

SEL-421 Relay

Protection and Automation System

Instruction Manual

Applications Handbook

20080110



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Preface

This manual provides information and instructions for installing and operating the SEL-421 Relay. The three volumes that comprise this manual are for use by power engineers and others experienced in protective relaying applications. Included are detailed technical descriptions of the relay and application examples. While this manual gives reasonable examples and illustrations of relay uses, you must exercise sound judgment at all times when applying the SEL-421 in a power system.

SEL-421 Versions and Supported Features on page U.1.8 shows the relay features supported by versions SEL-421-0, SEL-421-1, SEL-421-2, and SEL-421-3. Throughout the manual, we provide margin notes next to the text explaining a feature to specify the availability of that feature in different versions of the relay.

Manual Overview

The SEL-421 Relay Manual consists of three volumes:

- User's Guide
- Applications Handbook
- Reference Manual

In addition, the SEL-421 Relay Manual contains a comprehensive Index that encompasses the entire manual. The index appears at the end of each printed volume. In the electronic version of the manual, the index appears once; hyperlinks take you to material referenced in the index. Also included is a glossary that lists and defines technical terms used throughout the manual.

The SEL-421 Relay Manual is a comprehensive work covering all aspects of relay application and use. Read the sections that pertain to your application to gain valuable information about using the SEL-421. For example, to learn about relay protection functions, read the protection sections of this manual and skim the automation sections, then concentrate on the operation sections or on the automation sections of this manual as your job needs and responsibilities dictate. An overview of each manual section and section topics follows.

User's Guide

Preface. Describes manual organization and conventions used to present information (appears once in the electronic form of the manual; repeated in each printed volume).

Section 1: Introduction and Specifications. Introduces SEL-421 features; summarizes relay functions and applications; lists relay specifications, type tests, and ratings.

Section 2: Installation. Discusses the ordering configurations and interface features (control inputs, control outputs, and analog inputs, for example); provides information about how to design a new physical installation and secure the relay in a panel or rack; details how to set relay board jumpers and make proper rear-panel connections (including wiring to CTs, PTs, and a GPS receiver); explains basic connections for the relay communications ports.

Section 3: PC Software. Explains how to use the ACSELERATOR® QuickSet™ SEL-5030 software program.

Section 4: Basic Relay Operations. Describes how to perform fundamental operations such as applying power and communicating with the relay, setting and viewing passwords, checking relay status, viewing metering data, reading event reports and SER (Sequential Events Recorder) records, operating relay control outputs and control inputs, and using relay features to make relay commissioning easier.

Section 5: Front-Panel Operations. Describes the LCD display messages and menu screens; shows you how to use front-panel pushbuttons and read targets; provides information about local substation control and how to make relay settings via the front panel.

Section 6: Testing and Troubleshooting. Describes techniques for testing, troubleshooting, and maintaining the SEL-421; includes the list of status notification messages and a troubleshooting chart.

Applications Handbook

Appendix A: Firmware and Manual Versions. Lists the current firmware versions and details differences between the current and previous versions.

Section 1: Protection Application Examples. Provides the following protection schemes with explanations and settings:

- Overhead single 230 kV transmission line
- Overhead parallel 500 kV transmission lines with zero-sequence mutual coupling
- Overhead tapped 345 kV transmission line
- Parallel 230 kV underground cables

This section also provides separate application examples for out-of-step blocking and tripping, circuit breaker failure protection, and automatic reclose and synchronism checking.

Section 2: Monitoring and Metering. Describes how to use the circuit breaker monitors and the substation dc battery monitors; provides information on viewing fundamental and rms metering quantities for voltages and currents, as well as power and energy metering data.

Section 3: Analyzing Data. Explains how to obtain and interpret high-resolution raw data oscillograms, filtered event reports, event summaries, history reports, and SER reports; discusses how to enter SER trigger and alias settings.

Section 4: Time-Synchronized Measurements. Explains synchronized phasor measurements and estimation of power system states using the SEL-421 high-accuracy time-stamping capability; presents real-time load flow/power flow application ideas.

Section 5: Substation Automatic Restoration. Describes an example of automatic substation restoration; gives a real-world example of the programming ease and flexibility of free-form expanded SELOGIC® control equations.

Section 6: SEL Communications Processor Applications. Provides examples of how to use the SEL-421 with the SEL-2032, SEL-2030, and SEL-2020 Communications Processors for total substation automation solutions.

Section 7: Direct Network Communication. Explains how to use DNP3 (serial and LAN/WAN) and other Ethernet protocols such as Telnet, FTP, and IEC 61850.

Reference Manual

Section 1: Protection Functions. Describes the function of various relay protection elements; describes how the relay processes these elements; gives detailed specifics on protection scheme logic for POTT, DCB, DCUB, and DTT; provides trip logic diagrams, and current and voltage source selection details.

Section 2: Auto-Reclosing and Synchronism Check. Explains how to operate the SEL-421 two-circuit breaker multi-shot recloser; describes how to set the SEL-421 for single-pole reclosing, three-pole reclosing, or both; shows selection of the lead and follow circuit breakers; explains how to set and apply synchronism-check elements for automatic and manual closing.

Section 3: SELogIC Control Equation Programming. Describes multiple setting groups and SELOGIC control equations and how to apply these equations; discusses expanded SELOGIC control equation features

such as PLC-style commands, math functions, counters, and conditioning timers; provides a tutorial for converting older format SELOGIC control equations to new free-form equations.

Section 4: Communications Interfaces. Explains the physical connection of the SEL-421 to various communications network topologies.

Section 5: SEL Communications Protocols. Describes the various SEL software protocols and how to apply these protocols to substation integration and automation; includes details about SEL ASCII, SEL Compressed ASCII, SEL Fast Meter, SEL Fast Operate, SEL Fast SER, and enhanced MIRRORRED BITS® communications.

Section 6: DNP3 Communications. Describes the DNP3 communications protocol and how to apply this protocol to substation integration and automation; provides a Job Done® example for implementing DNP3 in a substation.

Section 7: Synchrophasors. Describes the Phasor Measurement Unit (PMU) functions of the SEL-421; provides details on synchrophasor measurement; describes the IEEE C37.118 synchrophasor protocol settings; describes the SEL Fast Message synchrophasor protocol settings.

Section 8: IEC 61850 Communications. Describes the IEC 61850 protocol and how to apply this protocol to substation automation and integration. Includes IEC 61850 protocol compliance statements.

Section 9: ASCII Command Reference. Provides an alphabetical listing of all ASCII commands with examples for each ASCII command option.

Section 10: Settings. Provides a list of all SEL-421 settings and defaults. The organization of the settings is similar to the settings organization in the relay and in the ACSELERATOR QuickSet software.

Appendix A: Relay Word Bits. Contains a summary of Relay Word bits.

Appendix B: Analog Quantities. Contains a summary of analog quantities.

CD-ROM

The CD-ROM contains the SEL-421 Relay Manual in an electronic form that you can search easily.

Conventions

Typographic Conventions

There are three ways to communicate with the SEL-421:

- Using a command line interface in a PC terminal emulation window.
- Using the front-panel menus and pushbuttons.
- Using ACSELERATOR® QuickSet™ SEL-5030 Software

The instructions in this manual indicate these options with specific font and formatting attributes. The following table lists these conventions:

Typographic Conventions

Example	Description
STATUS	Commands, command options, and command variables typed at a command line interface on a PC.
<i>n</i>	Variables determined based on an application (in bold if part of a command).
SUM <i>n</i>	
<Enter>	Single keystroke on a PC keyboard.
<Ctrl+D>	Multiple/combination keystroke on a PC keyboard.
Start > Settings	PC software dialog boxes and menu selections. The > character indicates submenus.
{CLOSE}	Relay front-panel pushbuttons.
ENABLE	Relay front- or rear-panel labels.
RELAY RESPONSE MAIN > METER	Relay front-panel LCD menus and relay responses visible on the PC screen. The > character indicates submenus.
U.3.1 A.3.1 R.3.1	Page numbers include a reference to the volume, section, and page number. U stands for User's Guide A stands for Applications Handbook R stands for Reference Manual.
SELOGIC control equations	SEL trademarks and registered trademarks contain the appropriate symbol on first reference in a section. In the SEL-421 Instruction Manual, certain SEL trademarks appear in small caps. These include SELOGIC control equations, MIRRORED BITS communications, and the ACSELERATOR QuickSet software program.
Modbus®	Registered trademarks of other companies include the registered trademark symbol with the first occurrence of the term in a section.

Examples

This instruction manual uses several example illustrations and instructions to explain how to effectively operate the SEL-421. These examples are for demonstration purposes only; the firmware identification information or settings values included in these examples may not necessarily match those in the current version of your SEL-421.

Notes

Margin notes serve two purposes in the SEL-421 Relay Manual. Notes present valuable or important points about relay features or functions. Use these notes as tips to easier and more efficient operation of the relay. Also in this manual, notes specify differences between the SEL-421-0, SEL-421-1, SEL-421-2, and SEL-421-3 models when these differences affect relay functions or operations.

Commands

You can simplify the task of entering commands by shortening any ASCII command to the first three characters (upper- or lowercase); for example, **ACCESS** becomes **ACC**.

Always send a carriage return **<CR>** character, or a carriage return character followed by a line feed character **<CR><LF>**, to command the relay to process the ASCII command. Usually, most terminals and terminal programs interpret the **<Enter>** key as a **<CR>**. For example, to send the **ACCESS** command, type the following:

ACC <Enter>

Cross-References

Cross-references are formatted as described below in both the hard copy and electronic documentation for the SEL-421. In the electronic documentation, clicking with the mouse on cross-references takes you to the referenced location.

- References to figures, tables, examples, and equations in the same volume include only the reference item:
 - *Table 3.1*
 - *Figure 4.5*
- References to headings on another page include the heading title and the page number:
 - *Disconnect Monitoring on page U.3.8*
- References to items in another volume include the reference item and page number (the first letter in the page number indicates the volume):
 - *Access Levels on page U.4.8*
 - *Figure 2.3 on page R.2.5.*
- References to a specific section in another volume or another volume include the reference item (if a section) and the volume title:
 - *Section 4: Basic Relay Operations in the User's Guide*
 - *User's Guide*

Step-by-Step Procedures

The SEL-421 Relay Manual contains many step-by-step procedures. These procedures lead you easily and efficiently through complex tasks. Each procedure lists required equipment, as well as the basic knowledge you need to perform the steps in the procedure. Throughout the procedure, the documentation references other SEL-421 Relay Manual sections where you can find more information.

Read the entire procedure before performing the listed steps. Read each step again before you perform it. The format of a single step is the following:

- Synopsis of the step (if the step involves multiple actions)
- Tasks to perform the step (listed as a., b., c., etc. if the step involves multiple actions)
- Explanatory text or how the relay responds (if applicable)

The following text shows sample steps. Steps include explanations, text references, table references, and figure references to further illustrate the step.

Step 1. Establish communication.

a. Press **<Ctrl+T>** to use the serial communications terminal in ACSELERATOR.

b. Press **<Enter>** to see if the communications link is active between the software and the relay.

You should see the Access Level 0 = prompt in the terminal window.

Step 2. Confirm that you have loaded the correct passwords in ACSELERATOR.

a. Click **Communication > Port Parameters**.

b. Confirm that you have entered the correct passwords in the **Level One Password** dialog box and the **Level Two Password** dialog box.

Step 3. Click **Settings > Read** to read the present configuration in the SEL-421.

The relay sends all configuration and settings data to ACSELERATOR.

Step 4. Select settings by clicking the + mark next to the **Group** you want to program on the **Settings** tree view.

This example uses Group 1, as shown in *Figure 1.2*.

Figure
Reference

Sample Step-By-Step Instructions

Numbers

This manual displays numbers as decimal values. Hexadecimal numbers include the letter **h** appended to the number. Alternatively, the prefix **0X** can also indicate a hexadecimal number. For instance, 11 is the decimal number eleven, but 11h and 0X11 are hexadecimal representations of the decimal value seventeen.

Safety Information

This manual uses three kinds of hazard statements, formatted as follows:

CAUTION

Indicates a potentially hazardous situation that, if not avoided, may result in minor or moderate injury or equipment damage.

WARNING

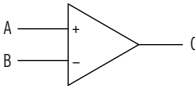







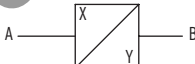
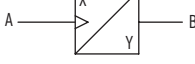
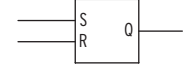

Indicates a potentially hazardous situation that, if not avoided, **could** result in death or serious injury.

DANGER

Indicates an imminently hazardous situation that, if not avoided, **will** result in death or serious injury.

Logic Diagrams

Logic diagrams in this manual follow the conventions and definitions shown below.

NAME	SYMBOL	FUNCTION
COMPARATOR		Input A is compared to input B. Output C asserts if A is greater than B.
INPUT FLAG		Input A comes from other logic.
OR		Either input A or input B asserted cause output C to assert.
EXCLUSIVE OR		If either A or B is asserted, output C is asserted. If A and B are of the same state, C is deasserted.
NOR		If neither A nor B asserts, output C asserts.
AND		Input A and input B must assert to assert output C.
AND W/ INVERTED INPUT		If input A is asserted and input B is deasserted, output C asserts. Inverter "0" inverts any input or output on any gate.
NAND		If A and/or B are deasserted, output C is asserted.
TIME DELAYED PICK UP AND/OR TIME DELAYED DROP OUT		X is a time-delay-pickup value; Y is a time-delay-dropout value. B asserts time X after input A asserts; B will not assert if A does not remain asserted for time X. If X is zero, B will assert when A asserts. If Y is zero, B will deassert when A deasserts.
EDGE TRIGGER TIMER		Rising edge of A starts timers. Output B will assert time X after the rising edge of A. B will remain asserted for time Y. If Y is zero, B will assert for a single processing interval. Input A is ignored while the timers are running.
SET RESET FLIP FLOP		Input S asserts output Q until input R asserts. Output Q deasserts or resets when R asserts.
FALLING EDGE		B asserts at the falling edge of input A.

Logic Diagram Symbols

SEL-421 Cautions, Warnings, and Dangers

The following hazard statements appear in the body of this manual in English. See the following table for the English and French translation of these statements.

Cautions, Warnings, and Dangers

English	French
<p>⚠CAUTION Equipment components are sensitive to electrostatic discharge (ESD). Undetectable permanent damage can result if you do not use proper ESD procedures. Ground yourself, your work surface, and this equipment before removing any cover from this equipment. If your facility is not equipped to work with these components, contact SEL about returning this device and related SEL equipment for service.</p>	<p>⚠ATTENTION Les composants de cet équipement sont sensibles aux décharges électrostatiques (DES). Des dommages permanents non-décelables peuvent résulter de l'absence de précautions contre les DES. Raccordez-vous correctement à la terre, ainsi que la surface de travail et l'appareil avant d'en retirer un panneau. Si vous n'êtes pas équipés pour travailler avec ce type de composants, contacter SEL afin de retourner l'appareil pour un service en usine.</p>
<p>⚠CAUTION There is danger of explosion if the battery is incorrectly replaced. Replace only with Ray-O-Vac® no. BR2335 or equivalent recommended by manufacturer. Dispose of used batteries according to the manufacturer's instructions.</p>	<p>⚠ATTENTION Il y a un danger d'explosion si la pile électrique n'est pas correctement remplacée. Utiliser exclusivement Ray-O-Vac® No. BR2335 ou un équivalent recommandé par le fabricant. Se débarrasser des piles usagées suivant les instructions du fabricant.</p>
<p>⚠CAUTION Equipment damage can result from connecting ac circuits to Hybrid (high-current-interrupting) control outputs. Do not connect ac circuits to Hybrid control outputs. Use only dc circuits with Hybrid control outputs.</p>	<p>⚠ATTENTION Des dommages à l'appareil pourraient survenir si un circuit CA était raccordé aux contacts de sortie à haut pouvoir de coupure de type "Hybrid." Ne pas raccorder de circuit CA aux contacts de sortie de type "Hybrid." Utiliser uniquement du CC avec les contacts de sortie de type "Hybrid."</p>
<p>⚠CAUTION Substation battery systems that have either a high resistance to ground (greater than 10 kΩ) or are ungrounded when used in conjunction with many direct-coupled inputs can reflect a dc voltage offset between battery rails. Similar conditions can exist for battery monitoring systems that have high-resistance balancing circuits or floating grounds. For these applications, SEL provides optional ground-isolated (optoisolated) contact inputs. In addition, SEL has published an application advisory on this issue. Contact the factory for more information.</p>	<p>⚠ATTENTION Les circuits de batterie de postes qui présentent une haute résistance à la terre (plus grande que 10 kΩ) ou sont isolés peuvent présenter un biais de tension CC entre les deux polarités de la batterie quand utilisés avec plusieurs entrées à couplage direct. Des conditions similaires peuvent exister pour des systèmes de surveillance de batterie qui utilisent des circuits d'équilibrage à haute résistance ou des masses flottantes. Pour ce type d'applications, SEL peut fournir en option des contacts d'entrée isolés (par couplage optoélectronique). De surcroît, SEL a publié des recommandations relativement à cette application. Contacter l'usine pour plus d'informations.</p>
<p>⚠CAUTION If you are planning to install an INT4 I/O Interface Board in your relay (see Table 2.3 and Table 2.4 for board descriptions), first check the firmware version of the relay—see Firmware Version Number on page U.6.41. If the firmware version is R111 or lower, you must first upgrade the relay firmware to the newest version and verify that the firmware upgrade was successful before installing the new board. Failure to install the new firmware first will cause the I/O Interface Board to fail, and it may require factory service. Complete firmware upgrade instructions are provided when new firmware is ordered.</p>	<p>⚠ATTENTION Si vous avez l'intention d'installer une Carte d'Interface INT4 I/O dans votre relais (voir Table 2.3 et Table 2.4 pour la description de la carte), vérifiez en premier la version du logiciel du relais (voir l'identification de la Version du logiciel [Firmware Version Number on page U.6.41]). Si la version est R111 ou antérieure, vous devez mettre à jour le logiciel du relais avec la version la plus récente et vérifier que la mise à jour a été correctement installée sur la nouvelle carte. Les instructions complètes de mise à jour sont fournies quand le nouveau logiciel est commandé.</p>
<p>⚠CAUTION Field replacement of I/O boards INT1, INT2, INT5, INT6, INT7, or INT8 with INT4 can cause I/O contact failure. The INT4 board has a pickup and dropout delay setting range of 0-1 cycle. For all other I/O boards, pickup and dropout delay settings (IN201PU-IN224PU, IN201DO-IN224DO, IN301PU-IN324PU, and IN301DO-IN324DO) have a range of 0-5 cycles. Upon replacing any I/O board with an INT4 board, manually confirm reset of pickup and dropout delays to within the expected range of 0-1 cycle.</p>	<p>⚠ATTENTION Le remplacement en chantier des cartes d'entrées/sorties INT1, INT2, INT5, INT6, INT7 ou INT8 par une carte INT4 peut causer la défaillance du contact d'entrée/sortie. La carte INT4 présente un intervalle d'ajustement pour les délais de montée et de retombée de 0 à 1 cycle. Pour toutes les autres cartes, l'intervalle de réglage du délai de montée et retombée (IN201PU-IN224PU, IN201DO-IN224DO, IN301PU-IN324PU, et IN301DO-IN324DO) est de 0 à 5 cycles. Quand une carte d'entrées/sorties est remplacée par une carte INT4, vérifier manuellement que les délais de montée et retombée sont dans l'intervalle de 0 à 1 cycle.</p>

Cautions, Warnings, and Dangers

English	French
<p>⚠ CAUTION Do not install a jumper on positions A or D of the main board J18 header. Relay misoperation can result if you install jumpers on positions J18A and J18D.</p>	<p>⚠ ATTENTION Ne pas installer de cavalier sur les positions A ou D sur le connecteur J18 de la carte principale. Une opération intempestive du relais pourrait résulter suite à l'installation d'un cavalier entre les positions J18A et J18D.</p>
<p>⚠ CAUTION Insufficiently rated insulation can deteriorate under abnormal operating conditions and cause equipment damage. For external circuits, use wiring of sufficiently rated insulation that will not break down under abnormal operating conditions.</p>	<p>⚠ ATTENTION Un niveau d'isolation insuffisant peut entraîner une détérioration sous des conditions anormales et causer des dommages à l'équipement. Pour les circuits externes, utiliser des conducteurs avec une isolation suffisante de façon à éviter les claquages durant les conditions anormales d'opération.</p>
<p>⚠ CAUTION Relay misoperation can result from applying other than specified secondary voltages and currents. Before making any secondary circuit connections, check the nominal voltage and nominal current specified on the rear-panel nameplate.</p>	<p>⚠ ATTENTION Une opération intempestive du relais peut résulter par le branchement de tensions et courants secondaires non conformes aux spécifications. Avant de brancher un circuit secondaire, vérifier la tension ou le courant nominal sur la plaque signalétique à l'arrière.</p>
<p>⚠ CAUTION Severe power and ground problems can occur on the communications ports of this equipment as a result of using non-SEL cables. Never use standard null-modem cables with this equipment.</p>	<p>⚠ ATTENTION Des problèmes graves d'alimentation et de terre peuvent survenir sur les ports de communication de cet appareil si des câbles d'origine autre que SEL sont utilisés. Ne jamais utiliser de câble de modem nul avec cet équipement.</p>
<p>⚠ CAUTION Do not connect power to the relay until you have completed these procedures and receive instruction to apply power. Equipment damage can result otherwise.</p>	<p>⚠ ATTENTION Ne pas mettre le relais sous tension avant d'avoir complété ces procédures et d'avoir reçu l'instruction de brancher l'alimentation. Des dommages à l'équipement pourraient survenir autrement.</p>
<p>⚠ CAUTION Use of controls or adjustments, or performance of procedures other than those specified herein, may result in hazardous radiation exposure.</p>	<p>⚠ ATTENTION L'utilisation de commandes ou de réglages, ou l'application de tests de fonctionnement différents de ceux décrits ci-après peuvent entraîner l'exposition à des radiations dangereuses.</p>
<p>⚠ WARNING Use of this equipment in a manner other than specified in this manual can impair operator safety safeguards provided by this equipment.</p>	<p>⚠ AVERTISSEMENT L'utilisation de cet appareil suivant des procédures différentes de celles indiquées dans ce manuel peut désarmer les dispositifs de protection d'opérateur normalement actifs sur cet équipement.</p>
<p>⚠ WARNING Have only qualified personnel service this equipment. If you are not qualified to service this equipment, you can injure yourself or others, or cause equipment damage.</p>	<p>⚠ AVERTISSEMENT Seules des personnes qualifiées peuvent travailler sur cet appareil. Si vous n'êtes pas qualifiés pour ce travail, vous pourriez vous blesser avec d'autres personnes ou endommager l'équipement.</p>
<p>⚠ WARNING This device is shipped with default passwords. Default passwords should be changed to private passwords at installation. Failure to change each default password to a private password may allow unauthorized access. SEL shall not be responsible for any damage resulting from unauthorized access.</p>	<p>⚠ AVERTISSEMENT Cet appareil est expédié avec des mots de passe par défaut. A l'installation, les mots de passe par défaut devront être changés pour des mots de passe confidentiels. Dans le cas contraire, un accès non-autorisé à l'équipement peut être possible. SEL décline toute responsabilité pour tout dommage résultant de cet accès non-autorisé.</p>
<p>⚠ WARNING Do not look into the fiber (laser) ports/connectors.</p>	<p>⚠ AVERTISSEMENT Ne pas regarder vers l'extrémité des ports ou connecteurs de fibres pour laser.</p>
<p>⚠ WARNING Do not look into the end of an optical cable connected to an optical output.</p>	<p>⚠ AVERTISSEMENT Ne pas regarder vers l'extrémité d'un câble optique raccordé à une sortie optique.</p>

Cautions, Warnings, and Dangers

English	French
<p>⚠ WARNING Do not perform any procedures or adjustments that this instruction manual does not describe.</p>	<p>⚠ AVERTISSEMENT Ne pas appliquer une procédure ou un ajustement qui n'est pas décrit explicitement dans ce manuel d'instruction.</p>
<p>⚠ WARNING During installation, maintenance, or testing of the optical ports, use only test equipment qualified for Class 1 laser products.</p>	<p>⚠ AVERTISSEMENT Durant l'installation, la maintenance ou le test des ports optiques, utilisez exclusivement des équipements de test homologués comme produits de type laser de Classe 1.</p>
<p>⚠ WARNING Incorporated components, such as LEDs, transceivers, and laser emitters, are not user serviceable. Return units to SEL for repair or replacement.</p>	<p>⚠ AVERTISSEMENT Les composants internes tels que les leds (diodes électroluminescentes), émetteurs-récepteurs ou émetteurs pour rayon laser ne peuvent pas être entretenus par l'utilisateur. Retourner ces unités à SEL pour toute réparation ou remplacement.</p>
<p>⚠ DANGER Disconnect or de-energize all external connections before opening this device. Contact with hazardous voltages and currents inside this device can cause electrical shock resulting in injury or death.</p>	<p>⚠ DANGER Débrancher tous les raccordements externes avant d'ouvrir cet appareil. Tout contact avec des tensions ou courants internes à l'appareil peut causer un choc électrique pouvant entraîner des blessures ou la mort.</p>
<p>⚠ DANGER Contact with instrument terminals can cause electrical shock that can result in injury or death.</p>	<p>⚠ DANGER Tout contact avec les bornes de l'appareil peut causer un choc électrique pouvant entraîner des blessures ou la mort.</p>

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Section 1

Protection Application Examples

This section provides detailed instructions for setting the SEL-421 Relay protection functions. Use these application examples to help familiarize yourself with the relay, and to assist you with your own protection settings calculations. The settings that are not mentioned in these examples do not apply.

Introduction

Detailed setting calculation guidelines are provided for the following applications:

- *230 kV Overhead Transmission Line Example on page A.1.2*
- *500 kV Parallel Transmission Lines With Mutual Coupling Example on page A.1.19*
- *345 kV Tapped Overhead Transmission Line Example on page A.1.52*
- *EHV Parallel 230 kV Underground Cables Example on page A.1.86*

Separate protection application examples are provided for the following functions:

- *Out-of-Step Logic Application Examples on page A.1.117*
- *Auto-Reclose Example on page A.1.136*
- *Auto-Reclose and Synchronism Check Example on page A.1.140*
- *Circuit Breaker Failure Application Examples on page A.1.151*

Relay Settings

Enter settings in the following order for the first four examples listed above:

- *Global Settings*
- *Breaker Monitor*
- *Group Settings*
- *Control Outputs*

All the settings are listed in a single table at the end of each application example.

230 kV Overhead Transmission Line Example

NOTE: The SEL-421-1 and the SEL-421-2 provide fast and secure tripping for the line segment but does not have the high-speed distance elements of the SEL-421.

Figure 1.1 shows a double-ended 230 kV line with SEL-421 protection at each end. This example explains how to calculate settings for the SEL-421 at Station S that protects the line between Stations S and R.

This application example uses step-distance protection to provide high-speed tripping for faults in the first 80 percent of the line and time-delayed tripping for the last 20 percent.

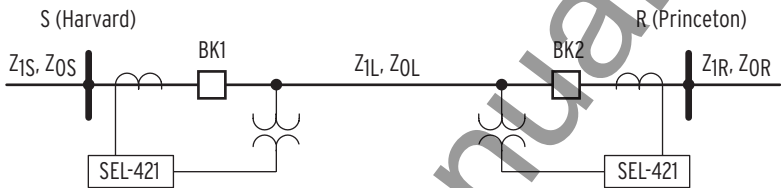


Figure 1.1 230 kV Overhead Transmission Line

Power System Data

Table 1.1 lists the power system data for this application example. Substitute the values and parameters that correspond to your system when you set the relay, using this example as a guide.

Table 1.1 System Data–230 kV Overhead Transmission Line

Parameter	Value
Nominal system line-to-line voltage	230 kV
Nominal relay current	5 A secondary
Nominal frequency	60 Hz
Line length	50 miles
Line impedances: Z_{1L}, Z_{0L}	$39 \Omega \angle 84^\circ$ primary, $124 \Omega \angle 81.5^\circ$ primary
Source S impedances: $Z_{1S} = Z_{0S}$	$50 \Omega \angle 86^\circ$ primary
Source R impedances: $Z_{1R} = Z_{0R}$	$50 \Omega \angle 86^\circ$ primary
PTR (potential transformer ratio)	230 kV:115 V = 2000
CTR (current transformer ratio)	500:5 = 100
Phase rotation	ABC

Convert the power system impedances from primary to secondary, so you can later calculate protection settings. Table 1.2 lists the corresponding secondary impedances. Convert the impedances to secondary ohms as follows:

$$k = \frac{CTR}{PTR} = \frac{100}{2000} = 0.05 \quad \text{Equation 1.1}$$

$$\begin{aligned} Z_{1L(\text{secondary})} &= k \cdot Z_{1L(\text{primary})} \\ &= 0.05 \cdot (39 \Omega \angle 84^\circ) \\ &= 1.95 \Omega \angle 84^\circ \end{aligned} \quad \text{Equation 1.2}$$

Table 1.2 Secondary Impedances

Parameter	Value
Line impedances: Z_{1L}, Z_{0L}	1.95 Ω $\angle 84^\circ$ secondary, 6.2 Ω $\angle 81.5^\circ$ secondary
Source S impedances: $Z_{1S} = Z_{0S}$	2.5 Ω $\angle 86^\circ$ secondary
Source R impedances: $Z_{1R} = Z_{0R}$	2.5 Ω $\angle 86^\circ$ secondary

The maximum load current is 495 A primary.

Application Summary

This particular example is for a single circuit breaker, three-pole tripping application with the following functions:

- Two zones of mho distance protection
 - Zone 1, forward-looking, instantaneous underreaching protection
 - Zone 2, forward-looking, time-delayed tripping
- Inverse-time directional zero-sequence overcurrent backup protection
- SOTF protection, fast tripping when the circuit breaker closes

Relay settings that are not mentioned in these examples do not apply to this application example.

Global Settings

General Global Settings

The SEL-421 has settings for identification. These settings allow you to identify the following:

- Station (SID)
- Relay (RID)
- Circuit Breaker 1 (BID1)

You can enter as many as 40 characters per identification setting.

SID := **HARVARD – 230 kV** Station Identifier (40 characters)

RID := SEL-421 **Relay** Relay Identifier (40 characters)

Configure the SEL-421 for one circuit breaker.

NUMBK := **1** Number of Breakers in Scheme (1, 2)

BID1 := **Circuit Breaker 1** Breaker 1 Identifier (40 characters)

You can select both nominal frequency and phase rotation for the relay.

NFREQ := **60** Nominal System Frequency (50, 60 Hz)

PHROT := **ABC** System Phase Rotation (ABC, ACB)

Current and Voltage Source Selection

The voltage and current source selection is for one circuit breaker. The relay derives the line current source from current input IW when you set ESS to N.

ESS := **N** Current and Voltage Source Selection (Y, N, 1, 2, 3, 4)

Figure 1.2 illustrates the current and voltage sources for this particular application. The relay uses potential input VY and current input IW for line relaying; potential input VAZ is for synchronism check. [Section 2: Auto-Reclosing and Synchronism Check in the Reference Manual](#) describes how to apply the synchronism-check function.

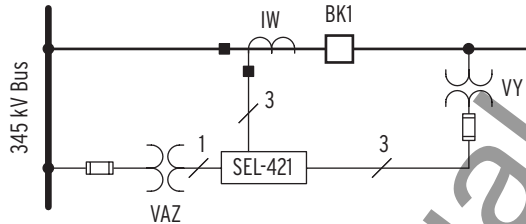


Figure 1.2 Circuit Breaker Arrangement at Station S

Breaker Monitor

Circuit Breaker Configuration

Set the relay to indicate that Circuit Breaker 1 is a three-pole trip circuit breaker.

BK1TYP := **3** Breaker 1 Trip Type (Single-Pole = 1, Three-Pole = 3)

Circuit Breaker 1 Inputs

The SEL-421 uses a normally open auxiliary contact from the circuit breaker to determine whether the circuit breaker is open or closed.

52AA1 := **IN101** A-Phase N/O Contact Input -BK1 (SELOGIC Equation)

Group Settings

Line Configuration

The SEL-421 has four transformer turns ratio settings that convert the secondary potentials and currents that the relay measures to the corresponding primary values. These settings are the potential transformer and current transformer ratios PTRY, PTRZ, CTRW, and CTRX.

Use the Y potential input for line relaying and the Z potential input for synchronism check. Use the W current input for line relaying. The settings VNOMY and VNOMZ specify the nominal secondary line-to-line voltage of the potential transformers (see [Figure 1.2](#)).

CTRW := **100** Current Transformer Ratio—Input W (1–50000)

PTRY := **2000** Potential Transformer Ratio—Input Y (1–10000)

VNOMY := **115** PT Nominal Voltage (L-L)—Input Y (60–300 V secondary)

PTRZ := **2000** Potential Transformer Ratio—Input Z (1–10000)

VNOMZ := **115** PT Nominal Voltage (L-L)—Input Z (60–300 V secondary)

Enter the secondary value of the positive-sequence impedance of the protected line. See [Table 1.2](#) for the secondary line impedances.

ZIMAG := **1.95** Positive-Sequence Line Impedance Magnitude
(0.05–255 Ω secondary)

ZIANG := **84.00** Positive-Sequence Line Impedance Angle (5.00–90 degrees)

Enter the secondary value of the zero-sequence impedance of the protected line.

ZOMAG := **6.20** Zero-Sequence Line Impedance Magnitude
 (0.05–255 Ω secondary)

ZOANG := **81.50** Zero-Sequence Line Impedance Angle (5.00–90 degrees)

Enable the fault locator.

EFLOC := **Y** Fault Location (Y, N)

The LL setting is the line length. This value has no defined unit; you can set the line length in miles, kilometers, ohms, etc. For this example, set the length in miles.

LL := **50** Line Length (0.10–999)

The fault locator uses the values you enter for Z1MAG, Z1ANG, ZOMAG, ZOANG, and LL.

Relay Configuration

You can select from zero to five phase zones of mho phase (E21P), mho ground (E21MG), and quadrilateral ground (E21XG) distance protection. You can independently select the number of zones per type of distance protection. Select only the number of zones needed. For this application example, use two zones of mho phase and ground distance protection.

E21P := **2** Mho Phase Distance Zones (N, 1–5)

E21MG := **2** Mho Ground Distance Zones (N, 1–5)

E21XG := **N** Quadrilateral Ground Distance Zones (N, 1–5)

Now enable the other logic you will need for this application example.

You do not need CVT transient detection if the SIR (Source Impedance Ratio) is less than five. SIR is equal to the ratio of the local source impedance to the relay reach. Calculate the ratio based on the Zone 1 reach because you do not want Zone 1 distance protection to overreach during an external fault.

$$\begin{aligned} \text{SIR} &= \frac{|Z_{1S}|}{0.8 \cdot |Z_{1L}|} \\ &= \frac{2.5 \, \Omega}{0.8 \cdot 1.95 \, \Omega} \\ &= 1.603, \text{ SIR} < 5 \end{aligned}$$

Equation 1.3

ECVT := **N** CVT Transient Detection (Y, N)

NOTE: The SEL-421-1 and the SEL-421-2 do not provide series-compensated line protection logic.

The transmission line is not series compensated.

ESERCMP := **N** Series-Compensated Line Logic (Y, N)

You can select a common time delay or an independent time delay per zone for phase and ground distance protection. If you choose independent timing, evolving faults (such as those changing from single phase to multi-phase) cause the timer to reset and result in additional delay. Select common time delay for this application.

ECDTD := **Y** Distance Element Common Time Delay (Y, N)

The SOTF logic permits tripping by specified protection elements for a settable time after the circuit breaker closes.

ESOTF := **Y** Switch-Onto-Fault (Y, N)

Do not enable the Out-of-Step logic for this application example.

E00S := **N** Out-of-Step (Y, N)

Do not enable the load-encroachment logic, as the minimum apparent load impedance is outside the mho phase distance characteristics.

ELOAD := **N** Load Encroachment (Y, N)

Use Level 1 high-set instantaneous phase overcurrent element for SOTF protection.

E50P := **1** Phase Instantaneous/Definite-Time Overcurrent Elements (N, 1–4)

This application does not require residual ground overcurrent protection.

E50G := **N** Residual Ground Instantaneous/Definite-Time Overcurrent Elements (N, 1–4)

This application does not require negative-sequence overcurrent protection.

E50Q := **N** Negative-Sequence Instantaneous/Definite-Time Overcurrent Elements (N, 1–4)

Use inverse-time overcurrent protection to provide backup protection for high-resistance ground faults. The 51S1 element provides backup protection for unbalanced faults if the step distance protection fails to operate.

E51S := **1** Selectable Inverse-Time Overcurrent Element (N, 1–3)

Set E32 to AUTO and the relay automatically calculates the settings corresponding to the ground directional element (32G).

E32 := **AUTO** Directional Control (Y, AUTO)

Communications-assisted tripping is not required.

E00M := **N** Communications-Assisted Tripping (N, DCB, POTT, POTT2, POTT3, DCUB1, DCUB2)

Fuses or molded case circuit breakers often protect potential transformers. Operation of one or more fuses, or molded case circuit breakers, results in a loss of polarizing potential inputs to the relay. Loss of one or more phase voltages prevents the relay from properly determining fault distance or direction.

Occasional LOP (loss-of-potential) to the distance relay, while unavoidable, is detectable. When the relay detects the loss-of-potential, the relay can block distance element operation, block or enable forward directional overcurrent elements, and issue an alarm for any true LOP condition.

NOTE: If line-side PTs are used, the circuit breaker(s) must be closed for the LOP logic to detect an LOP condition. Therefore, if three-phase potential to the relay is lost while the circuit breaker(s) is open (e.g., the PT fuses are removed while the line is de-energized), the relay cannot detect an LOP when the circuit breaker(s) closes again.

Table 1.3 LOP Enable Options

Option	Description
N	The LOP logic operates but does not disable voltage-polarized directional elements, distance elements, and forward directional overcurrent elements. Use LOP in this case for alarm only.
Y	The relay disables all voltage-polarized directional elements and distance elements, but enables forward directional overcurrent elements. These forward directional overcurrent elements effectively become nondirectional and provide overcurrent protection during an LOP condition.
Y1	The relay disables all voltage-polarized directional elements and distance elements. The relay also disables the overcurrent elements controlled by the voltage-polarized directional elements.

Set ELOP to Y1 for this application example. This choice reduces the chances of false tripping because of a loss-of-potential condition.

ELOP := **Y1** Loss-of-Potential (Y, Y1, N)

You do not need Advanced Settings for this application example.

EADVS := **N** Advanced Settings (Y, N)

Phase Distance Elements (21P)

Mho Phase Distance Element Reach

Employ each zone of mho phase distance protection as follows:

- Zone 1—Instantaneous underreaching tripping
- Zone 2—Time-delayed overreaching backup tripping

Zone 1 Phase Distance Element Reach. Zone 1 phase distance protection provides instantaneous protection for phase-to-phase, phase-to-phase-to-ground, and three-phase faults in the first 80 percent of the transmission line. Errors in the current transformers and potential transformers, modeled transmission line data, and fault study data do not permit setting Zone 1 for 100 percent of the transmission line. If you set Zone 1 for 100 percent of the transmission line, unwanted tripping could occur for faults just beyond the remote end of the line.

Set Zone 1 phase distance protection equal to 80 percent of the transmission line positive-sequence impedance.

$$Z1P = 0.8 \cdot Z1L = 1.56 \, \Omega$$

Z1P := **1.56** Zone 1 Reach (OFF, 0.05–64 Ω secondary)

Zone 2 Phase Distance Element Reach. Zone 2 phase distance protection must have adequate reach to detect all phase-to-phase, phase-to-phase-to-ground, and three-phase faults along the protected line to make certain delayed tripping occurs for faults located in the last 20 percent of the line. Set Zone 2 phase distance reach equal to 120 percent of the positive-sequence impedance of the transmission line.

$$Z2P = 1.2 \cdot Z1L = 2.34 \, \Omega$$

Z2P := **2.34** Zone 2 Reach (OFF, 0.05–64 Ω secondary)

Ground Distance Elements (21MG)

Mho Ground Distance Element Reach

Employ each zone of mho ground distance protection as follows:

- Zone 1—Instantaneous underreaching tripping
- Zone 2—Time-delayed overreaching backup tripping

Zone 1 Mho Ground Distance Element Reach. Zone 1 mho ground distance reach must meet the same requirement as that for Zone 1 mho phase distance protection; i.e., the reach setting can be no greater than 80 percent of the line.

$$Z1MG = 0.8 \cdot Z1L = 1.56 \, \Omega$$

Z1MG := **1.56** Zone 1 (OFF, 0.05–64 Ω secondary)

Zone 2 Mho Ground Distance Element Reach. Zone 2 mho ground distance reach must meet the same requirement as that for Zone 2 mho phase distance protection; i.e., set the reach equal to 120 percent of the line.

$$Z2MG = 1.2Z1L = 2.34 \Omega$$

$$Z2MG := \mathbf{2.34} \text{ Zone 2 (OFF, 0.05–64 } \Omega \text{ secondary)}$$

Zero-Sequence Current Compensation Factors

Zero-sequence current compensation helps to keep the phase and ground distance elements at the same reach if you set the reach equal per zone (for example, $Z1P = Z1MG$). Ground distance elements should measure fault impedance in terms of positive-sequence impedance only. The relay automatically calculates the setting for the Zone 1 zero-sequence current compensation factor when you set $k0M1$ to AUTO.

$$k0M1 := \mathbf{AUTO} \text{ Zone 1 ZSC Factor Magnitude (AUTO, 0.000–10)}$$

When you enter AUTO as the setting for $k0M1$, the relay calculates the zero-sequence current compensation as follows:

$$k01 = \frac{Z0MAG \angle Z0ANG - \angle Z1MAG \angle Z1ANG}{3 \cdot Z1MAG \angle Z1ANG} \quad \text{Equation 1.4}$$

Zone 2 uses the same zero-sequence current compensation factor as that for Zone 1 because the Advanced Settings are disabled.

The relay displays the following values for $k0M1$ and $k0A1$:

$$k0M1 := \mathbf{0.727} \text{ Zone 1 ZSC Factor Magnitude (AUTO, 0.000–10)}$$

$$k0A1 := \mathbf{-3.65} \text{ Zone 1 ZCS Factor Angle}$$

Distance Element Common Time Delay

Set the appropriate timers $Z1D$ and $Z2D$ for both phase and ground distance elements.

You do not need to delay Zone 1 distance protection; it trips instantaneously.

$$Z1D := \mathbf{0.000} \text{ Zone 1 Time Delay (OFF, 0.000–16000 cycles)}$$

Zone 2 distance protection must coordinate with downstream Zone 1 distance protection, plus downstream circuit breaker operating time and a safety margin. A typical Zone 2 phase and ground distance time delay setting is 20 cycles.

$$Z2D := \mathbf{20.000} \text{ Zone 2 Time Delay (OFF, 0.000–16000 cycles)}$$

SOTF Scheme

SOTF (Switch-Onto-Fault) logic is enabled when the circuit breaker closes. This logic provides protection for a short duration (setting $SOTFD$) until other protection (such as tripping from SELOGIC control equations TR and TRCOMM) is available. The TRSOTF SELOGIC control equation defines which protection elements cause the relay to trip when the SOTF scheme is active. Assertion of the protection elements assigned to TRSOTF during the $SOTFD$ time causes the relay to trip instantaneously.

Apply SOTF when using line-side potentials for relaying. Use nondirectional overcurrent protection to clear close-in faults. Also use instantaneous overreaching distance protection to clear faults along the line. Assign instantaneous Zone 2 mho phase and ground distance protection plus Level 1 phase overcurrent element to TRSOTF.

TRSOTF := **M2P OR Z2G OR 50P1** Switch-Onto-Fault Trip (SELOGIC Equation)

Single-Pole SOTF

This is a three-pole tripping application example; confirm that the SOTF protection is for three-pole tripping.

ESPSTF := **N** Single-Pole Switch-Onto-Fault (Y, N)

Voltage Reset

You can configure the logic such that the SOTF enable duration resets within at least 5 cycles after it first asserted, but before the SOTFD timer expires. To quickly reset the SOTF period, the relay must sense that the positive-sequence voltage is greater than 85 percent of the nominal voltage.

Use setting EVRST (Switch-Onto-Fault Voltage Reset) to enable fast reset. The advantage of resetting SOTF protection quickly is that unwanted tripping does not occur for subsequent faults external to the remote terminals during the SOTF period; these trips can occur if you set instantaneous Zone 2 distance protection elements in the TRSOTF SELOGIC control equation. Enable the voltage reset option.

EVRST := **Y** Switch-Onto-Fault Voltage Reset (Y, N)

SOTF Initiation

The SOTF logic asserts via one or both of the following methods:

- A change in the normally open auxiliary contact 52A status showing that the circuit breaker has just opened
- Assertion of the relay control input assigned to the circuit breaker close bus

The 52A method works well for both single and multiple circuit breaker applications and does not require an input from the close bus. However, the close bus method only enables SOTF protection immediately following the close command to the circuit breaker. For more information see [Switch-Onto-Fault Logic on page R.1.94](#).

Turn off 52AEND, 52A Pole Open Time Delay.

52AEND := **OFF** 52A Pole Open Time Delay (OFF, 0.000–16000 cycles)

Select the close bus option for this application and set the close enable delay (CLOEND) shorter than the shortest reclose open interval.

CLOEND := **10.000** CLSMON or Single-Pole Open Delay
(OFF, 0.000–16000 cycles)

SOTF Duration

Setting SOTFD determines the longest period the SOTF logic can assert after the circuit breaker closes.

SOTFD := **10.000** Switch-Onto-Fault Enable Duration (0.500–16000 cycles)

Close Signal Monitor

Assign the Relay Word bit CLSMON to a control input, so the relay can detect execution of the close command. Connect IN102 in parallel with the circuit breaker close coil.

CLSMON := **IN102** Close Signal Monitor (SELOGIC Equation)

Phase Instantaneous/Definite-Time Overcurrent Elements

Use 50P1, Level 1 phase instantaneous overcurrent element, as a nondirectional high-set phase overcurrent element for SOTF protection. If the local circuit breaker closes into a close-in three-phase bolted fault with line-side potential transformers, the polarizing voltage for the phase distance elements is zero. Therefore, the distance protection does not operate. In this case, the 50P1 element quickly trips the circuit breaker because this overcurrent element does not rely on the polarizing voltage.

To rapidly clear faults, set 50PIP equal to 50 percent of the fault current measured at the local terminal for a close-in three-phase fault; use weak source conditions so that the relay operates for low-level fault current.

50PIP := **13.29** Level 1 Pickup (OFF, 0.25–100 A secondary)

This application uses 50P1 as an instantaneous overcurrent element; you do not need time delay.

67PID := **0.000** Level 1 Time Delay (0.000–16000 cycles)

This application uses 50P1 as a nondirectional overcurrent element; you do not need torque control.

67P1TC := **1** Level 1 Torque Control (SELOGIC Equation)

Selectable Operating Quantity Time Overcurrent Element 1

Use inverse-time overcurrent protection to provide backup protection for high-resistance ground faults. The 51S1 element provides backup protection for unbalanced faults if the step distance protection fails to operate.

Select zero-sequence line current as the operating quantity.

