

Microprocessor-Based Distribution Relay Applications

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ABSTRACT

Advancements in technology using microprocessors have led to many improvements in distribution protection: lower installation and maintenance costs, better reliability, improved protection and control, and faster restoration of outages.

Microprocessor-based distribution relays provide technical improvements and cost savings in several ways. One improvement is the use of programmable logic to reduce and simplify wiring. The relays also provide protection for bus faults, breaker failure, and high-side transformer blown fuse detection at no or minimal additional cost. The relays have metering functions that reduce or eliminate the need for panel meters and transducers and provide remote targeting and fault location information to assist operators in the restoration of electrical service. Finally, microprocessor-based relays reduce maintenance costs by providing self-test features and high reliability.

INTRODUCTION

Microprocessor-based distribution relays contribute to improved reliability and reduced costs on electric power systems. Microprocessor-based relays, also called digital relays, have a proven track record of reliability, with over 100,000 relay-years of field experience. Microprocessor-based relays provide technical improvements and cost savings in several ways:

- The relays use programmable logic to reduce and simplify wiring.
- The relays provide protection for bus faults, breaker failure, and high-side transformer blown fuse detection at no or minimal additional cost.
- The relays have metering functions to reduce or eliminate the need for panel meters and transducers.
- The relays reduce maintenance costs by providing self-test functions and high reliability.
- The relays provide remote targets and fault location information to assist operators in restoration of electrical service.

In this paper, we show many examples of how these technical improvements and cost savings are manifest.

USING MICROPROCESSOR-BASED RELAYS REDUCES AND SIMPLIFIES WIRING

Many microprocessor-based relays have features that, when implemented, reduce and simplify the wiring and connections of an installation. We show three examples of this:

- How to use programmable logic to implement a fuse-saving scheme on a distribution feeder.

- How to use programmable logic and control inputs to provide fast bus protection to replace a current differential protection scheme.
- How to simplify CT connections for transformer differential protection.

Using Programmable Logic to Implement a Fuse-Saving Scheme

In a typical fuse-saving scheme, we apply time-overcurrent (51) and instantaneous overcurrent (50) relays with automatic reclosing on a breaker (F) to coordinate with a downstream fuse (F1). For a fault beyond the fuse F1, the intention is for the instantaneous overcurrent relay to trip the breaker so the fault clears before the fuse begins to melt. Then, we automatically reclose breaker F. If the fault is temporary, we avoid a prolonged outage to customers served from the F1 tap. However, all of the customers served by the feeder will have a momentary outage. If the fault is permanent, we block the instantaneous overcurrent at F, and allow the fuse to clear the fault. Figures 1a and 1b show a one-line diagram and time-overcurrent coordination for a fuse-saving scheme.

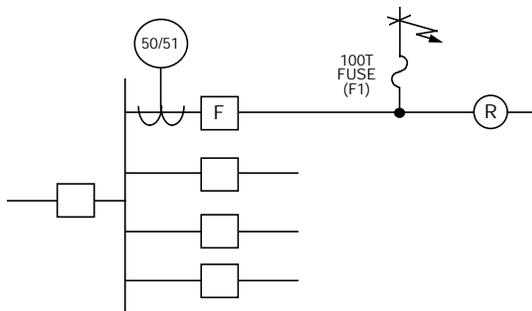


Figure 1a: One-Line of Distribution Feeder

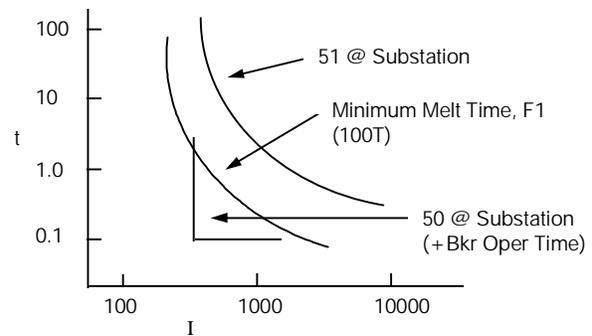


Figure 1b: Time-Overcurrent Curves for Fuse-Saving

Let us suppose we apply four single-phase overcurrent relays with time (51) and instantaneous (50) elements. In the dc control circuit connections, we must parallel all of the 51 elements and parallel all of the 50 elements. Then, we use a contact from a separate reclosing relay (INST BLOCK) to block the instantaneous elements after the first trip.

Using a microprocessor-based relay, we can program these functions internally. Suppose we want the phase and ground time-overcurrent elements (**51, 51N**) to trip directly and the phase and ground instantaneous (**50, 50N**) to trip only for the first shot. If we use the Boolean symbols AND (*) and OR (+), we can program the TRIP conditions as follows:

$$\text{TRIP} = 51 + 51N + (50 + 50N) * (1\text{st shot only})$$

Therefore, the relay programming allows a trip for phase OR ground time-overcurrent. Also, the relay programming allows trip for (phase OR ground instantaneous) AND (1st shot only). If a fault occurs on the feeder, the relay trips the breaker instantaneously on the first shot to “save” the fuse from operating. The relay then blocks the instantaneous overcurrents (50, 50N) on subsequent trips to allow the fuse to trip. Figures 2a and 2b show the control circuit connections using traditional relaying and microprocessor-based relaying with programmable logic.

