

Innovative, Robust, and Secure Industrial Solutions Using Microprocessor Relays

Christopher W. Seelig, P.E.

TEAMWORKnet, Inc.

Brian McDermott, P.E.

Schweitzer Engineering Laboratories, Inc.

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Christopher W. Seelig, P.E.
Member, IEEE
TEAMWORKnet, Inc.
6550 New Tampa Hwy, Suite B
Lakeland, FL 33815, USA
Phone: +1.863.327.1080
Fax: +1.863.327.1091
Email: cseelig@teamworknet.com

Brian McDermott, P.E.
Member, IEEE
Schweitzer Engineering Laboratories, Inc.
2401 Whitehall Park Drive, Suite 1000
Charlotte, NC 28273, USA
Phone: +1.704.504.4101
Fax: +1.704.504.4140
Email: Brian_McDermott@selinc.com

Abstract—This paper provides real-world examples of the benefits to industrial systems when aging and obsolete electromechanical relays are replaced with modern, microprocessor-based relays. Microprocessor-based relays eliminate failure and degradation of operations due to moving parts. They also reduce or eliminate the time to detect a failure via internal self-test diagnostics and monitoring, information storage, and communications that immediately publish alarms and alerts. Driving the mean time to detect failures to zero with instantaneous alerts of self-test alarms dramatically improves the reliability of systems that formerly relied on periodic manual tests of devices to detect failure. In fact, any failed electromechanical devices in service today will remain undetected until they are tested or until they fail to operate while in service. IEC and IEEE reliability measures based on time to detect failure and repair or replace are both improved with instantaneous detection and notification.

In addition to measurably improved reliability, microprocessor-based relays enable many new and innovative applications within industrial and power plant installations. Self-test information and analytics, sequential events records, event reports, and data and asset condition monitoring support a wealth of applications. Relay networks share information to improve system commissioning and then to manage the plant. Sophisticated load management, load shedding, and voltage regulation are easily deployed with built-in features of modern, microprocessor-based relays and information processors. Programmable automation controllers (PACs) are rugged devices with extremely high uptime due to construction methods similar to mission-critical relays. Since PACs perform power system and process control logic equally well, new opportunities exist to combine relays and PACs within the same communications network to improve power system efficiency and process availability.

This paper outlines real-world applications that brought value and justification to complete protective relay and PAC upgrades.

Index Terms—Microprocessor-based relays, advanced protection, synchrophasors, load management, multifunctional, load shedding, voltage regulation, programmable automation controllers, improved reliability.

I. INTRODUCTION

Protective relaying is just one component of a properly designed electrical system. Fuses, circuit breakers, and circuit switchers are also protective components of an electrical system. Protective relaying is commonly applied to medium- and high-voltage systems (2,400 V and above). The most common type of protective relaying is overcurrent protection, which is designed to respond when the current in a particular circuit exceeds a predetermined level. Overcurrent relaying is used to protect a circuit from overload and short circuits by sensing high-current levels and then initiating the disconnection of the overloaded or faulted circuit. Other types of protective relaying include over-/undervoltage, over-/under-frequency, and directional power. Table I shows some of the American National Standards Institute (ANSI) designations for protective relaying devices that are commonly used to protect modern electrical systems.

TABLE I
ANSI DESIGNATIONS FOR PROTECTIVE RELAYING DEVICES

ANSI Device Number	Description
21	Distance Relay
25	Synchronism Check and Synchronizing Relay
27	Undervoltage Relay
32	Directional Power Relay
46	Phase Balance Relay
47	Phase Sequence Relay
50	Instantaneous Overcurrent Relay
51	Time-Overcurrent Relay
52	Circuit Breaker
67	Directional Overcurrent Relay
81	Frequency Relay
86	Lockout Relay
87	Differential Relay

A typical electrical design includes the application of several different ANSI devices to provide an integrated, fully functional protection system. Fig. 1 shows a typical main substation transformer and its associated protection system.

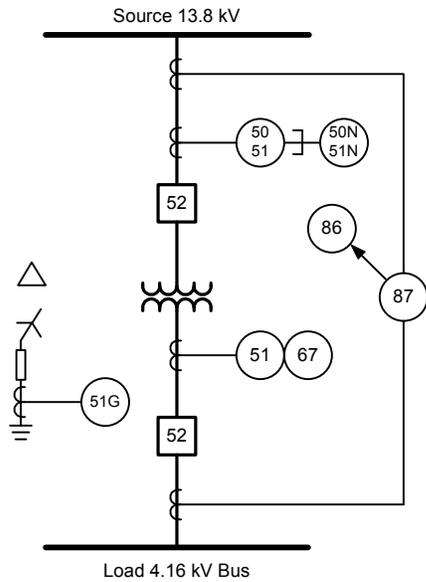


Fig. 1. Main substation transformer using single-function relays

The protection system for this transformer includes primary-side overcurrent protection (i.e., phase instantaneous, phase time, neutral instantaneous, and neutral time), secondary overcurrent protection (i.e., phase time, phase directional, and ground time), and differential protection. Additionally, restricted earth fault (REF) protection is included to provide sensitive ground fault protection for the wye transformer winding. The differential relay operates a lockout relay, which prevents the reclosing of the breakers without resetting the relay.

