-time, precise and synchronized grid measurements captured by the PMUs are time-aligned, concentrated and locally stored by the aggregate PDCs while at the same time being transmitted to the Control Centers where the data is processed by the super PDCs. The synchrophasor data is then distributed to the Wide Area Measurement System (WAMS), Adaptive Protection, Fault Detection and Location applications and many other analytic functions. The infrastructure supports data exchange with neighboring systems, the ISO, and the Western Electricity Coordinating Council (WECC) / PEAK Reliability Coordinator.

The architecture has been tested to support both IEEE C37.118.2 and IEC 61850-90-5. The deployed system was primarily engineered to support IEC 61850-90-5 with Internet Protocol (IP) Multicast over User Datagram Protocol (UDP). The system also supports IEEE C37.118.2 mainly for data exchange in case the data recipient prefers IEEE data frames.

The Architecture was designed to support both hierarchical data flow as well as meshed data flow. The meshed data flow allows applications to be distributed throughout the system. A good example of this is the implementation of Backup Current Differential where a given PDC may require data from another PDC.

KEYWORDS

Synchrophasors, Phasor Data Concentrator, PDC, System Architecture, Lessons Learned

SYSTEM IMPLEMENTATION PROECSS

A system implementation of such a large scale requires rigorous scheduling and planning to ensure a smooth deployment and timely delivery. The complete deployment has been realized as a three-step process. As a first step, testing at the Proof-of-Concept (PoC) facility, fitted with components from multiple vendors (PMUs, GPS clock, Ethernet switches, etc.), proved vital to overcome all the inter-operability issues. Since the PoC was a scaled version of the real installation, it also facilitated the write-up of the procedures required for field installation and system trouble-shooting. The second step involved the deployment of the solution in a limited number of geographically close substations acting as pilot sites. There were two main goals to this step. One was to establish and verify the process for deploying the equipment and technology. The second was to serve as a training basis for the specialists that would be in charge of the overall deployment. After strengthening the field commissioning process, the time came for the final deployment of all the devices and ultimate system integration where all the synchrophasor applications were also tested.

The following provides a brief introduction to the synchrophasor system design:

A. *Overall Redundant System Architecture*

The Synchrophasor System deployed at Pacific Gas and Electric Co. has been designed to operate in a disaster recover environment and is thus architected for redundancy and resiliency As such, each electrical measuring point is covered by two sets of CT/PTs, feeding independent PMU units. Each PMU feeds the synchrophasor measurements to its assigned PDC which, in turn, provides local storage of the data and streaming to the remote clients.

In addition to the PMU and PDC redundancy, the overall network devices and communication paths are carefully selected to achieve complete redundancy. Even the location of superPDC and the EMS applications are geographically separated for natural disaster considerations. Figure 1 is a high-level overview of the simplified synchrophasor system (redundancy not shown).

One branch of the synchrophasor data collected from the field PMUs by the aggregate PDCs are fed into the EMS superPDC where the utility applications then will take over for real-time stability monitoring and situational awareness analysis. The other path is fed into the ancillary superPDC for the centralized archiving and the data exchanges to WECC and other entities.