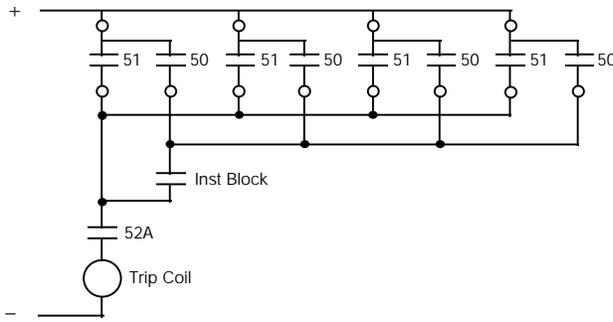


Figure 2a: Trip Circuit Using Conventional Relaying

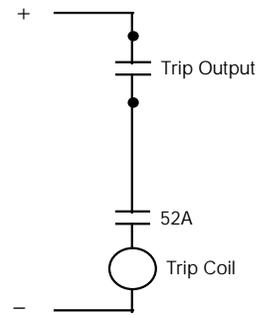


Figure 2b: Using Microprocessor-Based Relay

By using programmable logic, we require only one output contact, significantly reducing wiring and simplifying the control circuit.

Using Programmable Logic and Control Inputs to Provide Fast Bus Protection

Many utilities are applying microprocessor-based overcurrent relays in place of current differential relays to provide fast bus protection. In many cases, utilities do not apply bus differential protection because of the high installation cost of the breaker CTs and the profusion of CT wiring.

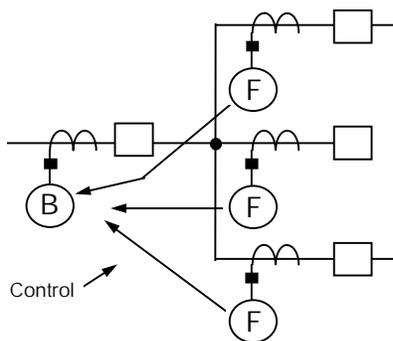


Figure 3a: Fast Bus Trip Scheme

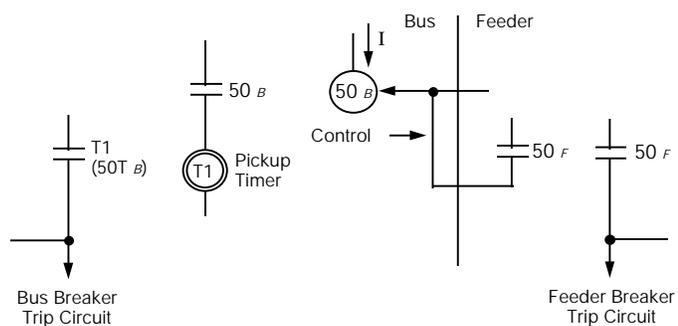


Figure 3b: DC Control Implementation

Figures 3a and 3b show fast bus protection. Instantaneous overcurrent relaying on the feeder breakers (50F) provides a control input to an instantaneous overcurrent relay with a short definite-time delay on a low-side transformer breaker or switch (50B, T1). If any of the feeder relays (F) assert, they trip their respective breaker and block the backup relay (B). However, if the fault is on the bus, none of the feeder relays operate, and the backup relay trips the bus nearly instantaneously. One utility has successfully applied this scheme with a 2-cycle time delay (pickup timer T1) for bus faults [1].

Simplifying Transformer Differential CT Connections

On power transformers greater than 10 MVA, most utilities apply transformer differential relays. With conventional relays, when any transformer winding is connected delta, you must connect the CTs wye, and vice versa. For example, if a transformer is connected delta-wye, you must connect the CTs wye on the delta side of the bank, and delta on the wye side of the bank. Figure 4 shows a typical connection.

