PRACTICAL CHALLENGES AND SOLUTIONS FOR PROTECTION ENGINEERING

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INTRODUCTION

Electric power system protection engineering includes modeling, specification, design, fault studies, settings, installation support, and documentation of a protection system. When performing these tasks protection engineers are faced with some practical challenges. These challenges are typically not addressed in college, are overlooked when planning a project, and are often addressed only in a crisis mode.

The following discussion addresses many of these challenges and presents an overview of some solutions. Each challenge is accompanied by one or more solutions for the protection engineer to implement. The solutions make use of typical utility practice, different design methods, new relay and peripherals technology, manufacturers software, standard off-the-shelf PC software, and basic methods of peer review.

OVERVIEW

Each main category is a general part of protection engineering. Each sub-topic is a challenge to be addressed. The text for each challenge provides a discussion of the solutions. This discussion is very practical and is not intended to be a textbook, but a source of practical ideas for each protection engineer that is actually modeling systems, designing schemes, setting relays, or assisting in the field.

MODELING	DESIGN	SPECIFICATION	FAULT STUDIES
Lack of Xfrm Impedance Data Incorrect T&D Line Data Model Uncertainty Too Many Scenarios to Model	Differences Between Relays Require Design Differences New Relays Provide Features that Old Designs Do Not Accommodate The System Must be Tested	Unfamiliar with the Latest Technology Design is Not Complete, but Specification is Required to Meet Delivery Dates	Study Does Not Match Recorded Ground Fault Magnitudes The Model is Changed after Settings are Calculated
SETTINGS	**INSTALLATION SUPPORT**	**DOCUMENTATION**	**RELAY/INTEGRATION**
Understanding Hundreds of Settings Managing Multiple Setting Groups Verifying Setting Thresholds are Correct Verifying that Logic is Correct	Getting Settings to the Field Identifying the Problem when Field Tests Fail	Recording Setting Calculations Settings Changes and Tracking Changes	Softpoints or Hardpoints Working with Other Departments Other Departments Make Changes that Impact Protection

MODELING

A goal of protection engineering is to minimize damage of equipment when a system unbalance occurs. The primary cause of damage is electrical short circuits which protection engineers call "faults." To develop a system that adequately protects the physical equipment, a "model" of the physical equipment should be constructed.

Models come in many forms. The most basic is a hand-calculated mathematical model. By using ideal formulas to represent the electrical characteristics of physical equipment, many scenarios and studies may be performed without using the actual equipment.

Another form of a model is a scaled down version of the physical system. Smaller analog components are used to create a miniature system. Again, this physical model is based on mathematical equations that represent the actual system.

Newer forms of computer-based modeling have improved the use of the models by making the calculations faster and more accurate while including a user interface that is easier to use.

No matter which type of model is used, the developed protection system is typically only as good as the model, or can it be better than the model?

There is some truth to the phrase, "the protection system is only as good as the model." However, on the positive side, the phrase should be modified to "the protection system ***can be*** as good as ***the understanding of*** the model ***limitations***," which may be better than we thought.

By understanding the limitations of our model, we can adjust our protection practices to make the protection system just as reliable, dependable, and secure as one developed from a more accurate model. Of course there are limitations to how much you can improve your model-limited protection.

Therefore, the challenge is how to understand and address our model limitations. Here, this challenge is addressed by presenting four main topics. They include the following four specific challenges:

- Lack of Transformer Impedance Data
- Incorrect Transmission and Distribution Line Data
- Model Uncertainty
- Too many Scenarios to Model

This is not an exhaustive list of challenges with regard to modeling, but they are some practical challenges protection engineers face on a regular basis. The following discussion suggests a few solutions that protection engineers may implement to address these challenges.

Lack of Transformer Impedance Data

When modeling a transformer for fault studies, you need the impedance data of the transformer. The best source of this information is usually a test report from tests performed at the manufacturing plant after construction and before the transformer is shipped. Transformer tests are described in an IEEE standard [1]. Within your transformer specification that is provided to the manufacturer, you may include the requirement to perform these tests. Unfortunately, without this in the specification, these tests are not always performed, so the following list is a recommendation of where to obtain transformer impedance data (in order of approximate accuracy):

- Factory test reports (use installed tap value)
- Installed field test reports
- Nameplate information
- Station records
- Other departments' records
- Contact the manufacturer
- Original specification for purchase

Another way to obtain transformer impedance data is to take measurements and make some calculations. Some options that are available include:

- Take the unit out of service and test.
- Test the fourth bank (spare) of a set of single-phase transformers.
- Back calculate from fault records.

In addition to measurements and calculations, a third way to obtain transformer impedance data is to estimate it based on as much information as you can gather. Keep in mind that the IEEE standard for transformer impedances is that transformers of the same design will have the same impedance to within 7.5%-10.0% depending on the transformer type.

- Use values from a similar transformer on your system.
- Use "typical" values your company may document.
- Use "typical" values provided by the manufacturer.

The zero sequence can be assumed to be the same as the positive sequence, with the exception of three-phase core-type transformers. For these cases the zero-sequence impedance will be about 10% less. Before making any assumptions or comparisons with other transformers, be sure you know a little about the construction of the transformer.

Using these methods, you should be able to get within 10% of the transformer's impedance. Knowing this limit of your model, you can adjust your protection system accordingly, but when the actual values are known, use them.

Incorrect Transmission and Distribution Line Data

Line impedances are often harder to come by, especially in rapidly changing systems such as distribution lines. Reconductoring, tapped lines, new tower or pole configurations, emergency repairs – all of these contribute to uncertainty of the model.

There are texts [2] that give "rule of thumb" impedances for transmission lines. These work very well. However, after using these numbers, a protection engineer can check them. Compare the resulting number to a similar line with a similar conductor. Again, as mentioned while discussing transformers, relay fault records may be useful to back calculate the impedance. Look at the ratios of fault current contribution (I1, I2) from each end of a line. I0 is not recommended for this comparison because it is even more uncertain for three wire systems that use the earth as a neutral return. The earth's resistivity is different between the mountains and the marshy plains. Many models assume a fixed earth resistivity.

For longer lines, if they are not transposed the line model has further uncertainty since most models assume a transposed line. The actual impedance can be calculated but a more practical approach may be to accommodate this error in your protection philosophy or even in the relay [3]**.** However, before doing this, be sure you understand what the error might be.

Model Uncertainty

Take the time to learn the system. The more you know about your system, the better you will be at recognizing bad data. Generally, line data errors have the most impact on coordination and end-of-line protection for transmission systems.

As mentioned earlier, by knowing the limitations of the model, you may adjust the protection scheme in order to provide expected security, reliability, and dependability.

If you have company standards that tell you to set an impedance element at 80% of the line length, know why this is 80%. Typically, these standards should include the expected error in the model that is used. If your new model has additional error, adjust the value accordingly.

Continuing with the impedance reach example, errors typically accommodated by such a standard include PT and CT error, relay measurement error, and model error. You do not want an instantaneous, under reaching element to overreach. In a perfect system, the reach could be set at 99.9% of the line length. However, the CT error of 1% and PT error of 1% for faults near the end of the line give Z% error of 2% as shown in Figure 1.

$$Z(error) = \frac{V_{pri} \Big/ PTR(1 \pm 0.01)}{I_{pri} \Big/ CTR(1 \pm 0.01)} = \frac{V_{pri}/PTR}{I_{pri}/CTR} \cdot \frac{(1 \pm 0.01)}{(1 \pm 0.01)} = Z \cdot \left(\frac{1.01}{0.99}, \frac{1.01}{1.01}, \frac{0.99}{0.99}, \frac{0.99}{1.01} \right)$$

$$Z(error) = Z \cdot (1 \pm 0.02)$$

$$Error = 2\%$$

Figure 1: Impedance Error Assuming a 1% Instrument Transformer Error

If relay error is 5%, then a setting of 80% leaves 13% error margin for the model. How does this work out practically?

Consider a system model that has a 5% error in every component. The most error the fault current will have is 5%. Figures 2 and 3 show a fictitious system and the fault current for a ground and 3-phase fault, respectively, in the middle of the system. Figures 4 and 5 show the same system with a 5% increase in all of the component impedance values. The result is a 5% change in the current. Errors in opposite directions will only help balance your model with regard to the error and the fault current levels.

On the other hand, an overreaching impedance element may be designed to reach at least 110% of the protected line but not past 50% of the next shortest line. If the shortest line is only 5 or 10% of the length of the protected line, then 5% error in the long line impedance could make a significant difference. Adjust your scheme to accommodate this possible error.

Another uncertainty to be aware of with typical models is how they compare to the actual system operating voltage. Many models calculate values based on an ideal 1.0 pu voltage, but your operators can tell you that your system may typically run at 1.03 pu. This will help your overcurrent settings with regard to seeing end-of-line faults, but it will reduce coordinating margins slightly. Again, be aware of the model uncertainty and adjust your protection philosophies accordingly.