51S1O := **3I0L** 51S1 Operate Quantity (I_{An} , I_{Bn} , I_{Cn} , I_{MAXn} , I_{1L} , $3I_{2L}$, $3I_{0n}$)

The n in the 51S1O setting is L for line, 1 for BK1, and 2 for BK2.

The relay measures 8.61 A secondary of $3I_0$ for a bolted single phase-to-ground fault at the remote terminal. Set the pickup to 20 percent of $3I_0$.

51S1P := **1.72** 51S1 Overcurrent Pickup (0.25–16 A secondary)

Use the following formula to determine approximately how much primary fault resistance coverage (R_F) is provided by 51S1P on a radial basis:

$$\begin{aligned} R_F &= \frac{PTR}{CTR} \cdot \frac{VNOMY/\sqrt{3}}{51S1P} \\ &= \frac{2000}{100} \cdot \frac{115V/\sqrt{3}}{1.72A} \\ &= 722 \, \Omega \end{aligned}$$

Equation 1.5

NOTE: Use your company practices and philosophy when determining these settings.

Use the following as a guide to set the curve and time dial; for secure backup protection, perform a coordination study. Set the local overcurrent element to coordinate with the downstream overcurrent element such that there is an 18-cycle (60 Hz nominal) safety margin for ground faults in front of the first downstream overcurrent element. Assume the operating time of the downstream overcurrent element is 12 cycles for a close-in ground fault. Therefore, set the local time-overcurrent element to operate approximately 30-cycles for ground faults in front of the first downstream overcurrent element.

51SIC := **U3** 51S1 Inverse-Time Overcurrent Curve (U1–U5)

51SITD := **1.96** 51S1 Inverse-Time Overcurrent Time Dial (0.50–15)

Set the overcurrent element to emulate electromechanical reset, so the overcurrent element coordinates properly with electromechanical relays.

51SIRS := **Y** 51S1 Inverse-Time Overcurrent Electromechanical Reset (Y, N)

Torque control the overcurrent element with the forward decision from the ground directional element.

51SITC := **32GF** 51S1 Torque Control (SELOGIC Equation)

Directional Control

The SEL-421 uses an array of directional elements to supervise the ground distance elements and residual ground directional overcurrent elements during ground fault conditions. Internal logic automatically selects the best choice for the ground directional element (32G) from among the negative-sequence voltage-polarized directional element (32QG), zero-sequence voltage-polarized directional element (32V), and the zero-sequence current-polarized directional element (32I).

The relay setting **ORDER** determines the order in which the relay selects directional elements to provide ground directional decisions. You can set **ORDER** with any combination of Q, V, and I. The listed order of these directional elements determines the priority in which these elements operate to provide the ground directional element. Only one specific directional element operates at any one time. Directional element classification is as follows:

- Q—Negative-sequence voltage-polarized directional element
- V—Zero-sequence voltage-polarized directional element
- I—Zero-sequence current-polarized directional element

Set **ORDER** equal to QV. The first listed directional element choice, Q, is the first priority directional element to provide directional control for the ground distance elements and residual ground directional overcurrent elements. If Q is not operable, the second listed directional element choice, V, provides directional control for the ground distance elements and residual ground directional overcurrent elements. A polarizing quantity was not available for choice I, so I is not selected for this particular application example.

ORDER := QV Ground Directional Element Priority (combine Q, V, I)

SELOGIC control equation E32IV must assert to logical 1 to enable V or I for directional control of the ground distance elements and residual ground directional overcurrent elements. Set E32IV equal to logical 1.

E32IV := 1 Zero-Sequence Voltage and Current Enable (SELOGIC Equation)

Pole Open Detection

The setting EPO, Enable Pole-Open logic, offers two options for deciding what conditions signify an open pole, as listed in [Table 1.4](#).

Table 1.4 Options for Enabling Pole-Open Logic

Option	Description
EPO := V	The logic declares a single-pole open if the corresponding phase under-voltage element asserts and the open phase detection logic declares the pole is open. <i>Select this option only if you use line-side potential transformers for relaying purposes.</i> A typical setting for the 27PO, pole-open undervoltage threshold, is 60 percent of the nominal line-to-neutral voltage. Do not select this option when shunt reactors are applied because the voltage slowly decays after the circuit breaker opens. With this option selected, the relay cannot declare an open pole during assertion of LOP.
EPO := 52	The logic declares a single-pole open if the corresponding 52A contact (e.g., 52AA1) from the circuit breaker deasserts and the open phase detection logic declares that the pole is open.

Select the second option because a 52A contact is available. The relay uses both open phase detection and status information from the circuit breaker to make the most secure decision.

EPO := **52** Pole-Open Detection (52, V)

Pole-Open Time Delay on Dropout

The setting 3POD establishes the time delay on dropout after the Relay Word bit 3PO deasserts. This delay is important when you use line-side potential transformers for relaying. Use the 3POD setting to stabilize the ground distance elements in case of pole scatter during closing of the circuit breaker.

3POD := **0.500** Three-Pole Open Time Dropout Delay (0.000–60 cycles)

Trip Logic

This logic configures the relay for tripping. These settings consist of four categories:

- Trip equations
- Trip unlatch options
- Trip timers
- Three-pole tripping enable

Trip Equations

Set these two SELOGIC control equations for tripping:

- TR (unconditional)
- TRSOTF (SOTF)

TR. The TR SELOGIC control equation determines which protection elements cause the relay to trip unconditionally. You typically set all direct tripping and time-delayed protection elements in the SELOGIC control equation TR. Direct tripping and time-delayed protection elements include step distance protection elements, plus instantaneous and time-overcurrent protection elements.

Set TR equal to Zone 1 instantaneous protection (Z1T), time-delayed Zone 2 distance protection, and the inverse-time overcurrent element (51S1T). For information on setting 51S1T, see [Selectable Operating Quantity Time Overcurrent Element 1 on page A.1.10](#).

TR := Z1T OR Z2T OR 51S1T Trip (SELOGIC Equation)

TRSOFT. The TRSOFT SELOGIC control equation defines which protection elements cause the relay to trip when the SOTF scheme is active. Assertion of these protection elements during the SOTFD time causes the relay to trip instantaneously (see [SOTF Scheme on page A.1.8](#)). Set instantaneous Zone 2 distance protection (M2P and Z2G) and Level 1 phase instantaneous overcurrent element (50P1) in the TRSOFT SELOGIC control equation.

TRSOFT := M2P OR Z2G OR 50P1 Switch-Onto-Fault Trip (SELOGIC Equation)

Trip Unlatch Options

Unlatch the control output you programmed for tripping (OUT101) after the circuit breaker 52A contacts break the dc current. The SEL-421 provides two methods for unlatching control outputs following a protection trip:

- ULTR—all three poles
- TULO—phase selective

ULTR. Use ULTR, the Unlatch Trip SELOGIC control equation, to unlatch all three poles. Use the default setting, which asserts ULTR when you push the front-panel {TARGET RESET} pushbutton.

ULTR := TRGTR Unlatch Trip (SELOGIC Equation)

TULO. Use TULO (Trip Unlatch Option) to select the conditions that cause the SEL-421 to unlatch the control outputs that you programmed for tripping. [Table 1.5](#) shows the four trip unlatch options for setting TULO.

Table 1.5 Setting TULO Unlatch Trip Options

Option	Description
1	Unlatch the trip when the relay detects that one or more poles of the line terminal are open, and Relay Word bit 3PT has deasserted.
2	Unlatch the trip when the relay detects that the corresponding 52A contact(s) from both circuit breakers (e.g., 52AA1 and 52AA2) are deasserted.
3	Unlatch the trip when the relay detects that the conditions for Options 1 and 2 are satisfied.
4	Do not run this logic.

Select Option 3 because a 52A contact is available; the relay uses both open phase detection and status information from the circuit breaker to make the most secure decision. For information on the pole-open logic, see [Pole Open Logic on page R.1.24](#).

TULO := 3 Trip Unlatch Option (1, 2, 3, 4)

Trip Timers

The SEL-421 provides dedicated timers for minimum trip duration.

Minimum Trip Duration. The minimum trip duration timer setting, TDUR3D, determines the minimum time that Relay Word bit 3PT asserts. For this application example, Relay Word bit 3PT is assigned to OUT101. The corresponding control output closes for TDUR3D time or the duration of the trip condition, whichever is longer.

A typical setting for this timer is 9 cycles.

TDUR3D := **9.000** Three-Pole Trip Minimum Trip Duration Time Delay
(2.000–8000 cycles)

Three-Pole Tripping Enable

The relay contains both three-pole and single-pole tripping logic. Set E3PT (Three-Pole Trip Enable) equal to logical 1 to enable the SEL-421 for three-pole tripping only.

E3PT := **1** Three-Pole Trip Enable (SELOGIC Equation)

Also set the appropriate three-pole tripping SELOGIC control equation for Circuit Breaker 1.

E3PT1 := **1** Breaker 1 3PT (SELOGIC Equation)

Control Outputs

Main Board

OUT101 trips Circuit Breaker 1.

OUT101 := **3PT**

Example Completed

This completes the application example describing configuration of the SEL-421 for step-distance protection of a 230 kV overhead transmission line. You can use this example as a guide when setting the relay for similar applications. Analyze your particular power system so you can properly determine your corresponding settings.

Relay Settings

[Table 1.6](#) lists the protection relay settings for this example. Settings used in this example appear in boldface type.

Table 1.6 Settings for 230 kV Overhead TX Example (Sheet 1 of 5)

Setting	Description	Entry
General Global (Global)		
SID	Station Identifier (40 characters)	HARVARD - 230 kV
RID	Relay Identifier (40 characters)	SEL-421 Relay
NUMBK	Number of Breakers in Scheme (1, 2)	1
BID1	Breaker 1 Identifier (40 characters)	Circuit Breaker 1
NFREQ	Nominal System Frequency (Hz)	60
PHROT	System Phase Rotation (ABC, ACB)	ABC
DATE_F	Date Format (MDY, YMD, DMY)	MDY
FAULT	Fault Condition Equation (SELOGIC Equation)	50P1 OR 51S1 OR M2P OR Z2G OR M3P OR Z3G

Table 1.6 Settings for 230 kV Overhead TX Example (Sheet 2 of 5)

Setting	Description	Entry
Current and Voltage Source Selection (Global)		
ESS	Current and Voltage Source Selection (Y, N, 1, 2, 3, 4)	N
Breaker Configuration (Breaker Monitoring)		
EB1MON	Breaker 1 Monitoring (Y, N)	N
BK1TYP	Breaker 1 Trip Type (Single Pole = 1, Three Pole = 3)	3
Breaker 1 Inputs (Breaker Monitoring)		
52AA1	A-Phase N/O Contact Input—BK1 (SELOGIC Equation)	IN101
Line Configuration Settings (Group)		
CTRW	Current Transformer Ratio—Input W (1–50000)	100
CTRX	Current Transformer Ratio—Input X (1–50000)	200
PTRY	Potential Transformer Ratio—Input Y (1–10000)	2000
VNOMY	PT Nominal Voltage (L–L)—Input Y (60–300 V secondary)	115
PTRZ	Potential Transformer Ratio—Input Z (1–10000)	2000
VNOMZ	PT Nominal Voltage (L–L)—Input Z (60–300 V secondary)	115
Z1MAG	Positive-Sequence Line Impedance Magnitude (0.05–255 Ω secondary)	1.95
Z1ANG	Positive-Sequence Line Impedance Angle (5.00–90 degrees)	84.00
Z0MAG	Zero-Sequence Line Impedance Magnitude (0.05–255 Ω secondary)	6.20
Z0ANG	Zero-Sequence Line Impedance Angle (5.00–90 degrees)	81.50
EFLOC	Fault Location (Y, N)	Y
LL	Line Length (0.10–999)	50
Relay Configuration (Group)		
E21P	Mho Phase Distance Zones (N, 1–5)	2
E21MG	Mho Ground Distance Zones (N, 1–5)	2
E21XG	Quadrilateral Ground Distance Zones (N, 1–5)	N
ECVT	CVT Transient Detection (Y, N)	N
ESERCMP	Series-Compensated Line Logic (Y, N)	N
ECDTD	Distance Element Common Time Delay (Y, N)	Y
ESOTF	Switch-Onto-Fault (Y, N)	Y
EOOS	Out-of-Step (Y, N)	N
ELOAD	Load Encroachment (Y, N)	N
E50P	Phase Inst./Def.-Time O/C Elements (N, 1–4)	1
E50G	Residual Ground Inst./Def.-Time O/C Elements (N, 1–4)	N
E50Q	Negative-Sequence Inst./Def.-Time O/C Elements (N, 1–4)	N
E51S	Selectable Inverse-Time O/C Elements (N, 1–3)	1
E32	Directional Control (Y, AUTO)	AUTO

Table 1.6 Settings for 230 kV Overhead TX Example (Sheet 3 of 5)

Setting	Description	Entry
ECOMM	Communications-Assisted Tripping (N, DCB, POTT, POTT2, POTT3, DCUB1, DCUB2)	N
EBFL1	Breaker 1 Failure Logic (N, 1, 2)	N
E25BK1	Synchronism Check for Breaker 1 (Y, N)	N
E79	Reclosing (Y, Y1, N)	N
EMANCL	Manual Closing (Y, N)	N
ELOP	Loss-of-Potential (Y, Y1, N)	Y1
EDEM	Demand Metering (N, THM, ROL)	N
EADVS	Advanced Settings (Y, N)	N
Mho Phase Distance Element Reach (Group)		
Z1P	Zone 1 Reach (OFF, 0.05–64 Ω secondary)	1.56
Z2P	Zone 2 Reach (OFF, 0.05–64 Ω secondary)	2.34
Mho Phase Distance Element Time Delay (Group)		
Z1PD	Zone 1 Time Delay (OFF, 0.000–16000 cycles)	OFF
Z2PD	Zone 2 Time Delay (OFF, 0.000–16000 cycles)	OFF
Mho Ground Distance Element Reach (Group)		
Z1MG	Zone 1 (OFF, 0.05–64 Ω secondary)	1.56
Z2MG	Zone 2 (OFF, 0.05–64 Ω secondary)	2.34
Zero-Sequence Current Compensation Settings (Group)		
k0M1	Zone 1 ZSC Factor Magnitude (AUTO, 0.000–10)	AUTO
k0A1	Zone 1 ZSC Factor Angle (–180.0 to +180.0 degrees)	–3.65
Ground Phase Distance Element Time Delay (Group)		
Z1GD	Zone 1 Time Delay (OFF, 0.000–16000 cycles)	OFF
Z2GD	Zone 2 Time Delay (OFF, 0.000–16000 cycles)	OFF
Distance Element Common Time Delay (Group)		
Z1D	Zone 1 Time Delay (OFF, 0.000–16000 cycles)	0.000
Z2D	Zone 2 Time Delay (OFF, 0.000–16000 cycles)	20.000
SOTF Scheme Settings (Group)		
ESPSTF	Single Pole Switch-Onto-Fault (Y, N)	N
EVRST	Switch-Onto-Fault Voltage Reset (Y, N)	Y
52AEND	52A Pole Open Delay (OFF, 0.000–16000 cycles)	OFF
CLOEND	CLSMON or Single Pole Delay (OFF, 0.000–16000 cycles)	10.000
SOTFD	Switch-Onto-Fault Enable Duration (0.500–16000 cycles)	10.000
CLSMON	Close Signal Monitor (SELOGIC Equation)	IN102
Phase Instantaneous Overcurrent Pickup Settings (Group)		
50P1P	Level 1 Pickup (OFF, 0.25–100 A secondary)	13.29
Phase Overcurrent Definite-Time Delay (Group)		
67P1D	Level 1 Time Delay (0.000–16000 cycles)	0.000
Phase Overcurrent Torque Control (Group)		
67P1TC	Level 1 Torque Control (SELOGIC Equation)	1

Table 1.6 Settings for 230 kV Overhead TX Example (Sheet 4 of 5)

Setting	Description	Entry
Selectable Operating Quantity Time Overcurrent Element Settings (Group)		
51S1O	51S1 Operating Quantity (I_{An} , I_{Bn} , I_{Cn} , $IMAXn$, $11L$, $3I2L$, $3I0n$) ^a	3I0L
51S1P	51S1 Overcurrent Pickup (0.25–16 A secondary)	1.72
51S1C	51S1 Inverse-Time Overcurrent Curve (U1–U5)	U3
51S1TD	51S1 Inverse-Time Overcurrent Time Dial (0.50–15.00)	1.96
51S1RS	51S1 Inverse-Time Overcurrent Electromechanical Reset (Y, N)	Y
51S1TC	51S1 Torque Control (SELOGIC Equation)	32GF
Directional Control (Group)		
ORDER	Ground Directional Element Priority (combine Q, V, I)	QV
E32IV	Zero-Sequence Voltage and Current Enable (SELOGIC Equation)	1
Pole Open Detection Settings (Group)		
EPO	Pole-Open Detection (52, V)	52
SPOD	Single-Pole Open Dropout Delay (0.000–60 cycles)	0.500
3POD	Three-Pole Open Dropout Delay (0.000–60 cycles)	0.500
Trip Logic Settings (Group)		
TR	Trip (SELOGIC Equation)	Z1T OR Z2T OR 51S1T
TRSOTF	Switch-Onto-Fault Trip (SELOGIC Equation)	M2P OR Z2G OR 50P1
DTA	Direct Transfer Trip A-Phase (SELOGIC Equation)	NA
DTB	Direct Transfer Trip B-Phase (SELOGIC Equation)	NA
DTC	Direct Transfer Trip C-Phase (SELOGIC Equation)	NA
BK1MTR	Manual Trip – Breaker 1 (SELOGIC Equation)	OC1 OR PB8_PUL
ULTR	Unlatch Trip (SELOGIC Equation)	TRGTR
ULMTR1	Unlatch Manual Trip – Breaker 1 (SELOGIC Equation)	NOT (52AA1 AND 52AB1 AND 52AC1)
TOPD	Trip During Open Pole Time Delay (2.000–8000 cycles)	2.000
TULO	Trip Unlatch Option (1, 2, 3, 4)	3
Z2GTSP	Zone 2 Ground Distance Time Delay SPT (Y, N)	N
67QGSP	Zone 2 Dir. Neg.-Seq./Residual O/C Single Pole Trip (Y, N)	N
TDUR1D	SPT Minimum Trip Duration Time Delay (2.000–8000 cycles)	6.000
TDUR3D	3PT Minimum Trip Duration Time Delay (2.000–8000 cycles)	9.000
E3PT	Three-Pole Trip Enable (SELOGIC Equation)	1
E3PT1	Breaker 1 3PT (SELOGIC Equation)	1

Table 1.6 Settings for 230 kV Overhead TX Example (Sheet 5 of 5)

Setting	Description	Entry
ER	Event Report Trigger (SELOGIC Equation)	R_TRIG M2P OR R_TRIG Z2G OR R_TRIG 51S1 OR R_TRIG M3P OR R_TRIG Z3G
Main Board (Outputs)		
OUT101	(SELOGIC Equation)	3PT

^a Parameter n is 1 for BK1, 2 for BK2, and L for Line.

500 kV Parallel Transmission Lines With Mutual Coupling Example

Figure 1.3 shows double-ended overhead 500 kV parallel lines with SEL-421 protection at each end of the first circuit. These transmission lines have zero-sequence mutual coupling. This example explains how to calculate settings for the SEL-421 at Station S that protects Line 1 in Figure 1.3 between Stations S and R.

This application example uses communications-assisted tripping with a digital communications channel to provide high-speed protection for faults along the 500 kV circuit. Distance protection is enabled.

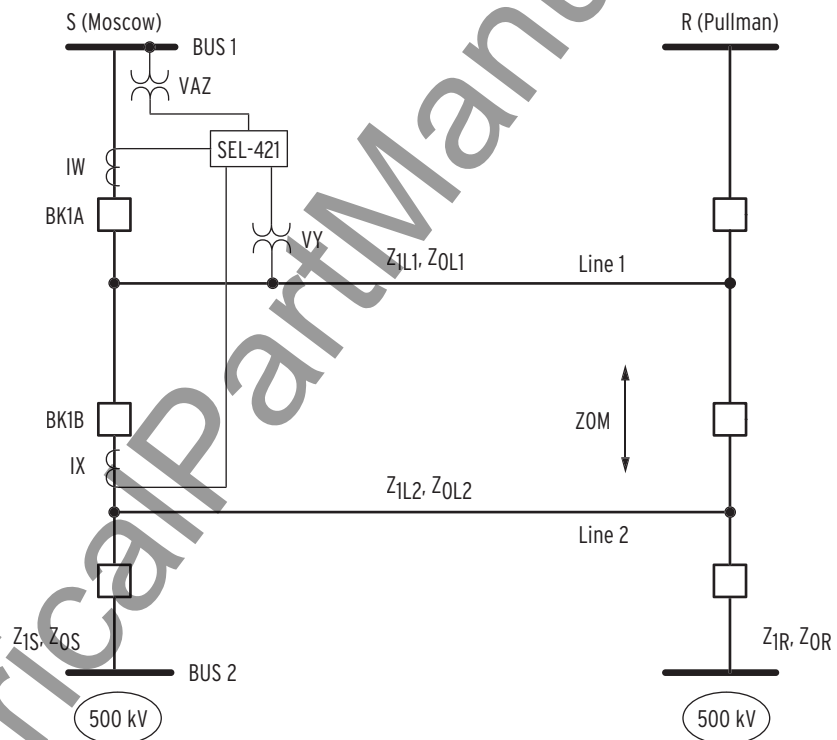


Figure 1.3 500 kV Parallel Overhead Transmission Lines

Power System Data

Table 1.7 lists the power system data for this application example. Substitute the values and parameters that correspond to your system when you set the relay using this example as a guide.

Table 1.7 System Data—500 kV Parallel Overhead Transmission Lines
(Sheet 1 of 2)

Parameter	Value
Nominal system line-to-line voltage	500 kV
Nominal relay current	5 A secondary
Nominal frequency	60 Hz
Line length	75 miles

Table 1.7 System Data—500 kV Parallel Overhead Transmission Lines
(Sheet 2 of 2)

Parameter	Value
Line impedances: $Z_{1L1} = Z_{1L2}$ $Z_{0L1} = Z_{0L2}$	44.78 Ω $\angle 87.6^\circ$ primary 162.9 Ω $\angle 82.1^\circ$ primary
Zero-sequence mutual coupling: Z_{0M}	88.35 Ω $\angle 76.6^\circ$ primary
Source S impedances: $Z_{1S} = Z_{0S}$	50 Ω $\angle 88^\circ$ primary
Source R impedances: $Z_{1R} = Z_{0R}$	20 Ω $\angle 88^\circ$ primary
PTR (Potential transformer ratio)	500 kV:111.11 V = 4500
CTR (Current transformer ratio)	2000:5 = 400
Phase rotation	ABC

Convert the power system impedances from primary to secondary so you can later calculate protection settings. [Table 1.8](#) lists the corresponding secondary impedances. Convert the impedances to secondary ohms as follows:

$$k = \frac{CTR}{PTR} = \frac{400}{4500} = 0.089 \quad \text{Equation 1.6}$$

$$\begin{aligned} Z_{1L1}(\text{secondary}) &= k \cdot Z_{1L1}(\text{primary}) \\ &= 0.089 \cdot (44.78 \Omega \angle 87.6^\circ) \\ &= 3.98 \Omega \angle 87.6^\circ \end{aligned} \quad \text{Equation 1.7}$$

Table 1.8 Secondary Impedances

Parameter	Value
Line impedances: $Z_{1L1} = Z_{1L2}$ $Z_{0L1} = Z_{0L2}$	3.98 Ω $\angle 87.6^\circ$ secondary 14.48 Ω $\angle 82.1^\circ$ secondary
Zero-sequence mutual coupling: Z_{0M}	7.86 Ω $\angle 76.6^\circ$ secondary
Source S impedances: $Z_{1S} = Z_{0S}$	4.45 Ω $\angle 88^\circ$ secondary
Source R impedances: $Z_{1R} = Z_{0R}$	1.78 Ω $\angle 88^\circ$ secondary

The maximum load current is 1302 A primary and occurs when the parallel line is out of service.

Application Summary

This application is for two circuit breakers, single-pole tripping application with the following functions:

- POTT (permissive overreaching transfer tripping) scheme

- Three zones of phase (mho) and ground (mho and quadrilateral) distance protection
 - Zone 1, forward-looking, instantaneous underreaching protection
 - Zone 2, forward-looking, communications-assisted and time-delayed tripping
 - Zone 3, reverse-looking, prevents unwanted tripping during current reversals
- Inverse-time directional zero-sequence overcurrent backup protection
- SOTF protection, fast tripping when the circuit breaker closes

Relay settings that are not mentioned in this example do not apply to this application example.

Global Settings

General Global Settings

The SEL-421 has settings for identification. These settings allow you to identify the following:

- Station (SID)
- Relay (RID)
- Circuit Breaker 1 (BID1)
- Circuit Breaker 2 (BID2)

You can enter as many as 40 characters per identification setting.

SID := **MOSCOW – 500 kV** Station Identifier (40 characters)

RID := **SEL-421 Relay** Relay Identifier (40 characters)

Configure the SEL-421 for two circuit breakers. This particular application uses two circuit breakers because the terminal is a circuit breaker-and-a-half configuration.

NUMBK := **2** Number of Breakers in Scheme (1, 2)

BID1 := **Circuit Breaker 1** Breaker 1 Identifier (40 characters)

BID2 := **Circuit Breaker 2** Breaker 2 Identifier (40 characters)

You can select both the nominal frequency and phase rotation.

NFREQ := **60** Nominal System Frequency (50, 60 Hz)

PHROT := **ABC** System Phase Rotation (ABC, ACB)

Current and Voltage Source Selection

The voltage and current source selection is for two circuit breakers in a circuit breaker-and-a-half configuration. Set ESS to 3.

ESS := **3** Current and Voltage Source Selection (Y, N, 1, 2, 3, 4)

After you select 3 for setting ESS, the relay automatically sets LINEI, BK1I, and BK2I as follows:

LINEI := **COMB** Line Current Source (IW, COMB)

BK1I := **IW** Breaker 1 Current Source (IW, IX, NA)

BK2I := **IX** Breaker 2 Current Source (IW, IX, NA)

In this application example Circuit Breaker BK1A is Breaker 1 in the relay settings and BK1B is Breaker 2 in the relay settings.

Figure 1.4 illustrates the current and voltage sources for this particular application. The relay uses potential input VY and the combination of current inputs IW and IX for line relaying; potential input VAZ is for synchronism check. *Auto-Reclose and Synchronism Check Example on page A.1.140* describes how to apply the synchronism-check function.

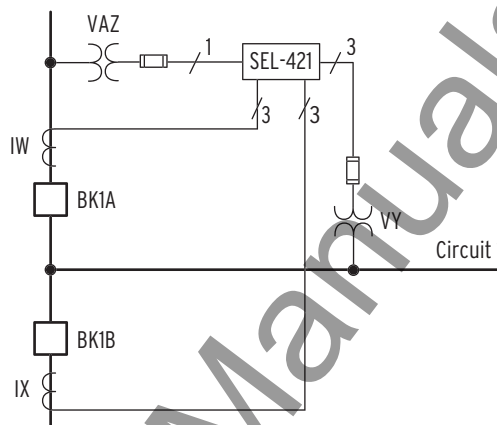


Figure 1.4 Circuit Breaker and a Half Arrangement: Station S, Line 1

Breaker Monitor

Circuit Breaker Configuration

Set the relay to indicate that both circuit breakers are single-pole trip type.

BK1TYP := 1 Breaker 1 Trip Type (Single-Pole = 1, Three-Pole = 3)

BK2TYP := 1 Breaker 2 Trip Type (Single-Pole = 1, Three-Pole = 3)

Circuit Breaker 1 Inputs

The SEL-421 uses normally open auxiliary contacts from the circuit breakers to determine whether each pole is opened or closed.

52AA1 := IN101 A-Phase N/O Contact Input—BK1 (SELOGIC Equation)

52AB1 := IN102 B-Phase N/O Contact Input—BK1 (SELOGIC Equation)

52AC1 := IN103 C-Phase N/O Contact Input—BK1 (SELOGIC Equation)

Circuit Breaker 2 Inputs

52AA2 := IN104 A-Phase N/O Contact Input—BK2 (SELOGIC Equation)

52AB2 := IN105 B-Phase N/O Contact Input—BK2 (SELOGIC Equation)

52AC2 := IN106 C-Phase N/O Contact Input—BK2 (SELOGIC Equation)

Group Settings

Line Configuration

The SEL-421 has four transformer turns ratio settings that convert the secondary potentials and currents that the relay measures to the corresponding primary values. These settings are the potential transformer and current transformer ratios PTRY, PTRZ, CTRW, and CTRX. Use the Y potential input for line relaying and the Z potential input for synchronism checks. Enable the

voltage and current source selection so you can combine W and X current inputs for the line current. VNOMY and VNOMZ specify the nominal secondary line-to-line voltage of the potential transformers (see [Figure 1.4](#)).

CTRW := **400** Current Transformer Ratio—Input W (1–50000)

CTRX := **400** Current Transformer Ratio—Input X (1–50000)

PTRY := **4500** Potential Transformer Ratio—Input Y (1–10000)

VNOMY := **111** PT Nominal Voltage (L–L)—Input Y
(60–300 V secondary)

PTRZ := **4500** Potential Transformer Ratio—Input Z (1–10000)

VNOMZ := **111** PT Nominal Voltage (L–L)—Input Z (60–300 V secondary)

Enter the secondary value of the positive-sequence impedance of the protected line. See [Table 1.8](#) for the secondary line impedances.

Z1MAG := **3.98** Positive-Sequence Line Impedance Magnitude
(0.05–255 Ω secondary)

Z1ANG := **87.6** Positive-Sequence Line Impedance Angle (5.00–90 degrees)

Enter the secondary value of the zero-sequence impedance of the protected line.

Z0MAG := **14.48** Zero-Sequence Line Impedance Magnitude
(0.05–255 Ω secondary)

Z0ANG := **82.1** Zero-Sequence Line Impedance Angle (5.00–90 degrees)

Enable the fault locator.

EFLOC := **Y** Fault Location (Y, N)

The LL setting is the line length. This value has no defined unit; you can set the line length in miles, kilometers, ohms, etc. Set the length in miles.

LL := **75.00** Line Length (0.10–999)

The relay fault locator uses the values you enter for Z1MAG, Z1ANG, Z0MAG, Z0ANG, and LL.

Relay Configuration

You can select from zero to five phase mho (E21P), ground mho (E21MG), and ground quadrilateral (E21XG) distance zones. You can independently select the number of zones per type of distance protection. Select only the number of zones needed. For this application example, use three zones of phase and ground distance protection.

E21P := **3** Mho Phase Distance Zones (N, 1–5)

E21MG := **3** Mho Ground Distance Zones (N, 1–5)

E21XG := **3** Quadrilateral Ground Distance Zones (N, 1–5)

Now enable the other logic you will need for this application example.

You do not need CVT transient detection if the SIR (Source Impedance Ratio) is less than five. SIR is equal to the ratio of the local source impedance to the relay reach. Calculate the ratio based on the Zone 1 reach because you do not want Zone 1 distance protection to overreach during an external fault. Double the source impedance magnitude because the relay measures half the total fault current when the parallel line is in service and the fault is located at the remote bus.

$$\begin{aligned} \text{SIR} &= \frac{2 \cdot |Z_{1S}|}{0.8 \cdot |Z_{1L}|} \\ &= \frac{2 \cdot 4.45 \, \Omega}{0.8 \cdot 3.98 \, \Omega} \\ &= 2.76, \text{ SIR} < 5 \end{aligned}$$

Equation 1.8

ECVT := **N** CVT Transient Detection (Y, N)

NOTE: The SEL-421-1 and the SEL-421-2 do not provide series-compensated line protection logic.

The transmission line is not series compensated.

ESERCOMP := **N** Series-Compensated Line Logic (Y, N)

You can select a common time delay or an independent time delay per zone for phase and ground distance protection. If you choose independent timing, evolving faults (such as those changing from single phase to multiphase) cause the timer to reset and result in additional delay. Select common time delay for this application.

ECDTD := **Y** Distance Element Common Time Delay (Y, N)

The SOTF logic permits tripping by specified protection elements for a settable time after the circuit breaker closes.

ESOTF := **Y** Switch-Onto-Fault (Y, N)

Do not enable the Out-of-Step logic for this application example.

E00S := **N** Out-of-Step (Y, N)

Do not enable the load-encroachment logic, as the minimum apparent load impedance is outside the mho phase distance characteristics.

ELoad := **N** Load Encroachment (Y, N)

Use Level 1 high-set instantaneous phase overcurrent element for SOTF protection.

E50P := **1** Phase Instantaneous/Definite-Time Overcurrent Elements (N, 1–4)

This application does not require residual ground overcurrent protection.

E50G := **N** Residual Ground Instantaneous/Definite-Time Overcurrent Elements (N, 1–4)

This application does not require negative-sequence overcurrent protection.

E50Q := **N** Negative-Sequence Instantaneous/Definite-Time Overcurrent Elements (N, 1–4)

Use inverse-time overcurrent protection to provide backup protection for high-resistance ground faults. The 51S1 element provides backup protection for unbalanced faults if both the communications-assisted and step distance protection fail to operate.

E51S := **1** Selectable Inverse-Time Overcurrent Element (N, 1–3)

Set E32 to AUTO and the relay automatically calculates the settings corresponding to the ground directional element (32G).

E32 := **AUTO** Directional Control (Y, AUTO)

Use the two-channel POTT trip scheme (POTT2) to quickly clear faults internal to the protected line.

ECOMM := **POTT2** Communications-Assisted Tripping (N, DCB, POTT, POTT2, POTT3, DCUB1, DCUB2)

Fuses or molded case circuit breakers often protect potential transformers. Operation of one or more fuses, or molded case circuit breakers, results in a loss of polarizing potential inputs to the relay. Loss of one or more phase voltages prevents the relay from properly determining fault distance or direction.

Occasional loss-of-potential to the distance relay, while unavoidable, is detectable. When the relay detects a loss-of-potential condition, the relay can block distance element operation, block or enable forward-looking directional overcurrent elements, and issue an alarm for any true loss-of-potential condition.

If line-side PTs are used, the circuit breaker(s) must be closed for the LOP logic to detect an LOP condition. Therefore, if three-phase potential to the relay is lost while the circuit breaker(s) is open (e.g., the PT fuses are removed while the line is de-energized), the relay cannot detect a loss-of-potential condition when the circuit breaker(s) closes again. At circuit breaker closing, the relay can detect one or two missing potentials that occurred while the circuit breaker was open. See [Loss-of-Potential Logic on page R.1.26](#) for more information.

[Table 1.9](#) lists the three choices for enabling LOP.

Table 1.9 LOP Enable Options

Option	Description
N	The LOP logic operates but does not disable voltage-polarized directional elements, distance elements, and forward-looking directional overcurrent elements. Use LOP in this case for alarm only.
Y	The relay disables all voltage-polarized directional elements and distance elements, but enables forward-looking directional overcurrent elements. These forward-looking directional overcurrent elements effectively become nondirectional and provide overcurrent protection during an LOP condition.
Y1	The relay disables all voltage-polarized directional elements and distance elements. The relay also disables the overcurrent elements controlled by the voltage-polarized directional elements.

Set ELOP to Y1 for this application example. This choice reduces the chances of false tripping because of a loss-of-potential condition.

ELOP := Y1 Loss-of-Potential (Y, Y1, N)

Enable the Advanced Settings so you can properly set the zero-sequence compensation factors for the zero-sequence mutual coupling between the parallel transmission lines.

EADVS := Y Advanced Settings (Y, N)

Phase Distance Elements (21P)

Mho Phase Distance Element Reach

Employ each zone of distance protection as follows:

- Zone 1—Instantaneous underreaching direct tripping
- Zone 2—Forward-looking tripping elements for the POTT scheme and backup tripping
- Zone 3—Current reversal guard for the POTT scheme, echo tripping, and weak infeed logic

Zone 1 Phase Distance Element Reach. Zone 1 phase distance protection provides instantaneous protection for phase-to-phase, phase-to-phase-to-ground, and three-phase faults in the first 80 percent of the transmission line. Errors in the current transformers, potential transformers, modeled transmission line data, and fault study data do not permit setting of Zone 1 for 100 percent of the transmission line. Unwanted tripping could occur for faults just beyond the remote end of the line if you set Zone 1 for 100 percent of the transmission line.

Set Zone 1 phase distance protection equal to 80 percent of the transmission line positive-sequence impedance.

$$Z1P = 0.8 \cdot Z_{IL1} = 3.18 \, \Omega$$

$$Z1P := \mathbf{3.18} \text{ Zone 1 Reach (OFF, 0.05–64 } \Omega \text{ secondary)}$$

Zone 2 Phase Distance Element Reach. Zone 2 phase distance protection must have adequate reach to detect all phase-to-phase, phase-to-phase-to-ground, and three-phase faults along the protected line. Set Zone 2 phase distance reach to 120 percent of the positive-sequence impedance of the transmission line. This setting provides high-speed tripping via the communications channel for faults located in the last 20 percent of the line.

$$Z2P = 1.2 \cdot Z_{IL1} = 4.78 \, \Omega$$

$$Z2P := \mathbf{4.78} \text{ Zone 2 Reach (OFF, 0.05–64 } \Omega \text{ secondary)}$$

Zone 3 Phase Distance Element Reach. Zone 3 phase distance protection must have adequate reach to prevent unwanted tripping during current reversals (this application example uses a permissive overreaching transfer tripping (POTT) scheme). Set the Zone 3 reach equal to Zone 2 and rely on the length of the protected transmission line for the safety margin. This setting makes the Zone 3 fault coverage greater than the Zone 2 fault coverage at the remote terminal.

$$Z3P = Z2P = 4.78 \, \Omega$$

$$Z3P := \mathbf{4.78} \text{ Zone 3 Reach (OFF, 0.05–64 } \Omega \text{ secondary)}$$

Ground Distance Elements (21MG and 21XG)

Mho Ground Distance Element Reach

Employ each zone of distance protection as follows:

- Zone 1—Instantaneous underreaching direct tripping
- Zone 2—Forward-looking tripping elements for the POTT scheme and backup tripping
- Zone 3—Current reversal guard for the POTT scheme, echo tripping, and weak infeed logic

Zone 1 Mho Ground Distance Element Reach. Zone 1 mho ground distance reach must meet the same requirement as that for Zone 1 mho phase distance protection; the reach setting should be no greater than 80 percent of the line.

$$Z1MG = 0.8 \cdot Z_{IL1} = 3.18 \, \Omega$$

$$Z1MG := \mathbf{3.18} \text{ Zone 1 (OFF, 0.05–64 } \Omega \text{ secondary)}$$

Zone 2 Mho Ground Distance Element Reach. Zone 2 mho and ground distance reach must meet the same requirement as that for Zone 2 mho phase distance protection; the reach setting is 120 percent of the line.

$$Z2MG = 1.2 \cdot Z_{1L1} = 4.78 \, \Omega$$

$$Z2MG := 4.78 \text{ Zone 2 (OFF, 0.05–64 } \Omega \text{ secondary)}$$

Zone 3 Mho Ground Distance Element Reach. Zone 3 mho ground distance reach must meet the same requirement as that for Zone 3 mho phase distance protection; it equals the Zone 2 reach.

$$Z3MG = Z2MG = 4.78 \, \Omega$$

$$Z3MG := 4.78 \text{ Zone 3 (OFF, 0.05–64 } \Omega \text{ secondary)}$$

Quadrilateral Ground Distance Element Reach

The reactive reach for each zone of quadrilateral ground distance protection lies on the relay characteristic angle ($Z1ANG$), rather than on the ordinate (reactance) of the impedance plane (see [Figure 1.5](#)).

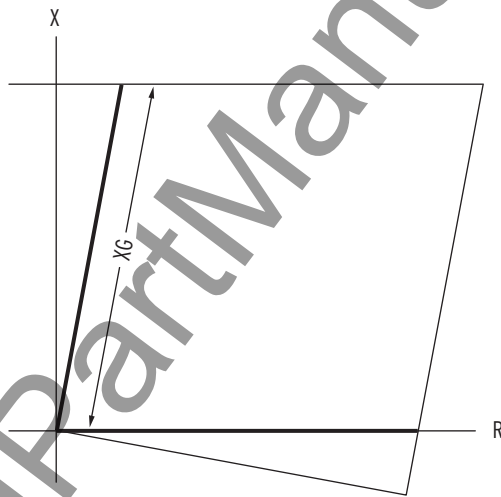


Figure 1.5 Quadrilateral Ground Distance Element Reactive Reach Setting

Zone 1 Reactance. Zone 1 quadrilateral ground distance reactance reach must meet the same requirement as that for Zone 1 mho phase distance protection; the reach setting should be no greater than 80 percent of the line.

$$XG1 = 0.8 \cdot Z_{1L1} = 3.18 \, \Omega$$

$$XG1 := 3.18 \text{ Zone 1 Reactance (OFF, 0.05–64 } \Omega \text{ secondary)}$$

Zone 1 Resistance. Find $RG1$ (Zone1 resistance) from the per-unit reach m of the Zone 1 reactance. Use [Equation 1.9](#) which is Equation (3) in *Appendix A—Quadrilateral Reactive Reach Versus Resistive Reach Setting Guideline* from the paper *Digital Communications for Power System Protection: Security, Availability, and Speed*. You can find a copy of this paper on the SEL website at www.selinc.com.

$$m = 1 - \frac{R}{X_{1L1} \cdot 20}$$

Equation 1.9

Where:

m = per-unit reach of $XG1$

R = $RG1$, the Zone 1 resistance

X_{1L1} = positive-sequence transmission line reactance

XG1 is set at 80 percent of the transmission line (i.e., $m = 0.8$ per-unit); the positive-sequence reactance of the overhead transmission line X_{1L1} is 3.977Ω secondary (from the rectangular form of Z_{1L1} in [Table 1.8](#)).

$$\begin{aligned} Z_{1L1} &= 3.98 \Omega \angle 87.6^\circ \\ &= R_{1L1} + jX_{1L1} \\ &= 0.167 + j3.977 \end{aligned} \quad \text{Equation 1.10}$$

Rearrange [Equation 1.9](#) as follows to calculate RG1:

$$\begin{aligned} RG1 &= (1 - m) \cdot 20 \cdot X_{1L1} \\ &= (1 - 0.8) \cdot 20 \cdot 3.977 \Omega \\ &= 15.9 \Omega \end{aligned} \quad \text{Equation 1.11}$$

SEL recommends that you apply a safety margin of 50 percent because single pole tripping is enabled for this particular application.

$$RG1 = 0.5 \cdot 15.9 \Omega = 7.96 \Omega$$

$RG1 := 7.96$ Zone 1 Resistance (0.05–50 Ω secondary)

Zone 2 Reactance. Zone 2 quadrilateral ground distance reach must meet the same requirement as that for Zone 2 mho phase distance protection; the reach setting is 120 percent of the line.

$$XG2 = 1.2 \cdot Z_{1L1} = 1.2 \cdot 3.98 = 4.78 \Omega$$

$XG2 := 4.78$ Zone 2 Reactance (OFF, 0.05–64 Ω secondary)

Zone 2 Resistance. Set Zone 2 quadrilateral resistive reach as follows:

$$\begin{aligned} RG2 &= XG2 \cdot \frac{RG1}{XG1} \\ &= 4.78 \Omega \cdot \frac{7.96 \Omega}{3.18 \Omega} \\ &= 11.97 \Omega \end{aligned} \quad \text{Equation 1.12}$$

$RG2 := 12.00$ Zone 2 Resistance (0.05–50 Ω secondary)

Zone 3 Reactance. Zone 3 quadrilateral ground distance reach must meet the same requirement as that for Zone 3 mho phase distance protection; it equals Zone 2 reach.

$$XG3 = XG2 = 4.78 \Omega$$

$XG3 := 4.78$ Zone 3 Reactance (OFF, 0.05–64 Ω secondary)

Zone 3 Resistance. The Zone 3 quadrilateral resistive reach is also scaled by an additional factor of 125 percent to ensure that it has greater coverage than the remote Zone 2 during external resistive ground faults behind the local terminal.

$$RG3 = 1.25 \cdot RG2 = 1.25 \cdot 12.00 = 15 \Omega$$

$RG3 := 15.00$ Zone 3 Resistance (0.05–50 Ω secondary)

Quadrilateral Ground Polarizing Quantity

You must enter two final settings for quadrilateral ground distance protection because Advanced Settings are enabled. These settings are XGPOL and TANG.

XGPOL allows you to choose the polarizing quantity for the quadrilateral ground distance protection. You can choose either negative- or zero-sequence current. Choose appropriately to reduce overreach and underreach of the reactance line. The reactance line can underreach or overreach during high-resistance single phase-to-ground faults. Nonhomogeneous negative- or zero-sequence networks can cause this underreach or overreach.

Figure 1.6 defines whether the negative- or zero-sequence network is homogeneous.

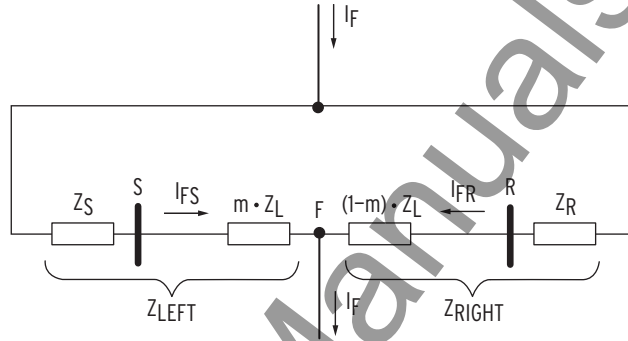


Figure 1.6 Definition of Homogeneous Network

Z_{LEFT} is the total impedance up to the fault (F) on the left-hand side, while Z_{RIGHT} is the total impedance up to the fault on the right-hand side. A network is homogeneous with respect to the particular fault location if equation 1.12 is satisfied:

$$\frac{X_{LEFT}}{R_{LEFT}} = \frac{X_{RIGHT}}{R_{RIGHT}} \quad \text{Equation 1.13}$$

Use Equation 1.14 and Equation 1.15 to determine the zero-sequence and negative-sequence homogeneity:

$$T_0 = \arg \left(\frac{Z_{0S} + Z_{0L} + Z_{0R}}{(1-m) \cdot Z_{0L} + Z_{0R}} \right) \quad \text{Equation 1.14}$$

$$T_2 = \arg \left(\frac{Z_{1S} + Z_{1L} + Z_{1R}}{(1-m) \cdot Z_{1L} + Z_{1R}} \right) \quad \text{Equation 1.15}$$

The values T_0 and T_2 represent how much the apparent fault impedance (Z_F) measured by relay tilts up or down (electrical degrees) because of the nonhomogeneity of the corresponding network for a fault at location m (see Figure 1.7).

