Large and Small Communications-Assisted Special Protection and Control Schemes: A Primer

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***Abstract*—In present day utility and industrial power systems, there is an increasing need for special protection and control schemes. The stability of power systems is the prime motivation for these schemes. Due to the wide area of operation, such a scheme is referred to as a wide-area monitoring, protection, automation, and control system (WAMPACS), wide-area protection system (WAPS), system integrity protection scheme (SIPS), remedial action scheme (RAS), or emergency control system (ECS) and is implemented with various types of communications channels. These power management systems implement essential control schemes, such as generator load balancing, islanding control, and precise load shedding.**

Special protection and control schemes take a variety of shapes and magnitudes. A simple transfer trip for breaker failure is actually a special protection and control scheme. A sophisticated power management system in a large industrial installation performing islanding control, load-shedding management, and automatic generation control (AGC) is also an example of this type of system. All systems follow the engineering steps to specify, design, build, test, install, commission, and maintain. Where appropriate, simpler schemes require less engineering effort at each step and less equipment. Sophisticated power management systems perform more elaborate protection and control based on more complete knowledge of the behavior of generators, transmission systems, and loads and all the possible configurations of their interaction. Therefore, sophisticated systems require more monitoring and mitigation devices as well as a larger engineering effort at each step of the engineering process. When choosing the appropriate solution, the value of each option must be understood and evaluated based on performance, cost, and who will do the work.

Contingencies in the power system, such as the sudden opening of a transmission line, determine the reaction of the scheme. Small systems are easy to visualize and implement. The number of contingencies is small. These systems are validated in small laboratories during the commissioning phase. For large systems, the number of contingencies can be significant. These systems require an engineering team and often the simulation of the power system and its associated contingencies.

This paper discusses the available technologies in communications, synchrophasors, and monitoring. Examples of small and large systems are described while discussing the types of contingencies monitored. This paper considers a large triple modular redundant subcycle RAS that manages four 530 MW generators and multiple high-voltage transmission circuits. This is compared with the simpler but equally fast ECS that frequently preserves the stability of 500 and 220 kV circuits in the country of Georgia. Off-the-shelf relays and communications were used to quickly design and install this system to manage both generation shedding and load shedding at the load center 350 kilometers away. The two systems react to similar contingencies to prevent power system collapse. The communications topologies, intelligent electronic devices (IEDs), project execution, logic complexity, and validation processes are drastically different, illustrating the range of possibilities for wide-area schemes.

Through in-service case studies, this paper illustrates that when evaluating the budget, size, and redundancy requirements, communications-assisted protection schemes have many suitable architectures.

I. Introduction

Although the physics involved in the functioning of power systems have not changed, in the present time, the stability of the system has been stressed by higher percentage loading and other imposed physical and procedural requirements. Power systems throughout the world are requiring the use of wide-area protection and control (WAPC) schemes to ensure their stability and continuous operation. Smaller microgrid or micropower systems, similar to those found in industrial installations and distributed generation, require sophisticated control schemes to maintain stability during islanding and loss of the utility tie.

Managing the overload of critical assets, such as power transformers, often requires a WAPC scheme. Power system operators study the effect of losing transmission paths on critical transformers in the power system. It is not uncommon, for example, to take action in remote locations when critical transformers become overloaded.

Overloading transmission paths can create instability in the power system, as well. The power transmitted through a transmission line is proportional to the sine function of the angle between the sending and receiving bus voltages. As angles increase, the power transfer demands a larger angle difference and a critical angle stability limit will be reached. Newer technologies that allow referencing two angle measurements across long distances dramatically improve the operating range and precision [1].

WAPC schemes help in preventing large blackouts. When two unbalanced electrical islands are formed, one of the islands will have excess generation and the other more load requirements than what the local generation can provide. The island with excess generation will accelerate, and the generators of that island will eventually reach a new stability point at a higher but acceptable frequency. If the acceleration is too great, generation shedding is required to prevent protective tripping, which may result in a blackout as a stability point.

The island with larger demand than generation, however, will drop its frequency. If left untouched, the system will reach a new stability point at a lower frequency. If the lower-frequency stability point is below the critical protective frequencies of generators, this island will lose generation when tripped by protective relays and eventually collapse into a blackout. Recovery from a complete black start will take from several minutes to several hours depending on the type of generation and load configurations. A WAPC scheme will shed sufficient load to balance the remaining generation to the new reduced load. The power system restoration becomes faster because no generator is taken out of service by its protective relays.

Stability of both large-area power systems, such as in an electric utility, and smaller concentrated power systems, such as on an oil platform, is maintained when there is sufficient margin in the generation to accommodate the load. A WAPC scheme in a utility or an equivalent remedial action scheme (RAS) in an oil platform should provide the required control actions to maintain the running power system and avoid blackouts.

Though localized protection may result in a blackout in an effort to reach a stable and safe operating condition, communications-assisted protective relaying is a form of control action that prevents blackouts. Schemes using communications channels for line protection (pilot protection schemes such as permissive overreaching transfer trip [POTT], directional comparison blocking [DCB], or line current differential) and more sophisticated breaker failure transfer trip schemes are forms of WAPC systems that protective relay engineers have been implementing for several years.

