

Optimized Distribution Feeder Protection With Remote and Local Control

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Presented at the
DistribuTECH Conference
San Diego, California
February 5–7, 2001

Originally presented at the
China International Conference on Electricity Distribution, October 2000

OPTIMIZED DISTRIBUTION FEEDER PROTECTION WITH REMOTE AND LOCAL CONTROL

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ABSTRACT

A recently developed microprocessor-based protective relay provides feeder protection, control, metering, monitoring, and automation functions in one package. Built-in local and remote switch functions, latching relay functions, local display elements, and serial port communications make this relay suitable for substation automation projects. Programmable front-panel operator control buttons and indicating lamps further enhance applications. The control buttons can enable/disable protection functions such as underfrequency load shedding and ground overcurrent elements. The relay front panel also supports breaker open and close functions. An application example illustrates the replacement of an electromechanical protection and control scheme by the microprocessor-based relay. This replacement brought significant cost savings while simultaneously providing automation capabilities for improved system operation.

INTRODUCTION

Microprocessor-based relaying opened new vistas for the design and application of substation feeder protection and control. The numerous features of numerical relays afford many functions that previously required single-function devices. For instance, typical hardware used in historic distribution feeder applications included single-phase overcurrent relays for phase and ground fault protection, a separate reclosing relay for multiple-shot breaker control, panel meters and associated selector switches for local viewing of feeder voltage and current, and breaker trip/close switches with associated indicating lamps. The relays, meters, and switches required regular inspection and testing to identify hardware degradation and loss of calibration. Faulty electromechanical relay components could, in theory, go undiscovered for long periods of time and fail to operate when needed. The latest generation of numerical feeder protection relays addresses reliability and testing concerns while providing extensive functionality at relatively low installation and operation costs.

PROTECTION FUNCTIONS

Figure 1 shows an example of the protection and control functions provided by a microprocessor feeder protection relay. Eight analog input channels accommodate four input currents and four input voltages. This combination supports a wide range of distribution feeder protection and control functions in a single hardware package.

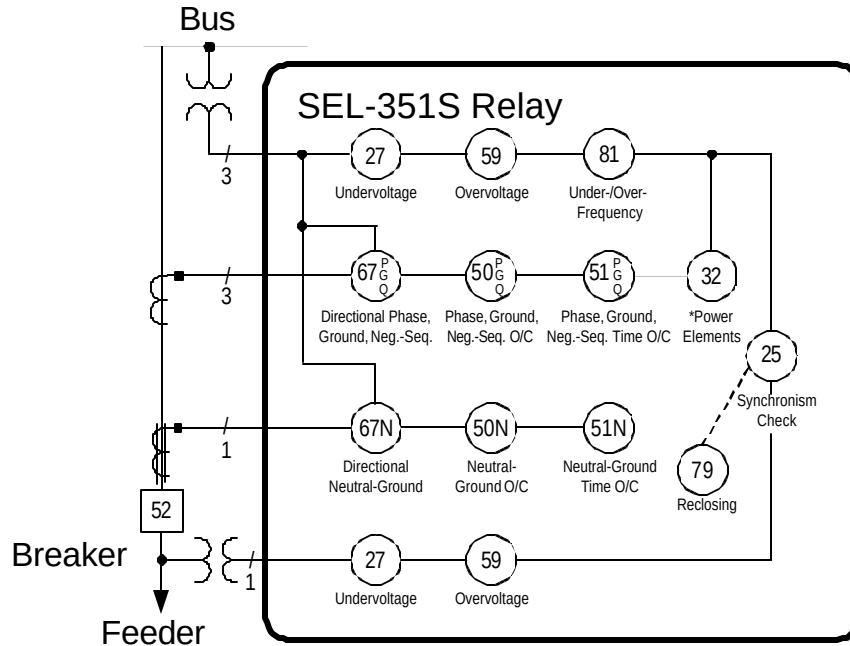


Figure 1 Functional Diagram for Digital Feeder Protection Relay

A common belief about electromechanical, single-function overcurrent protection schemes was that they had redundancy. In fact, they did not. For example, if the ground overcurrent relay failed, the typically higher-set phase overcurrent relay of the faulted phase could not sense a fault that had only a slight amount of resistance. Attempting to lower the pickup of the phase overcurrent protection only decreased security because of load concerns.

Phase Overcurrent Elements

As shown in Figure 1, a sensitive and secure mix of phase, negative-sequence, residual-ground, and neutral-ground overcurrent elements provides the core functions for coordinated overcurrent protection schemes. Both phase and negative-sequence overcurrent elements detect phase faults. The negative-sequence elements that do not respond to balanced three-phase load currents show an increased sensitivity for phase-to-phase faults, as compared with phase current elements. Phase overcurrent elements protect for three-phase faults where significant negative-sequence quantities are typically not present during a balanced fault.