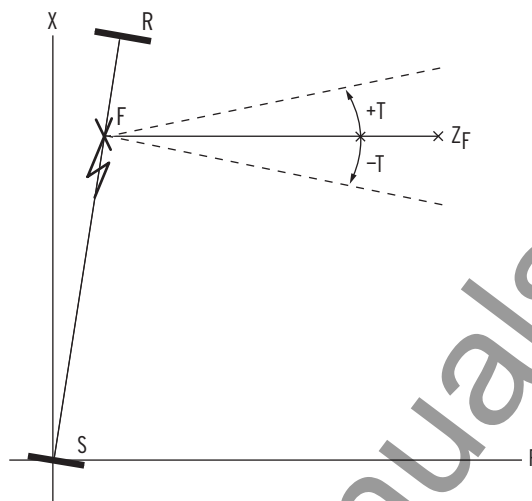


Figure 1.7 Tilt in Apparent Fault Impedance Resulting From Nonhomogeneity

Calculate T_0 and T_2 for a ground fault at the remote bus (i.e., m equals one per unit). The magnitude of whichever angle is greater indicates that the corresponding network is less homogeneous for a ground fault at the remote bus. The remote bus is selected for the fault location to prevent Zone 1 ground distance overreach.

Table 1.15 provides the results of Equation 1.14 and Equation 1.15 for both the negative-sequence and zero-sequence networks. The negative-sequence network is more homogeneous than the zero-sequence network because the magnitude of T_2 is less than the magnitude of T_0 .

Table 1.10 Tilt Resulting From Nonhomogeneity

Calculation	Angle
T_2	-0.2°
T_0	-4.1°

Select negative-sequence current flowing in the line as the polarizing quantity for the ground distance quadrilateral reactance measurement.

$XGPOL := I_2 \text{ IG}$ Quadrilateral Ground Polarizing Quantity (I_2 , IG)

Nonhomogeneous Correction Angle

TANG is the nonhomogeneous angle setting that also helps prevent overreach or underreach by compensating the angle of the reactance line.

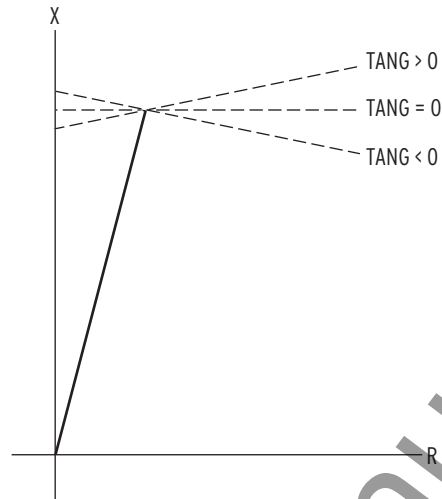


Figure 1.8 Nonhomogeneous Angle Setting

Set TANG to prevent the Zone 1 quadrilateral ground distance reactance measurement from overreaching for ground faults located at the remote bus. [Equation 1.15](#) (T_2) from Quadrilateral Ground Polarizing Quantity was approximately zero. Therefore, set TANG equal to zero.

TANG := 0 Nonhomogeneous Correction Angle (–40.0 to +40.0 degrees)

Zero-Sequence Current Compensation Factors

Zero-sequence current compensation helps to keep the phase and ground distance elements at the same reach if you set the reach equal per zone (for example, $Z1P = Z1MG$). Ground distance elements should measure fault impedance in terms of positive-sequence impedance only.

The relay has three zero-sequence current compensation factors ($k01$, $k0$, and $k0R$). The Zone 1 ground distance element has a dedicated zero-sequence current compensation factor ($k01$). Advanced Settings are enabled for this particular example; set two independent zero-sequence current compensation factors, one for forward-looking ($k0$) zones and one for reverse-looking ($k0R$) zones.

The SEL-421 ground distance elements do not employ zero-sequence mutual coupling compensation. Zero-sequence mutual coupling can cause under/overreaching problems on both the faulted line and the nonfaulted line relaying terminals for parallel line applications employing ground distance elements. Set the residual current compensation factors $k0$ and $k0R$ appropriately to compensate for the effect of mutual coupling on parallel lines.

Apply the following expression for the Zone 1 zero-sequence current compensation factor.

$$\begin{aligned} k01 &= \frac{Z_{0L1} - Z_{1L1}}{3 \cdot Z_{1L1}} \\ &= \frac{14.48 \angle 82.1^\circ - 3.98 \angle 87.6^\circ}{3 \cdot 3.98 \angle 87.6^\circ} \\ &= 0.88 \angle -7.6^\circ \end{aligned}$$

Equation 1.16

$k0M1$:= 0.880 Zone 1 ZSC Factor Magnitude (AUTO, 0.000–10)

$k0A1$:= -7.60 Zone 1 ZSC Factor Angle (–180.0 to +180.0 degrees)

Zone 2 ground distance elements tend to underreach for faults at the remote bus because residual current flows in the same direction for both parallel lines. Apply the following expression for the forward compensation factor so that Zone 2 ground distance elements see ground faults at the remote bus when zero-sequence mutual coupling is a concern.

$$\begin{aligned} k0 &= \frac{Z_{0L1} - Z_{1L1} + Z_{0M}}{3 \cdot Z_{1L1}} \\ &= \frac{14.48 \, \Omega \angle 82.1^\circ - 3.98 \, \Omega \angle 87.6^\circ + 7.86 \, \Omega \angle 76.6^\circ}{3 \cdot 3.98 \, \Omega \angle 87.6^\circ} \\ &= 1.54 \angle -9^\circ \end{aligned} \quad \text{Equation 1.17}$$

$k0M := 1.540$ Forward Zones ZSC Factor Magnitude (0.000–10)

$k0A := -9.0$ Forward Zones ZSC Factor Angle (–180.0 to +180.0 degrees)

Set the reverse compensation factor equal to the forward compensation factor so that Zone 3 ground distance protection has the same reach for external faults as the remote Zone 2 ground distance protection.

$k0MR := 1.540$ Reverse Zones ZSC Factor Magnitude (0.000–10)

$k0AR := -9.0$ Reverse Zones ZSC Factor Angle (–180.0 to +180.0 degrees)

Parallel Line Out-of-Service. When the parallel line is out-of-service, Zone 2 and 3 ground distance elements overreach; these elements still coordinate properly during external faults because the elements overreach by the same amount. Consider using an alternate settings group if Zone 2 ground distance protection provides time-delayed backup protection; Zone 2 ground distance protection and downstream Zone 1 ground distance protection could coordinate poorly.

Distance Element Common Time Delay

Set the appropriate timers Z1D, Z2, and Z3D for both phase and ground distance elements.

There is no need to delay Zone 1 distance protection since it trips instantaneously.

$Z1D = 0.000$ Zone 1 Time Delay (OFF, 0.000–16000 cycles)

Zone 2 distance protection must coordinate with downstream Zone 1 distance protection, downstream circuit breaker operating time, and a safety margin. A typical Zone 2 phase and ground distance time delay setting is 20 cycles.

$Z2D := 20.000$ Zone 2 Time Delay (OFF, 0.000–16000 cycles)

Set Zone 3 for zero time delay.

$Z3D := 0.000$ Zone 3 Time Delay (OFF, 0.000–16000 cycles)

SOTF Scheme

SOTF (Switch-Onto-Fault) logic is enabled when the circuit breaker closes. This logic provides protection for a short duration (setting SOTFD) until other protection (such as tripping from SELOGIC control equations TR and TRCOMM) is available. The TRSOTF SELOGIC control equation defines which protection elements cause the relay to trip when the SOTF scheme is active. Assertion of the protection elements assigned to TRSOTF during the SOTFD time causes the relay to trip instantaneously.

Apply SOTF when using line-side potentials for relaying. Use nondirectional overcurrent protection to clear close-in faults. Also use instantaneous overreaching distance protection to clear faults along the line. Assign instantaneous Zone 2 mho phase and ground distance protection plus Level 1 phase overcurrent element to TRSOTF.

TRSOTF := **M2P OR Z2G OR 50P1** Switch-Onto-Fault Trip (SELOGIC Equation)

Single-Pole SOTF

Single-pole tripping is applied for this particular example. The ability to single-pole trip when SOTF is enabled helps improve transient power system stability. The setting ESPSTF enables single-pole switch-onto-fault protection; the SOTF is armed following a single-pole reclose attempt. Enable this option.

ESPSHF := **Y** Single-Pole Switch-Onto-Fault (Y, N)

Voltage Reset

You can configure the logic so the SOTF enable duration resets within at least 5 cycles after it first asserted, but before the SOTFD timer expires. To quickly reset the SOTF period, the relay must sense that the positive-sequence voltage is greater than 85 percent of the nominal voltage.

Use setting EVRST (Switch-Onto-Fault Voltage Reset) to enable fast reset. The advantage of resetting SOTF protection quickly is that unwanted tripping does not occur for subsequent faults external to the remote terminals during the SOTF period; these trips can occur if you set instantaneous Zone 2 distance protection elements in the TRSOTF SELOGIC control equation. Enable the voltage reset option.

EVRST := **Y** Switch-Onto-Fault Voltage Reset (Y, N)

SOTF Initiation

The SOTF logic asserts via one or both of the following methods:

- A change in the normally open auxiliary contact 52A status showing that the circuit breaker has just opened
- Assertion of the relay control input assigned to the circuit breaker close bus

The 52A method works well for both single and multiple circuit breaker applications and does not require an input from the close bus. However, the close bus method only enables SOTF protection immediately following the close command to the circuit breaker. For more information, see [Switch-Onto-Fault Logic on page R.1.94](#).

Select the 52A option for this application and set the delay (52AEND) shorter than the shortest reclose open interval.

52AEND := **10.000** 52A Pole Open Time Delay (OFF, 0.000–16000 cycles)

Turn off CLOEND (CLSMON Delay) since this method is not used.

CLOEND := **OFF** CLSMON or Single Pole Open Delay
(OFF, 0.000–16000 cycles)

SOTF Duration

Setting SOTFD determines the longest period the SOTF logic can assert after the circuit breaker closes.

SOTFD := **10.000** Switch-Onto-Fault Enable Duration (0.500–16000 cycles)

Phase Instantaneous/Definite-Time Overcurrent Elements

Use 50P1, Level 1 phase instantaneous overcurrent element, as a nondirectional high-set phase overcurrent element for SOTF protection. If the local circuit breaker closes into a close-in three-phase bolted fault with line-side potential transformers, the polarizing voltage for the phase distance elements is zero. Therefore, the distance protection does not operate. In this case, the 50P1 element quickly trips the circuit breaker because this overcurrent element does not rely on the polarizing voltage.

To rapidly clear faults, set 50P1P equal to 50 percent of the fault current measured at the local terminal for a close-in three-phase fault; use weak source conditions so that the relay operates for low-level fault current.

50P1P := **7.21** Level 1 Pickup (OFF, 0.25–100 A secondary)

This application uses 50P1 as an instantaneous overcurrent element; you do not need time delay.

67P1D := **0.000** Level 1 Time Delay (0.000–16000 cycles)

This application uses 50P1 as a nondirectional overcurrent element; place no conditions on torque control.

67P1TC := **1** Level 1 Torque Control (SELOGIC Equation)

Selectable Operating Quantity Time Overcurrent Element 1

Use inverse-time overcurrent protection to provide backup protection for high-resistance ground faults. The 51S1 element provides backup protection for unbalanced faults if both the communications-assisted and step distance protection fail to operate.

NOTE: Use your company practices and philosophy when determining these settings.

Select zero-sequence line current as the operating quantity.

51S1O := **3I0L** 51S1 Operate Quantity (I_{an} , I_{bn} , I_{cn} , $IMAXn$, $I1L$, $3I2L$, $3I0n$)

The n in the 51S1O setting is L for line, 1 for BK1, and 2 for BK2.

The fault current ($3I_0$) measured by the relay for a bolted single phase-to-ground fault at the remote station with both lines in-service is 2.25 A secondary. (A remote end fault for the downstream relay gives a fault current of 1.22 A secondary.) Set the pickup to 30 to 50 percent of $3I_0$.

51S1P = **0.50** 51S1 Overcurrent Pickup (0.25–16 A secondary)

Use the following formula to determine approximately how much primary fault resistance coverage (R_F) is provided by 51S1P on a radial basis:

$$\begin{aligned} R_F &= \frac{PTR}{CTR} \cdot \frac{VNOMY / \sqrt{3}}{51S1P} \\ &= \frac{4500}{400} \cdot \frac{111.11 \text{ V} / \sqrt{3}}{0.50 \text{ A}} \\ &= 1443 \text{ } \Omega \text{ primary} \end{aligned} \quad \text{Equation 1.18}$$

Use the following as a guide to set the curve and time dial; for secure backup protection, perform a coordination study.

Set the local overcurrent element to coordinate with the downstream overcurrent element such that there is an 18-cycle (60 Hz nominal) safety margin for ground faults in front of the first downstream overcurrent element. Assume the operating time of the downstream overcurrent element is 12 cycles for a close-in ground fault. Therefore, set the local time-overcurrent element to operate approximately 30 cycles for ground faults in front of the first downstream overcurrent element.

5ISIC = **U3** 5IS1 Inverse-Time Overcurrent Curve (U1–U5)

5ISITD = **1.68** 5IS1 Inverse-Time Overcurrent Time Dial (0.50–15.0)

Set the overcurrent element to emulate electromechanical reset.

5ISIRS = **Y** 5IS1 Inverse-Time Overcurrent Electromechanical Reset (Y, N)

Torque control the overcurrent element with the forward decision from the ground directional element.

5SITC = **32GF** 5IS1 Torque Control (SELOGIC Equation)

Zone/Level Direction

Zone 1 and Zone 2 distance element directions are fixed in the forward direction. You can select the other zones independently as forward-looking (F), or reverse-looking (R). Set Zone 3 distance elements reverse-looking, because these are blocking elements for the POTT trip scheme.

DIR3 := **R** Zone/Level 3 Directional Control (F, R)

Directional Control

The SEL-421 uses an array of directional elements to supervise the ground distance elements and residual directional overcurrent elements during ground fault conditions. Internal logic automatically selects the best choice for the ground directional element (32G) from among the negative-sequence voltage-polarized directional element (32QG), zero-sequence voltage-polarized directional element (32V), and the zero-sequence current-polarized directional element (32I).

The relay setting ORDER determines the order in which the relay selects directional elements to provide ground directional decisions. You can set ORDER with any combination of Q, V, and I. The listed order of these directional elements determines the priority in which these elements operate to provide the ground directional element. Only one specific directional element operates at any one time. Directional element classification is as follows:

- Q—Negative-sequence voltage-polarized directional element
- V—Zero-sequence voltage-polarized directional element
- I—Zero-sequence current-polarized directional element

Set ORDER to QV. The first listed directional element choice, Q, is the first priority directional element to provide directional control for the ground distance elements and residual ground directional overcurrent elements. If Q is not operable, the second listed directional element choice, V, provides directional control for the ground distance elements and residual ground directional overcurrent elements. A polarizing quantity was not available for choice I, so I is not selected for this particular application example.

ORDER := **QV** Ground Directional Element Priority (combine Q, V, I)

SELOGIC control equation E32IV must assert to logical 1 to enable V or I for directional control of the ground distance elements and residual ground directional overcurrent elements. Set E32IV to logical 1.

E32IV := 1 Zero-Sequence Voltage and Current Enable (SELOGIC Equation)

Pole-Open Detection

The setting EPO, Enable Pole-Open logic, offers two options for deciding what conditions signify an open pole, as listed in [Table 1.11](#).

Table 1.11 Options for Enabling Pole-Open Logic

Option	Description
EPO := V	The logic declares a single-pole open if the corresponding phase undervoltage element asserts and the open phase detection logic declares the pole is open. <i>Select this option only if you use line-side potential transformers for relaying purposes.</i> A typical setting for the 27PO, pole-open undervoltage threshold, is 60 percent of the nominal line-to-neutral voltage. Do not select this option when shunt reactors are applied, because the voltage slowly decays after the circuit breaker opens. With this option selected, the relay cannot declare an open pole during assertion of LOP.
EPO := 52	The logic declares a single-pole open if the corresponding 52A contact (52AA1, for example) from the circuit breaker deasserts and the open phase detection logic declares that the pole is open.

Select the second option because a 52A contact is available. The relay uses both open phase detection and status information from the circuit breaker to make the most secure decision.

EP0= 52 Pole-Open Detection (52, V)

Pole-Open Time Delay on Dropout

SPOD is the time delay on dropout after the Relay Word bit SPO deasserts. This time delay allows power system transients to settle after the open-pole recloses, thereby stabilizing the ground distance elements corresponding to that phase. If a three-pole open condition (3PO) asserts, SPOD resets immediately.

SPOD := **0.500** Single Pole Open Dropout Delay (0.000–60 cycles)

The setting 3POD establishes the time delay on dropout after the Relay Word bit 3PO deasserts. This delay is important when you use line-side potential transformers for relaying. Use the 3POD setting to stabilize the ground distance elements in case of pole scatter during closing of the circuit breaker(s).

3POD := **0.500** Three-Pole Open Dropout Delay (0.000–60 cycles)

POTT Trip Scheme

The permissive overreaching transfer trip (POTT) scheme is selected to provide high-speed tripping for faults along the protected line.

The POTT scheme logic consists of four sections:

- Current reversal guard logic
- Echo
- Weak infeed logic
- Permission to Trip Received

Current Reversal Guard Logic

You need current reversal guard for this parallel line application. When a reverse-looking element detects an external fault, the relay does not key the transmitter and ignores reception of a permissive signal from the remote terminal. The Zone 3 Reverse Block Delay (Z3RBD) timer extends these two conditions after a current reversal occurs and the reverse-looking elements drop out.

Set Z3RBD timer to accommodate for the following:

- Remote terminal R circuit breaker maximum opening time
- Maximum communications channel reset time
- Remote terminal R Zone 2 relay maximum reset time

Assume a circuit breaker opening time of 3 cycles, a communications channel reset time of 1 cycle, and remote Zone 2 relay reset time of 1 cycle. The sum of these times gives a conservative setting of 5 cycles for a three-cycle circuit breaker.

Z3RBD := **5.000** Zone 3 Reverse Block Time Delay (0.000–16000 cycles)

Echo

If the local circuit breaker is open, or a weak infeed condition exists at the local terminal, the received permissive signal can echo back to the remote relay and cause it to issue a high-speed trip for faults beyond the remote relay Zone 1 reach. The SEL-421 includes logic that echoes the received permissive signal back to the remote terminal after specific conditions are satisfied. The echo logic includes timers for qualifying the permissive signal as well as timers for blocking the echo logic during specific conditions.

Use EBLKD (Echo Block Time Delay) to block the echo logic after dropout of local permissive elements. The recommended setting for the EBLKD timer is the sum of the following:

- Remote terminal R circuit breaker opening time
- Communications channel round trip time
- Safety margin

Assume a circuit breaker opening time of 3 cycles, a communications channel round trip time of 2 cycles, and a safety margin of 5 cycles. The sum of these three times gives a conservative setting of 10 cycles for a 3-cycle circuit breaker.

EBLKD := **10.000** Echo Block Time Delay (OFF, 0.000–16000 cycles)

The echo time delay, setting ETDPU, makes certain that the reverse-looking elements at the receiving end have sufficient time to operate and block the received echo signal for external faults behind the remote terminal. The delay also guards the echo and weak infeed logic against noise bursts that can occur on the communications channel during close-in external faults.

Because of the brief duration of noise bursts and the pickup time for the reverse-looking elements, a received signal must be present for a short time to allow the POTT scheme to echo the permissive signal back to the remote terminal. The ETDPU (Echo Time Delay Pickup) timer specifies the time a permissive trip signal must be present. The ETDPU setting depends upon your communications equipment, but a conservative setting for this timer is 2 cycles.

ETDPU := **2.000** Echo Time Delay Pickup (OFF, 0.000–16000 cycles)

The setting EDURD (Echo Duration Time Delay) limits the duration of the echoed permissive signal. Once an echo signal initiates, it should remain for a minimum period of time and then stop, even if a terminal receives a continuous permissive signal. This termination of the echo signal prevents the permissive trip signal from latching between the two terminals. Assume a 3-cycle circuit breaker at the remote terminal and a 1-cycle channel delay. The sum of these two is a setting of 4 cycles.

EDURD := **4.000** Echo Duration Time Delay (0.000–16000 cycles)

Weak Infeed

The SEL-421 provides weak infeed logic to high-speed trip both line terminals for internal faults near the weak terminal. The weak terminal echoes the permissive signal back to the strong terminal and causes the strong terminal to trip. The weak terminal trips by converting the echoed permissive signal to a trip signal after satisfaction of specific conditions.

This application does not require use of the weak-infeed feature.

EWFC := **N** Weak Infeed Trip (Y, N, SP)

Permission to Trip Received

Two Relay Word bits identify receipt of permission to trip:

- **PT1**—General permission to trip received
- **PT3**—Three-pole permission to trip received

Refer to [Cross-Country Fault Identification on page A.1.42](#) for a detailed explanation of this particular communications-assisted tripping scheme logic.

If PT1 is asserted, the relay can high-speed single-pole trip via the communications channel. However, if PT3 is asserted, the relay high-speed three-pole trips via the communications channel. This logic prevents the SEL-421 at Station S from three-pole tripping for cross-country faults (for example, A-phase-to-ground fault on Line 1 and B-phase-to-ground fault simultaneously on Line 2) beyond the reach of local Zone 1 ground distance protection.

Direct tripping is also implemented for reliability and to decrease the overall tripping time of the SEL-421 at Station S for cross-country faults beyond the reach of local Zone 1 ground distance protection. The logic PT1 and PT3 requires that the circuit breakers at Station R single-pole trip the external fault on line 2 first before the SEL-421 at Station S can single-pole trip for the case of cross-country faults beyond the reach of Zone 1 ground distance protection at Station S. Direct tripping for cross-country faults is faster since the SEL-421 at Station S do not have to wait for the remote circuit breakers to single-pole trip.

PT1 := **RMB1A** General Permissive Trip Received (SELOGIC Equation)

PT3 := **RMB2A** Three-Pole Permissive Trip Received (SELOGIC Equation)

Trip Logic

Trip logic configures the relay for tripping. These settings consists of the following:

- Trip equations

- Trip unlatch options
- Single-pole trip options
- Trip timers
- Enable single-pole tripping

Trip Equations

Set these six SELOGIC control equations for tripping:

- TR (unconditional)
- TRCOMM (communications-assisted)
- TRSOTF (SOTF)
- DTA, DTB, and DTC (direct tripping)

The TR SELOGIC control equation determines which protection elements trip unconditionally. Set TR to Zone 1 instantaneous distance protection, Zone 2 time-delayed distance protection, and inverse time overcurrent protection for backup.

TR := Z1T OR Z2T OR 51S1T Trip (SELOGIC Equation)

The TRCOMM SELOGIC control equation determines which elements trip via the communication-based scheme logic. Set instantaneous Zone 2 distance protection in the TRCOMM logic equation.

TRCOMM := M2P OR Z2G Communications-Assisted Trip (SELOGIC Equation)

The TRSOTF SELOGIC control equation defines which elements trip when SOTF protection is active. Set instantaneous overcurrent element 50P1 and Zone 2 distance protection in the TRSOTF SELOGIC control equation.

TRSOTF := M2P OR Z2G OR 50P1 Switch-Onto-Fault Trip (SELOGIC Equation)

The DTA, DTB, and DTC SELOGIC control equations receive single-pole direct transfer trips from the remote terminal whenever the remote SEL-421 single-pole trips. Use this tripping logic for reliability and to decrease SEL-421 operating time during cross-country faults beyond the reach of local Zone 1 ground distance protection.

DTA := RMB3A Direct Transfer Trip A-Phase (SELOGIC Equation)

DTB := RMB4A Direct Transfer Trip B-Phase (SELOGIC Equation)

DTC := RMB5A Direct Transfer Trip C-Phase (SELOGIC Equation)

Trip Unlatch Options

Unlatch the control output programmed for tripping after the circuit breaker auxiliary a contacts break the dc current. The SEL-421 provides three methods for unlatching control outputs programmed for tripping after occurrence of a protection trip:

- ULTR—following a protection trip, all three poles
- TOPD—Unlatch single-pole trip if another protection trip occurs during single-pole dead time
- TULO—following a protection trip, phase selective

ULTR. Use ULTR, the unlatch trip SELOGIC control equation, to unlatch all three poles. Use the default setting, to assert ULTR when you push the front-panel {TARGET RESET} pushbutton.

ULTR := **TRGTR** Unlatch Trip (SELOGIC Equation)

TOPD. It is common practice to trip the two remaining phases after the single-pole open dead time, or if the single-pole auto-reclose cycle does not reset, following the original single-pole trip. If the SEL-421 internal reclosing relay is being used, the E3PT, E3PT1, and E3PT2 settings in the trip logic should be set as shown in [Internal Recloser on page R.2.27](#). See [Auto-Reclose Example on page A.1.136](#) for information on using the SEL-421 reclosing relay.

To illustrate another way of using an external reclosing relay, this example will not use the SEL-421 Relay's auto-reclose logic, rather, it uses the TOP (Trip During Open Pole) Relay Word bit to control the trip logic.

The timer setting TOPD determines the length of time for converting any subsequent single-pole trips to a three-pole trip following the original single-pole trip. Set this timer to the single-pole open dead time (30 cycles) and the reset time (three seconds) for the recloser plus a 5-cycle safety margin. See [Trip During Open-Pole Time Delay on page R.1.117](#) and [External Recloser on page R.2.28](#) for additional information.

TOPD := **215.00** Trip During Open Pole Time Delay (2.000–8000 cycles)

TULO. Use TULO (Trip Unlatch Option) to select the conditions that cause the SEL-421 to unlatch the control outputs that you programmed for tripping. You can select from among the four trip unlatch options in [Table 1.12](#).

Table 1.12 Trip Unlatch Options

Option	Description
1	Unlatch the trip when the relay has detected that one or more poles of the line terminal are open, and Relay Word bit 3PT has deasserted.
2	Unlatch the trip when the relay has detected that the corresponding 52A contact(s) from both circuit breakers (e.g., 52AA1 and 52AA2) are deasserted.
3	Unlatch the trip when the relay has detected that the conditions for the first two options are satisfied.
4	Do not run this logic.

Select the third option if a 52A contact is available because the relay uses both open phase detection and status information from the circuit breaker(s). For information on the pole-open logic, see [Switch-Onto-Fault Logic on page R.1.94](#).

TULO := **3** Trip Unlatch Option (1, 2, 3, 4)

Single-Pole Trip Options

You can program the SEL-421 to single-pole trip for Zone 2 ground distance operations. Employ this method if you want single-pole tripping during ground faults within the last 20 percent of the protected line when the communications channel is not available. Do not enable this option.

Z2GTSP := **N** Zone 2 Ground Distance Time Delay SPT (Y, N)

The SEL-421 can assert a single-pole trip during high resistance ground faults such that the fault impedance lies outside of the ground distance protection characteristics; the FIDS logic selects the faulted phase when residual directional overcurrent elements provide communications-assisted tripping. Do not enable this option.

67Q6SP := N Zone 2 Dir. Negative-Sequence/Residual Ground Overcurrent
SPT (Y, N)

Trip Timers

The SEL-421 provides dedicated timers for minimum trip durations and open-pole time delays.

Minimum Trip Duration. The minimum trip duration timer settings, TDUR1D and TDUR3D, determine the minimum length of time that Relay Word bits TPA1, TPA2, TPB1, TPB2, TPC1, TPC2, and 3PT assert. Use these timers to control the designated trip control outputs. The control outputs programmed for tripping close for the greater of the TDUR n D time, or the duration of the trip condition.

TDUR1D is the minimum trip duration following a single-pole trip. TDUR3D is the minimum trip duration following a three-pole trip. If another trip occurs during the single-pole open dead time following a single-pole trip, TDUR3D replaces TDUR1D.

A typical setting for both of these timers is 9 cycles.

TDUR1D := **9.000** SPT Min Trip Duration Time Delay (2.000–8000 cycles)

TDUR3D := **9.000** 3PT Min Trip Duration Time Delay (2.000–8000 cycles)

Enable Single-Pole Tripping

The relay contains both three-pole and single-pole tripping logic. The relay uses single-pole tripping logic if the setting for E3PT, Three-Pole Trip Enable SELOGIC control equation, equals logical 0. For this example, an external reclosing relay is present. Use the TOP (Trip During Open Pole) Relay Word bit and the IN107 control input, to enable single-pole tripping. If E3PT equals logical 0 (assigned control input is deasserted), single-pole tripping is enabled.

E3PT := **IN107 OR TOP** Three-Pole Trip Enable (SELOGIC Equation)

Also set the appropriate three-pole tripping SELOGIC control equation for Circuit Breaker BK1 and Circuit Breaker BK2. In this example, the same three-phase trip selection input is used for both breakers. See [Trip Logic and Reclose Sources on page R.2.11](#) for details on the three-pole trip enable settings.

E3PT1 := **IN107** Breaker 1 3PT (SELOGIC Equation)

E3PT2 := **IN107** Breaker 2 3PT (SELOGIC Equation)

Control Outputs

Main Board

Use SELOGIC control equations to assign the control outputs for tripping.

Use the Main Board control outputs for tripping. The first three control outputs trip Circuit Breaker BK1A and the next three trip circuit breaker BK1B.

OUT101 := **TPA1**

OUT102 := **TPB1**

OUT103 := **TPC1**

OUT104 := **TPA2**

OUT105 := **TPB2**

OUT106 := TPC2

Cross-Country Fault Identification

Fault Identification

The SEL-421 provides two means of implementing simultaneous ground fault tripping logic for single-pole tripping applications in double-circuit tower applications. This particular example is based upon the POTT2 scheme, a 2-channel POTT scheme. The implementation of this logic uses the simplicity and flexibility of SELOGIC control equations and MIRRORRED BITS® communications.

For this particular example, when a cross-country fault occurs close in to Station R, the local line protection correctly identifies the faults as single phase-to-ground; Line 1 protection identifies a Zone 1 A Phase-to-ground fault, while Line 2 protection identifies a Zone 1 B Phase-to-ground fault. Tripping for both lines at Station R is instantaneous and independent from the communications channel. [Figure 1.9](#) illustrates a cross-country fault close in to Station R (that is, beyond Zone 1 reach with respect to Station S).

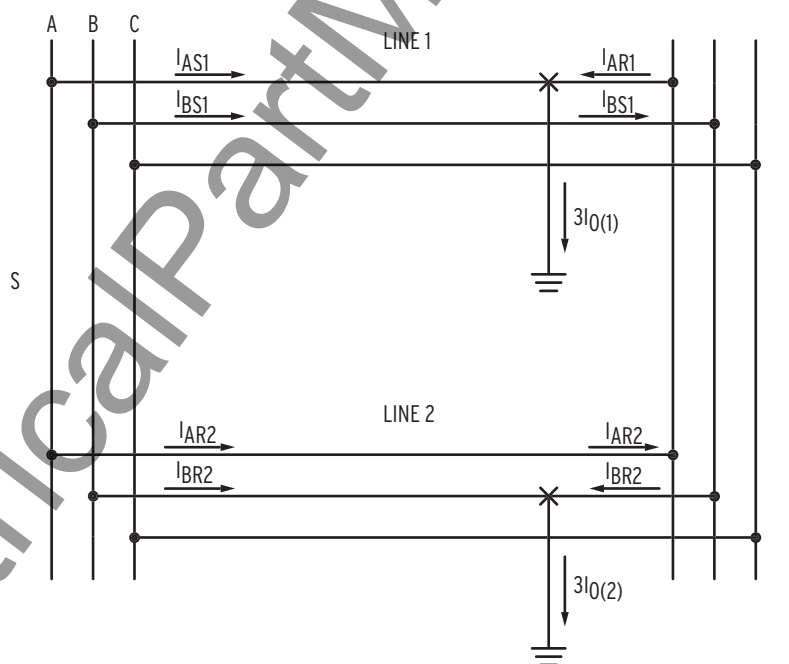


Figure 1.9 Current Distribution During Cross-Country Fault

The difficulty arises with the line protection at Station S prior to a circuit breaker opening at Station R (after the circuit breakers open at Station R, the line protection at Station S identifies each fault as single phase-to-ground). This difficulty diminishes as the fault location moves closer to Station S. At Station S, the relays for Lines 1 and 2 misidentify the fault as ABG. If the permissive trip signal from Station R arrives while an overreaching Zone 2 phase-phase distance element at Station S is picked up, an undesirable three-pole trip results for both lines at Station S. (An ABG fault involves more than one phase, so protection for this fault must use three-pole tripping.)

To avoid this, you must make provisions for identifying the mismatch in fault type identification between the line protection at both ends of the line. In doing so, you avoid three-pole tripping both lines at Station S while single-pole tripping both lines at Station R.

Transmit Equations

Overcoming this mismatch requires at least two communications channels, one for transmitting three-pole trip permission (KEY3) and another for transmitting all permissive trips (KEY1). The relay at Station S must receive both permissive signals before three-pole tripping via the communications scheme. Thus, the POTT2 scheme determines if there is agreement at both line ends on fault type declaration. The relay checks fault type agreement by comparing the local fault identification with the type of received permissive trip signal.

The Zone 2 phase distance (M2P) element asserts KEY1 and KEY3. The Zone 2 ground distance (Z2G) element asserts KEY1 only. Use two separate signals, rather than one, to send permission:

- KEY1—Transmit General Permissive Trip
- KEY3—Transmit Three-Phase Permissive Trip

Assign these two permissive signals to the first two Transmit MIRRORRED BITS signals.

TMB1A := KEY1 OR EKEY AND RMB1A Transmit MIRRORRED BIT 1A
(SELOGIC Equation)

TMB2A := KEY3 OR EKEY AND RMB2A Transmit MIRRORRED BIT 2A
(SELOGIC Equation)

Receive Equations

Any type of fault detected within Zone 2 at Station R transmit KEY1, which is converted to PT1 at Station S through the MIRRORRED BITS pair, TMB1A and RMB1A. The SEL-421 at Station S can high-speed single-pole trip via the communications channel if the fault type is identified as single-phase and single-pole tripping is enabled, regardless of fault selection at the remote terminal.

Figure 1.10 is a simplified logic diagram for the communications-assisted tripping logic.

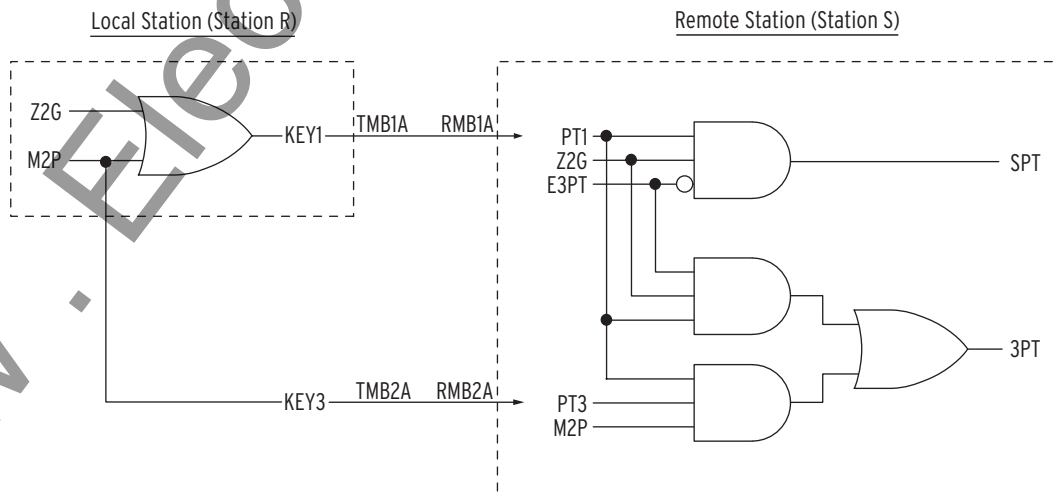


Figure 1.10 Simplified POTT Scheme KEY1/KEY3 Logic

If the SEL-421 at Station S detects a multiphase fault in Zone 2, it can high-speed three-pole trip only if both PT1 and PT3 assert. PT3 confirms that the remote terminal (Station R) has also identified the fault type as multiphase. If the SEL-421 detects a multiphase fault in Zone 2 and receives only PT1, like in the cross-country fault situation on a parallel-line system, the relay delays a trip until the permissive signal received agrees with the fault type detected locally. The fault type detected by the SEL-421 at Station S changes from a multiphase to a single-phase ground fault after Station R clears the external fault on line 2. The relay can then single-pole trip via the received PT1. Note that a desired single-pole trip at Station S occurs only after Station R clears the external fault on line 2. To avoid a delayed trip in a cross-country fault situation, you may choose the three-channel POTT scheme (POTT3), as described below.

Two Relay Word bits identify receipt of trip permission:

- PT1—General permission to trip received
- PT3—Three-pole permission to trip received

Assign PT1 to the corresponding Received MIRRORRED BITS signals.

PT1 := **RMB1A** General Permissive Trip Received (SELOGIC Equation)

PT3 := **RMB2A** Three-Pole Permissive Trip Received (SELOGIC Equation)

Three-Channel POTT Scheme, POTT3

In a cross-country fault situation of a mutually coupled parallel-line system, a relay using the one-channel POTT scheme will trip all three poles at the remote-to-fault terminal. This is because the relay at the remote terminal sees a multiphase fault and receives the only permissive trip signal. Both transmission lines will be out of service if even a single-phase ground fault occurs on each circuit.

The two-channel POTT scheme retains the much-desired single-pole tripping in the event of cross-country faults. However, the relay at the remote terminal has to delay a single-pole trip until the external fault is cleared at the close-in terminal. This application example uses direct transfer trips described below to compliment the two-channel POTT scheme and reduce the single-pole trip delay to a minimum.

As an alternative to the two-channel POTT scheme with direct transfer trips, you may use the phase-segregate three-channel POTT scheme (POTT3) to correctly single-pole trip without a delay in the event of cross-country faults. In the previous cross-country fault example, the SEL-421 on line 1 at Station R will transmit KEYA to the relay at Station S, which converts it to PTA, a permissive A-phase trip signal. The relay then combines a locally detected Zone 2 phase distance element with the received PTA and trips A-phase only without a time delay. Because the direct transfer trips are not necessary in the three-channel POTT scheme, the total communications channels used would be three.

For three-channel POTT applications, the following equations apply:

ECOMM := **POTT3** Communications-Assisted Tripping (N, DCB, POTT, POTT2, POTT3, DCUB1, DCUB2)

TMB1A := **KEYA** Transmit MIRRORRED BIT 1A (SELOGIC Equation)

TMB2A := **KEYB** Transmit MIRRORRED BIT 2A (SELOGIC Equation)

TMB3A := **KEYC** Transmit MIRRORRED BIT 3A (SELOGIC Equation)

PTA := **RMB1A** A-phase Permissive Trip Received (SELOGIC Equation)

PTB := **RMB2A** B-phase Permissive Trip Received (SELOGIC Equation)

PTC := **RMB3A** C-phase Permissive Trip Received (SELOGIC Equation)

Relay Word bit KEY is general permission to trip.

Single Line Applications

For single line applications, the following equations apply:

ECOMM := **POTT** Communications-Assisted Tripping (N, DCB, POTT, POTT2, POTT3, DCUB1, DCUB2)

TMB1A := **KEY** Transmit MIRRORRED BIT 1A (SELOGIC Equation)

PT1 := **RMB1A** General Permissive Trip Received (SELOGIC Equation)

Relay Word bit KEY is general permission to trip.

Direct Tripping

Direct tripping is faster because the SEL-421 relays at Station S do not have to wait for the circuit breakers at Station R to single-pole trip first; that is, the SEL-421 relays at Station R single-pole direct transfer trip the SEL-421 relays at Station S during crossing country faults beyond the reach of Zone 1 ground distance protection at Station S.

Transmit Equations

TMB3A := **TPA AND NOT 3PT** Transmit MIRRORRED BIT 3A (SELOGIC Equation)

TMB4A := **TPB AND NOT 3PT** Transmit MIRRORRED BIT 4A (SELOGIC Equation)

TMB5A := **TPC AND NOT 3PT** Transmit MIRRORRED BIT 5A (SELOGIC Equation)

Receive Equations

DTA := **RMB3A** Direct Transfer Trip A-Phase (SELOGIC Equation)

DTB := **RMB4A** Direct Transfer Trip B-Phase (SELOGIC Equation)

DTC := **RMB5A** Direct Transfer Trip C-Phase (SELOGIC Equation)

Example Completed

This completes the application example that describes how to set the SEL-421 for communications-assisted protection of 500 kV parallel overhead transmission lines with zero-sequence mutual coupling. Analyze your particular power system to determine the appropriate settings for your application.

Relay Settings

[Table 1.13](#) lists all protection relay settings for this example. Settings used in this example appear in boldface type.