WAPC schemes require the recognition of contingencies and decision making based on them. This is a process not much different from the traditional protective relaying schemes using communications. An abnormal condition in the power system is recognized, and an action is taken. For example, in traditional protective relaying, a short-circuit malfunction is recognized in a transmission line and the breakers are tripped open to mitigate the malfunction. In WAPC systems, numerous abnormal contingencies are anticipated, recognized, and acted upon. These actions require deterministic, rapid, secure, dependable, and reliable delivery of communications messages and that the message contents be acted upon immediately. These malfunctions are often rare but have significant adverse effects and are referred to as high impact, low frequency (HILF). Thus the communications system must be designed with near-zero message loss and fast transport in order to be constantly available for use during each and every unpredictable HILF malfunction. If no malfunctions were anticipated, we would not need high-performance communications. The reality is that for teleprotection, interlocking, and WAPC schemes, automation information must be exchanged as fast as 4 milliseconds after a change of state across hundreds of miles. The most stringent of these mitigation strategies demand no more than a 20-millisecond delay due to channel unavailability.

Industrial communications-assisted special control schemes, in general, will not cover as much territory as in an electric utility. There are exceptions to the rule (for example, where two industrial sites are linked to each other and special protection schemes are required to maintain stability in both facilities) [2]. Industrial schemes tend to control the whole industrial power system and are denoted as power management systems due to the different protection and control schemes they implement. Because of the distributed nature of these installations, communications are required to transmit measurements and control commands.

II. Communications-Assisted Special Control Schemes

Known by many different names—RASs, supplementary control schemes (SCSs), emergency control systems (ECSs), special protection schemes (SPSs), and wide-area monitoring protection and control systems (WAMPACS), among others—these schemes share the common feature of communications-assisted decision making.

In the energy and electric power industries, two types of communications technologies are predominantly used to send control commands.

Serial control protocols are reliable, easy to use, and widely available in protection and control equipment, and messages are sent directly to a specific device address [3]. Ethernet networks are now becoming very common in power systems. These are indirect multi-peer networks where multiple types of protocols are running. These are high-bandwidth networks with messages sent to one or more network addresses rather than specific device addresses. The popular IEC 61850 Generic Object-Oriented Substation Event (GOOSE) protocol has been shown to be highly appropriate and reliable for communications-assisted control schemes when the transport is dependable, secure, and reliable [4].

While serial communications technologies have been used in the power industry much longer than Ethernet, they are not necessarily outdated. Serial communications remain the most effective choice in the power industry to transmit measurements and data over low-bandwidth channels. With the highly accepted control protocol IEC 61850 GOOSE, the use of Ethernet is becoming desirable in communications-assisted control schemes. Moreover, the infrastructure allows for the presence of useful TCP/IP protocols, such as Telnet and FTP, which make use of the same hardware infrastructure and allow users to access additional functions and information.

Fig. 1 shows the different serial channels possibly used by a particular control protocol [3]. It is a point-to-point communication, and the link is easily identified. A bit state is mirrored on the other side, and commands are sent that way. Error checking is done on a per-data-package basis, and the data packet is repeated three times within the message to avoid false transmission of commands. It is designed specifically to support the required dependability and security of these communications-assisted schemes. Several years of operation have shown the robustness of the protocol in thousands of protection and control applications worldwide.

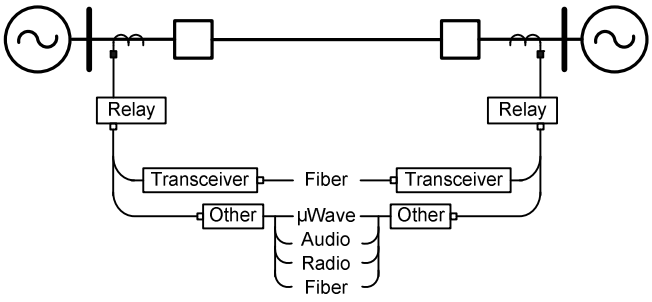

Fig. 1. Sending commands over serial networks

The point-to-point nature of the serial protocol, however, makes it difficult to broadcast a command as required when doing load-shedding schemes, and several loads are required to receive the command. If direct cabling is cost-prohibitive, the message would have to be retransmitted throughout the system, making the times appreciably longer than for a simple point-to-point link. However, when time delays are acceptable, serial communication for command transmission is a good option.

A modern Ethernet network for command transmission most likely relies on the use of IEC 61850 GOOSE. Fig. 2 illustrates the nature of the protocol. The source intelligent electronic devices (IEDs) publish the command into the network, and subscriber IEDs receive information from the network. The network is configured to send the command to multiple IEDs via a multicast process. This multicast nature of IEC 61850 GOOSE allows for multiple IEDs to listen to the same command at the same time, a very desirable feature in communications-assisted control schemes.