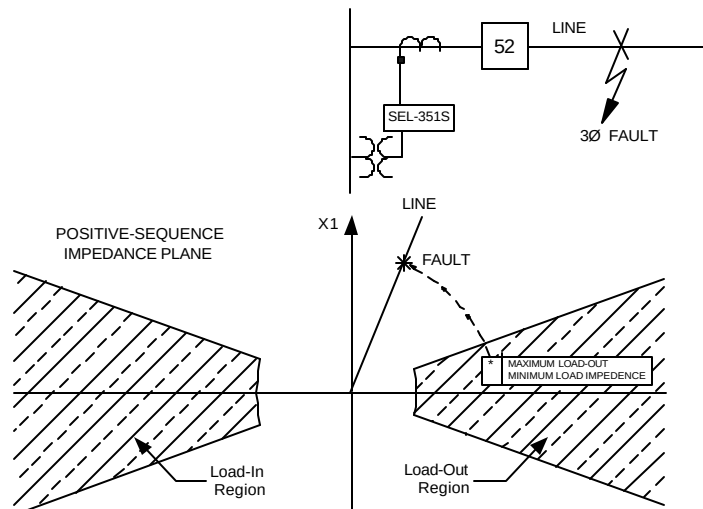


Figure 2 Load-Encroachment Logic Security for Sensitive Phase Overcurrent Settings

On heavily loaded feeders, load-encroachment logic adds security to an overcurrent protection scheme. This logic allows secure setting of phase overcurrent element pickup below load to see end-of-line phase faults in heavily loaded feeder applications. The logic uses positive-sequence load-in and load-out region elements to discriminate between load and fault conditions, as described by Roberts and Zimmerman in reference [1]. As shown in Figure 2, the load-encroachment logic blocks phase overcurrent elements when the load impedance, Z_1 , resides in a load region. When a three-phase fault occurs, Z_1 moves from a load region to the line angle, at which time the load-encroachment logic resets and unblocks the phase overcurrent elements. The logic also controls the phase directional element. Torque-controlling the phase overcurrent elements with the phase directional element then automatically includes load-encroachment torque control. It is also possible to torque control the phase overcurrent elements through external input.

Ground Overcurrent Elements

Residual (I_G) and neutral (I_N) overcurrent elements detect phase-to-ground faults. Controlling these elements using optoisolated inputs or with the internal ground directional element increases security. The ground directional element includes load-adaptive security logic for heavily or lightly loaded unbalanced feeder applications.

Directional Elements

Phase and ground directional elements provide directional control of the phase and negative-sequence overcurrent elements, and for the ground and neutral overcurrent elements, respectively. An automatic setting mode sets all directional threshold settings based upon replica line-impedance settings.

The phase directional characteristics include positive-sequence and negative-sequence directional elements that work together. Memory in the positive-sequence directional element provides a reliable output for close-in, forward- or reverse-bolted, three-phase faults where each phase voltage is zero. The negative-sequence directional element uses a patented operating principle implemented in other distance protection relays used in EHV/HV applications.

Three directional elements work together to provide ground directional function. They include a negative-sequence voltage-polarized element, a zero-sequence voltage-polarized directional element, and a zero-sequence current-polarized directional element. A unique logic scheme selects the best ground directional element for the system conditions. This logic eliminates directional element settings for almost all applications. It can be overridden for special applications.

Frequency Relaying

Up to six steps of under-/overfrequency levels allow implementation of an internal multistage frequency trip/restore scheme at each breaker location. Independently time-delayed outputs of these elements shed load or trip local generation. Phase undervoltage supervision prevents undesired frequency element operation during and immediately following faults. Built-in frequency elements avoid the cost of wiring a complicated trip and control scheme from a separate frequency relay. Figure 3 illustrates a portion of the user-interface setting screen for setting each frequency step and associated timer.

Frequency Elements

E81 Enable Frequency Elements

E81 Frequency Elements Enable: Select: N, 1 - 8

27581P Undervoltage Block (Volts secondary): Range = 40.00 - 300.00

Level 1

B1D1P Level 1 Pickup (Hz): Range = 40.10 - 65.00, OFF

B1D1D Level 1 Time Delay (cycles in 0.25 increments): Range = 2.00 - 16000.00

Level 2

B1D2P Level 2 Pickup (Hz): Range = 40.10 - 65.00, OFF

B1D2D Level 2 Time Delay (cycles in 0.25 increments): Range = 2.00 - 16000.00

Figure 3 User-Interface Screen for Setting Frequency Elements and Associated Timers

Power Elements

The relay includes four independently set power elements, each set to detect either: positive (forward) or negative (reverse) real power, or positive (forward lagging) or negative (reverse lagging) reactive power. Each element has an independently set time delay. Figure 4 shows a portion of the relay settings from the settings menu.

Power Elements

EPWR Enable Power Elements

4 Select: N, 1 - 4

Level 1 Per Phase Power Element Pickup

PWR1P Per Phase Power Element Pickup (VA secondary)

1.00 Range = 1.00 - 6500.00, OFF

PWR1T Power Element Type

+VARS Select: +WATTS, -WATTS, +VARS, -VARS

PWR1D Power Element Time Delay (cycles in 0.25 increments)

0.00 Range = 0.00 - 16000.00

Figure 4 User Settings for Directional Power Elements

Relay engineers often apply power elements in capacitor bank switching/VAR control schemes, for reverse power detection for cogeneration schemes, and for open phase detection.

Figure 5 shows a scheme with capacitor bank control, and overcurrent protection. In this scheme, Relay 1 senses total bus VAR loading and uses power elements (set as VAR elements) to provide VAR control by tripping and closing the capacitor bank circuit breaker 52-C at selected bus reactive-power levels.