Table 1.13 Settings for 500 kV Parallel TX Example (Sheet 1 of 7)

Setting	Description	Entry
General Global (Global)		
SID	Station Identifier (40 characters)	MOSCOW - 500 kV
RID	Relay Identifier (40 characters)	SEL-421 Relay
NUMBK	Number of Breakers in Scheme (1, 2)	2

Table 1.13 Settings for 500 kV Parallel TX Example (Sheet 2 of 7)

Setting	Description	Entry
BID1	Breaker 1 Identifier (40 characters)	Circuit Breaker 1
BID2	Breaker 2 Identifier (40 characters)	Circuit Breaker 2
NFREQ	Nominal System Frequency (50, 60 Hz)	60
PHROT	System Phase Rotation (ABC, ACB)	ABC
DATE_F	Date Format (MDY, YMD, DMY)	MDY
FAULT	Fault Condition (SELOGIC Equation)	50P1 OR 51S1 OR M2P OR Z2G OR M3P OR Z3G
Current and Voltage Source Selection (Global)		
ESS	Current and Voltage Source Selection (Y, N, 1, 2, 3, 4)	3
LINEI	Line Current Source (IW, COMB)	COMB
BK1I	Breaker 1 Current Source (IW, IX, NA)	IW
BK2I	Breaker 2 Current Source (IX, COMB, NA)	IX
Breaker Configuration (Breaker Monitoring)		
EB1MON	Breaker 1 Monitoring (Y, N)	N
EB2MON	Breaker 2 Monitoring (Y, N)	N
BK1TYP	Breaker 1 Trip Type (Single Pole = 1, Three Pole = 3)	1
BK2TYP	Breaker 2 Trip Type (Single Pole = 1, Three Pole = 3)	1
Breaker 1 Inputs (Breaker Monitoring)		
52AA1	A-Phase N/O Contact Input—BK1 (SELOGIC Equation)	IN101
52AB1	B-Phase N/O Contact Input—BK1 (SELOGIC Equation)	IN102
52AC1	C-Phase N/O Contact Input—BK1 (SELOGIC Equation)	IN103
Breaker 2 Inputs (Breaker Monitoring)		
52AA2	A-Phase N/O Contact Input—BK2 (SELOGIC Equation)	IN104
52AB2	B-Phase N/O Contact Input—BK2 (SELOGIC Equation)	IN105
52AC2	C-Phase N/O Contact Input—BK2 (SELOGIC Equation)	IN106
Line Configuration (Group)		
CTRW	Current Transformer Ratio—Input W (1–50000)	400
CTRX	Current Transformer Ratio—Input X (1–50000)	400
PTRY	Potential Transformer Ratio—Input Y (1–10000)	4500
VNOMY	PT Nominal Voltage (L-L)—Input Y (60–300 V secondary)	111
PTRZ	Potential Transformer Ratio—Input Z (1–10000)	4500
VNOMZ	PT Nominal Voltage (L-L)—Input Z (60–300 V secondary)	111
Z1MAG	Positive-Sequence Line Impedance Magnitude (0.05–255 Ω secondary)	3.98

Table 1.13 Settings for 500 kV Parallel TX Example (Sheet 3 of 7)

Setting	Description	Entry
Z1ANG	Positive-Sequence Line Impedance Angle (5.00–90 degrees)	87.6
Z0MAG	Zero-Sequence Line Impedance Magnitude (0.05–255 Ω secondary)	14.48
Z0ANG	Zero-Sequence Line Impedance Angle (5.00–90 degrees)	82.1
EFLOC	Fault Location (Y, N)	Y
LL	Line Length (0.10–999)	75
Relay Configuration (Group)		
E21P	Mho Phase Distance Zones (N, 1–5)	3
E21MG	Mho Ground Distance Zones (N, 1–5)	3
E21XG	Quadrilateral Ground Distance Zones (N, 1–5)	3
ECVT	CVT Transient Detection (Y, N)	N
ESERCMP	Series-Compensated Line Logic (Y, N)	N
ECDTD	Distance Element Common Time Delay (Y, N)	Y
ESOTF	Switch-Onto-Fault (Y, N)	Y
EOOS	Out-of-Step (Y, N)	N
ELOAD	Load Encroachment (Y, N)	N
E50P	Phase Inst./Def.-Time O/C Elements (N, 1–4)	1
E50G	Residual Ground Inst./Def.-Time O/C Elements (N, 1–4)	N
E50Q	Negative-Sequence Inst./Def.-Time O/C Elements (N, 1–4)	N
E51S	Selectable Inverse-Time O/C Elements (N, 1–3)	1
E32	Directional Control (Y, AUTO)	AUTO
ECOMM	Communications-Assisted Tripping (N, DCB, POTT, POTT2, POTT3, DCUB2, DCUB2)	POTT2
EBFL1	Breaker 1 Failure Logic (N, 1, 2)	N
EBFL2	Breaker 2 Failure Logic (N, 1, 2)	N
E25BK1	Synchronism Check for Breaker 1 (Y, N)	N
E25BK2	Synchronism Check for Breaker 2 (Y, N)	N
E79	Reclosing (Y, Y1, N)	N
EMANCL	Manual Closing (Y, N)	N
ELOP	Loss-of-Potential (Y, Y1, N)	Y1
EDEM	Demand Metering (N, THM, ROL)	N
EADVS	Advanced Settings (Y, N)	Y
Mho Phase Distance Element Reach (Group)		
Z1P	Zone 1 Reach (OFF, 0.05–64 Ω secondary)	3.18
Z2P	Zone 2 Reach (OFF, 0.05–64 Ω secondary)	4.78
Z3P	Zone 3 Reach (OFF, 0.05–64 Ω secondary)	4.78
Mho Phase Distance Element Time Delay (Group)		
Z1PD	Zone 1 Time Delay (OFF, 0.000–16000 cycles)	OFF
Z2PD	Zone 2 Time Delay (OFF, 0.000–16000 cycles)	OFF

Table 1.13 Settings for 500 kV Parallel TX Example (Sheet 4 of 7)

Setting	Description	Entry
Z3PD	Zone 3 Time Delay (OFF, 0.000–16000 cycles)	OFF
Mho Ground Distance Element Reach (Group)		
Z1MG	Zone 1 (OFF, 0.05–64 Ω secondary)	3.18
Z2MG	Zone 2 (OFF, 0.05–64 Ω secondary)	4.78
Z3MG	Zone 3 (OFF, 0.05–64 Ω secondary)	4.78
Quadrilateral Ground Distance Element Reach (Group)		
XG1	Zone 1 Reactance (OFF, 0.05–64 Ω secondary)	3.18
RG1	Zone 1 Resistance (0.05–50 Ω secondary)	7.96
XG2	Zone 2 Reactance (OFF, 0.05–64 Ω secondary)	4.78
RG2	Zone 2 Resistance (0.05–50 Ω secondary)	12.00
XG3	Zone 3 Reactance (OFF, 0.05–64 Ω secondary)	4.78
RG3	Zone 3 Resistance (0.05–50 Ω secondary)	15.00
XGPOL	Quadrilateral Ground Polarizing Quantity (I2, IG)	I2
TANG	Nonhomogeneous Correction Angle (–40.0 to +40.0 degrees)	0.0
Zero-Sequence Current Compensation Factor (Group)		
k0M1	Zone 1 ZSC Factor Magnitude (AUTO, 0.000–10)	0.880
k0A1	Zone 1 ZSC Factor Angle (–180.0 to +180.0 degrees)	–7.6
k0M	Forward Zones ZSC Factor Magnitude (0.000–10)	1.540
k0A	Forward Zones ZSC Factor Angle (–180.0 to +180.0 degrees)	–9.0
k0MR	Reverse Zones ZSC Factor Magnitude (0.000–10)	1.540
k0AR	Reverse Zones ZSC Factor Angle (–180.0 to +180.0 degrees)	–9.0
Ground Distance Element Time Delay (Group)		
Z1GD	Zone 1 Time Delay (OFF, 0.000–16000 cycles)	OFF
Z2GD	Zone 2 Time Delay (OFF, 0.000–16000 cycles)	OFF
Z3GD	Zone 3 Time Delay (OFF, 0.000–16000 cycles)	OFF
Distance Element Common Time Delay (Group)		
Z1D	Zone 1 Time Delay (OFF, 0.000–16000 cycles)	0.000
Z2D	Zone 2 Time Delay (OFF, 0.000–16000 cycles)	20.000
Z3D	Zone 3 Time Delay (OFF, 0.000–16000 cycles)	0.000
SOTF Scheme Settings		
ESPSTF	Single-Pole Switch-Onto-Fault (Y, N)	Y
EVRST	Switch-Onto-Fault Voltage Reset (Y, N)	Y
52AEND	52A Pole Open Time Delay (OFF, 0.000–16000 cycles)	10.000
CLOEND	CLSMON or Single Pole Open Delay (OFF, 0.000–16000 cycles)	OFF
SOTFD	Switch-Onto-Fault Enable Duration (0.500–16000 cycles)	10.000
CLSMON	Close Signal Monitor (SELOGIC Equation)	NA

Table 1.13 Settings for 500 kV Parallel TX Example (Sheet 5 of 7)

Setting	Description	Entry
Phase Instantaneous Overcurrent Pickup (Group)		
50P1P	Level 1 Pickup (OFF, 0.25–100 A secondary)	7.21
Phase Overcurrent Definite-Time Delay (Group)		
67P1D	Level 1 Time Delay (0.000–16000 cycles)	0.000
Phase Overcurrent Torque Control (Group)		
67P1TC	Level 1 Torque Control (SELOGIC Equation)	1
Selectable Operating Quantity Inverse-Time Overcurrent Element 1 (Group)		
51S1O	51S1 Operating Quantity (I_{An} , I_{Bn} , I_{Cn} , $IMAX_n$, I_{1L} , I_{2L} , I_{0n}) ^a	310L
51S1P	51S1 Overcurrent Pickup (0.25–16 A secondary)	0.50
51S1C	51S1 Inverse-Time Overcurrent Curve (U1–U5)	U3
51S1TD	51S1 Inverse-Time Overcurrent Time Dial (0.50–15)	1.68
51S1RS	51S1 Inverse-Time Overcurrent Electromechanical Reset (Y, N)	Y
51S1TC	51S1 Torque Control (SELOGIC Equation)	32GF
Zone/Level Direction (Group)		
DIR3	Zone/Level 3 Direction Control (F, R)	R
Directional Control (Group)		
ORDER	Ground Directional Element Priority (combine Q, V, I)	QV
E32IV	Zero-Sequence Voltage and Current Enable (SELOGIC Equation)	1
Pole Open Detection (Group)		
EPO	Pole-Open Detection (52, V)	52
SPOD	Single-Pole Open Dropout Delay (cycles)	0.500
3POD	Three-Pole Open Dropout Delay (cycles)	0.500
POTT Trip Scheme (Group)		
Z3RBD	Zone 3 Reverse Block Time Delay (0.000–16000 cycles)	5.000
EBLKD	Echo Block Time Delay (OFF, 0.000–16000 cycles)	10.000
ETDPU	Echo Time Delay Pickup (OFF, 0.000–16000 cycles)	2.000
EDURD	Echo Duration Time Delay (0.000–16000 cycles)	4.000
EWFC	Weak Infeed Trip (Y, N, SP)	N
27PWI	Weak Infeed Phase Undervoltage Pickup (1.0–200 V secondary)	47.0
27PPW	Weak Infeed Phase-Phase Undervoltage Pickup (1.0–300 V secondary)	80.0
59NW	Weak Infeed Zero-Sequence Overvoltage Pickup (1.0–200 V secondary)	5.0
PT1	General Permissive Trip Received (SELOGIC Equation)	RMB1A

Table 1.13 Settings for 500 kV Parallel TX Example (Sheet 6 of 7)

Setting	Description	Entry
PT3	Three-Pole Permissive Trip Received (SELOGIC Equation)	RMB2A
Trip Logic (Group)		
TR	Trip (SELOGIC Equation)	Z1T OR Z2T OR 51S1T
TRCOMM	Communications-Assisted Trip (SELOGIC Equation)	Z2G OR M2P
TRSOTF	Switch-Onto-Fault Trip (SELOGIC Equation)	M2P OR Z2G OR 50P1
DTA	Direct Transfer Trip A-Phase (SELOGIC Equation)	RMB3A
DTB	Direct Transfer Trip B-Phase (SELOGIC control equation)	RMB4A
DTC	Direct Transfer Trip C-Phase (SELOGIC Equation)	RMB5A
BK1MTR	Manual Trip–Breaker 1 (SELOGIC Equation)	OC1 OR PB7_PUL
BK2MTR	Manual Trip–Breaker 2 (SELOGIC Equation)	OC2 OR PB8_PUL
ULTR	Unlatch Trip (SELOGIC Equation)	TRGTR
ULMTR1	Unlatch Manual Trip–Breaker 1 (SELOGIC Equation)	NOT (52AA1 AND 52AB1 AND 52AC1)
ULMTR2	Unlatch Manual Trip–Breaker 2 (SELOGIC Equation)	NOT (52AA2 AND 52AB2 AND 52AC2)
TOPD	Trip During Open Pole Time Delay (2.000–8000 cycles)	215.000
TULO	Trip Unlatch Option (1, 2, 3, 4)	3
Z2GTSP	Zone 2 Ground Distance Time Delay SPT (Y, N)	N
67QGSP	Zone 2 Directional Neg.-Seq./Residual Ground Overcurrent SPT (Y, N)	N
TDUR1D	SPT Minimum Trip Duration Time Delay (2.000–8000 cycles)	9.000
TDUR3D	3PT Minimum Trip Duration Time Delay (2.000–8000 cycles)	9.000
E3PT	Three-Pole Trip Enable (SELOGIC Equation)	IN107 OR TOP
E3PT1	Breaker 1 3PT (SELOGIC Equation)	IN107
E3PT2	Breaker 2 3PT (SELOGIC Equation)	IN107
ER	Event Report Trigger (SELOGIC Equation)	R_TRIG M2P OR R_TRIG Z2G OR R_TRIG 51S1 OR R_TRIG M3P OR R_TRIG Z3G
Main Board (Outputs)		
OUT101	(SELOGIC Equation)	TPA1
OUT102	(SELOGIC Equation)	TPB1
OUT103	(SELOGIC Equation)	TPC1
OUT104	(SELOGIC Equation)	TPA2

Table 1.13 Settings for 500 kV Parallel TX Example (Sheet 7 of 7)

Setting	Description	Entry
OUT105	(SELOGIC Equation)	TPB2
OUT106	(SELOGIC Equation)	TPC2
MIRRORED BITS Transmit Equations (Outputs)		
TMB1A	(SELOGIC Equation)	KEY1 OR EKEY AND RMB1A
TMB2A	(SELOGIC Equation)	KEY3 OR EKEY AND RMB2A
TMB3A	(SELOGIC Equation)	TPA AND NOT 3PT
TMB4A	(SELOGIC Equation)	TPB AND NOT 3PT
TMB5A	(SELOGIC Equation)	TPC AND NOT 3PT
TMB6A	(SELOGIC Equation)	NA
TMB7A	(SELOGIC Equation)	NA
TMB8A	(SELOGIC Equation)	NA
TMB1B	(SELOGIC Equation)	NA
TMB2B	(SELOGIC Equation)	NA
TMB3B	(SELOGIC Equation)	NA
TMB4B	(SELOGIC Equation)	NA
TMB5B	(SELOGIC Equation)	NA
TMB6B	(SELOGIC Equation)	NA
TMB7B	(SELOGIC Equation)	NA
TMB8B	(SELOGIC Equation)	NA

^a Parameter n is 1 for BK1, 2 for BK2, and L for Line.

345 kV Tapped Overhead Transmission Line Example

Figure 1.11 shows a three-ended 345 kV transmission line with SEL-421 protection at Stations S and R. A tap midway between Stations S and R feeds an autotransformer. This example explains how to calculate settings for the SEL-421 at Station S that protects the 345 kV circuit between Substation S, Substation R, and the autotransformer. The 345 kV and 138 kV windings of the autotransformer are wye-connected and solidly grounded. The tertiary voltage windings are delta-connected and lag the other windings by 30 degrees.

This application example uses communications-assisted tripping with PLC (power line carrier) communication to provide high-speed protection for faults along the 345 kV circuit. The relay uses distance elements and residual ground directional overcurrent elements in this protection scheme.

Another SEL-421 located on the 138 kV side of the autotransformer blocks high-speed tripping at Stations S and R for faults on the 138 kV side of the autotransformer.

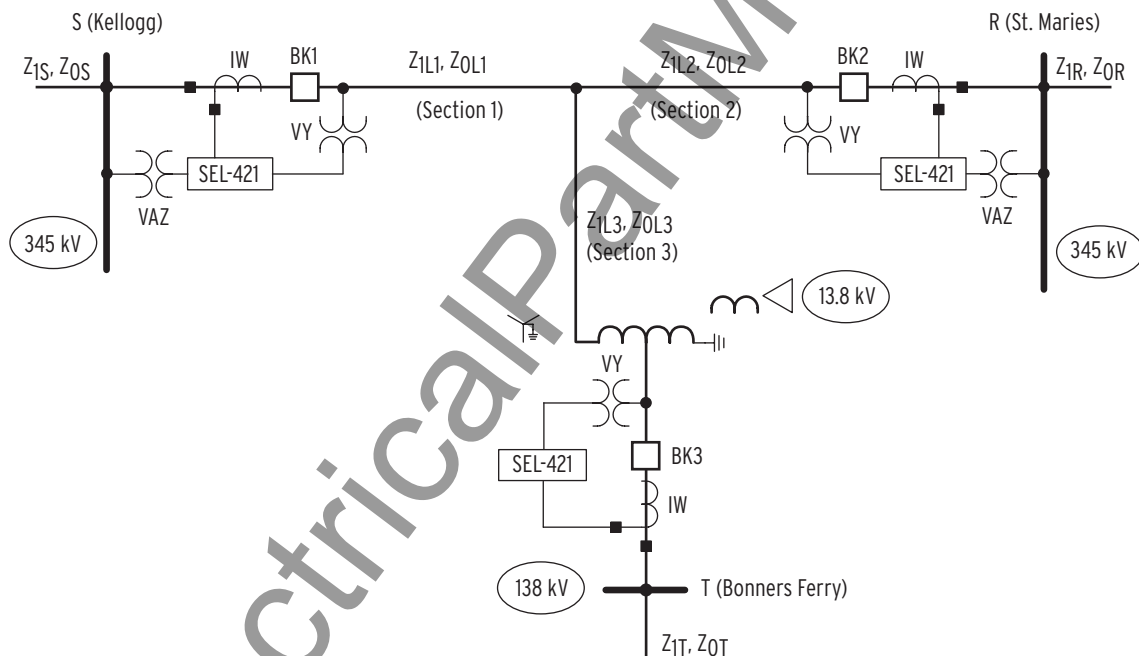


Figure 1.11 345 kV Tapped Overhead Transmission Line

Power System Data

[Table 1.14](#) lists the power system data for this application example. Substitute the values and parameters that correspond to your system when you set the relay using this example as a guide.

Table 1.14 System Data—345 kV Tapped Overhead Transmission Line

Parameter	Value
EHV nominal system line-to-line voltage (transformer primary)	345 kV
HV line-to-line voltage (transformer secondary)	138 kV
MV line-to-line voltage (transformer tertiary)	13.8 kV
Nominal relay current	5 A secondary
Nominal frequency	60 Hz
Line lengths ^a	
S–t (Section 1)	50 miles
t–R (Section 2)	50 miles
t–T (Section 3)	75 miles
Line impedances:	
$Z_{1L1} = Z_{1L2}$	29.67 Ω $\angle 84.7^\circ$ primary
$Z_{0L1} = Z_{0L2}$	96.65 Ω $\angle 73^\circ$ primary
Z_{1L3}	44.5 Ω $\angle 84.7^\circ$ primary
Z_{0L3}	144.98 Ω $\angle 73^\circ$ primary
Transformer impedances:	
X_{HM}	8% on 500 MVA; 1.6% on 100 MVA
X_{ML}	10% on 25 MVA; 40% on 100 MVA
X_{HL}	15% on 25 MVA; 60% on 100 MVA
Source S impedances: $Z_{1S} = Z_{0S}$	10 Ω $\angle 87^\circ$ primary
Source R impedances: $Z_{1R} = Z_{0R}$	35 Ω $\angle 87^\circ$ primary
Source T impedances: $Z_{1T} = Z_{0T}$	0.656 Ω $\angle 87^\circ$ per unit
PTR (potential transformer ratio)	345 kV:115 V = 3000
CTR (current transformer ratio)	1000:5 = 200
Phase rotation	ABC

^a Parameter t is the tap point on the 345 kV line; S and R are terminals at the ends of the 345 kV line (see [Figure 1.11](#)).

Convert the power system impedances from primary to secondary so you can later calculate protection settings. [Table 1.15](#) lists the corresponding secondary impedances. Convert the impedances to secondary ohms as follows:

$$k = \frac{CTR}{PTR} = \frac{200}{3000} = 0.067 \quad \text{Equation 1.19}$$

$$\begin{aligned} Z_{1L1(\text{secondary})} &= k \cdot Z_{1L1(\text{primary})} \\ &= 0.067 \cdot (29.67 \Omega \angle 84.7^\circ) \\ &= 2 \Omega \angle 84.7^\circ \end{aligned} \quad \text{Equation 1.20}$$

Table 1.15 Secondary Impedances

Parameter	Value
Line impedances:	
$Z_{1L1} = Z_{1L2}$	$2 \Omega \angle 84.7^\circ$ secondary
$Z_{0L1} = Z_{0L2}$	$6.44 \Omega \angle 73^\circ$ secondary
Z_{1L3}	$3 \Omega \angle 84.7^\circ$ secondary
Z_{0L3}	$9.65 \Omega \angle 73^\circ$ secondary
Transformer impedances:	
X_{HM}	8% @ 500 MVA; 1.6% on 100 MVA
X_{ML}	10% @ 25 MVA; 40% on 100 MVA
X_{HL}	15% @ 25 MVA; 60% on 100 MVA
Source S impedances:	
$Z_{1S} = Z_{0S}$	$0.67 \Omega \angle 87^\circ$ secondary
Source R impedances:	
$Z_{1R} = Z_{0R}$	$2.33 \Omega \angle 87^\circ$ secondary
Source T impedances:	
$Z_{1T} = Z_{0T}$	$0.656 \Omega \angle 87^\circ$ per unit

The tapped autotransformer is rated at 500 MVA; the corresponding maximum load current is 837 A primary at 354 kV.

Application Summary

This particular example is for a single circuit breaker, three-pole tripping application with the following functions:

- DCB (directional comparison blocking) trip scheme
- Three zones of mho phase and ground distance protection
 - Zone 1, forward-looking, instantaneous underreaching protection
 - Zone 2, forward-looking, communications-assisted high-speed tripping and time-delayed tripping
 - Zone 3, reverse-looking, starting element
- Two levels of zero-sequence directional overcurrent protection
 - Level 2, forward-looking, communications-assisted high-speed tripping
 - Level 3, reverse-looking, starting element
- Inverse-time directional zero-sequence overcurrent backup protection
- Load-encroachment logic: prevents unwanted tripping during heavy load conditions
- SOTF protection: fast tripping when the circuit breaker closes

Relay settings that are not mentioned in this example do not apply to this application example.

Global Settings

General Global Settings

The SEL-421 has settings for identification. These settings allow you to identify the following:

- Station (SID)
- Relay (RID)
- Circuit Breaker 1 (BID1)

You can enter as many as 40 characters per identification setting.

SID := **KELLOG - 345 kV** Station Identifier (40 characters)

RID := **SEL-421 Relay** Relay Identifier (40 characters)

Configure the SEL-421 for one circuit breaker.

NUMBK := **1** Number of Breakers in Scheme (1, 2)

BID1 := **Circuit Breaker 1** Breaker 1 Identifier (40 characters)

You can select both nominal frequency and phase rotation for the relay.

NFREQ := **60** Nominal System Frequency (50, 60 Hz)

PHROT := **ABC** System Phase Rotation (ABC, ACB)

Current and Voltage Source Selection

The voltage and current source selection is for one circuit breaker. The relay derives the line current source from current input IW when you set ESS to N.

ESS := **N** Current and Voltage Source Selection (Y, N, 1, 2, 3, 4)

Figure 1.12 illustrates the current and voltage sources for this particular application. The relay uses potential input VY and current input IW for line relaying; potential input VAZ is for synchronism check. [Section 2: Auto-Reclosing and Synchronism Check in the Reference Manual](#) describes how to apply the synchronism check function.

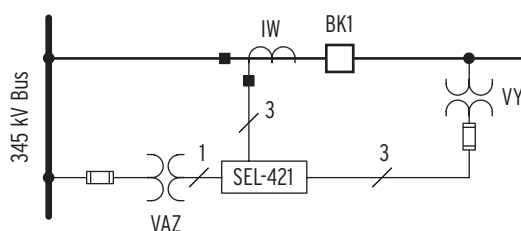


Figure 1.12 Circuit Breaker Arrangement at Station S

Breaker Monitor

Circuit Breaker Configuration

Set the relay to indicate that Circuit Breaker 1 is a three-pole trip circuit breaker.

BK1TYP := **3** Breaker 1 Trip Type (Single-Pole = 1, Three-Pole = 3)

Circuit Breaker 1 Inputs

The SEL-421 uses a normally open auxiliary contact from the circuit breaker to determine whether the circuit breaker is open or closed.

52AA1 := **IN101** A-Phase N/O Contact Input -BK1 (SELOGIC Equation)

Group Settings

Line Configuration

The SEL-421 has four transformer turns ratio settings that convert the secondary potentials and currents that the relay measures to the corresponding primary values. These settings are the potential transformer and current transformer ratios PTRY, PTRZ, CTRW, and CTRX. Use the Y potential input for line relaying and the Z potential input for synchronism checks. Use the W current input for line relaying. The settings VNOMY and VNOMZ specify the nominal secondary line-to-line voltage of the potential transformers (see [Figure 1.12](#)).

CTRW := **200** Current Transformer Ratio—Input W (1–50000)

PTRY := **3000** Potential Transformer Ratio—Input Y (1–10000)

VNOMY := **115** PT Nominal Voltage (L–L)—Input Y (60–300 V secondary)

PTRZ := **3000** Potential Transformer Ratio—Input Z (1–10000)

VNOMZ := **115** PT Nominal Voltage (L–L)—Input Z (60–300 V secondary)

Set Z1MAG equal to Z_{1L1} plus Z_{1L2} so the fault locator provides correct results for internal faults not located on the tap (i.e., source T is extremely weak and provides practically no infeed). See [Table 1.15](#) for the secondary line impedances.

Z1MAG := **4.00** Positive-Sequence Line Impedance Magnitude
(0.05–255 Ω secondary)

Z1ANG := **84.7** Positive-Sequence Line Impedance Angle (5.00–90 degrees)

Enter the secondary value of the zero-sequence impedance of the protected line from Station S to Station R, ignoring the tap.

Z0MAG := **12.88** Zero-Sequence Line Impedance Magnitude
(0.05–255 Ω secondary)

Z0ANG := **73.0** Zero-Sequence Line Impedance Angle (5.00–90 degrees)

Enable the fault locator.

EFLOC := **Y** Fault Location (Y, N)

The LL setting is the line length. This value has no defined unit; you can set the line length in miles, kilometers, ohms, etc. Set the length in miles.

LL := **100.00** Line Length (0.10–999)

The relay fault locator uses the values you enter for Z1MAG, Z1ANG, Z0MAG, Z0ANG, and LL.

Relay Configuration

You can select from zero to five phase zones of phase mho (E21P), ground mho (E21MG), and ground quadrilateral (E21XG) distance protection. You can independently select the number of zones per type of distance protection.

Select only the number of zones needed. For this application example, use three zones of mho phase and ground distance protection.

E2IP := **3** Mho Phase Distance Zones (N, 1–5)

E2IMG := **3** Mho Ground Distance Zones (N, 1–5)

E2IXG := **N** Quadrilateral Ground Distance Zones (N, 1–5)

Now enable the other logic you will need for this application example. ♦

You do not need CVT transient detection if the SIR (Source Impedance Ratio) is less than five. SIR is equal to the ratio of the local source impedance to the relay reach. Calculate the ratio based on the Zone 1 reach because you do not want Zone 1 distance protection to overreach during an external fault.

$$\begin{aligned} \text{SIR} &= \frac{|Z_{1S}|}{0.8 \cdot |Z_{1L1} + Z_{1L2}|} \\ &= \frac{0.67 \, \Omega}{0.8 \cdot (2 \, \Omega + 2 \, \Omega)} \\ &= 0.209, \text{ SIR} < 5 \end{aligned}$$

Equation 1.21

ECVT := **N** CVT Transient Detection (Y, N)

NOTE: The SEL-421-1 and the SEL-421-2 do not provide series-compensated line protection logic.

The transmission line is not series compensated.

ESERCMP := **N** Series-Compensated Line Logic (Y, N)

You can select a common time delay or an independent time delay per zone for phase and ground distance protection. If you choose independent timing, evolving faults (such as those changing from single phase to multiphase) cause the timer to reset and result in additional delay. Select common time delay for this application.

ECDTD := **Y** Distance Element Common Time Delay (Y, N)

The SOTF logic permits tripping by specified protection elements for a settable time after the circuit breaker closes.

ESOTF := **Y** Switch-Onto-Fault (Y, N)

♦ Do not enable the Out-of-Step logic for this application example.

E0OS := **N** Out-of-Step (Y, N)

The relay has a load-encroachment feature that prevents operation of the phase distance elements during heavy load. This unique feature permits the load to enter a predefined area of the phase distance characteristics without causing unwanted tripping.

ELoad := **Y** Load Encroachment (Y, N)

Use Level 1 high-set instantaneous phase overcurrent element for SOTF protection.

E50P := **1** Phase Instantaneous/Definite-Time Overcurrent Elements (N, 1–4)

Use residual ground overcurrent elements for the DCB trip scheme. The Level 2 residual ground overcurrent element (67G2) is forward-looking and provides communications-assisted tripping. The Level 3 residual overcurrent element (67G3) is reverse-looking and blocks the tripping at Station R during out-of-section faults behind Station S. Enable three levels of residual ground overcurrent protection.

E50G := **3** Residual Ground Instantaneous/Definite-Time Overcurrent Elements (N, 1–4)

This application does not require negative-sequence overcurrent protection.

E50Q := **N** Negative-Sequence Instantaneous/Definite-Time Overcurrent Elements (N, 1–4)

Use inverse-time overcurrent protection to provide backup protection for high-resistance ground faults. The 51S1 element provides backup protection for unbalanced faults if both the communications-assisted and step distance protection fail to operate.

E51S := **1** Selectable Inverse-Time Overcurrent Element (N, 1–3)

Set E32 to AUTO and the relay automatically calculates the settings corresponding to the ground directional element (32G).

E32 := **AUTO** Directional Control (Y, AUTO)

Use the DCB tripping scheme.

ECOMM := **DCB** Communications-Assisted Tripping (N, DCB, POTT, POTT2, POTT3, DCUB1, DCUB2)

Fuses or molded case circuit breakers often protect potential transformers. Operation of one or more fuses, or molded case circuit breakers, results in a loss of polarizing potential inputs to the relay. Loss of one or more phase voltages prevents the relay from properly determining fault distance or direction.

Occasional loss-of-potential to the distance relay, while unavoidable, is detectable. When the relay detects a loss-of-potential condition, the relay can block distance element operation, block or enable forward-looking directional overcurrent elements, and issue an alarm for any true loss-of-potential condition.

If line-side PTs are used, the circuit breaker(s) must be closed for the LOP logic to detect an LOP condition. Therefore, if three-phase potential to the relay is lost while the circuit breaker(s) is open (e.g., the PT fuses are removed while the line is de-energized), the relay cannot detect a loss-of-potential condition when the circuit breaker(s) closes again. At circuit breaker closing, the relay can detect one or two missing potentials that occurred while the circuit breaker was open. See [Loss-of-Potential Logic on page R.1.26](#) for more information.

[Table 1.16](#) lists the three choices for enabling LOP.

Table 1.16 LOP Enable Options

Option	Description
N	The LOP logic operates but does not disable voltage-polarized directional elements, distance elements, and forward-looking directional overcurrent elements. Use LOP in this case for alarm only.
Y	The relay disables all voltage-polarized directional elements and distance elements, but enables forward-looking directional overcurrent elements. These forward-looking directional overcurrent elements effectively become nondirectional and provide overcurrent protection during an LOP condition.
Y1	The relay disables all voltage-polarized directional elements and distance elements. The relay also disables the overcurrent elements controlled by the voltage-polarized directional elements.

Set ELOP to Y1 for this application example. This choice reduces the chances of false tripping because of a loss-of-potential condition.

ELOP := **Y1** Loss-of-Potential (Y, Y1, N)

You do not need Advanced Settings for this application example.

EADVS := N Advanced Settings (Y, N)

Phase Distance Elements (21P)

Mho Phase Distance Element Reach

Employ each zone of mho phase distance protection as follows:

- Zone 1—Instantaneous underreaching tripping
- Zone 2—DCB scheme tripping
- Zone 3—DCB scheme blocking

Zone 1 Phase Distance Element Reach. Zone 1 phase distance protection provides instantaneous protection for phase-to-phase, phase-to-phase-to-ground, and three-phase faults for 80 percent of the distance from Station S to Station R because this is the shortest line segment from one terminal to another. Errors in the current transformers, potential transformers, modeled transmission line data, and fault study data do not permit Zone 1 to be set equal to 100 percent of the distance to Station R. Otherwise, unwanted tripping could occur for faults just beyond the remote terminal.

Set Zone 1 phase distance protection equal to 80 percent of the positive-sequence impedance from Station S to Station R.

$$\begin{aligned} Z_{1P} &= 0.8 \cdot (Z_{1L1} + Z_{1L2}) \\ &= 0.8 \cdot (2 + 2) \, \Omega \\ &= 3.2 \, \Omega \end{aligned}$$

Equation 1.22

$Z_{1P} := 3.2$ Zone 1 Reach (OFF, 0.05–64 Ω secondary)

Zone 2 Phase Distance Element Reach. Set Zone 2 phase distance reach to include the tapped autotransformer.

Perform the following fault study to determine the apparent fault impedance the SEL-421 distance elements measure for faults at the 138 kV terminals of the autotransformer. Use these measurements to set the distance reach settings. Station R should be in service to account for infeed. Place an AG and ABC fault at the 138 kV terminals of the autotransformer and record the secondary voltage and current the relay measures at Station S. Apply these quantities in [Equation 1.23](#) and [Equation 1.26](#), to determine the fault impedance the relay measures for the two fault types shown in [Table 1.17](#). Use [Equation 1.23](#) for an A-phase-to-ground fault and [Equation 1.26](#) for the three-phase fault.

$$|Z_{AG}| = \left| \frac{V_A}{I_A + k_0 \cdot 3I_0} \right|$$

Equation 1.23

Where:

V_A = A-phase-to-neutral voltage

I_A = A-phase current

k_0 = zero-sequence compensation factor

$3I_0$ = zero-sequence current

The relay uses the zero-sequence compensation factor to measure zero-sequence quantities in terms of positive-sequence quantities.

$$k_0 = \frac{Z_{0L1} - Z_{1L1}}{3 \cdot Z_{1L1}} \quad \text{Equation 1.24}$$

The zero-sequence current is the sum of the phase currents.

$$3I_0 = I_A + I_B + I_C \quad \text{Equation 1.25}$$

The magnitude of the impedance for B-phase-to-C-phase, B-phase-to-C-phase-to-ground, and three-phase faults is $|Z_{BC}|$.

$$|Z_{BC}| = \left| \frac{V_{BC}}{I_{BC}} \right| \quad \text{Equation 1.26}$$

Where:

V_{BC} = B-phase-to-C-phase voltage

I_{BC} = B-phase-to-C-phase current

[Table 1.17](#) lists the results of the Z_{AG} and Z_{BC} calculations.

Table 1.17 Local Zone 2 Fault Impedance Measurements

Fault Type	$ Z_{AG} $	$ Z_{BC} $
AG	7.77 Ω	NA
ABC	NA	8.8 Ω

Select the phase-to-phase measurement from [Table 1.17](#). Multiply this value by a safety factor of 125 percent to obtain Zone 2 phase distance element reach.

$$\begin{aligned} Z_{2P} &= 1.25 \cdot 8.8 \, \Omega \\ &= 11.00 \, \Omega \end{aligned} \quad \text{Equation 1.27}$$

$Z_{2P} := 11.00$ Zone 2 Reach (OFF, 0.05–64 Ω secondary)

Zone 3 Phase Distance Element Reach

Zone 3 phase distance protection is reverse-looking. Zone 3 at Station S must have adequate reach to prevent unwanted tripping by the SEL-421 relays at Stations R or T during external faults behind the local terminal. The Zone 3 reach at Station S must cover overreach from the furthest reaching remote Zone 2 for reverse faults when there is no infeed from the other remote terminal.

[Figure 1.13](#) illustrates this coordination issue. You must set the Zone 2 reach at Station T to account for infeed during faults beyond the tap on the 345 kV system. However, when one 345 kV station is out of service, the Zone 2 at Station T overreaches for faults on the other side of the tap on the 345 kV system.

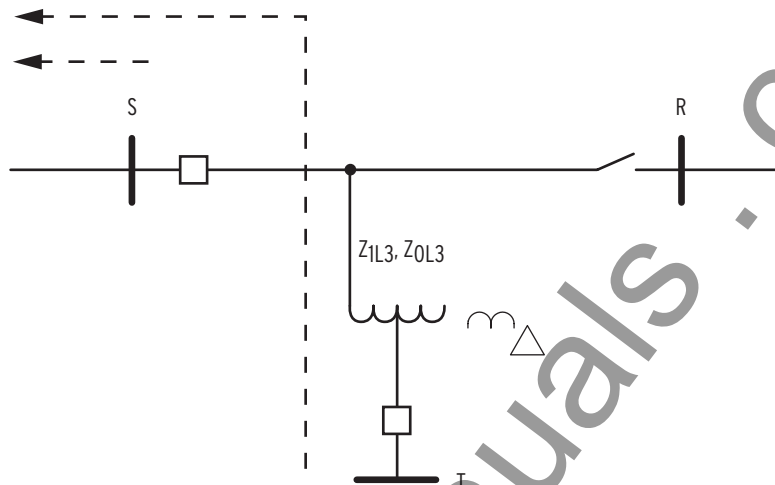


Figure 1.13 Reverse Zone 3 Coordination

Place AG and ABC faults at Station T and use [Equation 1.23](#) and [Equation 1.26](#) with respect to Station R to record the results in primary. Next place AG and ABC faults at Station R and use [Equation 1.23](#) and [Equation 1.26](#) with respect to Station T to record the results in primary. [Table 1.18](#) lists the results in primary and per unit.

Table 1.18 Apparent Impedance Measurement for Remote Faults

Station	$ Z_{AG} $	$ Z_{BC} $
Relay at Station R, Fault at Station T	152.7 Ω (0.128 per unit)	196.65 Ω (0.165 per unit)
Relay at Station T, Fault at Station S	79.605 Ω (0.418 per unit)	76.845 Ω (0.404 per unit)
Relay at Station T, Fault at Station R	103.86 Ω (0.545 per unit)	115.86 Ω (0.608 per unit)

The SEL-421 at Station T measures the largest apparent fault impedance for faults at Station R because the source at Station S is stronger than the source at Station R. Therefore, Zone 2 at Station T must be set to 115.86 Ω primary (plus a safety margin) so that the relay can detect faults at Station R when the source at Station S is in-service; this is the largest Zone 2 reach.

[Figure 1.14](#) is an impedance diagram of the 345 kV tapped overhead transmission line; only the reactances (per unit) are shown.

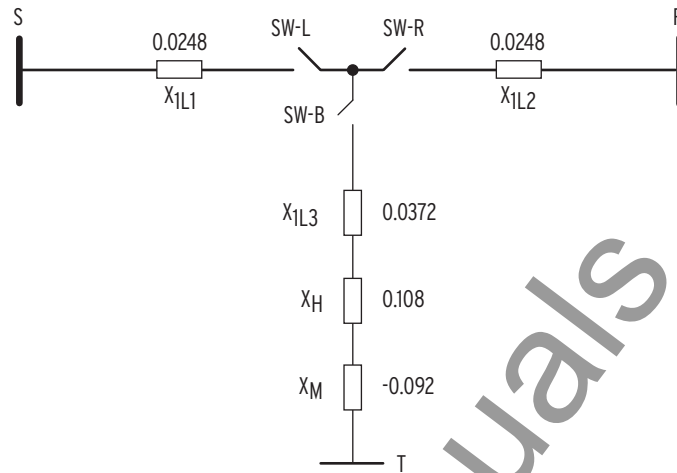


Figure 1.14 Impedance Diagram

To determine the greatest amount of overreach from a remote terminal during reverse faults with respect to Station S, subtract the fault impedance from the corresponding apparent impedance measurement from [Table 1.18](#).

Calculate the overreach at Station R (SW-B open; SW-L and SW-R closed).

$$\begin{aligned}\text{Overreach} &= |Z_{\text{APP}}| - X_{1L1} - X_{1L2} \\ &= 0.165 - 0.0248 - 0.0248 \\ &= 0.115 \text{ per-unit}\end{aligned}\quad \text{Equation 1.28}$$

Calculate the overreach at Station T (SW-R open; SW-L and SW-B closed).

$$\begin{aligned}\text{Overreach} &= |Z_{\text{APP}}| - X_M - X_H - X_{1L3} - X_{1L1} \\ &= 0.608 - (-0.092) - 0.108 - 0.0372 - 0.0248 \\ &= 0.53 \text{ per-unit}\end{aligned}\quad \text{Equation 1.29}$$

Station T has the greatest overreach. Use [Equation 1.30](#) to set Zone 3 phase distance element reach.

$$\begin{aligned}Z_{3P} &= \frac{\text{CTR}}{\text{PTR}} \cdot Z(\text{per-unit}) \cdot Z_{\text{base}} \cdot 120\% \\ &= \frac{200}{3000} \cdot 0.53 \cdot 1190.25 \cdot 1.2 \\ &= 50.5 \, \Omega\end{aligned}\quad \text{Equation 1.30}$$

Where:

$$\begin{aligned}Z_{\text{base}} &= \frac{(345\text{kV})^2}{100 \text{ MVA}} \\ &= 1190.25 \, \Omega\end{aligned}$$

$Z_{3P} := 50.50$ Zone 3 Reach (OFF, 0.05–64 Ω secondary)

Ground Distance Elements (21MG and 21XG)

Mho Ground Distance Element Reach

Employ each zone of mho ground distance protection as follows:

- Zone 1—Instantaneous underreaching tripping
- Zone 2—DCB scheme tripping
- Zone 3—DCB scheme blocking

Zone 1 Mho Ground Distance Element Reach. Zone 1 mho ground distance element reach must meet the same requirement as that for Zone 1 mho phase distance protection; the reach setting can be no greater than 80 percent of the protected line.

$$Z1MG = Z1P = 3.2 \, \Omega$$

$$Z1MG := \mathbf{3.20} \text{ Zone 1 (OFF, 0.05–64 } \Omega \text{ secondary)}$$

Zone 2 Mho Ground Distance Element Reach. Set Zone 2 ground distance element reach equal to Zone 2 phase distance element reach; this ensures that Zone 2 ground distance elements can see faults internal to the tapped autotransformer. Zone 2 phase distance element reach was set to see the largest apparent fault impedance for faults at the 138 kV terminal of the tapped autotransformer.

$$Z2MG = Z2P = 11 \, \Omega$$

$$Z2MG := \mathbf{11.00} \text{ Zone 2 (OFF, 0.05–64 } \Omega \text{ secondary)}$$

Zone 3 Mho Ground Distance Element Reach. Set Zone 3 ground distance element reach equal to Zone 3 phase distance element reach; this ensures that Zone 3 ground distance elements coordinate with the remote Zone 2 ground distance elements at Stations R and T for out-of-section faults behind the local terminal. Zone 3 phase distance element reach was set to coordinate with the largest remote Zone 2 phase distance element reach.

$$Z3MG = Z3P = 50.50 \, \Omega$$

$$Z3MG := \mathbf{50.50} \text{ Zone 3 (OFF, 0.05–64 } \Omega \text{ secondary)}$$

Zero-Sequence Current Compensation Factors

Zero-sequence current compensation helps to keep the phase and ground distance elements at the same reach if you set the reach equal per zone (for example, $Z1P = Z1MG$). Ground distance elements should measure fault impedance in terms of positive-sequence impedance only. The relay automatically calculates the setting for the Zone 1 zero-sequence current compensation factor when you set k0M1 to AUTO.

$$k0M1 := \mathbf{AUTO} \text{ Zone 1 ZSC Factor Magnitude (AUTO, 0.000–10)}$$

When you enter AUTO as the setting for k0M1, the relay calculates the zero-sequence current compensation as follows:

$$k01 = \frac{Z0MAG \angle Z0ANG - Z1MAG \angle Z1ANG}{3 \cdot Z1MAG \angle Z1ANG} \quad \text{Equation 1.31}$$

Zone 2 and Zone 3 use the same zero-sequence current compensation factor as that for Zone 1 because Advanced Settings are disabled.

The relay displays the following values for kOM1 and kOMA:

kOM1 := **0.750** Zone 1 ZSC Factor Magnitude (AUTO, 0.000–10)

kOMA := **-16.87** Zone 1 ZCS Factor Angle (–180.0 to +180.0 degrees)

Distance Element Common Time Delay

Set the appropriate timers Z1D, Z2D, and Z3D for both phase and ground distance elements.

You do not need to delay Zone 1 distance protection; it trips instantaneously.

Z1D := **0.000** Zone 1 Time Delay (OFF, 0.000–16000 cycles)

Zone 2 distance protection provides time-delayed tripping as a backup function. Set this delay to 20 cycles.

Z2D := **20.000** Zone 2 Time Delay (OFF, 0.000–16000 cycles)

Zone 3 distance protection is reverse-looking and you do not need to apply it for tripping in this application. Set Zone 3 for zero time delay.

Z3D := **0.000** Zone 3 Time Delay (OFF, 0.000–16000 cycles)

SOTF Scheme

SOTF (Switch-Onto-Fault) logic is enabled when the circuit breaker closes. This logic provides protection for a short duration (setting SOTFD) until other protection (such as tripping from SELOGIC control equations TR and TRCOMM) is available. The TRSOTF SELOGIC control equation defines which protection elements cause the relay to trip when the SOTF scheme is active. Assertion of the protection elements assigned to TRSOTF during the SOTFD time causes the relay to trip instantaneously.

Apply SOTF when using line-side potentials for relaying. Use nondirectional overcurrent protection to clear close-in faults. Also use instantaneous overreaching distance protection to clear faults along the line. Assign instantaneous Zone 2 mho phase and ground distance protection plus Level 1 phase overcurrent element to TRSOTF.

TRSOTF := **M2P OR Z2G OR 50P1** Switch-Onto-Fault Trip (SELOGIC Equation)

Single-Pole SOTF

This is a three-pole tripping application example; confirm that the SOTF protection is for three-pole tripping.

ESPSTF := **N** Single-Pole Switch-Onto-Fault (Y, N)

Voltage Reset

You can configure the logic so the SOTF enable duration resets within at least 5 cycles after it first asserted, but before the SOTFD timer expires. To quickly reset the SOTF period:

the relay must sense that the positive-sequence voltage is greater than 85 percent of the nominal voltage.

Use setting EVRST (Switch-Onto-Fault Voltage Reset) to enable fast reset. The advantage of resetting SOTF protection quickly is that unwanted tripping does not occur for subsequent faults external to the remote terminals during

the SOTF period; these trips can occur if you set instantaneous Zone 2 distance protection elements in the TRSOTF SELOGIC control equation. Enable the voltage reset option.

$EVRST := Y$ Switch-Onto-Fault Voltage Reset (Y, N)

SOTF Initiation

The SOTF logic asserts via one or both of the following methods:

- A change in the normally open auxiliary contact 52A status showing that the circuit breaker has just opened
- Assertion of the relay control input assigned to the circuit breaker close bus

The 52A method works well for both single and multiple circuit breaker applications and does not require an input from the close bus. However, the close bus method only enables SOTF protection immediately following the close command to the circuit breaker. For more information, see [Switch-Onto-Fault Logic on page R.1.94](#).

Turn off 52AEND, 52A Pole Open Time Delay, because the 52A method is not used.

$52AEND := OFF$ 52A Pole Open Time Delay (OFF, 0.000–16000 cycles)

Select the close bus option for this application and set the close enable delay (CLOEND) shorter than the shortest reclose open interval.

$CLOEND := 10.000$ CLSMON or Single-Pole Open Delay (OFF, 0.000–16000 cycles)

SOTF Duration

Setting SOTFD determines the longest period the SOTF logic can assert after the circuit breaker closes.

$SOTFD := 10.000$ Switch-Onto-Fault Enable Duration (0.500–16000 cycles)

Close Signal Monitor

Assign the Relay Word bit CLSMON to a control input, so the relay can detect execution of the close command.

$CLSMON := IN102$ Close Signal Monitor (SELOGIC Equation)

Load Encroachment

The relay uses a load-encroachment feature that prevents operation of the phase distance elements during heavy load. This unique feature permits the load to enter a predefined area of the phase distance characteristics without causing unwanted tripping. [Figure 1.15](#) illustrates the load-encroachment function superimposed on the mho phase distance protection characteristics.

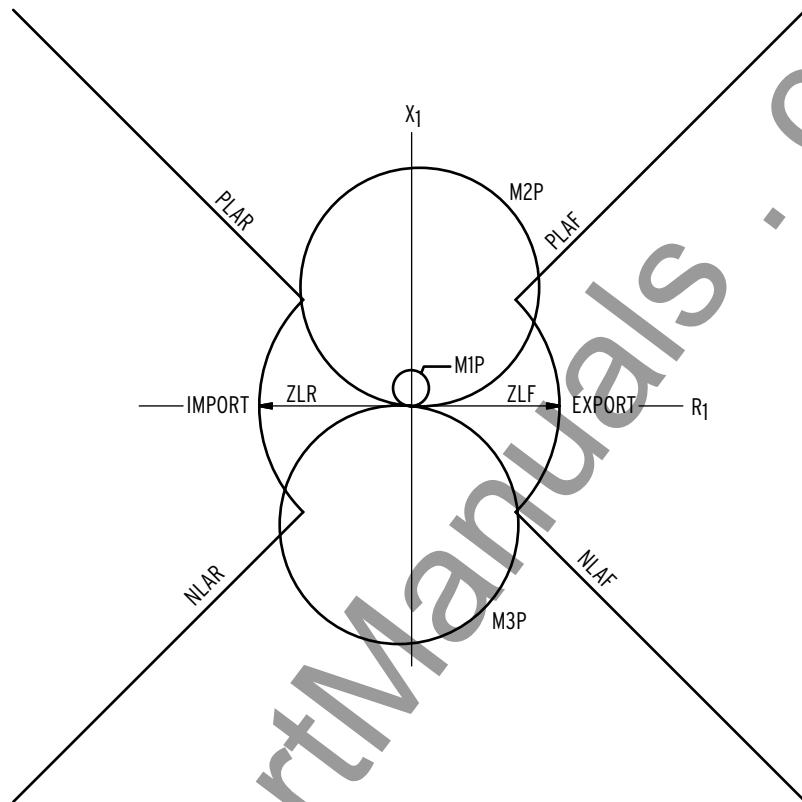


Figure 1.15 Load-Encroachment Function

Define the load-encroachment characteristic with load impedance settings in the forward (ZLF) and reverse (ZLR) directions. Define the two load sectors, export and import, with angle settings PLAF, NLAF, PLAR, and NLAR in the forward and reverse directions.

The transformer MVA rating is the maximum load. Assume that Station S can supply the total load the autotransformer draws. Set load encroachment according to maximum load for the protected line (4.2 A secondary). The bus voltage at Station S is 65.7 V line-to-neutral during maximum load.

$$V_{LN} = 65.7 \text{ V}$$

$$I_{\phi} = 4.2 \text{ A}$$

Therefore, the minimum load impedance the relay measures is as follows:

$$\begin{aligned} Z_{\text{load}} &= \frac{V_{LN}}{I_{\phi}} \\ &= \frac{65.7 \text{ V}}{4.2 \text{ A}} \\ &= 15.6 \text{ } \Omega \end{aligned} \quad \text{Equation 1.32}$$

Note that this load impedance is well inside the Zone 3 mho ground distance element reach, Z3MG, or 50.5 Ω .

Multiply Z_{load} by a safety factor of 80 percent to account for overload conditions.

$$\begin{aligned} Z_{\text{load}} &= 0.8 \cdot 15.6 \text{ } \Omega \\ &= 12.5 \text{ } \Omega \end{aligned} \quad \text{Equation 1.33}$$

Set the forward and reverse load impedance thresholds (ZLF and ZLR, respectively) according to the minimum load impedance.

ZLF := **12.5** Forward Load Impedance (0.05–64 Ω secondary)

ZLR := **12.5** Reverse Load Impedance (0.05–64 Ω secondary)

To be conservative, assume a load angle range of $\pm 45^\circ$. Assume both forward (export) and reverse (import) load ranges to be the same.

PLAF := **45.0** Forward Load Positive Angle (-90.0 to $+90.0$ degrees)

NLAF := **-45.0** Forward Load Negative Angle (-90.0 to $+90.0$ degrees)

PLAR := **135.0** Reverse Load Positive Angle ($+90.0$ to $+270.0$ degrees)

NLAR := **225.0** Reverse Load Negative Angle ($+90.0$ to $+270.0$ degrees)

Phase Instantaneous/Definite-Time Overcurrent Elements

Use 50P1, Level 1 phase instantaneous overcurrent element, as a nondirectional high-set phase overcurrent element for SOTF protection. If the local circuit breaker closes into a close-in three-phase bolted fault with line-side potential transformers, the polarizing voltage for the phase distance elements is zero. Therefore, the distance protection does not operate. In this case, the 50P1 element quickly trips the circuit breaker because this overcurrent element does not rely on the polarizing voltage.

To rapidly clear faults, set 50P1P equal to 50 percent of the fault current measured at the local terminal for a close-in three-phase fault; use weak source conditions to ensure the relay operates for low-level fault current.

