Optimizing and Integrating Transformer / Feeder Protection & Control Including Operations

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Introduction

This paper discusses two projects initiated by two utilities exploring operational efficiencies through integrating the protection and control of the transformer and feeders it serves. The challenges faced by utilities in maintaining distribution service with evolving DER deployment, distribution automation interfaces, service growth, and environmental events requires more than just traditional discrete protection functions. Each utility has similar needs but different goals that will be examined.

Substation automation systems using IEC 61850 can be engineered and deployed in a standardized and efficient way. Their flexible and distributed architecture provides many options for optimizing and reducing the number of physical interconnections and boxes used. When protection functions are integrated with operational and safety requirements the interlocking and logic becomes portable within the enterprise. And many different implementation philosophies can be applied including single vendor solutions, multi-vendor using compliant IEC 61850 features, and even point to point applications as well for the PAC system.

The Challenge

When implementing new technology, a common motivation is to improve the PAC system to reduce installed cost while extending the protection scheme, improving safety, and leverage available data for enhancing operations, analysis, and compliance.

The benefits targeted by one utility is to standardize a P&C scheme for their operational topology that can be reused in multiple substation configurations that may be similar but coordinate differently. They want to lower overall costs through installation time savings, lower recurring maintenance costs, provide new protection zones with no additional costs, provide unmet needs in event analysis and compliance documentation and achieve a measurable ROI overall. (Not a small list indeed!)

The other utility wants to develop a minimum footprint solution enabling a faster response time to a catastrophic weather event that destroys the control house or P&C system functions requiring the hardwired system to be replaced. The analysis that follows is based on a typical Main-Tie-Main configuration and can be adapted to any station configuration. An additional challenge is to merge the new technology and scheme with their existing conventional scheme (Hybrid solution) and still be a future Greenfield standard while looking to achieve similar benefits of the other utility.

Both of these utilities will leverage the IEC 61850 standard to achieve their desired goals. Some common goals are to make better use of available sensor data, provide integration points for their DA systems, improve security and safety, improve event response time, and share all station data internally.

A detailed comparison between the conventional and proposed integrated P&C zones, operational improvements, and new capabilities gained from the integration is presented. Plus, expected enhancements to overall operations, reporting, compliance, disturbance recording, predictive maintenance, asset health analysis, and operational safety.

Conventional P&C Zones

Utility-A and Utility-B have used a conventional distribution configuration for many years where the Main Transformer (TRF1) feeds a Main Breaker (MB1) into a common bus that each Feeder Breaker (F(n)) is connected. When load growth or reliability exceeds a single transformer station, the configuration is duplicated for TRF2 / MB2, its Bus and Feeders. A Bus Section or Tie Breaker (TB) is added between the buses for temporarily linking them when a forced or maintenance outage of one TRF occurs. This “rolled” load to one TRF can be maintained for the overload rating of the other TRF. (Usually a fixed time period per utility policy or ANSI standard)

Figure 1 shows this two TRF substation configuration along with the typical zones of protection applied. These zones can vary for the TRF and Bus sections depending on the utility philosophy. Still, it requires a minimum of four digital protection relays and often six when the TRF has its own zone. Each feeder has a protection relay and the bus section is a HiZ relay covering the MB, TB, and the Feeders. (Some only use Overcurrent from the MB CT for bus protection.) The TB is normally open and keeps the transformers from being paralleled. It is often the case that the Feeder CTs used for the HiZ bus protection are not ratio matched especially with the MB CTs, so this requires tapped injections (cable lengths are critical) and limits the effectiveness of the bus protection, station expansion and operations. Backup protection zones to these primary zones are typically not provided as this would double the number of protection relays. Thus, this P&C scheme requires a minimum of 14 relays but could be more depending on philosophy applied.

