COMMONWEALTH EDISON JEFFERSON SUBSTATION INTEGRATED IED DESIGN DESCRIPTION

Case study and description of Commonwealth Edison Jefferson 138 kV/69 kV substation instrumentation and control design using SEL protection, control, automation and communications products and technology to provide substation SCADA, monitoring, and automation.

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OVERVIEW

Innovative integration developments within multifunction microprocessor-based relays and other intelligent electronic devices (IEDs) have created new ways of collecting and reacting to data and using this data to create information. Power providers are dealing with demands to increase productivity and reduce costs that translate into the need to collect and act on reliable, available decision-making information. When integrated together, relays and IEDs become a powerful, economical, and streamlined instrumentation and control (I&C) system, capable of supporting all aspects of electric power protection, automation, control, monitoring, and analysis.

A great deal of interest has been expressed in the integrated IED technology being used in Commonwealth Edison's city substation upgrades. This white paper describes the methodology and technology behind one of the largest and most innovative integrated substation designs to date, the Commonwealth Edison Jefferson 138 kV/69 kV Substation. This and other stations around the world are being installed by SEL Systems and Services, end users, and third party system integration service providers using SEL protection, control, automation, and communications products and technology.

SEL SYSTEM TOPOLOGY

SEL products are providing I&C, SCADA, and substation automation in the Commonwealth Edison Jefferson Substation project using the SEL communications processor technology. The IEDs are connected to SEL communications processors using the star topology shown in Figure 1. The previously existing Commonwealth Edison SCADA strategy incorporated a substation computer SCADA master referred to as a field integration gateway (FIG). The SEL star topology architecture was used to build an SEL system in the substation that easily interfaces with the FIG. The SEL system can also easily connect with other Master and data client interfaces.
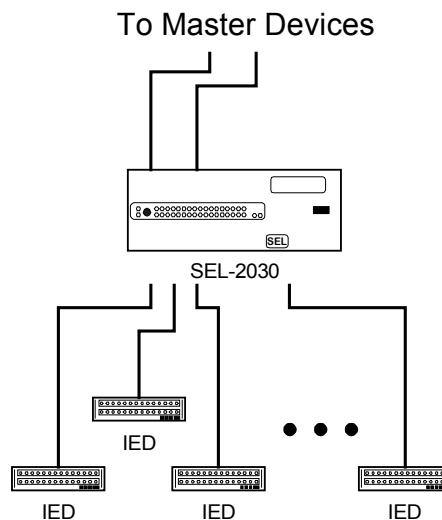

Figure 1   Star Topology

This star topology is the basic building block used around the world for integration of IEDs ranging from SEL relays to substation equipment monitoring products not manufactured by SEL. Several of these building blocks together form complete substation integration systems like that used in the Jefferson Substation.

In the current design of Jefferson Substation, the non-SEL equipment monitoring IEDs are connected through GE Harris RTUs though they could easily be connected to the SEL-2030 Communications Processors as well.

Each link in a star topology is an independent interface to the communications processor. Each interface operates with fully independent data rates and protocols. Rather than force equipment choices to be made based on some lowest common denominator communications protocol, the communications processor allows us to choose the best equipment for the job at hand.

The star network topology also offers significant peace of mind through electrical isolation of the equipment. Bus topology multidrop networks readily transmit ground potential rise to all devices interrupting or destroying vital and sensitive equipment during the time it is needed most. Fully isolating bus networks is often impossible and typically requires expensive hubs and transceivers. Using SEL's fiber-optic transceivers, the IEDs are easily isolated, shielding upstream communication and telemetry equipment from substation faults thereby significantly increasing reliability and overall system availability.

The SEL star topology also offers a unique benefit not afforded by bus topology networks. The communications processor is used to distribute IRIG time synchronization signals to connected IEDs that accept an unmodulated IRIG input. For example, once an IRIG signal is connected to the upper tier communications processor, all SEL devices are synchronized without additional cables or equipment. This synchronization is accomplished over fiber-optic links as well as metallic cables.

The SEL system upgrade for the Commonwealth Edison Jefferson Substation includes both upper and lower tiers as shown in Figure 2. The specific features of the upper and lower tiers are described in the following sections.
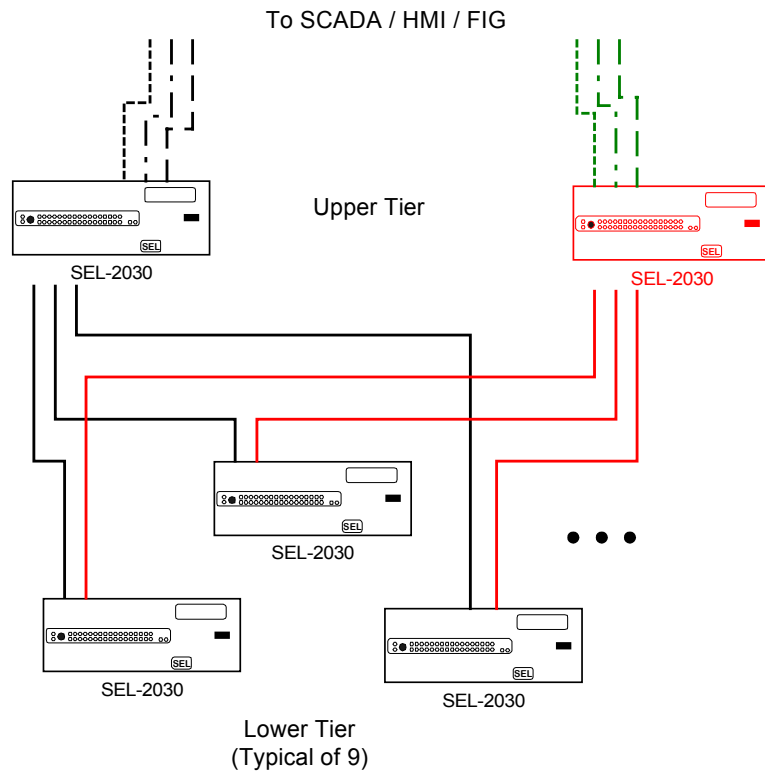