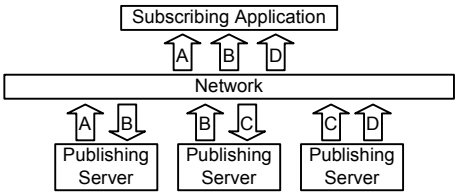

Fig. 2. IEC 61850 GOOSE multicast application

Point-to-point and multicast peer-to-peer protocol communications methods are both available in control IEDs and processors. Thus one or both can be chosen to accommodate elements of the logic requirements and the communications infrastructure available for the control scheme.

A. Communicating the Commands

When analyzing a communications-assisted control scheme, channel availability is a key factor. What are the available communications for the power system?

Because of their compact size, industrial schemes often justify highly sophisticated and high-bandwidth networks. Ethernet in these installations is highly popular. Multiplexed networks are also possible; however, most likely they are configured to provide an Ethernet network for local system control.

Because of their nature, large remotely connected sites, and perhaps a mixture of communications technologies, the channels for communications-assisted control schemes in electrical utilities are often more limited. Legacy communications, such as power line carrier systems that send and receive a few bits at a time, may be the available channel for sending and/or receiving commands.

The design of a WAPC scheme for an electrical utility should consider the available communications channels. Some projects, which are described later, benefit from new highly functional communications installations [4].

Besides the command transmission, a communications network must provide other beneficial functions. Access to configuration and oscillographic information and operational thresholds of IEDs, for example, is part of what is traditionally called engineering access.

B. Redundancy Considerations

If no component failures were expected, no redundancy would be required. However, redundancy is often a design consideration for WAPC communications-assisted control schemes due to the importance of their correct operation. Economic factors are also a consideration. Even if redundancy is desired, the project budget may be the limiting factor on the type of redundancy achieved.

Systems designed without any redundancy denote that the unavailability of the system for a single component failure is acceptable. The failure of a component, however, must be immediately communicated so that it can be repaired or replaced.

Several degrees of redundancy are possible. Partial redundancy of equipment and communications channels may be acceptable. Double, triple, or quadruple redundancy may be required if the system is highly critical and the decision-making process needs to be verified. Voting schemes are sometimes used to decide among several devices to issue a control command to take action. Other times, all redundant systems operate simultaneously, and the action is taken by the mitigation device if it receives one or more commands from the redundant systems. Redundancy is often designed in for the sole ability to leave part of the system in service while redundant parts are replaced during future upgrades.

Regardless of the type of redundancy used in the system, the designer must be aware of the limitations and consequences of equipment and channel failures in the operation of the scheme. Most importantly, however, the

failure of equipment should not be the cause of a misoperation of these critical schemes in the power system.

C. Contingencies

The application of these special control schemes requires the clear identification of the contingencies that the system should handle. These generally convey the change of topology of the power system or overloads in critical components of the system.

As previously mentioned, protective relaying breaker failure transfer trip schemes are considered WAPC systems, where the control command is sent through a communications channel. The contingency identified is the failure of the breaker, requiring an action to be taken. The action is to open the adjacent breakers and the remote breaker (transfer trip) when this happens. The logic required is relatively simple. A timer is started when the breaker trip coil is energized. If the breaker does not open in a predetermined time (current still flowing), then failure is assumed and an action is taken.

A critical transformer in the power system that is overloaded for a certain time can trigger a WAPC command to open remote loads. In this case, the contingency is the transformer overload.

The load through a transmission line is dependent on the angle between the voltages in sending and receiving buses. If the line is overloaded and perhaps the stability of the system is dependent on the power flow across the line, the monitoring of the angle would be required. A large angular difference is the contingency to initiate an action, which may actually require the tripping of the line breakers.

The most typical contingency is the loss of a transmission path (a transmission line) or an interconnection to a larger system (source) requiring the shedding of load. The contingency to recognize is the opening of the breakers of the line. Careful analysis should be carried out if this is the type of contingency to be identified so that the line protective relaying schemes do their work and the WAPC system does not interfere with this important function.

Other contingencies can also be the basis for the control scheme (disconnection from the utility in an industrial scheme, for example), but the control scheme should be carefully designed to clearly identify the contingency. Once identified, the logic of the WAPC scheme can be executed.

D. Tools

To implement the control schemes, present day technology offers several tools. Protection and control equipment that is simple to program is available from many manufacturers, with varying degrees of quality and flexibility. Also, automation and communications standards, such as IEC 61131 and IEC 61850, respectively, provide common methods among manufacturer products.

The status of breakers and the actual tripping of the breakers can be achieved with inexpensive I/O and logic devices that are integrated to Ethernet or serial communications networks.

Logic processing devices that can easily be programmed to implement the decision-making algorithms are used to implement decision and control actions of the schemes. Programmable logic in protective relays simplifies the implementation of decision logic schemes by performing high-speed concise automation logic and protection schemes in devices installed near the primary equipment. More advanced logic processors using IEC 61131 are used to implement even very thorough and sophisticated control logic in a few milliseconds.