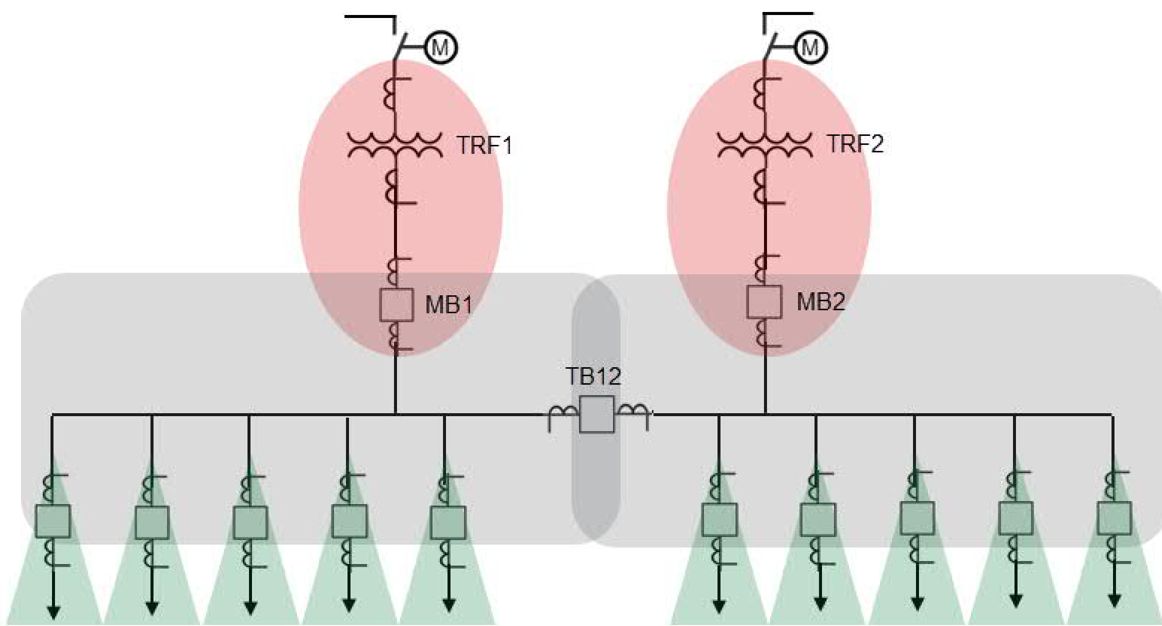

Figure 1: Typical Main-Tie-Main Substation Configuration

Utility A locates the FDR protection at each CB cabinet with its interlocking, controls, and SCADA communications. Due to policy they use two feeder protection relays for each FDR. The TRF and Bus protection is located in a control house requiring a panel for each. To avoid operations issues the Bus protection is LowZ and requires individual CT runs with test blocks to the control house from all apparatus in the zone.

The TRF is Diff primary protection on the TRF only zone and Diff backup protection on the TRF/MB zone. Circuit switcher protection is an Overcurrent relay. This amounts to 28 relays with supporting hardwired cables and interconnect wiring for the Figure 1 topology. Plus the numerous discrete communication cables, controls, and wiring for the SCADA system. Utility B implements all protection relays on panels in the control house, and generally applies only one TRF Diff protection and FDR protection relay. Still the hardwired system has about the same number of cables for the Figure 1 topology.

Operationally utilities design these substations differently than an industrial switchgear or similar critical load center switchgear. Where the critical switchgear configuration is sized to carry the full load if one transformer is lost (the tie breaker is critical for fast bus transfer), the utility application is different. The utility transformer is usually sized to carry its own feeders continuously and all the feeders for only its 8-hour overload rating. This usually gives enough time for feeder reconfigurations and load re-balancing to other substations until the outage transformer is returned to service.

If a full distribution automation (DA) scheme is employed this load balancing can happen rather quickly compared to manual field switching. But it also requires status and performance data from the substation to the DA system for these decisions to be made and verified. Operations are limited when DA interconnects are needed for feeder loop configurations and often the discrete protection zones do not know when these are active so their protection settings are static. Feeder loops could put the transformers in parallel causing operational loading problems if not protected. Implementing schemes for all possible scenarios using hardwired solutions is generally prohibitive, but are possible with an integrated PAC system and digital communications.

Integrated P&C Zones

To begin the process of optimizing the protection zones and the devices used we need to itemize the desired goals. IEC 61850 has a basic strength supporting a distributed architecture meaning the system designed is not bound by the physical box, but it can also support a compact centralized architecture which can provide benefits too. The target list includes:

- Minimizing Wiring -by using fiber and a substation network
- Optimize sensor data collection and share it everywhere it is logically needed.
- Reduce the number of physical devices to reduce and extend maintenance
- Maximize protection zone coverage and operational flexibility
- Improve safety for all operations through interlock extensions
- Plan/provide for DA integration
- Create a deployable engineering standard capable of multiple physical configurations
- Provide a Hybrid solution to leverage the new standard into Brownfield facilities

Referring to Figure 2 and reducing the scope to just one transformer and its feeders/MB/TB the desired protection zones can be overlaid to define the number of protection functions required and the sensor positions. The red dots indicate the minimum Merging Unit (MU) and Control Unit (CU) deployments. It can be seen that not every legacy CT would be required in order to still provide adequate and multiple protection zones for normal system operations even though some apparatus overlap is not accomplished.

