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Creating a Sustainable Protective Relay Asset Strategy

Jonathan Sykes Aaron Feathers Eric A. Udren Bryan Gwyn
Pacific Gas & Electric Company Quanta Technology, LLC

Introduction

Protection systems have evolved from assemblies of electromechanical single function devices, through multiple generations of analog solid state systems, to advanced microprocessor based protection systems. The newest generations of microprocessor relays can perform a myriad of applications and functions in one physical unit. The skills of the engineers and technicians who manage these protection and control assets are also evolving to meet the challenges of designing, commissioning and maintaining these complex programmable multifunctional devices, along with the fleet of legacy protection systems that remain in service.

Many utilities now face a complex tangle of challenges in managing the performance and reliability of multiple generations of relays in service, as they formulate the best strategy for designing and sequencing replacements. This paper explores the challenges of creating a sustainable relay upgrade and replacement program, and the positioning of engineers and technicians to carry out the program and to maintain old and new installations.

Protection and control asset owners, and their responsible managers, engineers, and technicians, can all benefit from high level guiding principles for fleet management strategies to meet the demands of today's operating and replacement pressures. The paper presents examples of methods that users can employ to maintain reliable and available designs, support testing and troubleshooting, and position the owner to maximize the asset reliability and longevity.

To develop plans for how to deal with mixed generations of relays, to identify those needing attention or replacement, and to create a strategy and a design for renewal of protection assets, the responsible team needs to understand:

- The differences among relay types or generations that impact reliability or drive replacement.
- Strategies for assessing maintenance versus replacement priorities.
- Standardized, sustainable design approaches for replacement installations – panels and complete buildings.
- Human factor design to reduce human errors, which are a documented cause of hidden failures and misoperations.
- Tools for managing the protective relay fleet - asset, maintenance, and configuration databases described further below, and analysis of the data they capture.

- New maintenance approaches that focus on real issues while reducing human interaction with devices not needing attention.
- Approaches to training of personnel.

The following sections address each of these topics in turn.

Characteristics of Relay Generations

Most utilities have already learned lessons about the differences among electromechanical, solid state, and microprocessor relays. Some utilities – more small ones than large ones – have replaced all of their aged EM relays with new microprocessor based devices. Is this necessary, or beneficial, or practical? Some users apply designs and methods from older generations to the latest equipment and installations. We characterize the evolution of relay generations and highlight features of each, to set the stage for design and management recommendations further below.

Relay Generations

- ***EM relays fail silently***
- ***SS relays are a lost generation***
- ***MP relays are evolving at a break neck speed***

Electromechanical (EM) Relays

EM relays are the reliable, simple, elegant, long-lived generation whose operation could be observed with the eye, and which served the industry from inception until recent decades.

- Electromechanical relays generally have the longest lives – the majority can last as long as the primary power apparatus they protect, with a few exceptions summarized just below. Some EM relays are 80 years old and still in service where functionality is acceptable. Their panels and installations have been designed around this longevity, as we discuss further below.
- The visual simplicity and limited number of settings hide the functional sophistication designed into the operating elements of these relays. Nonetheless, many modern applications need new combinations of measurements with math and logic that EM relays are not capable of providing.
- Most EM relays are single-function devices - at most a couple of functions are built into one case. As a result, the grouping of multiple EM relays to handle the complete protection job yields inherent redundancy. Most engineers and technicians are aware that a set of four EM feeder overcurrent relays – three phases and ground – will respond to most feeder faults even if one relay has failed. A single microprocessor relay includes all four measurements – a second relay is needed to handle the single-failure criterion.
- EM relays require more panel and floor space than newer replacements.
- The constant-dollar cost of a protection system for one zone (e.g. line terminal) may be shockingly high compared to today’s microprocessor relays. A complete EM line protection terminal on a panel wired by the vendor cost $30,000 in 1970 dollars (and had to be ordered a

year before the installation date). A pair of redundant microprocessor relays with far more flexibility and functions can be purchased for $6,000 in 2012 dollars, which is approximately $1,000 in 1970 dollars (and can be installed on the day after ordering if time pressure requires). While EM relays are still manufactured, there are few situations where a *new* EM relay installation makes economic sense.

- EM relays are very reliable, but fail silently – periodic testing is required to find hidden failures in protection systems which could cause misoperations. These hidden failures are a risk that exists between testing occasions, which may be years apart.
- In a moderate physical environment and with recommended application limits, most components have no wear-out mechanism. However, EM relays use calibrated mechanisms which are subject to drift of characteristics or inadvertent damage during maintenance work. Relays whose performance or calibration depends on components that do deteriorate – notably metal-can bathtub capacitors or with components that run very hot – are the worst actors in this regard; those without these critical parts may function without attention for decades.
- Lacking these issues that are visible in maintenance tracking, many of these relays have no obvious end of life, and will be replaced due to inadequate functionality, or as part of a complete zone or substation replacement program to address functional and/or maintenance demands.

Analog Solid State (SS) Relays

Analog Solid State (SS) relays are a lost generation. They introduced electronic components to EM relay functions, to achieve only focused performance benefits – some increase in the sophistication of trip logic, and higher trip speed.

- Many SS relays and systems were sold on these performance improvements and were even more expensive than EM relays. A limited class of single-function relays used SS technology to achieve lower cost.
- Over the generations of these SS relays, the package size did shrink and the functionality became more sophisticated than EM relays.
- SS relays gave up the long life capabilities of EM relays. As they age, relay failure rates can become quite high due to electronic component failures throughout the device, many of which are hidden and can lead to misoperations before a routine test reveals the problem. Maintenance of these relays becomes demanding and expensive.
- A knowledgeable technician can find and repair failed electronic components, for which replacements can still be found in many cases, but this sort of triage expertise is not widely available. Systems of SS relays have been or are being phased out at most utilities that used them.

Microprocessor (MP) Relays

In 1971, the world's first computer based relaying system was installed to protect a 230 kV transmission line of the Pacific Gas & Electric Company [1], [2]. This technology demonstration showed the world new capabilities never seen in prior design generations, including:

- Distance element reach characteristics with application-tailored shapes, not limited by element or circuit design.
- Event records for internal decisions including millisecond time tags.
- Oscillographic records with prefault saving, resembling a basic DFR.
- Multiple functions in one processor, with capability to expand up to processing limits.
- Fault location.
- No drift or calibration required or possible.
- Self-monitoring and failure reporting at the time of a failure, not at the time of a fault or a test.
- Communications between the relay itself and external human interface devices.

"The practical support time by a vendor for a new product is moving towards 10 years, and may plummet further, making us rethink relay replacement strategy."

This first highly successful minicomputer-based demonstration preceded the introduction of microprocessors and was not a commercial product. More than a decade later, the first microprocessor relays appeared on the market. They offered multifunctional capabilities and could replace all the elements of a conventional line terminal in a small rack mount package at very low cost. The external communications could be accessed locally with a PC or remotely by modem. Speed performance was unexceptional- notably slower than SS relays and in the range of, or slower than, typical EM relay times - but adequate for the bulk of routine applications. These relays showed stable and predictable behavior and good reliability. They offered all the new features of the first computer relay except the tailored reach characteristics, which did come later. The industry proceeded down the road of protective relaying based on sophisticated low cost computing platforms linked to the broader world of control and communications technologies. That road has been irreversibly linked to the evolution of those technologies, with its breakneck pace of innovation and obsolescence. Accordingly, the relays built on these platforms change at least every few years, and manufacturers are often unable to keep even a popular and widely applied relay type in production as long as many users would like. Utility protection system standards thus must change to keep pace; replacements for relays in service may require newer designs requiring revalidation of the application and/or modification of installations.

As new generations of MP relays have evolved, they have added vast arrays of new functions and capabilities. They have become so complex and flexible that understanding or setting them has become an educational journey for even a talented protection engineer. These recent relays have other characteristics that impact the industry strategy for their use:

- Sophisticated measurement and logic functions that can only be done on these modern platforms yet are essential for modern protection applications – including load restriction, new measurement planes, selectable settings groups, logic programming, and high-speed data communications among relays.
- High reliability and long MTBF, until certain components like capacitors reach end of life. Some units can operate for 20 years or longer, although there is no plug-in replacement strategy

for those that fail sooner. The longer life integrated MP relays may also not have a plug and play replacement due to lost applications and technology of the original device.

- Array of many functions in one unit – a hardware failure disables the relay including all the applications contained within, requiring separate backup units. When the time for unit replacement comes, all of the functions must be replaced together.
- Complete flexibility – the user is responsible for defining what a particular unit will actually do via hundreds of settings that configure the many functions in a single unit. The relay practitioner and relay technician must verify all of these settings for the application and/or each function?
- The hundreds of settings (including logic) replace the wiring among functions on EM relay panels. The scheme complexity did not go away with the wires – it is contained in these settings. Setting files must be controlled with the rigor of engineering drawing version control systems, to avoid "moving wires" malfunctions.
- Vastly reduced panel space and power consumption – MP relays use much less power and panel space than the EM relay equivalent, especially considering the full array of protection functions, plus non-relaying control and integration functions all contained in a single box.
- Product design and generation turnover – MP relays use complex digital computing and communications components from suppliers that also support broader electronic industries and product makers. The latest electronic components become obsolete and then are unavailable in a few years, and designs must evolve to keep pace. Each new generation requires massive new hardware and software development effort by manufacturers. Recent relays thus have a support life of only 15 years – yet even in this time window the manufacturer may replace the relay with a unit that does a similar function, but is not an identical product.
- Manufacturers are constrained by trends in electronic components and in other industries that use them. Consider the extreme example of smart phones and portable computing platforms, whose parts are obsolete in 1 to 2 years. The authors believe that the practical support time by a vendor for a new product is moving towards 10 years, and we expect it to plummet further, making us rethink relay replacement strategy.

Questions about relay generations

Key questions that arise specifically from our assessment of the generations of relays:

- *What tools does the organization need to manage a mixed fleet of new and old installations?*
- *What principles can we apply to decide about repairing and sustaining EM or SS relays versus replacing them with new MP relays?*
- *What new installation design principles apply when we are using MP relays?*
- *What new organizational approaches are needed to support MP relays?*

The following sections present analyses and advice to help in answering these questions.