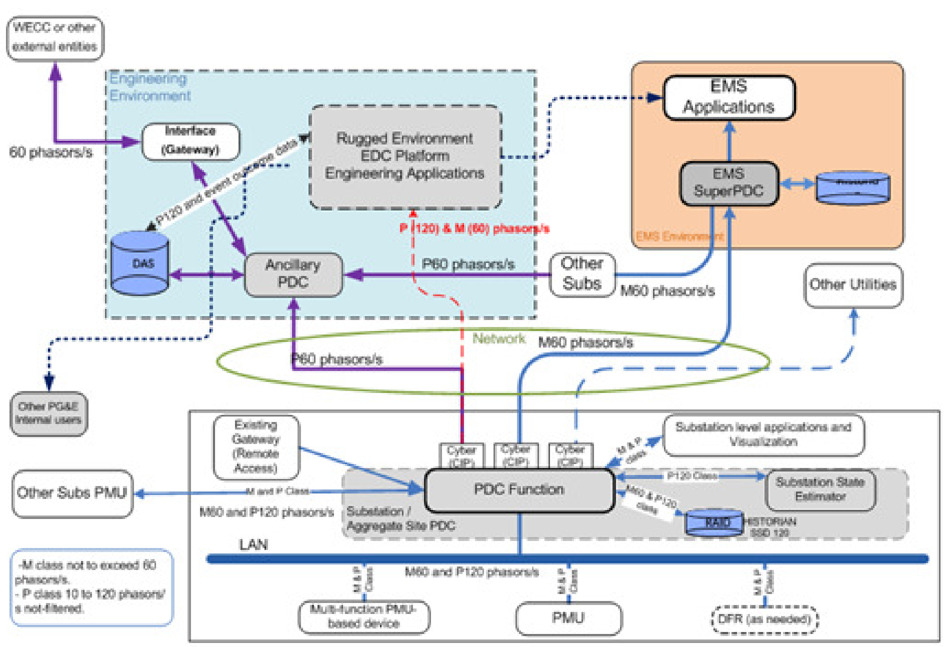

Figure 1 Simplified Synchrophasor System Architecture (redundant system not shown)

B. Allocation of PMU and Aggregate PDCs

In terms of PMU function, there are 432 PMU functional units between the two redundant and diverse systems and include both the P- and M-Class Synchrophasor measurements, for a total of 109 distinct electrical measurement points) spread over 176 PMU devices that make up the full complement of the two diverse systems including instrumentation inputs to the redundant measurement.

There are 26 Aggregate PDCs providing signal concentration as well as local data storage. The criteria for allocating PMUs and PDCs includes the diverse factors such as the application requirements, infrastructure architecture, communication bandwidth, deployment cost, etc. [2].

C. Control Center Environment

The Control Centers are divided in two isolated environments: the Production and the Engineering Environments.

1) Production Environment

The Production Environment provides the safety and security required for the daily mission-critical tasks of the Utility. The Synchrophasor and the traditional EMS functions overlap to provide such functions as:

- Oscillation Stability Monitoring
- Wide Area Situational Awareness
- Islanding Detection
- Disturbance Locator
- Congestion Management
- Enhanced State Estimator
- Fast Grid Topology Processor

2) Engineering Environment

The Engineering Environment provides the necessary flexibility for the Engineering evaluation and real-time system performance evaluation tasks such as:

- PMU Status Indicator
- Adaptive Protection
- Fault Location
- Engineering Visualization
- Interface to external entities (neighboring utilities, regulatory bodies).

D. Data Exchange with Neighboring Utilities

As power systems are tightly interconnected, events on the neighboring system have effects on the local system, thus information from neighboring systems is beneficial for understanding and responding to remote events. Extending visibility into key parameters of neighboring system can dramatically increase the power system reliability. In one application for example, some power system parameters from key locations are exchanged between two utilities to allow the monitoring of the power system stress level (large voltage angle difference). Based on a decision tree algorithm, the interconnecting lines are either protected by a voting scheme or non-voting scheme as a way of skewing protection between security and dependability [3].

E. EMS Application using Synchrophasor

Jampala et. al describe the new generation of synchrophasor applications and next generation production EMS, and the integration challenges associated with sub-second data, in [4], These synchrophasor applications include Linear State Estimator (LSE), Oscillation Detection, Voltage Stability indicators, etc. Implementation experiences of enhanced engineering solutions, tools to validate results, need for advanced simulation tools for training and the challenges in integration as well as many of the PMU and PDC industry guides and standards are described in [5].

F. Phasor Data Archiving

The Synchrophasor Measurements are first stored at the local Aggregate PDC. 250 GB of Solid State Disk (SSD) storage provides the necessary reliability in case of a communication disruption.