Figure 2   Two-Tier Integration System

Upper Tier

A typical upper tier communications processor is shown in Figure 3. The communications processor communicates directly with the FIG using multiple cables to allow simultaneous use of several protocols including file transfer and virtual terminal protocols, and DNP V3.00 to transfer data to the FIG.
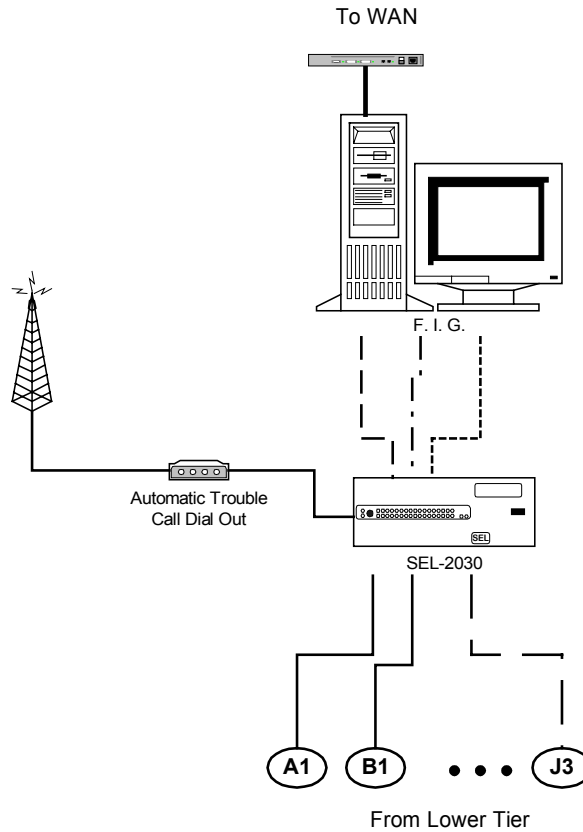

Figure 3   Upper Tier

Though not in the current plan, a redundant upper tier communications processor can provide a redundant link to the wide area network (WAN) removing the single point of failure vulnerability with the FIG and the FIG WAN interface equipment.

The FIG operates as a local human-machine interface (HMI), substation SCADA interface, and provides a gateway through the WAN to connected IEDs for configuration and data collection. Using the file transfer (ASCII) connection between the FIG and the upper tier communications processor, an engineer can connect across the WAN and retrieve fault event data without disturbing SCADA data collection and command.

In the Jefferson design, the FIG is in the substation. The SEL system could also connect to a remote FIG. This would allow a direct connection from the communications processor to the WAN. In this arrangement, the system functions identically, but the FIG functions are performed by an off-site FIG rather than within the substation control building.

Additional modems are used to provide automated trouble dial-out. These modems are also available for dial-in. Once again, the single points of failure are removed by using the automated trouble dial-out to signal critical alarms in case of network, WAN, or FIG failure.

Lower Tier

Communication with IEDs can be divided into two major categories. First, non-SEL devices can be integrated using their own custom protocols without the need to purchase, program or maintain network interface software modules as needed with RTU and PLC based solutions. Second, high performance communication capabilities with SEL products are built in to allow optimized collection of several types of data without extensive programming or configuration.

We tested and established communication between SEL-2030 Communications Processors and SEL relays, Harley, Hydran, Morgan Schafer, and Incon substation equipment monitoring devices, and many other popular substation components. Each SEL-2030 IED connection is also capable of emulating a Modbus® master to communicate with virtually any device with a Modbus interface. Communication configuration settings are used for custom messaging rather than complex and cryptic programming languages like C.

Communication with SEL devices occurs using a family of protocols known as SEL Interleave. SEL Interleave combines a full-featured binary protocol with interleaved ASCII communications. The result is that a binary conversation including protection, time synchronization, control, data collection, and alarm monitoring exists simultaneously with an ASCII conversation, which can include relay settings and event data collection via file transfer as well as virtual terminal. In other words, an engineer can connect to the relay through the network and collect analysis data without interrupting SCADA functions to the relay.

Single points of failure are removed by using multiple star networks to collect data. For example, primary and backup relays from the same circuit breakers are connected to different lower tier SEL-2030s.

The lowest tier of the system includes direct connections to all relays. The lower tier is connected to an upper tier discussed previously. The lower tier at Jefferson Substation consists of 9 SEL-2030s. The first three lower tier SEL-2030s are shown in Figure 4.
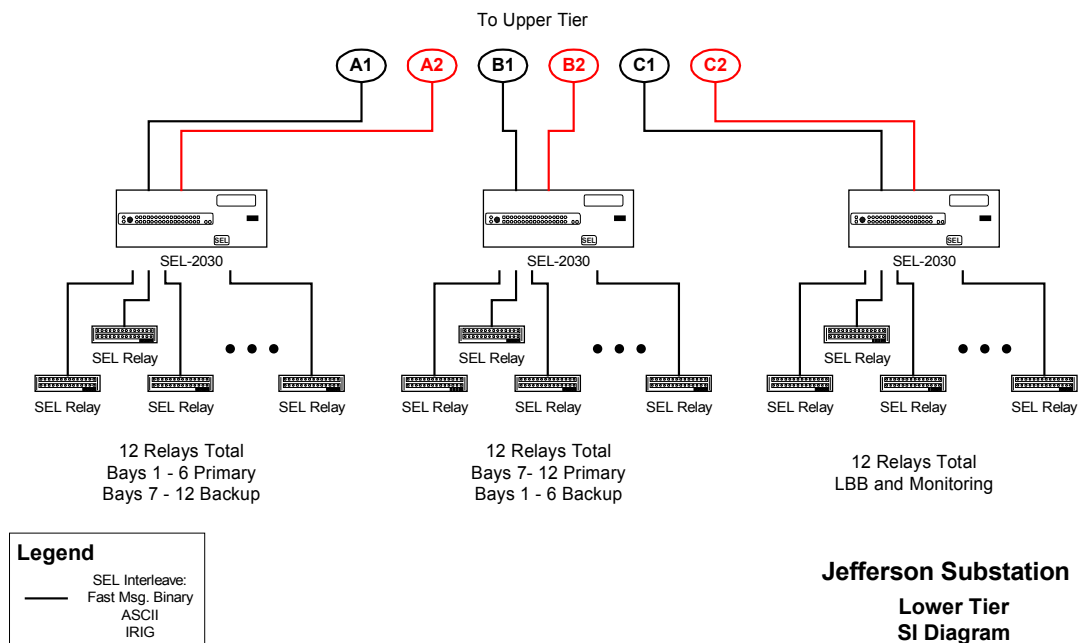

Figure 4   Lower Tier

As mentioned above, primary, backup, and local breaker backup (LBB) devices for bays are separated; primary relays, backup relays, and LBB relays are on different lower tier SEL-2030s. No single point of failure will prevent control from inside or outside the substation through the SEL-2030s to the relays.