Protection System Asset Management Challenges

Today, the relay practitioner and asset owner is faced with providing oversight of the resulting fleet of diverse relays. The strategy that was used decades ago needs to change to address issues with the addition of SS and MP based relays. This strategy must adjust as the fleet evolves from EM to MP relays. Many users confront a fleet made up of all 3 major technology generations of relays, each with several design generations, and each generation has its own set of features and issues.

The following example illustration shows one utility's relay fleet distribution of ages and generations.

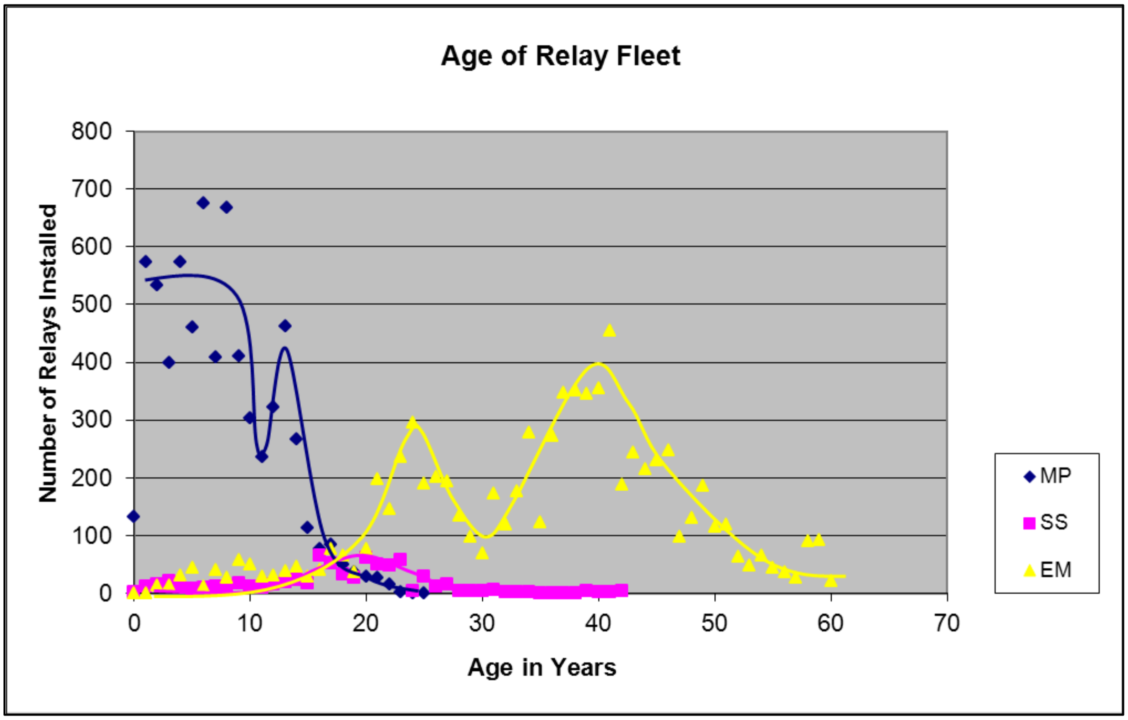

Figure 1 - Age of a Relay Fleet

Figure 1 illustrates that some EM relays are still providing service after 60 years. SS relays were only installed for about 20 years and now only MP relays get installed. The diagram also shows the amount of relays that were installed for a given year. The replacement strategy must be able to address the practical life of a relay. With every new year the relays installed for a particular year get closer to their end of life. The diagram shows that there are a peak number of EM relays about 40 years old. If these relays are at the end of their life we would expect to start seeing an increased number of failures and thus a need to replace these relays. The relay practitioner must have a viable strategy to address failures prior to the relay's end of life. There may not be enough reaction time or resources available to risk a failure that may occur prior to scheduled replacement of the device. This requires complete preparedness using proper designs, having resources available, knowing the skills of the work force, life of the relays, replacement plans, and tracking failure rates.

This is not a new strategy for some industries that are coupled to evolving technologies and products. The telephone industry followed this same progression and now it is not uncommon to replace a cell phone every couple of years. Computers have always been chasing the latest technology and these also do not last but a few years before they are replaced. MP relays will need to be replaced more frequently than the older EM relays. Some estimates indicate the MP relays will need to be replaced 2 times as often or more than EM relays. Thus, a fleet of 40,000 EM relays would require about 1000 relays to be replaced every year assuming the average life of the EM relay was 40 years. A fleet of 40,000 MP relays would require about 2000 relays to be replaced every year assuming the average life of a MP relay was 20 years. The difference in replacement strategies for EM and MP relays gets larger if we assume a life longer than 40 years for EM relays and a life shorter than 20 years for MP relays.

The industry will always be involved in modernizing the relay fleet but it cannot replace all the relays of a certain type or age very quickly and it takes many years for a large company to move to the next generation of relays. Thus, the replacement strategy of the relay cannot follow replacement strategy of the cell phone or computer. The Electric Utility industry will always have a diverse set of relays with varying ages, technology and functions and a combination of replacement strategies will be necessary for an owner to maintain a reliable fleet of relays.

The relay practitioner should track the characteristics of the relay fleet to help determine priorities for replacement. Some characteristics that can be considered are age, protection gaps, product performance, and design/maintenance problems and this is covered in more detail below

Strategies

The product age and technology distribution described above is typical of that faced by many utilities today. Relay practitioners must have a combination of strategies to manage this situation with finite resources – it is not generally practical to fund the replacement of all the aging relays at once.

The following three major sections present a set of strategies:

1. Triage of existing installations of aging relays
2. Design of new panels and buildings
3. Asset and fleet management strategies

Triage of Existing Installations of Aging Relays

The user needs to make repair or upgrade versus replace decisions according to operating experience data, generation, and situation at particular substations or groups of substations, all in the context of an overall replacement strategy. To begin, the user needs to know how existing installations are performing. Other issues to consider which will be discussed in this section include:

- Impact of misoperations
- Primary equipment replacement driver
- Physical or space limitations

- State of old wiring
- Nonstandard substations
- Replacement of a troublesome relay type with a new type in an old system
- Repair of a troublesome relay
- EM versus SS

Tools for Observing Performance

Tracking relay failures is one way to trend relay performance. This can be useful to identify poor performing relay types and prioritize relay replacements. Some useful parameters to track with relay failures are:

1. Relay identification information (substation, element protected, device number, etc.)
2. Failure date
3. Date relay installed
4. Date relay manufactured
5. Relay manufacturer and model
6. Relay serial number
7. Firmware version
8. Component failed (e.g., power supply, DSP, CPU, communications module, etc.)
9. Did relay trip (misoperate) when failure occurred? Yes or no.
10. How relay failure was identified
    a. Alarm
    b. Inspection
    c. Maintenance
    d. Commissioning
11. Relay manufacturer RMA number for relays returned for repair and failure analysis
12. Description of relay failure (complaint, cause and correction). May be beneficial to have separate fields for each.
13. Additional fields that may be beneficial for NERC reporting would be voltage level and whether the relay failure impacted the BES. Also who was notified (Balancing Authority, Regional Authority, impacted Transmission Operator, etc.)

MTBF = (Total Operating Time) / (Number of Failures)

Mean time between failures (MTBF) is a useful parameter that can be calculated for different relay types by evaluating relay failure data in conjunction with relay asset information for the number of relays installed. This can be broken down by relay class to evaluate relay class performance, or by manufacturer and model to evaluate performance of specific relay types. MTBF is normally calculated for in-service relay failure trends. MTBF can be monitored over time, such as quarterly, to determine positive or negative failure trends.

Relay failures identified during commissioning can be trended to identify quality of relays received out of the box. This may identify manufacturer defects or quality assurance issues. If a negative trend is identified for a particular relay manufacturer or model, then additional relay failure details can be trended to drill down further, such as trending by component failure type or by firmware version or hardware vintage or manufacture date.

The MTBF statistics for a certain type of relay provides a measure of the reliability of a quantity of relays; however this does not provide the owner with an idea of the practical life of a relay. As we have discussed, the MP relay is applied to perform a lot of functions that were at one time separated among different EM relays, auxiliary devices and external wiring. The MP relay is also subject to firmware upgrades and technological obsolescence of internal components. If the practical life of a MP relay is much smaller than an EM relay, even though the MTBF is very long, then the owners need to develop the implementations and replacement strategies around practical life of the relay and the MTBF of the relay. For example, a relay that has a very large MTBF may still need to be replaced much more often than the EM relay because of application, design pressures and equipment or component obsolescence.

Relay failures can be analyzed based on the age of the relays when a failure occurs. This can be useful to determine at what age relay failures start to increase significantly to determine an appropriate and practical relay life. The owner can use this practical life of a MP relay to be proactive and replace relays prior to end of life failure and avoid possible unplanned outages, loss of customers or damaged equipment.