50P1P := **49.80** Level 1 Pickup (OFF, 0.25–100 A secondary)

This application uses 50P1 as an instantaneous overcurrent element; you do not need time delay.

67PID := **0.000** Level 1 Time Delay (0.000–16000 cycles)

This application uses 50P1 as a nondirectional overcurrent element; you do not need torque control.

67P1TC := **1** Level 1 Torque Control (SELOGIC Equation)

Residual Ground Instantaneous/Definite-Time Overcurrent Elements

This application example has three levels of residual ground overcurrent elements. You will use these overcurrent elements later in the DCB scheme.

The Level 2 residual ground overcurrent element is set forward-looking to serve as a tripping element. The Level 3 residual ground overcurrent element is set as both a nondirectional (50G3) and reverse-looking (67G3) starting element. Be sure to set residual ground elements above any loading unbalance.

Disable Level 1 residual ground overcurrent element; this particular application does not use this element.

50G1P := **OFF** Level 1 Pickup (OFF, 0.25–100 A secondary)

Enable Level 2 residual ground overcurrent element for DCB tripping. Ground distance elements measure fault resistance consisting of arcing resistance and ground return resistance. Ground return resistance can consist of tower footing resistance and tree resistance. The total ground fault resistance can lie outside of the ground distance characteristics. Residual overcurrent protection is the

best method available for detecting high-resistance ground faults because this method of protection provides the greatest sensitivity. Set the pickup to 20 percent of the nominal current (5 A).

50G2P := **1.00** Level 2 Pickup (OFF, 0.25–100 A, secondary)

Enable Level 3 residual ground overcurrent element to send the blocking signal for out-of-section faults. Set the pickup of Level 3 residual ground overcurrent element (50G3) at Station S to half the remote forward-looking residual ground overcurrent element (50G2) at Station R.

$$50G3P_S = \frac{50G2P_R}{2} \quad \text{Equation 1.34}$$

This measure provides security during out-of-section faults, because the blocking elements are twice as sensitive as the tripping elements.

50G3P := **0.50** Level 3 Pickup (OFF, 0.25–100 A secondary)

You do not need to add intentional time delays for Level 2 and Level 3 pickups.

67G2D := **0.000** Level 2 Time Delay (0.000–16000 cycles)

67G3D := **0.000** Level 3 Time Delay (0.000–16000 cycles)

Set Level 2 torque control equation to the forward decision from the ground directional element, 32GF.

67G2TC := **32GF** Level 2 Torque Control (SELOGIC Equation)

Set Level 3 torque control equation to the reverse decision from the ground directional element, 32GR.

67G3TC := **32GR** Level 3 Torque Control (SELOGIC Equation)

Selectable Operating Quantity Time Overcurrent Element 1

Use inverse-time overcurrent protection to provide backup protection for high-resistance ground faults. The 51S1 element provides backup protection for unbalanced faults if both the communications-assisted and step distance protection fail to operate.

NOTE: Use your company practices and philosophy when determining these settings.

Select zero-sequence line current as the operating quantity.

51S1O := **3I0L** 51S1 Operating Quantity (I_{An} , I_{Bn} , I_{Cn} , $IMAX_n$, I_{1L} , $3I_{2L}$, $3I_{0n}$)

The n in the 51S1O setting is L for line, 1 for BK1, and 2 for BK2.

The relay measures 4.8 A secondary of $3I_0$ for a bolted single-phase-to-ground fault at the 345 kV terminals of the autotransformer. Set the pickup to 20 percent of $3I_0$.

51S1P := **0.96** 51S1 Overcurrent Pickup (0.25–16 A secondary)

Use the following formula to determine approximately how much primary fault resistance coverage (R_F) is provided by 51S1P on a radial basis:

$$\begin{aligned} R_F &= \frac{PTR}{CTR} \cdot \frac{VNOMY/\sqrt{3}}{51S1P} \\ &= \frac{3000}{200} \cdot \frac{115V/\sqrt{3}}{0.96A} \\ &= 1037 \, \Omega \text{ primary} \end{aligned} \quad \text{Equation 1.35}$$

Use the following as a guide to set the curve and time dial; for secure backup protection, perform a coordination study.

Set the local overcurrent element to coordinate with the downstream overcurrent element such that there is an 18-cycle (60 Hz nominal) safety margin for ground faults in front of the first downstream overcurrent element. Assume the operating time of the downstream overcurrent element is 12 cycles for a close-in ground fault. Therefore, set the local time-overcurrent element to operate approximately 30 cycles for ground faults in front of the first downstream overcurrent element.

51SIC := **U3** 51S1 Inverse-Time Overcurrent Curve (U1–U5)

51SITD := **2.0** 51S1 Inverse-Time Overcurrent Time Dial
(0.50–15.0)

Set the overcurrent element to emulate electromechanical reset, so the overcurrent element coordinates properly with electromechanical overcurrent relays.

51SIRS := **Y** 51S1 Inverse-Time Overcurrent Electromechanical
Reset (Y, N)

Torque control the overcurrent element with the forward decision from the ground directional element.

51SITC := **32GF** 51S1 Torque Control (SELOGIC Equation)

Zone/Level Direction

Zone 1 and Zone 2 distance element directions are fixed in the forward direction. You can select the other zones independently as forward-looking (F) or reverse-looking (R). Set Zone 3 distance elements reverse-looking because these are blocking elements for the DCB trip scheme.

DIR3 := **R** Zone/Level 3 Directional Control (F, R)

Directional Control

The SEL-421 uses an array of directional elements to supervise the ground distance elements and residual directional overcurrent elements during ground fault conditions. Internal logic automatically selects the best choice for the ground directional element (32G) from among the negative-sequence voltage-polarized directional element (32QG), zero-sequence voltage-polarized directional element (32V), and the zero-sequence current-polarized directional element (32I).

The relay setting ORDER determines the order in which the relay selects directional elements to provide ground directional decisions. You can set ORDER with any combination of Q, V, and I. The listed order of these directional elements determines the priority in which these elements operate to provide the ground directional element. Only one specific directional element operates at any one time. Directional element classification is as follows:

- Q—Negative-sequence voltage-polarized directional element
- V—Zero-sequence voltage-polarized directional element
- I—Zero-sequence current-polarized directional element

Set ORDER to QV. The first listed directional element choice, Q, is the first priority directional element to provide directional control for the ground distance elements and residual directional overcurrent elements. If Q is not

operable, the second listed directional element choice, V, provides directional control for the ground distance elements and residual directional overcurrent elements. A polarizing quantity was not available for choice I, so I is not selected for this particular application example.

ORDER := **QV** Ground Directional Element Priority (combine Q, V, I)

SELOGIC control equation E32IV must assert to logical 1 to enable V or I for directional control of the ground distance elements and residual directional overcurrent elements. Set E32IV to logical 1.

E32IV := 1 Zero-Sequence Voltage and Current Enable (SELOGIC Equation)

Reverse Ground Directional Checks

32QG and 32V makes forward and reverse directional decisions during unbalanced faults based upon the following four settings:

- Z2F—Forward Directional Z2 Threshold
- Z2R—Reverse Directional Z2 Threshold
- Z0F—Forward Directional Z0 Threshold
- Z0R—Reverse Directional Z0 Threshold

For 32QG, if the apparent negative-sequence impedance measured by the relay ($z2$) is less than Z2F, the unbalanced fault is declared forward. If $z2$ is greater than Z2R, the unbalanced fault is declared reverse.

For 32V, if the apparent zero-sequence impedance measured by the relay ($z0$) is less than Z0F, the unbalanced fault is declared forward. If $z0$ is greater than Z0R, the unbalanced fault is declared reverse.

The SEL-421 automatically calculates these four settings as follows when Advanced Settings are disabled and setting E32 is AUTO:

$$\begin{aligned} Z2F &= 0.5 \cdot Z1MAG \\ &= 0.5 \cdot 4.00 \, \Omega \\ &= 2.00 \, \Omega \end{aligned} \quad \text{Equation 1.36}$$

$$\begin{aligned} Z2R &= Z2F + \frac{0.5}{I_{nom}} \\ &= 2.00 \, \Omega + 0.10 \, \Omega \\ &= 2.10 \, \Omega \end{aligned} \quad \text{Equation 1.37}$$

$$\begin{aligned} Z0F &= 0.5 \cdot Z0MAG \\ &= 0.5 \cdot 12.88 \, \Omega \\ &= 6.44 \, \Omega \end{aligned} \quad \text{Equation 1.38}$$

$$\begin{aligned} Z0R &= Z0F + \frac{0.5}{I_{nom}} \\ &= 6.44 \, \Omega + 0.10 \, \Omega \\ &= 6.54 \, \Omega \end{aligned} \quad \text{Equation 1.39}$$

Perform the following two checks to make sure the ground directional element does not incorrectly make a forward decision during a reverse unbalanced fault.

32QG Reverse Directional Check. You set Z1MAG equal to Z_{1L1} plus Z_{1L2} so the fault locator provides correct results for internal faults not located on the tap (i.e., source T is extremely weak and provides practically no infeed).

Figure 1.16 is the negative-sequence network for the 345 kV tapped overhead transmission line. Assume that the negative-sequence impedances are equal to the positive-sequence impedances.

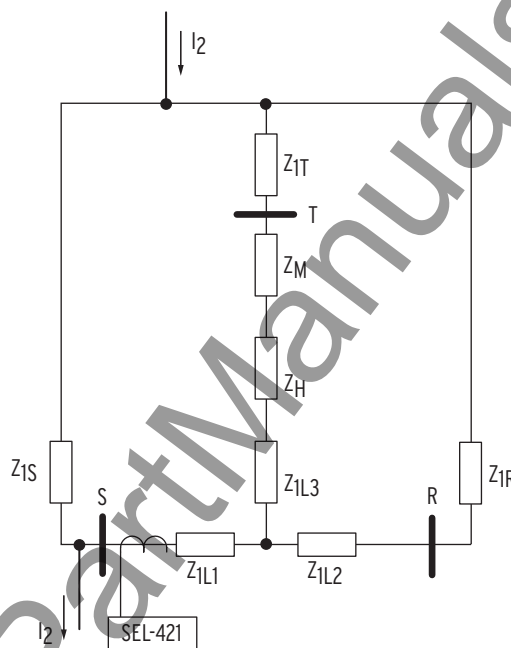


Figure 1.16 345 kV Tapped Line Negative-Sequence Network

Z_n is an approximation of the impedance calculation for the n-sequence voltage-polarized directional statement for a reverse fault.

If $z2$ is less than $Z2F$ during a reverse unbalanced fault, 32QG incorrectly declares that the fault is forward with respect to the relay location (CT shown in Figure 1.16). The relay automatically sets $Z2F$ equal to one-half $Z1MAG$. Equation 1.40 is the apparent negative-sequence impedance $z2$ measured by the 32QG element during a reverse unbalanced fault.

$$z2 = Z_{1L1} + Z_{2P} \quad \text{Equation 1.40}$$

Where:

Z_{2P} = parallel combination of the Line 3 impedance, transformer reactances (neglect resistance), and the Bus T impedance with Line 2 and the Bus R impedance

X_H = transformer high-side winding reactance

X_M = transformer low-side winding reactance

X_L = transformer tertiary winding reactance

The downstream parallel impedance, Z_{2P} , is the Line 3 impedance, the transformer reactances, and the Bus R impedance.

$$Z_{2P} = (Z_{1L3} + jX_H + jX_M + jX_{1T}) \parallel (Z_{1L2} + Z_{1R}) \quad \text{Equation 1.41}$$

Use the following two assumptions to simplify the calculations:

1. Assume the power system is purely reactive
2. Ignore source impedances Z_{1R} and Z_{1T} (a conservative assumption)

Calculate the transformer reactances.

$$\begin{aligned} X_H &= 0.5 \cdot (X_{HM} + X_{HL} - X_{ML}) \\ &= 0.5 \cdot (0.016 + 0.6 - 0.4) \\ &= 0.108 \text{ per-unit} \end{aligned}$$

$$\begin{aligned} X_M &= 0.5 \cdot (X_{HM} + X_{ML} - X_{HL}) \\ &= 0.5 \cdot (0.016 + 0.4 - 0.6) \\ &= -0.092 \text{ per-unit} \end{aligned}$$

$$\begin{aligned} X_L &= 0.5 \cdot (X_{HL} + X_{ML} - X_{HM}) \\ &= 0.5 \cdot (0.6 + 0.4 - 0.016) \\ &= 0.492 \text{ per-unit} \end{aligned}$$

Equation 1.42

Use these assumptions from [Equation 1.41](#) to create a simplified form of the downstream parallel impedance.

$$\begin{aligned} Z_{2P} &= j([X_{1L3} + X_H + X_M] \parallel [X_{1L2}]) \\ &= j\left(\frac{(X_{1L3} + X_H + X_M) \cdot X_{1L2}}{(X_{1L3} + X_H + X_M) + X_{1L2}}\right) \\ &= j\left(\frac{(0.038 + 0.108 - 0.092) \cdot 0.025}{(0.038 + 0.108 - 0.092) + 0.025}\right) \\ &= j0.017 \text{ per-unit primary} \end{aligned}$$

Equation 1.43

The secondary base impedance is calculated as follows:

$$\begin{aligned} Z_{\text{base}} &= \frac{CTR \cdot (345 \text{ kV})^2}{PTR \cdot 100 \text{ MVA}} \\ &= \frac{200 \cdot (345 \text{ kV})^2}{3000 \cdot 100 \text{ MVA}} \\ &= 79.35 \Omega \end{aligned}$$

Equation 1.44

Calculate the parallel impedance in secondary ohms.

$$\begin{aligned} Z_{2P(\text{secondary})} &= Z_{2P(\text{primary})} \cdot Z_{\text{base}} \\ &= j0.017 \cdot 79.35 \Omega \\ &= 1.35 \Omega \text{ secondary} \end{aligned}$$

Equation 1.45

To determine whether the 32QG element always operates correctly during reverse unbalanced faults, check the following condition:

$$\begin{aligned} 2ZF &< |Z_{1L1}| + |Z_{2P}| \\ 2 \Omega &< 2 \Omega + 1.35 \Omega \\ 2 \Omega &< 3.35 \Omega \end{aligned}$$

The condition is satisfied; the reverse negative-sequence voltage-polarized directional element decision is correct during reverse unbalanced faults.

32V Reverse Directional Check. You set ZOMAG equal to Z_{0L1} plus Z_{0L2} so the fault locator provides correct results for internal faults not located on the tap (that is, source T is extremely weak and provides practically no infeed).

Figure 1.17 is the zero-sequence network for the 345 kV tapped overhead transmission line.

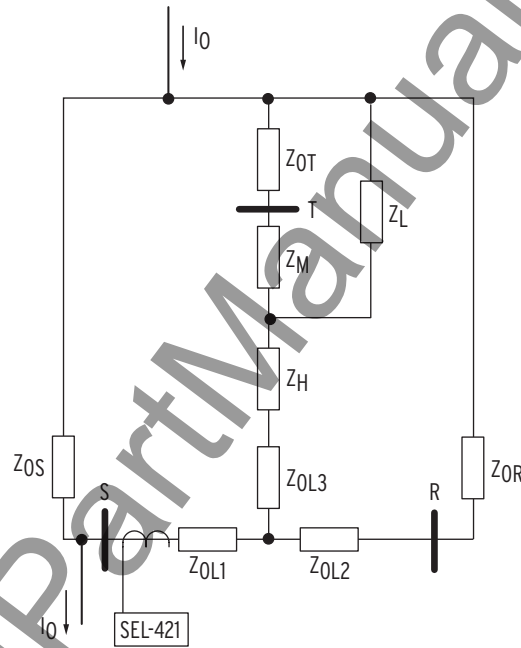


Figure 1.17 345 kV Tapped Line Zero-Sequence Network

If z_0 is less than Z_0F during a reverse unbalanced fault, 32V incorrectly declares that the fault is forward with respect to the relay location (CT shown in Figure 1.17). The relay automatically sets Z_0F equal to one-half Z_0MAG . Equation 1.46 is the apparent zero-sequence impedance measured by 32V during reverse unbalanced faults:

$$z_0 = Z_{0L1} + Z_{0P} \quad \text{Equation 1.46}$$

Where:

Z_{0P} = parallel combination of the Line 3 impedance, transformer high-side reactance (neglect resistance), and the parallel combination of the transformer low-side and Bus T impedance in parallel with the transformer tertiary impedance, in parallel with Line 2 and the Bus R impedance (see Figure 1.17).

$$Z_{0P} = (Z_{0L3} + jX_H + Z_{0PP}) \parallel (Z_{0L2} + Z_{0R}) \quad \text{Equation 1.47}$$

Where:

Z_{0PP} = the parallel combination of the transformer low-side and Bus T impedance in parallel with the transformer tertiary impedance

Use the following two assumptions to simplify the calculations:

1. Assume the power system is purely reactive
2. Ignore source impedances Z_{0R} and Z_{0T} (a conservative assumption)

Calculate the effect of transformer low side and transformer tertiary impedances.

$$\begin{aligned}
 Z_{0PP} &= (Z_M + Z_{0T}) \parallel Z_L \\
 &= \frac{j^2 X_M \cdot X_L}{j \cdot (X_M + X_L)} \\
 &= \frac{-j \cdot -1 \cdot -0.092 \cdot 0.492}{-0.092 + 0.492} \\
 X_{0PP} &= -j0.113 \text{ per-unit, } X_{0PP} \quad \text{Equation 1.48}
 \end{aligned}$$

Use these assumptions to create a simplified form of the downstream parallel impedance (from [Equation 1.47](#)).

$$\begin{aligned}
 Z_{0P} &= (X_{0L3} + X_H + X_{0PP}) \parallel (X_{0L2}) \\
 &= j \left(\frac{(X_{0L3} + X_H + X_{0PP}) \cdot X_{0L2}}{(X_{0L3} + X_H + X_{0PP}) + X_{0L2}} \right) \\
 &= j \left(\frac{(0.122 + 0.108 - 0.113) \cdot 0.081}{(0.122 + 0.108 - 0.113) + 0.081} \right) \\
 &= j0.048 \text{ per unit} \quad \text{Equation 1.49}
 \end{aligned}$$

Calculate the parallel impedance using Z_{base} from [Equation 1.44](#).

$$\begin{aligned}
 Z_{0P} &= Z_{0P} \cdot Z_{base} \\
 &= j0.048 \cdot 79.35 \, \Omega \\
 &= 3.8 \, \Omega \text{ secondary} \quad \text{Equation 1.50}
 \end{aligned}$$

To determine whether the zero-sequence voltage-polarized 32V element always operates correctly during reverse unbalanced faults, check the following condition:

$$\begin{aligned}
 Z_{0F} &< |Z_{0L1}| + |Z_{0P}| \\
 6.44 \, \Omega &< 6.44 \, \Omega + 3.8 \, \Omega \\
 6.44 \, \Omega &< 10.24 \, \Omega
 \end{aligned}$$

The condition is satisfied; the reverse zero-sequence voltage-polarized directional element decision is correct during reverse unbalanced faults.

Pole Open Detection

The setting EPO, Enable Pole-Open logic, offers two options for deciding what conditions signify an open pole, as listed in [Table 1.19](#).

Table 1.19 Options for Enabling Pole-Open Logic

Option	Description
EPO := V	The logic declares a single-pole open if the corresponding phase undervoltage element asserts and the open phase detection logic declares the pole is open. Select this option only if you use line-side potential transformers for relaying purposes. A typical setting for the 27PO, pole-open undervoltage threshold, is 60 percent of the nominal line-to-neutral voltage. Do not select this option when shunt reactors are applied because the voltage slowly decays after the circuit breaker opens. With this option selected, the relay cannot declare an open pole during assertion of LOP.
EPO := 52	The logic declares a single-pole open if the corresponding 52A contact (e.g., 52AA1) from the circuit breaker deasserts and the open phase detection logic declares that the pole is open.

Select the second option because a 52A contact is available. The relay uses both open phase detection and status information from the circuit breaker to make the most secure decision.

EPO := **52** Pole Open Detection (52, V)

Pole-Open Time Delay on Dropout

The setting 3POD establishes the time delay on dropout after the Relay Word bit 3PO deasserts. This delay is important when you use line-side potential transformers for relaying. Use the 3POD setting to stabilize the ground distance elements in case of pole scatter during closing of the circuit breaker(s).

3POD := **0.500** Three Pole Open Time Dropout Delay (0.000–60 cycles)

DCB Trip Scheme

This application example uses DCB trip scheme. In this scheme high-speed tripping occurs during internal autotransformer faults when the communications channel is not available.

The DCB trip scheme consists of the following three sections:

- Starting elements
- Coordination timers
- Extension of the blocking signal

Starting Elements

You can select nondirectional elements (NSTRT), directional elements (DSTRT), or both to detect out-of-section faults behind the local terminal. These elements send a blocking signal to Station R to prevent unwanted tripping during out-of-section faults. Nondirectional elements are always faster than directional elements, because directional elements need additional time to process the directional decision. Select both types of elements for this application.

Assign Relay Word bit NSTRT (Nondirectional Start) to OUT102 to start transmission of the blocking signal. NSTRT asserts if Level 3 residual ground overcurrent element (50G3) picks up. However, Relay Word bit STOP has priority over Relay Word bit NSTRT. If a M2P, Z2G, or 67G2 assert, the relay halts transmission of the blocking signal that nondirectional overcurrent elements started.

You have enabled three levels of residual ground overcurrent elements. The Level 2 residual ground directional overcurrent element provides communications-assisted tripping for internal unbalanced faults. The Level 3 residual ground overcurrent element provides nondirectional start (50G3) and directional start (67G3).

The Relay Word bit DSTRT asserts if any of the following elements pick up:

- Zone 3 phase distance elements (M3P)
- Zone 3 ground distance elements (Z3MG)
- Level 3 residual ground directional overcurrent element (67G3)

Relay Word bit DSTRT is useful when a bolted close-in three-phase fault occurs behind the relay. If the polarizing voltage for the distance elements collapses to zero, the corresponding Zone 3 supervisory phase-to-phase current level detectors latch the Zone 3 phase distance elements. Therefore, the Zone 3 phase distance characteristics do not need a reverse offset for this particular situation.

Assign Relay Word bit DSTRT (Directional Start) to OUT102 to start transmission of the blocking signal.

OUT102 := **NSTRT AND NOT STOP OR DSTRT**

OUT103 stops the local transmitter from sending the blocking signal to the remote terminal.

OUT103 := **STOP OR 3PT**

Time delay on pickup prevents transmission of the blocking signal if a transient causes a reverse-looking element to pick up momentarily. Set the corresponding timer to 1 cycle.

Z3XPU := **1.000** Zone 3 Reverse Pickup Time Delay (0.000–16000 cycles)

You can also extend the blocking signal during current reversals. Set the corresponding dropout timer to 5 cycles.

Z3XD := **5.000** Zone 3 Reverse Dropout Delay (0.000–16000 cycles)

Coordination Timers

The forward-looking elements that provide high-speed tripping at Station S must be delayed momentarily so the local circuit breaker does not trip for external faults behind Station R. This time delay provides time for the nondirectional and reverse-looking blocking elements at Station R to send a signal to Station S during out-of-section faults. This particular time delay is the coordination time for the DCB trip scheme. There are separate coordination timers for Zone 2 distance elements (21SD) and Level 2 residual directional overcurrent elements (67SD).

The recommended setting for the 21SD timer is the sum of the following three times:

- Control input recognition time (including debounce timer)
- Remote Zone 3 distance protection maximum operating time
- Maximum communications channel time

If the control input time delay on pickup debounce timer is zero, the maximum recognition time for the control input is 0.125 cycles. Assume a remote Zone 3 distance protection pickup time of one cycle; the remote Zone 3 distance protection should operate faster than the local Zone 2 distance

protection because the apparent fault impedance is deeper inside the remote Zone 3 distance protection characteristic. Finally, assume a communications channel time of 0.5 cycle. The sum of these times provides a conservative setting of 1.63 cycles.

$2\text{ISD} := 1.625$ Zone 2 Distance Short Delay (0.000–16000 cycles)

The recommended setting for the 67SD timer is the sum of the following three times:

- Control input recognition time (including debounce timer)
- Remote Level 3 nondirectional low-set overcurrent element maximum operating time
- Maximum communications channel time

If the control input time delay on pickup debounce timer is zero, the maximum recognition time for the control input is 0.125 cycles. Assume a 1-cycle pickup for remote Level 3 nondirectional blocking elements; the remote Level 3 current level detectors operate faster than the local Level 2 current level detectors because the remote Level 3 current level detectors pickup is lower. Finally, assume a communications channel time of 0.5 cycle. The sum of these times provides a conservative setting of 1.63 cycles.

$67\text{SD} := 1.625$ Level 2 Overcurrent Short Delay (0.000–16000 cycles)

Blocking Signal Extension

Assign a control input to recognize when the local terminal receives a blocking signal from the remote terminal during external faults.

$\text{BT} := \text{IN103}$ Block Trip Received (SELOGIC Equation)

The DCB trip scheme uses an on/off carrier signal to block high-speed tripping at Stations S and R for out-of-section faults. Connect the carrier receive block signal output from the teleprotection equipment to a control input assigned to the SELOGIC control equation BT. This control input must remain asserted to block the forward-looking tripping elements after the coordination timers expire. If the blocking signal drops out momentarily, the distance relay can trip for out-of-section faults.

A built-in timer, BTXD, delays dropout of the control input assigned to BT. This timer maintains the blocking signal at the receiving relay by delaying the dropout of BT. However, delayed tripping can occur for internal faults because this DCB protection scheme employs nondirectional elements; the relay always sends a blocking signal regardless of fault location. Therefore, set this timer to zero so that high-speed tripping occurs when the nondirectional starting elements assert for an internal autotransformer fault.

$\text{BTXD} := 0.000$ Block Trip Received Extension Time (0.000–16000 cycles)

Figure 1.18 illustrates the dc schematic for the DCB trip scheme.

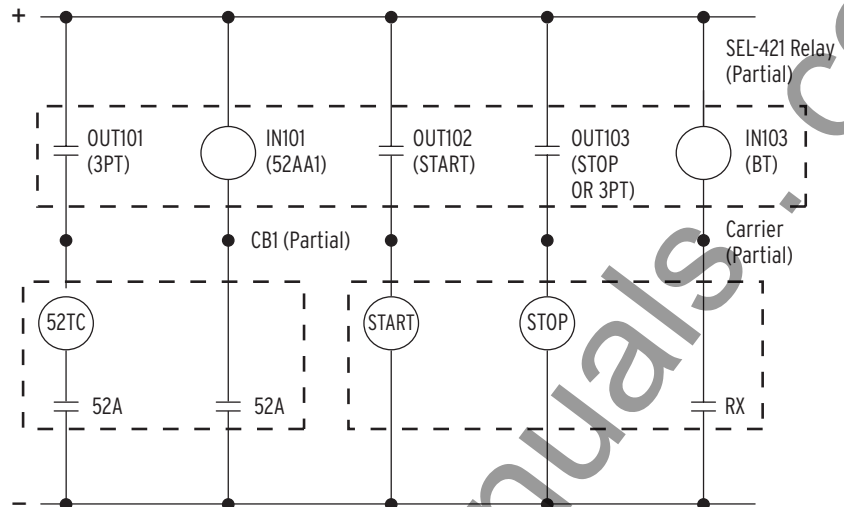


Figure 1.18 DC Schematic for DCB Trip Scheme

Trip Logic

Trip logic configures the relay for tripping. There are four trip logic settings:

- Trip equations
- Trip unlatch options
- Trip timers
- Three-pole tripping enable

Trip Equations

Set these three SELOGIC control equations for tripping:

- TR (unconditional)
- TRCOMM (communications-assisted)
- TRSOTF (Switch-Onto-Fault)

TR. The TR SELOGIC control equation determines which protection elements cause the relay to trip unconditionally. Set TR to the Zone 1 instantaneous distance protection (Z1T), Zone 2 time-delayed distance protection, and the inverse-time overcurrent element (51S1) for backup protection. For information on setting 51S1, see [Selectable Operating Quantity Time Overcurrent Element 1 on page A.1.68](#).

TR := Z1T OR Z2T OR 51S1T Trip (SELOGIC Equation)

TRCOMM. The TRCOMM SELOGIC control equation determines which protection elements cause the relay to trip via the communications-assisted tripping scheme logic. Set delayed Zone 2 mho phase and ground distance protection (Z2PGS) plus delayed Level 2 negative-sequence residual ground directional overcurrent element (67QGS2) in the TRCOMM SELOGIC control equation. See [Directional Comparison Blocking Scheme on page R.1.98](#) for more information.

TRCOMM := Z2PGS OR 67QGS2 Communications-Assisted Trip (SELOGIC Equation)

TRSOTF. The TRSOTF SELOGIC control equation defines which protection elements cause the relay to trip when the SOTF scheme is active. Assertion of these protection elements during the SOTFD time causes the relay to trip instantaneously (see [SOTF Scheme on page A.1.64](#)). Set instantaneous Zone 2 distance protection (M2P and Z2G) and Level 1 phase instantaneous overcurrent element (50P1) in the TRSOTF SELOGIC control equation.

TRSOTF := **M2P OR Z2G OR 50P1** Switch-Onto-Fault Trip (SELOGIC Equation)

Trip Unlatch Options

Unlatch the control output you programmed for tripping (OUT101) after the circuit breaker auxiliary “a” contacts break the dc current. The SEL-421 provides two methods for unlatching control outputs following a protection trip:

- ULTR—all three poles
- TULO—phase selective

ULTR. Use ULTR, the Unlatch Trip SELOGIC control equation, to unlatch all three poles. Use the default setting, which asserts ULTR when you push the front-panel target reset button.

ULTR := **TRGTR** Unlatch Trip (SELOGIC Equation)

TULO. Use TULO (Trip Unlatch Option) to select the conditions that cause the SEL-421 to unlatch the control outputs that you programmed for tripping. [Table 1.20](#) shows the four trip unlatch options for setting TULO.

Table 1.20 Setting TULO Unlatch Trip Options

Option	Description
1	Unlatch the trip when the relay detects that one or more poles of the line terminal are open and Relay Word bit 3PT has deasserted.
2	Unlatch the trip when the relay detects that the corresponding 52A contact(s) from both circuit breakers (e.g., 52AA1 and 52AA2) are deasserted.
3	Unlatch the trip when the relay detects that the conditions for Options 1 and 2 are satisfied.
4	Do not run this logic.

Select Option 3 because a 52A contact is available; the relay uses both open phase detection and status information from the circuit breaker to make the most secure decision. For information on the pole-open logic, see [Pole Open Logic on page R.1.24](#).

TULO := **3** Trip Unlatch Option (1, 2, 3, 4)

Trip Timers

The SEL-421 provides dedicated timers for minimum trip duration.

Minimum Trip Duration. The minimum trip duration timer setting, TDUR3D, determines the minimum time that Relay Word bit 3PT asserts. For this application example, Relay Word bit 3PT is assigned to OUT101. The corresponding control output closes for TDUR3D time or the duration of the trip condition, whichever is longer.

A typical setting for this timer is 9 cycles.

TDUR3D := **9.000** Three-Pole Trip Minimum Trip Duration Time Delay
 (2.000–8000 cycles)

Three-Pole Tripping Enable

The relay contains both three-pole and single-pole tripping logic. Set E3PT (Three-Pole Trip Enable) to logical 1 to enable three-pole tripping only.

E3PT := 1 Three-Pole Trip Enable (SELOGIC Equation)

Also set the appropriate three-pole tripping SELOGIC control equation for Circuit Breaker BK1.

E3PT1 := 1 Breaker 1 3PT (SELOGIC Equation)

Control Outputs

Main Board

OUT101 trips Circuit Breaker 1.

OUT101 := 3PT

OUT102 keys the local transmitter to send the blocking signal to the remote terminal during out-of-section faults behind Station S.

OUT102 := NSTRT AND NOT STOP OR DSTRT

OUT103 stops the local transmitter from sending the blocking signal to the remote terminal.

OUT103 := STOP OR 3PT

Example Completed

This completes the application example that describes setting of the SEL-421 for communications-assisted protection of a 345 kV tapped overhead transmission line. Analyze your particular power system to determine the appropriate settings.

Relay Settings

Table 1.21 lists all protection relay settings for this example.

Table 1.21 Settings for 345 kV Tapped TX Example (Sheet 1 of 6)

Setting	Description	Entry
General Global (Global)		
SID	Station Identifier (40 characters)	KELLOG -- 345 kV
RID	Relay Identifier (40 characters)	SEL-421 Relay
NUMBK	Number of Breakers in Scheme (1, 2)	1
BID1	Breaker 1 Identifier (40 characters)	Circuit Breaker 1
NFREQ	Nominal System Frequency (50, 60 Hz)	60
PHROT	System Phase Rotation (ABC, ACB)	ABC
DATE_F	Date Format (MDY, YMD, DMY)	MDY
FAULT	Fault Condition Equation (SELOGIC Equation)	50P1 OR 51S1 OR M2P OR Z2G OR M3P OR Z3G
Current and Voltage Source Selection Settings (Global)		
ESS	Current and Voltage Source Selection (Y, N, 1, 2, 3, 4)	N

Table 1.21 Settings for 345 kV Tapped TX Example (Sheet 2 of 6)

Setting	Description	Entry
Breaker Configuration (Breaker Monitoring)		
EB1MON	Breaker 1 Monitoring (Y, N)	N
BK1TYP	Breaker 1 Trip Type (Single Pole = 1, Three Pole = 3)	3
Breaker 1 Inputs (Breaker Monitoring)		
52AA1	A-Phase N/O Contact Input—BK1 (SELOGIC Equation)	IN101
Line Configuration (Group)		
CTRW	Current Transformer Ratio—Input W (1–50000)	200
CTRX	Current Transformer Ratio—Input X (1–50000)	200
PTRY	Potential Transformer Ratio—Input Y (1–10000)	3000
VNOMY	PT Nominal Voltage (L-L)—Input Y (60–300 V secondary)	115
PTRZ	Potential Transformer Ratio—Input Z (1–10000)	3000
VNOMZ	PT Nominal Voltage (L-L)—Input Z (60–300 V secondary)	115
Z1MAG	Positive-Sequence Line Impedance Magnitude (0.05–255 Ω secondary)	4.00
Z1ANG	Positive-Sequence Line Impedance Angle (5.00–90 degrees)	84.7
Z0MAG	Zero-Sequence Line Impedance Magnitude (0.05–255 Ω secondary)	12.88
Z0ANG	Zero-Sequence Line Impedance Angle (5.00–90 degrees)	73.0
EFLOC	Fault Location (Y, N)	Y
LL	Line Length (0.10–999)	100.00
Relay Configuration (Group)		
E21P	Mho Phase Distance Zones (N, 1–5)	3
E21MG	Mho Ground Distance Zones (N, 1–5)	3
E21XG	Quadrilateral Ground Distance Zones (N, 1–5)	N
ECVT	CVT Transient Detection	N
ESERCMP	Series-Compensated Line Logic (Y, N)	N
ECDTD	Distance Element Common Time Delay (Y, N)	Y
ESOTF	Switch-Onto-Fault (Y, N)	Y
EOOS	Out-of-Step (Y, N)	N
ELOAD	Load Encroachment (Y, N)	Y
E50P	Phase Inst./Def.-Time O/C Elements (N, 1–4)	1
E50G	Residual Ground Inst./Def.-Time O/C Elements (N, 1–4)	3
E50Q	Negative-Sequence Inst./Def.-Time O/C Elements (N, 1–4)	N
E51S	Selectable Inverse-Time O/C Elements (N, 1–3)	1
E32	Directional Control (Y, AUTO)	AUTO
ECOMM	Communications-Assisted Tripping (N, DCB, POTT, POTT2, POTT3, DCUB1, DCUB2)	DCB

Table 1.21 Settings for 345 kV Tapped TX Example (Sheet 3 of 6)

Setting	Description	Entry
EBFL1	Breaker 1 Failure Logic (N, 1, 2)	N
E25BK1	Synchronism Check for Breaker 1 (Y, N)	N
E79	Reclosing (Y, Y1, N)	N
EMANCL	Manual Closing (Y, N)	N
ELOP	Loss-of-Potential (Y, Y1, N)	Y1
EDEM	Demand Metering (N, THM, ROL)	N
EADVS	Advanced Settings (Y, N)	N
Mho Phase Distance Element Reach (Group)		
Z1P	Zone 1 Reach (OFF, 0.05–64 Ω secondary)	3.20
Z2P	Zone 2 Reach (OFF, 0.05–64 Ω secondary)	11.00
Z3P	Zone 3 Reach (OFF, 0.05–64 Ω secondary)	50.5
Mho Phase Distance Element Time Delay (Group)		
Z1PD	Zone 1 Time Delay (OFF, 0.000–16000 cycles)	OFF
Z2PD	Zone 2 Time Delay (OFF, 0.000–16000 cycles)	OFF
Z3PD	Zone 3 Time Delay (OFF, 0.000–16000 cycles)	OFF
Mho Ground Distance Element Reach (Group)		
Z1MG	Zone 1 (OFF, 0.05–64 Ω secondary)	3.20
Z2MG	Zone 2 (OFF, 0.05–64 Ω secondary)	11.00
Z3MG	Zone 3 (OFF, 0.05–64 Ω secondary)	50.5
Zero-Sequence Current Compensation Factor (Group)		
k0M1	Zone 1 ZSC Factor Magnitude (AUTO, 0.000–10)	0.750
k0A1	Zone 1 ZSC Factor Angle (–180.00 to +180 degrees)	–16.87
Ground Distance Element Time Delay (Group)		
Z1GD	Zone 1 Time Delay (OFF, 0.000–16000 cycles)	OFF
Z2GD	Zone 2 Time Delay (OFF, 0.000–16000 cycles)	OFF
Z3GD	Zone 3 Time Delay (OFF, 0.000–16000 cycles)	OFF
Distance Element Common Time Delay (Group)		
Z1D	Zone 1 Time Delay (OFF, 0.000–16000 cycles)	0.000
Z2D	Zone 2 Time Delay (OFF, 0.000–16000 cycles)	20.000
Z3D	Zone 3 Time Delay (OFF, 0.000–16000 cycles)	0.000
SOTF Scheme (Group)		
ESPSTF	Single-Pole Switch-Onto-Fault (Y, N)	N
EVRST	Switch-Onto-Fault Voltage Reset (Y, N)	Y
52AEND	52A Pole Open Time Delay (OFF, 0.000–16000 cycles)	OFF
CLOEND	CLSMON or Single Pole Open Delay (OFF, 0.000–16000 cycles)	10.000
SOTFD	Switch-Onto-Fault Enable Duration (0.500–16000 cycles)	10.000
CLSMON	Close Signal Monitor (SELOGIC Equation)	IN102
Load Encroachment (Group)		
ZLF	Forward Load Impedance (0.05–64 Ω secondary)	12.50

Table 1.21 Settings for 345 kV Tapped TX Example (Sheet 4 of 6)

Setting	Description	Entry
ZLR	Reverse Load Impedance (0.05–64 Ω secondary)	12.50
PLAF	Forward Load Positive Angle (–90.0 to +90 degrees)	45.0
NLAF	Forward Load Negative Angle (–90.0 to +90 degrees)	–45.0
PLAR	Reverse Load Positive Angle (+90.0 to +270 degrees)	135.0
NLAR	Reverse Load Negative Angle (+90.0 to +270 degrees)	225.0
Phase Instantaneous Overcurrent Pickup (Group)		
50P1P	Level 1 Pickup (OFF, 0.25–100 A secondary)	49.80
Phase Overcurrent Definite-Time Delay (Group)		
67P1D	Level 1 Time Delay (0.000–16000 cycles)	0.000
Phase Overcurrent Torque Control (Group)		
67P1TC	Level 1 Torque Control (SELOGIC Equation)	1
Residual Ground Instantaneous Overcurrent Pickup (Group)		
50G1P	Level 1 Pickup (OFF, 0.25–100 A secondary)	OFF
50G2P	Level 2 Pickup (OFF, 0.25–100 A secondary)	1.00
50G3P	Level 3 Pickup (OFF, 0.25–100 A secondary)	0.50
Residual Ground Overcurrent Definite-Time Delay (Group)		
67G2D	Level 2 Time Delay (0.000–16000 cycles)	0.000
67G3D	Level 3 Time Delay (0.000–16000 cycles)	0.000
Residual Ground Overcurrent Torque Control (Group)		
67G2TC	Level 2 Torque Control (SELOGIC Equation)	32GF
67G3TC	Level 3 Torque Control (SELOGIC Equation)	32GR
Selectable Operating Quantity Inverse-Time Overcurrent Element 1 (Group)		
51S1O	51S1 Operating Quantity (I_{An} , I_{Bn} , I_{Cn} , I_{MAXn} , I_{1L} , $3I_{2L}$, $3I_{0n}$) ^a	3I0L
51S1P	51S1 Overcurrent Pickup (0.25–16 A secondary)	0.96
51S1C	51S1 Inverse Time Overcurrent Curve (U1–U5)	U3
51S1TD	51S1 Inverse Time Overcurrent Time Dial (0.50–15.00)	2.0
51S1RS	51S1 Inverse Time Overcurrent Electromagnetic Reset (Y, N)	Y
51S1TC	51S1 Torque Control (SELOGIC Equation)	32GF
Zone/Level Direction (Group)		
DIR3	Zone/Level 3 Directional Control (F, R)	R
Directional Control (Group)		
ORDER	Ground Directional Element Priority (combine Q, V, I)	QV
E32IV	Zero-Sequence Voltage and Current Enable (SELOGIC Equation)	1
Pole-Open Detection (Group)		
EPO	Pole Open Detection (52, V)	52
SPOD	Single Pole Open Dropout Delay (0.000–60 cycles)	0.500

Table 1.21 Settings for 345 kV Tapped TX Example (Sheet 5 of 6)

Setting	Description	Entry
3POD	Three Pole Open Dropout Delay (0.000–60 cycles)	0.500
DCB Trip Scheme (Group)		
Z3XPU	Zone 3 Reverse Pickup Time Delay (0.000–16000 cycles)	1.000
Z3XD	Zone 3 Reverse Dropout Delay (0.000–16000 cycles)	5.000
21SD	Zone 2 Distance Short Delay (0.000–16000 cycles)	1.625
67SD	Level 2 Overcurrent Short Delay (0.000–16000 cycles)	1.625
BT	Block Trip Received (SELOGIC Equation)	IN103
BTXD	Block Trip Receive Extension Time (0.000–16000 cycles)	0.000
Trip Logic (Group)		
TR	Trip (SELOGIC Equation)	Z1T OR Z2T OR 51S1T
TRCOMM	Communications-Assisted Trip (SELOGIC Equation)	Z2PGS OR 67QG2S
TRSOTF	Switch-Onto-Fault Trip (SELOGIC Equation)	M2P OR Z2G OR 50P1
DTA	Direct Transfer Trip A-Phase (SELOGIC Equation)	NA
DTB	Direct Transfer Trip B-Phase (SELOGIC Equation)	NA
DTC	Direct Transfer Trip C-Phase (SELOGIC Equation)	NA
BK1MTR	Manual Trip–Breaker 1 (SELOGIC Equation)	OC1 OR PB8_PUL
ULTR	Unlatch Trip (SELOGIC Equation)	TRGTR
ULMTR1	Unlatch Manual Trip–Breaker 1 (SELOGIC Equation)	NOT (52AA1 AND 52AB1 AND 52AC1)
TOPD	Trip During Open Pole Time Delay (2.000–8000 cycles)	2.000
TULO	Trip Unlatch Option (1, 2, 3, 4)	3
Z2GTSP	Zone 2 Ground Distance Time Delay for Single-Pole Tripping (Y, N)	N
67QGSP	Zone 2 Directional Negative-Sequence/Residual Overcurrent Single-Pole Trip (Y, N)	N
TDUR1D	Single-Pole Trip Minimum Trip Duration Time Delay (2.000–8000 cycles)	6.000
TDUR3D	Three-Pole Trip Minimum Trip Duration Time Delay (2.000–8000 cycles)	9.000
E3PT	Three-Pole Trip Enable (SELOGIC Equation)	1
E3PT1	Breaker 1 Three-Pole Trip (SELOGIC Equation)	1
ER	Event Report Trigger (SELOGIC Equation)	R_TRIG M2P OR R_TRIG Z2G OR R_TRIG 51S1 OR R_TRIG M3P OR R_TRIG Z3G
Main Board (Outputs)		
OUT101	(SELOGIC Equation)	3PT

Table 1.21 Settings for 345 kV Tapped TX Example (Sheet 6 of 6)

Setting	Description	Entry
OUT102	(SELOGIC Equation)	NSTRT AND NOT STOP OR DSTRT
OUT103	(SELOGIC Equation)	STOP OR 3PT

^a Parameter n is 1 for BK1, 2 for BK2, and L for Line.

EHV Parallel 230 kV Underground Cables Example

This application example presents an underground cable system with double-ended 230 kV parallel cables (see [Figure 1.19](#)). SEL-421 relays protect each end of the first circuit. This example explains settings calculations for the SEL-421 at Station S that protects Cable 1 between Station S and Station R.

The SEL-421 uses communications-assisted high-speed tripping to provide protection for faults along the 230 kV underground cable.

The two 230 kV underground cables run from Station S to Station R. Each circuit consists of three single-phase cables, each having an oil-filled copper conductor (hollow core). The cables are insulated with impregnated paper and have a lead sheath to prevent intrusion of moisture and to withstand fluid pressure. The cables are also grounded at both ends. Depending on the nature of a ground fault, ground fault current can return via the sheath, the ground, or both the sheath and ground.

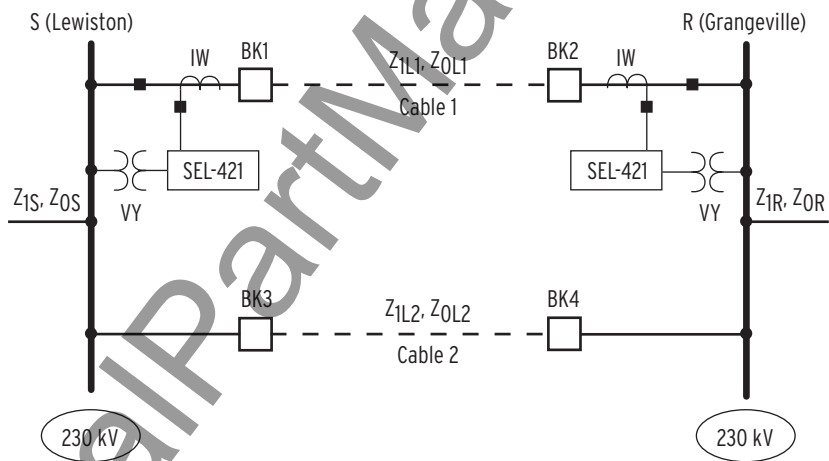


Figure 1.19 230 kV Parallel Underground Cables

Power System Data

[Table 1.22](#) lists the power system data for this application example. Substitute the values and parameters that correspond to your system when you set the relay, using this example as a guide.