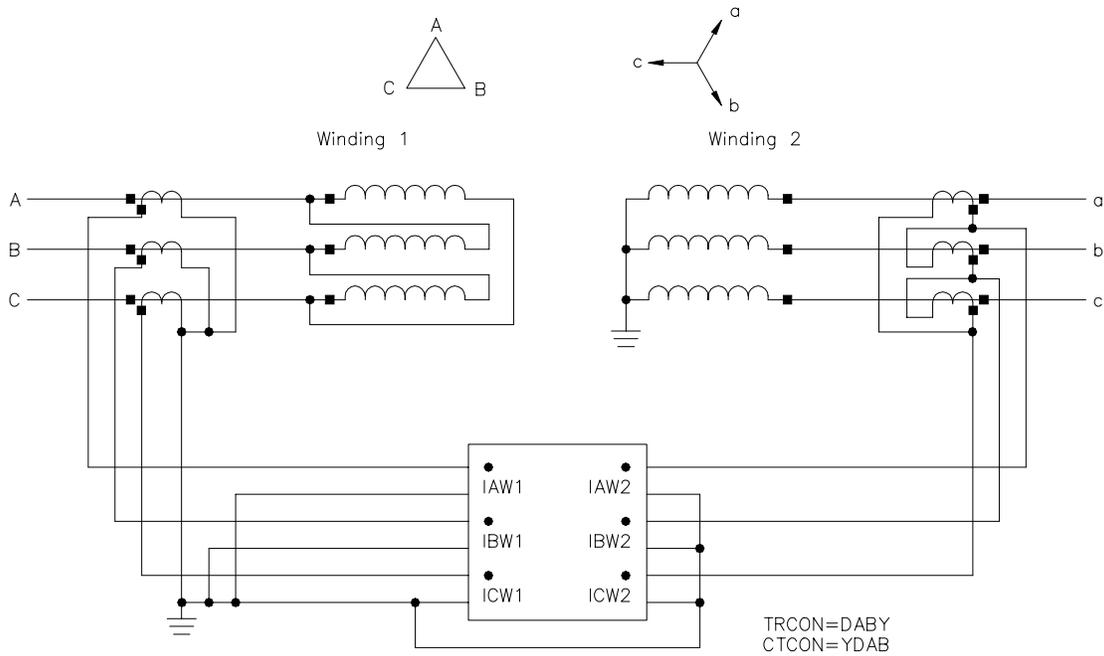


Figure 4: Delta-Wye Transformer With Wye-Delta Connected CTs

Microprocessor-based transformer differential relays can "make" the delta internally. Therefore, you can connect the CTs in wye on both sides of the bank, regardless of the transformer bank connection. Also, microprocessor-based relays can provide easy current magnitude and angle checks to ensure proper connections.

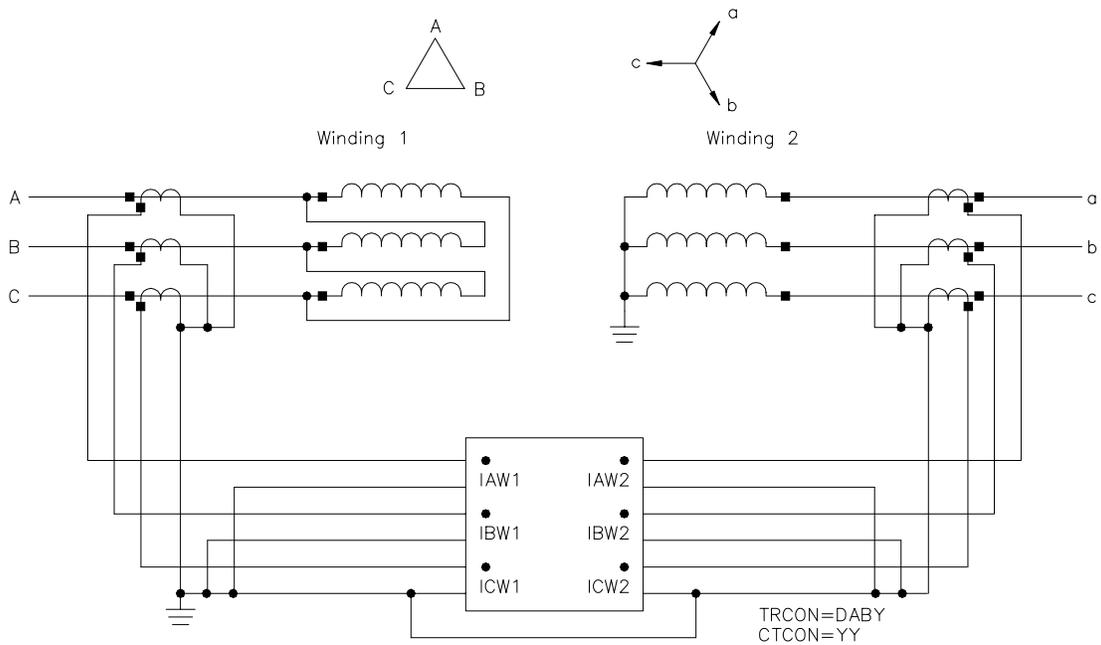


Figure 5: Delta-Wye Transformer With Wye-Wye Connected CTs

This provides two advantages:

- Wye-delta transformer applications no longer require dedicated CTs. We can use the transformer differential CTs for other overcurrent protection or metering functions.
- Using wye-connected CTs eliminates common wiring errors that often occur when making up a delta connection.

IMPROVED PROTECTION AND CONTROL FOR COMMON DISTRIBUTION PROBLEMS

Backup Protection

One common concern when using microprocessor-based relays is backup protection. What if a relay fails? Do you have “all eggs in one basket”?

Here is an example of how numerous utilities address this concern. An alarm contact from each of the feeder relays is connected to permit the backup relay to directly trip the breaker for the alarmed feeder. At the same time, the settings on the backup relay can be changed to provide additional sensitivity to permit the backup relay to adequately protect the alarmed feeder, without sacrificing coordination with other feeder relays.