EVENT DATA COLLECTION

Event data are collected by the relays during protection events for future analysis. The two-tiered system described above allows for direct connection to the relays. Once an ASCII conversation is established to the top tier SEL-2030, a transparent connection is initiated to the lower tier of interest and then a second transparent connection is established to the relay below. As discussed above, binary command and control, and binary data collection continue with the relay while the engineer or automated system extracts the ASCII event report from the relay.

EQUIPMENT MONITORING DATA

Substation equipment monitoring data are collected by SEL relays and SEL distributed I/O as well as several non-SEL IEDs and the SEL-2505 Remote I/O Module. Protective relay data include operating conditions of the power system such as metering and status, IED self test diagnostics, and archived records representing the reaction of the power system over time or to an event. These records include system profiles, and event, SER, power quality, and protection quality reports. Relays also create and archive operating parameters for substation dc battery monitoring, circuit breaker monitoring, and transformer operational and thermal modeling

Harley LTC monitors and Hydran gas monitors were selected by Commonwealth Edison to provide additional equipment monitoring. In a departure from the rest of the architecture, these non-SEL equipment monitoring IEDs will be polled by GE Harris RTUs and the data forwarded to the Jefferson Substation computer via DNP V3.00 protocol from the RTU.

> **Note:** The data can also be collected from the Harley and Hydran IEDs by the SEL-2030, as is being done by other utilities. The SEL-2030 collects real time data as well as reports and makes the data available through a DNP V3.00 connection between the SEL-2030 and the substation.

> Additional circuit breaker monitoring is possible with the SEL-2505. Data from the SEL-2505 is transmitted to a relay using SEL's MIRRORED BITS™ communications protocol.

SCADA

The SEL system provides existing and new SCADA data collection and control functionality. All substation supervisory control, data telemetering, and data recording are performed by the SEL system and communicated to the Commonwealth Edison SCADA Master, FIG, and/or other dispatch and system operation offices.

The SCADA Master or FIG scans the upper tier SEL-2030 for analog data (AMPS, MW, MVAR, kV, Tap Positions, and Phase Angles, etc.) and for alarms and status indication data (circuit breaker, recloser and MOD status, alarm indication, back-feed indication, etc.). The SCADA Master or FIG communicates commanded control to the upper tier SEL-2030 to operate

substation equipment (opening and closing circuit breakers, reclosers, MODs, and other switches; raise and lower tap changers).

The SEL system is designed to provide all initial SCADA requirements as well as expected future additions. Spare contacts on system IEDs can be used for future status or control needs. The system is also designed to easily support the addition of more IEDs as future requirements are identified.

The SCADA FIG collects metering, status, and historical records to be provided to databases, which capture and store substation information.

SELOGIC® control equations are used within the SEL relays and communications processors to perform programmed control of substation devices.

Control

SEL relays are available with high-current interrupting output contacts. These contacts are rated at:

    6 A continuous carry
    30 A make per IEEE C37.90:1989
    330 Vdc MOV for differential surge protection
    Breaking Capacity 10 A 10,000 operations
        48 and 125 V L/R = 40 ms
        250 V L/R = 20 ms
    Cyclic Capacity 10 A 4-cycles in 1 second, followed by 2 minutes idle for thermal dissipation.
        48 and 125 V L/R = 40 ms
        250 V L/R = 20 ms

These relays are suitable for the higher momentary current in circuit breaker control circuits. Two outputs are configured for device operation, one TRIP and one CLOSE, as default.

> **Note:** The SEL-351R Recloser Control is available as a SCADA-compatible controller for retrofit and new installation.

Motor-operated disconnect switches with SCADA control are operated using output contacts on the SEL relays. A SELOGIC control equation can verify that the transformer is de-energized prior to permitting an open (TRIP) command.

AUTO REG ON-OFF control is provided for each LTC transformer via SEL relay output contacts. In addition, when necessary, group control for all transformers in a substation is provided.

Each three-phase transformer or three-phase bank of single-phase transformers has SCADA LTC control. This control functions with the transformer auto-local or auto-manual in the auto position and is independent of the SCADA AUTO REG ON-OFF control. A status indication point is provided to show potential on the LTC automatic control circuit (AUTO REG POWER).

Control to enable and inhibit the automatic reclosing function of circuit breakers and automatic circuit reclosers (AUTO RECL ON-OFF control) is provided where automatic reclosing is used. This function is performed locally and remotely using local bits, remote bits, and latch bits as controls and permissives within the SEL relays.

AUTOMATIC CONTROL ON-OFF control is provided for all automatic control functions performed by the SCADA equipment, such as automatic control of capacitor switching and LTC operation. This function is performed locally and remotely using local bits, remote bits, and latch bits as controls and permissives within the SEL relays.

Metering

Metering accuracy of selected SEL relays is listed below. The metering performed by the SEL relays is used to provide voltages, currents, phase angles, MW, and MVAR. No external transducers are necessary. Accuracies are specified at 20°C and at nominal system frequency unless otherwise noted.