Table 1.22 System Data–230 kV Parallel Underground Cables (Sheet 1 of 2)

Parameter	Value
Nominal System Line-to-Line Voltage	230 kV
Nominal Relay Current	5 A secondary
Nominal Frequency	60 Hz
Cable Length	25 miles
Cable Impedances:	
$Z_{1L1} = Z_{1L2}$	4.78 Ω $\angle 42.5^\circ$ primary
Z_{0L1} (sheath return) = Z_{0L2} (sheath return)	9.45 Ω $\angle 17.4^\circ$ primary
Z_{0L1} (ground return) = Z_{0L2} (ground return)	91.4 Ω $\angle 84.9^\circ$ primary
Z_{0L1} (sheath and ground return) = Z_{0L2} (sheath and ground return)	9.58 Ω $\angle 21.7^\circ$ primary

Table 1.22 System Data—230 kV Parallel Underground Cables (Sheet 2 of 2)

Parameter	Value
Cable Admittances: $Y_{1L1} = Y_{1L2}$ $Y_{0L1} = Y_{0L2}$	$j6.71 \cdot 10^{-6}$ S primary (susceptance) $j6.71 \cdot 10^{-6}$ S primary (susceptance)
Source S Impedances: $Z_{1S} = Z_{0S}$	$50 \Omega \angle 87^\circ$ primary
Source R Impedances: $Z_{1R} = Z_{0R}$	$35 \Omega \angle 87^\circ$ primary
PTR (potential transformer ratio)	230 kV:115 V = 2000
CTR (current transformer ratio)	1000:5 = 200
Phase Rotation	ABC

Convert the power system impedances from primary to secondary so you can later calculate protection settings. [Table 1.23](#) lists the corresponding secondary quantities. Convert the impedances to secondary ohms as follows:

$$k = \frac{CTR}{PTR} = \frac{200}{2000} = 0.1 \quad \text{Equation 1.51}$$

$$\begin{aligned} Z_{1L1}(\text{secondary}) &= k \cdot Z_{1L1}(\text{primary}) \\ &= 0.10 \cdot 4.78 \Omega \angle 42.5^\circ \\ &= 0.48 \Omega \angle 42.5^\circ \end{aligned} \quad \text{Equation 1.52}$$

Table 1.23 Secondary Impedances

Parameter	Value
Cable Impedances: $Z_{1L1} = Z_{1L2}$ $Z_{0L1}(\text{sheath return only}) = Z_{0L2}(\text{sheath return only})$ $Z_{0L1}(\text{ground return only}) = Z_{0L2}(\text{ground return only})$ $Z_{0L1}(\text{sheath and ground return}) = Z_{0L2}(\text{sheath and ground return})$	$0.48 \Omega \angle 42.5^\circ$ secondary $0.95 \Omega \angle 17.4^\circ$ secondary $9.14 \Omega \angle 84.9^\circ$ secondary $0.96 \Omega \angle 21.7^\circ$ secondary
Cable Admittance: $Y_{1L1} = Y_{1L2}$ $Y_{0L1} = Y_{0L2}$	$6.71 \cdot 10^{-5}$ S $\angle 90^\circ$ secondary $6.71 \cdot 10^{-5}$ S $\angle 90^\circ$ secondary
Source S Impedances: $Z_{1S} = Z_{0S}$	$5.0 \Omega \angle 87^\circ$ secondary
Source R Impedances: $Z_{1R} = Z_{0R}$	$3.5 \Omega \angle 87^\circ$ secondary

The maximum load current of 777 A primary occurs when the parallel cable is out of service.

Application Summary

This particular example is for a single circuit breaker, three-pole tripping application with the following functions:

- POTT (permissive overreaching transfer trip) scheme

- Three zones of phase (mho) and ground (quadrilateral) distance protection
 - Zone 1—forward-looking, provides instantaneous underreaching protection
 - Zone 2—forward-looking, provides communications-assisted and time-delayed tripping
 - Zone 3—reverse-looking, prevents unwanted tripping during current reversals
- Two levels of negative-sequence directional overcurrent protection
 - Level 2—forward-looking, provides communications-assisted high-speed tripping
 - Level 3—reverse-looking, prevents unwanted tripping during current reversals
- Inverse-time directional negative-sequence overcurrent backup protection
- SOTF protection (fast tripping when the circuit breaker closes)

Relay settings that are not mentioned in this example do not apply to this application example.

Global Settings

General Global Settings

The SEL-421 has settings for identification. These settings allow you to identify the following:

- Station (SID)
- Relay (RID)
- Circuit Breaker 1 (BID1)

You can enter as many as 40 characters per identification setting.

SID := **LEWISTON -- 230 kV** Station Identifier (40 characters)

RID := **SEL-421 Relay** Relay Identifier (40 characters)

Configure the SEL-421 for the one circuit breaker that this particular application uses:

NUMBK := **1** Number of Breakers in Scheme (1, 2)

BID1 := **Circuit Breaker 1** Breaker 1 Identifier (40 characters)

Set the relay for nominal frequency and phase rotation.

NFREQ := **60** Nominal System Frequency (50, 60 Hz)

PHROT := **ABC** System Phase Rotation (ABC, ACB)

Current and Voltage Source Selection

The voltage and current source selection is for one circuit breaker. The relay derives the line current source from current input IW when you set ESS to N.

ESS := **N** Current and Voltage Source Selection (Y, N, 1, 2, 3, 4)

Figure 1.20 illustrates the current and voltage sources for this particular application. The relay uses potential input VY and current input IW for line relaying.

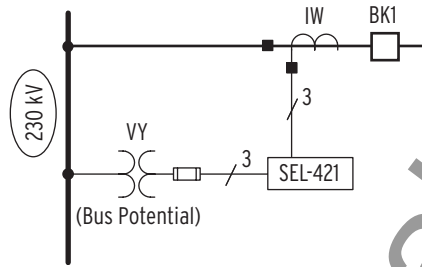


Figure 1.20 Circuit Breaker Arrangement at Station S, Cable 1

Breaker Monitor

Circuit Breaker Configuration

Set the Circuit Breaker BK1 type for a three-pole trip circuit breaker.

BK1TYP := **3** Breaker 1 Trip Type (Single-Pole = 1, Three-Pole = 3)

Circuit Breaker 1 Inputs

The SEL-421 uses a normally open auxiliary contact (52A) from the circuit breaker to determine whether the circuit breaker is open or closed.

52AA1 := **IN101** N/O Contact Input—BK1 (SELOGIC Equation)

Group Settings

Line Configuration

The SEL-421 has four transformer turns ratio settings that convert the secondary potentials and currents the relay measures to the corresponding primary values. These settings are the potential transformer and current transformer ratios (PTRY, PTRZ, CTRW, and CTRX). Use the VY potential input for line relaying; these come from the bus potentials (see Figure 1.20). Use the IW current input for line current. Relay setting VNOMY is the nominal secondary line-to-line voltage of the potential transformers.

PTRY := **2000** Potential Transformer Ratio—Input Y (1–10000)

VNOMY := **115** PT Nominal Voltage (L–L)—Input Y (60–300 V secondary)

CTRW := **200** Current Transformer Ratio—Input W (1–50000)

Enter the secondary values of the positive-sequence impedance of the protected cable. See Table 1.23 for the secondary cable impedances.

Z1MAG := **0.48** Positive-Sequence Line Impedance Magnitude
(0.05–255 Ω secondary)

Z1ANG := **42.5** Positive-Sequence Line Impedance Angle (5.00–90 degrees)

Enter the secondary values of the zero-sequence impedance of the protected cable. The zero-sequence impedance should correspond to the parallel sheath and ground fault return path (see $Z0_{L1}(\text{sheath and ground})$ in Table 1.23).

$$Z0MAG = k \cdot |Z0_{L1}(\text{sheath and ground})| \quad \text{Equation 1.53}$$

Where:

k = the result of [Equation 1.51](#)

$$ZOMAG = 0.1 \cdot |Z_{0L1(\text{sheath and ground})}| = 0.1 \cdot |9.58 \Omega \angle 21.7^\circ| = 0.96 \Omega$$

$ZOMAG := 0.96$ Zero-Sequence Line Impedance Magnitude
(0.05–255 Ω secondary)

$ZOANG := 21.7$ Zero-Sequence Line Impedance Angle (5.00–90 degrees)

Enable the fault locator.

$EFLOC := Y$ Fault Location (Y, N)

The LL setting is the line length. This value has no defined unit; you can set the line length in miles, kilometers, ohms, etc. Set the length in miles.

$LL := 25.00$ Line Length (0.10–999)

The relay fault locator uses the values you enter for $Z1MAG$, $Z1ANG$, $ZOMAG$, $ZOANG$, and LL .

Relay Configuration

You can select from zero to five phase mho ($E21P$), ground mho ($E21MG$), and ground quadrilateral ($E21XG$) distance zones. The number of zones per type of distance protection is independently selectable. Select only the number of zones you need. For this application example, use three zones of mho phase distance protection and three zones of quadrilateral ground distance protection.

$E21P := 3$ Mho Phase Distance Zones (N, 1–5)

$E21MG := N$ Mho Ground Distance Zones (N, 1–5)

$E21XG := 3$ Quadrilateral Ground Distance Zones (N, 1–5)

You do not need CVT (capacitive voltage transformer) transient detection because PTs with wound windings are used for this particular application example.

$ECVT := N$ CVT Transient Detection (Y, N)

The underground cable is not series-compensated.

$ESERCMP := N$ Series-Compensated Line Logic (Y, N)

You can select a common time delay or an independent time delay per zone for phase and ground distance protection. If you choose independent timing, evolving faults (such as those changing from single phase to multiphase) cause the timer to reset and result in additional delay. Select common time delay for this application.

$ECDTD := Y$ Distance Element Common Time Delay (Y, N)

The SOTF (switch-onto-fault) protection logic permits tripping by specified protection elements for a settable time after the circuit breaker closes.

$ESOTF := Y$ Switch-Onto-Fault (Y, N)

Do not enable the out-of-step logic for this application example.

$E00S := N$ Out-of-Step (Y, N)

Do not enable the load-encroachment logic; the minimum apparent load impedance is outside the mho phase distance characteristics.

$ELOAD := N$ Load Encroachment (Y, N)

NOTE: The SEL-421-1 and the SEL-421-2 do not provide series-compensated line protection logic.

Use Level 1 high-set instantaneous phase overcurrent element for SOTF protection.

E50P := **1** Phase Instantaneous/Definite-Time Overcurrent Elements (N, 1–4)

This application does not require residual ground overcurrent protection.

E50G := **N** Residual Ground Instantaneous/Definite-Time Overcurrent Elements (N, 1–4)

Enable three levels of negative-sequence overcurrent protection. Use these negative-sequence current level detectors in conjunction with the communications-assisted tripping scheme.

E50Q := **3** Negative-Sequence Instantaneous/Definite-Time Overcurrent Elements (N, 1–4)

Use inverse-time overcurrent protection to provide backup protection for high-resistance ground faults. The 51S1 element provides backup protection for unbalanced faults if both the communications-assisted and step distance protection fail to operate.

E51S := **1** Selectable Operating Quantity Inverse-Time Overcurrent Element (N, 1–3)

The relay automatically calculates all of the ground directional elements settings when you select AUTO.

E32 := **AUTO** Directional Control (Y, AUTO)

Use the POTT trip scheme to quickly clear faults internal to the protected line.

ECOMM := **POTT** Communications-Assisted Tripping (N, DCB, POTT, POTT2, POTT3, DCUB1, DCUB2)

Fuses or molded case circuit breakers often protect potential transformers. Operation of one or more fuses, or molded case circuit breakers, results in a loss of polarizing potential inputs to the relay. Loss of one or more phase voltages prevents the relay from properly determining fault distance or direction.

Occasional loss-of-potential to the distance relay, while unavoidable, is detectable. When the relay detects a loss-of-potential condition, the relay can block distance element operation, block or enable forward-looking directional overcurrent elements, and issue an alarm for any true loss-of-potential condition.

If line-side PTs are used, the circuit breaker(s) must be closed for the LOP logic to detect a loss-of-potential condition. Therefore, if three-phase potential to the relay is lost while the circuit breaker(s) is open (e.g., the PT fuses are removed while the line is de-energized), the relay cannot detect a loss-of-potential condition when the circuit breaker(s) closes again. At circuit breaker closing, the relay can detect one or two missing potentials that occurred while the circuit breaker was open. See [Loss-of-Potential Logic on page R.1.26](#) for more information.

[Table 1.24](#) lists the three choices for enabling LOP protection.

Table 1.24 LOP Enable Options

Option	Description
N	The LOP logic operates but does not disable voltage-polarized directional elements, distance elements, and forward-looking directional overcurrent elements. Use LOP in this case for alarm only.
Y	The relay disables all voltage-polarized directional elements and distance elements, but enables forward-looking directional overcurrent elements. These forward-looking directional overcurrent elements effectively become nondirectional and provide overcurrent protection during a loss-of-potential condition.
Y1	The relay disables all voltage-polarized directional elements and distance elements. The relay also disables the overcurrent elements controlled by the voltage-polarized directional elements.

Set ELOP to Y1 for this application example. This choice reduces the chances of false tripping because of a loss-of-potential condition.

ELOP := Y1 Loss-of-Potential (Y, Y1, N)

Enable the Advanced Settings so you can properly set the zero-sequence compensation factors.

EADVS := Y Advanced Settings (Y, N)

Phase Distance Elements (21P)

Mho Phase Distance Element Reach

Employ each zone of distance protection as follows:

- Zone 1—Instantaneous underreaching tripping
- Zone 2—Forward-looking fault detector for the POTT scheme and backup time delayed tripping
- Zone 3—Current reversal guard for the POTT scheme, echo tripping, and weak infeed logic

Zone 1 Phase Distance Element Reach. Zone 1 phase distance protection provides instantaneous protection for phase-to-phase, phase-to-phase-to-ground, and three-phase faults in the first 80 percent of the cable. Errors in the current transformers, potential transformers, modeled cable data, and fault study data do not permit a Zone 1 setting for 100 percent of the cable; unwanted tripping could occur for faults just beyond the remote end of the cable.

Set Zone 1 phase distance protection to 80 percent of the cable positive-sequence impedance.

$$Z1P = 0.8 \cdot Z_{1L1} = 0.8 \cdot 0.48 \, \Omega = 0.38 \, \Omega$$

Z1P := 0.38 Zone 1 Reach (OFF, 0.05–64 Ω secondary)

Zone 2 Phase Distance Element Reach. Zone 2 phase distance protection must have adequate reach to detect all phase-to-phase, phase-to-phase-to-ground, and three-phase faults along the protected cable. Set Zone 2 phase distance protection to 120 percent of the cable positive-sequence impedance. With this reach, high-speed tripping occurs via the communications channel for faults located in the last 20 percent of the cable.

$$Z2P = 1.2 \cdot Z_{1L1} = 1.2 \cdot 0.48 \, \Omega = 0.58 \, \Omega$$

Z2P := 0.58 Zone 2 Reach (OFF, 0.05–64 Ω secondary)

Zone 3 Phase Distance Element Reach. Zone 3 phase distance protection must have adequate reach to prevent unwanted tripping during current reversals when the parallel line is in service because this example uses a POTT scheme. So that Zone 3 has greater fault coverage than Zone 2 at the remote terminal, set the reach to remote Zone 2 and rely upon the length of the protected cable as the safety margin.

$$Z3P = Z2P = 0.58 \, \Omega$$

$Z3P := 0.58$ Zone 3 Reach (OFF, 0.05–64 Ω secondary)

Ground Distance Elements (21XG)

Quadrilateral Ground Distance Element Reach

The main advantage of ground distance protection is that Zone 1 provides instantaneous protection independent of the communications channel. Typically cable faults have little fault resistance; it is advantageous to conservatively set the resistance reach for quadrilateral ground distance protection. Supplement quadrilateral ground distance protection with directional negative-sequence overcurrent elements. The directional negative-sequence overcurrent elements employed in the communications-assisted tripping scheme provide excellent resistive coverage for high-resistance ground faults (e.g., a contaminated pothead flashes over).

The reactive reach for each zone of quadrilateral ground distance protection lies on the relay characteristic angle (Z1ANG), rather than on the ordinate (reactance) of the impedance plane (see [Figure 1.21](#)).

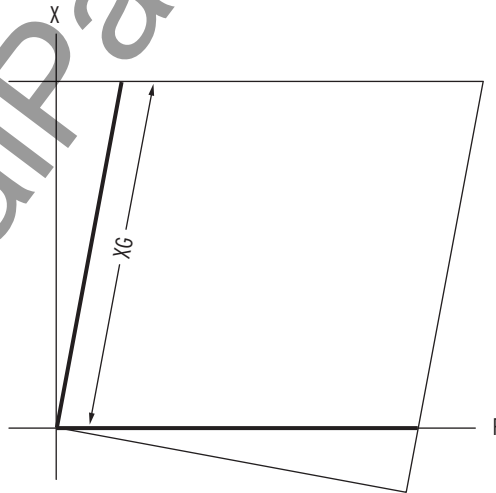


Figure 1.21 Quadrilateral Ground Distance Element Reactive Reach Setting

Employ each zone of distance protection as follows:

- Zone 1—Instantaneous underreaching direct tripping
- Zone 2—Forward-looking tripping elements for the POTT scheme and backup tripping
- Zone 3—Current reversal guard for the POTT scheme, echo tripping, and weak infeed logic

Zone 1 Reactance. The reach of the Zone 1 reactance measurement of the quadrilateral ground distance elements must meet the same requirement as that for Zone 1 mho phase distance protection; the reach setting can be no greater than 80 percent of the cable.

$$X_{G1} = 0.8 \cdot |Z_{1L1}| = 0.8 \cdot 0.48 \, \Omega = 0.38 \, \Omega$$

$$X_{G1} := \mathbf{0.38} \text{ Zone 1 Reactance (OFF, 0.05–64 } \Omega \text{ secondary)}$$

Zone 1 Resistance. Find R_{G1} (Zone 1 Resistance) from the per-unit reach m of the Zone 1 reactance. Use [Equation 1.54](#), which is Equation (3) in *Appendix A—Quadrilateral Reactive Reach Versus Resistive Reach Setting Guideline* from the paper *Digital Communications for Power System Protection: Security, Availability, and Speed* (go to www.selinc.com for a copy of this paper):

$$m = 1 - \frac{R}{X_{1L1} \cdot 20} \quad \text{Equation 1.54}$$

Where:

m = per-unit reach of X_{G1}

R = R_{G1} (the Zone 1 resistance)

X_{1L1} = positive-sequence transmission line reactance

X_{G1} is set at 80 percent of the underground cable (i.e., $m = 0.8$ per-unit); the positive-sequence reactance of the cable, X_{1L1} , is $0.323 \, \Omega$ secondary (from the rectangular form of Z_{1L1} in [Table 1.23](#)).

$$\begin{aligned} Z_{1L1} &= R_{1L1} + jX_{1L1} \\ &= 0.48 \, \Omega \angle 42.5^\circ \\ &= 0.354 + j0.323 \, \Omega \end{aligned}$$

Rearrange [Equation 1.54](#) to calculate R_{G1} :

$$\begin{aligned} R_{G1} &= (1 - m) \cdot 20 \cdot X_{1L1} \\ &= (1 - 0.8) \cdot 20 \cdot 0.323 \, \Omega \\ &= 1.29 \, \Omega \end{aligned} \quad \text{Equation 1.55}$$

$$R_{G1} := \mathbf{1.29} \text{ Zone 1 Resistance (0.05–50 } \Omega \text{ secondary)}$$

Zone 2 Reactance. Zone 2 quadrilateral ground distance reach must meet the same requirement as that for Zone 2 mho phase distance protection; the reach setting is 120 percent of the cable.

$$X_{G2} = 1.2 \cdot |Z_{1L1}| = 1.2 \cdot 0.48 = 0.58 \, \Omega$$

$$X_{G2} := \mathbf{0.58} \text{ Zone 2 Reactance (OFF, 0.05–64 } \Omega \text{ secondary)}$$

Zone 2 Resistance. Use the following formula to set R_{G2} :

$$\begin{aligned} R_{G2} &= X_{G2} \cdot \frac{R_{G1}}{X_{G1}} \\ &= 0.58 \, \Omega \cdot \frac{1.29}{0.38 \, \Omega} \\ &= 0.58 \, \Omega \cdot 3.4 \\ &= 1.97 \, \Omega \end{aligned} \quad \text{Equation 1.56}$$

$$R_{G2} := \mathbf{1.97} \text{ Zone 2 Resistance (0.05–50 } \Omega \text{ secondary)}$$

Zone 3 Reactance. Zone 3 quadrilateral ground distance reach must meet the same requirement as that for Zone 3 mho phase distance protection; it equals Zone 2 reach.

$$X_{G3} = X_{G2} = 0.58 \, \Omega$$

$XG3 := 0.58$ Zone 3 Reactance (OFF, 0.05–64 Ω secondary)

Zone 3 Resistance. Set the Zone 3 resistance reach equal to Zone 2 resistance reach and multiply the reach by 125 percent for a safety margin to account for external resistive ground faults.

$$RG3 = 1.25 \cdot RG2 = 1.25 \cdot 1.97 = 2.46 \Omega$$

$RG3 := 2.46$ Zone 3 Resistance (0.05–50 Ω secondary)

Quadrilateral Ground Polarizing Quantity

Advanced Settings are enabled, so you must enter two final settings for the quadrilateral ground distance protection. With setting $XGPOL$, you can choose the polarizing quantity for the quadrilateral ground distance protection. You can choose either negative-sequence current (I_2) or zero-sequence current (I_0). Choose the appropriate quantity to reduce overreach and underreach of the reactance line. The reactance line can underreach or overreach during high-resistance single phase-to-ground faults because of nonhomogeneous negative-sequence or zero-sequence networks, and prefault load flow.

Figure 1.22 shows the network to determine negative-sequence or zero-sequence homogeneity.

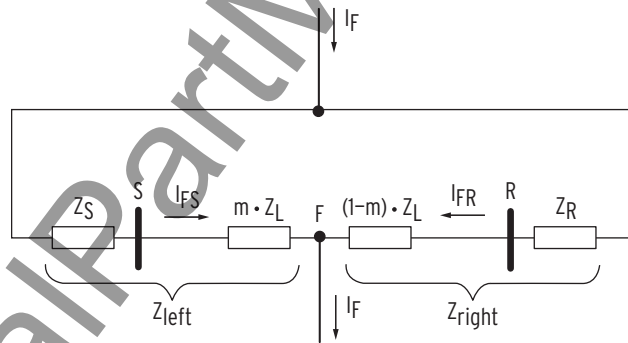


Figure 1.22 Circuit to Determine Network Homogeneity

Z_{left} is the total impedance up to the fault (F) on the left side of the fault location, while Z_{right} is the total impedance up to the fault on the right side of the network. A network is homogeneous with respect to the particular fault location if Equation 1.57 is satisfied:

$$\frac{X_{left}}{R_{left}} = \frac{X_{right}}{R_{right}} \quad \text{Equation 1.57}$$

Use Equation 1.58 and Equation 1.59 to determine the zero-sequence and negative-sequence homogeneity:

$$T_0 = \text{ARG} \left(\frac{Z_{0S} + Z_{0L} + Z_{0R}}{(1-m) \cdot Z_{0L} + Z_{0R}} \right) \quad \text{Equation 1.58}$$

$$T_2 = \text{ARG} \left(\frac{Z_{1S} + Z_{1L} + Z_{1R}}{(1-m) \cdot Z_{1L} + Z_{1R}} \right) \quad \text{Equation 1.59}$$

The values T_0 and T_2 represent how much the apparent fault impedance measured by XAG tilts up or down (electrical degrees) due to the nonhomogeneity of the corresponding network. Figure 1.23 illustrates the possible tilt situations caused by a nonhomogeneous network.

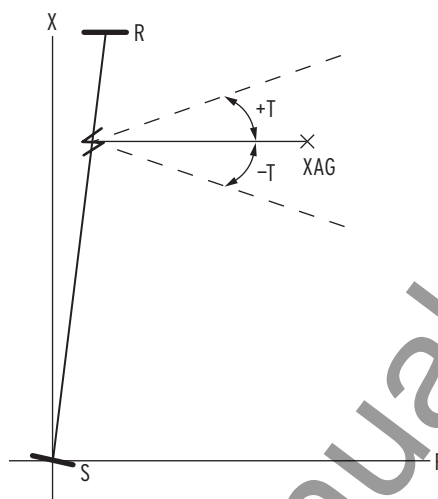


Figure 1.23 Apparent Fault Impedance Resulting From Nonhomogeneity

Table 1.25 provides the results of Equation 1.58 and Equation 1.59 for both the negative-sequence and zero-sequence networks. Remember that T_0 depends on the return path of the ground fault; i.e., sheath, ground, or a parallel combination of both. The distance to fault is assumed to be 100 percent (m equals 1).

Table 1.25 Tilt Resulting From Nonhomogeneity

Angle	T_2	T_0 (sheath)	T_0 (ground)	T_0 (ground and sheath)
Negative-Sequence Network	-2.2°			
Zero-Sequence Network		-5.8°	-1.1°	-5.6°

The negative-sequence network is more homogeneous than the zero-sequence network when compared with two of the three corresponding cable zero-sequence impedances. Choose negative-sequence current for polarizing the quadrilateral ground distance protection.

$XGPOL := I_2$ Quadrilateral Ground Polarizing Quantity (I_2 , IG)

Selection I_2 indicates that the negative-sequence current flowing in the cable is the polarizing quantity for the reactance line.

Nonhomogeneous Correction Angle

TANG, the nonhomogeneous angle setting, also helps prevent overreach or underreach for ground faults at a specific fault location by compensating the angle of the reactance line.

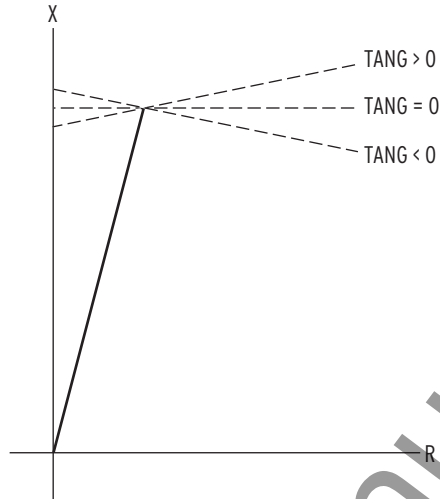


Figure 1.24 Nonhomogeneous Angle Setting

Set TANG to prevent the Zone 1 quadrilateral ground distance reactance measurement from overreaching for ground faults located at the remote bus. Use the result from [Equation 1.59](#) (T_2 in [Quadrilateral Ground Polarizing Quantity](#) on page A.1.95).

TANG := -2.2 Nonhomogeneous Correction Angle (-40.0 to +40.0 degrees)

Zero-Sequence Current Compensation Factors

Zero-sequence current compensation helps keep the phase and ground distance elements at the same reach if you set the phase reach and the ground reach equal per zone (e.g., Z1P = XG1). Ground distance elements should measure fault impedance in terms of positive-sequence impedance only.

The relay has three zero-sequence current compensation factors (k01, k0, and k0R). The Zone 1 ground distance element has a dedicated zero-sequence current compensation factor (k01). Advanced Settings are enabled for this particular example (EADVS := Y), so you must set two additional independent zero-sequence current compensation factors, one for forward-looking zones (k0) and one for reverse-looking zones (k0R).

The zero-sequence cable impedance depends on the return path of the ground fault current during ground faults. The zero-sequence current compensation factors must be set so the Zone 1 ground distance elements do not see ground faults external to the protected cable, while Zone 2 and Zone 3 ground distance elements must see all internal ground faults.

The SEL-421 uses [Equation 1.60](#) to calculate the A-phase-to-ground distance reactance measurement.

$$X_{AG} = \frac{\text{Im}[V_A \cdot (I_{POL} \cdot e^{j \cdot TANG})^*]}{\text{Im}[z1 \cdot (I_A + k01 \cdot 3I_0) \cdot (I_{POL} \cdot e^{j \cdot TANG})^*]} \quad \text{Equation 1.60}$$

Where:

V_A = A-phase-to-ground voltage measured at Station S

I_A = A-phase current measured through Cable 1 at Station S

$3I_0$ = zero-sequence current measured through Cable 1 at Station S

I_{POL} = negative-sequence or zero-sequence current measured through Cable 1 at Station S (based on the XGPOL setting, see [Quadrilateral Ground Polarizing Quantity on page A.1.95](#))

TANG = nonhomogeneous correction angle

$\text{Im}[\]$ = imaginary part

* = complex conjugate

$$z1 = \frac{Z_1}{|Z_1|} \quad \text{Equation 1.61}$$

Where:

Z_1 = Cable 1 positive-sequence impedance

$$k01 = \frac{Z_{0L1} - Z_{1L1}}{3 \cdot Z_{1L1}} \quad \text{Equation 1.62}$$

k01. You can set k01 based on three values for the zero-sequence cable impedance: $Z_{0L1}(\text{sheath})$, $Z_{0L1}(\text{ground})$, or $Z_{0L1}(\text{sheath and ground})$. Select the zero-sequence cable impedance that prevents Zone 1 ground distance element overreach.

To determine the best setting for k01, place an A-phase-to-ground fault at Station R with the parallel cable out of service. Find the ground distance reactance measurement XAG that does not overreach for this fault. Perform this evaluation using $Z_{0L1}(\text{sheath and ground})$ and $Z_{0L1}(\text{sheath})$ for the zero-sequence cable impedance. There is no need to determine the XAG measurement for ground faults at the remote terminal when k01 is set based on $Z_{0L1}(\text{ground})$ because severe overreach occurs in all cases for the ground-only path.

Sheath and Ground Return Path. First apply [Equation 1.60](#) with k01 based on $Z_{0L1}(\text{sheath and ground})$ (k01 equal to $0.374 \angle -39.2^\circ$). This is the most common ground fault return path. Set TANG equal to zero and assume that I_{POL} is equal to negative-sequence current (i.e., XGPOL is equal to I2).

[Table 1.26](#) lists the corresponding XAG (reactance of the phase-to-ground fault) calculations for the remote single phase-to-ground fault for each of the three possible zero-sequence cable impedances when the k01 calculation is based on the parallel return path. Use [Equation 1.63](#) to determine the amount of overreach/underreach:

$$\text{Overreach/Underreach} = \frac{XAG}{|Z_{1L1}|} \cdot 100\% \quad \text{Equation 1.63}$$

Table 1.26 XAG Measurement for Remote AG Fault
($k_{01} = 0.374 \angle -39.2^\circ$, sheath and ground return path)

Calculation	$Z_{OL1}(\text{sheath})$	$Z_{OL1}(\text{ground})$	$Z_{OL1}(\text{sheath and ground})$
XAG (secondary ohms)	0.45 Ω	3.04 Ω	0.48 Ω
Overreach/Underreach ^a	93.8% (O)	633% (U)	100%

^a O indicates overreach, U indicates underreach.

The results in [Table 1.26](#) show that the XAG calculation overreaches by 6.2 percent (i.e., $100\% - 93.8\% = 6.2\%$) if the sheath is the return path for the ground fault; therefore, you should not set k_{01} based on the sheath and ground (parallel) return path.

Sheath Return Path. [Table 1.27](#) lists the corresponding XAG (reactance of the phase-to-ground fault) calculations for the remote single phase-to-ground fault for each of the three possible zero-sequence cable impedances when the k_{01} calculation is based on the sheath return path.

Table 1.27 XAG Measurement for Remote AG Fault
($k_{01} = 0.385 \angle -46.7^\circ$, sheath return path)

Calculation	$Z_{OL1}(\text{sheath})$	$Z_{OL1}(\text{ground})$	$Z_{OL1}(\text{sheath and ground})$
XAG (secondary ohms)	0.48 Ω	3.17 Ω	0.51 Ω
Overreach/Underreach ^a	100%	660% (U)	106% (U)

^a O indicates overreach, U indicates underreach.

The results in [Table 1.27](#) show that there is no Zone 1 ground distance overreach. Therefore, set k_{01} based on $Z_{OL1}(\text{sheath})$.

$k_{0M1} := 0.385$ Zone 1 ZSC Factor Magnitude (AUTO, 0.000–10)

$k_{0A1} := -46.7$ Zone 1 ZSC Factor Angle (–180.0 to +180.0 degrees)

k_0 and k_{0R} . Set the forward (k_0) and reverse (k_{0R}) zero-sequence current compensation factors so that the overreaching zones of ground distance protection do not underreach for any internal ground fault. Put both parallel cables in service. [Table 1.28](#) lists the corresponding XAG calculations for a remote (Station R) ground fault for each of the three possible zero-sequence cable impedances when the k_0 calculation is based on $Z_{OL1}(\text{ground})$. (Replace k_{01} with k_0 or replace k_{01} with k_{0R} in [Equation 1.60](#) and [Equation 1.62](#).)

Table 1.28 XAG Measurement for Remote AG Fault
($k_0 = 6.105 \angle 44.5^\circ$, ground return path)

Calculation	$Z_{OL1}(\text{sheath})$	$Z_{OL1}(\text{ground})$	$Z_{OL1}(\text{sheath and ground})$
XAG (secondary ohms)	0.04 Ω	0.48 Ω	0.05 Ω
Overreach/Underreach ^a	8.33% (O)	100%	10.4% (O)

^a O indicates overreach, U indicates underreach

The results of [Table 1.28](#) show that the XAG calculation does not underreach when you set k_0 based on the ground return path. Set k_0 and k_{0R} based on $Z_{OL1}(\text{ground})$.

$k_{0M} := 6.105$ Forward Zones ZSC Factor Magnitude (0.000–10)

$k_{0A} := 44.5$ Forward Zones ZSC Factor Angle (–180.0 to +180.0 degrees)

$k_{0MR} := 6.105$ Reverse Zones ZSC Factor Magnitude (0.000–10)

$k_{0AR} := 44.5$ Reverse Zones ZSC Factor Angle (–180.0 to +180.0 degrees)

Distance Element Common Time Delay

Set the operation time delay of both the phase and ground distance elements.

Zone 1

There is no need to delay Zone 1 distance protection; the relay trips instantaneously for faults in Zone 1.

$Z1D = 0.000$ Zone 1 Time Delay (OFF, 0.000–16000 cycles)

Zone 2

Zone 2 distance protection must coordinate with downstream Zone 1 distance protection plus the downstream circuit breaker operating time and a safety margin. A typical Zone 2 phase and ground distance time delay setting is 20 cycles.

$Z2D := 20.000$ Zone 2 Time Delay (OFF, 0.000–16000 cycles)

Short Adjacent Lines. You do not need to consider the following fault current return path scenario for this application example; this information is provided here for applications with short adjacent lines. [Figure 1.25](#) illustrates an important consideration if you apply time-delayed Zone 2 ground distance protection to backup downstream Zone 1 ground distance protection.

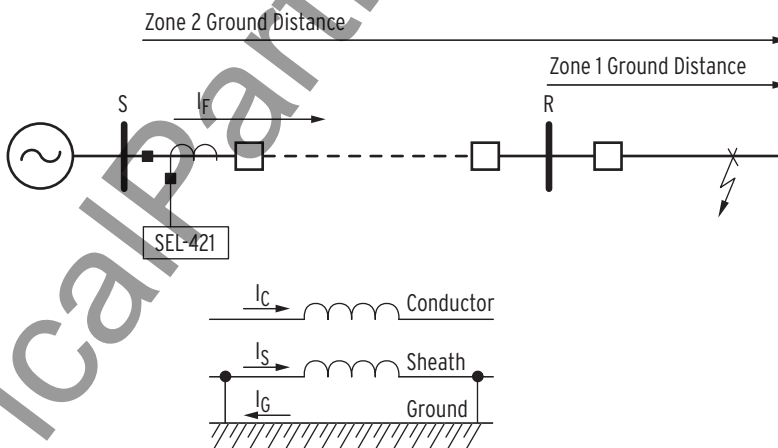


Figure 1.25 External Ground Fault

Fault current flows through the sheath and ground with respect to the cable because the sheath is grounded at each end during external ground faults. However, because you must make sure that Zone 2 ground distance elements see all ground faults at remote Station R, the $k0$ setting was for the ground path only. Therefore, Zone 2 ground distance protection may overreach for external ground faults, especially for the case of a short adjacent line. The solution is to increase Zone 2 time delay.

Zone 3

Zone 3 has reverse-looking distance protection that you do not need to apply for tripping in this application. Set Zone 3 for zero time delay.

$Z3D := 0.000$ Zone 3 Time Delay (OFF, 0.000–16000 cycles)

SOTF Protection

SOTF (Switch-Onto-Fault) logic is enabled when the circuit breaker closes. This logic provides protection for a short duration (setting SOTFD) until other protection (such as tripping from SELOGIC control equations TR and TRCOMM) is available. The TRSOTF SELOGIC control equation defines which protection elements cause the relay to trip when the SOTF scheme is active. Assertion of the protection elements assigned to TRSOTF during the SOTFD time causes the relay to trip instantaneously.

Use nondirectional overcurrent protection to clear close-in faults. Also use instantaneous overreaching distance protection to clear faults along the line. Assign instantaneous Zone 2 mho phase and ground distance protection plus Level 1 phase overcurrent element to TRSOTF.

TRSOTF := **M2P OR Z2G OR 50P1** Switch-Onto-Fault Trip (SELOGIC Equation)

Voltage Reset

You can configure the logic so the SOTF enable duration resets within at least 5 cycles after it first asserted but before the SOTFD timer expires. To quickly reset the SOTF period before this time, the relay must sense that the positive-sequence voltage V_1 is greater than 85 percent of nominal voltage.

Use setting EVRST (Switch-Onto-Fault Voltage Reset) to enable fast reset. The advantage of resetting SOTF protection quickly is that unwanted tripping does not occur for subsequent faults external to the remote terminals during the SOTF period; these trips can occur if you set instantaneous Zone 2 distance protection elements in the TRSOTF SELOGIC control equation. Enable the voltage reset option.

EVRST := **Y** Switch-Onto-Fault Voltage Reset (Y, N)

SOTF Initiation

The SOTF logic asserts via one or both of the following methods:

- A change in the normally open auxiliary contact 52A status showing that the circuit breaker has just opened
- Assertion of the relay control input assigned to the circuit breaker close bus

The 52A method initiation works well for both single and multiple circuit breaker applications and does not require an input from the close bus. However, close bus only initiation enables SOTF protection immediately following the close command to the circuit breaker. For more information see [Switch-Onto-Fault Logic on page R.1.94](#).

Turn off 52AEND (52A Pole Open Time Delay).

52AEND := **OFF** 52A Pole Open Time Delay (OFF, 0.000–16000 cycles)

Select the close bus option for this application and set the close enable delay (CLOEND) shorter than the shortest reclose open interval.

CLOEND := **10.000** CLSMON or Single-Pole Open Delay (OFF, 0.000–16000 cycles)

SOTF Duration

Setting SOTFD determines the longest period the SOTF logic can assert after the circuit breaker closes.

SOTFD := **10.000** Switch-Onto-Fault Enable Duration (0.500–16000 cycles)

Close Signal Monitor

Assign the Relay Word bit CLSMON to a control input, so the relay can detect execution of the close command.

CLSMON := **IN102** Close Signal Monitor (SELOGIC Equation)

Phase Instantaneous/Definite-Time Overcurrent Elements

Use Level 1 instantaneous phase overcurrent element (50P1) as a nondirectional high-set phase overcurrent element for SOTF protection. To rapidly clear faults, set pickup threshold 50P1P equal to 50 percent of the fault current measured at the local terminal for a close-in three-phase fault; use weak source conditions so that the relay operates for low-level fault current.

50P1P := **9.57** Level 1 Pickup (OFF, 0.25–100 A secondary)

This application uses 50P1 as an instantaneous overcurrent element; you do not need time delay.

67PID := **0.000** Level 1 Time Delay (0.000–16000 cycles)

This application uses 50P1 as a nondirectional overcurrent element; you do not need torque control.

67P1TC := **1** Level 1 Torque Control (SELOGIC Equation)

Negative-Sequence Instantaneous/Definite-Time Overcurrent Elements

Negative-sequence directional overcurrent protection is an excellent choice for underground cable. The cable zero-sequence impedance depends on the current return paths, but the cable negative-sequence impedance does not. Negative-sequence directional overcurrent protection provides reliable and sensitive protection for cables against all unbalanced faults. Be sure to set negative-sequence overcurrent elements above system unbalances.

Negative-Sequence Overcurrent Elements

Enable three levels of negative-sequence overcurrent elements.

E500 := **3** Negative-Sequence Instantaneous/Definite-Time Overcurrent Elements (N, 1–4)

Disable Level 1 negative-sequence overcurrent element. This application does not use 50Q1.

50Q1P := **OFF** Level 1 Pickup (OFF, 0.25–100 A secondary)

The Level 2 negative-sequence directional overcurrent element (67Q2) provides communications-assisted tripping for internal unbalanced faults. This element detects unbalanced faults in the forward direction and trips via the communications channel. The 50Q2P setting is the pickup for the directional overcurrent element 67Q2. Apply a setting equal to the default for the pickup of 32QG (Negative-Sequence Voltage Polarized Directional Element), which is 50FP (Forward Supervisory Overcurrent Pickup)

$50Q2P = 50FP = 0.12 \cdot I_{nom} = 0.12 \cdot 5 \text{ A} = 0.6 \text{ A}$

50Q2P := **0.60** Level 2 Pickup (OFF, 0.25–100 A secondary)

The Level 3 negative-sequence directional overcurrent element (67Q3) provides current reversal guard during unbalanced faults on the parallel cable to prevent unwanted tripping. The 50Q3P setting is the pickup for directional overcurrent element 67Q3. Set the pickup of Level 3 negative-sequence overcurrent element equal to the default for the pickup of 32QG (Negative-

Sequence Voltage Polarized Directional Element), which is 50RP (Reverse Supervisory Overcurrent Pickup). The reverse-looking element is 150 percent more sensitive than the forward-looking element.

$$50Q3P = 50RP = 0.08 \cdot I_{nom} = 0.08 \cdot 5 \text{ A} = 0.4 \text{ A}$$

$$50Q3P := 0.40 \text{ Level 3 Pickup (OFF, 0.25–100 A secondary)}$$

Negative-Sequence Overcurrent Pickup Coordination Check.

Figure 1.26 illustrates why you need to check the sensitivity of the forward (50Q2P) and reverse (50Q3P) negative-sequence overcurrent pickup settings.

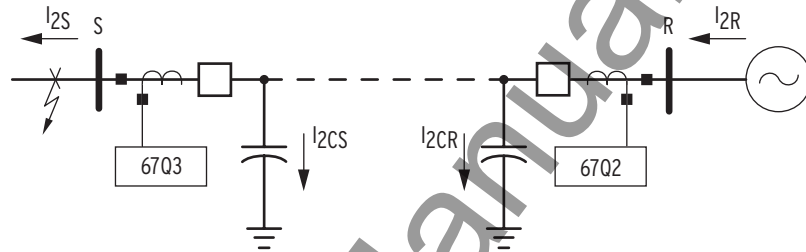


Figure 1.26 Negative-Sequence Fault Current Distribution-External Ground Fault

The shunt capacitance of the 230 kV cable causes the SEL-421 at Station S to measure less negative-sequence fault current for a reverse out-of-section ground fault than at Station R.

$$I_{2S} = I_{2R} - I_{2CR} - I_{2CS} \quad \text{Equation 1.64}$$

Where:

I_{2R} = negative-sequence fault current supplied from Source R

I_{2S} = negative-sequence fault current flowing through the line terminal at Station S

I_{2CR} = negative-sequence shunt current at Station R

I_{2CS} = negative-sequence shunt current at Station S

Therefore, if the reverse-looking directional element at the local station is not more sensitive than the forward-looking directional element at the remote station, unwanted tripping can occur during external ground faults; the local 67Q3 element can fail to detect a reverse unbalanced fault that the remote 67Q2 element sees.

Use a short-circuit study to determine I_{2S} for a close-in reverse single phase-to-ground fault with respect to Station S; make sure to perform the fault calculations for the parallel cable both in service and out of service. The results of the study for this particular application show that the maximum difference between I_{2S} and I_{2R} for any close-in reverse unbalanced fault at Station S is 8.5 mA secondary. Therefore, the existing settings provided for 50Q2P and 50Q3P maintain coordination for external unbalanced faults.

There is no need to add any intentional time delay on pickup for Level 2 or 3 negative-sequence overcurrent elements.

$$67Q2D := 0.000 \text{ Level 2 Time Delay (0.000–16000 cycles)}$$

$$67Q3D := 0.000 \text{ Level 3 Time Delay (0.000–16000 cycles)}$$

Set the Level 2 torque control equation to the forward decision from the ground directional element.

67Q2TC := **326F** Level 2 Torque Control (SELOGIC Equation)

Set the Level 3 torque control equation to the reverse decision from the ground directional element.

67Q3TC := **326R** Level 3 Torque Control (SELOGIC Equation)

Selectable Operating Quantity Time Overcurrent Element 1

Use inverse-time overcurrent protection to provide backup protection for unbalanced faults including high-resistance ground faults. Selectable Operating Quantity Time Overcurrent Element 1 51S1 provides backup protection for unbalanced faults if both the communications-assisted and step distance protection fail to operate.

NOTE: Use your company practices and philosophy when determining these settings.

Select negative-sequence line current 3I2L as the operating quantity rather than 3IOL because ground current return paths vary.

51S1O := **3I2L** 51S1 Operating Quantity
(IA_n, IB_n, IC_n, IMAX_n, I1L, 3I2L, 3I0_n)

The fault current (3I₂) that the relay measures for a bolted single phase-to-ground fault at the end of the longest line from the remote station with the parallel cable in service at minimum generation is 3.0 A secondary (this is the minimum of minimums). Set the pickup between 30 to 50 percent of this current.

$$51S1P = 1/3 \cdot 3I_{2\text{FAULT}} = 1/3 \cdot 3.00 \text{ A} = 1.00 \text{ A}$$

51S1P = **1.00** 51S1 Overcurrent Pickup (0.25–16 A secondary)

Use the following formula to determine approximately how much primary fault resistance coverage (R_F) that 51S1P provides on a radial basis:

$$\begin{aligned} R_F &= \frac{PTR}{CTR} \cdot \frac{\frac{VNOMY}{\sqrt{3}}}{51S1P} \\ &= \frac{2000}{200} \cdot \frac{\frac{115 \text{ V}}{\sqrt{3}}}{1.00 \text{ A}} \\ &= 664 \text{ } \Omega \text{ primary} \end{aligned}$$

Equation 1.65

Use the following as a guide to set the curve and time dial; for secure backup protection, perform a coordination study. Set the local overcurrent element to coordinate with the downstream overcurrent element so there is a 12-cycle (60 Hz nominal) safety margin for phase-to-phase (high current) faults in front of the first downstream overcurrent element. Assume the operating time of the downstream overcurrent element is 12 cycles for close-in phase-to-phase faults. Therefore, set the local time-overcurrent element to operate at approximately 24 cycles for phase-to-phase faults in front of the first downstream overcurrent element.

The fault current (3I₂) that the relay measures for a bolted close-in phase-to-phase fault at the remote station with the parallel cable out of service is 18.67 A secondary. The pickup multiple is shown in [Equation 1.66](#).

$$\begin{aligned}
 M &= \frac{I_{2\text{FAULT}}}{51S1P} \\
 &= \frac{18.67 \text{ A}}{1.00 \text{ A}} \\
 &= 18.67
 \end{aligned}
 \quad \text{Equation 1.66}$$

Use the parameters of 24 cycles operating time and $M = 18.67$ to choose the curve and time dial settings for the 51S1 element. For curve and timing information, see [Inverse-Time Overcurrent Elements on page R.1.80](#).