The PMU can also be set to record the phasor data locally in case of a detected event such as a line outage, under/over frequency and rate of change frequency. The recorded data can serve as a backup in case of the archived data being unavailable due to a communication failure or device failure farther up in the system.

When the data arrives at the Control Center PDCs, the Historian Archive ensures the preservation of information for long-term purposes and NERC compliance.

G. Engineering Data Concentrator and Fault Location Calculation

The Engineering Data Concentrator (EDC) collects data from the local Aggregate PDC storage units on-demand. The data collection is based on either a pre-determined set of trigger conditions or by manual user-defined criteria.

Based on configured PMU triggers, the EDC detects major events occurring on a line (e.g. a Line Outage) and retrieves the pre- and post-event data necessary for analysis. It can automatically calculate the Fault Location and provide this information to the EMS.

Alternatively, a power system engineer could decide to retrieve, after the fact, the Synchrophasor measurement pertaining to a given set of PMUs for a desired time range. The EDC would coordinate the collection of data from the PDC involved and export it to either CSV or COMTRADE 2013 formats.

H. Adaptive Protection using PG&E and Neighboring Sychrophasor Measurenents

In order to mitigate the potential effects of relay mis-operation during stressed power system conditions, an Adaptive Protection Scheme (APS) is being studied as a research project. The APS closely monitors the key current and voltage parameters across the utility and adjacent neighbors. Once the system status is deemed stressed ($\Delta\theta \geq$ Setting), the three relays protecting the transmission line are placed in a two-out-of-three voting scheme. Under normal circumstances – when speed of operation is more desirable than the risk of a false operation– any of the three relays is able to trip the circuit breaker.

I. Substation State Estimator

One key advantage of distributed state estimation (DSE) / Substation State Estimation (SSE) versus centralized state estimation derives from distributed intelligence.; placing processing power closer to the monitored equipment. By processing the bulk of the data locally (at the substation level) and sending only a fraction of the most pertinent results upstream, central state estimation can be updated 60-plus times/sec. This is a vast improvement from current approaches that refresh central state estimation every minute or so. Add data streams from other Intelligent Electronic Devices (IEDs) that track power quality and data transport, and storage may become impractical. The distance between IEDs in the field and centralized processing can lead to inaccurate or compromised data, based on line impedance alone. Processing torrents of data at the control center can burden servers and detract from other processing priorities [5].

Other advantages of localized state computation is when a substation with multiple switchyards of different voltage levels may not be equipped with PMU devices at each of the different switchyards, or some of the switchyards may only have traditional microprocessor type information. For example, a substation with 500kV, 230kV, and 115kV may only have PMU devices at the 500kV and the 115kV switchyards. The availability of synchronized measurements from an appropriate node selection together with good model of the primary equipment interconnecting between the switchyards allows the Substation State Estimator (SSE) to compute the missing data and feed it as a stream of data into the synchrophasor system [6].

In the architecture described in Figure 1, the required PMU data arriving at the Aggregate PDC are sent on a dedicated stream to the SSE. After performing the computation, the SSE in turn sends the new computed data to the Aggregate PDC for inclusion into the outgoing streams configured for the PMU data consumers. The SSE can also calibrate the phasor values according to the real CT/PT characteristics modeled in the SSE [6].

J. PMU and PDC Naming Convention

Given the 16-character limitation imposed on the Station Name by the C37.118.2 [7] Standard, a concise yet meaningful naming convention was adopted. It follows the following model:
SS_511_B1_1P_AC, where

- SS is the substation identification
- 511 refers a 500 kV (5) multifunctional relay (11)
- B is followed by the Bay number
- 1P is for the P-Class stream out of the 1st magnetic module
- AC is one of the two redundant systems.