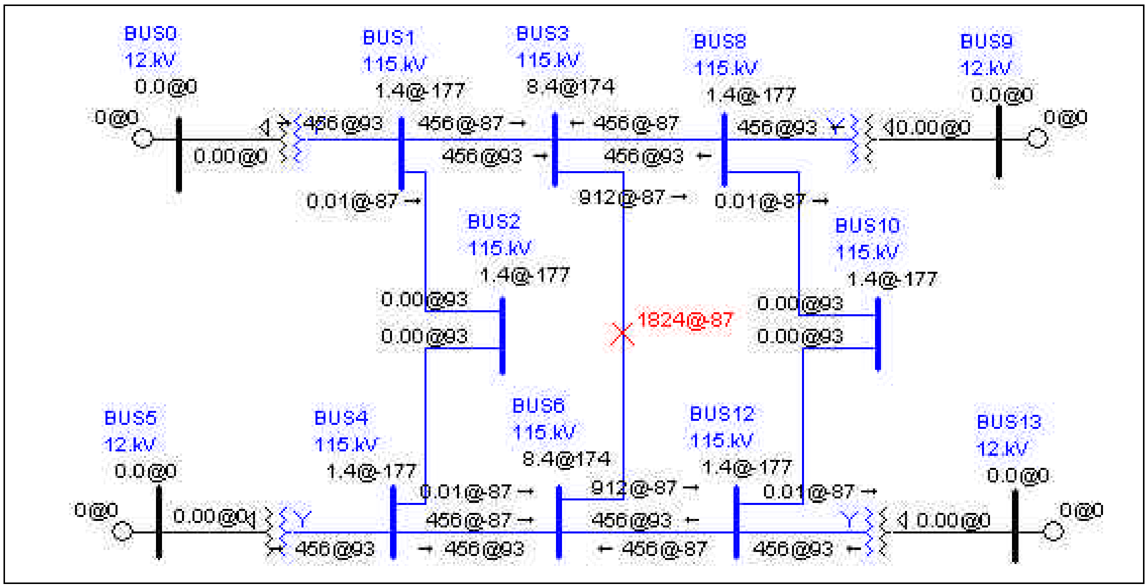


Figure 2: Fictitious System Showing Ground Fault Values

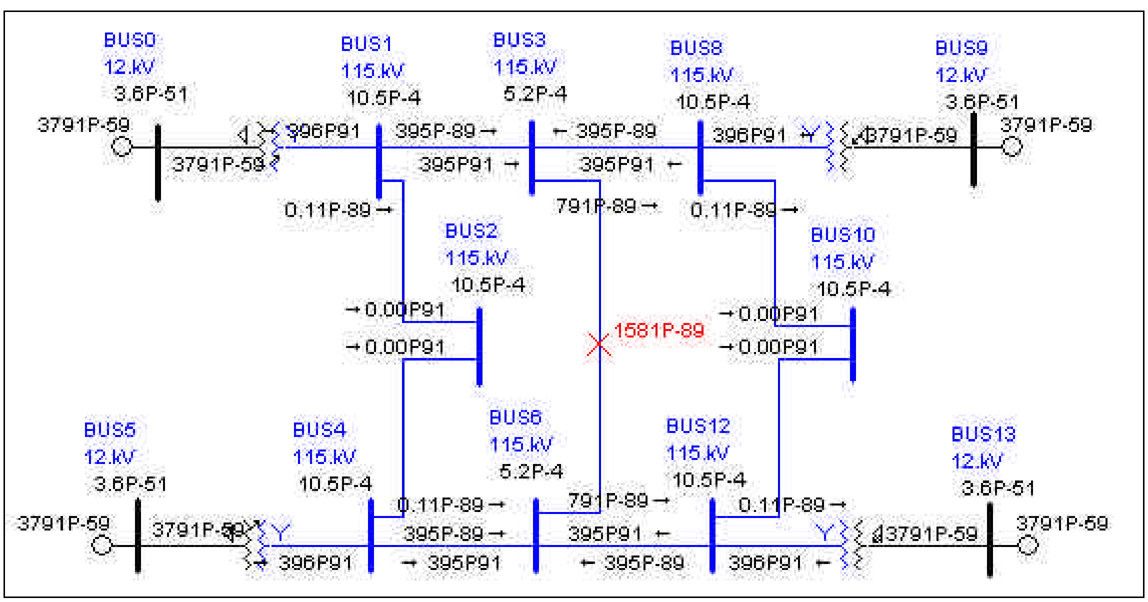


Figure 3: Fictitious System Showing 3-phase Fault Values

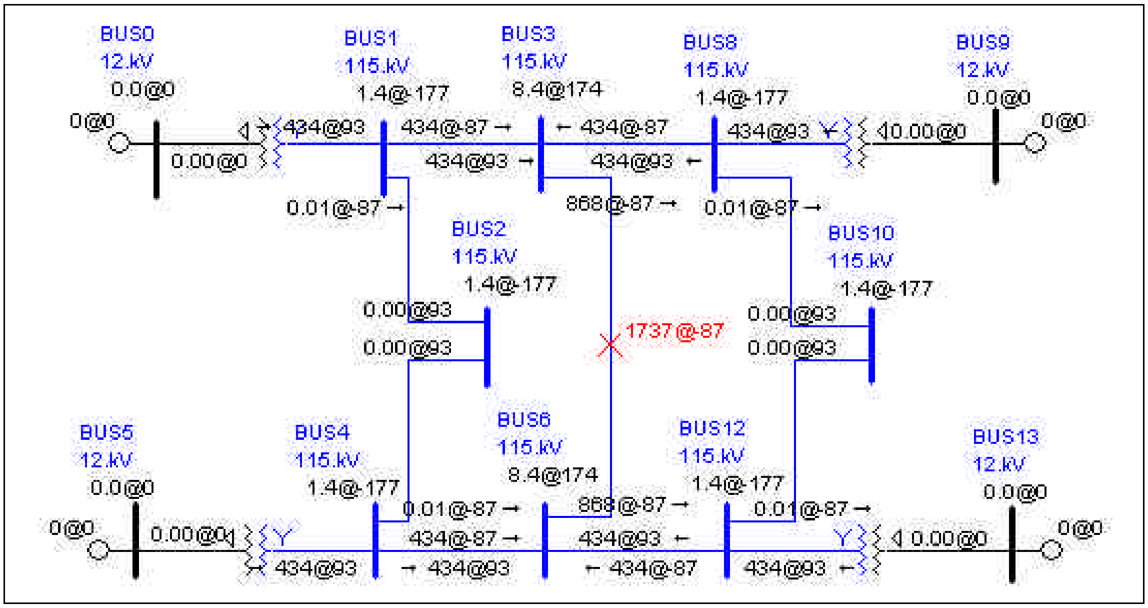


Figure 4: Fictitious System Showing Ground Fault Values

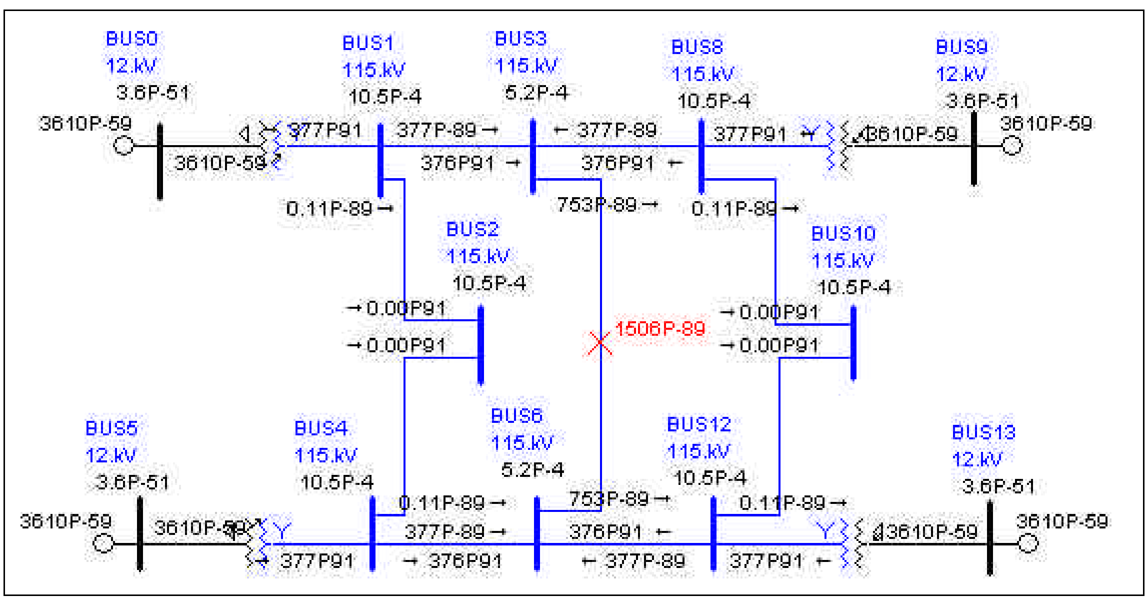


Figure 5: Fictitious System Showing 3-phase Fault Values

Too Many Scenarios to Model

When running fault studies and coordination studies, knowing the cases to run that produce the worst-case conditions saves a lot of time. Depending on the protection scheme, this may be the maximum or minimum fault current seen by the relay, the lowest voltage seen by the relay, or other factors.