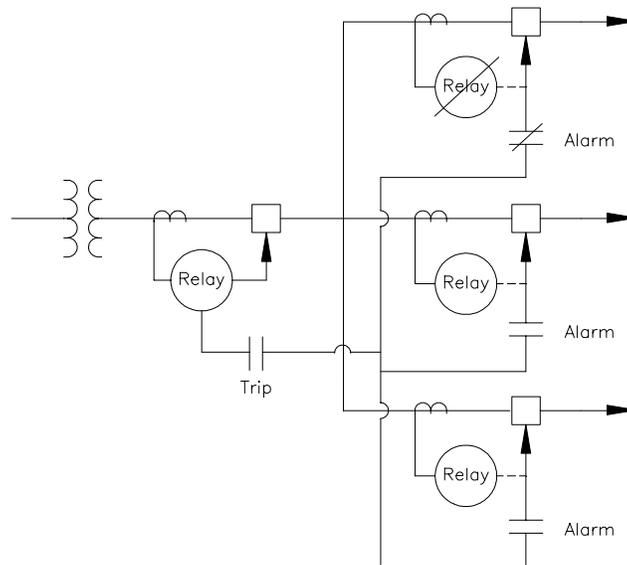


Figure 6: Improve Backup Relaying

If a feeder relay fails, its alarm contact closes. We connect the alarm contact in series with a trip output from a backup relay, which, when asserted, produces a feeder breaker trip. If the utility applies a low-side transformer overcurrent relay, there is no additional cost except for the control wiring of the trip circuit.

Breaker Failure Protection

Many microprocessor-based distribution relays are equipped with internal timers that, along with a relay trip condition, can be used to provide breaker failure protection.

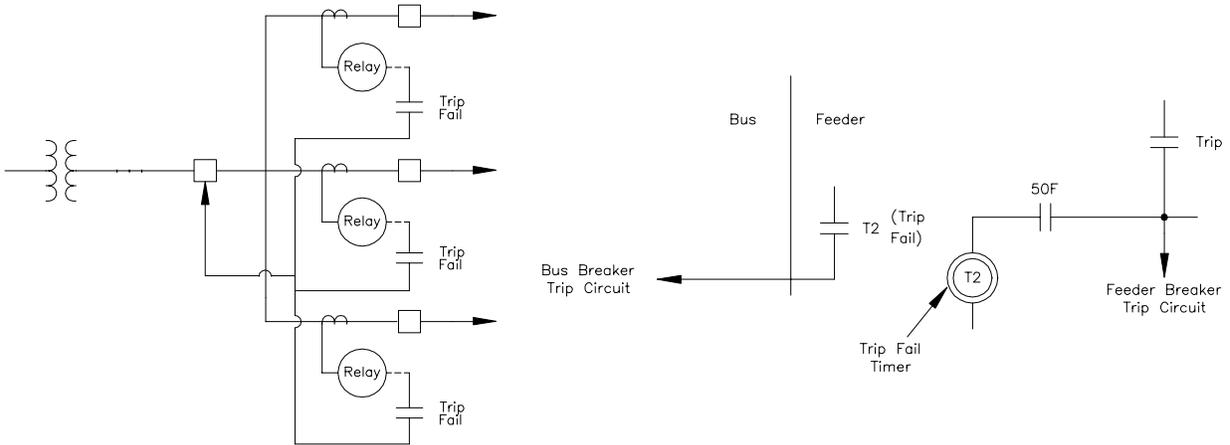


Figure 7: Breaker Failure Relaying

Change Protection Based on Day/Date/Hour

Utilities may wish to provide fuse-saving or other sensitive protection, but they may also wish to avoid or reduce nuisance operations during hours when critical customers are in operation. Microprocessor-based relays allow the utility to change protection settings and logic based on time-of-day and day-of-week.

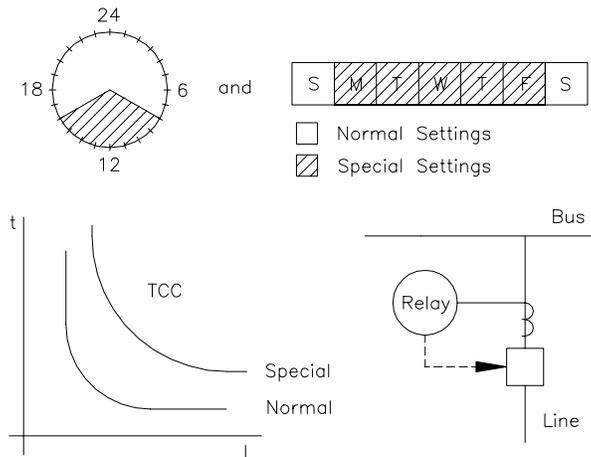


Figure 8: Change Protection Based on Time-of-Day and Day-of-Week

Change Protection Based on System Conditions

Protection requirements can change with system load and configuration. Conventional protection schemes must accommodate the worst-case operating scenario, compromising sensitivity and/or coordination under normal conditions. One improvement to distribution protection may be to change distribution relay settings on each digital feeder relay when phase current demand or neutral current demand exceeds specified levels. The original settings are highly sensitive. The new setting has less sensitive phase and residual overcurrent settings that tolerate higher loading but have reduced, but adequate, sensitivity. Relay settings on all circuits are changed to a third level when any one of the distribution relays trip. The third level settings have a longer time delay to tolerate cold load inrush

following an outage on any of the distribution circuits. When all conditions return to normal for a prescribed time, the digital relays change back to their original settings.