Wide-area network communications switches for single-mode fiber allow the implementation of wide-area networks that are used for control schemes. In-service utility multiplexed networks easily support low-speed asynchronous serial channels that are used for serial control protocols [3]. Multiplexed equipment also provides bandwidth to implement Ethernet networks with appropriate bandwidth provisioning. If network control protocols like IEC 61850 GOOSE are used, the multiplexed network is configured to support a dedicated channel that acts like an Ethernet pipe between stations. This provides deterministic delivery and guaranteed performance, unlike bandwidth sharing technologies like multiprotocol label switching (MPLS) and others.

In traditional technology, power system measurements are not synchronized or coherent, meaning they are not all measured at the same instant. The devices measuring power flows, for example, report measurements that were not all measured at the same instant in time. The use of synchronized measurements in control schemes in power systems is relatively recent. The measurements are taken practically at the same instant in time at all locations, and they are coherent. A good example of their application is the comparison of angle differences from two distant voltage measurements. Moreover, the mathematical use of these measurements yields results that are also coherent. For example, the sum of two power flows measured in two parallel lines is coherent and can be compared to any other synchronized measurement. With synchronized measurements, the sum of power flows can be used to analyze oscillatory conditions, for example. Modal analysis is a tool that benefits greatly from the coherency of measurements.

III. Large Versus Small Special Control Schemes

The previous section presented some of the available technologies for engineering and implementing communications-assisted control schemes. These technologies are simple to use and can allow the implementation of small or large schemes.

Simple schemes that recognize a few contingencies and have limited logic requirements are successfully implemented by a single engineer or a small team of engineers. These smaller systems are limited in their ability to react to topology and contingency changes and allow only minimal adaptive logic reconfiguration. However, this keeps the designs small and concise to design, build, and test. For decades, utilities and industrial systems have used Mirrored Bits® communications to create small RASs or ECSs.

These projects are similar to implementing a breaker failure transfer trip. Protection engineers are very familiar with this

implementation, and the amount of work can be handled by few engineering resources.

Larger schemes, on the other hand, require detailed documentation of data and diagrams that have to be handled by an engineering team and generally take longer to implement. These larger schemes satisfy much larger quantities and types of contingencies. Also, they are often engineered to be much more reactive to topology and contingency changes by very flexible adaptive logic reconfiguration. The additional emphasis on documentation and communication is appropriate for a large dispersed engineering team to design, build, and test these more sophisticated solutions.

The tools are exactly the same, but the amount of documentation and detail may require a large team. Moreover, the complexity may require supplemental programming in controllers using IEC 61131 programming language in addition to logic in protective relays.

In simpler and smaller systems, communications-assisted control schemes can be designed with no (or minimal) operator interface. The logic is predefined and installed in the IED with no need for user programming. This is similar to the line protection schemes (POTT schemes, for example) that protective relay engineers implement.

On the other hand, due to the larger possible thresholds and conditions, larger projects allow operators to interface with the present operating thresholds and the system to report the measurements. Sophisticated human-machine interface (HMI) screens can be provided for these schemes. The HMI by itself is a project on its own, mimicking a supervisory control and data acquisition (SCADA) HMI. Industrial power management systems provide complete and well-designed screens for operators to visualize the contingency recognition and the actions to be taken.

IV. Example 1: Simple Project

The country of Georgia is located east of the Black Sea with boundaries with Russia to the north, Turkey to the southwest, Armenia to the south, and Azerbaijan to the southeast. Most of the electrical load is consumed at the capital city Tbilisi, located in the southeast of the country. To the west of the country, an important hydroelectric plant in Enguri generates the majority of the power to be transmitted to Tbilisi. There are links to the neighboring countries, but at the present time, these links do not influence the stability concerns of the power system.

The Enguri power plant in the Imereti power plant region generates the power that is delivered to the Tbilisi load region via the 500 kV Imereti and Kartli 2 lines, as shown in a simplified diagram of the power system in Fig. 3. The flow in the 220 kV system to the Tbilisi region is considered secondary compared with the 500 kV backbone.

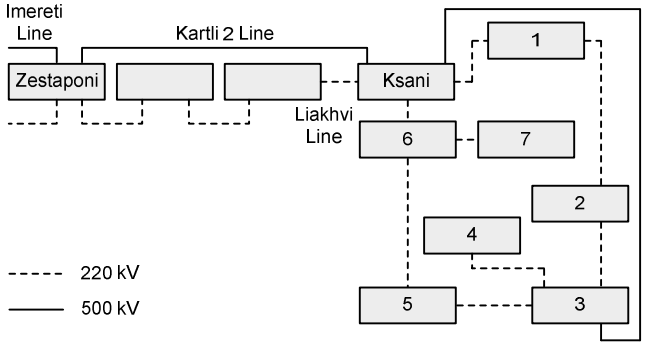

Fig. 3. Simplified Georgian power system

If either the Imereti or the Kartli 2 line is lost, the power system can be effectively divided into two electrical islands (considering the 500 kV system only), and as a consequence, the 220 kV system can be overloaded. The Tbilisi load region will lack generation, and the Enguri power plant region will have a power surplus; therefore, the two electrical islands will be unstable. In the Tbilisi load region, loads should be shed to mitigate the generation deficit. At the Enguri power plant, the excess generation needs to be reduced by shedding the appropriate number of generators.