New software allows the protection engineer to run faults and batches of faults in a matter of seconds. Over the course of a few minutes, the worst-case scenario often can be determined by trial and error.

If you run a batch of faults with various contingencies you can easily generate a large log of data for review. To optimize the amount of data, use the following to your advantage:

- Always take the time to consider and learn more about your system.
- Look for the largest and smallest contributor to fault current on each bus considered.
- Graphically model the system with line lengths and right-of-ways relative to one another based on the physical line lengths and right-of-ways (even if it is just for the study area).
- Look for runs/faults to throw away, not which ones to keep.
- Communicate with operators. Ask them about "likely" operating scenarios.
- Put limits on the number of operating scenarios considered.

For example, a particular fault run may generate five different scenarios of 800, 820, 1000, 1200, and 2400 amps. Based on fault currents alone, you may quickly conclude to throw out the 1000 A and 1200 A scenarios, assuming there are no other reasons to keep them. This is because they are not extreme cases. Keep the 820 A fault because it is so close to the 800 A fault that the difference might just be model error and other issues may determine which one to keep. Continue your study to pinpoint the actual worst-cases that you need for determining your settings. This process will eliminate the 800 A or 820 A scenario because of switching conditions, likelihood of certain generation outages, etc.

Another example is to ignore unrealistic operating scenarios like an open transmission switch that must be manually operated, as opposed to a preferred scenario that utilizes a remotely operated switch. The first scenario is possible, but Operations may agree that it is not worth considering.

Some systems or parts of a system have redundant items such as a wind farm (many generators and transformers), or industrial facility (several motors). When this is the case, protection engineers often lump these items into a single component model. This is okay (especially for transmission-only studies) as long as you understand how you have limited the accuracy of your model (see the discussion above). The most accurate approach is to model each individual item.

Using the user-friendly interface of the newer programs makes this simple to do, but it can be time consuming to create them one at a time and check each entry. Instead, learn about additional features of the program like copy and paste. Also, consider using the text data file for inputting data. Model programs typically have an underlying data file. Using copy and paste techniques within the text data file works well to create numerous entries that are similar. Reviewing the text data file is often an easier method to verify that the data was entered correctly.

Use these ideas and methods to reduce the amount of conditions and data that must be considered when modeling a system.

DESIGN

When designing a protection system, the engineer usually starts from an existing company design standard or his or her own knowledge of previous designs. Some very new technologies like implementing UCA™ GOOSE [4] or MIRRORED BITS™ [5] networks for breaker failure, bus, and other protection control, require completely new designs or translating "wired" designs to "logic" designs.

In all of these cases, there are challenges when developing a design. Some solutions to the following challenges are addressed here:

- Differences Between Relays Require Design Differences
- New Relays Provide Features that Old Designs do not Accommodate
- The System Must be Functionally Tested

Differences Between Relays Require Design Differences

Converting to a different manufacturer's relay or designing a system with multiple manufacturers' relays creates challenges.

Some of the challenges include:

- Different mounting requirements
- Different contact input requirements ("wetted" or not)
- Different analog inputs (3-wire or 4-wire)
- Addressing Company Culture or the Human Factor

To tackle these challenges, here are some solutions:

- Develop company standards with new technology in mind.
- Use standards for at least two to three years.
- Use functionally the same scheme if different relays are used.
- Talk to operations, construction, and maintenance personnel early in a design change.
- Limit the number of manufacturers and number of relay types used.
- Consider using one manufacturer but different styles of relays.
- Only change standards or a design because of a need or the value the new product adds, not because it is the latest technology.
- Know the differences between manufacturers' relays.
- Select relays that can change with your system. Can you change the scheme, the logic, the I/O?

New Relays Provide Features that Old Designs do not Accommodate

The newest relays have hundreds or even thousands of settings if a user wants to use them. Some relays allow setting only a few elements and turning the others off.

Too often we modify an old design of electromechanical phase and ground overcurrent protection with a new microprocessor relay with big plans of using all the new features.

Some challenges this presents us with include:

- Wiring the third phase
- Monitoring the 52A contact
- DC connections in the breaker for trip coil monitoring
- Connecting the relay to bus or line voltage sources
- Supervision circuits to other relays
- Multiple SCADA and/or Alarm outputs (i.e. relay failure, loss-of-potential)

The following are some suggestions that will help with these challenges:

- Only use what you need today and plan for tomorrow.
- Don't use a feature just because it is there.
- Know what benefit you will gain by implementing a new feature and acknowledge what it will cost you.
- A single new relay can replace many old ones – consider redundancy and monitor the alarm contacts.

The System Must be Functionally Tested

When designing a new protection scheme or modifying an old scheme with new technology, always consider how field personnel are going to test the system. Different companies test their systems differently, but there should always be a way to test the system safely. The solution to this challenge is to simply answer some questions while designing the system.

- How will I prove that this feature is working correctly?
- Is the system still adequately protected while I test this scheme?
- If I test this scheme will it operate any other devices (breakers, switches, relays, auxiliaries, alarms, etc.)?
- By testing this scheme in this way, does it change the operating requirements in any way (increased contact interrupting current, slower breaker operation indication, blocked integration information, etc.).

SPECIFICATION

This discussion is intended to address some of the problems and solutions that protection engineers have when specifying a protection scheme including the protection method and relay hardware. There are additional problems and solutions with regard to writing a complete specification for control buildings, panels, testing, etc., but these topics are beyond the scope of this paper.

Unfamiliar with the Latest Technology

Your company has been working on the design of a new substation and transmission lines to increase transmission capabilities and to provide better stability during system contingency cases. The project is now into the stages where the protection system should be specified. The company design standards are about six years old, and are based on relays that were two years old at the time. In this case, you must solve two problems. The first is "knowing what technology is available", and the second is "how to specify the relays correctly."

Too often we limit the capabilities of our protection system because we are unfamiliar with the latest technology. And an incorrect specification is likely to increase project time and costs. In this scenario there are many ways to address the problem. Here are a few:

Phone-a-friend

Other engineers are usually comfortable receiving calls. Don't expect them to do your research for you, but they may be familiar with the new technology and can answer your question, or they may know the person that could answer your question. Colleagues will usually be open to sharing their experience of customer support for certain manufacturers, certain relay types, or consultants. This information may save you significant time as you learn about the new technology.

Ask a consultant

Some consultants are willing to answer quick questions over the phone. If you are worried about the "consultation" fee, don't call a consultant that charges for every five-minute phone call.

Start off the conversation with something like "We are planning on completing this project internally, but I was wondering if you could comment on…"

Manufacturers

Manufacturers disseminate product information over the web and through representatives or sales personnel. They often have application papers that explain new technology, and even offer courses specifically on new products. Manufacturers have application engineers that can help as well. The concern with going to a manufacturer for information is that you must stay focused on what your needs are, not what they want to sell you. On the other hand you may not know your needs, and in these cases you will want to get some good feedback from application engineers or consultants.

The manufacturers may also be able to provide a list of users that are willing to be a reference for the technology you are considering. Call and ask these individuals for feedback, but again, guard their time – make it brief.

Keep it simple

One possible solution is to use familiar relays. Consider the total project cost of changing technology including training for engineers, technicians, and operators; or changing the design prints. On the other hand, consider the cost of the old technology, including the need for additional auxiliary equipment, obsolete relays or parts, troubleshooting questionable operations when data is minimal, and warranty expiration.

When reviewing new technology, compare features and how the relay operates relative to the old design. Ask yourself if the new relay will require significant design changes. Some manufacturers have products that even include the terminal numbers of the older relays. This makes the upgrade very simple from the design standpoint.

Design is not Complete but the Specification is Required to Meet Delivery Dates

Relays typically do not require a long lead-time relative to other power system equipment. Some relays can be delivered in less than two weeks, whereas some transformers may take more than a year. However, on relay replacement projects, the relay becomes the long lead item. Particularly with a new relay scheme, the relay usually must be specified before the new scheme design is complete. This allows the relays to be ordered and arrive in time for the panels to be built. Not knowing the exact design requirements can create a problem when specifying a relay. Some solutions to this problem are as follows:

Multifunction relays

Specify multifunction relays that include multiple protection schemes. Most microprocessor relays will support this.

