Implementing a Modern, Secure Relay Integration Solution with Existing IED's

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***Abstract*--This paper presents a summary and analysis deployment of a secure Intelligent Electronic Device (IED) management system at a utility in North America. The utility began their investigation into technologies and methodologies for securing their system for North America Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) standards. This report is intended for anyone considering the implementation of an IED management system**

Keywords— Legacy Devices, Multi-Vendor, Interoperability, Device Management, Integration

I. Executive Summary

This paper presents a summary and analysis deployment of a secure Intelligent Electronic Device (IED) management system at a utility in North America. The utility began their investigation into technologies and methodologies for securing their system for North America Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) standards [1]. This report is intended for anyone considering the implementation of an IED management system.

The electric utility industry is entering a new era of substation communication and operations. The confluence of technological economies of scale and the increasingly competitive business model encouraged by partial deregulation has created a need for data management on an unprecedented scale. Today, utilities generate mountains of data that could be useful, but that instead lie untapped, locked away in hundreds of multi-vendor devices speaking obscure and proprietary protocols. Moreover, the data that is being used is shunted through a web of conflicting priorities, its usefulness diluted by the lack of a coherent system for secure information transfer, dissemination and analysis. In their attempts to build a more efficient and responsive power transmission system, utilities often find themselves struggling to simply maintain the illusion of managed chaos. Developing a solution to such a complex problem is not easy. Approaching the issues methodically and with an eye towards the end goal of vendor agnostic total device management system will lay the foundation for an intelligent substation network and for more effective power management.

The utility featured in this paper had several goals when first initiating their project; to meet NERC CIP standards by implementing IED management systems that assist with non-operational data collection, provide secure remote access and increase system reliability. However, due to old, yet reliable protection equipment, the utility encountered issues with integrating legacy devices with modern IED management systems.

This paper summarizes the lifecycle of a real world project, including a description of the problems and challenges the utilities faced during the implementation to meet their unique challenges, while keeping in mind their expansion plans over the next few years.

II. Case Study

A utility was able to cost-effectively implement a secure and powerful relay and meter integration and management solution.

The objectives of this utility's project were;

1. Centralized relay event file data collection and archiving
2. Centralized power quality PQDIF data collection and archiving
3. Centralized secure remote relays engineering access
4. Centralized relay password management
5. Centralized relay SCADA data collection
6. Centralized relay HMI and alarming logging
7. Full auditing and logging of relay users for NERC CIP compliance

A key to this project's cost-effectiveness was that the utility was able to avoid significant capital and labor costs associated with relay firmware upgrades and/or relay replacement and recommissioning. Instead, the utility was able to implement a solution that met the objects listed above without changing any of the relays they have deployed over the last two decades.

A. Project Goals

The utility's main goal is to meet NERC CIP standard by implementing additional security and record keeping for protection relays and meters at minimum cost. However, the utility's system consists of old devices and contains schemas that were designed before NERC CIP existed. The question of "How do you implement new functionality to existing infrastructure at minimum cost?" presented itself to the utility.

B. *Existing System And Issues*

The existing system can be described as a large coal generation plant connected to a Bulk Electric System (BES) at 230kV supplying power to a large vehicle manufacturer. The distribution grid for the system operates at 230kV, 120kV and 34.5kV. The plant generates 750 MW of power to supply the vehicle manufacturer, but has sufficient capacity so that it can sell some of the power to the state for other consumer purposes.

The protection system is comprised of GE Universal Relay (UR) relays that have version 2.xx firmware. These relays have been in place since the plant was commissioned and are functioning as expected.

The secondary protection scheme is comprised of Alstom Micom and Schweitzer Engineering Laboratories (SEL) relays. The system metering is handled by Power Measurement Laboratories model 7600 and 7650 revenue meters.