Based on stability studies and considerations, the ECS is required to operate in less than 100 milliseconds. The load and generation shedding consider the power flow at the time of the loss of the 500 kV line and compare it with three predetermined thresholds linked to the amount of load and generation to be shed.

A. Contingency Recognition

The loss of either the 500 kV Imereti or Kartli 2 transmission line and the overload of the 220 kV circuit can effectively split the power system in two. The system must therefore quickly and reliably recognize the opening of breakers associated with these transmission lines.

At both the Zestaponi and Ksani substations, the power flow is constantly monitored and remembered to provide pre-event measurements in the event of line loss. These measurements are used for calculating the load-shedding

signals sent to seven substations in the Tbilisi region. The severity of the load shedding is based on the comparison of the measured power flow with three defined power thresholds. These three severity levels are used to decide which loads to disconnect among the seven substations in the Tbilisi region, as shown in Fig. 3.

The ECS uses two decision-making devices located in the 500 kV Zestaponi and Ksani substations. These devices, referred to as ECS processors, are the "brains" of the ECS. Their main purposes are to measure power flow, determine the severity levels based on the power flow, detect the loss of the 500 kV lines, and provide indication, oscillography, and sequential events records.

B. Communications Infrastructure

Georgian State Electrosystem is the owner of the single-mode fiber-optic network linking the majority of the substations in the country. The ECS project was implemented using a single fiber-optic pair to complete the entire scheme. IEC 61850 GOOSE messages were selected for digital transmission of the severity limits to mitigation substations. These messages and all other required Ethernet traffic coexist on the fiber network. IEEE 802.1 network segregation and message priority methods are used to allow the IEC 61850 GOOSE messages to travel efficiently and with more deterministic behavior. The fiber-optic pair provided for this project allows separation from other forms of communication using other fiber-optic pairs from the bundle. The addition of time-division multiplexing (TDM) multiplexers at each station would allow the same fiber pair to multiplex numerous communications with the determinism and dependability required for the high-speed ECS [5].

C. Communications Considerations

The availability of fiber-optic links between substations makes it easier to implement a system with modern protocols. Two possible solutions were analyzed: the first using MIRRORED BITS communications as a peer-to-peer protocol recognized as high speed with triple-redundant payload integrity [3] and the second using GOOSE messages. For this type of control system over a wide area, security and low latency in the delivery of the control signals are required.

The main advantages of MIRRORED BITS communications were its successful history in similar ECS projects for more than a decade [6] and the direct connection of the devices via a simple serial-to-optical converter. No additional communications equipment was required.

However, IEC 61850 GOOSE messaging was selected as the solution for sending the severity signals because of its multicast behavior. The decision-making ECS processors and action-taking shedding processors were chosen with Ethernet ports and provide IEC 61850 connectivity.

Fig. 4 shows the implemented Ethernet network. Managed substation-rated Ethernet switches with single-mode optical ports are used. The network uses redundant paths where possible. There are additional switches in intermediate substations because of the long distance involved and for future mitigation substations.

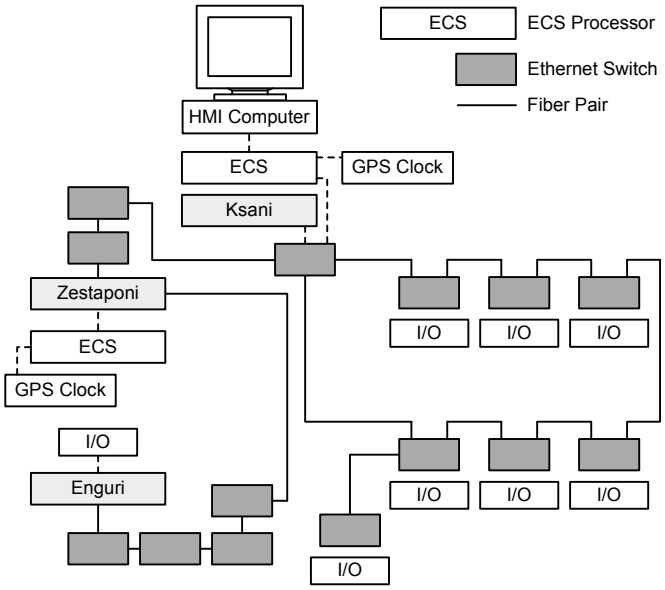

Fig. 4. ECS Ethernet network

The multicast IEC 61850 GOOSE messages publish simultaneously to multiple devices with high priority on the network [7]. This multicast feature requires disciplined use of IEEE 802.1p and Q virtual local-area network (VLAN) GOOSE message priority and segregation in the protection, control, and monitoring (PCM) IEDs and Ethernet switches for fast and dependable delivery.

D. Ksani Contingency Detection

The Ksani substation is at an important location in the system and includes the HMI computer interface for the system. It is also where the Kartli 2 line outage is detected.