Utilizing electromechanical or single-function, single-phase, solid-state relays to implement this protection scheme would require the use of fifteen relays. Using three-phase, single-function, solid-state relays, the number of devices may be reduced to seven. Several manufacturers offer multifunction, microprocessor-based protective relays (MMBPRs) that incorporate all the protection functions shown in Fig. 1 into a single device. The advantages that the MMBPRs have over the electromechanical or solid-state-based designs are obvious; reduced component count should provide lower initial cost and lower maintenance cost, which has proven to be the case in most applications. Additional features of MMBPR systems have the potential to provide even greater benefits. This paper explores some of the features and benefits that MMBPR systems can provide in new and retrofit installations.

II. LOWER INITIAL COST

Table II summarizes the approximate cost for using single-function relays to protect the transformer, as shown in Fig. 1.

TABLE II
TRADITIONAL PROTECTION COST

Quantity	Relay	Approximate Unit Cost	Extended Cost
3	50/51	\$400	\$1,200
1	50N/51N	\$400	\$400
3	51	\$400	\$1,200
3	67	\$1,500	\$4,500
3	87	\$1,700	\$5,100
1	86	\$250	\$250
1	51G	\$400	\$400
Total			\$13,050

The same transformer could be protected with MMBPRs, which would incorporate all the protection elements shown in Fig. 1 and more. Fig. 2 shows a typical main substation transformer protected by an MMBPR. Note that the number of current transformers (CTs) is reduced with the use of the MMBPR. The number of CTs required with single-function electromechanical or solid-state relays is thirteen, whereas only seven CTs are required when using an MMBPR. Depending on the type of installation, the cost of a CT ranges from \$200 to \$500. When using an MMBPR to protect the substation transformer, the reduced number of CTs creates a savings of \$1,200 to \$3,000.

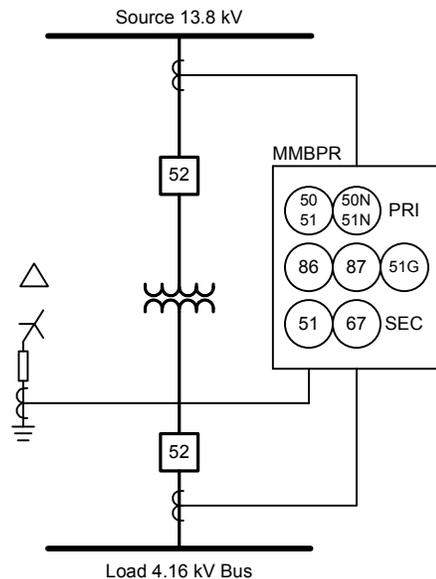


Fig. 2. Main substation transformer using an MMBPR

Some consideration should be given to the reliability of the installed device. Since many protection functions may be contained in this single device, the availability of the device is of utmost importance. Care should be taken to select a robust product that is designed for a rugged power system and industrial environment. Additionally, the selected product should have a self-test feature that monitors the health of the relay. This self-test alarm should be monitored continuously to alert system operators of a condition where protection has been lost. The very high mean time between failure (MTBF) statistics achieved by some MMBPR manufacturers result in an anticipated availability figure near 100 percent. Given that any failure would be immediately known and these failures should be rare, backup protection from an overlapping protection zone may be sufficient. Additionally, given the savings realized from installing these MMBPRs and their functionality when compared to electromechanical relays, redundant or additional protection can be added easily for very little additional cost.

Another significant savings is the elimination of metering and other monitoring components. Most MMBPR manufacturers incorporate sophisticated and accurate metering features into their protective relays. These features and their benefits are discussed later. The cost of dedicated metering, which would be eliminated with the use of an MMBPR, is anywhere from \$500 to \$2,500.

Additional initial cost savings are realized through lower wire and termination counts and reduced installation costs. An MMBPR designed for transformer protection, as shown in Fig. 2, typically costs less than \$5,000. The total initial cost savings when using an MMBPR instead of single-function relaying and dedicated metering approaches \$14,000. Similar savings are available for the protection of substation transformers as well as distribution feeders, large motors, and generators. It is easy to understand why most new installations utilize MMBPRs for protection of electrical systems.