The PMU ID Code, limited between 1 and 65534 and needing to be unique in the system, follows the following convention:
20013, where:

- 2 is the voltage level (1:115 kV, 2:230 kV, 5:500 kV, 6:60 kV)
- 00 is the substation number
- 1 is the PMU device number (in that substation)
- 3 is the PMU instance of a given PMU device

A similar approach has been used for the Aggregate PDC where the Name matches this pattern:
SS_n_AC_xPDC_P, where

- SS is the substation acronym
- n is the PDC instance
- AC is one of the two redundant system
- x is the destination (S for Super PDC and A for Ancillary PDC)
- P is the measurement class (either P or M)

While the ID Code follows this pattern:
40025, where:

- 4 indicates an Aggregate PDC
- 00 is the substation number
- 2 is the Aggregate PDC device instance (1-4 for one redundant system, 5-8 for the other)
- 5 is the Aggregate PDC Output stream instance.

K. Deployment in a Secured NERC IP Network Environment

Communications throughout the system was based on the Internet Protocol – Ipv4. As such, IP addresses were assigned to all devices. Specifically, Multicast IP addresses were assigned to the PDC where one PDC published Synchrophasors to 2 Super PDCs. One of the communication security measures taken was the use of firewalls – communication filters – spread throughout the enterprise. In order to minimize Denial of Service attacks, PING messages were filtered out on the system.

Access to the PMUs and PDCs was secured through multiple levels of "strong" password access (required a certain length and combination of characters). More specifically, the devices implemented Role Based Access Control (RBAC) which limited functional access based on the Password entered. Examples of Roles include View Only, Record Access, Control, Setting, and Administrator.

Security testing was performed on the PMUs and PDCs used in the project. Relevant communication tests included Denial of Service attacks, Network Congestion, Ping of Death, Known Security flaws vulnerability, Password Attack, Open Port scan, Address Resolution Protocol (ARP) Spoofing, and Penetration attacks. The devices under test responded appropriately to these tests.

COMMISSIONING PROCESS

Because the PG&E Service Area extends over an area of approximately 70,000 square miles, careful steps needed to be taken to ensure a smooth field deployment. As several devices were still in development as well as the fact that several manufacturers were involved in the project, it was crucial to perform system-wide testing prior to full-scale installation and commissioning. Ensuring the field personnel were familiar with the equipment, functions and processes was also key to the successful completion of the project.

L. Proof of Concept Lab as a Real Environment for Preparation for Field Commissioning

There are 469 miles of roads that separate the PMU-equipped substations at the north and south of the PG&E Service Area. To avoid unnecessary travel, a world-class Proof-of-Concept (PoC) laboratory facility was used to test the complete system in an environment that was as close to an actual substation as possible (without the HV equipment). It consisted of:

- Power System Simulator with detailed system model
- 6 Current & Voltage amplifiers for secondary signal injection
- 9 PMU devices from 4 different manufacturers to ensure compatibility (and 1 PMU Simulator for up to 40 additional PMUs)
- 3 Aggregate PDCs permitting various modes of redundancy
- 2 superPDCs
- Communication equipment connected to the enterprise network
- EMS and EDC
- 4 IRIG-B/IEEE 1588 clocks

Figure 2 View of the PoC facility

The PoC (Figure 2) gave an opportunity to the various manufacturers and partners to get together and test on a real system and have open discussions on how to resolve the various issues that were encountered during the implementation stage.

Additionally, it offered a perfect environment to draft and review the field deployment procedures as well as a training platform for the Utility personnel that will be in charge of executing the project.

Finally, the PoC facility made it possible to test the performance of the various pieces of equipment in a controlled environment. Some of the key tests included:

- Clocks against a known standard,
- Protocol conversion capabilities,
- Loading the PDCs to maximum capacity,
- Compliance of the various devices to the standards.

M. Pilot Sites

The last step before full-scale deployment was to implement the system in three substations in the vicinity of the teams in charge. This was realized in collaboration between the Utility personnel and the manufacturer's representatives. Not only did it allow for a more efficient transfer of knowledge but it also gave the opportunity to fine-tune the procedures and receive first-hand feedback regarding the products, software and procedures.