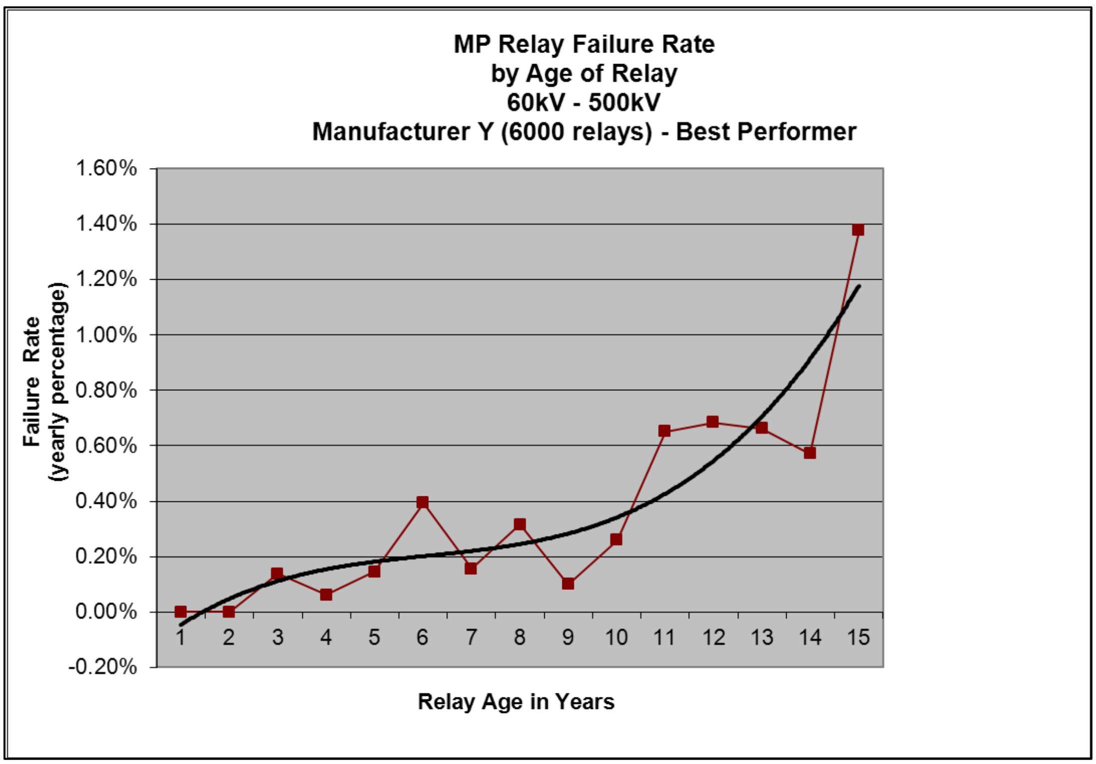

Figure 2 – MP Relay Failure Rate, Example 1

Trending relay failures by age can also show quality issues if an expected trend is not followed. For the relay manufacturer and model trended in Figure 3 below, newer vintage relays of the same type were experiencing much higher failure rates than their older counterparts which had good performance. The utility decided to discontinue purchases of this relay model due to the negative trend of increasing relay failures for relays that were less than 5 years old.

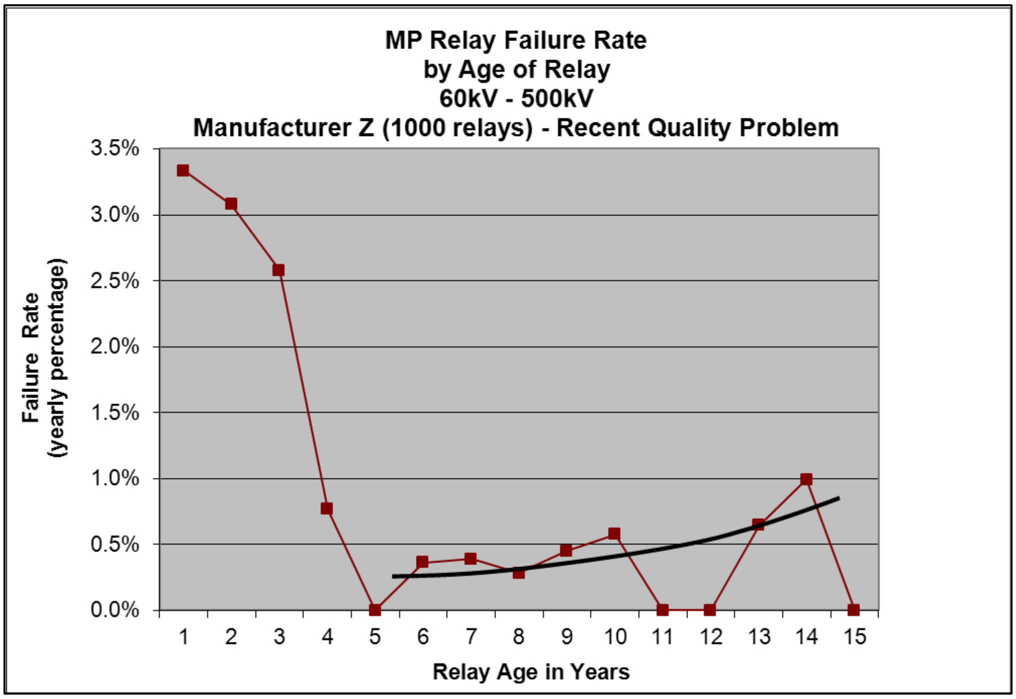

Figure 3 – MP Relay Failure Rate, Example 2

<u>Relay Failures and Misoperations</u>

Relay failure modes that result in misoperation are much more concerning since a customer or path outage may result and reliability can be impacted. Tracking relay failures that result in misoperation and trending those by relay manufacturer and model, is important to identify negative trends and take corrective actions to address performance. Relay misoperation may be unavoidable for some MP relay failure modes, such as analog to digital failure; however for most cases a MP relay should properly disable itself when a failure occurs.

A small number of poor performing relays can have a big impact on reliability, as demonstrated by one utility in the charts in Figure 4. Trending showed that high failure rate relay models and aging relays (those beyond expected service life) caused greater than 50% of the relay failure caused trips (relay failures that resulted in misoperation). High failure rate model relays are less than 2% of this utility's relay fleet but caused 32% of the relay failure caused trips.

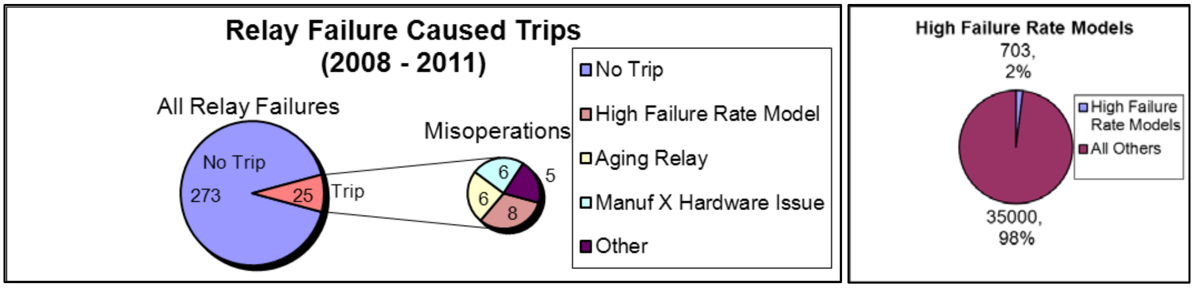

Figure 4 – Relay Failure Caused Trips

Gathering and using performance data is a critical element for managing the relay asset. When used in conjunction with an accurate relay database, risks can be assessed by determining the number of high failure rate models in the relay fleet, where they are located, and the criticality of the element the relay is protecting. This can then be factored into an overall relay replacement strategy.

Along with performance data, following are some additional factors to consider when making repair or/ upgrade versus replace decisions.

Primary Equipment Change Drivers

With EM relay schemes, replacement of the relays was commonly done in conjunction with replacement of the primary equipment. Line relays were replaced concurrently with the circuit breaker and transformer relays with the transformer. The life cycle of the EM relays and primary equipment were compatible for concurrent replacements where expected life cycles could be around 30 to 50 years. Expected life cycles of MP relays cannot be expected to be as long as the primary equipment. MP relay life cycles should not be expected to exceed 20 years. The design of MP relay schemes should facilitate more frequent replacement that can be independent of the primary equipment. One example to facilitate relay replacement for outdoor distribution feeder breakers would be to install MP relays in an enclosure separate from the breaker cabinet.

Physical or Space Limitations

Reduced panel space requirements can be a benefit of moving from EM relay schemes to MP relay schemes. Panel space for EM schemes that required a duplex switchboard (separate relay and control panels) may be able to be consolidated into one relay panel. If utilizing a non-integrated MP relay design with discrete relays (separate line relay set A, set B, breaker failure and reclosing relay), it may be a challenge to fit all components including test switches, control switches and meters on one very full relay panel, but it can be done.

Some relay functions can be consolidated, such as combining the breaker failure and reclosing functions into one device. Consolidating these functions with the line relays, additional panel space can be saved. The most panel space can be saved by applying a fully integrated scheme making use of the protective relays for metering and SCADA control and utilizing relay pushbuttons to eliminate physical control switches.

When deploying fully integrated designs the owner must take into account maintenance and testing and a single MP relay failure and replacement. Fully integrated designs have the most complicated testing requirements. Furthermore, the failure of a MP relay within a fully integrated design should have a similar device available within the life time of the application. Some relays will be designed to a specific hardware or firmware and the new relays only a few years older than the failed relay may not be compatible.

When formulating a relay replacement strategy a balanced approach may be best when determining how much integration should be done and how many functions should be consolidated into one device. Discrete relay design is generally more flexible and can be easily applied to different bus configurations. Discrete relay design is also more plug and play for relay replacement and facilitates a 1 for 1 relay replacement capability.

State of Old Wiring

The state of old wiring should be taken into account when considering a one for one relay replacement or upgrade, versus replacement of the entire relay panel, or replacement of the entire control building if utilizing a drop in place control building replacement strategy. The state of outdoor wiring and conduits may also be a determining factor for a drop in place control building since new conduits or cable trenching and associated wiring may be part of a drop in place control building strategy.

Nonstandard Substations

EM relay designs and discrete MP relay design (separate MP relays for basic protective functions) are flexible and can be easily applied to different bus configuration or to non-standard substations. Integrated MP relay schemes with complex relay logic tend to be bus configuration specific, where separate design standards are applied based on the bus configuration and separate relay logic templates are applied with corresponding site acceptance test (SAT) procedures. To manage the complex integrated relay schemes requires standardization and this usually results in a rigid design that cannot be easily applied to non-standard configurations.

The owner needs to evaluate the upgrade and replacement strategies to find the correct balance of integration based on testing complexity and relay failure and replacement options.