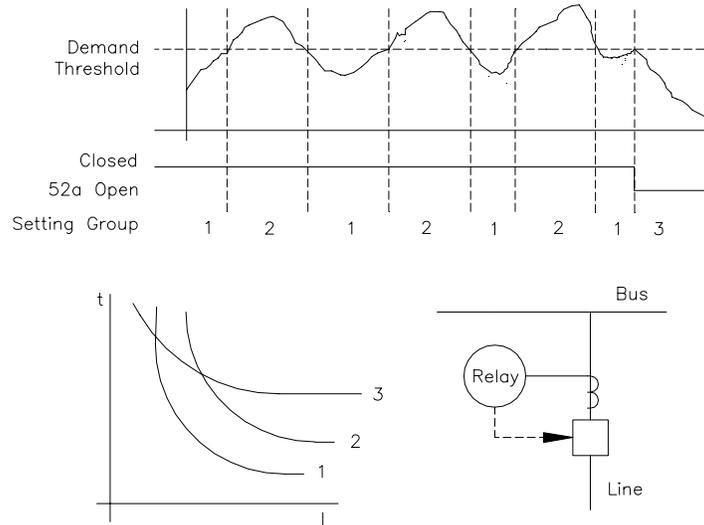


Figure 9: Change Protection Based on Load and Breaker Status

Detecting High-Side Fuse Operations

Delta-wye connected distribution transformer banks are frequently protected by fuses connected in the bank high-side, as shown in Figure 10. When a fuse blows, the voltages applied to the transformer bank and its connected load are unbalanced. The unbalanced voltage causes a large amount of negative-sequence current to flow in the load. When the load consists of induction motors, the motors can sustain damage if the negative-sequence current is present too long. It is also important to avoid tripping if a low-side VT fuse blows.

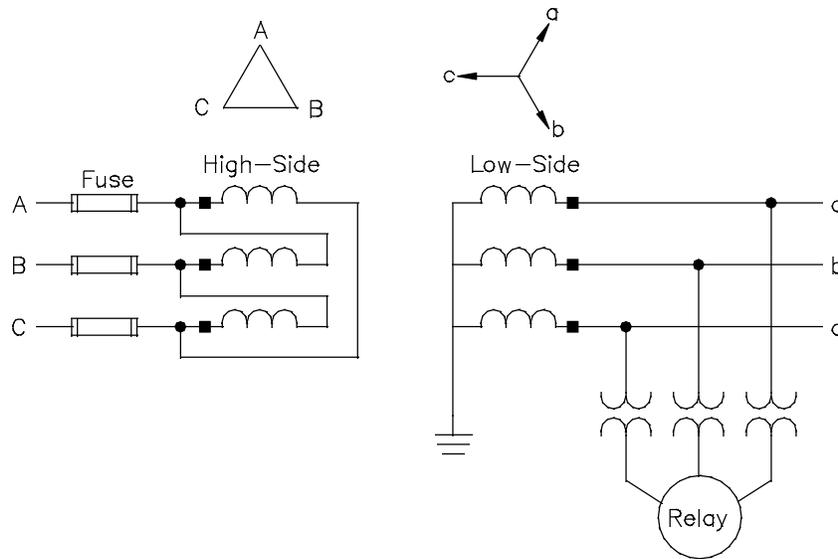


Figure 10: High-Side Blown Fuse Detection

When a transformer high-side fuse operates, the low-side phase-to-phase voltage magnitudes decrease. One phase-to-phase voltage magnitude goes to zero (assuming balanced load conditions), and the remaining two decrease to 0.87 per unit of nominal voltage. If two high-side fuses operate, the low-side phase-to-phase voltages all go to zero.

If a VT secondary fuse blows while the transformer bank is otherwise operating normally, two of the phase-to-phase voltages presented to the relay decrease to 0.58 per unit of nominal voltage. If two VT secondary fuses operate, one phase-to-phase voltage measured by the relay goes to zero, while the other two decrease to 0.58 per unit.

To use the undervoltage logic in this application, make the following relay setting calculations:

$$27L = 0.40 \cdot V_{nom}$$

$$27H = 0.72 \cdot V_{nom}$$

$$V_{nom} = \text{Nominal Phase - Phase Voltage, } V \text{ secondary}$$

Internal logic in the relay provides for an undervoltage, **27** element, where:

$$\mathbf{27} = (\text{Any phase-to-phase voltage less than } 0.4 \text{ pu}) * (\text{Any phase-to-phase voltage greater than } 0.72 \text{ pu})$$

(* = AND)

If a transformer fuse operates, one phase-to-phase voltage approaches zero (satisfying the left portion of the equation above), and the remaining phase-to-phase voltages stay above 0.72 per unit (satisfying the right portion of the equation). If one or more VT fuses operate, the phase-phase voltages drop below the 0.72 per unit threshold, and the **27** equation is not satisfied.