Voltages
V_A, V_B, V_C, V_S, $3V_0$, V_1, V_2
V_{AB}, V_{BC}, V_{CA}, V_S, V_1, V_2

±0.1% (33.5 - 150 V; wye-connected) {150 V voltage inputs}
±0.2% (67.0 - 300 V; wye-connected) {300 V voltage inputs}
±0.3% (33.5 - 260 V; delta-connected) {150 V voltage inputs}

Currents I_A, I_B, I_C

±1 mA and ±0.1% (0.5 - 10 A) (5 A nominal)
±0.2 mA and ±0.1% (0.1 - 2 A) (1 A nominal)
Temperature coefficient: $[(0.0002\%)/(°C)^2] * ((temp) °C - 20°C)^2$
(see metering accuracy example below)

Currents I_N, I_1, $3I_0$, $3I_2$

±0.05 A and ±3% (0.5 - 100 A) (5 A nominal)
±0.01 A and ±3% (0.1 - 20 A) (1 A nominal)
±1 mA and ±5% (0.01 - 1.5 A) (0.05 A nominal channel IN current input)

Phase Angle Accuracy

±0.5°

MW / MVAR
(A, B, C, and 3-phase; 5 A nominal; wye-connected voltages)

Accuracy (MW / MVAR)	at load angle
for 0.5 A s ≤ phase current < 1.0 A s:	
0.70% / -	0° or 180° (unity power factor)
0.75% / 6.50%	±8° or ±172°
1.00% / 2.00%	±30° or ±150°
1.50% / 1.50%	±45° or ±135°
2.00% / 1.00%	±60° or ±120°
6.50% / 0.75%	±82° or ±98°
- / 0.70%	±90° (power factor = 0)
for phase current ≥ 1.0 A s:	
0.35% / -	0° or 180° (unity power factor)
0.40% / 6.00%	±8 or ±172°
0.75% / 1.50%	±30° or ±150°
1.00% / 1.00%	±45° or ±135°
1.50% / 0.75%	±60° or ±120°
6.00% / 0.40%	±82° or ±98°
- / 0.35%	±90° (power factor = 0)

Metering accuracy calculation example for currents I_A, I_B, and I_C due to preceding stated temperature coefficient:

For temperature of 40°C, the additional error for currents I_A, I_B, and I_C is:

$$[(0.0002\%)/(°C)^2] \cdot (40°C - 20°C)^2 = 0.08\%$$

Status and Alarm

Multiple change detection (MCD) counters are provided for each circuit breaker and automatic circuit recloser to provide indication of multiple status changes, which may occur between successive scans of the relay.

Within most IEDs, the status of discrete inputs is available only as the current state of the physical discrete input. Client devices performing data acquisition of the IED, collect the current state each time they poll the IED. Change of state (COS) indication, is only available if the client device determines it based on the COS of the discrete input between polls. Most client devices are not capable of COS detection. Also, if the status within the IED changes and then changes back to its original state, one or several times, before the client polls the IED, the client will not detect the status change.

Some IEDs attempt to provide COS indication by making two bits of data available. One bit is the current state of the discrete input, the other, a COS bit, indicates a status change. However, this method is unreliable due to the difficulty in determining when to clear the COS bit, especially when there are multiple communication interfaces to the IED. If the COS bit is left too long, it would indicate more changes than actually occurred. If one client clears the bit after seeing it, this may happen before another client acquires it. If the discrete status changes multiple times, the COS bit does not provide multiple change detection (MCD).

The MCD counter is a function that has been available in SEL relays for several years. Using SELOGIC control equations, a counter is created that monitors the COS of a bit and keeps a running total of transitions. Three bits are generally used to create a count that increments from 0 to 7 before rolling over. The current status and three bits of transition count are then acquired by one or more clients.

In the SEL system, the SEL-2030 provides the current status and three bits of transition count to the Commonwealth Edison FIG as well as other clients polling the SEL-2030. The previously installed Commonwealth Edison SCADA system was configured to use this type of MCD indication, therefore, SEL MCD function directly supports the existing Commonwealth Edison MCD counter feature.

Motor-operated disconnect switches and circuit switchers require separate CLOSED and OPEN status points. Two status points are provided via SEL relay optoisolated inputs for switching equipment where the CLOSED and OPEN positions must be positively indicated.

The SEL system enables an innovative technique for automated monitoring and comparison of metered values from redundant sources. Rather than relying on a SCADA operator to notice discrepancies in readings, the system automatically detects and alarms when values diverge indicating a failure in one of the measuring devices or associated transformers.

LOCAL DISPLAY AND CONTROL

The SEL system provides several methods for local display and control that simultaneously coexist. Off normal indication, status display, metering display and local control is achieved. In the first method, the relay front panels support default and customized indication as well as display of off normal status. Combined with trip target displays and local operation through pushbuttons on the relays, the front panel provides a local interface for local operation completely independent of the integration system.

In the second method for local display, the FIG is used as an HMI device in the substation. This provides a real-time local display of operating parameters and alarms combined with a single point of access for a local operator. This system can also be coordinated and provided with the local indication and control afforded by the relay's front panels.

Third, a connection for a laptop HMI or other portable device is available. This HMI plugs locally into any device in the system, or connects via a WAN or phone-line connection. As before, this solution for local display and control can be layered with the preceding solutions while the relay front panels provide local backup.

SUBSTATION SER

Even without the SEL integration system, SEL relays provide sequential events recorder (SER) reports that are optimized for use by engineers and operators. SEL relays transmit time-tagged SER messages to the lower tier SEL-2030 in an efficient binary format. Improvements in the relays and the communications processor support fast forwarding and collection of the information at the upper tier. Coupled with a SCADA Master application or FIG application that collects and displays the data, these components comprise a complete SER system for the substation.

COMMUNICATIONS PERFORMANCE

SEL staged and tested an integrated system of IEDs, similar to the current design at the Jefferson Substation. The tested system had the non-SEL equipment monitors communicating through the SEL-2030s. The measurements reflect the characteristics of the true physical system in operation, like many successfully functioning field-installed systems.

An SEL-2030 communicating with 12 SEL relays was staged with a test source used to simulate power system values and breaker operation into the relays. The breaker operation time was simulated at 4-milliseconds. Data traffic for nine lower tier SEL-2030s, each communicating with 12 SEL relays, was created and forwarded to an upper tier SEL-2030. This upper tier SEL-2030 acted as the substation controller and as such, was the single point of contact for substation data into the staged system. Various performance measurements were taken to characterize the performance of this large two-tiered SEL integrated system.