> ***Integration or Conventional Design***
> *The relay design strategy must provide a fast and efficient method of relay replacements that does not jeopardize the protection or create traps for field personnel or unnecessary risk to system operation. Complicated designs that are difficult to set, track, and test should be avoided. Each design should take into account that a relay may not be available in the near future. The owner must also understand the risks of including leading edge technologies within the design. A best practices design facilitates easy setting and programming, testing, maintaining, replacement and longevity.*

Replacement of troublesome relays can be difficult to implement in a relay replacement program if attempting to replace the whole panel. The relays may be spread across many substations and if the replacement work cannot be combined with other capital work at the substation it may be difficult to get scarce resources to do the engineering and construction. One option is to do a one for one relay replacement, which can be easily implemented in the field. This mitigates the risk and allows delaying installation of the whole panel, or building. If a MP relay panel is designed for a sustainable relay asset management strategy, it will facilitate easy one for one relay change outs.

Repair of Troublesome Relays

Repair of troublesome relays can be difficult to implement due to scarce relay technician resources. The recommendation to repair a relay is usually the result of a manufacturer service advisory or bulletin identifying a faulty component or vulnerability in the relay that could either lead to accelerated failure or unintended operation. The risk of not doing the repair or deferring the repair must be assessed and weighed against other relay replacement priorities. One compromise may be to defer the repair until the next scheduled relay maintenance is to occur.

EM versus SS

SS relays may be difficult to sustain unless you have specialized technicians or you have experience of recent stable performance. It may not be good to sustain SS relays unless your experience shows that you know how to succeed. Some older SS relay systems may be fragile, such as old phase comparison systems, and the act of performing maintenance itself may cause failures and spare parts may not be available. For this reason one large utility moved to performing end-to-end testing on the SS phase comparison systems as the routine maintenance, instead of attempting to calibrate the relays.

Other Sustainment Activities

When making sustainment decisions and actions multiple factors must be considered when deciding whether to replace or upgrade a relay as outlined above. Performance monitoring is a key factor. Also, to provide the most flexibility for doing a relay replacement, the relay scheme design should facilitate easy one for one relay replacements. A flexible design should be a key component in a sustainable relay replacement program, since relay lifecycle replacement times will continue to get shorter.

New P&C Design Standards, Buildings, and Panels

Prior sections have talked about the evolution of relays and protection system components, and the criteria or methods for sustaining serviceable protection systems versus deciding to replace them. This section offers guidance on principles to apply when designing new installations around the relays that are available today. These methods are all aimed at controlled flexibility in an era of rapid change.

Design Standards

A core principle, applied by many utilities for decades, is to create a series of standard design packages for transmission lines at different voltage or application levels, as well as other protection zone types and repetitive applications. If this seems like obvious advice, the authors report that they find a surprising number of unique custom installations, even within one utility. There are other users who have elevated strict standardization to an inviolate core principle. That adherence to standards achieves these benefits:

- Technician efficiency and reduced human error. One utility uses the same transmission line design for all lines from subtransmission to 500 kV backbone transmission, including identical System A and System B designs where redundancy is installed. Having started years ago with a long term focus on this standardization, that utility has deployed standard panels across the system. A technician entering a station anywhere knows exactly what she or he is facing. Any required access or work is performed quickly. Errors are infrequent. Troubleshooting is more effective than for technicians facing a variety of unique installations.

- Efficient construction and installation with minimum time and errors.
- Reduced engineering time and effort for new or renewal projects.
- Clear focus of data and results in asset and maintenance management processes.
- Easier configuration management (settings and functions).
- Much easier introduction of condition-based and performance based maintenance strategies as allowed in the new NERC Protection System maintenance standard PRC-005-2 [3]. The design standard becomes the major component of the documentation for the condition monitoring design, eliminating vast effort for time-based system component testing, as well as the documentation and record keeping for all of the avoided testing.

> ***Regulatory Standards***
> *Owners will need to keep one eye on regulatory standards…A good plan is always more effective and efficient than reacting just in time.*

- Easier and less constrained strategic decisions regarding successive changes or advances of the standard.
- Easy stocking, and rapid configuration and installation of spares to replace failed field units.
- Reduced time and errors in ordering equipment from manufacturers.

Some features of an effective set of standard designs are:

- *Predefined, specific, limited standard options to handle different field situations.* Not all protection zones are the same, but the bulk of applications for a particular zone type generally fall into a small number of categories known to the experienced protection system designers at a utility. Clearly coded optional features to handle these will keep the different stations and installations under full control of standards.
- *Acceptance of the higher cost of standard relay types with extra capability.* The authors recommend focusing strongly on choosing a single capable relay or component type and using it in every application where it can fit. There are some users who look at individual specific applications, and select the specific product that does the job at the lowest cost. However, saving even thousands of dollars on a scaled-down relay type in an installation project worth tens or hundreds of thousands of dollars is a benefit that is easily swamped by the extra human effort and organizational focus the uniquely selected product will demand over the years of its service life.
- *Periodic review of emerging products and technologies* – with the goal of introducing evolutionary changes to the standards in groups at specific revision times. Investigate interesting new offerings from manufacturers on a regular basis. Collect new choices and selections (that are not urgent corrections of field problems) over time and introduce all changes in a single standard revision. Typical updating intervals are two to four years. The updating interval need not always be the same, but overly frequent revision of standards will lead to many design generations in service, confronting field personnel with more variations and adding to risk.
- *Engineering peer review process* - for any exceptions or modifications to standards during their intervals of use.

- *Firmware and hardware control* - include firmware and hardware versions of MP products in the standard documents, and accepting revisions only as clearly required or forced by application or external circumstances. Apply the peer review process above and the testing validation procedures applied below before making changes.
- *Setting templates* - of the thousands of settings in an MP relay or product, the majority can be locked down in a template or a list of templates to align with standard options. The template will include configuration and system logic that are defined as part of the standard design - it becomes a version controlled standard document along with all the drawings and specifications. Some users have employed tools that make it easy to identify and apply the application-specific settings (such as distance zone reaches and overcurrent settings for a transmission line relay) for a particular job without risk of corrupting the template settings. This reduces the risk associated with the huge number of settings in contemporary MP relays.
- *Standard design laboratory* – when developing a new standard, create a laboratory system for testing of products, designs, and settings. Focus during project planning on allocating budget for laboratory facilities, equipment, and generous space. When the standard is finalized, lock down and control the configuration of the laboratory facility in full conformance with the standard. The lab then performs critical functions in support of the standard field installations:
  - Safe test bed for urgent corrections to firmware, hardware, or settings.
  - Facility for replication and analysis of misoperations and field problems.
  - Facility for training of engineers and technicians.
  - Starting point for trial of new components and designs aimed at the next generation standard (with care to restore standard configuration after contained trials, or otherwise to start a new design validation panel).
- *Repository for experience and feedback* – provide a publicized record location where engineers, technicians, power apparatus technical experts, asset managers, and other stakeholders can record complaints, issues, experiences, and suggestions for improvement of the next standard generation. When the revision takes place, all the experience with the last generation is available in one place and solutions are checked off.

P&C Buildings and Wiring - Drop-in Control Buildings

In recent decades, many utilities have adopted the practice of having a vendor build new P&C panels inside a prefabricated building which is then shipped to the substation and dropped onto a new foundation as shown in Figure 5. Racks of terminal blocks in the building provide the demarcation point for connection of switchyard wiring. In most legacy substation installations, new switchyard wiring is installed at the same time – rerouting and reusing old wiring can be a liability and a logistical problem.

A new drop-in building can have these advantages:

1. A standard building fits ideally into an overall strategy of standardized design as described in the last section. It can be a familiar standard in itself, supporting all the other goals of tight standardization we listed above. Variations of panel installation to suit old buildings require more options and variations in the P&C standards.

2. Cutover from old to new P&C may be easier – the old systems may be left in place and in service through much of the new installation work. There are no position juggling challenges as individual old panels are cut over to temporary panels while the new equipment is installed in the old location.
3. The new building can be ordered with enough space to handle all the P&C panels in a legacy station that has expanded over its history until the original building is overcrowded.
4. The layout can be optimized for easy maintenance and modern design. For example, an EHV P&C building can be configured with separated, walled, ventilated rooms for System A and System B batteries – redundant station battery banks have become far more popular only in recent years.
5. A factory-produced and wired drop-in building can bring high quality and consistency of construction along with lower cost, as compared to field installation in an existing building. This is even truer if the P&C system itself is highly standardized as discussed in the last subsection.

These benefits suggest criteria for use of these buildings:

1. When the existing building is already crowded and has no room for cutover maneuvers.
2. When the existing switchyard wiring is aged and is to be replaced with the P&C systems.
3. When the switchyard has enough room for installation of a new building, so that the old building can be abandoned or committed to a different use afterwards.
4. When most or the entire P&C infrastructure are to be replaced at once. This may be the case if new standard designs are being deployed across the system.

Figure 5 - Drop-in Control Building

Note the iterative interaction of the new building/wholesale replacement decision with decisions about the remaining service lives of specific P&C components. If many of these components need replacement, they support the business case for changing the entire building. Conversely, once the case has been made for installing the building, it drives replacement of components that might otherwise have carried on for some time with triage support.

Once installed, the new building will outlast its contents – modern relays inside will become obsolete and need replacement with new standard designs. While drop-in buildings are cost effective in comparison to new on-site building construction, it doesn't follow that the whole building is replaced when the P&C

systems inside are due for replacement. If the panel design recommendations of the next section are applied to the P&C systems in the building as delivered, it becomes far easier to replace and renew those systems within a drop-in building that will remain serviceable for many decades.

Reuse of Old Buildings

New drop-in buildings are not always the best answer – consider whether the existing P&C building is suitable for reuse. Factors in favor of reuse include:

1. Good condition of the existing building. This may include a preservationist perspective on historic architecture.
2. Adequate space for installation of new panels as the old ones are decommissioned and removed.
3. Switchyard wiring recently replaced, or in known good condition with long additional service life available.
4. Existing building design for easy replacement of switchyard and building wiring.
5. Congested substation site with no room for dropping in a new building, or difficult access for bringing an entire preassembled building to the site.

Figure 6 – Spacious former center aisle in P&C building.