Coordination With Other Devices

Microprocessor-based distribution relays can coordinate easily with other overcurrent devices. Relay characteristics are usually defined by mathematical equations. These equations model electrical and physical characteristics. We can set most microprocessor-based relays to emulate induction disk (time-delayed) reset characteristics or solid state “instantaneous” reset. A new IEEE standard defines the equations for inverse, very inverse, moderately inverse, and extremely inverse curves [4].

Since overcurrent elements and reclosing functions are usually included in the same hardware package, we can also use these functions for improved coordination. In addition to the “fuse-saving” scheme described earlier, we can also coordinate with downstream line reclosers.

If the reset time delay of a traditional reclosing relay is less than the trip time of an overcurrent relay for a low-current fault, the following can occur. A low-current fault occurs, causing an overcurrent relay to trip the breaker. Then, the reclosing relay closes the breaker. The reclosing relay times to reset, and then the overcurrent relay trips the breaker again. Because the reclosing relay times to reset, it never advances to its second reclose attempt. Some utility operators have reported locking out breakers that have reclosed over ten times! Microprocessor-based relays solve this by blocking automatic reclose of a breaker whenever an overcurrent element asserts.

MICROPROCESSOR-BASED RELAYS REDUCE MAINTENANCE

Microprocessor-based relays, also called digital relays, typically consist of an ac signal data acquisition system, a microprocessor, memory components containing relay algorithms, contact inputs to control the relay, and contact outputs to control other equipment. Figure 11 shows a simple hardware block diagram.

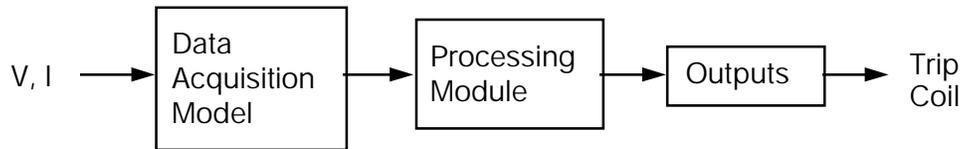


Figure 11: Simple Functional Block Diagram of Digital Relay

Voltage and current inputs are isolated, filtered, and sampled. Then they are scaled and converted to digital quantities for the microprocessor. The microprocessor program filters the data, creates the relay characteristics, and controls the relay outputs.

Most digital relays have automatic self-test functions, which verify the correct operation of the relay. Virtually everything in the relay is subject to self-tests except the analog inputs and contact input and output circuitry. If a self-test detects an abnormal condition, it can close an output contact, send a message, or provide some other indication of failure. We can connect the self-test alarm output to a SCADA RTU or other monitoring point to quickly dispatch a technician to repair or replace the device. Therefore, when we test a digital relay, we need to test only what is necessary. This usually consists of executing a meter check through a communication port, and verifying that the outputs operate.

If we compare this to a traditional scheme, here is what we may find:

- For a typical feeder with four electromechanical overcurrent relays, if it takes approximately one hour to test each relay, it takes four hours to test the feeder relays.
- For a substation with four feeders, it would take approximately two days to test the relays.
- A typical microprocessor-based relay, with simple meter checks on the input currents and voltages and trip checks on the outputs, takes less than one hour to test.
- For a substation with four feeders, a technician can test every relay on the bus in four hours, leaving time for other important testing.

One important study [5] supports this philosophy of relay testing. The study shows that digital relays equipped with effective self-tests provide better availability than traditional (electromechanical) relays. Also, digital relays are more available to protect feeders when they are not removed from service for routine maintenance tests unless a self-test failure is detected. Put another way, we reduce reliability when we remove relays from service for routine testing.

MICROPROCESSOR-BASED RELAYS PROVIDE DATA THROUGHOUT THE UTILITY

Microprocessor-based relays provide metering data, targets, status information, and fault location, in addition to protection functions. This data is accessed through relay communications ports, local displays, or other human-machine interface (HMI). Many individuals within a utility organization use the data. For example, operators may need to know targets and fault location for a particular electrical disturbance. Planning engineers may wish to analyze load demand data collected from a feeder relay.

Relay engineers may need to analyze an event report to explain a fault on a line that serves a critical customer load. Figure 12 shows a “relaycentric” view of the utility.

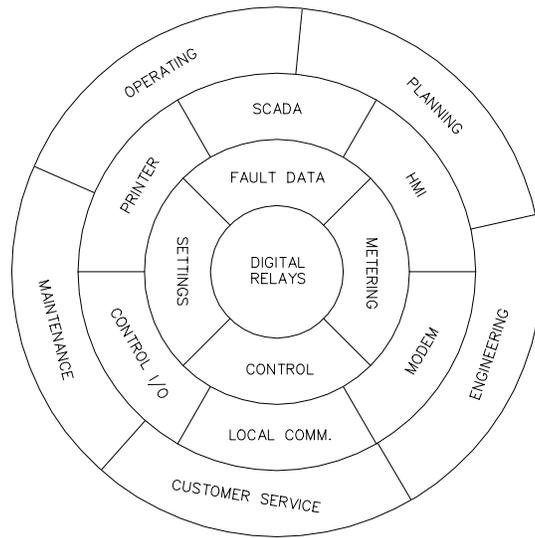


Figure 12: Relay Interface with Utility

Metering and SCADA/RTU Interface

Real-time digital relay data is of particular value for system operating personnel. Real-time voltage, current, watt, and VAR data are needed to operate a system. Fault type and fault location, unavailable until the advent of fault-locating digital relays, are now required by most operating and dispatch centers to guide system restoration.

