C-RAS

Centralized Remedial Action Scheme

THE ANATOMY OF A CENTRALIZED REMEDIAL ACTION SYSTEM:

WHAT CAN BE DONE IN 50 MILLISECONDS?

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One of the major issues facing electric utilities today is optimization of delivery through constrained transmission networks. It is a common practice to deploy Remedial Action Schemes (RAS) at substations to protect transmission facilities from overloading under contingency conditions. Each locally controlled RAS system is typically implemented with a limited scope of protection to unload a single transmission line or multiple lines in a corridor following loss of a transmission facility. As the transmission system has become more constrained (due to load growth or generation additions), RAS schemes have become increasingly complex and difficult to implement because of overlapping contingency and/or tripping requirements between separate RAS schemes. In the case of overlapping RAS protection, neither RAS typically has a full view of the information from the other RAS.

Therefore, when overlapping schemes react to a contingency, the result is either over shedding of load or generation. The central issue is that in either case, more customer service is disrupted than necessary. In the case of Southern California Edison (SCE) Centralized RAS (SCE C-RAS) implementation, optimization of the delivery through constrained transmission networks was addressed. Through sharing of information, more optimal contingency resolution or optimization solutions are possible that may not even involve the corridor under the contingency situation.

As such, SCE envisions utilizing the solution to acquire field information and make control decisions regarding the application domains of: angular stability, voltage stability, frequency stability, system restoration, and others.

The architecture and technology choices have allowed SCE large capital expense savings when compared against previous implementations.

THE DRIVING FORCES

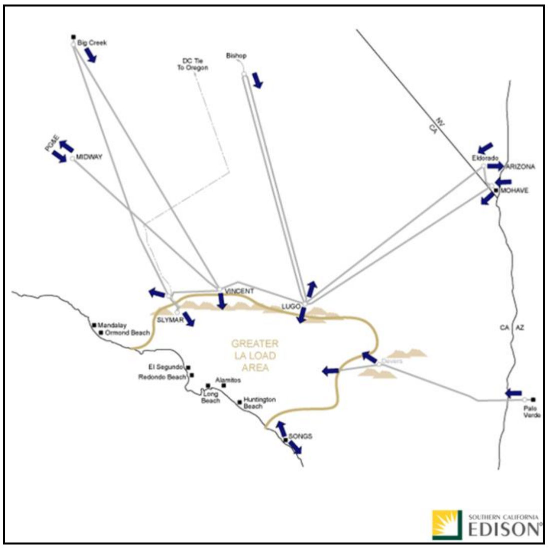

Fig. 1: Transmission Corridors of SCE

Figure 1 shows the transmission corridor situation for SCE. There are five (5) major corridors through which SCE imports 57% [2] of the energy that it needs to provide to its service territory.

SCE delivered 87.34 billion kWh of electricity in 2011 [1]	
Service Territory	**Electrical Assets**
▪ 14 million+ people	▪ 1.5 million+ electric poles
▪ 180 cities	▪ 700,000+ transformers
▪ 11 counties	▪ 55,000+ distribution switches
▪ 50,000 square miles of service area	▪ 88,000+ miles of distribution lines
▪ 5,000 large businesses	
▪ 280,000 small businesses	

Fig. 2: SCE Summary

California has mandates regarding renewable generation content in the overall generation portfolio. The California Public Utility Commission 2020 portfolio requirement of 33% renewable content [3] coupled with the inter-connect requirements for customer owned renewables adds considerable concerns regarding how to provide grid security.

The SCE transmission system already makes use of approximately thirty (30) existing and planned remedial action schemes (RASs)[1] to provide enhanced grid security and stability. There are currently one-hundred fifty renewable connection requests pending. It is estimated that over an additional fifty RASs will need to be added in order to allow the connection queue to be satisfied.

However, with the current methodology of RAS deployment and available manpower, typically only 2-3 RASs per year can be deployed once approval is given by the Western Electricity Coordinating Council (WECC). The approval process, itself, can take approximately one (1) year.

As the need for more deployments increases, the complexity of the protection and the need to potentially overlap zones of RAS protection also increases. With decreasing manpower, a need for wider observation and reaction, a different alternative to standalone point-to-point RAS schemes needed to be developed.

All of the aforementioned drivers led SCE to the concept of Centralized Remedial Action Schemes (C-RAS).

[1] RASs are also known as Special Protection Schemes (SPSs)

SCE C-RAS REQUIREMENTS

In order to defer the building of expensive additional transmission lines, the C-RAS system has high-level functional performance specifications:

- Must provide supervision and control over 120 substations.
- Must be able to support up to 20 C-RAS Intelligent Electronic Devices (IEDs) per substation.
- Must have a system availability of 99.9999%.
  This means that the system must not be unavailable for more than approximately 5 minutes per year.
- Must support different vendors of IEDs and have communications based upon international standards.
  In most current RAS implementations the A side is implemented by one vendor and the B side by a different vendor. Each vendor has its own proprietary I/O exchange mechanism (e.g. Direct I/O or Mirror Bits). Since C-RAS was required to support multiple vendors, and standardized communications, the use of the IEC 61850 Generic Object Oriented Substation Event (GOOSE) was chosen.
- Must be able to operate in less than 16 cycles.