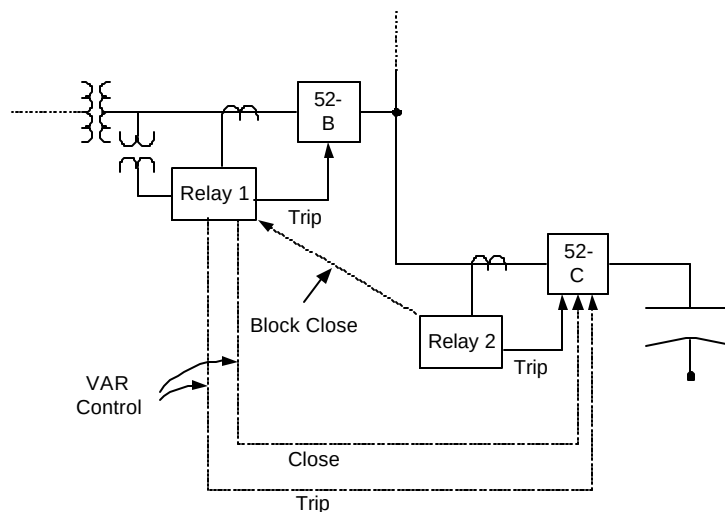


Figure 5 Capacitor Bank Protection and Control

Relay 2 provides overcurrent protection for the capacitor bank. If Relay 2 trips the capacitor off-line for a fault condition, it sends a block signal to Relay 1 to prevent Relay 1 from trying to close circuit breaker 52-C for VAR control. Internal relay logic performs these control functions.

Fault Locator

An accurate estimation of fault location contributes to efficient dispatch of line crews and faster restoration of electric service to customers. The fault-locating algorithm uses fault type, replica line impedance settings, and fault conditions to develop an estimate of fault location without communications channels, special instrument transformers, or pre-fault information.

CONTROL FUNCTIONS

Programmable operator controls on the relay provide an interface for 10 different functions. Figure 6 shows the assigned factory defaults for these controls. The availability of operator controls on the relay helps minimize panel space requirements and the cost for wiring external control switches and indicating lamps.

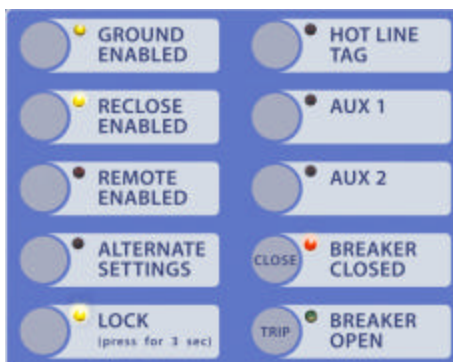


Figure 6 Programmable Front-Panel Operator Control Buttons

Breaker Trip

Figure 7a shows an application of the “TRIP” pushbutton. This example has the “TRIP” operator control button set with a fixed time delay since most situations involving front-panel tripping are not emergencies (e.g., the operator has to open the breaker after bypassing it for maintenance). The time delay allows an operator to move a safe distance away from the breaker before the relay issues a trip.

The operational sequence follows:

After an operator presses the “TRIP” control button, the corresponding BREAKER OPEN LED flashes on and off, indicating a pending trip. After a user-set time delay, the relay completes the trip sequence, and the BREAKER OPEN LED illuminates continuously.

The pending trip can be aborted by pressing the “TRIP” control button again or by pressing the “CLOSE” control button.

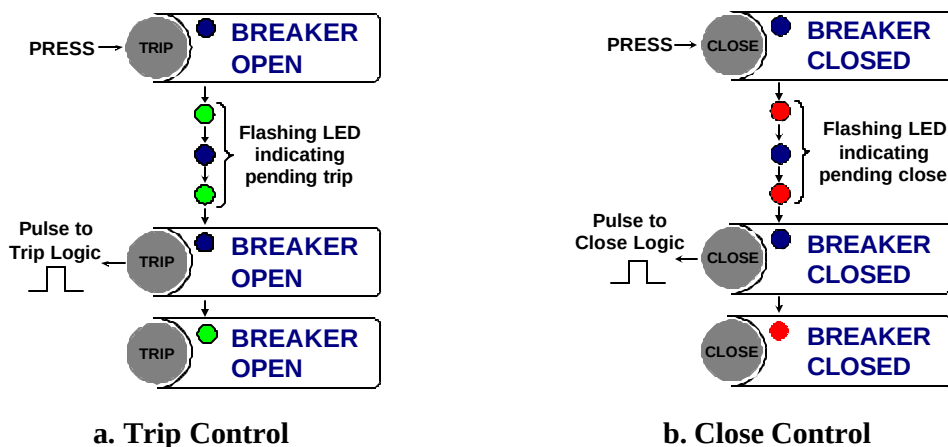


Figure 7 Operational Sequence for Operator-initiated Breaker Trip and Close Commands

Breaker Close

Figure 7b shows an application of the “CLOSE” control button. This example has the “CLOSE” command set with a fixed time delay so that the operator can move a safe distance away from the breaker before the relay issues a close.

The operational sequence follows:

After an operator presses the “CLOSE” control button, the corresponding “BREAKER CLOSED” LED flashes on and off, indicating a pending close. After a user-set time delay, the relay completes the close sequence, and the “BREAKER CLOSED” LED illuminates.

Pressing the “CLOSE” control button again or the “TRIP” operator control pushbutton before the closing sequence is completed aborts the pending close.

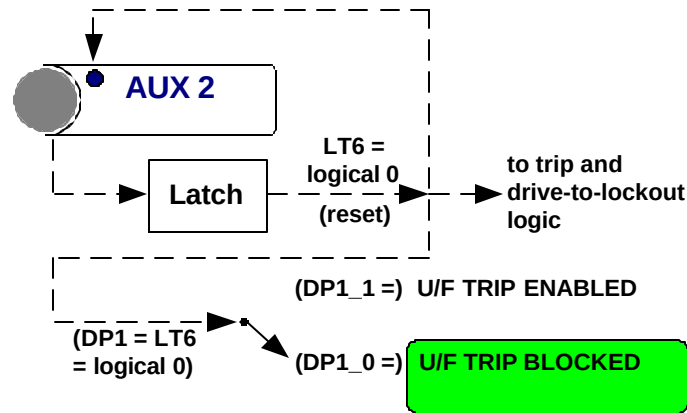


Figure 8 User-programmed Logic for Underfrequency Load-shedding Scheme Control

Underfrequency Load Shedding Scheme Control

The AUX 2 control button does not have a pre-assigned function as shipped from the factory. Figure 8 illustrates an example, with AUX 2 field-programmed for operator control of an underfrequency load-shedding function.