Conventional SCADA RTUs accept only analog inputs (scaled current or voltage) and status inputs (dry or voltage wetted contacts). Often, it is less costly to use a digital-to-analog converter for operators to gain access to relay data, rather than install separate transducers and additional wiring.

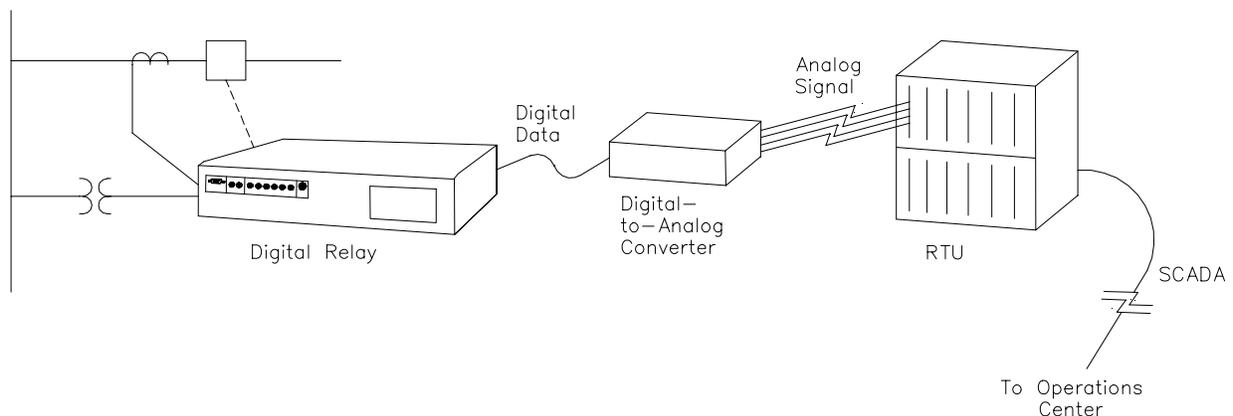


Figure 13: Interface Between Digital Relay and Analog RTU

Many modern RTUs operate on digital principles that allow direct acquisition of digital data, permitting a direct interface between the RTU and digital relays. Although communication protocol issues can

complicate the use of this interface, many RTU vendors have developed simple and effective methods to establish this communication interface. Maintaining the digital relay data in digital format has the obvious advantage of security, maintained accuracy, and data handling efficiencies that produce better results at a lower cost. Other advantages accrue because more data are available from the digital relay than basic meter and fault data, including relay targets, relay elements, breaker interruption data, event history, relay self-test status, and settings.