I/O expansion

Rough out your I/O requirements and then add some additional I/O for margin. Also, select relays that can have I/O added later by adding an auxiliary device or by adding an I/O card.

Use old standards

If you know you want newer technology but not sure what, you can base your requirements on the old design. Have a manufacturer give you the model number of the newer relay that performs all of the functions of the old standard.

Break down lead times

Often internal lead times have more of an impact on the schedule than the manufacturer lead times do. By knowing what the total time will be, you can set the date for specification with confidence that you will meet your deadline. Some hidden lead times include getting the request for quote and/or the order through a purchasing department, the amount of time the manufacturer requires for a response, and your time to review the responses.

Multiple bids

If your purchasing process allows it, one method is to spec multiple relays in your request for quote, and then select the appropriate relay later after you know more about your design.

Utilize a logic design

New relays and systems can be specified without detailed design knowledge because a system can be designed such that all of the detailed logic is completed in software and programming of the device. Or, the complicated/unknown portion of the scheme could be implemented in a logic design.

Protocols are available today that have five or more years of field operation experience that allow relays to communicate status points across a secure communication system. The protection system hardware and connections can be designed without designing exactly how the system will work. Effectively, the panels could be built while the detailed design is being completed. This reduces the total project time by allowing panel construction and detailed design to occur simultaneously.

FAULT STUDIES

A fault study is performed using the system model. The fault study is fundamental to most protection schemes. The fault study is used to set protection elements in order to accomplish two things. First, the protection must be able to reliably detect certain fault conditions for a specified part of the system. Second, the timing or operation sequence is expected to be coordinated to minimize the outage area.

When faced with study results that do not match recorded system ground fault magnitudes, or when the model changes in the middle of the project, the protection engineer must have solutions to keep the project on schedule.

Study Does Not Match Recorded Ground Fault Magnitudes

When the study does not match recorded ground-fault magnitudes, three steps are required:

1. Determine if this impacts your objectives above.
2. Determine the cause of the difference.
3. Fix the determined cause if possible, or determine how to live with the difference.

Identifying if the difference really matters is a very practical step. Many engineers may see the difference as a problem just because it's different. Practically, it may not matter. For example, a ground overcurrent pickup setting is usually set with much greater margins than most other protection elements. Your company standard for setting a ground overcurrent element may be to set the ground pickup at 50% of the end-of-line ground-fault magnitude, or it may be 15% of the maximum load on the line. In either case, these standards usually have significant margins relative to the fault study.

This margin does not mean that a difference will not impact your protection. If for example, your pickup setting is 200 A primary based on a fault study of 400 A, and a recent recorded ground fault magnitude is 210 A, you should know why the magnitude is so close to the pickup point, even though the protection picked-up and tripped appropriately. The difference could be from:

- Fault resistance (look at the recorded fault angle)
- Inaccurate model (see model discussion)
- Recording equipment (equipment calibration, CT ratios, etc.)

If the difference is from fault resistance, the lower current magnitude reduces the margin for seeing end-of-line faults, but it helps by increasing coordination margins. Look at the angle between the faulted phase voltage and current. In general, for a radial system, fault resistance will reduce this angle to something less than the line angle. For a multiple source system, the fault resistance has a similar effect, but the angle shift is dependent on the remote source angle as well. The precise impact can only be determined if you have data from both ends of the line.

If fault resistance is ruled out, then consider your model. Refer to the discussion on the model.

Recording equipment may be the cause for the difference. Look at recorded multi-phase faults and see how they compare. Multi-phase faults are less likely to have fault resistance. If the recording equipment is the relay itself, it is a critical issue to make sure the relay is measuring correctly. Simply checking the measurements under load conditions and comparing them to another measurement device usually will suffice.

Some exceptions to this include high impedance contact points in the secondary system or shorts/failures in the CT that may not be noticeable unless high currents are present. The only way to detect this is to compare the recorded data from two devices for the same fault. In one known case this was identified when a relay tripped for an out-of-section fault. Another microprocessor relay monitoring the same CT circuit did not trip or even record the fault. The relay test block of the tripped relay was damaged and was shorting some current around the relay.

Another scenario to consider is if a recording device is in a circuit with a high burden. This can often be the case when an electromechanical ground relay is set with a very low tap, and/or the station is very large with long CT circuit runs. Under a ground fault condition the CT may saturate causing the recorded current to be less than your model current. In these cases the CT saturation will be evident from the shape of the waveform shown by the recording equipment. When investigating this type of concern, be sure you know the sampling, filtering and recording specifications of the device to determine which harmonics are and are not filtered out [6] [7] [8].

If the recording device is an oscillograph or other monitoring equipment, check the settings, look for recent system changes, such as CT ratio changes, and also compare to other known measurements on the same system. This type of problem is not critical to the protection, but it makes fault analysis difficult.

The Model is Changed After Settings are Calculated

Your project is virtually complete. You have issued the settings to the technicians for installation and testing. However, you get the phone call that is hopefully the exception to the norm. It is the Operations Department. For two months, they need to reconfigure the system to support emergency maintenance at a substation near your project. They are going to feed the new station from the two weak sources while the strong source is not available for two months.

Your protection settings accommodated a single source contingency, so the settings are fine with the strong source out, but they may not accommodate another outage such as losing one of the weak sources during the two-month period. There are many things to look at other than protection on a case like this, but assuming all operational issues are addressed, what should the protection engineer do?

First, identify how much the study changes. If distance relays are used, verify that the fault detector levels are adequate. For any overcurrent element, verify that the percent change of the fault duties is within your typical settings margin. Your margin might be less now, but that should be okay, knowing that the system will be normal in two months.

This fictitious scenario seems simple to tackle, but now let's say that you issued settings and later a small change in the system or model occurs. Some engineers may want to have technicians spend the next week changing relay settings while they spend the week changing documentation. Before doing this, consider that your standard margins are intended to cover small, unknown changes. In this case, you are aware of the error or change. Ask what it would take to make the changes, and for what value. It is likely that you do not need to make any immediate changes. After deciding not to make a change you still should document that a change occurred and put this on a future list to be changed when time and budget allows.

Typically the small change doesn't impact the protection, so nothing is done. Then six months later another small change occurs. This process repeats itself over the course of years, and like a frog in boiling water, you don't see the problem coming until it is too late. For each change, you looked to see how much the fault study changed. It may have only been a few percent each time, but now the relays may not see the end-of-line faults.

Some utilities require a complete system review every few years, depending on the amount of system changes. Another approach to avoid this problem is to always check end-of-line protection in the vicinity of any change. If your ground fault margin is ever reduced by 50% with respect to the relay setting, then change the relay settings. If your phase-fault margin is ever reduced by 25%, then change your relay settings. You may want to change the settings prior to reaching these thresholds based on how your company margins are set.

Here are a few examples:

Example 1: A 69 kV transmission line has a ground pickup setting of 200 A based on an EOL ground fault duty of 400 A. Due to an operational change in the system, the ground fault duty changes to 300 A. This value is still within the limits of the pickup setting, but remember why your margin exists. Ground minimum settings accommodate error, but they may also accommodate ground fault impedance. You have effectively reduced your ground fault coverage by 50%. Also, you now only have 25% error margin for other errors even if the fault is solidly grounded. Definitely change your setting.

Example 2: Now let's consider the same line, but the fault duty drops from 400 A to 385 A due to a correction or change in the model. Do you get the technicians out on overtime to change relay settings? The quick answer is, "absolutely not." However, you do document this change so that it is not forgotten, and you may even put it in a list of items to fix if these relays are taken out of service for some other reason.

Example 3: Now consider the same line for phase faults. The EOL three-phase fault duty may change from 1400 A to 1260 A. Your company standard is 60% of three-phase faults, so the setting was 840 A. According to the recommendation above, the margin has changed by 25% (560 A to 420 A) so the setting should be changed. Look at why the company standard is 60% to determine why the change is necessary. Typically a standard such as this covers phase-to-phase faults (100-86 =14%), relay error (5%), and CT error (1%), which totals 20% of the total fault current. The 25% change in your margin subtracts another 10% from the original margin. The 25% actually cut your effective margin in half not just by 25%.

For smaller changes, you must consider each case, and know why the margins exist. If the change is temporary you may be willing to take more risk, if it is permanent the least you should do is document the change and recommend a change the next time it is feasible. If your margins are compromised by 50% for ground faults or 25% for phase faults, you definitely need to change the settings. For your situation, these percentages may be smaller.

For fault duty changes in the opposite direction (they go up), your EOL protection is no longer an issue, but coordination is now tighter. Each utility will have different curve shapes and time dial standards, so a rule of thumb based on fault current is not practical, but coordination times are practical. Industry standard is approximately 0.3 seconds of margin between coordinating pairs. If both relays are microprocessor based, this margin may be reduced if necessary. In both cases you must again understand where these numbers come from: CT differences, relay differences, electromechanical operation error, and setting adjustment error.