As part of the project to increase security and record keeping, the utility deployed a new IED Management system and Human Machine Interface (HMI) system. The IED Management system allow the utility's personnel to securely access the relay and meters for maintenance and automatically manage the devices' passwords for NERC CIP compliance. The HMI system allows the utility to have better visual knowledge of their protection system. The HMI system provides real-time visual displays, digital alarm panels and data trending. As part of the IED management system, the system can also automatically retrieve event files from the SEL and GE UR relays.

The main issue that was observed during the IED management system deployment was the advanced capabilities of the newer Modbus protocol used for Event File Collection in the GE UR relays caused the version 2.xx GE UR relay to go into a restart sequence on every event file collection cycle. In other words, during the event file collection sequence, the command would begin power cycling every relay in the entire system, one at a time. It was determined that the newer Modbus commands produced this unexpected result with the older GE UR relays. GE was unaware of the issue with the version 2.xx firmware and recommended the replacement of the GE UR relays with newer hardware and firmware version 7.xx.

The utility contemplated these two solutions for the project:

- Replace all GE UR version 2.xx relays with version. 7.xx relays
- Leave all GE UR version 2.xx relays in place and modify the Modbus protocol used for Event File Collection

III. Solutions

A. *Solution 1: Replace All GE UR Version 2 Relays*

This solution is to remove and replace all existing UR relays with newer version of the relays. There are several problems with this solution. The first issue is the cost. Thirty-seven relays at a cost of $6000 per relay is approximately $222,000. This significant number was not budgeted into the cost of the project. The second issue is the manpower and outage time required to replace every single relay. Allocating manpower resources and scheduling time for systems to be down while relays are replaced would have added a significant increase in the budget. The third issue is the need to recommission every device and connection because all the original wiring would have to be disconnected and then reconnected to all thirty-seven relays. Once again, there are significant time and financial costs associated with the commissioning effort.

B. *Solution 2: Modify Modbus Protocol*

This solution is leaving the current relays in place and have them function as they had in the past. This was the best idea for the utility, but the issue with restart sequence caused by event file collection needed to be resolved. In discussions with the IED management system vendor, they determined that it would be possible to modify the Modbus protocol in the IED management system to handle older GE UR relays.

After some testing with older GE UR relays, a modification to the Modbus protocol was implemented and a hotfix for the system was provided to the utility.

C. *Final Design Solution*

The final decision made by the utility was to implement Solution 2. A hotfix was created by the integration company and the utility was able to successfully retrieve event files from the old GE UR relays without restart issues. Once the Modbus protocol change was proven to be working as expected, the utility realized they made the right decision. The cost to pay the vendor to modify the Modbus protocol was a small fraction of what it would have cost to replace all the GE UR relays.

In regards to labor cost, the implementation of the hotfix took only a few hours, and minimal labor cost, to install and test the functionality on the live system in comparison to the labor cost associated with commissioning of new relays and its protection schema. Event file collection for all GE UR relays was resumed and the entire system performed as expected with no issues for any relays.

IV. Conclusion

With vendors implementing new functionalities to the industry every year, it's very easy for hardware vendors to implement these new features in new hardware and not old hardware; thereby enticing utilities to upgrade their relays and meters. However, depending on the functionality, it can be implemented somewhere else in the system. Utilities need to analyze their current system and determine if certain functionalities can be implemented at a higher level which can be pushed to all their hardware to reduce implementation cost as well as labor cost. As stated in this case study, a simple hotfix to an upper level system that was communicating to all the relays saved this specific utility a large amount of money and labor.

Ultimately, the main goal for any utility is to make their system safer, reliable and cost effective. Some utilities lack internal expertise or teams that understand IT technologies. For some of these utilities, they are turning towards vendors to bring that level of expertise and knowledge to secure and manage their IEDs by bringing in proven IT technologies. Instead of looking to hardware vendors who are in the business of selling more hardware, look to integration companies that are willing to innovate and develop a multi-vendor solution that will work with your current existing system.

V. REFERENCES

Standards:

[1] North American Electric Reliability Corporation [Online]. Available: http://www.nerc.com/pa/Stand/Pages/CIPStandards.aspx