III. LOWER MAINTENANCE COSTS

In order to achieve 100 percent reliability, protective relaying systems must be properly maintained. For electromechanical relays, this means testing for proper operation, cleaning, and adjusting the relays once every one to three years, depending on the environment in which the relays are installed. For solid-state relays, maintenance may be on a two- to five-year cycle. Electromechanical overcurrent relays have a spring, which may need to be adjusted, and contacts, which may need to be cleaned. In a corrosive environment, the required maintenance is more frequent. It is becoming more difficult to find replacement parts and qualified technicians who are skilled in the testing and maintenance of electromechanical relays. Solid-state relays generally include no moving parts and have sealed components, which are less susceptible to environmental contamination. However, because this is a passive device, it must be tested periodically to make sure it is working properly and that no internal components have failed.

MMBPRs also have no moving parts, but they are not passive devices. They give the user feedback regarding how much current is actually in the circuit being protected. As will be discussed later in this paper, they may also be used to actually control the circuit breaker. Therefore, every time the circuit breaker is opened for normal operation, a "test" is being performed as to whether or not the relay will open the breaker when a fault occurs. By examining the fault and sequential events reports in the MMBPRs, we can

determine if the relay is performing properly. The most significant feature of an MMBPR in reducing relay maintenance cost is its ability to run self-diagnostics and alarm the user if it has a failure. Manufacturer recommendations on testing of MMBPRs vary. Statistical analysis shows that extensive testing of MMBPRs with self-diagnostics is not required. Routine testing must include meter checks and input/output tests, greatly reducing the cost of maintenance and testing of MMBPRs over traditional relaying [1].

MMBPRs also can help reduce maintenance costs of other electrical components. Some of these devices have sophisticated routines that monitor the usage of the circuit breaker that they control. They keep track of the number and magnitude of the faults the breaker has cleared. These data can be compared to the breaker manufacturer's recommended maintenance requirements and allow for longer time between scheduled maintenance. The theory is that if the breaker has not been stressed, maintenance may not be required as often.

IV. COMPREHENSIVE METERING

Typically, an MMBPR includes metering of voltage, current, frequency, real power, reactive power, and energy. The data are often available on a single-phase or three-phase basis. Peak and minimum values are also stored. Demand over time is also available in many of these devices. These data can usually be displayed on the front panel of the MMBPR.

When an MMBPR is utilized, there is usually no need to include additional metering. In some instances, however, separate, sophisticated metering may be required. If revenue-grade metering or monitoring for IEEE 519 compliance (harmonic content) on a particular circuit is required, it is sometimes desirable to add additional metering because these capabilities are typically beyond the ability of an MMBPR. Generally, we would only find this requirement on a main service entrance circuit to a facility or perhaps on a large generator within a facility. For most circuits, the metering capability of the MMBPR is more than sufficient.

V. FAULT DIAGNOSTICS/SEQUENCE OF EVENTS

Unscheduled outages in many facilities have serious, undesirable consequences that usually have a negative financial impact. In some instances, an unscheduled interruption of electrical power can cause costly damage to equipment. In a batch process, the interruption of power may result in the loss of valuable product. Certain processes take hours or even days to come back up to full production.

When a failure or unscheduled interruption occurs, it is important to understand why it happened and what could be done to prevent it from happening in the future. It is also important to understand how the protective devices in the system performed. What caused the outage? Did the proper device operate correctly? Was the outage caused by the failure minimized? Knowing the answers to these questions can help minimize the effects of future failures or unscheduled interruptions on production.

Most protective relays have a "target" that indicates when the relay has operated. When a fault occurs on an electrical circuit and an overcurrent relay senses the fault, picks up, and times out, a contact is closed that energizes the trip coil of a circuit breaker, resulting in the clearing of the fault. The overcurrent relay that timed out would have a target indicating that it operated, giving personnel

an indication of what happened to cause the outage that they now must troubleshoot. If there is just one target on one relay on one circuit breaker, troubleshooting is generally a fairly simple procedure. Perhaps a ground relay operated, indicating there was a ground fault on the subject circuit. Or even better still, perhaps a ground relay target and an A-phase relay target are showing, indicating that the ground fault occurred on the A-phase of the subject circuit. Now the maintenance personnel have somewhere to start. They can inspect all the equipment connected to the subject circuit, paying particular attention to the A-phase. In many instances, this is just what we might find. Unfortunately, in many instances, it is much more complicated, and finding the cause of the outage and gaining a complete understanding of exactly what happened are difficult. However, having a complete understanding is imperative if we are to minimize the chances of having a similar outage in the future.

A more challenging example scenario follows. An outage occurs when two seemingly unrelated circuit breakers operate. Fig. 3 shows a circuit with a fault on the circuit fed from Breaker C. Both Breakers C and B operate. Is this possible? Yes, and we have seen more than one instance when this has occurred. The term commonly used to describe this phenomenon is “sympathetic tripping.” With the fault on C, we do not want Breaker B to operate, causing unnecessary interruption of service. Sympathetic tripping is a well-known phenomenon, and several technical papers have been written on how to analyze and avoid it [2].