51S1C = **U3** 51S1 Inverse-Time Overcurrent Curve (U1–U5)

51S1TD = **3.72** 51S1 Inverse-Time Overcurrent Time Dial (0.50–15.0)

Set the overcurrent element to emulate electromechanical reset.

51S1RS = **Y** 51S1 Inverse-Time Overcurrent EM Reset (Y, N)

Torque control the overcurrent element with the forward decision from the ground directional element.

51S1TC = **32GF** 51S1 Torque Control (SELOGIC Equation)

Zone/Level Direction

Zone 1 and Zone 2 distance element directions are fixed in the forward direction. You can select the other zones independently as forward-looking (F), or reverse-looking (R). Set Zone 3 distance elements reverse-looking; these are blocking elements for the POTT scheme.

DIR3 := **R** Zone/Level 3 Directional Control (F, R)

Directional Control

The SEL-421 uses an array of directional elements to supervise the ground distance elements and residual directional overcurrent elements during ground fault conditions. Internal logic automatically selects the best choice for the ground directional element (32G) from among the negative-sequence voltage-polarized directional element (32QG), zero-sequence voltage-polarized directional element (32V), and the zero-sequence current-polarized directional element (32I).

The relay setting ORDER determines the order in which the relay selects directional elements to provide the ground directional decisions. You can set ORDER with any combination of Q, V, and I. The listed order of these directional elements determines the priority in which these elements operate to provide ground directional decisions. Only one specific directional element operates at any one time. Directional element classification is as follows:

- Q—Negative-sequence voltage-polarized directional element
- V—Zero-sequence voltage-polarized directional element
- I—Zero-sequence current-polarized directional element

Set ORDER to Q. This setting selects only the negative-sequence voltage-polarized directional element. You rely on 32QG to provide high-speed reliable and sensitive protection during unbalanced faults via the communications channel. Cable zero-sequence impedance depends on the fault current return path; the negative-sequence impedance of the cable does not.

ORDER := **Q** Ground Directional Element Priority (combine Q, V, I)

The relay hides the Z0F, Z0R, a0, and E32IV settings because ORDER does not contain V or I.

Negative-Sequence Voltage-Polarized Directional Element Reverse Decision (R32QG) Check

The setting Z2R is the reverse threshold for the negative-sequence voltage-polarized directional element. If the apparent negative-sequence impedance (z_2) that the relay measures is greater than Z2R, the relay declares that an unbalanced fault is reverse. For overhead transmission lines, ignore the shunt admittance that represents the charging capacitance. The shunt negative-sequence admittance of the underground cable is significant and modifies the z_2 measurement during reverse faults. You must include this admittance in the cable model to verify proper operation of the default setting.

Figure 1.27 illustrates the effect of the shunt admittance at both ends of the circuit for a reverse unbalanced fault.

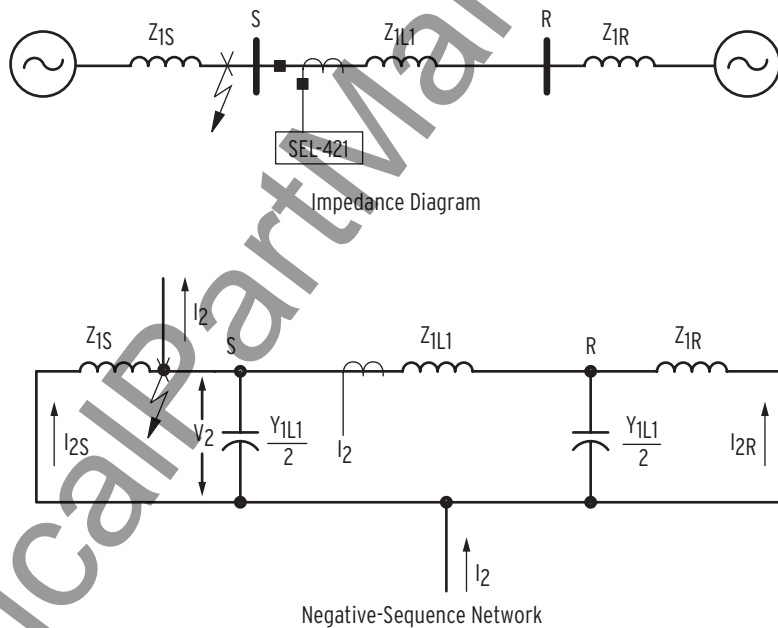


Figure 1.27 Reverse Unbalanced Fault on Cable Circuit (Shunt Admittance)

The technical paper *Underground/Submarine Cable Protection Using a Sequence Directional Comparison Scheme* (see www.selinc.com for a copy of this paper) provides an equation that allows you to express the apparent negative-sequence impedance at the relay terminal for a reverse unbalanced fault when accounting for charging capacitance:

$$\begin{aligned}
 |Z_{2S}| &= \left| \frac{-V_{2S}}{I_{2S}} \right| \\
 &= \frac{4 \cdot Z_{1L1} + 2 \cdot Y_{1L1} \cdot Z_{1L1} \cdot Z_{1R} + 4 \cdot Z_{1R}}{4 + 4 \cdot Y_{1L1} \cdot Z_{1R} + 2 \cdot Y_{1L1} \cdot Z_{1L1} + Y_{1L1}^2 \cdot Z_{1L1} \cdot Z_{1R}} \\
 &= 3.86 \, \Omega
 \end{aligned}
 \tag{Equation 1.67}$$

The SEL-421 uses [Equation 1.68](#) to calculate the apparent negative-sequence impedance during unbalanced faults:

$$Z_2 = \frac{\text{Re}[V_2 \cdot (I_2 \cdot \angle Z_1 \text{ANG})^*]}{|I_2|^2} \quad \text{Equation 1.68}$$

[Equation 1.68](#) yields a more conservative result for the negative-sequence impedance when the parallel cable is out of service:

$$|Z_{2S}| = 2.97 \, \Omega$$

The result of [Equation 1.68](#) is greater than the default setting for Z2R; Z2R = (Z2F + 1/(2 • I_{nom})). (See [Ground Directional Element on page R.1.31](#) for more information.)

Pole-Open Detection

The setting EPO, Enable Pole-Open logic, offers two options for deciding what conditions signify an open pole, as listed in [Table 1.29](#).

Table 1.29 Options for Enabling Pole-Open Logic

Option	Description
EPO := V	The logic declares a single-pole open if the corresponding phase undervoltage element asserts and the open phase detection logic declares the pole is open. Select this option only if you use line-side potential transformers for relaying purposes. A typical setting for the 27PO, pole-open undervoltage threshold, is 60 percent of the nominal line-to-neutral voltage. Do not select this option when shunt reactors are applied because the voltage slowly decays after the circuit breaker opens. With this option selected, the relay cannot declare an open pole during assertion of LOP.
EPO := 52	The logic declares a single-pole open if the corresponding 52A contact (52AA1) from the circuit breaker deasserts and the open phase detection logic declares that the pole is open.

Select the second option because a 52A contact is available. The relay uses both open phase detection and status information from the circuit breaker to make the most secure decision.

EPO := **52** Pole-Open Detection (52, V)

Pole-Open Time Delay on Dropout

The setting 3POD is the time delay on dropout after the Relay Word bit 3PO deasserts. The setting 3POD stabilizes the ground distance elements during pole scatter when the circuit breaker closes.

3POD := **0.500** Three-Pole Open Dropout Delay (0.000–60 cycles)

POTT Trip Scheme

This application example presents the permissive overreaching transfer trip (POTT) scheme to high-speed trip for faults along the protected cable.

The POTT scheme logic consists of the following sections:

- Current reversal guard logic
- Echo

- Weak infeed logic
- Permission to trip received

Current Reversal Guard Logic

This is a parallel cable application, so you must use current reversal guard. When the reverse-looking elements detect an external fault, the relay does not key the transmitter and ignores reception of a permissive signal from the remote terminal. The Zone 3 Reverse Block Delay (Z3RBD) timer extends these two operations after a current reversal occurs and the reverse-looking elements drop out.

Set the Z3RBD timer to accommodate the following:

- Remote Station R circuit breaker maximum opening time
- Maximum communications channel reset time
- Remote Station R Zone 2 relay maximum reset time

Assume a circuit breaker opening time of 3 cycles, a communications channel reset time of 1 cycle, and remote Zone 2 relay reset time of 1 cycle. The sum of these times gives a conservative setting of 5 cycles for a three-cycle circuit breaker.

Z3RBD := **5.000** Zone 3 Reverse Block Time Delay (0.000–16000 cycles)

Echo

If the circuit breaker is open, or a weak infeed condition exists at the local terminal, the received permissive signal can echo back to the remote relay and cause it to issue a high-speed trip for faults beyond the remote relay Zone 1 reach. The SEL-421 includes logic that echoes the received permissive trip signal back to the remote terminal after specific conditions are satisfied. The echo logic includes timers for blocking the echo logic as well as timers for qualifying the permissive signal.

Use EBLKD (Echo Block Time Delay) to block the echo logic after dropout of local permissive elements. The recommended setting for the EBLKD timer is the sum of the following:

- Remote Station R circuit breaker opening time
- Communications channel round trip time
- Safety margin

Assume a circuit breaker opening time of 3 cycles, a communications channel round trip time of 2 cycles, and a safety margin of 5 cycles. The sum of these times gives a conservative setting of 10 cycles for a three-cycle circuit breaker.

EBLKD := **10.000** Echo Block Time Delay (OFF, 0.000–16000 cycles)

The echo time delay, setting ETDPU, makes certain that the reverse-looking elements at the receiving end have sufficient time to operate and block the received echo signal for external faults behind the remote terminal. The delay also guards the echo and weak infeed logic against noise bursts that can occur on the communications channel during close-in external faults.

Because of the brief duration of noise bursts and the pickup time for the reverse-looking elements, a received signal must be present for a short time to allow the POTT scheme to echo the permissive signal back to the remote terminal. The ETDPU (Echo Time Delay Pickup) timer specifies the time a

permissive trip signal must be present. The ETDPU setting depends upon your communications equipment, but a conservative setting for this timer is 2 cycles.

ETDPU := **2.000** Echo Time Delay Pickup (OFF, 0.000–16000 cycles)

The setting EDURD (Echo Duration Time Delay) limits the duration of the echoed permissive signal. Once an echo signal initiates, it should remain for a minimum period of time and then stop, even if a terminal receives a continuous permissive signal. This cessation of the echo signal prevents the permissive trip signal from latching between the two terminals. Assume a 3-cycle circuit breaker at the remote terminal and a 1-cycle channel delay. The sum of these two is a setting of 4 cycles.

EDURD := **4.000** Echo Duration Time Delay (0.000–16000 cycles)

Weak Infeed

The SEL-421 provides weak-infeed logic to high-speed trip both line terminals for internal faults near the weak terminal. The weak terminal echoes the permissive signal back to the strong terminal and causes the strong terminal to trip. The weak terminal trips by converting the echoed permissive signal to a trip signal if specific conditions are satisfied.

This application example does not use the weak-infeed feature.

EWFC := **N** Weak Infeed Trip (Y, N, SP)

Permission to Trip Received

Assign a control input to receive trip permission from the remote terminal.

PT1 := **IN103** General Permissive Trip Received (SELOGIC Equation)

Trip Logic

Trip logic configures the relay for tripping. There are four trip logic settings components:

- Trip equations
- Trip unlatch options
- Trip timers
- Three-pole tripping enable

Trip Equations

Set these three SELOGIC control equations for tripping:

- TR (unconditional)
- TRCOMM (communications-assisted)
- TRSOTF (SOTF)

TR. The TR SELOGIC control equation determines which protection elements cause the relay to trip unconditionally. Set TR to the Zone 1 instantaneous distance protection (Z1T), Zone 2 time-delayed distance protection, and the inverse-time overcurrent element (51S1) for backup protection. For information on setting 51S1, see [Selectable Operating Quantity Time Overcurrent Element 1 on page A.1.104](#).

TR := **Z1T OR Z2T OR 51S1T** Trip (SELOGIC Equation)

TRCOMM. The TRCOMM SELOGIC control equation determines which elements trip via the communication-assisted tripping logic. In the TRCOMM SELOGIC control equation, set Zone 2 mho phase distance protection (M2P) for phase faults, and Level 2 negative-sequence directional overcurrent element (67Q2) for ground faults.

TRCOMM := **M2P OR 67Q2** Communications-Assisted Trip (SELOGIC Equation)

TRSOTF. The TRSOTF SELOGIC control equation defines which protection elements cause the relay to trip when the SOTF scheme is active. Assertion of these protection elements during the SOTFD time causes the relay to trip instantaneously (see [SOTF Protection on page A.1.101](#)). Set instantaneous Zone 2 distance protection (M2P and Z2G) and Level 1 phase instantaneous overcurrent element (50P1) in the TRSOTF SELOGIC control equation.

TRSOTF := **M2P OR Z2G OR 50P1** Switch-Onto-Fault Trip (SELOGIC Equation)

Trip Unlatch Options

Unlatch the control output you programmed for tripping (OUT101) after the circuit breaker auxiliary a contacts break the dc current. The SEL-421 provides two methods for unlatching control outputs following a protection trip:

- ULTR—all three poles
- TULO—phase selective

ULTR. Use ULTR, the Unlatch Trip SELOGIC control equation, to unlatch all three poles. Use the default setting to assert ULTR when you push the front-panel target reset button.

ULTR := **TRGTR** Unlatch Trip (SELOGIC Equation)

TULO. Use TULO (Trip Unlatch Option) to select the conditions that cause the SEL-421 to unlatch the control outputs that you programmed for tripping. [Table 1.30](#) shows the four trip unlatch options for setting TULO.

Table 1.30 Setting TULO Unlatch Trip Options

Option	Description
1	Unlatch the trip when the relay detects that one or more poles of the line terminal are open, and Relay Word bit 3PT has deasserted.
2	Unlatch the trip when the relay detects that the corresponding 52A contact(s) from both circuit breakers (52AA1 and 52AA2) are deasserted.
3	Unlatch the trip when the relay detects that the conditions for Options 1 and 2 are satisfied.
4	Do not run this logic.

Select Option 3 because a 52A contact is available; the relay uses both open phase detection and status information from the circuit breaker to make the most secure decision. For information on the pole-open logic, see [Pole Open Logic on page R.1.24](#).

TULO := **3** Trip Unlatch Option (1, 2, 3, 4)

Trip Timers

The SEL-421 provides dedicated timers for minimum trip duration.

Minimum Trip Duration. The minimum trip duration timer setting, TDUR3D, determines the minimum time that Relay Word bit 3PT asserts. For this application example, Relay Word bit 3PT is assigned to OUT101. The corresponding control output closes for TDUR3D time or the duration of the trip condition, whichever is longer.

A typical setting for this timer is 9 cycles.

TDUR3D := **9.000** Three-Pole Trip Minimum Trip Duration Time Delay
(2.000–8000 cycles)

Three-Pole Tripping Enable

The relay contains both three-pole and single-pole tripping logic. Set E3PT (Three-Pole Trip Enable) to logical 1 to enable the SEL-421 for three-pole tripping only.

E3PT := **1** Three-Pole Trip Enable (SELOGIC Equation)

Also set the appropriate three-pole tripping SELOGIC control equation for Circuit Breaker BK1.

E3PT1 := **1** Breaker 1 3PT (SELOGIC Equation)

Control Outputs

Main Board

Use SELOGIC control equations to assign the control output for tripping.

Use the main board control outputs for tripping and keying the transmitter of the external teleprotection equipment.

OUT101 := **3PT** (SELOGIC Equation)

OUT102 := **KEY** (SELOGIC Equation)

Example Completed

This completes the application example that describes setting of the SEL-421 for communications-assisted protection of 230 kV underground cables. You can use this example as a guide when setting the relay for similar applications. Analyze your particular power system to determine the proper settings for your application.

Relay Settings

[Table 1.31](#) lists the protection relay settings available for this example.

Table 1.31 Settings for 230 kV Parallel Cables Example (Sheet 1 of 6)

Setting	Description	Entry
General Global Settings (Global)		
SID	Station Identifier (40 characters)	LEWISTON -- 230 kV
RID	Relay Identifier (40 characters)	SEL-421 Relay
NUMBK	Number of Breakers in Scheme (1, 2)	1
BID1	Breaker 1 Identifier (40 characters)	Circuit Breaker 1
NFREQ	Nominal System Frequency (50, 60 Hz)	60
PHROT	System Phase Rotation (ABC, ACB)	ABC
DATE_F	Date Format (MDY, YMD, DMY)	MDY

Table 1.31 Settings for 230 kV Parallel Cables Example (Sheet 2 of 6)

Setting	Description	Entry
FAULT	Fault Condition Equation (SELOGIC Equation)	50P1 OR 51S1 OR M2P OR Z2G OR M3P OR Z3G
Current and Voltage Source Selection (Global)		
ESS	Current and Voltage Source Selection (Y, N, 1, 2, 3, 4)	N
Breaker Configuration (Breaker Monitoring)		
EB1MON	Breaker 1 Monitoring (Y, N)	N
BK1TYP	Breaker 1 Trip Type (Single Pole = 1, Three Pole = 3)	3
Breaker 1 Inputs (Breaker Monitoring)		
52AA1	N/O Contact Input—BK1 (SELOGIC Equation)	IN101
Line Configuration (Group)		
CTRW	Current Transformer Ratio—Input W (1–50000)	200
CTRX	Current Transformer Ratio—Input X (1–50000)	200
PTRY	Potential Transformer Ratio—Input Y (1–10000)	2000
VNOMY	PT Nominal Voltage (L-L)—Input Y (60–300 V secondary)	115
PTRZ	Potential Transformer Ratio—Input Z (1–10000)	2000
VNOMZ	PT Nominal Voltage (L-L)—Input Z (60–300 V secondary)	115
Z1MAG	Positive-Sequence Line Impedance Magnitude (0.05–255 Ω secondary)	0.48
Z1ANG	Positive-Sequence Line Impedance Angle (5.00–90 degrees)	42.5
Z0MAG	Zero-Sequence Line Impedance Magnitude (0.05–255 Ω secondary)	0.96
Z0ANG	Zero-Sequence Line Impedance Angle (5.00–90 degrees)	21.7
EFLOC	Fault Location (Y, N)	Y
LL	Line Length (0.10–999)	25
Relay Configuration Settings (Group)		
E21P	Mho Phase Distance Zones (N, 1–5)	3
E21MG	Mho Ground Distance Zones (N, 1–5)	N
E21XG	Quadrilateral Ground Distance Zones (N, 1–5)	3
ECVT	CVT Transient Detection (Y, N)	N
ESERCMP	Series-Compensated Line Logic (Y, N)	N
ECDTD	Distance Element Common Time Delay (Y, N)	Y
ESOTF	Switch-Onto-Fault (Y, N)	Y
EOOS	Out-of-Step (Y, N)	N
ELOAD	Load Encroachment (Y, N)	N
E50P	Phase Inst./Def.-Time O/C Elements (N, 1–4)	1
E50G	Res. Ground Inst./Def. Time O/C Elements (N, 1–4)	N

Table 1.31 Settings for 230 kV Parallel Cables Example (Sheet 3 of 6)

Setting	Description	Entry
E50Q	Negative-Sequence Inst./Def. Time O/C Elements (N, 1–4)	3
E51S	Selectable Inverse Time O/C Element (N, 1–3)	1
E32	Directional Control (Y, AUTO)	AUTO
ECOMM	Comm.-Assisted Tripping (N, DCB, POTT, POTT2, POTT3, DCUB1, DCUB2)	POTT
EBFL1	Breaker 1 Failure Logic (N, 1, 2)	N
E25BK1	Synchronism Check for Breaker 1 (Y, N)	N
E79	Reclosing (Y, Y1, N)	N
EMANCL	Manual Closing (Y, N)	N
ELOP	Loss-of-Potential (Y, Y1, N)	Y1
EDEM	Demand Metering (N, THM, ROL)	N
EADVS	Advanced Settings (Y, N)	Y
Mho Phase Distance Element Reach (Group)		
Z1P	Zone 1 Reach (OFF, 0.05–64 Ω secondary)	0.38
Z2P	Zone 2 Reach (OFF, 0.05–64 Ω secondary)	0.58
Z3P	Zone 3 Reach (OFF, 0.05–64 Ω secondary)	0.58
Mho Phase Distance Element Time Delay (Group)		
Z1PD	Zone 1 Time Delay (OFF, 0.000–16000 cycles)	OFF
Z2PD	Zone 2 Time Delay (OFF, 0.000–16000 cycles)	OFF
Z3PD	Zone 3 Time Delay (OFF, 0.000–16000 cycles)	OFF
Quadrilateral Ground Distance Element Reach (Group)		
XG1	Zone 1 Reactance (OFF, 0.05–64 Ω secondary)	0.38
RG1	Zone 1 Resistance (0.05–50 Ω secondary)	1.29
XG2	Zone 2 Reactance (OFF, 0.05–64 Ω secondary)	0.58
RG2	Zone 2 Resistance (0.05–50 Ω secondary)	1.97
XG3	Zone 3 Reactance (OFF, 0.05–64 Ω secondary)	0.58
RG3	Zone 3 Resistance (0.05–50 Ω secondary)	2.46
XGPOL	Quad Ground Polarizing Quantity (I2, IG)	I2
TANG	Nonhomogeneous Correction Angle (–40.0 to +40 degrees)	–2.2
Zero-Sequence Current Compensation Factor (Group)		
k0M1	Zone 1 ZSC Factor Magnitude (AUTO, 0.000–10)	0.385
k0A1	Zone 1 ZSC Factor Angle (–180.0 to +180 degrees)	–46.7
k0M	Forward Zones ZSC Factor Magnitude (0.000–10)	6.105
k0A	Forward Zones ZSC Factor Angle (–180.0 to +180 degrees)	44.5
k0MR	Reverse Zones ZSC Factor Magnitude (0.000–10)	6.105
k0AR	Reverse Zones ZSC Factor Angle (–180.0 to +180 degrees)	44.5

Table 1.31 Settings for 230 kV Parallel Cables Example (Sheet 4 of 6)

Setting	Description	Entry
Ground Distance Element Time Delay (Group)		
Z1GD	Zone 1 Time Delay (OFF, 0.000–16000 cycles)	OFF
Z2GD	Zone 2 Time Delay (OFF, 0.000–16000 cycles)	OFF
Z3GD	Zone 3 Time Delay (OFF, 0.000–16000 cycles)	OFF
Distance Element Common Time Delay (Group)		
Z1D	Zone 1 Time Delay (OFF, 0.000–16000 cycles)	0.000
Z2D	Zone 2 Time Delay (OFF, 0.000–16000 cycles)	20.000
Z3D	Zone 3 Time Delay (OFF, 0.000–16000 cycles)	0.000
SOTF Scheme (Group)		
ESPSTF	Single-Pole Switch-Onto-Fault (Y, N)	N
EVRST	Switch-Onto-Fault Voltage Reset (Y, N)	Y
52AEND	52A Pole Open Time Delay (OFF, 0.000–16000 cycles)	OFF
CLOEND	CLSMON or Single Pole Open Delay (OFF, 0.000–16000 cycles)	10.000
SOTFD	Switch-Onto-Fault Enable Duration (0.500–16000 cycles)	10.000
CLSMON	Close Signal Monitor (SELOGIC Equation)	IN102
Phase Instantaneous Overcurrent Pickup (Group)		
50P1P	Level 1 Pickup (OFF, 0.25–100 A secondary)	9.57
Phase Overcurrent Definite-Time Delay (Group)		
67P1D	Level 1 Time Delay (0.000–16000 cycles)	0.000
Phase Overcurrent Torque Control (Group)		
67P1TC	Level 1 Torque Control (SELOGIC Equation)	1
Negative-Sequence Instantaneous Overcurrent Pickup (Group)		
50Q1P	Level 1 Pickup (OFF, 0.25–100 A secondary)	OFF
50Q2P	Level 2 Pickup (OFF, 0.25–100 A secondary)	0.60
50Q3P	Level 3 Pickup (OFF, 0.25–100 A secondary)	0.40
Negative-Sequence Overcurrent Definite-Time Delay (Group)		
67Q2D	Level 2 Time Delay (0.000–16000 cycles)	0.000
67Q3D	Level 3 Time Delay (0.000–16000 cycles)	0.000
Negative-Sequence Overcurrent Torque Control (Group)		
67Q2TC	Level 2 Torque Control (SELOGIC Equation)	32GF
67Q3TC	Level 3 Torque Control (SELOGIC Equation)	32GR
Selectable Operating Quantity Inverse-Time Overcurrent Element 1 (Group)		
51S1O	51S1 Op. Qty (IAN, IBn, ICn, IMAXn, I1L, 3I2L, 3I0n) ^a	3I2L
51S1P	51S1 O/C Pickup (0.25–16 A secondary)	1.00
51S1C	51S1 Inverse Time O/C Curve (U1–U5)	U3
51S1TD	51S1 Inverse Time O/C Time Dial (0.50–15)	3.72
51S1RS	51S1 Inverse Time O/C EM Reset (Y, N)	Y

Table 1.31 Settings for 230 kV Parallel Cables Example (Sheet 5 of 6)

Setting	Description	Entry
51S1TC	51S1 Torque Control (SELOGIC Equation)	32GF
Zone/Level Direction (Group)		
DIR3	Zone/Level 3 Directional Control (F, R)	R
Directional Control (Group)		
ORDER	Ground Dir. Element Priority (combine Q, V, I)	Q
Pole Open Detection (Group)		
EPO	Pole Open Detection (52, V)	52
SPOD	Single Pole Open Dropout Delay (0.000–60 cycles)	0.500
3POD	Three Pole Open Dropout Delay (0.000–60 cycles)	0.500
POTT Trip Scheme (Group)		
Z3RBD	Zone 3 Reverse Block Time Delay (0.000–16000 cycles)	5.000
EBLKD	Echo Block Time Delay (OFF, 0.000–16000 cycles)	10.000
ETDPU	Echo Time Delay Pickup (OFF, 0.000–16000 cycles)	2.000
EDURD	Echo Duration Time Delay (0.000–16000 cycles)	4.000
EWFC	Weak Infeed Trip (Y, N, SP)	N
PT1	General Permissive Trip Received (SELOGIC Equation)	IN103
Trip Logic (Group)		
TR	Trip (SELOGIC Equation)	Z1T OR Z2T OR 51S1T
TRCOMM	Communications-Assisted Trip (SELOGIC Equation)	M2P OR 67Q2
TRSOTF	Switch-Onto-Fault Trip (SELOGIC Equation)	M2P OR Z2G OR 50P1
DTA	Direct Transfer Trip A-Phase (SELOGIC Equation)	NA
DTB	Direct Transfer Trip B-Phase (SELOGIC Equation)	NA
DTC	Direct Transfer Trip C-Phase (SELOGIC Equation)	NA
BK1MTR	Manual Trip–Breaker 1 (SELOGIC Equation)	OC1 OR PB8_PUL
ULTR	Unlatch Trip (SELOGIC Equation)	TRGTR
ULMTR1	Unlatch Manual Trip–Breaker 1 (SELOGIC Equation)	NOT (52AA1 AND 52AB1 AND 52AC1)
TOPD	Trip During Open Pole Time Delay (2.000–8000 cycles)	2.000
TULO	Trip Unlatch Option (1, 2, 3, 4)	3
Z2GTSP	Zone 2 Ground Distance Time Delay SPT (Y, N)	N
67QGSP	Zone 2 Dir. Negative-Sequence/Residual Overcurrent Single Pole Trip (Y, N)	N
TDUR1D	SPT Min Trip Duration Time Delay (2.000–8000 cycles)	6.000
TDUR3D	3PT Min Trip Duration Time Delay (2.000–8000 cycles)	9.000

Table 1.31 Settings for 230 kV Parallel Cables Example (Sheet 6 of 6)

Setting	Description	Entry
E3PT	Three-Pole Trip Enable (SELOGIC Equation)	1
E3PT1	Breaker 1 3PT (SELOGIC Equation)	1
ER	Event Report Trigger (SELOGIC Equation)	R_TRIG M2P OR R_TRIG Z2G OR R_TRIG 51S1 OR R_TRIG M3P OR R_TRIG Z3G
Main Board (Outputs)		
OUT101	(SELOGIC Equation)	3PT
OUT102	(SELOGIC Equation)	KEY

^a Parameter n is 1 for BK1, 2 for BK2, and L for Line.

Out-of-Step Logic Application Examples

The SEL-421 features OOS (out-of-step) logic for the following two functions:

- OSB (out-of-step blocking) logic blocks phase distance elements and Zone 1 ground distance elements during power swings.
- OST (out-of-step tripping) logic trips the circuit breaker(s) during unstable swings.

There are two application examples that explain how to apply OOS logic: an out-of-step blocking scheme and an out-of-step tripping and blocking scheme. The examples provide detailed setting procedures for a 5 A relay.

These examples are for three-pole tripping in a 500 kV power system. Applications for single-pole tripping are similar. Refer to [Figure 1.28](#) for a one-line diagram of the 500 kV system.

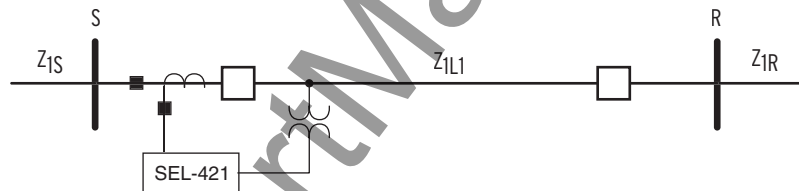


Figure 1.28 500 kV Power System

[Table 1.32](#) lists the power system parameters.

Table 1.32 Positive-Sequence Impedances (Secondary)

Parameter	Value
Line impedances: Z_{1L1}	8.00 Ω $\angle 87.6^\circ$ secondary ($Z1MAG$ Ω $\angle Z1ANG^\circ$)
Zone 2 Phase Distance Reach: $Z2P$	9.60 Ω secondary
Source S impedances: Z_{1S}	8.8 Ω $\angle 88^\circ$ secondary
Source R impedances: Z_{1R}	3.52 Ω $\angle 88^\circ$ secondary
Nominal frequency (f_{nom})	60 Hz
Nominal current (I_{nom})	5 A secondary
Line Length	100 miles

Power System Parameters

Out-of-Step Blocking

This example demonstrates setting OSB function. Use this logic to discriminate between power swings and faults to prevent unwanted distance element trips. This application example assumes that you have set the phase-to-phase mho distance element Zone 2 reach. First, enable the OOS logic. Next, calculate the impedance reach settings for Zones 6 and 7 ($R1R6$, $R1R7$, $X1T6$, and $X1T7$), and then calculate OSBD (out-of-step block time delay). All of the OOS settings appear in [Table 1.33](#) and [Table 1.34](#) at the end of this example.

Enable OOS Logic

NOTE: The relay automatically calculates and hides settings when you set EADVS to N and EOOST to N. Table 1.33 lists these settings.

Access Group settings to enable the out-of-step logic.

E00S := **Y** Out-of-Step (Y, N)

You do not need to enable the Advanced Settings for this application example.

EADVS := **N** Advanced Settings (Y, N)

Out-of-Step Tripping

Disable the OST logic for this particular application example.

E00ST := **N** Out-of-Step Tripping (N, I, O)

Phase Distance Element Blocking

OSB logic blocks phase distance protection during a swing when the measured positive-sequence impedance enters the operating characteristics of the phase distance elements (see Zone 1 and Zone 2 in Figure 1.29). In practice, it is not necessary to block all zones. In this application example, the OSB logic blocks zones that generate instantaneous tripping. The OSB logic blocks instantaneous Zone 1 and Zone 2 (Zone 2 is part of the communications-assisted tripping scheme).

The OSB logic typically supervises forward-looking Zones 1 and 2 because the operation time of these two zones is ordinarily shorter than the time period during which the impedance of a power swing resides in these protection zones. For example, if the period of a swing is 1.5 seconds, OSB logic should supervise instantaneous Zone 1 and communications-assisted Zone 2.

During a power swing, the relay typically does not block overreaching zones of protection that provide time-delayed tripping. Do not block reverse-looking Zone 3 when this zone serves as a starting element for the DCB (directional comparison blocking) scheme or when this zone provides current reversal guard for the POTT (permissive overreaching transfer tripping) scheme. For example, if the OSB logic inhibits the DCB blocking signal during swings that pass behind the local relay, over-tripping can occur at the remote terminal. If a power swing enters both the local reverse-looking Zone 3 and the remote overreaching Zone 2, high-speed tripping occurs at the remote terminal because OSB logic removes the local Zone 3 element DCB scheme block.

Set the relay to block Zone 1 and Zone 2.

O0SB1 := **Y** Block Zone 1 (Y, N)

O0SB2 := **Y** Block Zone 2 (Y, N)

O0SB3 := **N** Block Zone 3 (Y, N)

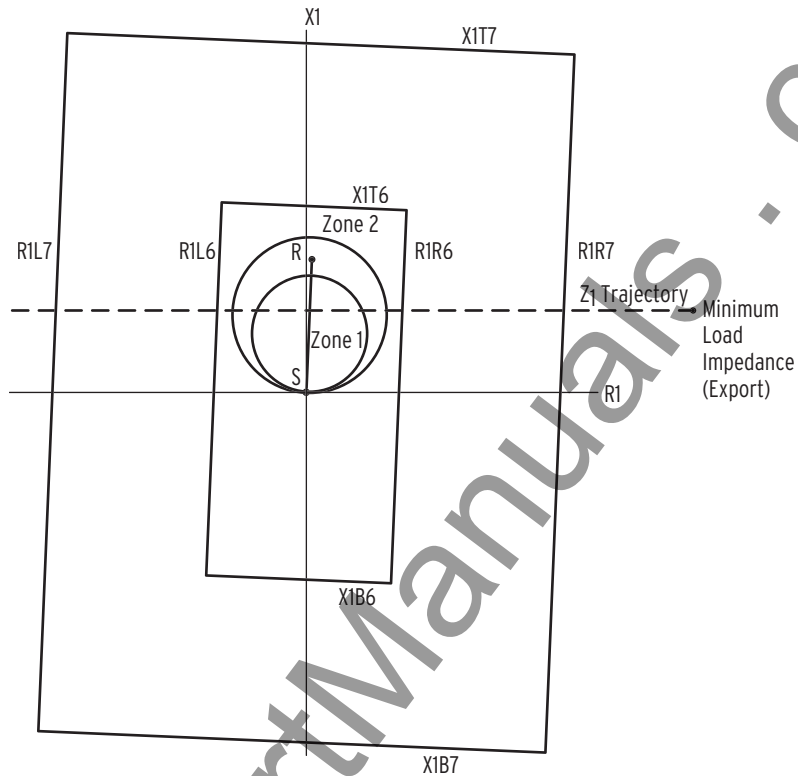


Figure 1.29 OOS Characteristic Settings Parameters

Zone 6 and Zone 7 Impedance Settings

The OOS logic uses two zones of concentric polygons, outer Zone 7 and inner Zone 6 (see [Figure 1.29](#)). The relay uses Zone 6 and Zone 7 for OOS logic timing to differentiate between power swings and faults. The relay measures a traveling positive-sequence impedance locus (Z_1) in Zone 6 and Zone 7 when a power swing or fault occurs. Two factors affect the Zone 6 and Zone 7 impedance settings:

- The outermost overreaching zone of phase distance protection that you want to block.
- The load impedance that the relay measures during maximum load (minimum load impedance locus).

NOTE: This settings philosophy provides the most time for the relay to decide whether a fault or a power swing has occurred.

Set inner Zone 6 (X1T6, R1R6, X1B6, and R1L6) to encompass the outermost zone of phase distance protection that you have selected for out-of-step blocking. Set Zone 7 so that the closest minimum load impedance locus is outside the Zone 7 characteristic for all loading conditions.

Resistance Blinders

Zone 2 is the outermost characteristic for this particular example. Include a safety margin (20 percent for this example).

$$\begin{aligned} R1R6 &= 1.2 \cdot \frac{Z2P}{2 \cdot \sin(Z1ANG)} \\ &= 1.2 \cdot \frac{9.60 \, \Omega}{2 \cdot \sin(87.6^\circ)} \\ &= 5.77 \, \Omega \end{aligned}$$

Equation 1.69

Where:

Z2P = Zone 2 mho phase distance element reach (see [Table 1.32](#)).

R1R6 := **5.77** Zone 6 Resistance—Right (0.05–70 Ω secondary)

Set Zone 7 outer resistance blinders according to maximum load. In other words, set the Zone 7 outer right-hand resistance blinder just inside the corresponding minimum export load impedance locus (maximum load locus). The maximum load current is 2.41 A secondary, determined from load studies. The corresponding line-to-neutral voltage during maximum load at Station S is 61.44 V secondary.

$$I_{L(\max)} = 2.41 \text{ A}$$

$$V_{LN} = 61.44 \text{ V}$$

Determine the minimum load impedance that the relay measures:

$$\begin{aligned} Z_{L_{\min}} &= \frac{V_{LN}}{I_{L(\max)}} \\ &= \frac{61.44 \text{ V}}{2.41 \text{ A}} \\ &= 25.49 \text{ } \Omega \end{aligned}$$

Equation 1.70

Assume that the maximum load angle is $\pm 45^\circ$. Use trigonometry to calculate R1R7, which is the distance from the origin to the right-hand resistance blinder along line OP, the c side of the right triangle (see [Figure 1.30](#)). The resistance blinders are parallel to the line characteristic impedance Z_{IL1} , for which the angle is setting Z1ANG.

$$\cos(A) = \frac{c}{b}$$

Equation 1.71

Where:

$$A = 45^\circ + (90^\circ - \angle Z1ANG)$$

$$b = Z_{L(\min)}$$

$$c = \text{setting R1R7}$$

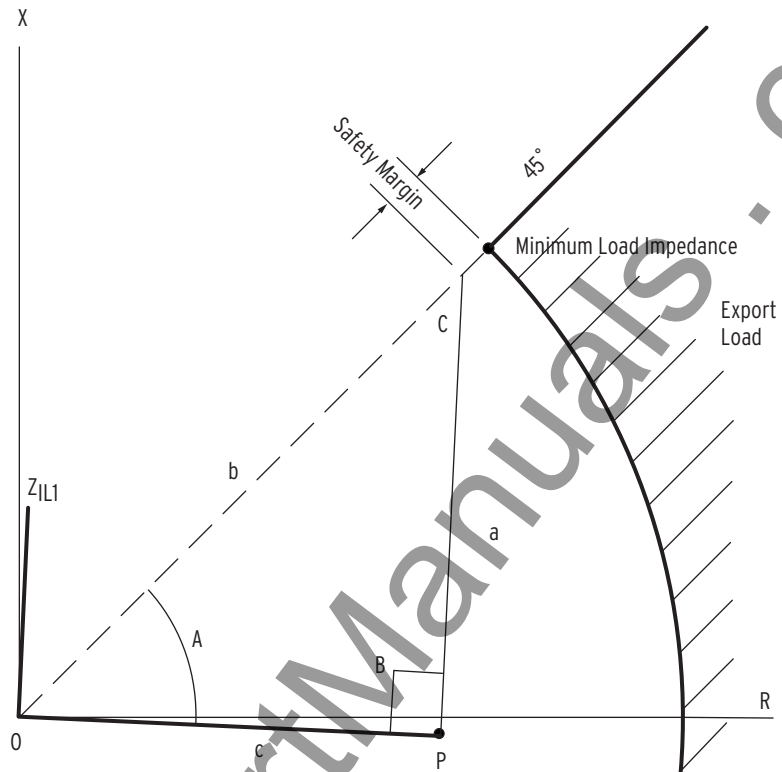


Figure 1.30 Calculating Setting R1R7

Rearrange [Equation 1.71](#) and multiply by a safety factor of 90 percent to calculate R1R7.

$$\begin{aligned}
 R1R7 &= 0.9 \cdot Z_{L(\min)} \cdot \cos(A) \\
 &= 0.9 \cdot Z_{L(\min)} \cdot \cos[45^\circ + (90^\circ - Z1ANG)] \\
 &= 0.9 \cdot 25.49 \cdot \cos[45^\circ + (90^\circ - 87.6^\circ)] \\
 &= 0.9 \cdot 25.49 \cdot \cos(47.4^\circ) \\
 &= 15.53 \, \Omega
 \end{aligned}$$

Equation 1.72

R1R7 := **15.53** Zone 7 Resistance—Right (0.05–70 Ω secondary)

Reactance Lines

Zone 6 inner reactance lines X1T6 and X1B6 should completely encompass the outermost zone of phase distance protection that you want to block from tripping during a power swing. Include a safety margin (20 percent).

$$\begin{aligned}
 X1T6 &= 1.2 \cdot Z2P \\
 &= 1.2 \cdot 9.60 \, \Omega \\
 &= 11.52 \, \Omega
 \end{aligned}$$

Equation 1.73

Where:

Z2P = Zone 2 mho phase distance element reach

X1T6 := **11.52** Zone 6 Reactance—Top (0.05–96 Ω secondary)

The distance between Zones 6 and 7 top reactance lines should equal the distance between Zones 6 and 7 right-hand resistance blinders.

NOTE: The value for X1T7 must be at least 0.1Ω greater than that for X1T6.

$$\begin{aligned} X1T7 &= X1T6 + (R1R7 - R1R6) \\ &= 11.52 \Omega + (15.53 \Omega - 5.76 \Omega) \\ &= 21.29 \Omega \end{aligned} \quad \text{Equation 1.74}$$

X1T7 := **21.29** Zone 7 Reactance—Top (0.05–96 Ω secondary)

Out-of-Step Block Time Delay

When the Z_1 impedance locus initially moves inside Zone 7, the relay starts the OSBD (out-of-step block time delay) timer. The Z_1 impedance trajectory is shown in [Figure 1.31](#) for the case of $|E_A| = |E_B|$ (E_A is the voltage at Node A and E_B is the voltage at Node B). The OSBD timer detects slow swings. If the OSBD timer expires before the Z_1 trajectory enters Zone 6, the relay detects a power swing blocking condition.

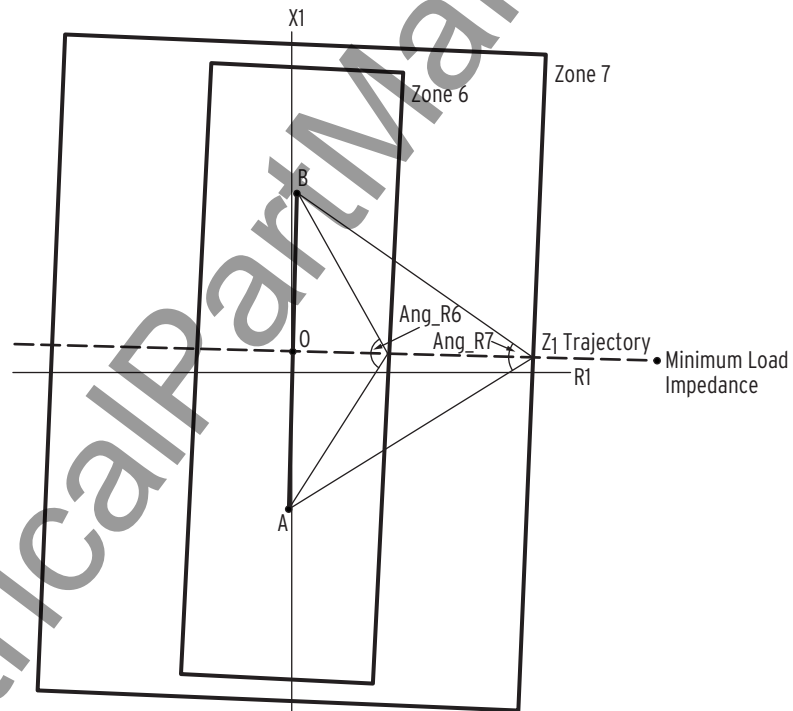


Figure 1.31 Swing Trajectory to Determine the OSBD Setting

Use [Equation 1.75](#) through [Equation 1.78](#) to calculate the OSBD setting. These equations are derived from the impedance trajectory shown in [Figure 1.31](#). Line section AB is the transfer impedance, Z_T . The horizontal dashed line represents the trajectory of the power swing perpendicular to line section AB. The trajectory passes through the midpoint of line section AB.

$$Z_T = Z_{1S} + Z_{1L1} + Z_{1R} \quad \text{Equation 1.75}$$

Where:

- Z_T = transfer impedance
- Z_{1S} = positive-sequence source impedance
- Z_{1L1} = positive-sequence impedance for Line 1
- Z_{1R} = positive-sequence remote impedance

$$\begin{aligned}\text{Ang_R6} &= 2 \cdot \text{atan} \left[\frac{\frac{|Z_T|}{2}}{(R1R6)} \right] \\ &= 2 \cdot \text{atan} \left[\frac{\frac{|8.8 \angle 88^\circ + 8.00 \angle 87.6^\circ + 3.52 \angle 88^\circ|}{2}}{5.77 \angle} \right] \\ &= 120.9^\circ\end{aligned}\quad \text{Equation 1.76}$$

$$\begin{aligned}\text{Ang_R7} &= 2 \cdot \text{atan} \left[\frac{\frac{|Z_T|}{2}}{R1R7} \right] \\ &= 2 \cdot \text{atan} \left[\frac{\frac{|8.8 \angle 88^\circ + 8.00 \angle 87.6^\circ + 3.52 \angle 88^\circ|}{2}}{15.53 \angle} \right] \\ &= 66.4^\circ\end{aligned}\quad \text{Equation 1.77}$$

A typical stable swing frequency is $f_{\text{slip}} = 5$ Hz. Use this value in Equation 1.78 to find setting OSBD.

$$\begin{aligned}\text{OSBD} &= \frac{(\text{Ang_R6} - \text{Ang_R7}) \cdot f_{\text{nom}}}{\frac{360^\circ}{\text{cycle}} \cdot f_{\text{slip}}} \text{ cycles} \\ &= \frac{(120.9^\circ - 66.4^\circ) \cdot 60 \text{ Hz}}{\frac{360^\circ}{\text{cycle}} \cdot 5 \text{ Hz}} \text{ cycles} \\ &= 1.82 \text{ cycles}\end{aligned}\quad \text{Equation 1.78}$$

Where:

f_{nom} = nominal power system frequency (Hz)

f_{slip} = maximum slip frequency (Hz)

The OSBD timer settings are in increments of 0.125 cycle; round up to the nearest valid relay setting.

OSBD := **1.875** Out-of-Step Block Time Delay (0.500–8000 cycles)

Latch Out-of-Step Blocking

The SEL-421 automatically resets the OSB logic if this logic asserts for more than two seconds while the positive-sequence impedance locus is inside Zone 7. During an unstable power swing, the relay also resets the OSB logic each time the swing impedance exits Zone 7. You can latch on the OSB function during an unstable power swing to continue blocking the distance elements if the power swing impedance locus moves outside of Zone 7 and before it comes back inside Zone 7 on its next swing cycle. If latched, the OSB logic resets one second after the power system stops the out-of-step. Latching the OSB gives you an advantage in that the relay can successfully block uncontrolled distance element operations if a fault occurs when the

unstable swing impedance is outside of Zone 7. Relay elements detect internal faults that occur during a power swing and take the appropriate action (unblock).

OSBLTCH := Y Latch Out-of-Step Blocking (Y, N)

Out-of-Step Unblocking

The relay disables out-of-step blocking automatically when a fault occurs during a power swing. Therefore, the distance protection successfully detects all fault types and trips the circuit breaker(s) during internal faults.