Fig. 5 shows the monitoring 500 kV bay at Ksani. It is a double bus arrangement with two breakers. Both breaker position (52b) contacts are brought to the ECS processor to detect the opening of the Kartli 2 line.

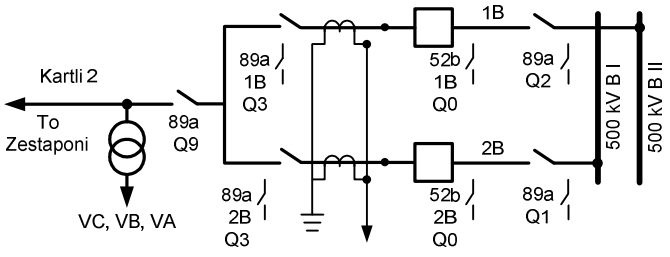

Fig. 5. Ksani 500 kV Kartli 2 line bay

For security, in addition to the breaker position, current sensing (the absence of current) is used with sensitive undercurrent detectors, denoted by LOPH*x* in Fig. 6. While the logic described does not fully avoid the dependence of the contingency detection on simple binary input circuitry, it provides sufficient security for this project [8].

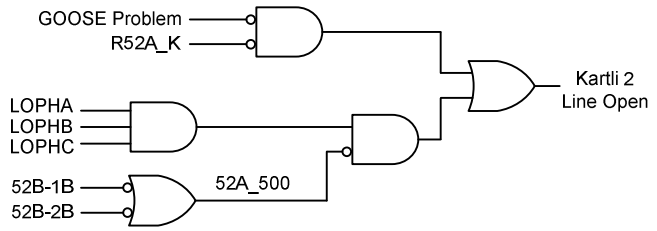

Fig. 6. Kartli 2 line open contingency detection

The breaker status bit from the remote terminal (located in the Zestaponi substation) is also received and incorporated in the logic. The R52A_K bit is part of the GOOSE message received from Zestaponi and qualified by the GOOSE integrity bit. This GOOSE integrity bit monitors the integrity of the GOOSE communication. It is normally deasserted and will block the remote breaker position signal (R52A_K) when a problem with the GOOSE message transmission is detected.

V. Example 2: Large Project

The Jim Bridger Power Plant is located east of Rock Springs in southwestern Wyoming in the United States. The coal-fired electrical generating plant with its four 530 MW units is adjacent to a coal mine from which most of the fuel for the plant is obtained. The plant, which is jointly owned by PacifiCorp and Idaho Power Company, is operated by PacifiCorp. The transmission system that connects the Jim Bridger Power Plant to the transmission grid consists of three 345 kV lines and three 230 kV lines. Although the plant is in Wyoming, it is an energy resource for the PacifiCorp and Idaho Power loads in Idaho, Oregon, and Washington. The power from the plant is transported over three 345 kV and two 230 kV transmission lines that radiate out to the west. Those transmission lines and the critical parts of the transmission system across the states of Wyoming, Utah, Idaho, and Oregon are parts of the transmission system monitored by a RAS located at the Jim Bridger Substation. Since the plant was built in the early 1970s, a RAS has been required to achieve the transmission path rating needed to move the energy from the plant to the loads. When the transmission path is being operated at the path limit and a transmission line in the path is lost, the generation at Jim Bridger must be reduced to maintain the transient stability of the power grid.

When a fault occurs on the transmission system, the power flow as a result of the fault is predominantly reactive power because the impedances of the transformers and lines are predominantly inductive. During the fault, the voltage at the fault is zero and the voltage at the terminals of the generators is significantly reduced. The low voltage restricts the real power flow from the generators. Because the turbines driving the generators are continuing to pour real power into the generators, the units start to accelerate. This acceleration continues until the faulted transmission line is disconnected from the system. With the fault removed, the real power starts moving from the generators to the load and the generators decelerate. With the removal of the faulted transmission line from the power system, the transmission path impedance is increased.

The increase of the transmission path impedance combined with the generator acceleration during the fault results in an oscillation between the generator rotors and the power system. If the real power flow is low enough and the increase in transmission path impedance small enough, the oscillations will dampen and a new equilibrium state will be reached. If the new conditions are too extreme, the oscillations will not dampen and the Jim Bridger generators will go out of step with the PacifiCorp power system. The generation oscillations will cause the voltage at Jim Bridger to swing in magnitude.

A. Timing Requirements

Based on stability studies for the most severe fault case (a multiphase fault on a 345 kV line close to Jim Bridger), the total time from event to resulting action must not exceed 5 cycles. Fig. 7A1 shows the time allocation for this case. Zone 1 faults (faults close to Jim Bridger) are the most severe N events; for these events, the overall reaction time is 3.7 cycles. When the typical fault detection, communications time, and unit breaker opening time are excluded from the total time budget, the RAS is left with 20 milliseconds of operating time.