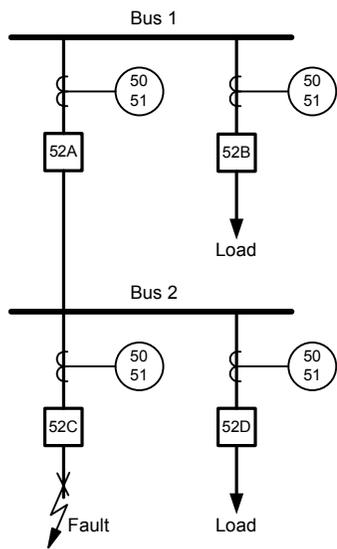


Fig. 3. Fault on the circuit fed from Breaker C

What would cause Breaker B to operate when a fault occurs on the circuit fed from Breaker C? Assuming the overcurrent relays on Breakers C and B both have targets, we could conclude that a large amount of current flowed in Circuit B. But why? How much current

and for how long? Could making the relay on Breaker C trip faster eliminate the tripping on B? Could making the time delay longer on B solve the problem? Computerized fault-current analysis may shed some light on the problem, but even then, we still may not be able to model what has occurred.

If electromechanical or solid-state relays were used, it is unlikely that we would even know for certain which of the breakers opened first. It would be almost impossible to know how much time (measured in milliseconds) passed between the opening of the two breakers. But if we had this information, we would have a good understanding of what exactly happened and how to decrease the probability of reoccurrence. Historically, this is done through the use of sophisticated fault-recording devices located at various points in the electrical system and through the use of sequential events recorders (SERs). Every device that could trip a circuit breaker, each protective relay, control switch, and interlock, would be wired to a high-speed data recorder. This adds tremendous expense to a design and is generally found only in extremely critical applications.

Most MMBPRs have fault and sequence of events (SOE) recording capabilities built in. When a breaker is operated, the MMBPR can record exactly how much current was flowing in the circuit, what time the relay picked up (millisecond resolution), what time a breaker trip was initiated, and what time the breaker actually opened. If configured properly, this relay can also record when an operator initiated a trip. Most MMBPRs that have fault and SOE recording capabilities keep a record of at least ten previous trips or events (the relay may be set up to record other abnormalities, not necessarily just a circuit breaker trip). The data from the relay can be displayed in graphic form utilizing software provided by the relay manufacturer (see Fig. 4).

The graph in Fig. 4 shows the relationship between the elements in the relay (87 and 51G), the voltage on the circuit, and the current in the circuit. The performance of the relay and the circuit breaker is clearly depicted in this graphical format, providing a very useful tool that may be utilized to optimize the system under study.

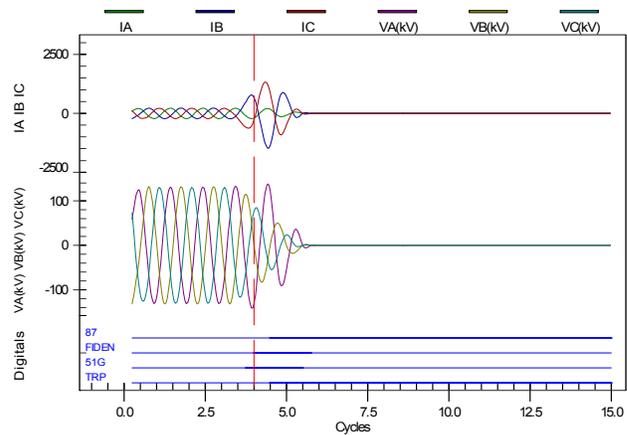


Fig. 4. Analyze event reports with oscillograms

The clocks of multiple MMBPRs can be synchronized utilizing IRIG-B, a standard time signal that can be set by GPS. Doing so allows us to compare the fault and SOE recording in one MMBPR with that of another, both internal to a facility and external to a facility. Assuming the breakers in Fig. 3 were equipped with MMBPRs and their clocks were synchronized, the fault data recorded by the devices would provide valuable information on the outage. With careful study, we should come to a complete understanding of what happened and be able to develop the necessary changes to minimize the chance of reoccurrence. And hopefully, the next time there is a fault on Circuit C, Circuit B will not be affected.

VI. CONTROL SYSTEM INTEGRATION

Many MMBPRs are equipped with multiple discrete inputs and outputs. These are usually rated for at least 120 Vac and 125 Vdc to accommodate the trip and close circuits associated with power circuit breakers. In order to take advantage of the SOE recording capability of the MMBPR, all the devices associated with a particular breaker need to be wired to the MMBPR. Fig. 5 shows a simplified control schematic for a circuit breaker protected and controlled by an MMBPR. Note that the breaker trip coil (52/TC) and close coil (52/CC) are only operated by the MMBPR. The circuit breaker auxiliary contacts (52/a and 52/b) and the circuit breaker control switch trip and close (CS/T and CS/C) are wired to inputs on the MMBPR. With this arrangement, the MMBPR is, in essence, the control system of the circuit breaker. This allows for easy integration of the circuit breaker, protected and controlled by an MMBPR, with other supervisory control and data acquisition (SCADA) systems.