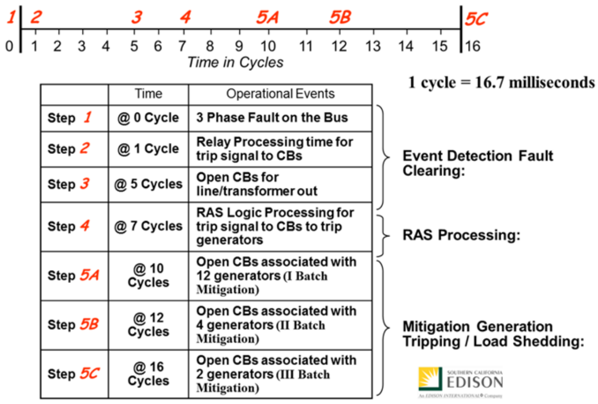

Fig. 3: SCE C-RAS System Performance Requirements

Of the entire system performance budget, three (3) cycles (e.g. approximately 50 msec) are allocated to communication and controller/logic latency. Of the 50 msec, 38 msec was designated for communication latency and 4 msec for controller reaction time. The 50 msec allows for an operational variance of 8 msec.

During the initial investigation phase of the project, the team discovered that the actions taken by the A and B sides of the current RASs were different up to 80% of the time. Although system integrity was maintained, the fact that different actions were taken led to over shedding. Therefore, an additional requirement was added to attempt to synchronize the information upon which A and B decisions was based upon within C-RAS.

DESIGN

The central control system design borrowed methodologies from the nuclear industry. Each control center has three (3) controller pairs that independently receive and process the incoming information. The controllers are known as the Unified Analytic Platform (UAP). Two-of-three voting is implemented via the active controllers issuing the commands to the field IEDs and the voting logic is implemented in the IEDs.

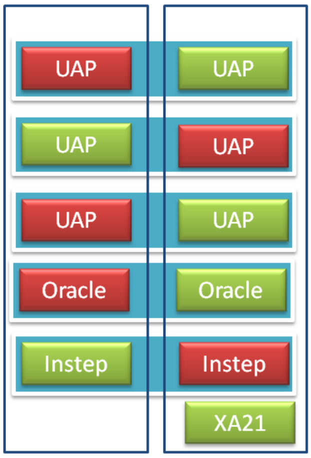

Fig. 4: Conceptual Control Center

The use of multicast communications and IEC 61850 Generic Object Oriented Substation Event (GOOSE) allows the IED information to be delivered to the three controllers almost simultaneously. GOOSE utilizes normal Ethernet IT infrastructures to be utilized, thus decreasing the amount of telecommunication equipment that needs to be installed at the control center. This helps decrease the MTBF.

Besides decreasing the telecommunication footprint, it was decided to also use Blade computers instead of normal servers. This choice was made in order to help meet the availability requirement as well as decreasing the time to repair. Blade computers can be hot-swapped and the replacements can be configured to “boot” the last known configuration of the computer that was replaced. The controller configurations are stored in a redundant database and all information is historized into a fault tolerant cluster of Instep eDna historians.

Fig. 5: 40% of a C-RAS Control Center

These design choices significantly decreased the footprint needed in the control center as shown in Figure 5 .

In order to comply with NERC reliability requirements (e.g. no single point of failure), there are two control centers and independent telecommunication and field IEDs for each system. These systems are known as the

A and B systems. The A and B systems operate in an Active-Active mode thereby creating a dual triple redundant controller environment.

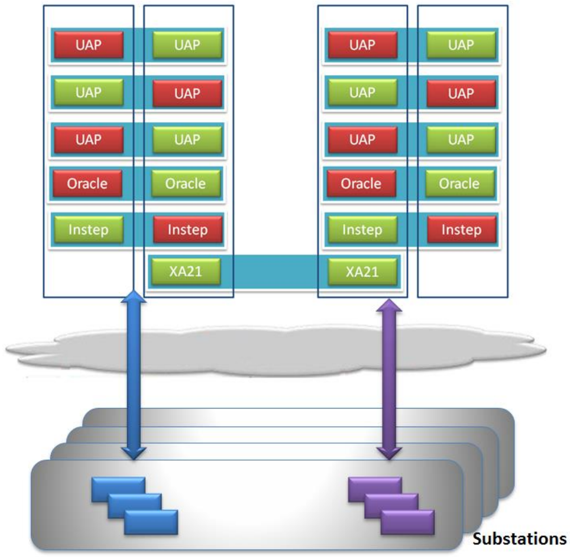

Fig. 6: Dual-Triple Redundant System

Even though a dual-triple redundant system achieves the 99.9999% system availability, it became obvious that improvements could be made to normal situations that cause decreased "operational integrity". Operational integrity differs from system availability in that the system can be available and functioning, but not all parts of the system are operating properly.

A typical example is that an A-side IED is taken out of service for testing or replacement. The B-side still is processing fully, but the A-side is operating in a decreased capacity since some of the A-side signals are not present. The entire system is available, but the overall integrity of the operational system has been decreased since the IED signals are not available to the A system.