Again, the goal is to reduce the number of devices where possible; however; if for example we wanted Feeder/BF backup protection, adding a MU on the MB1 TRF side can provide it and the first bus zone can be extended. Using the total bus current minus the adjacent feeders leaves the feeder current requiring backup. So, if that feeder's MU needed to be serviced, tested, or has a failure, it could be automatically switched over to this calculated value. (If true redundancy is a factor, there are two possibilities; a System B could be defined with additional MU units and Protection IED either by physical redundancy or distributed LN redundancy, or the redundant feeder protection functions could be part of the MU/CU at the feeder breaker, making it another full IED.)

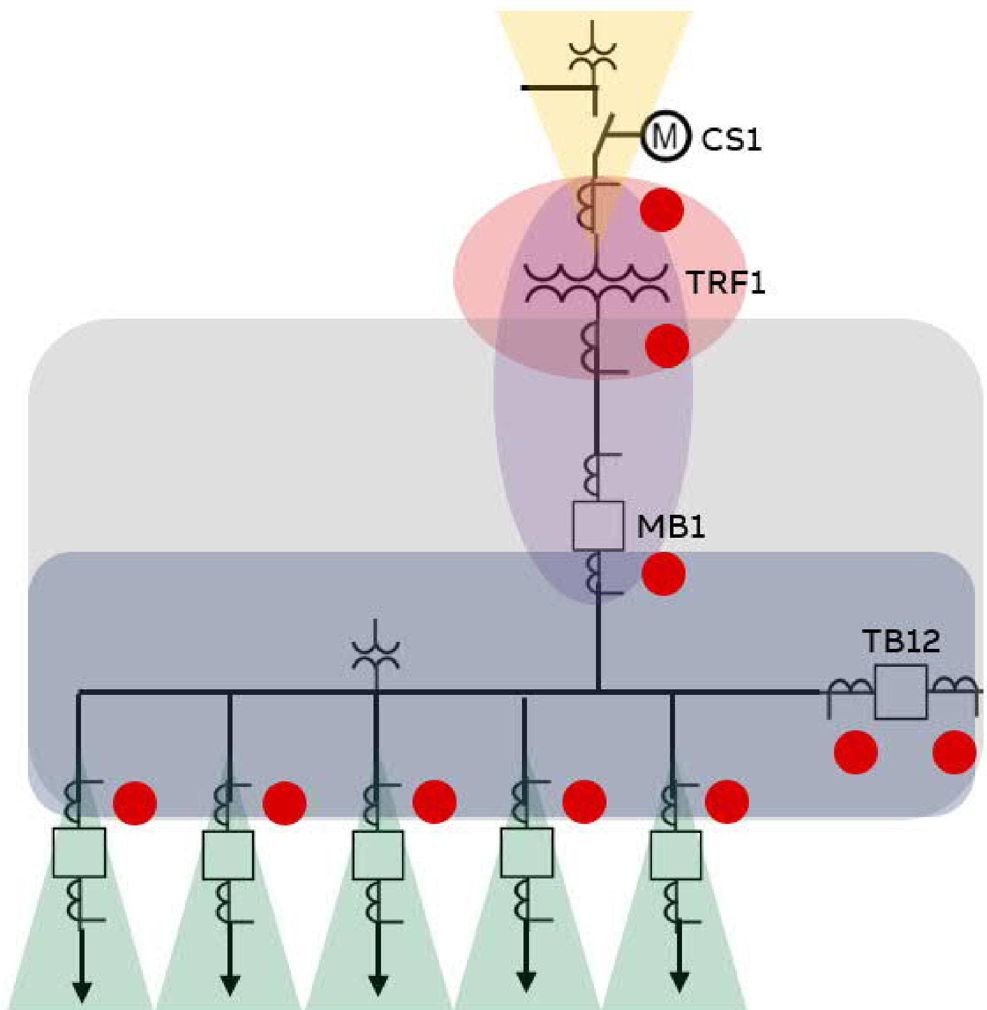

Figure 2: Redefined protection zones with Merging/Control Units

Due to the flexibility of IEC 61850 architecture there are many possible solutions to such implementation philosophies. The common thread is the standardized data and communications. Once a protection scheme/concept is defined it is reduced to the input and output data required to execute and it can be categorized into the respective critical communication category for implementation. (GOOSE, RCB, MMS) These definitions do not generally change and therefore should be applicable to a standard engineering approach defined by the Utility's SCD file for that design and portable to any compliant device.

Feeder protection for example should be a straight forward application of the Utility's operational philosophy and may have several options for the point of application in the distribution grid but should not be re-engineered for each project. A well thought out IEC 61850 design would incorporate each protective and operational requirement allowing a simple setting based enable/disable mechanism. Operationally available to the IEC 61850 communications it can be controlled locally, remotely, SCADA, or by DA rules. (It should also be possible to link this to external hardwired inputs for Hybrid integration where required.)