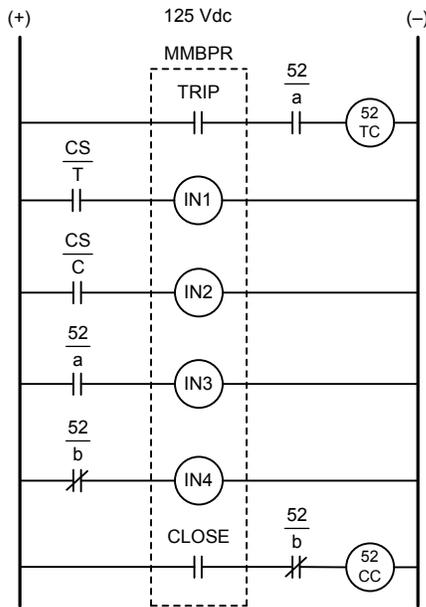


Fig. 5. Simplified control schematic

Consideration must be given to select the proper MMBPR. For advanced control systems, the MMBPR should include the following features:

- Multifunction protection
- Remote I/O
- Metering
- Power quality monitoring
- Deterministic programmable logic
- Local and Ethernet user interface
- High-speed communications protocol
- Continuous self-diagnostics
- Synchrophasors
- DC battery monitoring
- Front-panel interface that allows replacement of all control switches and pushbuttons
- Logic for maintenance and clearance tags to reside in the device, close to the equipment

Most MMBPRs used in plants include integrated communications capability supporting the Modbus[®] protocol, an open-standard communications protocol. In the past, this protocol has utilized serial data connections. It is totally adequate for traditional control and monitoring applications. However, TCP/IP Ethernet communication is emerging as an alternative, supporting protocols such as Fast Messaging, DNP3, and IEC 61850. These protocols offer advanced data acquisition and control not possible using Modbus. Implementing robust communications protocols allows the relay to be connected to most SCADA or plant distributed control systems, thereby eliminating transducers, meters, and other components that previously would have been necessary with protection systems based on electromechanical relays. With this capability, local and remote monitoring and control of circuit breakers and other apparatus are easy to implement. All the metering data in the MMBPR can be made available to the SCADA and local control systems. The system can monitor the status of the equipment and be configured to alarm if a trip or other abnormal condition occurs. Advanced load shedding, voltage and VAR control, and automatic generation control systems can be implemented. Due to the distributed nature and power of the MMBPR, these systems can be designed with complete flexibility not possible in the past.

Advanced industrial power management systems can be designed based on an integrated platform solution. An example power management solution is based on utilizing the power and functionality found in today's MMBPRs. Listed below are some of the advanced schemes that can easily and cost-effectively be implemented by a properly designed protection system using MMBPRs:

- Load shedding
- Island control
- Load management
- Power management
- Generation control
- Voltage control
- Automatic decoupling

Fig. 6 represents the many functions that can be implemented by a properly designed protection system utilizing MMBPRs. These functions utilize the rich data available in the MMBPR and will be discussed in further detail. Total integration of all system devices is required for power system operation; this includes the MMBPRs, meters, tap change controllers, capacitor controllers, governors, excitors, etc.

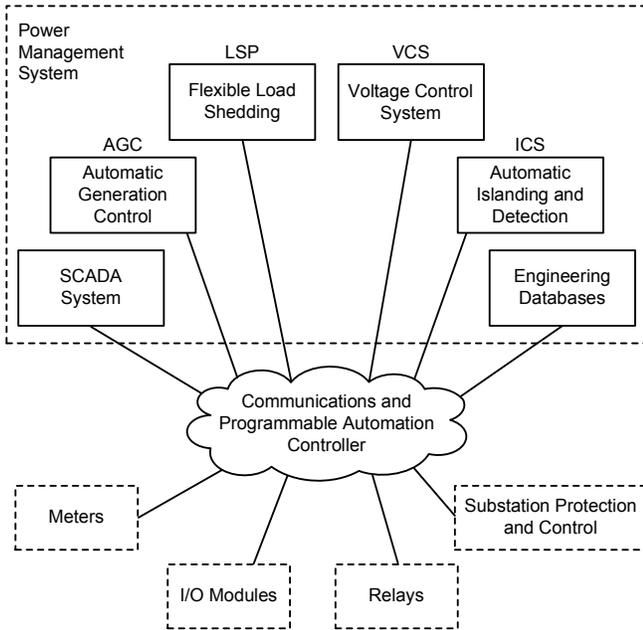


Fig. 6. Many advanced functions can be implemented by utilizing MMBPRs

A typical application of this system is an oil refinery where extensive MMBPRs, remote I/O modules, and meters bring in data from around the plant. The power management system algorithms acquire this information, make decisions, and send commands back to the MMBPRs. Closed-loop, wide-area control systems run on each of the programmable automation controllers (PACs), forming a distributed network of intelligence.