The SEL-2030 architecture operates differently than multidrop, or "party line," communications schemes. The SEL communications processor communicates with many IEDs simultaneously, and is constantly refreshing the entire substation database. Commanded control is done via *Fast Operate* commands between the SEL-2030s and the SEL relays. Status indication and metering values are retrieved from the relays via *Fast Meter* messages, which are solicited from the SEL relays into the lower tier SEL-2030s. This information is then sent to the upper tier SEL-2030 via

an Unsolicited Fast Message Write where it becomes available to the SCADA Master or FIG. Measurements were taken at the upper tier SEL-2030.

The typical time to execute a commanded control of a breaker by operating the SEL relay output contacts in the staged architecture is 0.049 seconds. The typical time to refresh the entire substation database for 108 IEDs is 1.57 seconds. The typical round trip time to execute a commanded control action of a breaker, monitor its COS and refresh the entire substation database for 108 IEDs, including the COS of the breaker operation in the architecture is 1.62 seconds.

Table 1   Communications Performance

	Command to Relay Output (Sec)	Complete Database Refresh (Sec)	Database Refresh Including Command COS (Sec)
Minimum	0.030	0.80	0.85
Maximum	0.068	2.89	2.95
Typical	0.049	1.57	1.62

CHOOSING A RELIABLE SUBSTATION COMMUNICATIONS ARCHITECTURE

The challenge in designing a substation communication topology is choosing the most efficient, cost effective and reliable architecture possible. Usually, once the functional requirements of a system are met, designers are left struggling to balance these three attributes. Additionally, these attributes are often inversely proportional to one another. In order to increase the speed of a system, it is often necessary to add devices to the topology that in turn increase the cost and reduce the reliability of the system.

Speed can be measured, equipment cost can be calculated and engineering effort estimated, but designers are constantly challenged to quantify reliability.

Fault tree analysis is a tool that compares the reliability of systems. The inverse of the failure rate of a device, or mean time between failure (MTBF) compares the reliability of devices. These values are used to compare availability down time and maintainability of systems. Comparison of different I&C designs, for a system similar to that of the Jefferson Substation, yields the following results.

Table 2   Reliability Comparison for Station With 54 Breakers

Substation Design	Non-Redundant		Redundant	
	Unavailability	Availability	Unavailability	Availability
RTU Centric	$15{,}490 \times 10^{-6}$	98.45 %	240×10^{-6}	99.98 %
PLC Centric	$16{,}410 \times 10^{-6}$	98.35 %	269×10^{-6}	99.97 %
Multidropped Microprocessor Relays	$7{,}158 \times 10^{-6}$	99.28 %	$3{,}427 \times 10^{-6}$	99.66 %
Communications Processor Star to Microprocessor Relays	$4{,}150 \times 10^{-6}$	99.59 %	11×10^{-6}	99.999 %

Table 3   Maintainability Comparison for Station With 54 Breakers

Substation Design	Non-Redundant		Redundant	
	Five-Year Maintenance Budget	Annual Down Time	Five-Year Maintenance Budget	Annual Down Time
RTU Centric	109 hrs	8,142 min	217 hrs	126 min
PLC Centric	121 hrs	8,625 min	243 hrs	141 min
Multidropped Microprocessor Relays	71 hrs	3,762 min	176 hrs	1,801 min
Communications Processor Star to Microprocessor Relays	67 hrs	2,181 min	110 hrs	6 min

RESULTS OF FAULT TREE ANALYSIS

Why is the communications processor star relay network centric design so much more reliable? This protection subsystem is elegant by its simplicity. The streamlined architecture performs all the necessary functions with a minimal number of components. Thus, the system design is more reliable. The modular nature of the architecture allows for future expansion as well.

The reliability of these substation-grade components as well as the use of fiber-optics further adds to the reliability of this system design. These components all meet IEEE SWC and radiated EMI test standards as well as IEC impulse voltage, vibration, shock, and bump tests -- to name a few. SEL employs an innovative arc interruption technology in the relays which eliminates contact wear and auxiliary relays as well as speeds tripping time. Relays and communications processors are often mounted on doors, in swing panels, or directly in equipment that subject them to vibration. Also, during shipment they might be dropped or otherwise abused. Recognizing this long ago, SEL incorporated vibration testing as part of its design. The wide operational temperature range of SEL products also adds to their reliability. In addition to the ability to use the relays in extremely harsh environmental conditions such as the pole-top, they will suffer

degradation, due to temperature, at a much slower rate than products designed to meet lower standards.

An interesting benefit to this analysis was that there existed two direct correlations between reliability and cost. The obvious one is that redundant systems of a particular design are more reliable and more costly than nonredundant systems of the same design. However, when comparing different designs, the most reliable design has fewer devices and components. Fewer components translate into fewer costs. Therefore, as you drive reliability up using SEL technology, you drive cost down.

Many conclusions can be drawn from the fault tree analysis of substation systems.

- SEL star topology is many times more reliable than other architectures
- Redundant devices and connections dramatically improve system reliability
- High MTBF devices dramatically reduce maintenance costs
- High MTBF devices dramatically improve system reliability
- Highly reliable systems dramatically reduce system down time
- Highly reliable systems dramatically reduce total ownership costs

COMMUNICATIONS PROCESSOR STAR RELAY NETWORK IS MOST RELIABLE

Using the SEL star topology, the completely integrated microprocessor-based protective relay and equipment monitoring design further minimizes maintenance cost through the use of self-checking and relay setting verification. The protection and control network of SEL relays and communications processors is designed to provide the SCADA interface to the FIG with redundant access to all of the controls in the substation. Should the PC fail, remote control would be unaffected.

This design offers full redundancy of primary and backup protection as well as communications. The failure of any one of the protection or communications components does not prevent monitoring or control of any one of the breakers in the substation.

Other Communications Processor Star Relay Network Advantages

- IED integration enhances distribution automation, SCADA, and protection by migrating some of the communications functions to an intermediate substation device. Moving protocols into the IEDs adds to their cost and accelerates their obsolescence as technology advances. The resources available within the IEDs are instead better focused on optimizing protection solutions.