For a temporary arrangement, you may be willing to risk the miscoordination, but for a permanent change if your coordination margin is compromised, consider making the change.

SETTINGS

Protection engineers must develop settings for the relays to protect the system correctly. These settings include thresholds and scheme logic when setting new microprocessor-based relays. Some practical challenges include how to understand hundreds of settings in one device, how to manage different setting groups for different operating conditions, and how to prove that the threshold and logic settings are correct.

Understanding Hundreds of Settings

Newer relays have hundreds, maybe thousands of settings. This can be an overwhelming, practical challenge for a protection engineer.

Tackle this challenge like most engineering problems. Break the challenge down into smaller parts like protection elements, or individual settings. Address these one at a time. Be sure you understand how to get analog and digital measurements into the relay, into the right algorithm, and generate the desired output contact operation. Complete this process for each protection element you want to use.

Do not worry about elements that you will not use. Turn them off if the relay allows this and verify that they do not impact other elements. If needed, remove logic diagrams from the manual and paste them together to get the big picture. Remember that the learning curve is often just learning new terminology or the fact that the new relay just has more of the same (i.e. overcurrent elements).

Some tools that are available to assist in learning all of the settings include manufacturer's software, training courses, the relay manual, and manufacturers' application engineers. Another approach is to have a consultant that is familiar with the technology perform the first project with the intent of handing it off to you for the next one. Require extra documentation and setting calculation descriptions. Also require an informal training session to walk through all of the settings to make sure that you understand how they were determined.

Managing Multiple Setting Groups

Most microprocessor relays now have multiple setting groups. These setting groups may be used for many different things. The most common and most appropriate use is for system configuration changes that occur at least once a year to a known condition that requires changing settings. This is often the case for a bus-tie breaker, or by-pass breaker. When routine maintenance is performed on a breaker, the by-pass breaker is used for protection. The relay may have several different setting groups to cover the several different protection scenarios that the by-pass breaker must address.

Fundamentally, you must document this to avoid problems, but practically, how do you do that? Each relaying scheme should have some sort of documentation, hard copy or electronic. If a relay has multiple setting groups, consider each one of these as another relay scheme requiring documentation. Also within the documentation of each scheme it should indicate how many other setting groups are used. For each relay scheme, the documentation should indicate the operating condition.

The documentation may look like one of the following:

"Normal"

"Line 2 Out of Service"

"Bypass for Bkr 142"

This documentation addresses the protection engineer, but don't forget the operator and technicians. If the panel includes a selector switch for the different setting groups, the placard should clearly indicate what scenario each group is for, or there should be a cross-reference list for the field personnel. There should also be a written procedure for the order of the switching so that the system is never without protection. Note that some relays take several seconds to switch from one setting group to another.

Having said all this, there are wrong ways to use multiple setting groups. Never use them for dynamic changes that occur many times a day. In these cases, and whenever else possible, use logic in a single setting group to change how the protection works. The way relays store settings and implement protection may have limits to the number of times a relay can change setting groups without wearing out electronic components. Consult the manufacturer for these limitations.

Another practical solution is to reduce the number of scenarios. Just because a breaker is the by-pass for six breakers does not mean you need to use six setting groups. You may have one or two positions that can use identical settings. Try to consolidate these as much as possible. Then whenever a relaying scheme is updated, always look for related setting groups that are impacted.

Verifying Setting Thresholds are Correct

Many of us have considered whether to test the new microprocessor relays or not. The detailed answer to that is beyond the scope of this paper, but the short answer is to test what cannot be tested by the relay or the design itself. For example, a relay cannot determine that you entered 50 when you should have entered 55.

Testing of the protection scheme does not start when the technician gets involved. It should start when the project starts. For example, your setting calculations could have simple checks in place to automatically check that some settings are within a certain range. Always have another person look over your settings and check fundamental thresholds, like minimum pickups for end of line faults and zone 2 reaches. If you are the only engineer, check your settings on a different day and in a different manner. If it is the first time you have set this type of relay, have it on your desk and load the settings yourself to confirm that the settings are acceptable to the relay and that they work as expected.

The next line of defense against incorrect setting thresholds is your field personnel. Establish a relationship with them such that they are challenged to find problems in your settings – encourage questions. This should not be offensive to you because it is better for them to find the problems before the incorrect settings create a major problem. They may save your career. A simple example is an incorrect CT ratio setting. The print you used to set the relay may have had the wrong CT ratio. The field personnel may recognize that these do not match. The field personnel should not even think twice about asking you if this is really what you want or if the CT ratio is on the wrong tap.

Provide the field personnel with a simple test plan that verifies the key threshold settings. If an automated system such as a setting database is used, this step may be skipped, but the field personnel should perform a compare function on the settings and always retrieve an "as-left" setting record that is later reviewed. If the threshold test is skipped you will remove the opportunity for the technicians to learn and understand relay operation and settings, so consider this before removing all forms of threshold testing.

Verifying that Logic is Correct

A great way to verify that logic is correct is to test it on the bench. This should always be done for "first-time-out" schemes. Again, a functional description should be written based on the expected operation. An independent person, such as field personnel, should test to the functional description to verify the logic.

After this is complete the field-testing should verify each logic scenario. In contrast, if the scheme has been used before, then the final input/output field-testing should be designed to prove some of the logic. Schemes that have complex wiring should have every scenario tested in order to prove the wiring.

You do not need to re-verify that the microprocessor relay logic scheme works every maintenance interval, or for every installation if it has been used before. Only verify what changes for each installation. For example, if a particular scheme has been used across your system, but it is now being installed in a new panel, test the scheme connections (I/O) but you do not need to test every scenario and re-prove the internal relay logic. You still need to verify that the settings are in the relay, like using a compare feature of the settings, and that the wiring is correct.

INSTALLATION SUPPORT

No matter how much engineering is accomplished, a project is not very useful until the information gets put into practice. The installation or implementation needs the protection engineer's support.

Two practical challenges to supporting the installation include getting the settings to the field and into the relay, and identifying the problems when field tests fail.

Getting Settings to the Field

Consider new microprocessor relays. You develop the settings one at a time or with your company's standard settings, or follow a consultant's work on a previous project. In any case, all 742 settings are complete and ready for the field. Getting these settings to the field can be a challenge. Fortunately, e-mail and corporate networks have developed along with relays.

Protection engineers tackle this problem by using one or more of the following tools:

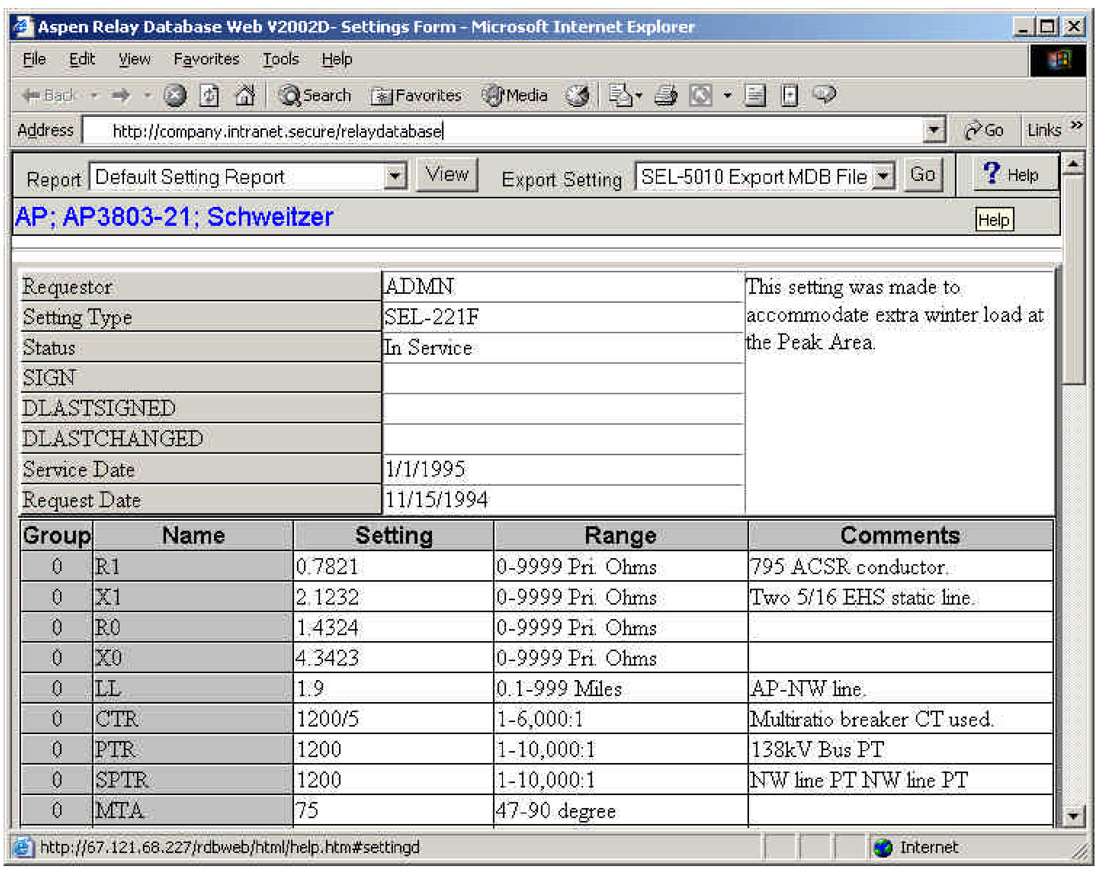
- Manufacturer setting sheets
- Self-made documents
  - Microsoft® Excel spreadsheets
  - Microsoft® Word documents
  - Mathcad® spreadsheets
- Manufacturer's setting database programs
- Third party setting databases
- Third party spreadsheets/documents