The flexibility in zone coverage results from taking the MU data in once and distributing it to the required P&C functions. For example, the high side transformer MU provides currents for both transformer differential wraps and also provide them for a backup zone for the high side circuit switcher in the same way the conventional CT hardwiring can but without a burden issue. However, if TRF1 terminates into an adjacent HV ring bus position, then the same MU stream can be easily subscribed for the HV position and be part of a bus/line differential scheme at no cost. (Note: another option could be if high side potentials are available these could be used with the TRF1 high side currents for directional overcurrent or even impedance-based elements providing even more topology flexibility.)

In addition to the MU data, all the station's apparatus status is known via the respective GOOSE messages. If safety is a primary goal, then having the disconnect switch status of each apparatus may be a new addition to the scope of the control and interlocking scheme, but for IEC 61850 it has always been available as part of the standard. (Today quality weather sealed position indication should be mandatory and there is no reason they should not be natively a GOOSE device using POE if the industry wants it.) All protection functions can be managed and supervised with complete logic of the entire station which means all operations whether automatic, remote, or local can be intelligently interlocked. This results in an overall big improvement to apparatus and personnel safety.

Although the engineering process initially requires more upfront effort to include the additional protection zones, interlocking, and safety protocols; the overall station design is still containerized via IEC 61850 making it completely reusable and portable for other topologies by protection zone or apparatus type.

Optimized Scheme and Benefits

These utility projects are ongoing and the decisions on a final design for each utility are in the near future. But to compare their project status to their legacy counterparts even now yields some notable progress. Figure 3 illustrates the zones and IEC 61850 functions required for their current implementation.

Available IEC 61850 IEDs are no longer just data converted versions of a vendor's proprietary structured services, algorithms, and data map. Instead the entire data structure and services are designed as IEC 61850 at its core, and then the algorithms and auxiliary services are defined from that data and communication services structure. These IEDs with IEC 61850 at the core of their design are more efficient, less memory wasted from repetition and application conversion, with easier extension of core functionality.

Taking advantage of these IEDs means we can approach the P&C design from a pragmatic engineer's perspective that allows leveraging centralized data assets. Think of it in the same way as the evolution of the CPU in computers; they are more efficient because they put more and more circuitry and functionality into a single chip. They combine functions to speed data exchange and increase performance – like the CPU and Graphics Processor (GPU) being combined on one chip.

One approach is to use one physical IED that supports all of the Protection & Control functions and logic. Transformer zone 1 contains PDIF1, PTOC1, PIOC1, RBRF1, CSWI1, MMXU1 & MMXU2. Transformer zone 2 contains PDIF2, PTOC2, PIOC2, CSWI2, RSYN2, RBRF2, RREC2 & MMXU3. Feeder 1-5 zones contain PTOC 3-7, PIOC 3-7, CSWI 3-7, RSYN 3-7, RREC 3-7, RBRF 3-7, & MMXU 4-8. (Bus zone 1 or 2 could also be implemented using a HiZ function shown with the dotted line even for a Hybrid (Brownfield) solution.)