- System automation, control, and supervisory data available in protective relays enhance protection and control of individual power system components as well as the entire power system by permitting rapid, well-informed decisions. Adaptive protection and control methods are used as the power system configuration changes dynamically.

- Device diagnostic data enhance system automation, SCADA, and protection by maximizing the availability of the protection system.

- Historical data, available in protective relays, enhance system automation, SCADA, and protection through dynamic system trend analysis and are the source for remote operator and

process forensic analysis. By continually monitoring conditions of devices over time, operators and processes develop a clearer picture of device performance.

- The communications processor can act as a client/server, data concentrator, substation archive, programmable logic platform, gateway, router, dial-out device, SER, communications switch, and time synchronization broadcaster.

- The communications processor can communicate without developing vendor-specific protocol software and can eavesdrop on conversations between two devices in the I&C system.

- Star networks can acquire and transfer substation integration data using independent direct connections. These direct connections are also more reliable, more robust, and less expensive.

- The communications processor simplifies implementation through auto-configuration. This is similar, though not as comprehensive, as current efforts by the utility communication architecture (UCA) to create a self description function.

- Direct connection designs allow the network to support a wide range of IED capabilities. Simple, slow-communicating devices can coexist with more complex fast-communicating relays.

- Communications processors enhance the value of the system automation, SCADA, and protection I&C system data by making it available to multiple master systems and other users.

- As protocol requirements change in the substation, an individual communications processor can be upgraded instead of each of the IEDs. Protection, monitoring, and control are left undisturbed and in service as a protocol change is made. It is also more economical to make this change in a single device.

- The age of IEDs in substations today varies widely. Many of these IEDs are still useful but lack the most recent protocols. Rarely is a substation integration upgrade project undertaken where all existing IEDs are discarded. A communications processor that can communicate with each IED via a unique baud rate and protocol can extend the usefulness of IEDs. Using a communications processor for substation integration also easily accommodates future IEDs.

- Networks are made up of direct and multidrop connections. Point-to-point star networks are much more reliable than multidrop networks. It is important to keep in mind that if the mediation of control of data transmission should fail, none of the multidropped devices can communicate.

- Troubleshooting communications problems is much faster and more efficient through simple LED indication on direct links from a communications processor than attempting to decipher multidrop networks.

- Protocol standardization does **not** mean that every IED must use the same protocol; it means that each protocol must be explicitly defined to support interoperability.

APPENDIX

SEL UCA SUBSTATION NETWORK STRATEGY

As with all areas of research and development, SEL is committed to providing highly robust, secure, efficient and cost effective Ethernet UCA/IEC 61850 inter-connectivity. We are participating in the Utility Initiative for UCA with many other vendors and customers to develop descriptions and standards. SEL is also participating in the IEC Technical Committee 57 working on power system control and associated communications. IEC TC 57 is expected to adopt the UCA work within the IEC 61850 umbrella so that it eventually becomes a standard.

The SEL strategy to implement UCA has been to build onto our success with fast, cost effective, and reliable substation integration rather than begin again. We plan to add UCA connectivity to completely integrated in-service and new substations at the substation controller level and then migrate UCA into individual relays and controllers. Our customers can utilize their installed base of IEDs and their existing communications architecture as they phase in UCA. This strategy allows customers to migrate to UCA with minimal disruption and expense as the technology matures. It also gives instantaneous UCA interconnection to most IEDs available or installed today as the SEL communications processors are compatible with all SEL relays and controllers and many other vendor products.

Recognizing that the market will wish to have UCA connectivity direct to the relays and controllers, future relays will support a direct UCA connection. Again, rather than revisit previous relay designs to add a new interface, we can best serve the market by designing new technology with performance and functionality appropriate to the intent of UCA.

The star network is truly open and accommodates multiple protocols, multiple baud rates, and multiple network interfaces. Using the SEL-2030, which supports UCA, as the substation controller and future relays which directly support UCA, a hybrid system is created that designs itself as individual devices are chosen based on their merit rather than their interface. Customers choose from the best in-service or new IEDs to perform control, monitoring, automation, protection, analysis, test, maintenance, and operation of the power system. Backward compatibility will be assured through the SEL-2030 and future relays will have direct UCA support.

QUANTIFY RELIABILITY AS THE INVERSE OF UNAVAILABILITY

Major motivators of quantifying reliability issues include deriving the best decision-making on how to improve the system, how to manage dependability versus security tradeoffs, as well as how to get the best results for the least money when selecting a design. A quantitative understanding is essential to making these decisions.

Failure Rate

Since reliability is the reciprocal of failure, and failure is a random event, probabilistic measures are most appropriate, and we apply the laws of probability theory.

For example, suppose the reliability of a device is expressed with a mean time between failure (MTBF) of 100 years. The failure rate is 1/100 failures per year. And, if a system has 300 of these devices, then we expect 300 x (1/100) = 3 or fewer device failures per year.

Failure

Failure does not mean that the device is inoperable. A failure exists any time the device cannot create an accurate representation of sensor data, cannot process automated logic or control, or cannot operate an output correctly etc. Causes of failure include settings out of calibration, reaction to environmental extremes, and hardware failure. Some failure modes can be corrected but may not be detected until recalibration or periodic maintenance occurs.

Unavailability

The failure rate of a component, device, or system is only part of the story. Reliability can be further quantified by comparing unavailability. In calculating unavailability, we are determining the percentage of a duty cycle that a component, device, or system is unable to perform its function. Some devices perform and communicate self-test diagnostics. Detection of failure of devices that do not communicate a self-test diagnostic is performed during periodic testing and maintenance, or when the device misoperates. Though we must rely on statistics to predict unavailability, the root causes are intuitive.

- Unavailability increases in proportion to the rate of failure.
- Unavailability increases in proportion to the amount of time it takes to repair or replace a failure.
- Unavailability increases in proportion to the amount of time that a failure remains undetected.