The Pilot Site was also the first time that a data stream flowed on the entire communication path from the PMU device all the way to the Control Center. This testing allowed the fine-tuning of the IT procedures (related to firewall rules and multicast messaging) and ensured that the preparation work for the following substations would be complete.

Pilot-site testing highlighted differences between actual substation designs.

N. PMU Testing at the Substations

One of the challenges with the testing of PMUs at various locations is the fact that a PMU is a multi-functional device. At PG&E, most of the PMUs are part of the critical Remedial Action Scheme (RAS). Upgrade of PMU firmware to support the required PMU functionality had to be done during a scheduled clearance time window. As such, time to verify the existing RAS function as well as testing of the new PMU functionality was very limited. Creating a practical and quick testing procedure with consideration for clearance verification, network communication, PMU data streaming, 1588 clock verification and system restoration was critical.

The redundant system design allowed the testing of PMUs one system at a time so that the operation of the RAS was not compromised. The PMUs were set to stream automatically on power up. This facilitated the testing of PMUs individually without a connection to a PDC. This was especially useful during the construction phase when a communication path between the PMU and PDC was not always available. PMU steaming was verified using a network sniffer during the testing.

O. Aggregate PDC Testing

PDC testing is somewhat more relaxed than the PMU testing described above. Since the PDC was not yet part of the Production Environment, there was no clearance window required to perform the commissioning procedure. The PMU devices were streaming their data, if nothing collected it, it was not an issue. Also, the Aggregate PDC clients were not yet relying on a constant data stream because the existing EMS was working in parallel with the new system.

One of the problems encountered has been the data incoming into the Aggregate PDC being rejected at the aggregate PDC itself. The root-cause for the data being ignored is identified as the clock timing sources between the PMU and the aggrrgate PDC. The PDC has been connected to an Inter-Range Instrumentation Group Timecode Format B (IRIG-B) signal while the PMU devices are connected to a dual IRIG-B / IEEE 1588 signal (with priority assigned to IEEE 1588 when valid). In this particular scenario, the 1588 clock was found to be off by several seconds yet it was reporting that the signal was valid (identified as a 1588 clock issue). When the Synchrophasor data stream arrived at the PDC, the data was being rejected as invalid because it was outside the wait-time window of the PDC [8].

Another difficulty was coordination of the Utility field personnel, the manufacturer representatives and the IT department. Not being in a Production environment meant that there were sometimes urgent matters that needed to be attended by one department or another in the time-slots that were allocated to the field deployment.

P. System Level Testing with EMS Sychrophasor Applications

The Fault Location application requires interface with EMS. Open Platform Communication – Data Access (OPC-DA) has been chosen as the application. In as much as the Proof of Concept (PoC) had a model of the EMS system computers, it is a simple matter to post the data via OPC and verify that it is appropriately received in the EMS. Few problems have been encountered during implementation this portions of process.

GENERAL LESSONS LEARNED

Q. Challenges Encountered in Implementing a New Standard

As the inaugural implementation of IEC61850-90-5 as well as an early adopter of the IEEE C37.238 profile for 1588, the project did spend time in making sure the pieces fit – and finding out what didn't fit

1) Errors in the Standard Text

Although IEC61850-90-5 had been vetted via a Proof of Concept implementation, final implementation did uncover a few errors/interpretation issues. Specifically, the count of the bytes in the message was required. Although the image of what should be covered in the message byte count was clear, the migration of this value into the standard had an error. Testing in the PoC uncovered this issue early on.

2) Interpretation of the Standard by the Various Parties

With multiple parties involved in a complex project, the interpretation of technical standards can often play a significant role.