Figure 6 shows the interior of a large legacy control building at a 500 kV transmission substation – with generous unused floor space between the old panels. Preexisting SS and early generation MP relay panels are not visible in this photo, standing in large open spaces *behind* the visible panels. Switchyard wiring enters a massive and mostly empty basement space beneath the floor of the Figure 6 P&C area as shown in Figure 7; rerouting of switchyard connections to different locations on the floor above is straightforward. Investigation for a P&C standard panel replacement project showed that the existing switchyard wiring had been replaced about 12 years before that time and was in excellent condition. Accordingly, replacement panels are installed in empty spaces of the existing building P&C floor, with new connections easily made through the floor, for an economical replacement process. This example contrasts with typical 115 kV and 230 kV P&C replacements at this utility, which are normally carried out with standard drop-in buildings.

Figure 7 – Newer switchyard wiring enters via the basement of control building.

Process Bus in Place of Switchyard Wiring

The North American industry is watching the emergence of process bus technology, with which switchyard voltage, current, and status signals are conveyed to the control building as multiplexed data on a few optical fibers in lieu of hundreds of large shielded copper cables [4]. Electronic packages known as merging units are installed at strategic switchyard locations, generally near breakers and instrument transformers, to interface the fiber signals with the primary power apparatus. Fibers also convey control signals back to the switchyard merging units for tripping and control of breakers and other apparatus. Data communications and application modeling standards for process bus include IEC 61850-9-2 sampled values service; multivendor implementation agreement 61850-9-2 Lite Edition (LE); commercial product design open-source documents using IEC 61850 sampled values streaming and 61850-8-2 GOOSE messaging; and most recently, the new IEC 61869-9 merging unit standard that brings a more rigidly standardized and interoperable design.

When a user is able to qualify merging unit and process bus products that meet its requirements, and incorporates these into its design standards, the use of drop-in buildings becomes considerably easier than it is today. The wiring replacement portion of the installation work may be reduced by 60% or more.

For reuse of an existing building, a process bus solution can support an incremental approach to replacement. To maintain standard designs, the merging units can be used even when wiring is not replaced right away. They can be installed in the building and connected to incoming wiring in such a way that they simplify the rerouting of wires in the building. When wires are to be replaced, new merging units can be installed in the switchyard and their fiber connections brought back to the relay panels as the existing P&C remains in service. Then, cutover requires just moving a few optical fibers and reconnecting devices in the switchyard, a zone at a time. The control house merging units can then be removed and reused in other substations.

Merging units will also be useful for interfacing new P&C installations to existing legacy panels without the need for numerous cross-connections – place merging units as needed in the old panels and make the connections with a few optical fibers.

Designing Standard Panels - Evolution of Panel Design

P&C panel designs have evolved to align with the service characteristics of the relays mounted on them. For much of the 20th Century, electromechanical (EM) relays were installed on expansive and robust panels capable of virtually unlimited service lives as shown in Figure 8. Large numbers of discrete relays and components, each performing only a single function or at most a few functions, required masses of interconnection wiring. Replacement in kind of individual EM relays was facilitated by drawout case design.

Figure 8 - Typical EM Relay Panels

Figure 9 - Typical SS Relay Panels

Relay applications did not change significantly when analog solid state (SS) relays were introduced, but 19-inch rack based panel installations were introduced as shown in Figure 9. Robust custom wiring practices were carried forward from the EM relay era – the panel wiring was customized to the terminals and positioning of the selected relays. Later generation SS relays incorporated an array of functions for a zone of protection in one rack-mounted unit, as compared to one or two functions in an EM relay draw out case; this resulted in wiring and layouts that were even more specific to the selected relay types than was the case for EM relay panels. The SS relays had power supplies and electronics that introduced new failure modes and required more frequent module or rack replacement. The industry learned that, on average, the service life of these SS relays was much shorter than that of EM relays. Rack mounting supported easier unit replacement, but changing to a different type of protective relaying unit required a lot of rewiring work.

Figure 10 - Typical MP Relay Panels

As MP relays were introduced, they were typically installed in racks in the fashion of SS relays as shown in Figure 10, with similar wiring practices. These relays include many or all functions for a zone of protection in one unit, saving even more panel space, and most of the interconnecting wiring has gone away. Changing individual functional units was easy with EM relay panels, even while the other functions remained in service, but this is no longer an option with MP relays. The field wiring and relay-to-relay wiring that remains is still custom fitted to the relays as arranged on the panel in most cases, and an outage is needed to replace either a relay or a complete panel.

New Standard Panel Design Principles

There is nothing fundamentally wrong with the industry's highly evolved practices of rack-mounting new multifunctional MP relays and interfacing to external wiring via terminal blocks on the panels. However, a few specific arrangements driven by today's requirements can make the asset maintenance and replacement tasks easier in the future.

The authors propose the following key issues to address when designing a new panel:

1. Assume that the relay will have a short service life, and must be easy to replace after fewer years than has been the case until now.
2. Arrange the panel so that it is possible to replace the functional protection units required for a zone as a single physical assembly.
3. Arrange and separate the zone assemblies with buffer spaces and barriers so that each can be worked on with no risk to others in service.
4. Arrange wiring, fiber, and communications connections along one side for easy replacement and reconnection of the entire functional assembly.
5. Include the physical and electrical facilities required to perform safe and low-risk removal and replacement or a functional assembly *without an outage of the primary zone*. Outages are difficult to get today, especially on bulk transmission systems in high load seasons, and may become impossible to get in the future.
6. Redundant systems for a single zone are treated as separate functional assemblies, each of which can be worked on or replaced while the other remains in service.
7. Functional assemblies and their connections have distinctive, concise, clear standard marking and coding schemes that are vetted with field personnel and then strictly enforced.

Figure 11 shows a *concept* for design of four redundant protection panels for a very critical transmission line (this concept sketch does not show actual physical appearance or equipment). While such an application is not common, the same principles can be applied with dual or triple redundant installations, which are common; and the listed approaches can be used even where redundancy is not employed.

In this case, there are two line current differential systems operating on digital channels and two directional comparison schemes, one using power line carrier and one using POTT over a data channel interface. Redundant transfer trip capability is integrated with relay communications. Features of this panel design approach are as follows:

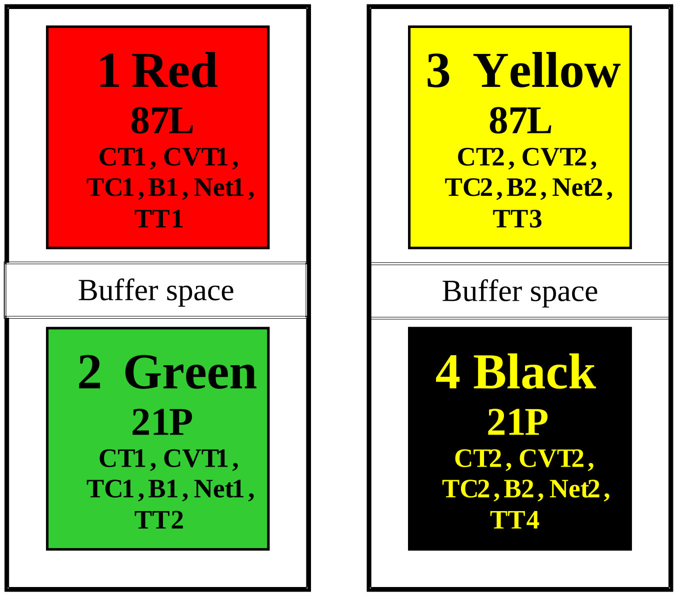

Figure 11 – Line Protection Panel Design Approach

1. The MP relays, associated communications sets, test switches, and other components for each protection system are mechanically tied together and treated as a unit that occupies less than half of a standard 84-inch or 90-inch high relay rack.
2. There are four number and color based codes in a scheme to clearly distinguish each of the four subsystems in any human interaction, and to assure correct associations between line ends. The physical panels are not actually painted solid colors as the concept sketch shows (although nothing would prevent this except outrageous appearance). However, the number and color associations are clearly shown on each panel section and in all labeling and wire/cable marking, both front and back.
3. Panel wiring in grouped bundles goes to separate rows of grouped terminations on the racks with a standardized layout, all designed for safe live replacement of a complete protection system panel unit without an outage. Trip circuit isolation, CT circuit shorting, and safe live disconnection of ac and dc voltages are all supported, duplicating functionality provided by the test switches on the panel assembly that are provided for normal field maintenance – dc terminal blocks, current-shorting CT and blocks, and communications connections.
4. It is possible to insert a physical buffer, such as a fiberglass panel, between the upper and lower systems in the rear of the panel, and to isolate the panel not subject to maintenance work, so that either panel can be worked on with no danger of contacting the redundant companion system above or below that may be in service. This eliminates major causes of human error misoperations and technician electrocutions. In one author's experience, dropped hand tools cause a surprising number of false trips.

With these features, a complete line protection system can be replaced safely and without error on a live transmission line. This replacement may be in kind to handle a failure, or may be a new standard design installed as part of an asset sustainment program.

The authors recognize that technology innovations will render the standardized system interface as imperfect over time. For example, new types of data communications media and new integration connections will call for changes on both sides of the interface - leave extra space for cutover of new interfaces if possible. When process bus solutions arrive, much of the interface will be reconfigured. But in all cases, this arrangement makes maintenance and generational standard updating as easy as it can be.

Asset and Fleet Management Strategies

Strategies Should Include

- *Asset Management Database – including 5 Year replacement Plans and Asset Prioritization*
- *Setting Configuration Management*
- *Protection System Maintenance Program*
- *Training and Tools*
- *Misoperation Tracking*

The following sections present analyses and advice to help in addressing these topics.

Asset Management Database

The foundation to a sound asset management strategy is a comprehensive and accurate asset database. A large utility can have tens of thousands of relays on its system and having an accurate inventory of protection assets is essential to developing a sustainable asset strategy. The following is a more detailed list of data that should be stored in the asset database for a single relay:

- Make
- Model
- Serial number (not applicable for electromechanical relays)
- Firmware version (not applicable for electromechanical relays)
- Basic relay range
- Installation date
- Substation that the relay is located
- Element that it is protecting
- Scheme identifier

With this information entered in the database for every relay, reports can be run to identify families of relays and where they are located. This can be particularly useful for manufacturer bulletins regarding firmware upgrades for example.