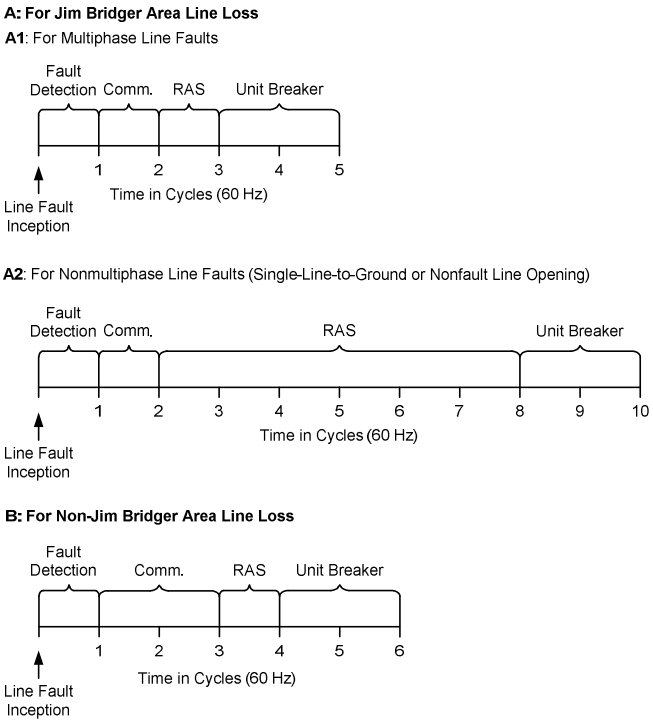

Fig. 7. Timing charts

For less severe fault cases, less speed is required. Fig. 7A2 shows the time allocation for a single-line-to-ground fault on a 345 kV line. Although the Jim Bridger RAS has the capability to process the signals in the time needed for the most severe case, the process is deliberately delayed for single-line-to-ground faults.

For the loss of a transmission line at a great distance from Jim Bridger, the line loss status needs to be communicated to Jim Bridger. This communication over several hundred kilometers adds additional delay, but studies have shown that the delayed response will not have an adverse effect on the stability of the power system. Fig. 7B shows the time allocation for the loss of a remote transmission line, such as the Three Mile Knoll – Goshen line.

B. Triple Modular Redundant Requirement

With the correct and timely response of the Jim Bridger RAS being critical to the stability of the power grid, the dependability of the Jim Bridger RAS is important. Therefore, a new modern Jim Bridger RAS was required to contain redundant inputs, outputs, and processing units [8].

The average incidence of faults on this transmission system is 0.8 faults per week. The plant is base loaded 24 hours a day. Between the plant loading and the transmission line fault incidents, the Jim Bridger RAS is often called on to react. Most of these events do not require generator unit tripping because the plant is operated at loading levels below the arming level for the most common transmission line faults, single-line-to-ground faults. The consequence of tripping a 530 MW coal-fired unit involves significant costs and reduces the reliability of the unit. For these reasons, balancing dependability with security against false operations is very important. This is why the Jim Bridger RAS is a triple modular redundant (TMR) voting control system. Two out of three identical systems must agree on the status of the inputs and the resulting outputs for the system to cause a generator unit to trip. This triple modular redundancy is extended to the power transducers feeding the RAS data.

The communications equipment using the alternative communications network and fault severity units is connected to the second TMR system. Both TMR systems are normally in service, and either system can trip the generator units. Due to the speed at which the Jim Bridger RAS must operate, the accuracy of the power transducers, and the scanning nature of a programmable logic controller (PLC), there are several predictable circumstances where the two TMR systems will not select the same generator unit to trip for the same event. Two independent processors review what each of the TMR systems is planning to do if an event were to occur. This is possible because of the way the TMR systems predetermine their action for each of the possible line loss events based on current system conditions. Statuses as to the health of the subsystems are communicated to the monitoring systems. If the predetermined actions of the two TMR systems do not agree, the system with the healthier subsystems is permitted to take the action if the event takes place. If the health of all systems is equal and the two TMR systems will perform different actions for the event, a predetermined TMR system will be permitted to perform the action.

The two new RAS systems, C and D, are identical, triple redundant systems with full two-out-of-three voting. Each I/O point to the field is wired to three independent I/O points on both systems. Each half of the RAS I/O is separately wired to terminal blocks, and all RAS controllers and whetting voltages are powered by separate dc battery systems. This creates a system of two completely autonomous control systems, hence the system is considered “dual primary.” Within each RAS system (C and D), there are three autonomous IEC logic controllers with fully independent I/O modules. These three controllers perform two-out-of-three voting via high-speed communications links. A single substation-hardened computer provides a user interface (HMI), sequence of events viewing (SOE logs), and event report viewing (oscillography). Another hardened computer is used as an engineering workstation and contains the development environment for all hardware (IEC 61131-compliant programming). Each RAS system (C and D) has its own protocol gateway for communication to the PacifiCorp energy management system (EMS).

RAS Systems C and D are completely isolated on separate networks, and all logic on each system runs without any knowledge of the other system. Each dynamically calculates the generation needed to be shed for each of the pre-identified events and then selects generators to shed based on a generation selection algorithm.

The RAS should be available under all circumstances. Having dual primary systems (RAS Systems C and D) satisfies this requirement. The two systems are independent of each other, which gives the flexibility to disable RAS Systems C or D for testing or maintenance. Having a triple modular system, two-out-of-three voting, and independent communications paths in each RAS greatly increases system availability.