One of the early examples was regarding the C37.118.2 protocol. The standard indicates that either TCP or UDP must be implemented. The various manufacturers came up with the following combinations:

1. TCP commands and TCP data
2. UDP commands and UDP data
3. TCP commands and UDP data
4. No command, unsolicited configuration frame and UDP data.

All of the above are compliant with the standard but not all of them are compatible with each other. If a PMU server implements configuration 2 but the client implements configuration 3, communication is impossible.

3) Step-by-Step Implementation of a Complex Standard: Intermediary and Temporary Meaures

Perhaps the major challenge of this project was the end-to-end implementation of the IEC 61850-90-5 standard. At the early stages, the standard was not complete and, obviously, none of the devices implemented it.

In order to complete the implementation within the project schedule and in-line with industry standards, the adoption of an Implementation Agreement has been key. Considering the project participants include many IEEE and IEC standard members, a proposal for Standard Mapping between the C 37.118 and IEC 61850-90-5 is presented to the IEEE Power System Relaying Committee. The IEEE work is in progress under the PSRC "H" subcommittee, working group H21. The initial work leading to the formation of the IEEE Working group is made by the project team at Pacific Gas and Electric CO. (PG&E). The C37.118.2 commands are used to carry the cconfiguration of the PMUs (Configuration Frame 2, also referred to as CFG-2) while data transmission is using the IEC 61850-90-5 standard.

The document also proposed a mapping between the profiles of the C37.118 and IEC 61850-90-5 standards to cover for the incompatibilities that could arise from the limitations of either one of the standards as well as to facilitate the receipt of data in existing C37.118 clients. For instance, the C37.118 Status Word (STAT) was mapped as an Int16U as a 16 bit - bit string did not exist in the 61850 definitions for Sample Values. An updated Implementation Agreement should address this issue. To facilitate mapping into the existing historian, the Sample data values (Synchrophasors) were to be transmitted in the 61850-90-5 in the same order in which they are mapped into the C37.118.1 frame.

R. Challenges of Working in a Multi-Disciplinary Team

1) Protection Engineers and IT working on the Production System

Since the new system interfaced with the Production Environment through networking equipment, and because of the NERC compliance requirements, the implementation of the routing and firewall rules are internal Utility practice..

Traditionally, Protection Engineers are not versed in the telecommunication and networking fields and IT specialists might consider Protection & Control (P&C) traffic the same as any other traffic not recognizing the reliability, resiliency, latency, or the time-critical requirements for mission critical systems for Power System aplications. In this type of a project, it was critical to have a group of people familiar with both fields to permit meaningful and productive discussions. In a project where the products are developed while the standards are being written and while the implementation is moving forward, this was particularly important.

2) Challenges Related to Distances

Another challenge was related to the number of equipment providers and partners, was the geographical distances between the parties. In addition to the distances involved in the project system itself, subject matter experts from the various partners were sometimes located several time zones away or even on different continents.

In our experience, there were two keys to minimizing the effects of the geographical separation. The first was the segmentation of expertise. A clear definition of the responsibilities of a given individual, and designating this person as the contact for a given part of the project facilitated communications tremendously. Many multi-parties meetings occurred in the various “sub-teams”, but the communication links between the various teams was clearly defined so at the project level status and control was easier to maintain.

The second key was not only the professional but also the personal investment that the many participants made to the project. All of the participants to this project had to push themselves and challenge their own technical knowledge and expertise, go back and improve on it in order to provide the best solutions to the most difficult issues. Personal involvement was also pivotal to the success of the project. The many hours spent together testing and re-testing in the PoC facility, working toward a common goal brought the overall team together so that, for example, when a conference call was later necessary to support troubleshooting, the individuals from the various organizations did not hesitate in being present and supporting the common effort.

It must be said that distance did present some advantages. Sometimes questions that were sent out to factories at the end of the working day were resolved and answered the next morning, because the team responsible was working in a different time zone.