Manufacturer setting sheets are great for the first time through a relay and for a quick reference, but they generally do not work well for getting the settings to the field. One reason is the volume of pages. You can expect 15 to 30 pages of setting sheets from the manufacturer. Then these settings must be typed into the relay or relay software.

Self-made documents can be paired down to address only the necessary settings but still require the settings to be hand-typed by the technicians. These documents are very useful for record keeping (see the documentation discussion) but do not improve on getting the settings to the field.

Manufacturer setting database programs work well for the field personnel if they are familiar with them. The program directly loads the settings into the relay. The downside of using this approach is that manufacturers often require different programs for different relays. This approach also has limitations for the engineer. The programs often have limited means for documenting the settings and associated calculations. Some manufacturers are improving on this. These databases can even be shared across networks for the field to access as needed.

Third party setting databases work well to integrate the fault study, relay settings, and exporting to the relay manufacturer format. One example is shown in Figure 6. There are again some documentation limitations, but this approach again eliminates the need to hand enter the settings.

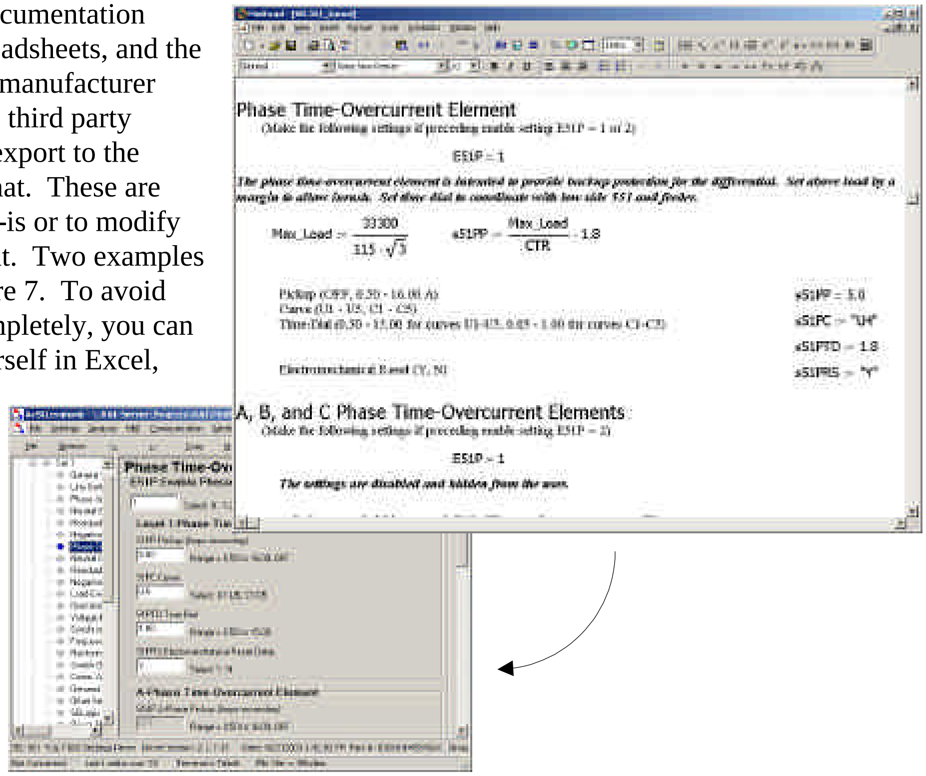


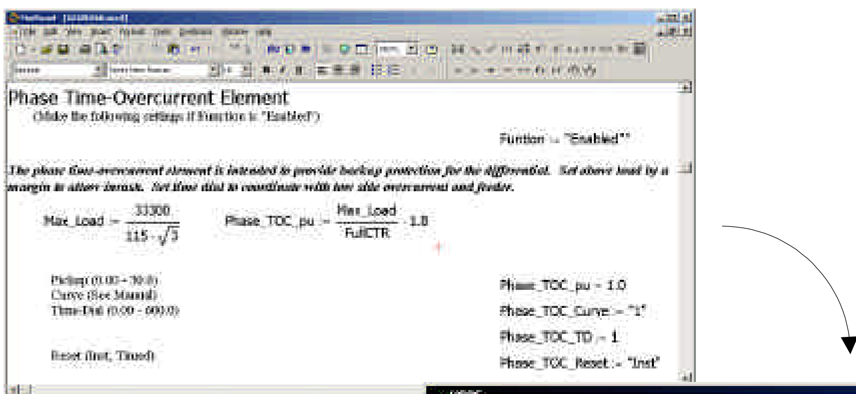
Requestor	ADMN	This setting was made to accommodate extra winter load at the Peak Area.
Setting Type	SEL-221F	
Status	In Service	
SIGN		
DLASTSIGNED		
DLASTCHANGED		
Service Date	1/1/1995	
Request Date	11/15/1994	

Group	Name	Setting	Range	Comments
0	R1	0.7821	0-9999 Pri. Ohms	795 ACSR conductor.
0	X1	2.1232	0-9999 Pri. Ohms	Two 5/16 EHS static line.
0	R0	1.4324	0-9999 Pri. Ohms	
0	X0	4.3423	0-9999 Pri. Ohms	
0	LL	1.9	0.1-999 Miles	AP-NW line.
0	CTR	1200/5	1-6,000:1	Multiratio breaker CT used.
0	PTR	1200	1-10,000:1	138kV Bus PT
0	SPTR	1200	1-10,000:1	NW line PT NW line PT
0	MTA	75	47-90 degree	

Figure 6: Example Setting Database Program

To build on the documentation advantages of spreadsheets, and the auto upload using manufacturer software, there are third party spreadsheets that export to the manufacturer format. These are available to use as-is or to modify in their own format. Two examples are shown in Figure 7. To avoid the third party completely, you can develop these yourself in Excel, Mathcad, and with some extra Visual Basic® programming – in Word.





The resulting system would allow the engineer to enter the data in a self-documenting spreadsheet, which exports to the manufacturer database software format. The manufacturer database file is sent to the field for upload into the relay.

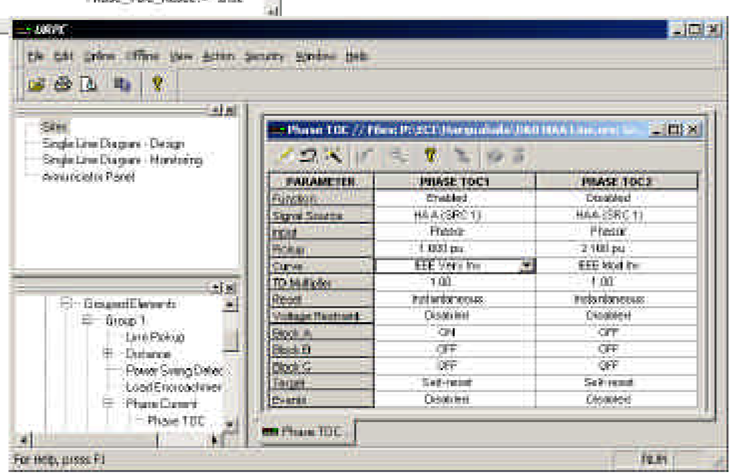


Figure 7: Two Example Mathcad Spreadsheets with Manufacturer File-Format Export Feature

Identifying the Problem when Field Tests Fail

A second practical problem when providing support to the field is helping field personnel determine why a test fails. There are some fundamental things that are prerequisites before this challenge can be approached. The first is to be comfortable and familiar with the field. This can only occur if you spend time in the field. Second, you must develop a relationship with the field personnel. Know their strengths and weaknesses, and they should know yours. You can complement one another. The third prerequisite is to know the relay and scheme. If it is the first time the relay or scheme is being used on your system, learn it, by having it at your desk prior to installation. This opportunity should also be made available for technicians.