As this figure shows, relay logic control equations route the logic output of the AUX 2 operator control into a programmable latch LT6. Latch output LT6 controls a display point setting DP1. The front panel of the relay displays one of two messages, depending on the state of display point setting DP1:

“U/F TRIP ENABLED” (DP1 = LT6 = logical 1; latch LT6 set)

“U/F TRIP BLOCKED” (DP1 = LT6 = logical 0; latch LT6 reset)

The corresponding AUX 2 LED illuminates when internal latch LT6 enables underfrequency load shedding. The trip and drive-to-lockout logic depend on internal latch LT6 supervising an underfrequency element.

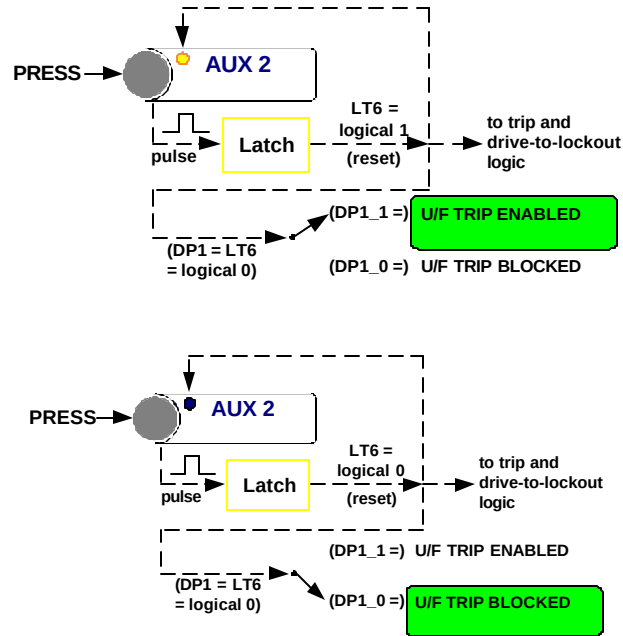


Figure 9 Application of AUX 2 for Controlling an Underfrequency Load-shedding Scheme

The operational sequence for enabling/disabling the load-shedding scheme follows:

1. The operator presses the AUX 2 operator control and the pulsed output (PB8 = logical 1) causes latch LT6 to go from logical 0 to logical 1.
2. The front-panel display then shows:
 “U/F TRIP ENABLED” (DP1 = LT6 = logical 1; latch LT6 set).
 The corresponding AUX 2 LED illuminates:
 LED8 = LT6 (= logical 1).
3. The underfrequency element (81D1T) in the trip and drive-to-lockout logic, now enabled, can get through to trip. The operator presses the AUX 2 control again and the pulsed output (PB8 = logical 1) causes latch LT6 to go from logical 1 to logical 0.
5. The front-panel display then shows:
 “U/F TRIP BLOCKED” (DP1 = LT6 = logical 0; latch LT6 reset)
 The corresponding AUX 2 LED illuminates:
 LED8 = LT6 (= logical 1).
6. The underfrequency element (81D1T) in the trip and drive-to-lockout logic, now disabled, cannot get through to trip.

Circuit Breaker Reclosing Control

The relay provides a four-shot reclosing control scheme. The available scheme makes a variety of application practices possible. Synchronism and voltage check functions supervise reclosing logic when needed. Figure 10 illustrates settings applied for reclosing control.

Reclosing Relay
E79 Enable Reclosing Relay Elements

2 Select: M, 1, 4

Reclosing Relay Elements

79C01 Open Interval 1 (cycles in 0.25 increments)
300.00 Range = 0.00 - 99999.90

79C02 Open Interval 2 (cycles in 0.25 increments)
0.00 Range = 0.00 - 99999.90

79C03 Open Interval 3 (cycles in 0.25 increments)
1.00 Range = 0.00 - 99999.90

79C04 Open Interval 4 (cycles in 0.25 increments)
1.00 Range = 0.00 - 99999.90

79P60 Reset Time from Reclose Cycle (cycles in 0.25 increments)
1800.00 Range = 0.00 - 99999.90

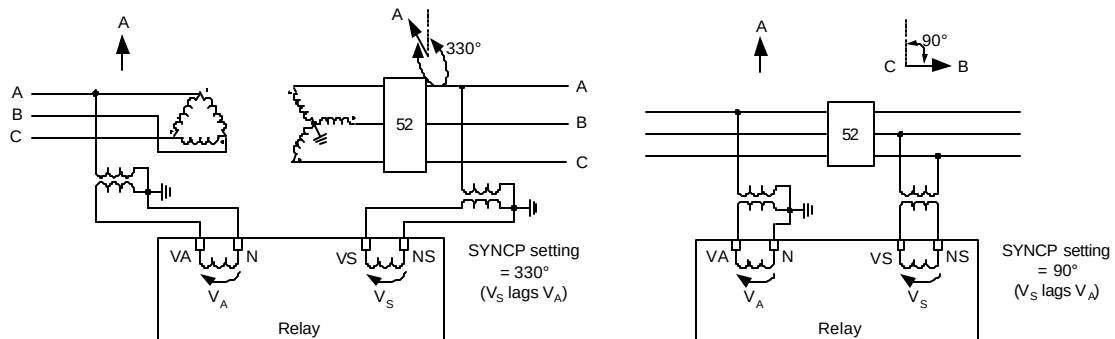
79P61D Reset Time from Lockout (cycles in 0.25 increments)
300.00 Range = 0.00 - 99999.90