The unavailability, q, is calculated using mean time to repair (MTTR) and MTBF. The MTTR is the sum of the mean time to detect failure plus the mean time to repair or replace. Therefore, we address the root causes of unavailability with one simple equation.

$$q = \frac{\text{MTTR}}{\text{MTBF}}$$

For example, assuming the device mentioned above performs and communicates self-test diagnostics constantly, detection of failure is immediate. The failure rate is 1/100 failures per year and MTBF is 100 years. The time to repair or replace the device is the industry average of two days.

q =[(mean time to detect = 0) + (mean time to repair or replace = 2 days)] / (MTBF = 100 years)

q = (2 days)/(100 years) = 0.02 days/year = (0.02 days/year)(1 year/365 days) = 55 x 10^{-6}

Therefore, the predicted unavailability of this device is 0.02 days per year. Normalizing the ratio by removing the units leaves us with a device unavailability value of 55 x 10^{-6}. It is essential that the designer use specific product unavailabilities to create a realistic representation of the system or proposed design. Unavailabilities of common I&C system devices were calculated using MTBF values and averages from publicly available sources such as vendor publications and studies performed in the workplace [1]. Rather than inappropriately positively influence the unavailability of microprocessor-based relays and communications processors with high MTBF values from SEL, these values were reduced to reflect an industry average.

Table 4   Approximate Unavailabilities of Devices

Device	Unavailability
IED Ethernet Interface	285×10^{-6}
Industrial Personal Computer	385×10^{-6}
Personal Computer	2135×10^{-6}
SCADA Gateway	385×10^{-6}
Ethernet Hub	46×10^{-6}
Equipment Monitoring IED	320×10^{-6}
Substation Communications Processor	30×10^{-6}
Protective Relay Hardware	55×10^{-6}
Ethernet Router	577×10^{-6}
Sonet Interface Card	320×10^{-6}
Sonet Interface Power Supply	60×10^{-6}
Sonet to Serial Card	171×10^{-6}
Leased Telephone Line	1000×10^{-6}
IED Ethernet Interface Network Failure	57×10^{-6}
Modem	30×10^{-6}
Simple Fiber-Optic Transceiver	10×10^{-6}
Current Transformer (Per Phase)	10×10^{-6}
Voltage Transformer (Per Phase)	10×10^{-6}
Medium Remote Terminal Unit	480×10^{-6}
Transducer	80×10^{-6}
Programmable Logic Controller	320×10^{-6}
Protective Relay Multidrop Network Failure	11×10^{-6}
Network Repeater	385×10^{-6}
Network Repeater Multidrop Network Failure	70×10^{-6}
Circuit Breaker	300×10^{-6}
DC Power System	50×10^{-6}

We assume that mean time to detect failure is negligible since microprocessor-based devices alert the system immediately if there is a failure in the system. Therefore, the MTTR is just the mean time to repair, which is assumed to be two days or .005 years.

Example: for a PC Server, unavailability is (MTTR = .005)/(MTBF = 2.56) = .002135.

Further, if the failure of interest can be caused by a PC Server or a microprocessor-based relay, it can be seen that a relay is (2135)/(55) = 39 times more reliable than a PC.

Reliability is inversely proportional to unavailability. The higher the unavailability value, the less available a device or system is to perform its function and therefore cause failure.

IDENTIFY A SELECTION PROCESS

Fault Tree Method

"Fault tree analysis," a concept first proposed by H. A. Watson of Bell Telephone Laboratories to analyze the Minuteman Launch Control System, can be used to combine device unavailabilities. This method, used and refined over the ensuing years [2], is attractive because it does not require extensive theoretical work and is a practical tool that any engineer can learn to use. While computer programs are available to assist in developing and analyzing complex fault trees, small fault trees, which are easily analyzed manually, are also useful.

If a system consists of several devices, use a fault tree to combine device unavailabilities to calculate the system reliability. Refer again to our device, which has an unavailability of 0.02 days per year. The device might consist of two components, each with an unavailability of 0.01 days per year. Both components must operate properly for the device to be sound. The individual unavailabilities of the two components add up to the total unavailability of 0.02 days per year. Add the component unavailabilities to obtain the device unavailability if either component in a device can cause the device to fail.

Similarly, for a system with two devices, which must operate properly for the system to be sound, add the device unavailabilities to obtain the system unavailability since either device could cause the system to fail.

On the other hand, our device with unavailability of 0.02 days per year might consist of two redundant components, each with an unavailability of 0.1414 days per year. Though the individual component unavailability is greater, in this example the components are redundant and either component can give satisfactory performance to the device. Therefore, the product of the individual component unavailabilities is the device unavailability. Multiply the component unavailabilities to obtain the device unavailability, if both components must fail to cause a device failure.

Similarly, for a system with two devices that operate redundantly, multiply the device unavailabilities to obtain the system unavailability since both devices must fail in order for the system to fail.

Fault Tree Construction

A fault tree is tailored to a particular failure of interest and models the part of the system that influences the probability of the failure. The failure of interest is called the top event. A given system may have more than one top event that merits investigation. As an example, consider the traditional RTU centric power and I&C system in Figure 5, which consists of a circuit breaker, a leased line, a modem, three CTs and three VTs, a battery, an RTU, and eight associated transducers. What is the chance that the I&C system will fail to perform its function, i.e., acquire line data such as currents, voltages, kV, and kW, or fail to control the breaker. To answer this, consider the top event "No Line Data or Control." The fault tree in Figure 5 helps analyze this chance.

Use the fault tree to break the top event into lower-level events. The OR gates in Figure 5 express the idea that any of several failures can cause the top event. The circuit breaker could fail OR the leased line could fail, OR the modem could fail, etc. For these simple fault trees, the lower-level events are basic events that are depicted with a circle and referred to as "roots." The

roots are failures of devices such as the leased line, modem, instrument transformers, or the dc subsystem.

It is important to identify all causes of the event of a system you are evaluating. This discipline helps find opportunities to improve overall reliability and helps calibrate the contribution of alternatives relative to other common failure causes. Use OR gates to combine multiple events, when any one failure will result in the failure of the event above the gate. Use AND gates to combine multiple events when all devices directly below the gate must fail in order to have a failure above the gate.