Once these prerequisites are taken care of you can address this challenge. If you have to address the challenge prior to completing any of these, you can still address the challenge but with a little more difficulty.

For example, manufacturer application engineers may not have much field experience (some have a lot) and they usually do not have an ongoing relationship with the technicians (although some do), but they make up for it by knowing the relay extremely well (or they should).

On the other hand, a protection engineer may be supporting the installation of a brand new relay. The lack of understanding of the relay may be made up by knowledge of the field and the relationship with the field personnel.

Some practical solutions to identifying the problem when a field test fails include the following:

- Discontinue any further testing or changes.
- Know the test or procedure that failed.
- Ask lots of questions about the setup and situation, ensuring the field personnel that you are just trying to learn about what led up to the problem.
- Have prints available.
- Be aware of all equipment involved, auxiliaries, test switches, breakers, lights, SCADA, etc.
- Use the relay data recording capabilities to determine the problem.
- Try to repeat the problem.
- Use a temporary data recording set up and repeat the problem.
- Use analysis tools to monitor the relay – not the test equipment (See Figure 8 and Figure 9).
- Check if the relay is getting the test values properly.
- Have another set of eyes look at the data – another field person, another engineer, a manufacturer application engineer, or a consultant.

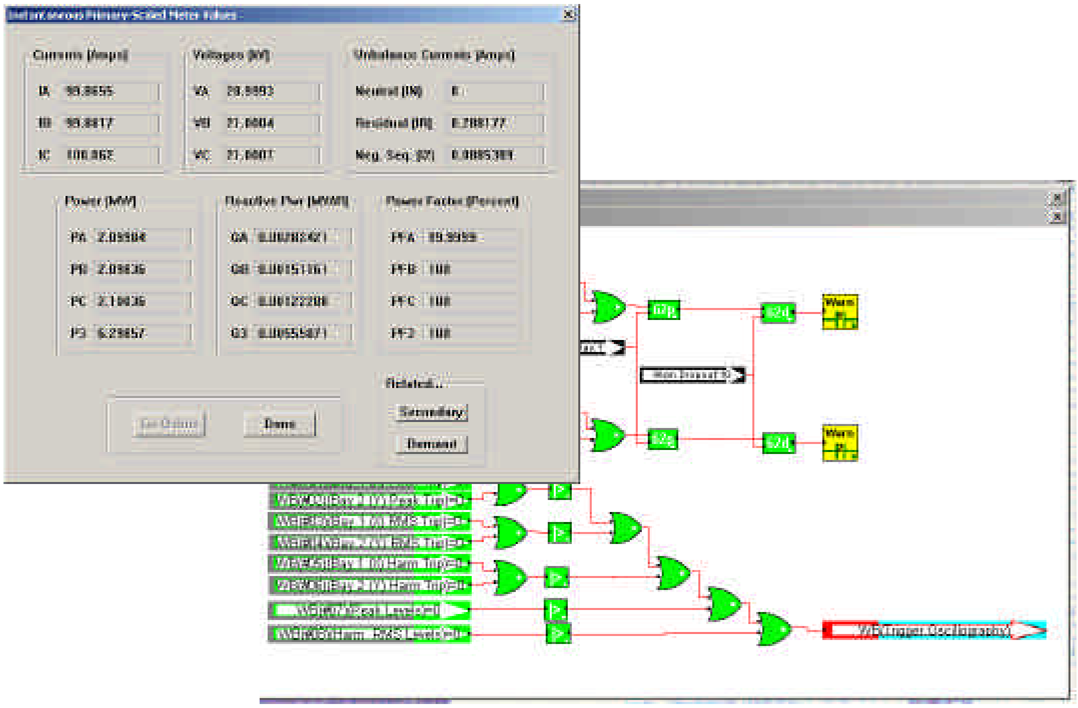


Figure 8: Example Manufacturer Monitoring Software Showing Logic States and Metering

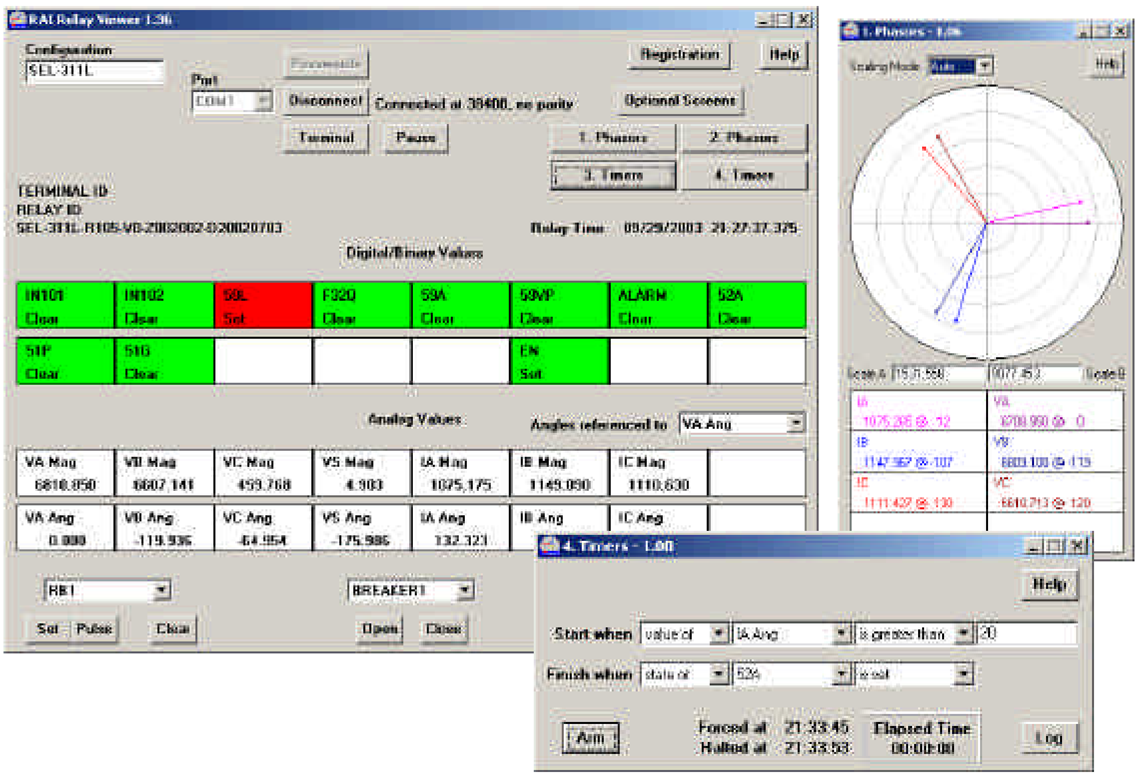


Figure 9: Example Third-party Relay Monitoring Software Showing Digital Logic States, Metering Phasors, and Test Timing Records

DOCUMENTATION

Recording Setting Calculations

When one engineer calculates setting thresholds for a relay and another engineer is tasked with changing them, reviewing them, or translating them to another relay, we realize the importance of recording the calculations. Recording calculations is fundamental to engineering, but it is often left undone. Which of these have you heard or used yourself?

“We have deadlines to meet. . .”

“The calculation is too simple to document. . .”

“It’s too much of a judgment call. . .”

“It’s what the instruction manual recommended. . .”

Documenting your calculations does not have to be difficult. The obvious method is to simply get out the pencil and paper. However, the first problem with this is that the return on your investment is minimal relative to other methods. For example, if the input value changes you must recalculate everything and change your document.

Software is already available on your PC to help you with this. Microsoft Excel, which is very common on business PCs, can perform calculations. For example, if you want to set your ground overcurrent element to 15% of an end-of-line fault, your Excel spreadsheet may look like Figure 10.

	A	B	C	D
1	**Relay Name**			
2	**Setting Name**	**Setting Value**	**Input Data**	
3	50NP	120	EOL GND-Fault	800
4				
5				
6				
7				

Figure 10: Example Excel Spreadsheet Calculation

The cell B3 contains the formula, ‘+D3*0.15’. Further sophistication is possible by letting 0.15 be input data as well. A downside of Excel is that to see the formula used for the calculation, one must highlight that particular cell.

Microsoft Word can also do calculations using the field codes and bookmarks equation. It’s a little more difficult to set up, but Word allows for a much better interface for adding desired text and formatting to the file. This is very useful for identifying “why” a setting is set at the shown value instead of just documenting “what” the setting is.

Often, utilities have standards that define the “why”. In these cases further documentation may not be necessary. As a consultant, each project may be different, so documenting the “why” is very important. So ask yourself “why” a setting is set to a certain value. If the documentation answers that question, it has achieved its goal.