79C1SD Reclose Superv. Time Limit (cycles in 0.25 increments)
0.00 Range = 0.00 - 99999.90, OFF

Figure 10 Settings Applied for Reclosing Control

Synchronism Check Supervision

In applications where an undesirable phase angle difference can exist across the open poles of a circuit breaker, a synchronism check function supervises automatic reclosing control. Figure 11 shows two possible scenarios where dissimilar transformer connections cause steady-state apparent phase angle differences. Appropriate user-applied settings compensate constant phase angle differences that result from VT and/or power transformer connections.



a. Synchronism Across a Delta-Wye Transformer

b. Synchronism Across a Breaker

Figure 11 Constant Apparent Phase Angle Differences Introduced by Dissimilar Transformer Connections

The circuit in Figure 11a shows that both voltage inputs V_{A-N} and V_{S-NS} are connected phase-to-neutral on either side of the breaker. However, synchronism check voltage input VS/NS is beyond a delta-wye transformer bank, just as it would be for a unit transformer connected to a generator. The resultant voltage V_S lags voltage V_A by 330° because of the phase shift introduced by the delta-wye transformer bank. In this case, “SYNCP” is set = 330. Setting “SYNCP” = 330 accounts for the constant 330° phase angle difference (voltage V_S lags voltage V_A) in performing synchronism check between voltage V_A and voltage V_S . This representation also presumes counter-clockwise ABC rotation. Figure 11a does not show the other two voltage inputs, V_B and V_C . They likewise connect to terminal N, forming a three-phase wye connection with V_A .

The circuit in Figure 11b has voltage input V_{AN} connected phase-to-neutral on one side of the breaker. However, synchronism check voltage input VS/NS is connected phase-to-phase on the

other side of the breaker. The resultant voltage V_S lags voltage V_A by 90° . Thus, the steady-state phase angle difference setting “SYNCP” is set = 90. Setting SYNCP = 90 accounts for the constant 90° phase angle difference (voltage V_S lags voltage V_A) in performing synchronism check between voltage V_A and voltage V_S . The above representation presumes counter-clockwise ABC rotation. Figure 11b does not show the other two voltage inputs, V_B and V_C . They likewise connect to terminals V_{BN} and V_{CN} , respectively, forming a three-phase wye connection with V_{AN} .

The synchronizing phase setting “SYNCP” is in 30-degree increments (0° , 30° , 60° , ..., 270° , 300° , 330° , see Figure 12). Set “SYNCP” to V_A , V_B , or V_C if the synchronism check voltage input VS/NS is to be connected phase-to-neutral, directly across the breaker from voltage input V_{A-N} , V_{B-N} , or V_{C-N} , respectively.

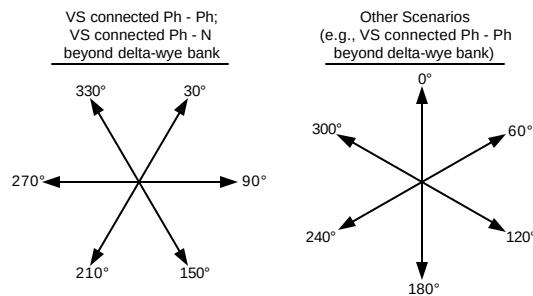


Figure 12 Steady-state Synchronizing Phase Angle Compensation Settings

The user setting menu for the synchronism check function is shown in Figure 13.

Figure 13 User Settings for Synchronism Check Function

AUTOMATION FUNCTIONS

The automation features in numerical relays reduce the need for external metering and control devices. Automation elements include 16 each local control switches, remote control switches, latch control switches, and display points.

Local control switch elements function as separately mounted switches, without the cost burden of installing and documenting physical devices. Any one of the 16 switches is available for a variety of purposes including inputs to internal relay logic and for operator-entered switch values to other devices or systems. Figure 14 depicts the local control switch elements and LCD on the front of the relay.

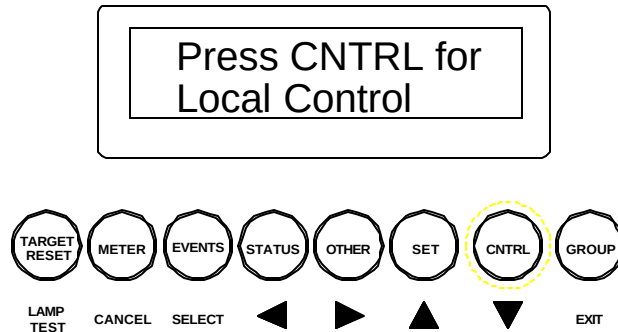


Figure 14 Local Control Switch Elements

Remote control switch elements, configured as on/off/momentary switches, are set, cleared, and/or pulsed via serial port commands from remote systems or human-machine interfaces. These elements provide inputs to relay logic and control of relay output contacts. Typical applications include input to nonvolatile latched control switches for SCADA operations such as trip, close, and settings group selection.

Examples of latch control switch applications include enabling/disabling reclose functions, ground protection elements, and hot-line tags. Latch control switches can select relay setting groups to adapt to different operating conditions, such as during live-line maintenance procedures and for seasonal changes in ground protection sensitivity. Figure 15 is a diagrammatic representation of one of 16 latch control switches provided in the relay.