Keeping defect records for protection assets can also be very useful for comparison with other devices. If a particular failure is being noticed on a relay it can be compared to the number of that relay type on the system, to ascertain if there is an upward trend that could be of concern. For example two failures in a population of thousands would not be of concern but if an upward trend is seen over time, then action can be taken to manage the failures and replace the relays over a planned period rather than be caught with a large population failing at a high rate. A predictive strategy is more efficient and effective than a reactive strategy.

Predicting a protection asset life can be difficult due to a number of factors. These include the failure rate, obsolescence, operating system obsolescence, utility and manufacturer knowledge, required functions of new protection asset generations, and general substation condition. The age of a protection asset alone is usually not justification to replace them. It is a combination of these factors against a prioritization criteria that will be the most cost effective approach balanced against maintaining reliability.

As discussed in previous sections, electromechanical relays have proved themselves to be very reliable and to have extremely long life. It is other factors like the loss of institutional knowledge and the need to apply functionality of microprocessor relays that can drive their replacement. For example, if load encroachment is needed on a distance scheme to comply with the NERC Loadability Standard PRC-023, that is not available on an electromechanical relay, then this need will drive its replacement.

Solid State relays are a good example of failure rates increasing and driving replacements. Electronic components are known to degrade over time and cause drifting of measuring circuits; this in turn causes the relay to go out of calibration and increases the risk of misoperation. Eventually components fail and cause unpredictable actions by the relays, either failing to operate or misoperating.

Microprocessor relays will have different factors driving their replacement, apart from failure rate which is common to all three types. Factors such as component availability effecting obsolescence and operating system obsolescence have a large influence.

With any asset replacement program there needs to be prioritization of which assets are to be replaced first, in order to match the funding available to invest. For many utilities there is a need to prioritize replacing assets based on risk. If an asset is in imminent danger of failing and the consequences of the failure have a large impact on system reliability then it will get a high priority for replacement, compared to an asset that has a lower risk of failure and a smaller impact on system reliability. There is a problem with this approach relative to protection assets because the single failure of a protection relay does not necessarily have a big impact on system reliability, especially at the transmission level compared to a large transformer for example. There may be a need to strategically assign a portion of available funds to protection asset replacement in order to ensure that some replacement gets done.

Prioritization scoring mechanisms based on risk are commonly applied to replacement needs; they can be applied to identify which protection assets need to be replaced first. Factors that can be used in a scoring mechanism are:

- Impact on system reliability – where is it used, and what is the potential impact of a misoperation?
- Frequency of failure compared to asset family population
- Manufacturers' and/or industry recommendations
- Compliance
- Safety
- Other replacements being carried out at a substation

The following is a chart that can be used to rank protection schemes (Relay Replacement Prioritization Chart). Each protection scheme can be scored based on the characteristics in the chart with the higher the score the more likely that a relay scheme should be replaced. Various categories could carry a weighting factor based on an individual owner's priorities.

Rating 1-5	Age in years (A)	Protection Gap (G)	Product Performance (P)	Design/Maintenance Prob. (M)
1	• EM < 10 • MP or SS < 5	• None	• None	• None
2	• EM 10 to < 20 • MP or SS 5 to < 10	• Lack of Operational Flexibility	• Lack of desired features • Lack of optimal functions and settings	• Lack of maintenance flexibility • Obsolete Design
3	• EM 20 to < 30 • MP or SS 10 to < 15	• Possible over Trip no loss of customers. • Compliance issue for emerging standards	• History of failures with no loss of customers • No longer meets company standards • MF does not support but no problems	• Restoration Problems • Consistently out of tolerance • No long meets company standard
4	• EM 30 to < 40 • MP or SS 15 to < 20	• Over trip with loss of customers for N-2 • Under trip for N-2 • Possible Compliance violation	• History of failures with loss of customers for N-2 • Not compatible with company equipment	• Cannot be tested without isolating element. • MF does not support this product • Unique skills are needed for testing
5	• EM > 40 • MP or SS > 20	• Over trip with loss of customers for N-1 • Under trip for N-1 • Compliance violation	• History of failures with loss of customers • Not compatible with company equipment • MF does not support but significant problems	• Cannot be tested without dropping customers. • MF has recall on this product • Skills are no longer available • Limited spares
SCORE = A * G * P *M				

Figure 12 – Relay Replacement Prioritization Chart

The Impact of **Age** on Replacement Strategies

The age of a relay does not necessarily mean that it must be replaced. There are two ways to approach replacement strategies associated with age: reactive - wait until the relay fails, or proactive - replace the relay as close to its end of life as possible while managing the risks. Of course the proactive process is more efficient and effective and less impacting on customers. But the proactive process requires some detailed analysis and discussions with manufacturers. For example, if we assume that an EM relay will last 40 years and a MP relay will last 20 years, we could develop a replacement strategy around these parameters. As a relay gets older it moves up in the priority list for replacement.

The practitioner will need to examine existing installations of relays and document the age of the relays. If the manufacturer has stopped supporting the relays, even though they are still providing good performance, the owner will need to decide if the amount of available spares and risk of failure is acceptable. Clearly, replacement strategies focusing on age are not as critical and provide some flexibility on a multi-year relay replacement plan. Funds designated for this purpose could be diverted to cover other replacement criteria or emergencies as necessary.

The owner can weigh the age of EM, SS or MP relays in such a way that as a relay gets older the replacement priority gets larger.

The Impact of **Protection Gaps** on Replacement Strategies

The owner must also take into account the protection gaps associated with relay application design and implementation. These gaps could manifest as lack of security and cause a relay to be too sensitive to some disturbances and over trip. The gaps could be more severe and leave an element only partially or not protected (i.e. lack of end of line protection). The latter situation is a dependability gap with the relay.

Compliance issues could also be a gap with the relay such that the relay application does not meet a particular compliance or regulatory requirement. For example, the relay cannot be set above facility ratings and therefore will trip on normal or emergency load. The owner must risk a compliance violation unless the relay and/or scheme are replaced.

The owner can weigh the protection gap based on severity of consequences and risk.

The Impact of **Performance** on Replacement Strategies

Performance problems can be associated with lack of features, failure rates, obsolete firmware/software, lack of manufacturer support, and compatibility with other products. The owner must also take into account the performance of each model and application and rank the performance based on the business need, and be willing to make changes to approved products and/or standard designs. For example, a certain model of relay may not have fault location or remote accessibility and therefore would be a candidate for upgrade or replacement.

The frequency of failures of relays is another performance issue and the owner will need be able to keep track of these failure rates. Obsolete firmware/software will force the owner to discontinue using the relay if the owner does not keep older tools and computers to access the older relays (i.e. DOS based or Windows base etc.). Relays that are no longer supported by the manufacturer may require owners to keep spares or replace the relay to reduce impact. Typically performance problems require medium or long term solutions even though a more severe problem might cause immediate changes.

The owner can weigh the performance based on severity of consequences and risk.

The Impact of **Design/Maintenance** on Replacement Strategies

The ability to maintain a relay scheme is another factor to consider in the replacement strategy. Older schemes may not meet current company standards and require special or outdated equipment to test and maintain. These older schemes may require frequent preventative or even corrective maintenance. This could stress resources or divert resources from other tasks. Schemes that no longer conform to current standards may require the owner stock adequate spares. However, if the older relays do not facilitate maintenance or cause nuisance trips then they may be candidate for replacement.

The owner can weigh the ease of maintenance and rank each relay and scheme.

The assessment of asset life and replacement prioritization both go into making up the business case for replacing a protection asset. Strategic decisions may also need to be made in order to secure funding if comparisons are being made with other assets in a prioritizing process. A number of scenarios should be analyzed as options including “Do Nothing” and recommendations made on the best option to proceed with.

Settings and Configuration Management

Managing relay settings has become a major issue in the industry today. With the emergence of microprocessor relays in favor of electro-mechanical relays, the number of settings in an individual relay has gone from the tens into the thousands. With this number of settings in a relay the probability of making an inadvertent setting error is high. Even if the settings are not being used they can still be erroneously set while enabling other functions.

In Order to manage the risk of erroneous settings the entire lifetime of a relay needs to be taken into account. There are a number of instances that trigger a relay setting change [5] that includes:

- Planned replacement
- Failure of a relay
- Transmission line reconductoring
- Neighboring utility changes
- New interconnections
- Externally mandated changes.

> ***Relay Settings***
> *MP relays have hundreds if not thousands of relay settings. Tracking these settings can be a daunting task for all owners but especially for those owners that have more than 10,000 MP relays.*

In order to manage these changes and reduce the risk of human errors, a robust process is needed. This should include a review of all internal and external standards before engineering work begins, creating setting and test data, peer reviews, traceable methods for issuing settings to the field, loading settings into a relay, commissioning tests and to close the loop on the process a method for downloading the commissioned settings and return them to the engineer for verification to assure they are the same as what was issued to the field.

A management process should also be put in place for storing setting files. There are a number of methods being used in the industry [6] including using database tools, workflow and server storage libraries. Whichever method is chosen the following attributes should be included:

- A file naming convention linking the electronic setting file to the relay
- Provisions for electromechanical relay settings
- Audit trail capabilities for compliance requirements where applicable
- Access during maintenance to compare test results and investigate trends
- Measures to ensure the security of the data and access to it

Protection System Maintenance Programs

Relay testing requirements should also be considered when migrating from electromechanical or solid state relays to microprocessor based relay schemes. The impact on the testing resources may not be significant if a MP relay is applied in a very simplistic manner, similar in design and function to EM and SS relay schemes. However, if a MP relay scheme is implemented in a highly integrated fashion with complex relay logic, then there will be a big impact to the testing resources and processes and procedures. Following are some issues to consider:

> ***NERC Standard PRC-005***
> *Transmission Owners in North America are required to comply with the maintenance standard PRC-005. This is one of the more violated regulatory standards.*

Time to test

- EM and simple MP relay schemes take roughly the same amount of time to test. A simple MP relay scheme may only have protective elements feeding into simple trip logic as one example. These schemes are easy to understand and test.
- Complex MP (integrated) relay schemes take significantly longer to commission test. One large utility estimates at least double on labor. This is after the site acceptance test (SAT) documents have been developed, including steps to prove all protection and control logic. Complex MP schemes are much more time intensive when testing due to need to review settings, logic diagrams, relay job aids, and follow detailed test procedure (SAT) document. Complex logic typically is not 100% correct and requires trouble shooting logic during commissioning.