A third choice requires purchasing additional software. Mathcad is a great tool for documenting calculations. The same calculation above looks like Figure 11 in Mathcad:

```
EOLGNDFAULT := 800

_50NP := 0.15·EOLGNDFAULT                    _50NP = 120
```

Figure 11: Example Mathcad Spreadsheet Calculation

In each of these cases a protection engineer could develop a file for a particular relay type and use it over and over again for future projects. It gives a reviewer a file for verification, and it is a training tool for new engineers setting relays on the next project. The upfront time to develop these files may be more than is available for a given protection engineer. If that is the case, pre-made Mathcad "spreadsheets" are available for some relays through third party companies.

There is no excuse not to document your calculations. Consider the person who follows you. They must be able to understand what you have done. That person may be you a few years from now.

Some preplanning will help. If the calculation is a judgment call, then say that in the documentation. If it is a simple calculation, then it is easy to automate and you don't have to worry about it again. If it is based on a manufacturer's recommendation, then you should know and understand why they recommend that and document their reasons as well.

These tools can also be used to input settings into manufacturers' programs or other setting databases. Manufacturer programs typically have a data file format for importing settings into the software. If you know what this format is, then your tool could build a file that may be read by the manufacturer's software. Again, this feature may be available through third party companies as well.

Settings Changes and Tracking Changes

Two weeks ago you completed your relay settings for Substation X. A call from operations informs you that they need to have the new line protection accommodate a longer line. Another section of line is going to be tapped into the new line to provide an alternate feed for a customer. Because of the timing of the clearances, the changes need to be issued as soon as possible.

Most protection engineers know this or a variation of it. This is not out of the ordinary. For most protection engineers, tackling this problem is very simple – but the simple solution is often the cause of future problems.

The simple solution is lowering the pickup or increasing the reach of a few settings. Because documentation of these changes can slow a project down it is apt to be left undone, which can cause future confusion and mistakes.

There are some solutions to quickly documenting a change. The first and probably most important is a revision number or date code that is correlated to the settings provided in the field. It can be as simple as an e-mail message:

From... Protection
To... Technician
Cc...
Subject: Sub X, Line 123, Relay A, Rev 1

To accommodate longer line change, the Sub X, Line 123,
Relay A settings as follows. These changes are considered Rev 1.

Existing:
Z1 = 3.2
51NP = 120

New:
Z1 = 4.5
51NP = 80

Figure 12: Example Email Message Documentation

The e-mail serves as a quick fix to keep the project moving, and it automatically records the date. Don't forget to give the settings a revision number. If you don't know what the last revision number was, go strictly by the date and time.

The follow-up step is to update your calculation documentation and note the corresponding revision number. If there isn't enough project time the e-mail step is of less importance and should be skipped, and your setting calculations become the document of record.

The final, but probably the most important solution to proper documentation and tracking changes, is to record the "as-left" settings. The last thing the field personnel should do is download the final relay settings. This is often referred to as the "as-left" or "as-built" settings.

RELAYS USED FOR INTEGRATION, AUTOMATION, AND CONTROL

This topic could easily be another paper, but the following discusses some challenges and solutions that should get you thinking about other challenges and even better solutions.

The protective relay is now a device that has most of the information that a traditional SCADA system requires plus much more event diagnostic information [9]. Many relays even allow breaker control to occur through the relay without additional electrically operated auxiliary switches. Automation is possible on the relay level using logic and protocols between relays instead of completely separate PLCs and additional wiring [5] [10].

Because of these capabilities protection engineers are faced with new practical challenges.

Softpoints or Hardpoints

Many systems today have an RTU in the substation along with the new relays. This provides a means for getting data either through the relay integration system (softpoint) or by direct wire (hardpoint). A simple example is the 52A status. A breaker auxiliary contact may be wired directly to an RTU or the relay integration system may report it since new designs have this status point already wired to the relay. Making the decision between using a hardpoint or a softpoint may not be within the protection engineer's job description. A separate department or consultant may be determining this.

At a minimum, the protection engineer should know how the decision affects the protection and be able to offer assistance to whoever is going to make the decision.

The following are some solutions to tackling this practical decision:

Develop a Standard

Integration standards will likely change faster than relaying standards, but an attempt should be made to have some consistency with other stations. Unless there is a significant advantage to changing how the data is gathered, then lean towards how it was done in the neighboring station.

Consider the Entire Cost of Each Choice

Are spare wires already in place or will new wire need to be installed? Do the softpoints require additional relay programming? Will the operation or testing of the softpoint limit the availability of the protection (i.e. relay must be cutout).

Be Cautious of Scope Creep

Once one data point is setup and available as a softpoint, many more may be very intriguing to you or others. This may be a good thing, or it could overwhelm a project budget and schedule.

Working with Other Departments

Anytime humans are involved, the challenge moves up a level. Often the integration system is determined and controlled by a department other than the protection department. A few solutions to addressing this challenge are as follows, but there are many more.

Stay Focused on the Primary Job of the Relay – Protection

Other aspects of the relay may reduce operating costs, simplify the wiring, provide quicker system restoration, or increase system capacities. These things are great advantages and should be used when possible, but none of them are worth the compromise of limiting protection or postponing a needed protection upgrade.

Never specify a relay solely on its integration capabilities. First identify a list of relays that meet your protection requirements. Then it is okay to select from this list which relay best meets your integration needs.

Leverage the Funding for Integration

New integration and control systems have significant financial advantages. Some were mentioned above. Therefore it is often easier to financially justify a new integration system as opposed to a new relay system. Now that the relays have the needed integration features plus more, the funding may be applied to the protection system.

Other Departments Make Changes That Impact Protection

As departments and companies get bigger, it becomes harder to communicate the right information to the right people. A challenge protection engineers are faced with is when other departments or even individuals make decisions that are within their own scope, but they do not realize the impact on the protection system. The following are some ways to avoid this.

Build Relationships

Stay in communication with other departments in order to build relationships and build the relationships to facilitate communication.

Meetings

As much as meetings take up our time, it is important to have a presence at project meetings. At least consider attending kickoff meetings to introduce yourself, provide contact information, and request regular updates. Consider this even if the project is considered a non-protection project.

Identify Relay Usage

During the development of standards, at the beginning of a project, or when considering a system change, identify all of the non-protection functions the relay will perform. This scope will likely change over the course of the project, but if something is added, the person will know you had not planned for it, and if something is removed, the person will know that it was part of the relay function. In both cases there is a basis for notifying the protection department of the change.

List Protection Items

Consider providing a list of items, systems, procedures, and policies that impact protection. Over the course of a 6-month period, write down all of the “types” of these items that you encounter in your job. At the end of 6 months you should have a fairly complete list. Provide the list to each department. An informal submission to other departments at a kickoff meeting usually works well. The other departments do not want more check-off lists to follow, so don’t force it upon them. Review this list once a year. If you are having formal trouble with departments not considering protection, ask to formalize the list as a procedural requirement.

Communicate with Manufacturers and Representatives

Another form of “department” is the manufacturer. Sometimes manufacturers change firmware, ordering options, or customer notification procedures, and it may impact your system. Know how each manufacturer provides technical update, product upgrade, product obsolescence, and procedural information. Include yourself on the appropriate notification lists or regularly check the website for posted information. Depending on the company or products, this communication may be through sales personnel, independent representatives, or company technical departments. Use industry conferences to communicate with the manufacturers, sales personnel, and other users about these items. Some manufacturers may agree to always send you the same version of firmware on all future relays purchased by your company. This can reduce many problems associated with updating software, setting sheets, and test plans, but it increases the risk of having older firmware with known operating concerns that are addressed by the new firmware.

Summary

Protection Engineering for power systems includes many challenges. These challenges range from very technical, unique system requirements, to deciding how to record an overcurrent element setting. The common technical challenges are often discussed in college and in industry training classes. The unique very technical issues are addressed in some industry texts. The practical, every day challenges are often overlooked and the engineer is left to figure them out on their own.

These challenges have solutions, but protection engineers must address them before the challenge affects the protection of the system. Many solutions take time, people skills, software, and experience that engineers do not have or are not comfortable using.

The solutions presented here are within the reach of any protection engineer and will help address the practical challenges before they adversely affect our protection systems.

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In January of 2000, Larry founded Relay Application Innovation, Inc. to provide services and tools to the power system protection industry. He has performed protection and integration services for a relay manufacturer, utilities, design consultants, industrial plants, system integrators, and construction companies.

Larry has written several application guides and technical papers about power system protection, monitoring, and control, and has presented in the U.S. and internationally.

He is author of a patent regarding protection against slow circuit breaker closures while synchronizing a generator. He has served on the Executive Board for the Advisory Council of the Electrical and Computer Science department of Washington State University. He is a registered Professional Engineer in several states, and is a Senior Member of the IEEE.