In the power management design, load-shedding processors (LSPs) consist of crosspoint switches that have been configured using MMBPRs or other utility-grade, microprocessor-based, protection-class equipment. These LSPs provide quick and secure outputs that control load shedding based on plant conditions and operating parameters. By providing this feature in an electronic crosspoint (Fig. 7), the trigger tables can be updated quickly and securely, unlike the older, hard-wired load-shedding systems. The power management system provides the plant operations group with flexibility as they run different processes. Data in the form of digital I/O and analog MW, MVAR, voltage, and current are received from the installed MMBPRs, meters, and remote I/O modules. These data are fed into the LSPs, where they are compared to the matrix that the operators have set into the LSP (Fig. 8). If the on-site generation or utility inertia is lost or any other event occurs that requires load to be shed, then load shedding is initiated and appropriate, noncritical loads are shed to preserve the running process.

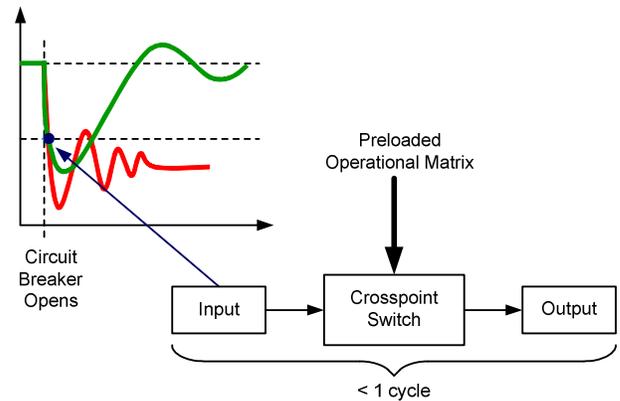


Fig. 7. Electronic crosspoint

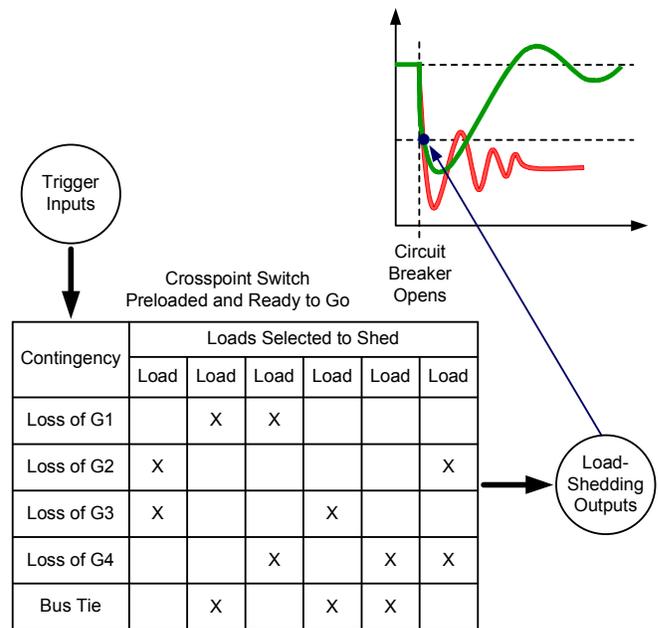


Fig. 8. Load-shedding processor logic

The elegance of this design is the scalability it offers. As the complexity of the matrix increases (number of loads to control), different design architectures can be selected with varying degrees of speed and complexity. The total time between when a contingency input occurs and a load-shedding signal is asserted varies from 12 to 57 milliseconds (worst case) for up to 480 loads for modern, state-of-the-art designed systems. Systems implemented with static lookup tables inside the MMPBR are very fast (less than 5 milliseconds) and secure, but can control less than 50 loads. More complex schemes that can control hundreds of loads have been implemented securely under 60 milliseconds. These schemes implement protocols such as MIRRORING[®] communications or IEC 61850 GOOSE (Generic Object-Oriented Substation Event) messaging. LPS systems have been designed as single, dual primary, or triple modular redundant (TMR). In a dual primary system, two independent systems are available to take action, whereas a TMR system relies on a voting scheme of two out of three systems before action is taken. A typical application for these schemes is a wide-

area power network implementing a remedial action scheme (RAS). Dual primary and TMR are deemed necessary to maintain the security of the transmission grid. These schemes are more complex and costly and typically would not be used in an industrial plant application.

The Saudi Aramco Shaybah Oil Refinery power management LPS uses IEC 61850 GOOSE protocol to transport the trip signals to loads over 12 kilometers from the controller. In this system, the round-trip timing to remote stations is 42 milliseconds, while the round-trip timing to local I/O is less than 12 milliseconds. This system is shown in Fig. 9.