Maintenance

- EM schemes are more maintenance intensive. They require more frequent maintenance intervals than MP relays due to the need to calibrate to keep the relay within acceptable tolerances and that EM relays fail silently.
- Simple MP relay – There is no need to calibrate a MP relay and therefore traditional maintenance of the relay (similar to EM relay) is not needed. However, the owner can take advantage of relay self-diagnostics and alarming to extend maintenance intervals.
- Complex MP relay schemes - Time to test may not be any more than simple MP scheme depending on the maintenance approach taken. Relay settings comparison can be done to prove the logic is the same as originally commissioned. If logic is reproved with SAT document, then maintenance will be much more labor intensive, possibly more than double with an increased risk of unintended outages due to human error factors.

Isolation Concerns During Testing

EM – EM relays generally contained isolation with the case. The relays were simple and the knowledge and experience is mature.

MP – Complex integrated

- It is difficult to know if relay is totally isolated. There is a lack of visual isolation points for relay to relay communicated digital I/O points (e.g. IEC-61850, or direct fiber). There may be logic in the relay that could affect other relays that may be overlooked.
- Unknowns with digital points
- Design errors and programming errors are easier to pick up on hard wired EM or simple MP relay schemes.
- Replacement of failed devices is much more difficult and time consuming with increased risk of unintended outages (for both simple and complex MP relay schemes)

Testing Methodology and Expertise

EM and simple MP schemes

- Technicians understand the basic concepts of the protective scheme and what tests are required to prove the scheme functionality.
- Do not require a step by step instruction.

MP – Complex integrated

- Detailed test (SAT) document is required to prove complex relay logic. Relay test processes have to be modified to functionally test complex relay logic. The amount of settings and logic applied in some integrated microprocessor relay schemes is just too large to rely on the relay settings being perfect as issued by the protection engineer. Setting files for complex relay settings also require special attention for setting change management as mentioned in the previous section.
- Testing expertise may be sacrificed due to development of detailed test procedures. The technicians may not understand the procedures and are just executing the steps. Technicians may lose expertise on the relay schemes due to the requirement to follow the detailed SAT test procedure to prove each logic piece. The cookie cutter approach does not facilitate understanding of the scheme and logic. Use of SAT's may flatten the much higher learning curve for the technician, which sounds good on the surface but can lead to loss of scheme knowledge. The burden that was once shared between the protection engineer and the relay technician will be shifted to the protection engineer to get the test procedure perfect. The last line of defense (the knowledgeable technician) should be maintained.
- There may be a need to continually update the test documents, even for minor logic changes, since the technician may not have the scheme knowledge to fill in the gaps.

Other

- Commissioning - Commissioning of MP relays is much different than EM relays and takes much more time and detailed documentation. The skill sets and experience needed to commission a complex integrated MP application may not be available on staff.
- Data Retrieval - Access to MP relays is becoming more difficult with CIP security requirements, even the local connection to the relays. What used to be a major advantage of being able to remotely access a relay may be negated by CIP requirements?

Training and Tools

Just as important as addressing the processes and procedures, the employees must have the skill sets to manage the relay schemes through their life cycle. Complex relay schemes require a higher technical competency and skill diversity for those individuals (engineers and technicians) that deal with them. This is especially true when it comes to trouble shooting the relay logic when things don't work, which can be common during commissioning exercises complex relay schemes. For a sustainable relay life cycle program, it is recommended to design the relay schemes for a journey level skill set for the employees that design, set and test them.

The merging of protection and automation functions into a single relay requires addressing the roles and responsibilities of the protection engineer and automation engineer if these are separate job functions. This is especially important regarding the relay settings responsibility and relay settings management. The choice of whether to merge automation and protection functions into a single relay needs to be weighed to see if the benefits outweigh the additional complexity introduced in the relay logic and also procedurally.

Additional tools are necessary to manage complex multifunctional relay schemes. For electromechanical relays, the scheme functionality could be deduced from the schematic diagrams. This is no longer the case with integrated microprocessor relay designs where the relay has become a black box, performing multiple protection, automation and control functions. Additionally, information shared between relays that used to be hard wired can now be shared through relay to relay communication, either with a direct digital connection from relay to relay or through network Ethernet communications such as IEC-61850. To fully understand an integrated microprocessor relay scheme requires an understanding of the relay logic. The easiest way to accomplish this is with a relay logic diagram. A relay logic diagram drawing should be a standard element for complex multifunctional relay scheme design.

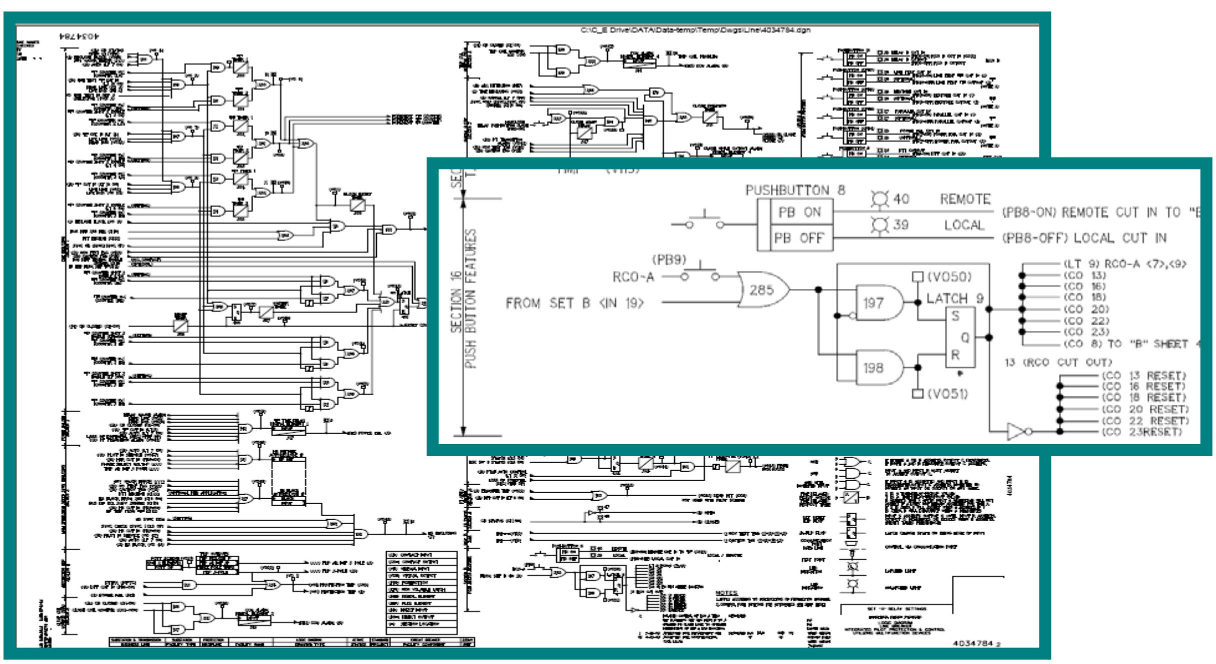

Figure 13 – Relay Logic Diagram

Additional reference tools may be necessary that provide an overview of the applied relay functions for reference by the protection engineer, relay technician or automation/SCADA engineer, such as excel templates that list the assigned function for various relay logic elements, virtual I/O, SCADA points, etc. Some relay manufacturers offer relay software that can assist with configuring relay to relay IEC-61850 settings and provide a relay to relay configuration summary. Diagnostic software for trouble shooting relay logic is also available from some relay manufacturers.

Location:				**Substation: Design Standard**	**Bay: Line Distance CB, Double Bus**	
Scheme Type Code:				**XYZ - Set "B"**		
Relay Type Code:				**SEL-311C, 0311 C01H2425421**		
Relay Name:				**CB xxx**		
Direct I/O Device No:				**SEL 2505**		
				Relay Configuration		
Remote Bit #		***ID (12 characters)***	***LD#***	***Function Description***	***Source***	***SelfReset Latched***
1	**RB1**			MANUAL		
2	**RB2**			AUTO		
3	**RB3**			RCO B Cut-out		
4	**RB4**			RCO B Cut-In		
5	**RB5**			DTT C/O to A (CXR C/O TO A)		
6	**RB6**			DTT C/I to A (CXR C/I TO A)		
7	**RB7**					
8	**RB8**					
9	**RB9**			SPARE		
10	**RB10**			HS RECLOSE CUTOUT		
11	**RB11**			HS RECLOSE CUTIN		
12	**RB12**			SETTING GROUP CHANGE TO A		
13	**RB13**			RCO A C/O to A (out 210)		
14	**RB14**			RCO A C/I to A		
15	**RB15**					
16	**RB16**					
	OC			SCADA OPEN		
	CC			SCADA CLOSE		

Figure 14 – Relay Excel Template for SCADA Control Points

Tracking Misoperations

Misoperations of protection systems can lead to loss of customers, equipment damage, and injury to people. The asset owner needs to track performance of the protection systems and the actions of the people that provide oversight of these systems. Human errors and equipment failures will occur and the owner will need to triage the events to determine root cause of the outages. The owner can use this data to make changes in procedures and processes, tools and skills, or design and equipment. This data could be the catalyst to change to another relay or a simpler design. For example if a particular device is failing more frequently than other devices it could be prioritized for replacement at critical facilities and elements or discontinued all together. Similarly, if technicians are having difficulty testing, commissioning and programming relays then a simpler design or a simpler application could be deployed.