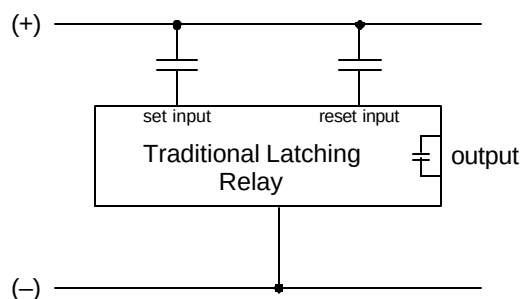


Figure 15 Functional Equivalent of Latch Control Switch

Display points provide 16 user-programmed messages for the front-panel LCD. Custom-created messages report power system and relay conditions. Relay logic handles the control of displayed messages. Any logical point in the relay can drive the LCD. Figure 16 illustrates an example of a custom message that indicates the logical state of an underfrequency load-shedding scheme.

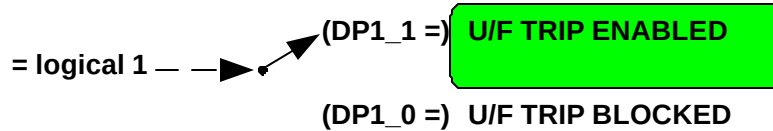


Figure 16 User-programmed Display Points for Logic Status and System Condition

MONITORING FUNCTIONS

Circuit Breaker Contact Wear

Circuit breakers experience mechanical and electrical wear every time they operate. Intelligent scheduling of breaker maintenance compares manufacturers' published breaker wear data, interruption levels, and operation count with actual field data. The numeric relay breaker monitoring function captures the total interrupted current and number of operations.

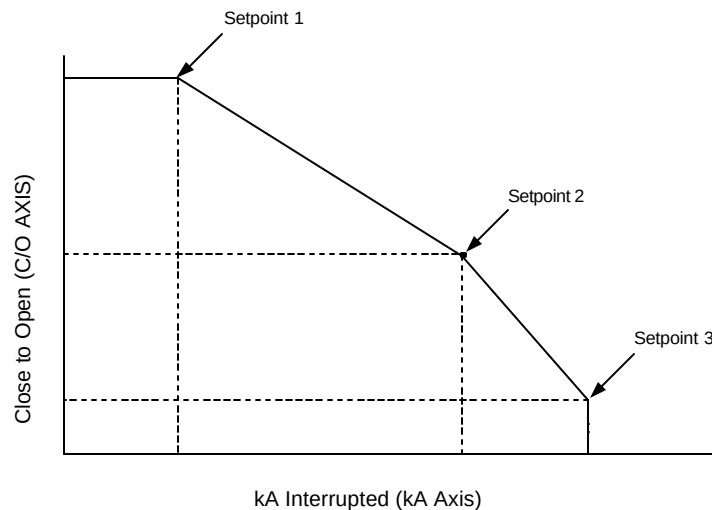


Figure 17 Breaker Contact Wear Curve and Settings

Each time the monitored breaker trips, the relay integrates the interrupted current with previously stored current values. When the results exceed the threshold set by the breaker wear curve as shown in Figure 17, the relay initiates an alarm via an output contact, serial port, or front-panel display. This information permits timely, economical scheduling of breaker maintenance.

Substation Battery Voltage

The numeric relay measures and reports the substation battery voltage presented to its power supply terminals. It also provides two programmable threshold comparators and associated logic for alarm and control. For example, if the substation battery charger fails, the measured dc voltage eventually falls below a programmed threshold. An alarm message notifies operations personnel before the substation battery voltage reaches unsatisfactory levels. Supplementary communications processor hardware can monitor these thresholds and trigger messages, telephone calls, or other actions to alert operations personnel of low battery voltage levels.

The relay reports the measured dc battery voltage in real time, as well as in oscillographic event reports. Event reports show how much the substation battery voltage drops during trip, close, and other control operations.

Power Quality and Event Oscillography

Momentary voltage sags (or dips) and interruptions cause most industrial power quality problems. A large percentage of supply-side voltage variations result from power system faults. When momentary interruptions or sags occur, sensitive electronic equipment such as programmable logic controllers and adjustable speed drive controllers can fail to “ride through” the event. The subsequent resetting of critical process control devices can mean significant economic losses for the affected industry.

The microprocessor-based relay detects and records RMS voltage variations. Figure 18 shows user-entered threshold settings for reporting voltage sags, swells, and interruptions. IEEE Standard 1159-1995 [2] defines a short duration voltage interruption as when the voltage magnitude falls below 0.1 per-unit nominal RMS voltage for a period of time not exceeding one minute. Voltage sags are short duration reductions in phase voltage to between 0.1 and 0.9 per-unit nominal RMS voltage. A voltage swell is a short duration phase voltage increase between 1.1 and 1.8 per-unit nominal RMS voltage. The time duration for sags and swells is from 0.5 cycle to one minute.

The screenshot shows a software interface titled "Voltage Sag/Swell/Interrupt". It contains a section "ESSI Enable Sag/Swell/Interrupt" with a dropdown menu set to "Y" and the text "Select: Y, N". Below this is a section "Sag/Swell/Interrupt Elements" containing three settings: "VINT %V1 Phase Voltage Interruption Pickup" with a value of "10.00" and a range of "1.00 - 6500.00, OFF"; "VSAG %V1 Phase Voltage Sag Pickup (cannot be set less than VINT)" with a value of "90.00" and a range of "10.00 - 90.00"; and "VSWELL %V1 Phase Voltage Swell Pickup" with a value of "110.00" and a range of "110.00 - 180.00".