S. Do not Trust the Specs!

When dealing with products that are being developed, it is best to consider the product specifications provided by the manufacturer as subject to change. The amount of work required to ensure that all the detailed specifications of a given product are met under all scenarios is typically more than what is physically possible to accomplish. It is thus recommended to test the product for the specifications that are critical to a given project, under the real conditions of utilization [9].

Here is an example to illustrate this point: In the case where a complete system is built from PMU devices to a PDC to an EMS system, it is reasonable to consider using the actual values received at the EMS for power system model validation. Now, what if one of the GPS antennae (that provides synchronization to the PMU devices) received a spoofed GPS-signal? The system would provide some erroneous data that might be fed into the system model.

Another example was the lack of proper Time Quality values reported by GPS clock. In a test, the GPS antenna was disconnected from the clock leaving the clock to drift. The amount of drift was measured by comparing the drifting clock to a known accurate clock. The drift in the un-synchronized clock was measured as 150 µsec, however, the unsynchronized clock claimed 1µsec accuracy in its time quality field.

SPECIFIC LESSONS LEARNED

T. IEEE 1588 Time Source versus IRIG-B Time Source

Both IEEE 1588 and IRIG-B with DC shifted option time source can be used for synchrophasors so that PMUs at different geographic locations can be time synchronized. Ideally both PDC and PMUs are synchronized with an accurate time source and the time accuracy shall be within a few hundred nanoseconds. However, this is not always the case due to incorrect settings or malfunction of GPS clock. During the commissioning testing, a large time difference between IEEE 1588 and IRIG-B source has been seen and diagnosed as the root cause of invalid data at the superPDC level.

U. Synchrophasor Network, VLANs, Subnets, and Firewall Rules

The Synchrophasor networks at the substation level are operated on independent redundant networks that are separated from the RAS system. Only designated aggregate PDCs can communicate with the PMUs that are in the same Virtual Local Area Network (VLAN) and Subnet. VLAN, Subnet, and firewall rules are enforced at the substation routers to satisfy the NERC CIP [10] requirements. PMUs and PDC also have been designed to support multi-level of security authorization. All of those features proved necessary. However, this added up the complexity of commissioning testing. Many hours were spent in identifying incorrect firewall and subnet settings. In addition, in one situation, a switch port connected to a PDC was configured as a Trunk port wherein all traffic on through the switch was sent to that port…..a challenging situation for the PDC.

V. *Ethernet Switch, Router and Traffic Filtering Setup*

A situation that was encountered for several months was a random communication disruption on the Ethernet network. The affected equipment and the frequency of occurrence seemed to be random. Tremendous effort was made to analyze the network load, review of the communication equipment logs and including re-doing the whole PoC Ethernet wiring. It was finally root-caused to a device that would sometimes respond to an Address Resolution Protocol (ARP) request not directed at it. When the faulty device responded first, the ARP request would be overwritten by the correct device (responding second). But when the correct device responded first, the faulty device would overwrite the correct MAC/IP and would cause communications to go down, until the next ARP request.

W. *IEC61850 90-5 Unicasting and Multicasting*

One of the benefits of IEC 61850-90-5 is the option of using multicast transmission of a data stream. Multicast communications saves bandwidth when delivering the same data to multiple locations not only reducing the load on the PMU/PDC Servers but also reducing the resulting traffic on the network. It does, however, delegate the data client management (data reception source) into the hands of the network protocols.

At the substation level (in the Local Area Networks), unicast was used in order to reduce the traffic. For the data going out of the substation (or, in other words, being routed through the enterprise-level network), multicasting was the obvious choice to allow the routers to manage the traffic towards the desired consumer(s) of data.

In order to establish a path between the publisher and a subscriber of data, a protocol called the Internet Gateway Management Protocol (IGMP) is required. Specifically, the IEC61850-90-5 profile specifies the use of Version 3 of the standard. One of the obstacles that were faced is that IGMPv3 did not allow messages to be transmitted through "older" firewalls. This fact was not immediately obvious as the function worked fine when initial testing was performed without the firewall. The short term solution for this problem was to back down to Version 2 of the standard. Although Version 2 functioned in this application, in the long term Version 3 – which selects a path based not only on the destination address but also the source address – is the appropriate solution. This does imply that in the long term, upgraded firewalls with support for IGMPv3 will be required.