Due to the multicast nature of IEC 61850 GOOSE, it was possible to utilize this capability to allow the A system to process B system signals in the event A signals were not available. Within the SCE project, this flow of information is known as "cross-pollination".

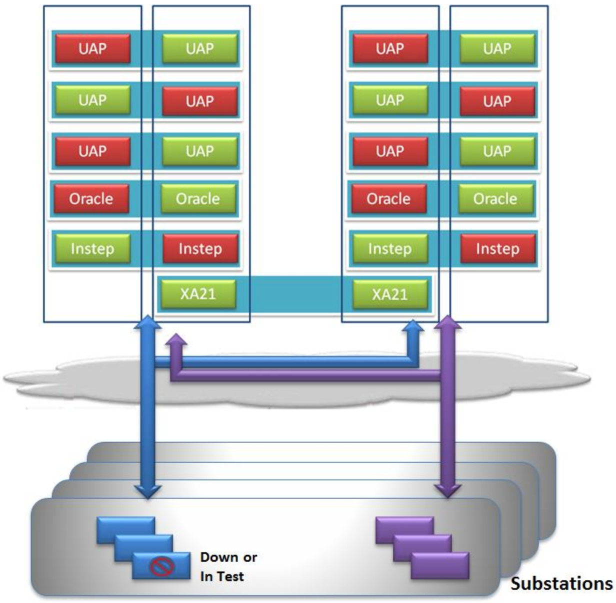

Fig. 7: Concept of Cross-Pollination

The multicast capability of IEC 61850 GOOSE allowed the IT infrastructure to perform the cross-pollination without any additional controllers or data concentrators.

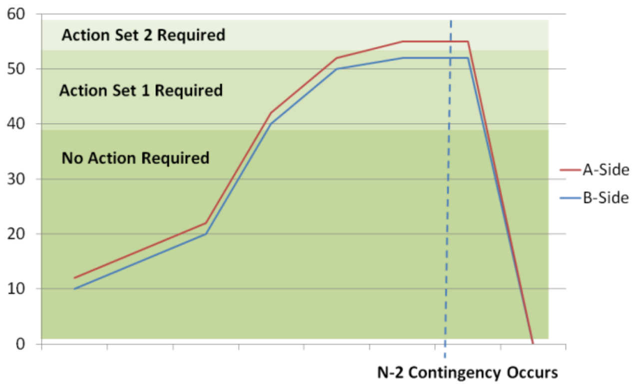

Fig.8: How Analog Values Influence Action

Figure 8 depicts how slightly different MW readings can impact the action choices made by the A and B systems. As shown, when the N-2 contingency occurs, the A-Side will take the actions as prescribed in Action Set 2, whereas the B-Side will take action based upon Action Set 1. This provides adequate grid protection, but typically overreacts/oversheds load.

Cross-pollination also allows the improvement of this situation. Since the A and B MW values are available to both systems, the systems can be programmed/configured which values to choose to take action on based upon values and not from which system they are sourced.

The SCE system also allows detection and alarm notification on the GE XA21 should the received values not agree within some specified range. Thus allowing potential measurement issues in the field to gain visibility and be addressed proactively.

MEASURING THE 50 MSEC SLA

The Service Level Aggrements (SLAs) for both network and controller latencies must be able to be measured in order to prove that the SLAs are being met. The measurements that are required are substation control center GOOSE latency (both inbound and outbound for the control center) and the controller latency itself.

In order to measure the outbound network latency, measurement agents are needed in both the control center and substations. The timestamp in the GOOSE packet is not viable for use in this measurement of all packets as it is the timestamp of the data change that caused the initial GOOSE message to be sent. This timestamp does not change as the GOOSE retransmissions occur. This coupled with the lack of the IEDs to calculate the latency, created a need for an external third-party solution. The solution that was chosen was NetScout.

Measuring the latency within the controllers was done via a transit log concept. This log information is carried through the non-linear processing of the controllers and is returned to the GOOSE interface when action is required. The GOOSE interface can then calculate and expose the latency of input to action output.

CONCLUSION

The SCE C-RAS system shows what can be accomplished through an appropriate design and helps to understand the issues confronting RAS systems in general. The system provides solutions to some complicated RAS/control issues and allows post event analysis through the use of historian technology.

The availability SLAs have been achieved and operational integrity has been increased beyond normal systems. Confidence in the system continues to increase as the SLAs are continuously monitored.

But what about the 50 msec... Is it really achievable?

> At the time of writing this paper, the system was in pre-FAT. Observed end-to-end performance is in the 22 msec range...well below the 50 msec requirement.

LITERATURE

[1] Who We Are. (n.d.). Retrieved May 5, 2013, from Southern California Edison: https://www.sce.com/wps/portal/home/about-us/who-we-are

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[5] Jun Wen; Arons, P.; Liu, W.-H.E., "The role of Remedial Action Schemes in renewable generation integrations," *Innovative Smart Grid Technologies (ISGT), 2010* , vol., no., pp.1,6, 19-21 Jan. 2010 doi: 10.1109/ISGT.2010.5434770