The data gathered concerning operations and misoperations will help the owner determine the proper actions to take. Some categories that asset owners can use to track performance are device failures, setting errors, and testing errors. The owner should consider that regulatory agencies will also require performance data in an effort to identify common mode or systemic problems that are impacting the reliability of the bulk electric system (BES).

NERC has been tracking misoperations for over a year with owners supplying data in standardized templates. NERC Staff has sorted this data to provide various statistics on relay misoperations and have provided this data back to the industry in the form of Webinars and reports. This data indicates that the greatest causes of misoperations are the following factors [9]:

1. Incorrect settings, logic or design errors
2. Relay Failures and Malfunctions
3. Communication Failures

When focusing on misoperations per cause listed above the following data is provided:

1. Incorrect Settings – MP relays are 5 times more likely to cause a misoperation than EM relays.
2. Relay Failures – MP and EM relays cause approximately the same number of misoperations.

The data is not normalized over the total population of operations. However, a general conclusion would be that the more complicated the design and the more settings required will lead to additional errors and more misoperations. If the owner could reduce the sources of other errors such as relay failures then this might be an appropriate trade off.

A large utility tracked work procedure errors over the last few years this utility has over a 1000 busses and over 30,000 relays. A summary of the data is shown below:

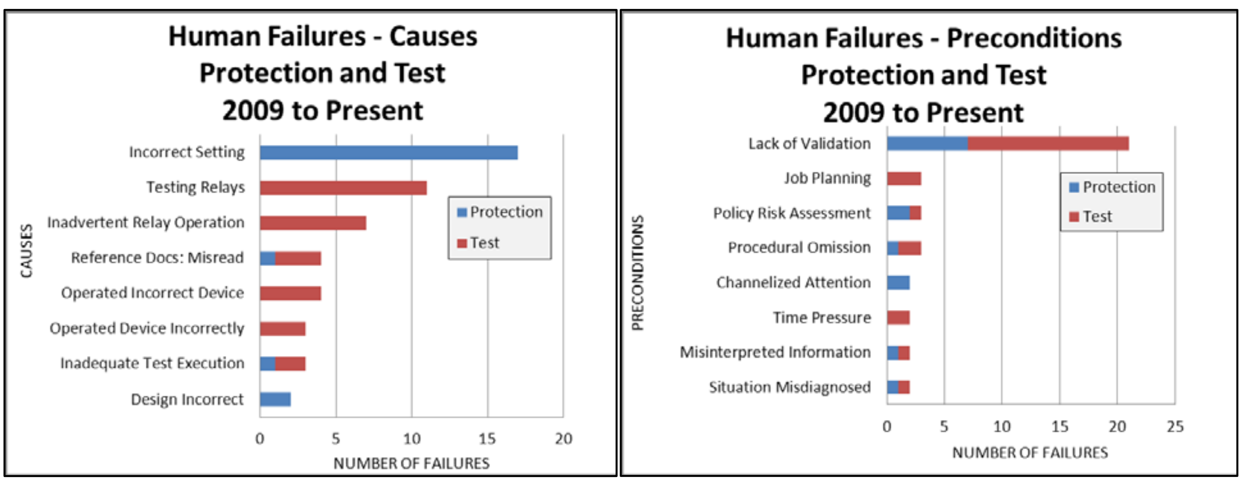

Figure 15 – Human Failure Causes and Preconditions, Example Data

There are many reasons and causes for human errors but it is clear that more complicated designs are a major cause for setting and testing errors. Asset owners and relay practitioners need a robust plan and setting process to place more barriers that can prevent problems. Designs and setting templates need to be locked down and owners should consider a cookie cutter approach to applications and implementations. Obviously setting errors and different than testing errors and asset owners should consider items like peer review and process audits as added barriers to prevent setting errors. Relay technicians could also use a second pair of eyes when testing and tools, signs, and placards to help prevent errors in the substations during testing. Additional information about setting up a misoperations tracking process is provided from IEEE PSRC working group I3 [10].

Conclusion and Future Considerations

Microprocessor based relays with their rapid pace of technology change and high integration of functions will be at the center of protective relaying implementation for the foreseeable future. The industry has more than 20 years of experience with these devices, and is still learning about how to deal most effectively with their characteristics. Notably, generations of protection must be updated far more often in the future. It is the responsibility of the relay practitioner and the owner to implement a sustainable relay asset strategy. As discussed in this paper there are many factors to consider; there are also market variables that will play a role in how utilities approach this task. Each owner will need to examine its particular systems and choose the course to take - no one plan will suit all users.

This industry is unique and our protection systems must stand like silent sentinels providing secure, reliable, trouble free service. The industry feels pressure from the pace of evolution of MP devices and must engage with the features of these products to optimize applications and create a sustainable future. As shown above the industry is quickly moving from relays that would serve for more than 40 years to devices that may need to be replaced in less than 20 years, or even less in the future. The performance of these devices should be understood and tracked and each owner should clearly have a plan to address deficiencies or problems. A good plan is always more effective and efficient than reacting just in time.

The skills of the employees that provide oversight of the relays must be in lock step with this evolution of MP devices. As stewards of the industry these engineers and technicians make up a work force that has the skills and tools to maintain the fleet of diverse relays. The workers may at any time be called to work on the most complex scheme or the simplest, the oldest or the brand new. The schemes deployed must match skills of workforce. We have developed some simple concepts (Guiding Principles) to use when deploying new technology:

Protection System Guiding Principles

User Friendliness — Install infrastructure that is user and human performance friendly and flexible to accommodate changes, while at the same time maintaining public and employee safety, customer satisfaction, reliability, work efficiency and overall human performance.

Reliability – Incorporate reliability in designs so that no single points of failure in the protection systems cause the elements to be removed from service and insure there is no interdependency between systems and equipment. These designs must meet regulatory standards for reliability of protection systems.

Simplicity – Incorporate simplicity in designs so that engineers and technicians working with this equipment for testing and programming need only a Journey level of knowledge and experience. The deployment of new technology must be studied to understand how this technology will impact long term strategies (i.e. workforce skills).

Sustainability – Incorporate sustainability in designs so that changes in equipment or firmware can occur without major redesign or lengthy outages to equipment. Designs should not be manufacturer dependent.

Our industry has a very reliable and proud history and the new engineers entering our field will bring new skill sets. These engineers deserve a system that is ready to test their skills and abilities to confront the challenges that we all have faced. The customers we serve also need our undivided attention. This is why we need to create a sustainable protective relay asset strategy.

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Biographies

Jonathan Sykes is Manager of System Protection at Pacific Gas and Electric Company in Oakland California. Jonathan graduated from the University of Arizona in 1982, is a Professionally Licensed Electrical Engineer, and has 30 years of engineering experience in System Protection. He is active on several committees in the Western Electric Coordinating Council and is Chairman of the North American Electric Reliability Corporation System Protection and Control Subcommittee. Jonathan has authored and co-authored papers for conferences and publications and is an active senior member of IEEE and regularly contributes to the Power System Relay Committees. Jonathan has been involved in EHV protection and control for over 15 years and established standards in EHV relaying and SPS/RAS design and implementation. Jonathan has been active in NERC and WECC standards interpretation and development and is a subject matter expert in the interpretation of various protection and critical infrastructure related standards.

Aaron Feathers is a Principal Engineer in System Protection at Pacific Gas and Electric Company, where he has been employed since 1992. He has 20 years of experience in the application of protective relaying and control systems on transmission systems. Aaron's current job responsibilities include design standards, wide area RAS support, NERC PRC compliance, and relay asset management support. He has a BSEE degree from California State Polytechnic University, San Luis Obispo and is a registered Professional Engineer in the State of California. He is also a member of IEEE and is on the Western Protective Relay Conference planning committee and the NERC Protection System Maintenance Standard Drafting Team developing NERC Standard PRC-005-2.

Eric A. Udren has a 43 year career in design and application of protective relaying, substation control, and wide area protection and control applications. He programmed the world's first computer based transmission line relay, led development of the world's first LAN-based substation protection and control system, and managed relay development and application at Westinghouse, ABB, and Eaton Electrical. He is Executive Advisor with Quanta Technology, LLC of Raleigh, NC, USA where he has worked with major utilities to develop new substation protection, control, data communications, SPS, and wide are monitoring, control, and protection designs. Eric is IEEE Fellow, and Chair of the Relaying Communications Subcommittee of the IEEE Power System Relaying Committee (PSRC). He is US Technical Advisor for IEC TC 95 relay standards; and is a member of the IEC TC 57 WG 10 that develops IEC 61850. Eric serves on the North American Electric Reliability Corporation (NERC) System Protection and Control Subcommittee (SPCS), and the NERC Protection System Maintenance Standard Drafting Team developing NERC Standard PRC-005-2. He has written and presented over 80 technical papers and book chapters. Eric can be reached at eudren@quanta-technology.com.

Bryan Gwyn Senior Director, Protection and Control Asset Management at Quanta Technology, has over 30 years' experience in the Utility Industry with over 20 years' experience in Protection and Control. Bryan was Director of Protection, Telecommunications and Metering at National Grid prior to joining Quanta Technology in 2011. He was responsible for delivery of multi-million dollar capital projects, Standards development, system disturbance analysis, NERC Standard compliance and Asset Strategy in these fields of engineering. He has held several leadership positions including managing teams in

Protection Engineering, Standards and Events Analysis. He moved to the US in 2001 from National Grid in the UK where he held several senior positions in Protection and Control Engineering. Bryan is a Senior Member of the IEEE and has co-chaired several working groups at the Power System Relay Committee. He is Chair of the Boston IEEE PES Chapter that recently won the most Outstanding Chapter award. He is also a Member of the Institute of Engineering and Technology and a Chartered Engineer in the UK. He is a Member of the NERC System Protection & Control Subcommittee and is a past Chair and Lifetime Member of the NPCC Task Force on System Protection. He is a Member of a CIGRE Working Group on Managing Relay Settings and has published over 20 papers and articles. Bryan holds a Bachelor degree in Electrical and Electronic Engineering and a PhD from the City University, London.