X. *Setting Software and Testing Tools*

To facilitate the complex work of site testing and remote configuration of the many devices, a series of tools were either identified (e.g. WireShark), modified, or developed specifically for this project.

1) *Setting File Conformity Tool*

The utility had strict requirements for the 200 plus setting files that were required only for PMUs and PDCs. Given that the PMU devices were in the Production Environment and required a standard Clearance procedure to modify the settings, a zero-tolerance process was put in place to ensure that the 1000's of signal names, PMU Station Names, ID Codes, etc., were compliant with the Utilities' standard. A triple-verification system was adopted: the files were created or modified by an application engineer, the various files making up one substation (PMUs and PDC) were then submitted to electronic verification to ensure conformity with the previously defined Setting Guidelines and, finally, a second application engineer would review the file before releasing it to the field team.

This electronic verification tool was developed in-house to guarantee that the files would comply with the internal standards.

2) *Network Traffic Tools*

The Ethernet traffic tools were invaluable in troubleshooting the handshaking and protocols but were also used as a tool to troubleshoot the data being transmitted as well as to view and analyze the various flags involved in the messaging. It also allowed delving into the formatting of the data.

This network sniffing tool (WireShark) was essential as it allowed for automatic stream decoding which was used to inspect the incoming and outgoing traffic from the various devices. It also provided the means to analyze the message bits on the wire. It was therefore possible to ensure that the protocols, ports, packet forming, CRC … were as per the standards, down to the individual bits or bytes. Special modifications were made to WireShark to enable the decoding of the Payload sections of the 61850-90-5 profile.

These tools allowed for the verification that a PMU device was generating Fraction of Seconds (timestamp) that were not standard (e.g. 0.008312 s while the standard reporting rates only covers 0.008333 (1/120) or 0.016667 s (1/60)). In another case, it was shown that some PMUs were reporting non-compliant angles (e.g. 240º while the standards indicate that angles should be between -180º and +180º).

3) Progress Tracking Tool

Various management tools were created at the various levels of the projects. For the PMUs, a simple spreadsheet listing the various pieces of equipment was put together with updates for setting file release dates, commissioning dates etc. The same applied to the PDCs.

Y. Testing Procedures

Perhaps the single most important lesson learned from the Testing Procedures is: Test it! Test it! Test it! Many times, the person creating the field Testing Procedure is the subject matter expert. Because of this, it is easy to overlook some aspects that less experienced personnel might struggle with.

The Testing Procedures are an important document for knowledge transfer between the design team and the implementation team. It cannot be the only tool. Sitting together with the people that will be executing it, paying attention to the Sections where they struggle, taking notes, listening to their comments and constructive feedback, and providing them with more information, tools and knowledge than it might appear that they strictly need all translates into providing them with what they will need to face unexpected situations.

It is also very important to understand the different teams that will use these procedures, especially when it comes to the task delimitation of the various professional groups. The Procedures should also blend with the culture of the company. In this particular case, the personnel in charge of the synchrophasor system also were previously in charge of the RAS system. Preparing procedures that mimic the ones they already knew facilitated the transition to this new system.

CONCLUSION

The implementation of complex systems is bound to be wrought with challenges. The Synchrophasor system installed on the PG&E system was such a system. The challenges of integrating and testing the diverse pieces of this system were many – a number of which are documented here to facilitate future implementations by others. The use of a Proof of Concept facility to expose, identify, and rectify these issues proved invaluable and is strongly recommended as a best practice. The PoC facility remains in place and will be used to vet additional new technologies as they are introduced onto the PG&E system and into the industry.

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