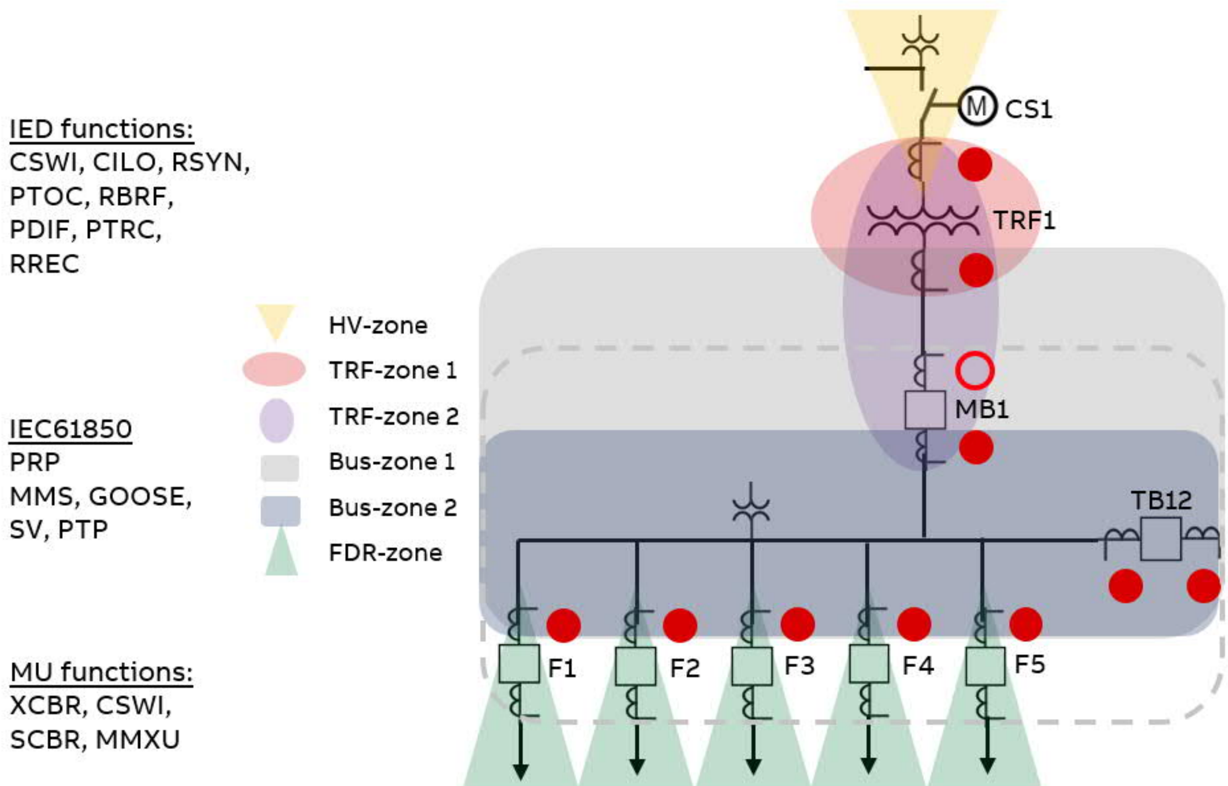

Figure 3: Optimized zones with basic IEC 61850 required functions

For this example, one can choose to have the Bus zones implemented in another IED since the plan is to use it to cover the two transformer configuration. The dual zone bus

IED will control TB12 and the bus logic operations. It will also contain the zone 2 LowZ bus protection PDIF1 & PDIF2, PTRC, RSYN, PTOC, RBFR, CSWI, & MMXU.

Common to all zones and/or functions will be required voltage and frequency LNs, logic blocks and timers, interlocking and SBO control, event and disturbance reporting, SCADA and HMI integration, and calculated measurements.

Key benefits from this centralized focus in just two IEDs are:

- Reduced protection devices from 14 to 2
  (reduce installation time, maintenance, and cost)
- Standardized integrated scheme eliminates wiring and settings errors
- Station expansions are covered for the planned configuration
  (add feeders, enable protection block and verify settings)
- Event and disturbance reports are automatically time aligned/stamped.
  (Simplifies analysis from one DR report)
- Station logic is consolidated, no auxiliary relays required
- Cross checking of CT/MU data extends routine testing (Compliance Reporting)
- Performance monitoring of all CBs and Transformers
  (includes alarms, trending, and online data)
- Compliance reporting based on operation/outage monitoring
- Enhanced security for operators and field personnel

Conclusions

The IEC 61850 standard is now maturing within the industry and devices are being built with its architecture at their core. This leverages many benefits that can be engineered into the P&C systems for the utility industry. This initial review of these two projects shows the desire and needs of utilities striving to improve and upgrade their distribution level P&C systems while educating themselves on the benefits of IEC 61850 and compliant devices.

As the specific utility decisions and engineering progress is made on these projects in the future, a much clearer picture will come into focus on the total benefits these systems can provide. Pilot installations will confirm the vision and goals can be achieved and the cost details will show that the benefits can be compounded as the technology is adopted system wide.

The benefits of replacing copper wire with fiber optics is well known, what is less known are the benefits of data inclusion and distribution within a well-engineered P&C system capable of drastically reducing the overall impact on time and labor throughout the P&C enterprise. As this overview has shown, the flexibility to consolidate the P&C system into a few physical boxes is another example of IEC 61850 maturing as a technology. Reliability and redundancy can be achieved in many different ways if we consider the bigger picture. More updates as these projects progress.

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Biography

Benton Vandiver III received a BSEE from the University of Houston in 1979.

He is currently the Technical Sales Engineer for ABB in the South & Central Regions located in Houston, TX. A registered Professional Engineer in TX, he is also an IEEE / PSRC / PSCC senior member. He has been in the power industry for 40 years and worked previously with Houston Lighting & Power, Multilin Corp., and OMICRON electronics. He has authored, co-authored, and presented over 100 technical papers and published numerous industry articles.