Figure 18 User Settings for Voltage Sag/Swell/Interruption Thresholds

IEEE Standard 1159 further defines three classifications of short duration voltage variations: instantaneous (0.5 to 30 cycles), momentary (30 cycles to 3 seconds), and temporary (3 seconds to 1 minute). The relay detects and identifies each classification of voltage variation, and reports them in a sequential events recorder report. Figure 19 shows an example report.

FEEDER 1			Date: 03/07/98					Time: 03:29:48.297								
STATION A																
No.	Date	Time	Current(%Inom)					Voltage(%Vbase)				Vbase (kV)	SSI Condition			
			Ia	Ib	Ic	Ig	In	Va	Vb	Vc	Vs					
85	03/07/98	03:29:29.107	100	100	100	0	0	100	97	100	0	18.0	PRE			
84	03/07/98	03:29:29.111	100	100	100	0	0	100	97	100	0	18.0	PRE			
83	03/07/98	03:29:29.115	100	100	100	0	0	100	92	100	0	18.0	PRE			
82	03/07/98	03:29:29.119	100	100	100	0	0	100	91	100	0	18.0	PRE			
81	03/07/98	03:29:29.123	100	100	100	0	0	100	90	100	0	18.0	PRE			
80	03/07/98	03:29:29.128	100	100	100	0	0	100	89	100	0	18.0	PRE			
79	03/07/98	03:29:29.132	100	100	100	0	0	100	89	100	0	18.0	PRE			
78	03/07/98	03:29:29.136	100	100	100	0	0	101	89	101	0	17.9	PRE			
77	03/07/98	03:29:29.140	100	100	100	0	0	101	90	101	0	17.9	SAG			
76	03/07/98	03:29:29.144	100	100	100	0	0	101	90	101	0	17.9	SAG			
.	.	.	.	.	.	.	.	.	.	.	.	.	.			
2	03/07/98	03:29:30.140	100	100	100	1	0	101	90	101	0	17.9	SAG			
1	03/07/98	03:29:33.499	100	100	100	0	0	101	97	101	0	17.9	POST			

=>>

Figure 19 Example Sag/Swell/Interruption Report

Including RMS voltage variation recording in a protective device provides a low-cost alternative to more expensive, dedicated power quality monitoring equipment. Factual power quality data is a necessity for correlating and validating utility customer complaints and identifying the root cause of voltage-disturbance-related problems.

Voltage Interruption Trigger

As shown in Figure 18, the relay compares each phase voltage magnitude against a settable interruption threshold, “VINT.” This threshold is a percentage of the positive-sequence memory voltage. By using memory voltage as a reference, the trigger thresholds are able to adapt to slow system voltage variations such as from load-tap changer operations, for example, which helps avoid nuisance power quality triggers.

If the A-phase voltage magnitude drops below the “VINT” threshold, the relay records the event as an interruption. When the A-phase voltage returns above the “VINT” restoration threshold for one-cycle, the corresponding power quality interruption logic resets. The voltage restoration level is five percent higher than the “VINT” threshold to prevent threshold detection logic chatter for boundary conditions.

Voltage Sag and Swell Triggers

The relay also compares each phase voltage magnitude against two adaptive thresholds, “VSAG” and “VSWELL” (refer to Figure 18). Each threshold is a set percentage of the memorized positive-sequence voltage.

As an example, consider the case when the A-phase voltage magnitude drops below the “VSAG” threshold, and remains above the “VINT” threshold (typically $0.1 \cdot V_{NOM}$) for one-cycle. The appropriate relay logic asserts. There is similar logic for B- and C-phase voltages. When the phase voltage(s) magnitude(s) increases above the “VSAG” restoration threshold for one-cycle, the voltage sag logic resets.

Event Oscillography

Oscillographic event reports simplify analysis of faults and power quality events, and help improve the user's understanding of simple and complex protective scheme operations. In response to a user-selected trigger, the voltage, current, frequency, and relay element status information confirms relay, scheme, and system performance for every recorded event. Figure 20 shows an example of an oscillographic event.