Fig. 9. Saudi Aramco Shaybah Oil Refinery power management LPS

Fig. 10 shows a dual primary TMR system that has a design speed of less than 17 milliseconds. It is implemented as a RAS for PacifiCorp. This system is the fastest and most secure TMR in the world.



Fig. 10. Dual primary TMR system

One unique benefit of utilizing the MMBPR as the LPS is the ability to utilize a Real Time Digital Simulator (RTDS[®]) to test the response time and system response to load shedding. With an RTDS, all system parameters can be verified before the LPS is turned on at the plant. When system abnormalities do occur, real-time data captured by the MMBPR can be reviewed to verify correct LPS operation. Furthermore, these data can be fed back into the system during testing and simulation to verify correct operation or teach operators.

Fig. 11 depicts one of the test simulation screens that is used to run “what if” scenarios and verify correct operation. This is invaluable as the plant gains operational history and operational data are fed into the simulator to review system performance. This level of checking can only be accomplished through the proper design and use of MMBPR power management schemes.



Fig. 11. One of the test simulation screens

An island control system (ICS) is very important when industrial plants have on-site generation. Being able to detect and then determine when the plant should island itself to protect from utility disturbances is critical to successful plant operation. Using the correctly featured MMBPR provides the critical functions needed to implement ICS. These necessary ICS relay functions are:

- Undervoltage
- Underfrequency
- Reverse power
- Circulating current
- DFDT
- Phase angle
- Overfrequency

Fig. 12 shows the protection architecture that implements this scheme at Gulf Petrochemical Industries Company (GPIC).

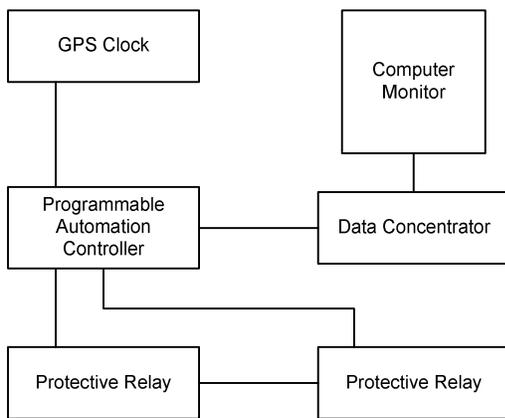


Fig. 12. Architecture for island control scheme

This same scheme can provide an autosynchronizer for on-site generation. The MMBPR must provide an accurate phase-locked loop that can implement this feature. Once this is determined, a synchroscope can accurately depict phase angle and slip across any Ethernet or serial network, even with data through a PAC. Using a human-machine interface (HMI), the scope in Fig. 13 can easily be drawn and displayed.



Fig. 13. Autosynchronizer display

A voltage control system (VCS) in the power management system controls many devices to optimally share total MVAR load. These can include capacitor banks, load tap changers, generator field exciters, large synchronous motor exciters, static synchronous compensators (STATCOMs), and static VAR compensators (SVCs). This system is used to provide electrical system stability during disturbances. It keeps active MVAR-producing devices off limits and allows them to reject system disturbances. System inerties (MVAR) and bus voltages are kept to operator set points. In multigeneration installations, MVARS can be distributed between generation units.

A properly designed VCS can work under any number of system “islands.” It uses proven and secure methods to propagate signals through a communications medium and has algorithms that can handle low-quality data yet still make the “right” decision. This is done by using many distributed data sources (MMBPRs) that are providing redundant data to the VCS. With active VCS, complex bus configurations are now possible.

An automatic generation control (AGC) is easily implemented in the power management solution. Frequency and MW controls can simultaneously manage inerties for requested power transfers (MW). System frequency is controlled and maintained to nominal during all conditions. This system can optimize generator dispatch by using the most efficient generation first. Heat-rate curves can be used for economic dispatching yet adapt to different output limitations from generators. Unique tuning parameters can be used for changing conditions to ensure the most economic dispatch of plant generation. This is especially important during an island condition. Under these conditions, LPS, VCS, and AGC systems work together to optimize plant configurations to keep critical processes running. Fig. 14 shows a typical power management AGC screen.

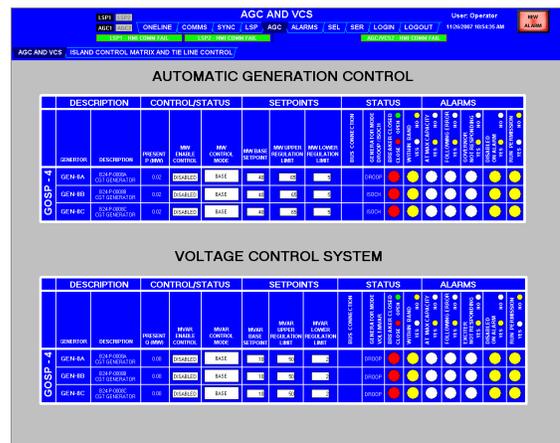


Fig. 14. Typical power management AGC screen

data through binary Fast Messaging and presenting the SOEs from all the SOE sources connected to the power management system. Fig. 19 shows the HMI screen depicting these data. Systems that contain 25,000 SOEs have been implemented without additional cost.