Fault Tree Analysis

After entering event data, analysis of the fault tree shown in Figure 5 is straightforward using a single simplifying assumption known as the rare event approximation. It ignores the possibility that two or more rare events can occur simultaneously. For two events, each of which occurs with probability less than 0.1, the rare event approximation produces less than 5% error. When the events in question are failures, the rare event approximation is always conservative; the approximated probability of failure is always greater than the actual probability of failure [3].

Employing the rare event approximation, calculate the unavailability associated with each event expressed with an OR gate as the sum of the unavailability for each input to the OR gate. For example, the unavailability associated with the lower left OR Gate in Figure 5 is the sum of the unavailability of the five inputs to that OR gate. The fault tree of Figure 5 contains only basic events and OR gates. A failure could be caused by the circuit breaker, OR leased line, OR the modem, OR any of six instrument transformers, OR the battery, OR the RTU, OR any of eight associated transducers. Therefore, the unavailability associated with the Top Event is simply the sum of all of the basic events or 2160×10^{-6}.
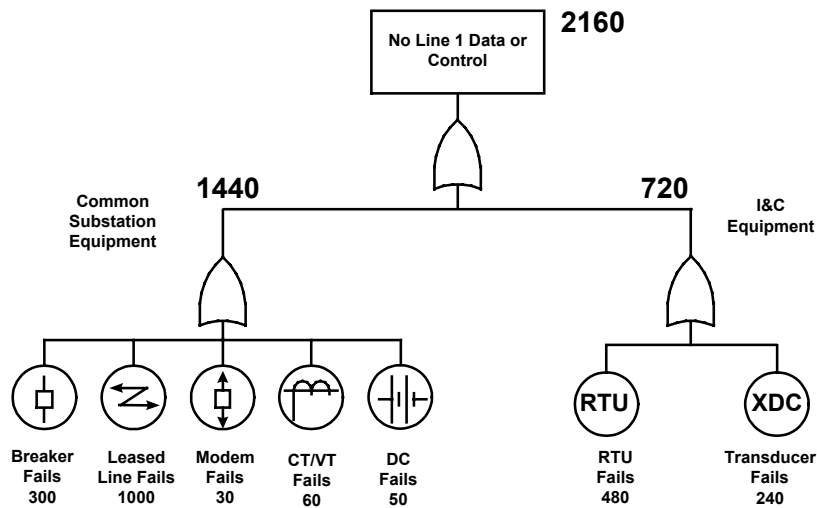

Figure 5   Fault Tree for RTU-Based I&C System

Fault Tree for a Relay and Communications Processor Star I&C System

The fault tree in Figure 6 includes a relay for the line and a communications processor to communicate with the master.
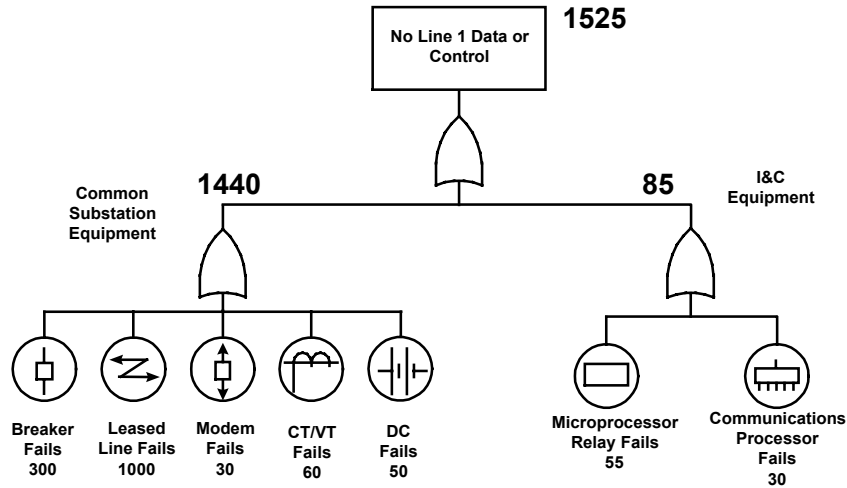
1525 No Line 1 Data or Control

1440 Common Substation Equipment

85 I&C Equipment

| Breaker Fails 300 | Leased Line Fails 1000 | Modem Fails 30 | CT/VT Fails 60 | DC Fails 50 | Microprocessor Relay Fails 55 | Communications Processor Fails 30 |

Figure 6   Fault Tree for Relay and Communications Processor Star I&C System

In this design, the communications processor acts as a substation grade client/server with a high MTBF, high availability, and great support for enhancement or expansion. The microprocessor-based relays connected in a star topology [4] collect data and refine it into information. It is also interesting to recognize that, in this design, as information is collected, it can be acted on at the appropriate level and passed no further than necessary. This reduces bandwidth requirements as you pass along only the information truly needed by a host.

Observe that for these examples the relay and communications processor star network I&C subsystem is 8.5 times more reliable than the RTU-based subsystem.

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BIOGRAPHIES

David J. Dolezilek received his BSEE from Montana State University in 1987. In addition to independent control system project consulting, he worked for the State of California, Department of Water Resources, and the Montana Power Company before joining Schweitzer Engineering Laboratories, Inc. in 1996 as a system integration project engineer. In 1997 Dolezilek became the Director of Sales for the United States and Canada, then moved on to serve as the Engineering Manager of Research and Development in SEL's Automation and Communications Engineering group. In 2000, Dolezilek was promoted to Automation Technology Manager to research and design automated systems. He continues to research and write technical papers about innovative design and implementation affecting our industry, as well as participate in working groups and technical committees. He is a member of the IEEE, the IEEE Reliability Society and the International Electrotechnical Commission (IEC) Technical Committee 57 tasked with global standardization of communication networks and systems in substations.

Darold Woodward, PE has a B.S. in Electrical Engineering from Washington State University. He joined Schweitzer Engineering Laboratories in 1998 in the position of System Integration Engineer. He was with the consulting firms of HDR Engineering since 1992 and with R. W. Beck and Associates from 1990 to 1992 in the areas of automation and integration in water, wastewater, and generation projects. He obtained his Professional Engineering license in Washington State in 1994.