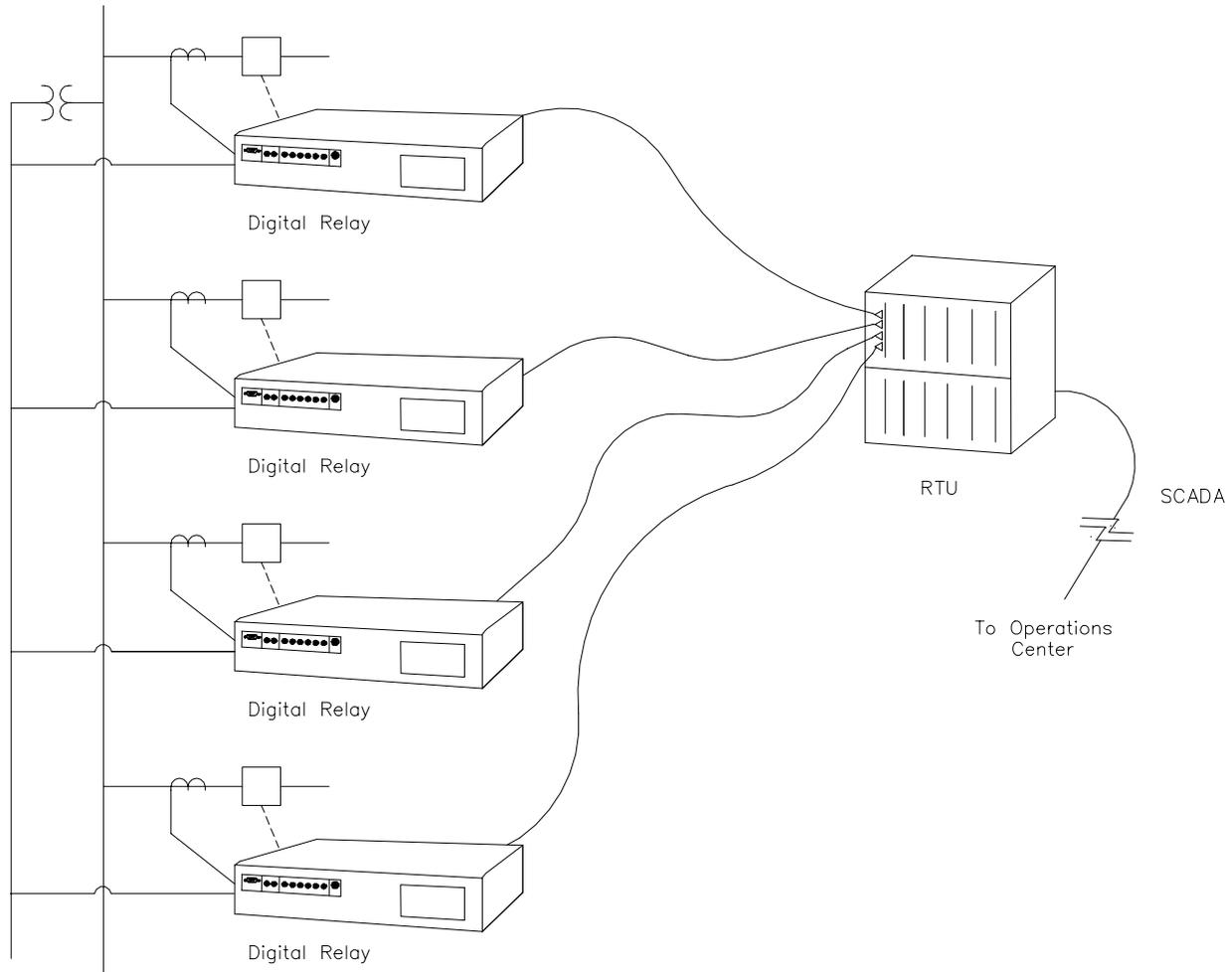


Figure 14: Communication Interface Between Digital Relays and Multiport Digital RTU

Locating Faults

Although fault location on distribution feeders is accurate only with limitations, the data is still useful for sectionalizing or even dispatching line crews for repairs. Ideally, the line has the same conductor size throughout the length of the line, is an overhead line, and has no infeed through grounded transformer banks, capacitors, generators, or other sources. Figure 15 shows that engineers, operators, and customer service personnel can access the relay remotely via modem communications.

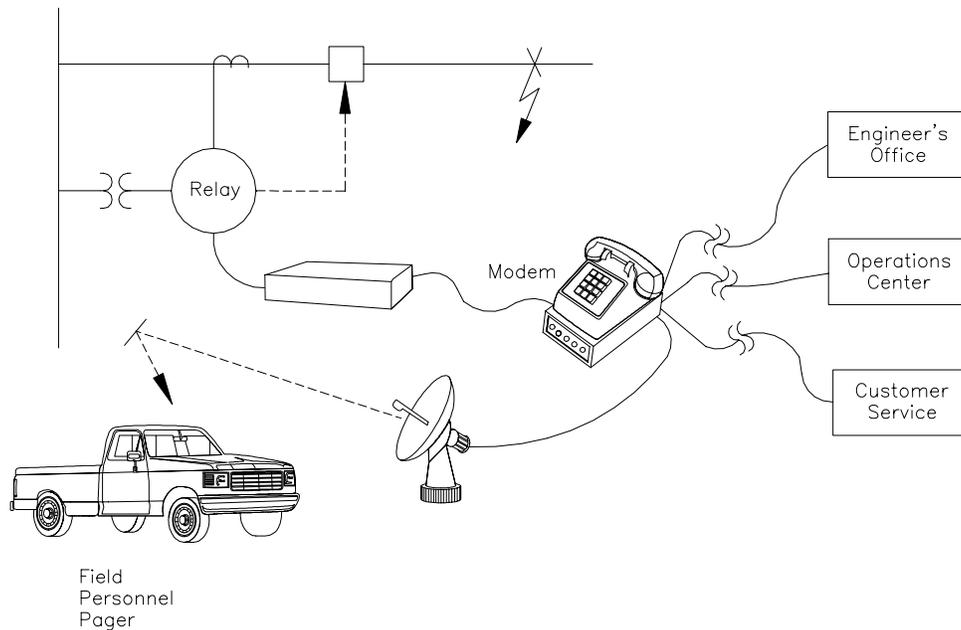


Figure 15: Remotely Accessing a Relay for Fault and Targeting Data

CONCLUSIONS

Many utilities are now applying microprocessor-based relays on distribution circuits. One utility attributes savings of \$40K on their 13 kV substations and savings of \$150K on their 34 kV substations to the use of microprocessor-based distribution relays [1].

Although technology is continually evolving, microprocessor-based relays cannot be considered “new.” Protective relays have been produced since the mid-1980’s, with over 100,000 relay-years of experience. In the future, we expect to see more innovations and improvements that contribute to more reliable and lower cost electric power systems.

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