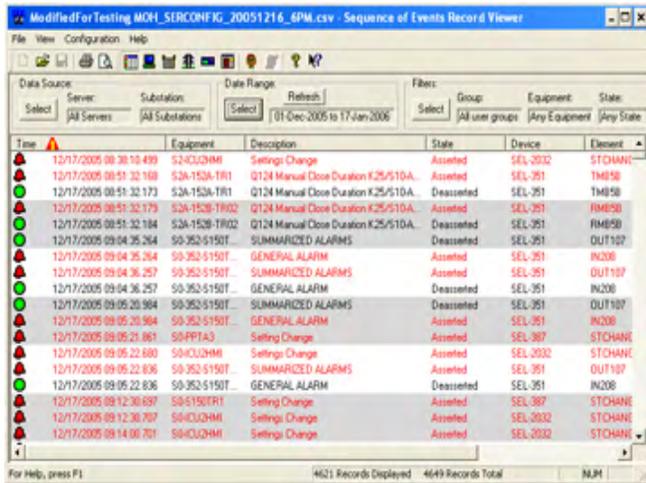


Fig. 19. SER data display screen

Advanced fault analysis is implemented in the power management system through the communications connection. Any time an electrical event occurs, the MMBPR provides a “snapshot” of the digital inputs/outputs, analog inputs, and other critical elements inside the relay. Fault records are very beneficial to determining the root cause of a fault. These fault records are gathered automatically as they occur and are transferred to a server connected to the network. This provides a convenient place for the protection engineer to review faults and removes the burden of plant personnel having to manually retrieve these records. Fig. 20 shows a typical event record.

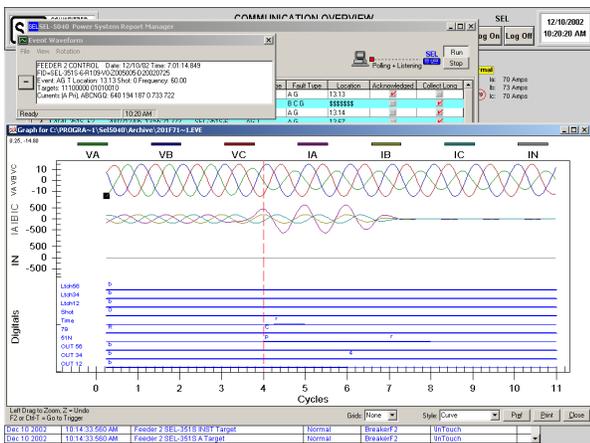


Fig. 20. Typical event record

VII. CONCLUSIONS

MMBPRs offer many features that can significantly lower the costs associated with the operation of a large electrical system. Lower initial cost and greater capability over traditional, single-function relay designs have made MMBPRs the standard for new installations. The benefits of MMBPRs also make them viable to consider retrofitting existing electrical systems to take advantage of the advanced features of the MMBPR to lower costs by providing more efficient operation of electrical systems.

Properly integrated MMBPRs can further the benefit of implementing MMBPRs. Load shedding, operator oversight, automatic generation control, voltage control, island control, and many more advanced control and diagnostic features can be implemented. This implementation can be very cost-effective and reliable through the careful selection of the MMBPR.

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IX. FURTHER READING

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B. Cho, M. Almulla, H. Kim, and N. Seeley, “The Application of a Redundant Load-Shedding System for Islanded Power Plants,” proceedings of the 35th Annual Western Protective Relay Conference, Spokane, WA, October 2008.

S. Shah and S. Manson, “Automated Power Management Systems for Power Consumers With On-Site Generation,” presented at the 16th Annual Joint ISA POWID/EPRI Controls and Instrumentation Conference, June 2006.

X. VITAE

Christopher W. Seelig, P.E. graduated from the University of South Florida in 1988 with a Bachelor of Science in Electrical Engineering. He began his career as a co-op student with BuShea & Associates, Inc. He became a full partner in 1993, and the name of the company was changed to BuShea, Seelig & Associates, Inc. BuShea, Seelig & Associates is now TEAMWORKnet, Inc., a part of Fortune7, Inc., a multidiscipline engineering company. Chris is the president of TEAMWORKnet, Inc.

Brian A. McDermott, P.E. is a registered Professional Engineer in the state of North Carolina and worked 22 years at Duke Power in various roles, the last one leading the Transmission Substation Automation Team. He joined Schweitzer Engineering Laboratories, Inc. in 2003 as an integrated systems manager. In 2003, he was promoted to director of integrated systems. In 2004, he became the regional sales and service director for the east region. He holds U.S. Patent Number 5,055,766, titled “Voltage Regulator Compensation in Power Distribution Circuits.”

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