VI. Conclusion

Special protection and control schemes take a variety of shapes and magnitudes, from a small simple breaker failure transfer trip to a sophisticated power management system in a large industrial installation performing microgrid control. All systems follow the engineering steps to specify, design, build, test, install, commission, and maintain.

Small simpler schemes manage fewer contingencies and less dynamic adaptive real-time reconfiguration and therefore require less engineering effort at each step and less equipment. Breaker failure, RAS, and ECS systems are typical examples and have been in service for years.

Communications-assisted special control schemes are simpler to implement with state-of-the-art tools, including rugged hardware, digital communications, and standardized programmable logic. Utility engineers have been implementing these schemes when performing teleprotection (POTT and DCB schemes, for example) or breaker failure transfer trip, for example, using these tools. Modern power systems increasingly need special control schemes that are

natural extensions of the protective schemes already being implemented by utility engineers.

Smaller schemes can be implemented by a single engineer or a small team of engineers. The available tools facilitate the implementation. For more complex schemes, an engineering team will be required to methodically document the implementation of the project.

Contingencies in the power system, such as the sudden opening of a transmission line, determine the reaction of the scheme. Small systems are easy to visualize and implement. The number of contingencies is small. These systems are validated in small laboratories during the commissioning phase. For large systems, the number of contingencies can be significant. These systems require an engineering team and often simulation of the power system and its associated contingencies.

Smaller systems continue to be very cost-effective. They are small but sufficient and simple systems for rapid, low-cost deployment. These mission-critical solutions have the following characteristics:

- Contingencies are kept to a minimum by focusing on those with high impact and those that change frequently.
- Smaller systems have the same thorough project design and management processes as larger systems, but simpler design and smaller teams result in need for fewer resources and less time.
- Simple, adaptive reconfiguration in smaller systems is less flexible but quickly responds to the most likely changes. The logic is able to monitor thresholds and adapt to new power flow and topologies by changing logic in real time; however, this is limited. The logic is optimized to anticipate and react to a concise number of contingency and topology changes.
- Having fewer components, communications channels, and command messages results in lower product cost and faster deployment for smaller systems. Redundancy is a consideration but not always required.

The larger, more sophisticated power management systems perform more elaborate protection and control based on more complete knowledge of the behavior of generators, transmission systems, and loads and all the possible configurations of their interaction. Therefore, sophisticated systems require more monitoring and mitigation devices as well as a larger engineering effort at each step of the engineering process. When choosing the appropriate solution, the value of each option must be understood and evaluated based on performance, cost, and who will do the work.

Large and sophisticated systems are more comprehensive and adaptive for complete power management solutions. These mission-critical solutions have the following characteristics:

- Contingency management is very inclusive and comprehensive to satisfy a high percentage of changes and combinations thereof.
- Thorough project design and management processes support multiple teams and locations for distributed locations performing engineering and construction.
- Real-time adaptive reconfiguration responds to both predicted and unpredicted situations. The logic is able to monitor thresholds, adapt to new power flow and topologies, and then recalculate responses based on real-time data acquisition. The logic calculates responses to unanticipated combinations and publishes a response matrix for the large number of contingency and topology changes.
- Double, triple, and quadruple modular redundancy and multiple communications channels and command strategies in larger systems result in ultra-high availability and granular mitigation.

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VIII. BIOGRAPHIES

David Dolezilek received his BSEE from Montana State University and is the technology director of Schweitzer Engineering Laboratories, Inc. He has experience in electric power protection, integration, automation, communication, control, SCADA, and EMS. He has authored numerous technical papers and continues to research innovative technology affecting the industry. David is a patented inventor and participates in numerous working groups and technical committees. He is a member of the IEEE, the IEEE Reliability Society, CIGRE working groups, and two International Electrotechnical Commission (IEC) technical committees tasked with global standardization and security of communications networks and systems in substations.

Fernando Calero received his BSEE in 1986 from the University of Kansas, his MSEE in 1987 from the University of Illinois (Urbana-Champaign), and his MSEPE in 1989 from the Rensselaer Polytechnic Institute. From 1990 to 1996, he worked in Coral Springs, Florida, for the ABB relay division in the support, training, testing, and design of protective relays. Between 1997 and 2000, he worked for Itec Engineering, Florida Power and Light, and Siemens. In 2000, Fernando joined Schweitzer Engineering Laboratories, Inc. and presently is a senior automation systems engineer.

Diego Rodas received his BS in electronic and control engineering from Escuela Politécnica Nacional in 1994. He has broad experience in automation and control systems. Upon graduating, he worked for nearly 16 years in automation systems, from senior field engineering for the oil industry to senior systems design engineering for several additional industries, including food and pharmaceutical. In the last five years, he has been involved in integration and automation projects for numerous substations. Prior to joining Schweitzer Engineering Laboratories, Inc. in 2007, Diego was involved in the development of automatic machinery for process control and validation of new technology petrochemical data acquisition and telemetry systems.