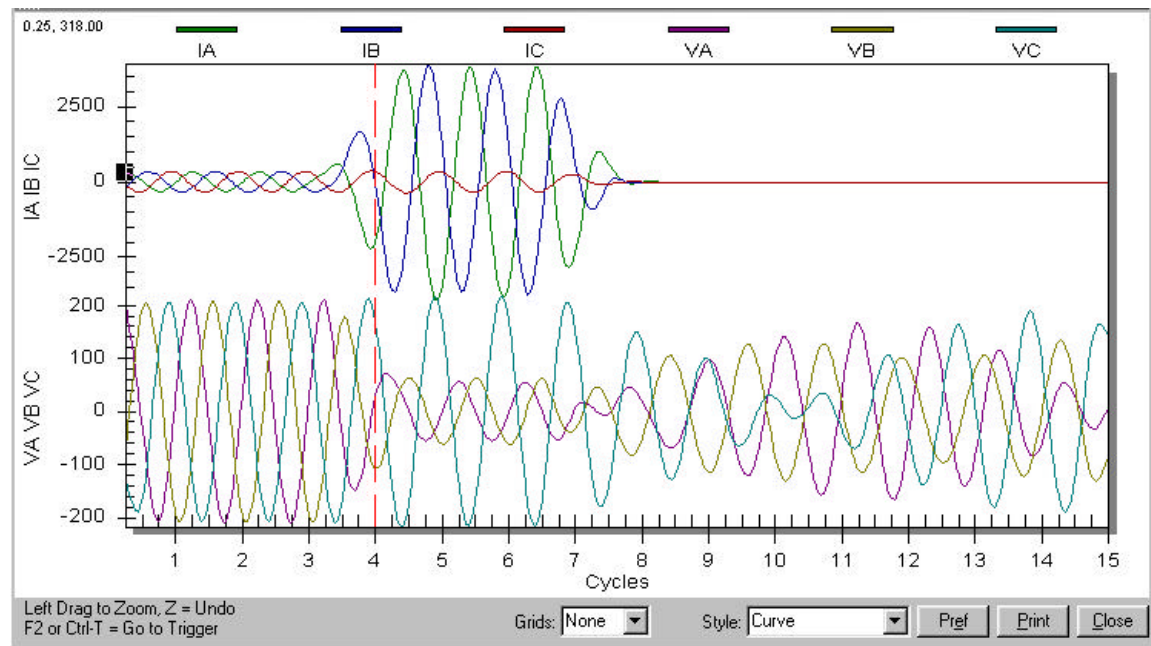


Figure 20 Oscillographic Event Report

METERING FUNCTIONS

Volts, Amperes, Power

The relay computes instantaneous values of voltage, current, and power, efficiently transferring this metering information to communications processing devices in a binary format. System operators can access this data to determine circuit loads, bus voltage, and reactive power flows.

Load Profiling

The Load Profile function provides trend data of parameters measured and computed by the relay. As shown in Figure 21, the relay makes periodic measurements every 5, 10, 15, 30, or 60 minutes, depending on the user-applied setting. Table 1 shows the measured and computed parameters available in Load Profile reports.



Figure 21 User Settings for Load Profile Recording Function

Table 1 Measured and Computed Parameters Available in Load Profile Reports

Label	Quantity Recorded
IA, IB, IC, IN	Phase and neutral current magnitudes
VA, VB, VC, VS	Phase and sync voltage magnitudes
IG, I1, 3I2, 3V0, V1, V2	Sequence current and voltage magnitudes
VDC	Battery voltage
FREQ	Phase frequency
MWA, MWB, MWC, MW3	Phase and 3 phase megaWATTs
MVARA, MVARB, MVARC, MVAR3	Phase and 3 phase megaVARs
PFA, PFB, PFC, PF3	Phase and 3 phase power factor
LDPFA, LDPFB, LDPFC, LDPF3	Phase and 3 phase power factor lead/lag status (0 = lag, 1= lead)
IADEM, IBDEM, ICDEM, INDEM, IGDEM, 3I2DEM	Demand ammeter quantities
MWADI, MWBDI, MWCDI, MW3DI	Phase and 3 phase demand megaWATTs in
MWADO, MWBDO, MWCDO, MW3DO	Phase and 3 phase demand megaWATTs out
MVRADI, MVRBDI, MVRCDI, MVR3DI	Phase and 3 phase demand megaVARs in
MVRADO, MVRBDO, MVRCDO, MVR3DO	Phase and 3 phase demand megaVARs out
MWHAI, MWHBI, MWHCI, MWH3I	Phase and 3 phase megaWATT hours in
MWHAO, MWHBO, MWHCO, MWH3O	Phase and 3 phase megaWATT hours out
MVRHAI, MVRHBI, MVRHCI, MVRH3I	Phase and 3 phase megaVAR hours in
MVRHAO, MVRHBO, MVRHCO, MVRH3O	Phase and 3 phase megaVAR hours out

APPLICATION EXAMPLE

This brief illustration describes a numeric relay applied for feeder protection and control. A large utility company created a plan to improve their distribution system efficiency during peak system demand periods. Their project goals were twofold: maintaining a nearly constant voltage from the substation bus to the line-end and being able to control load by reducing voltage levels during system peaks.

The initial plan called for installation of “Smart” meters into the breaker relay cabinets at each outgoing distribution feeder breaker. However, the new metering devices were relatively expensive. This project also presented an opportunity to consider replacing existing older electromechanical relays.

After further review, the utility created a new plan for each feeder breaker protection and control cabinet. The new objectives were replacing existing protective devices, replacing all control and toggle switches, replacing all indicating lamps, and providing for highly accurate metering, all at a cost that was competitive with the “Smart” meter.

Figure 22 shows the existing hardware before implementation of the new design.



Figure 22 Breaker Control Cabinet with Electromechanical Relays, Meters, Control Switches and Indicating Lamps

The estimated cost for all devices mounted in the panel shown in Figure 22, including a new “Smart” meter, was \$7400, excluding labor and installation costs. By comparison, the numeric relay selected for this project provided all of the needed functions and cost less than half this amount. Figure 23 illustrates the resulting installation of the retrofitted numeric relay into the breaker control cabinet.

The benefits to the utility included being able to operate their distribution feeders more efficiently using accurate metering information. In addition, the oscillographic event reports and sequential event recorder (SER) reports provided them with a higher level of secure, improved, reliable protection.



Figure 23 Breaker Control Cabinet with Retrofitted Numeric Relay

CONCLUSION

Technological advances in the design and application of microprocessor-based protective relays have extended the functionality of single hardware platforms. Programmable logic functions, local and remote operator control functions, and a variety of monitoring and metering functions now join traditional relay functions such as protection and control. Having these new capabilities in a highly reliable hardware platform means the need for programmable logic controllers (PLCs), remote terminal units (RTUs), external control switches and indicating lamps, as well as separately mounted metering devices, is either greatly reduced or eliminated altogether. This results in considerable cost savings for retrofit projects and new construction.

REFERENCES

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BIOGRAPHY

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