Out-of-Step Unblocking During Three-Phase Faults. The trajectories of a three-phase fault and a power swing appear the same to phase distance elements because both a three-phase fault and a power swing consist of positive-sequence quantities only (V_1 and I_1). Therefore, if a power swing evolves into an internal three-phase fault, typical OSB logic cannot detect the occurrence of the balanced fault. The SEL-421 includes an additional set of inner blinders to provide proper detection of the internal three-phase fault (see [Figure 1.32](#)). If the positive-sequence impedance resides between these blinders for a specific duration, OSB logic unblocks. The relay calculates this duration (UBOSBD) each time the power swing enters Zone 7. A short timer setting is adequate for fast swings, but the relay needs a longer timer setting for slow power swings. For example, if the positive-sequence impedance passes gradually between the two inner blinders during a slow swing, a short timer setting would cause unwanted tripping.

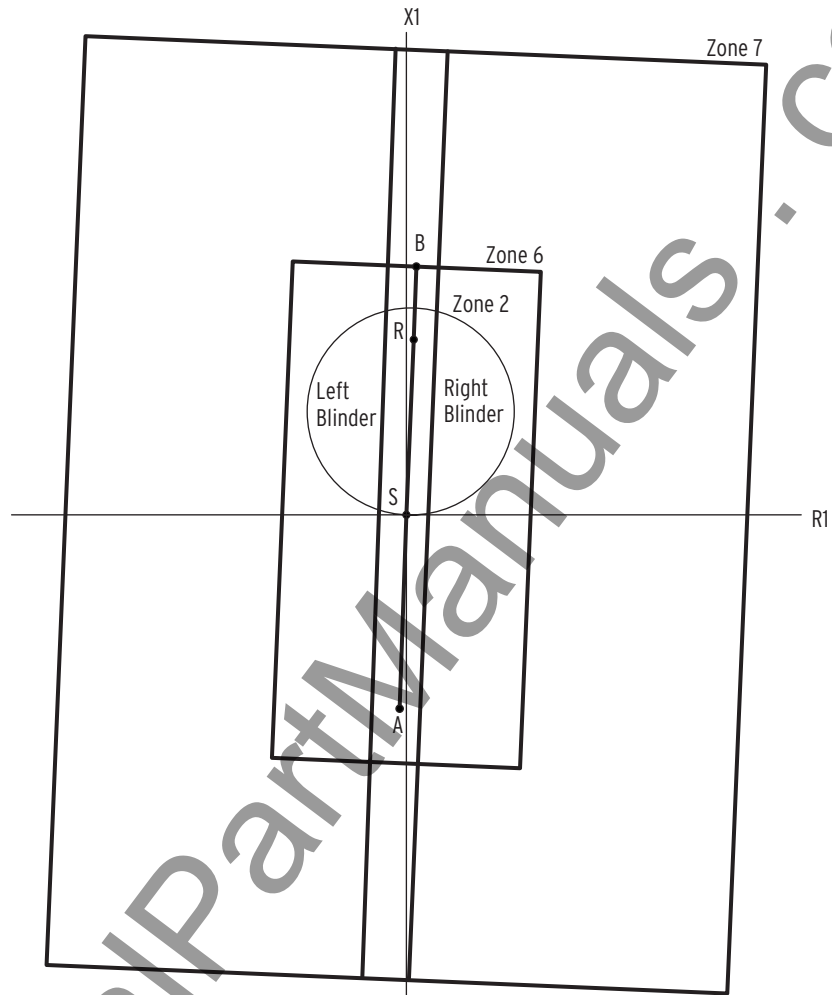


Figure 1.32 Inner Blinders

The UBOSBD timer length is the expected duration of the power swing within the inner blinders. The relay bases the calculation on the actual time required for the swing to traverse from Zone 7 to Zone 6, before entering the inner blinders. If the swing remains inside the inner blinders for a period greater than UBOSBD, an unblock signal asserts.

You can increase the adaptive UBOSBD timer calculation in multiples of setting UBOSBF. If UBOSBF is a multiplier of one, the relay calculates the expected time to traverse across the inner blinders based on the rate at which the swing moved from Zone 7 to Zone 6. Similarly, if UBOSBF is a multiplier of four, the relay multiplies UBOSBD by four.

Out-of-Step Unblocking During Unbalanced Faults. The SEL-421 treats Zone 1 phase and ground distance elements differently than phase distance elements of other zones.

Operation of either of two negative-sequence directional elements, 67QUBF (forward-looking), or 67QUBR (reverse-looking), defeats the OSB logic and unblocks the phase distance elements (except the Zone 1 elements) when an unbalanced fault occurs following a power swing. Therefore, the phase distance protection operates in the POTT scheme and high-speed clears the unbalanced fault if it is an internal one. The time-delayed elements of

associated zones also start timing to initiate backup protection functions. The 67QUBF element unblocks forward-looking zones and 67QUBR unblocks reverse-looking zones.

The relay supervises the 67QUBF and 67QUBR elements with negative-sequence pickup setting 50QUBP. When you set the 50QUBP pickup level to other than OFF, the level of negative sequence current exceeds the 50QUBP setting threshold, and the relay has made a valid directional decision (32 elements), the relay asserts either the 67QUBF or the 67QUBR directional element after time delay setting UBD. In this manner the relay removes out-of-step blocking for phase distance elements other than Zone 1 elements during unbalanced faults.

The 50QUBP setting is an advanced setting and must be coordinated with the distance protection for the protected line. Setting UBD is also an advanced setting; set the UBD timer to coordinate clearing times with protection external to the protected line.

For out-of-step unblocking on unbalanced faults you must do the following:

- Step 1. Set EADVS := Y to enable advanced settings.
- Step 2. Set the negative sequence unblocking element pickup with setting 50QUBP (Negative-Sequence Current Supervision).
Coordinate with line distance protection.
- Step 3. Set the unblock delay timer UBD (Negative-Sequence Current Unblock Delay).
Coordinate clearing times with other protection.

If a power swing center is on the line under protection, the Zone 1 distance elements at one or both terminals may operate if the OSB is removed. For example, during an unstable swing, if an external A-phase ground fault occurs beyond the remote terminal R in [Figure 1.28](#), the A-phase ground distance elements at both terminals operate correctly; that is, A-phase distance element picks up in Zone 2 at the S terminal, and in reverse Zone 3 at the R terminal. However, all Zone 1 phase and ground distance elements at both terminals may also operate if the swing center is within the Zone 1 reach and a negative-sequence overcurrent element removes the OSB. The undesirable operations of Zone 1 elements may trip all three phases at both terminals for an external A-phase fault.

The SEL-421 uses a directional negative-sequence element (67Q1T) to supervise the out-of-step blocking of Zone 1 distance elements. 67Q1T is independent from 67QUBF and 67QUBR, which are used to defeat the OSB for distance elements other than Zone 1 elements. This separation gives you a choice to control the Zone 1 element operations during an unstable swing situation.

For those applications that allow the relay to operate for any internal and external faults on a system during a power swing, set the 67Q1T element similar to the 67QUBF element:

- 50Q1P := **same value as of 50QUBP** Level 1 Pickup (OFF, 0.25–100 amps sec.)
- 67Q1D := **same value as of UBD** Level 1 Time Delay (0.000–16000 cycles)
- 67Q1TC := **1** Level 1 Torque Control (SELOGIC Equation)

For those applications that require the relay only trip for internal faults during a power swing, disable the 67Q1T element by setting 50Q1P to OFF or E50Q = N. This way, the Zone 1 distance elements are always blocked by the OSB logic. The relay relies on Zone 2 overreaching elements together with the POTT scheme to make high-speed trips for internal faults.

Example Completed

This completes the application example that describes setting the SEL-421 for out-of-step blocking. Analyze your particular power system to determine the appropriate settings for your application.

Relay Settings

[Table 1.33](#) lists the settings that the relay automatically calculates and hides when you set EADVS to N and EOOST to N.

Table 1.33 Automatically Calculated/Hidden Settings

Setting	Description	Default Setting
X1B7	Zone 7 Reactance—Bottom (–0.05 to –96 Ω secondary)	X1B7 = –X1T7
X1B6	Zone 6 Reactance—Bottom (–0.05 to –96 Ω secondary)	X1B6 = –X1T6
R1L7	Zone 7 Resistance—Left (–0.05 to –70 Ω secondary)	R1L7 = –R1R7
R1L6	Zone 6 Resistance—Left (–0.05 to –70 Ω secondary)	R1L6 = –R1R6
OSTD	Out-of-Step Trip Delay (0.500–8000 cycles)	0.500
50ABCP	Positive-Sequence Current Supervision (1.00–100 A secondary)	50ABCP = $0.2 \cdot I_{nom}$
50QUBP	Negative-Sequence Current Supervision (OFF, 0.50–100 A secondary)	OFF
UBD	Negative-Sequence Current Unblock Delay (0.500–120 cycles)	0.500
UBOSBF	Out-of-Step Angle Unblock Rate (1–10)	4

[Table 1.34](#) and [Table 1.35](#) list the protection relay settings available in this example.

Table 1.34 Relay Configuration (Group)

Setting	Description	Entry
EOOS	Out-of-Step (Y, N)	Y
EADVS	Advanced Settings (Y, N)	N

Table 1.35 Out-of-Step Tripping/Blocking

Setting	Description	Entry
OOSB1	Block Zone 1 (Y, N)	Y
OOSB2	Block Zone 2 (Y, N)	Y
OOSB3	Block Zone 3 (Y, N)	N
OSBD	Out-of-Step Block Time Delay (0.500–8000 cycles)	1.875
OSBLTCH	Latch Out-of-Step Blocking (Y, N)	Y
EOOST	Out-of-Step Tripping (N, I, O)	N
X1T7	Zone 7 Reactance—Top (0.05 to 96 Ω secondary)	21.29
X1T6	Zone 6 Reactance—Top (0.05 to 96 Ω secondary)	11.52
R1R7	Zone 7 Resistance—Right (0.05 to 70 Ω secondary)	15.53
R1R6	Zone 6 Resistance—Right (0.05 to 70 Ω secondary)	5.77
X1B7	Zone 7 Reactance—Bottom (–0.05 to –96 Ω secondary)	–21.29
X1B6	Zone 6 Reactance—Bottom (–0.05 to –96 Ω secondary)	–11.52
R1L7	Zone 7 Resistance—Left (–0.05 to –70 Ω secondary)	–15.53
R1L6	Zone 6 Resistance—Left (–0.05 to –70 Ω secondary)	–5.77
50ABCP	Positive-Sequence Current Supervision (1.00–100 A secondary)	1.00
50QUBP	Negative-Sequence Current Supervision (OFF, 0.50–100 A secondary)	OFF
UBD	Negative-Sequence Current Unblock Delay (0.500–120 cycles)	0.500
UBOSBF	Out-of-Step Angle Unblock Rate (1–10)	4
50Q1P	Level Pickup (OFF, 0.25–100 amps sec.)	OFF
67Q1D	Level 1 Time Delay (0.000–16000 cycles)	0.000
67Q1TC	Level 1 Torque Control (SELOGIC Equation)	1

Out-of-Step Tripping

This example demonstrates how to set the OST (out-of-step tripping) function. Use OST logic to detect an unstable power swing and trip the local terminal. With OST logic, you can split the power system at predetermined locations after an OST condition occurs.

The Zone 6 and Zone 7 settings for the OST logic depend on the positive sequence impedance (Z_1) trajectory of the power swing (see [Figure 1.33](#)). Set inner Zone 6 at the point along the trajectory where the power system cannot regain stability. Set Zone 7 so that the impedance due to maximum load conditions is outside the Zone 7 characteristic for all loading conditions.

NOTE: This setting philosophy provides the most time for the relay to decide whether the power swing is unstable.

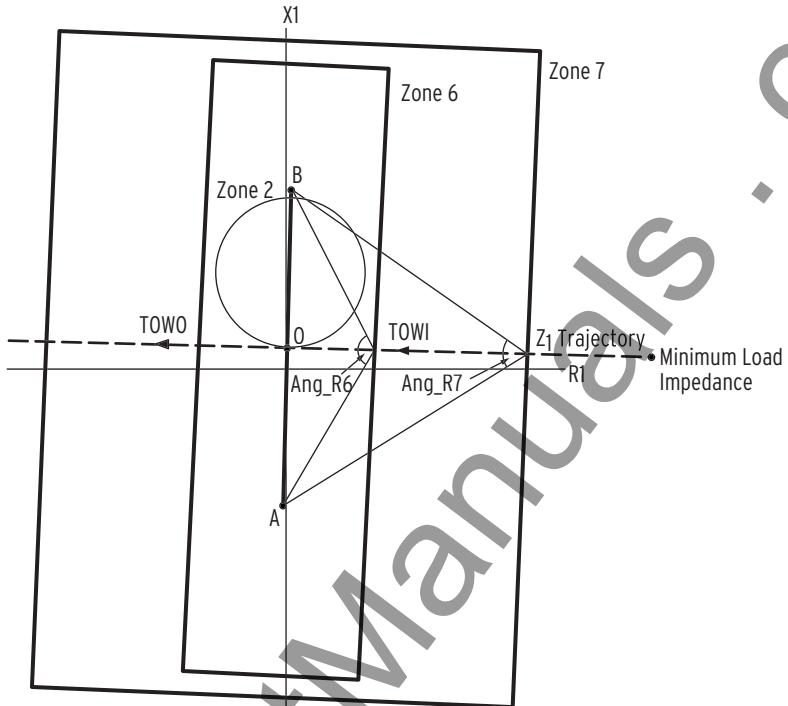


Figure 1.33 OST Characteristics

To configure the OOS logic for out-of-step tripping, enable the OOS logic. Next, calculate the impedance reach settings for Zones 6 and 7 (R1R6, R1R7, X1T6, and X1T7), and then calculate OSTD (out-of-step trip delay) and OSBD (out-of-step block time delay). All of the OOS settings appear in [Table 1.37](#) and [Table 1.38](#).

Enable OOS Logic

Access Group settings to enable the out-of-step logic.

E00S := **Y** Out-of-Step (Y, N)

NOTE: [Table 1.36](#) lists the settings that the relay automatically calculates and hides when you set EADVS to N.

You do not need to enable the Advanced Settings for this application example.

EADVS := **N** Advanced Settings (Y, N)

Out-of-Step Tripping

When the positive-sequence impedance locus enters Zone 7, both OOS logic timers (OSBD and OSTD) start (see [Figure 1.33](#)). If OSTD expires before OSBD and Zone 6 asserts, the relay declares an out-of-step tripping condition. Enable the relay to trip when Zone 6 drops out (Trip-On-the-Way-Out). See [Out-of-Step Tripping and Blocking on page A.1.131](#) for OSTD and OSBD calculations.

E00ST := **0** Out-of-Step Tripping (N, I, O)

Where:

- I = Enable out-of-step tripping (Trip-On-the-Way-In)
- O = Enable out-of-step tripping (Trip-On-the-Way-Out)
- N = Disable out-of-step tripping

Phase Distance Element Blocking

Enable the OSB function to prevent tripping when the positive-sequence impedance locus enters the Zone 1 and Zone 2 distance protection characteristics during an unstable power swing. Therefore, in this application example, the relay trips after the Z_1 impedance locus exits Zone 6 (Zone 6 drops out).

Block Zone 1 and Zone 2 distance protection elements during power swings.

00SB1 := **Y** Block Zone 1 (Y, N)

00SB2 := **Y** Block Zone 2 (Y, N)

00SB3 := **N** Block Zone 3 (Y, N)

Zone 6 and Zone 7 Impedance Settings

The purpose of this OOS application example is to configure the relay to trip when the power system reaches a critical angle limit to prevent system collapse. Thus, the Zone 6 impedance setting differs from *Out-of-Step Blocking* on page A.1.117.

Resistance Blinders

If the angle of the power swing Z_1 trajectory passes 120 degrees with respect to the transfer impedance, the power system cannot recover. The transfer impedance is the total impedance of the power system (line AB in *Figure 1.33*). Set the Zone 6 right-hand inner resistance blinder R1R6 so Ang_R6 equals 120 degrees. Rearrange *Equation 1.76* as shown in *Equation 1.79*:

$$\begin{aligned} R1R6 &= \frac{\frac{|Z_T|}{2}}{\tan\left(\frac{\text{Ang_R6}}{2}\right)} \\ &= \frac{\frac{|8.80 \angle 88^\circ + 8.00 \angle 87.6^\circ + 3.52 \angle 88^\circ|}{2}}{\tan\left(\frac{120^\circ}{2}\right)} \\ &= \frac{10.16}{\tan\left(\frac{120^\circ}{2}\right)} \\ &= 5.87 \Omega \end{aligned}$$

Equation 1.79

R1R6 := **5.87** Zone 6 Resistance—Right (0.05 to 70 Ω secondary)

Use the minimum load impedance $Z_{L(\min)}$ (*Equation 1.70*) and the 90 percent safety margin criterion (see *Equation 1.72*) applied earlier in *Resistance Blinders* on page A.1.119 to set the Zone 7 right-hand resistance blinder.

$$\begin{aligned} R1R7 &= 0.9 \cdot Z_{L(\min)} \cdot \cos[45^\circ + (90^\circ - Z1\text{ANG})] \\ &= 0.9 \cdot 25.49 \cdot \cos[45^\circ + (90^\circ - 87.6^\circ)] \\ &= 0.9 \cdot 25.49 \cdot \cos[47.4^\circ] \\ &= 15.53 \Omega \end{aligned}$$

R1R7 := **15.53** Zone 7 Resistance—Right (0.05–70 Ω secondary)

Reactance Lines

Set the reactance lines equal to the maximum values to help the relay detect power swings far from the relay location.

Set the Zone 7 top reactance line equal to the maximum setting.

$$X1T7 := 96 \text{ Zone 7 Reactance—Top (0.05–96 } \Omega \text{ secondary)}$$

Set the Zone 6 top reactance line to the maximum setting minus one ohm.

$$\begin{aligned} X1T6 &= X1T7 - 1 \Omega \\ &= 96 \Omega - 1 \Omega \\ &= 95 \Omega \end{aligned} \quad \text{Equation 1.80}$$

$$X1T6 := 95 \text{ Zone 6 Reactance—Top (0.05–96 } \Omega \text{ secondary)}$$

Out-of Step Tripping and Blocking

The OOS logic uses two zones of concentric polygons, outer Zone 7 and inner Zone 6 (see [Figure 1.33](#)). The relay uses Zone 6 and Zone 7 for OOS logic timing to differentiate OOS blocking conditions, OOS tripping conditions, and faults. The relay measures a traveling positive-sequence impedance locus (Z_1) in Zone 6 and Zone 7 when a power swing or fault occurs. When the impedance locus initially moves inside Zone 7, the relay starts two OOS logic timers. One OOS timer detects OOS blocking conditions (OSBD), while the other timer detects OOS tripping conditions (OSTD).

NOTE: You must set OSTD shorter than OSBD by at least a half cycle.

The OOS logic declares a blocking condition if OSBD expires before the positive-sequence impedance locus enters Zone 6. The logic declares a tripping condition if OSTD expires and the positive-sequence impedance locus enters Zone 6 prior to OSBD timing out.

Trip-On-Way-In/Trip-On-Way-Out

You can select one of two methods to trip during an unstable swing. You can enable the relay to trip if OSTD expires and the positive-sequence impedance enters Zone 6; this method is Trip-On-the-Way-In (TOWI in [Figure 1.33](#)). The relay asserts Relay Word bits OSTI and OST for a Trip-On-the-Way-In condition.

You can also enable the relay to trip if OSTD expires and the positive-sequence impedance enters and exits Zone 6; this second method is Trip-On-the-Way-Out (TOWO in [Figure 1.33](#)). The relay asserts Relay Word bits OSTO and OST for a Trip-On-the-Way-Out condition. Relay Word bit OST is the OR combination of OSTI and OSTO (see [Out-of-Step Logic on page R.1.51](#)).

Trip-On-the-Way-Out (TOWO) is selected for this application example (see [Enable OOS Logic on page A.1.129](#)).

Out-of-Step Tripping Time Delay

Use [Equation 1.81](#), [Equation 1.82](#), and [Equation 1.83](#) to calculate the OSTD setting. These equations are derived from the impedance trajectory shown in [Figure 1.33](#). Line section AB is the transfer impedance, Z_T . The horizontal dashed line represents the trajectory of the power swing perpendicular to line section AB. The trajectory passes through the midpoint of line section AB.

$$Z_T = Z_{1S} + Z_{1L1} + Z_{1R} \quad \text{Equation 1.81}$$

Where:

- Z_T = transfer impedance
- Z_{1S} = positive-sequence source impedance
- Z_{1L1} = positive-sequence impedance for Line 1
- Z_{1R} = Positive-sequence remote impedance

Angle Ang_R6 was specified at 120.0° as a design criterion for this application example (see [Zone 6 and Zone 7 Impedance Settings on page A.1.130](#)).

$$\begin{aligned} \text{Ang_R7} &= 2 \cdot \text{atan} \left[\frac{|Z_T|}{2} \right] \\ &= 2 \cdot \text{atan} \left[\frac{|8.80 \angle 88^\circ + 8.00 \angle 87.6^\circ + 3.52 \angle 88^\circ|}{2} \right] \\ &= 66.4^\circ \end{aligned} \quad \text{Equation 1.82}$$

Apply a fast unstable swing frequency and calculate OSTD (for this application example, $f_{\text{slip}} = 10$ Hz for an unstable power swing).

$$\begin{aligned} \text{OSTD} &= \frac{(\text{Ang_R6} - \text{Ang_R7}) \cdot f_{\text{nom}}}{\frac{360^\circ}{\text{cycle}} \cdot f_{\text{slip}}} \\ &= \frac{(120.0^\circ - 66.4^\circ) \cdot 60 \text{ Hz}}{\frac{360^\circ}{\text{cycle}} \cdot 10 \text{ Hz}} \\ &= 0.89 \text{ cycles} \end{aligned} \quad \text{Equation 1.83}$$

Where:

- f_{nom} = nominal power system frequency (Hz)
- f_{slip} = maximum slip frequency (Hz)

The OSTD timer settings are in increments of 0.125 cycle; round up to the nearest valid relay setting.

OSTD := **0.875** Out-of-Step Trip Delay (0.500–8000 cycles)

To find the effective slip rate for OOS tripping, solve [Equation 1.83](#) for f_{slip} :

$$\begin{aligned} f_{\text{slip}} &= \frac{(\text{Ang_R6} - \text{Ang_R7}) \cdot f_{\text{nom}}}{\frac{360^\circ}{\text{cycle}} \cdot f_{\text{slip}}} \\ &= \frac{(120^\circ - 66.4^\circ) \cdot 60 \text{ Hz}}{\frac{360^\circ}{\text{cycle}} \cdot 10 \text{ Hz}} \\ &= 10.2 \text{ Hz} \end{aligned} \quad \text{Equation 1.84}$$

Out-of-Step Block Time Delay

Set OSBD longer than OSTD by the next timer setting step (0.125-cycle step size) greater than 0.500 cycle. Thus, the OSBD setting is calculated in [Equation 1.85](#).

$$\begin{aligned}\text{OSBD} &= \text{OSTD} + 0.500 \text{ cycle} + \text{timer step} \\ &= 0.875 + 0.500 + 0.125 \\ &= 1.500 \text{ cycles}\end{aligned}\quad \text{Equation 1.85}$$

OSBD := **1.500** Out-of-Step Block Time Delay (0.500–8000 cycles)

To find the effective slip rate for OOS blocking, solve [Equation 1.86](#) for f_{slip} .

$$\begin{aligned}f_{\text{slip}} &= \frac{(\text{Ang_R6} - \text{Ang_R7}) \cdot f_{\text{nom}}}{\frac{360^\circ}{\text{cycle}} \cdot \text{OSBD}} \\ &= \frac{(120.0^\circ - 66.4^\circ) \cdot 60 \text{ Hz}}{\frac{360^\circ}{\text{cycle}} \cdot 1.500 \text{ cycle}} \\ &= 5.5 \text{ Hz}\end{aligned}\quad \text{Equation 1.86}$$

The relay detects OOS blocking conditions for power swing slip frequencies up to 5.95 Hz and OOS tripping conditions for power swing slip frequencies from 5.95 Hz to 10.2 Hz (see [Equation 1.84](#)). Zone 1 and Zone 2 elements remain blocked during these OSB and OST conditions. The event is not a swing condition if the Z_1 impedance locus crosses Zone 7 and Zone 6 before the OSTD and OSBD timers time out. The relay identifies this event as a fault condition.

Latch Out-of-Step Blocking

Latch out-of-step blocking to maintain the blocking condition throughout the entire swing cycle. See [Latch Out-of-Step Blocking on page A.1.123](#) for information on OSB latching and relay tripping during this condition.

OSBLTCH := **Y** Latch Out-of-Step Blocking (Y, N)

Control Outputs

For local OOS tripping, configure the relay control outputs for tripping and remote notification of an out-of-step condition. Include Relay Word bit OST in the direct tripping SELOGIC control equation TR. (Add **OR OST** to the existing TR equation; the default is shown here.)

TR := **M1P OR Z1G OR M2PT OR Z2GT OR OST** Trip (SELOGIC Equation)

Set a control output for remote notification of the out-of-step tripping condition. This example uses OUT205. Select a relay control output that is appropriate for your particular application.

OUT205 := **OST** Output OUT205 (SELOGIC Equation)

Example Completed

This completes the application example that describes setting the SEL-421 for out-of-step tripping. Analyze your particular power system to determine the appropriate settings for your application.

Relay Settings

Table 1.36 lists the settings that the relay automatically calculates and hides when you set EADVS to N.

Table 1.36 Automatically Calculated/Hidden Settings

Setting	Description	Default Setting
X1B7	Zone 7 Reactance—Bottom (–0.05 to –96 Ω secondary)	$X1B7 = -X1T7$
X1B6	Zone 6 Reactance—Bottom (–0.05 to –96 Ω secondary)	$X1B6 = -X1T6$
R1L7	Zone 7 Resistance—Left (–0.05 to –70 Ω secondary)	$R1L7 = -R1R7$
R1L6	Zone 6 Resistance—Left (–0.05 to –70 Ω secondary)	$R1L6 = -R1R6$
50ABCP	Positive-Sequence Current Supervision (1.00–100 A secondary)	$50ABCP = 0.2 \cdot I_{nom}$
50QUBP	Negative-Sequence Current Supervision (OFF, 0.50–100 A secondary)	OFF
UBD	Negative-Sequence Current Unblock Delay (0.500–120 cycles)	0.500
UBOSBF	Out-of-Step Angle Unblock Rate (1–10)	4

Table 1.37 and Table 1.38 list the protection relay settings available in this example.

Table 1.37 Relay Configuration (Group)

Setting	Description	Entry
EOOS	Out-of-Step	Y
EADVS	Advanced Settings (Y, N)	N

Table 1.38 Out-of-Step Tripping/Blocking (Sheet 1 of 2)

Setting	Description	Entry
OOSB1	Block Zone 1 (Y, N)	Y
OOSB2	Block Zone 2 (Y, N)	Y
OOSB3	Block Zone 3 (Y, N)	N
OSBD	Out-of-Step Block Time Delay (0.500–8000 cycles)	1.500
OSBLTCH	Latch Out-of-Step Blocking (Y, N)	Y
EOOST	Out-of-Step Tripping (N, I, O)	O
OSTD	Out-of-Step Trip Delay (0.500–8000 cycles)	0.875
X1T7	Zone 7 Reactance—Top (0.05 to 96 Ω secondary)	96.00
X1T6	Zone 6 Reactance—Top (0.05 to 96 Ω secondary)	95.00
R1R7	Zone 7 Resistance—Right (0.05 to 70 Ω secondary)	15.53
R1R6	Zone 6 Resistance—Right (0.05 to 70 Ω secondary)	5.87
X1B7	Zone 7 Reactance—Bottom (–0.05 to –96 Ω secondary)	–96.00
X1B6	Zone 6 Reactance—Bottom (–0.05 to –96 Ω secondary)	–95.00
R1L7	Zone 7 Resistance—Left (–0.05 to –70 Ω secondary)	–15.53
R1L6	Zone 6 Resistance—Left (–0.05 to –70 Ω secondary)	–5.87

Table 1.38 Out-of-Step Tripping/Blocking (Sheet 2 of 2)

Setting	Description	Entry
50ABCP	Positive-Sequence Current Supervision (1.00–100 A secondary)	1.00
50QUBP	Negative-Sequence Current Supervision (OFF, 0.50–100 A secondary)	OFF
UBD	Negative-Sequence Current Unblock Delay (0.500–120 cycles)	0.500
UBOSBF	Out-of-Step Angle Unblock Rate (1–10)	4
50Q1P	Level Pickup (OFF, 0.25–100 amps sec.)	OFF
67Q1D	Level 1 Time Delay (0.000–16000 cycles)	0.000
67Q1TC	Level 1 Torque Control (SELOGIC Equation)	1
TR	Trip (SELOGIC Equation)	M1P OR Z1G OR M2PT OR Z2GT OR OST
OUT205	Output OUT205 (SELOGIC Equation)	OST

Auto-Reclose Example

This application example is for a double-ended 230 kV overhead transmission line with SEL-421 protection at each end. The one-line drawing for this circuit is shown in [Figure 1.34](#). This example shows settings for the SEL-421 at Station S (Harvard) in [Figure 1.35](#).



Figure 1.34 230 kV Example Power System

Application

Auto-Reclose Mode of Operation

Apply the SEL-421 for one shot of three-pole auto-reclose.

Solution

Auto-Reclose Conditions

The relay initiates three-pole auto-reclosing if a Zone 1 trip occurs because of a multiphase fault.

Circuit Breaker1 attempts the three-pole reclose if Bus 1 is hot and the line is dead. For this application example, block auto-reclose if any of the following events occur:

- Manual trip
- Time-delayed trip
- Bus trip
- Circuit breaker failure trip

If the SEL-421 detects an LOP (loss-of-potential) condition, the auto-reclose logic drives the auto-reclose function to lockout.

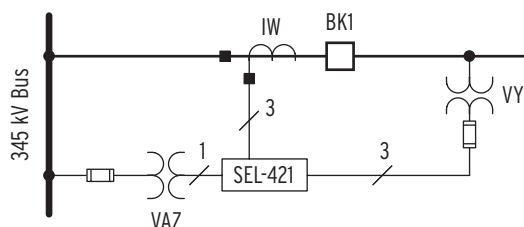


Figure 1.35 Circuit Breaker Arrangement at Station S

Relay Settings

Select the relay settings for this application example.

Relay Configuration

NOTE: Setting E79 := Y1 is intended for certain double circuit breaker applications. Use E79 := Y for a single circuit breaker.

Enable reclosing:

E79 := **Y** Reclosing (Y, Y1, N)

Recloser Closing

Select one shot of three-pole auto-reclose.

N3PSHOT := **1** Number of Three-Pole Reclosures (N, 1–4)

Use an external switch to select when Circuit Breaker 1 is enabled for three-pole auto-reclose.

E3PRI := **IN106** Three-Pole Reclose Enable -BK1 (SELOGIC Equation)

If Circuit Breaker 1 fails to close within 10 seconds after the reclose command is received, the auto-reclose logic goes to lockout.

BKCFD := **600** Breaker Close Failure Delay (1–99999 cycles)

Unlatch the reclose command to Circuit Breaker 1 when all three poles are closed.

ULCL1 := **52AA1 AND 52AB1 AND 52AC1** Unlatch Closing for Circuit Breaker 1 (SELOGIC Equation)

Drive the auto-reclose logic to lockout if the SEL-421 detects an LOP condition.

79DTL := **LOP** Recloser Drive to Lockout (SELOGIC Equation)

You can block the reclaim timing. However, it is not necessary for this single shot application example.

79BRCT := **NA** Block Reclaim Timer (SELOGIC Equation)

When leaving the lockout condition, the recloser goes to the Ready or Reset state after the 3PMRCD (Manual Close Reclaim Time Delay) timer has expired.

3PMRCD := **900** Manual Close Reclaim Time Delay (1–99999 cycles)

If Circuit Breaker 1 reclose supervision conditions fail to occur within 300 cycles after the three-pole open interval time delay expires, BK1CLST will assert, and the auto-reclose logic goes to lockout.

BK1CLSD := **300** BK1 Reclose Supervision Delay (OFF, 1–99999 cycles)

Three-Pole Reclose

Set the three-pole open interval time equal to 30 cycles.

3POID1 := **30** Three-Pole Open Interval 1 Delay (1–99999 cycles)

There is no need to enable fast three-pole auto-reclose because we have already used the first and only three-pole shot for this purpose.

3PFARC := **NA** Three-Pole Fast ARC Enable (SELOGIC Equation)

Set the reset time following a three-pole auto-reclose cycle equal to 900 cycles.

3PRCD := **900** Three-Pole Reclaim Time Delay (1–99999 cycles)

Initiate a three-pole auto-reclose cycle when the SEL-421 three-pole trips because of Zone 1 phase distance protection. Communications-assisted tripping is not enabled.

3PRI := **3PT AND MIP** Three-Pole Reclose Initiation (SELOGIC Equation)

You can force the auto-reclose logic to skip a three-pole shot. However, it is not necessary for this application example.

79SKP := **NA** Skip Reclosing Shot (SELOGIC Equation)

Only attempt to reclose Circuit Breaker 1 if the bus is hot and the line is dead (setting cannot be set to NA or logical 0).

3PICLS := **DLLB1** Three Pole BK 1 Reclose Supervision (SELOGIC Equation)

Voltage Elements

The SEL-421 checks the Bus and Line conditions when you enable the voltage check elements. [Figure 1.36](#) shows a typical checking scheme. Potentials VAY and VAX are the default synchronism inputs for V_P (setting SYNCP) and V_{S1} (setting SYNCS1), respectively (see [PT Connections on page R.2.57](#)).

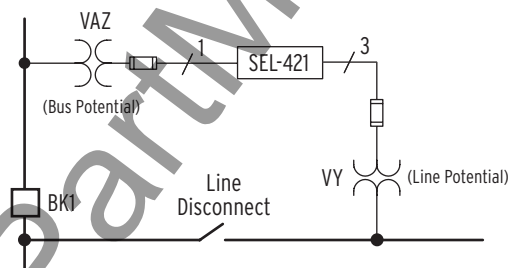


Figure 1.36 Potential Sources

Enable the voltage check elements.

EVCK := **Y** Reclosing Voltage Check (Y, N)

Set the dead line voltage threshold equal to 15 V secondary.

27LP := **15.0** Dead Line Voltage (1.0–200 V secondary)

Set the live line voltage threshold equal to 50 V secondary.

59LP := **50.0** Live Line Voltage (1.0–200 V secondary)

Set the dead bus voltage threshold for Circuit Breaker 1 equal to 15 V secondary.

27BK1P := **15.0** Breaker 1 Dead Busbar Voltage
(1.0–200 V secondary)

Set the live bus voltage threshold for Circuit Breaker 1 equal to 50 V secondary.

59BK1P := **50.0** Breaker 1 Live Busbar Voltage
(1.0–200 V secondary)

Example Complete

This completes the application example that describes setting the SEL-421 for one shot of three-pole reclosing for a single circuit breaker. Analyze your particular power system to determine the appropriate settings for your application.

Relay Settings

Table 1.39 provides a list of all the SEL-421 auto-reclose settings. Those settings that were applied for this particular application appear in boldface.

Table 1.39 Settings for Auto-Reclose Example

Setting	Description	Entry
Relay Configuration		
E79	Reclosing (Y, Y1, N)	Y
Recloser Closing (Group)		
NSPSHOT	Number of Single-Pole Reclosures (N, 1, 2)	N
N3PSHOT	Number of Three-Pole Reclosures (N, 1–4)	1
E3PR1	Three-Pole Reclose Enable—BK1 (SELOGIC Equation)	IN106
BKCFD	Breaker Close Failure Delay (OFF, 1–99999 cycles)	600
ULCL1	Unlatch Closing for Breaker 1 (SELOGIC Equation)	52AA1
79DTL	Recloser Drive to Lockout (SELOGIC Equation)	LOP
79BRCT	Block Reclaim Timer (SELOGIC Equation)	NA
3PMRCD	Manual Close Reclaim Time Delay (1–99999 cycles)	900
BK1CLSD	BK1 Reclose Supervision Delay (OFF, 1–99999 cycles)	300
Three-Pole Reclose (Group)		
3POID1	Three-Pole Open Interval 1 Delay (1–99999 cycles)	30
3PFARC	Three-Pole Fast Automatic Reclose Enable (SELOGIC Equation)	NA
3PRCD	Three-Pole Reclaim Time Delay (1–99999 cycles)	900
3PRI	Three-Pole Reclose Initiation (SELOGIC Equation)	3PT AND M1P
79SKP	Skip Reclosing Shot (SELOGIC Equation)	NA
3P1CLS^a	Three-Pole BK 1 Reclose Supervision (SELOGIC Equation)	DLLB1
Voltage Elements (Group)		
EVCK	Reclosing Voltage Check (Y, N)	Y
27LP	Dead Line Voltage (1.0–200 V secondary)	15.0
59LP	Live Line Voltage (1.0–200 V secondary)	50.0
27BK1P	Breaker 1 Dead Busbar Voltage (1.0–200 V secondary)	15.0
59BK1P	Breaker 1 Live Busbar Voltage (1.0–200 V secondary)	50.0

^a This setting cannot be set to NA or logical 0.

Auto-Reclose and Synchronism Check Example

Use the SEL-421 to provide automatic reclosing and synchronism check for overhead transmission lines. This application example is for double-ended 500 kV parallel lines with SEL-421 protection at each end of the first circuit as shown in [Figure 1.37](#). This example shows the settings for the SEL-421 at Station S protecting Line 1 in [Figure 1.38](#) between Buses S (Moscow) and R (Pullman).

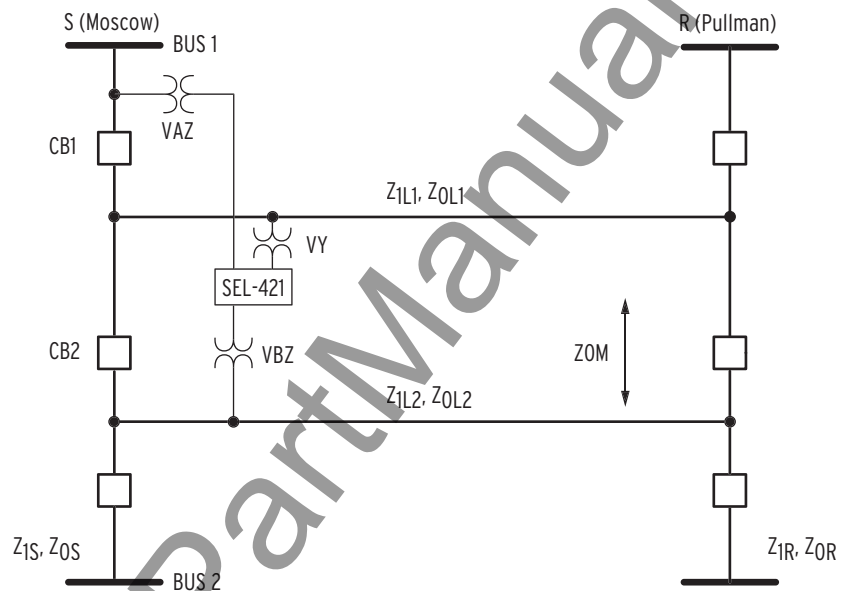


Figure 1.37 500 kV Power System

First set the auto-reclose logic, and then set the synchronism-check function.

Auto-Reclose Application

Apply the SEL-421 for one shot of single-pole reclosing and one shot of three-pole reclosing.

Select the recloser mode with the enable setting E79 := Y or Y1, and set E3PR1 and E3PR2 to logical 1.

Modes of Operation

The SEL-421 auto-reclose logic operates in one of two modes at all times:

- Single-pole mode (SPAR)
- Three-pole mode (3PAR)

Single-pole trips initiate single-pole reclosing. For this application example, if the single-pole reclose is unsuccessful, the second trip is a three-pole trip. Three-pole trips initiate three-pole reclosing. If a single-pole auto-reclose cycle is in progress and the relay receives an initiation for three-pole reclosing, the relay immediately starts a three-pole auto-reclose cycle.

Select the recloser mode with the three-pole enable settings and the single-pole enable settings E3PR1, E3PR2, ESPR1, and ESPR2.

Auto-Reclose Sequence

The relay performs one shot of reclosing for both single-pole and three-pole automatic reclosing.

When $E79 := Y$, the leader circuit breaker (CB1) recloses if the line is dead and Bus 1 is hot. If the leader successfully recloses, the follower circuit breaker (CB2) also attempts a reclose if the synchronism check is successful. CB2 can also close if the line is dead and Bus 2 is hot if CB1 is out of service. A similar SEL-421 installation would protect line 2, and provide auto-reclose capabilities.

When $E79 := Y1$, if CB2 trips from the line 2 protection (not shown), the SEL-421 on line 1 would attempt to reclose CB2. This configuration would typically employ a hot bus check.

Open interval timing does not begin until the faulted phase(s) is opened.

If another trip occurs while the single-pole auto-reclose cycle is in progress the relay trips the other two poles.

The auto-reclose logic resets after the reclaim timer (SPRCD or 3PRCD) expires.

Dynamic Determination of the Leader Circuit Breaker

If Circuit Breaker 1 (the leader breaker) is out of service, the leader settings are automatically routed to Circuit Breaker 2. Circuit Breaker 2 operates as the leader circuit breaker when Circuit Breaker 1 is out of service. When Circuit Breaker 2 is the leader, this circuit breaker can single-pole reclose.

Auto-Reclose Solution

Auto-Reclose Conditions

The relay initiates single-pole auto-reclose if a Zone 1 trip or a communications-assisted trip occurs for a single phase-to-ground fault. The relay initiates three-pole auto-reclose if a Zone 1 trip or a communications-assisted trip occurs for a multiphase fault.

Circuit Breaker 1 can attempt a reclose if Bus 1 is hot and the line is dead. Circuit Breaker 2 can attempt a reclose if the synchronism check is successful or if Circuit Breaker 1 is out of service and the line is dead and Bus 2 is hot.

Block auto-reclose if any of the following events occur:

- Manual trip
- Time-delayed trip
- Bus trip
- Circuit breaker failure trip

If the SEL-421 detects a loss-of-potential condition, the auto-reclose logic drives the auto-reclose function to lockout.

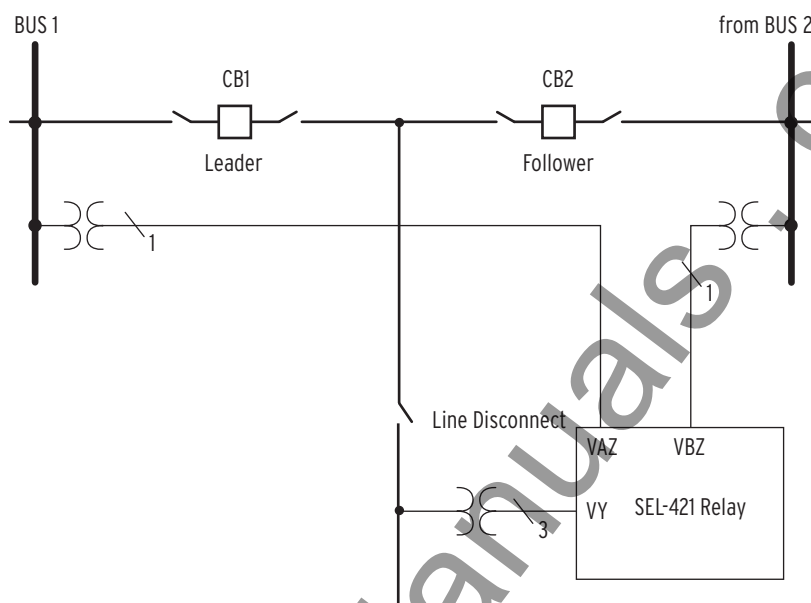


Figure 1.38 Partial Circuit Breaker-and-a-Half Arrangement at Station S, Line 1

Auto-Reclose Relay Settings

Select the auto-reclose relay settings for this application example.

Relay Configuration

Enable reclosing.

E79 := **Y** Reclosing (Y, Y1, N)

Selection Y1 can be used in circumstances where CB2 can be tripped externally, yet the SEL-421 is to be able to auto-reclose.

Recloser Closing

Select one shot of single-pole auto-reclose.

NSPSHOT := **1** Number of Single-Pole Reclosures (N, 1, 2)

Use an external switch to select when the leader or follower circuit breaker is enabled for single-pole auto-reclose.

ESPR1 := **IN205** Single-Pole Reclose Enable—BK1 (SELOGIC Equation)

ESPR2 := **IN206** Single-Pole Reclose Enable—BK2 (SELOGIC Equation)

Select one shot of three-pole auto-reclose.

N3PSHOT := **1** Number of Three-Pole Reclosures (N, 1–4)

Use an external switch to select when the leader or follower circuit breaker is enabled for three-pole auto-reclose.

E3PR1 := **IN207** Three-Pole Reclose Enable—BK1 (SELOGIC Equation)

E3PR2 := **IN208** Three-Pole Reclose Enable—BK2 (SELOGIC Equation)

The time delay before Circuit Breaker 2 attempts a reclose after Circuit Breaker 1 has successfully reclosed is 15 cycles. The short delay prevents both circuit breakers closing back into a permanent fault.

TBBKD := **15** Time Between Breakers for ARC (1–99999 cycles)

If either circuit breaker fails to close within 10 seconds after the reclose command is received, the auto-reclose logic goes to lockout for the failed circuit breaker.

BKCFD := 600 Breaker Close Failure Delay (OFF, 1–99999 cycles)

You can use a normally closed auxiliary contact from the Circuit Breaker 1 disconnect switch to denote that this circuit breaker is the leader when in service. Use the contact to energize a control input; if the disconnect switch is closed, the input is energized.

SLBK1 := IN107 Lead Breaker = Breaker 1 (SELOGIC Equation)

We have selected Circuit Breaker 1 as the leader. The auto-reclose logic automatically recognizes Circuit Breaker 2 as the leader when Circuit Breaker 1 is out of service.

SLBK2 := 0 Lead Breaker = Breaker 2 (SELOGIC Equation)

Circuit Breaker 2 is the follower circuit breaker. The follower can attempt to reclose if all three poles of Circuit Breaker 2 are actually open or if Circuit Breaker 1 is out of service.

FBKCN := 3POBK2 OR (NOT LEADBK1) Follower Breaker Closing Enable (SELOGIC Equation)

Unlatch the reclose command to Circuit Breaker 1 when all three poles are closed.

ULCL1 := 52AA1 AND 52AB1 AND 52AC1 Unlatch Closing for Breaker 1 (SELOGIC Equation)

Unlatch the reclose command to Circuit Breaker 2 when all three poles are closed.

ULCL2 := 52AA2 AND 52AB2 AND 52AC2 Unlatch Closing for Breaker 2 (SELOGIC Equation)

Drive the auto-reclose logic to lockout if the SEL-421 detects a loss-of-potential condition.

79DTL := LOP Recloser Drive to Lockout (SELOGIC Equation)

You can block reclaim timing. However, it is not necessary for this application example.

79BRCT := NA Block Reclaim Timer (SELOGIC Equation)

When leaving the lockout condition, the recloser goes to the Ready or Reset state after the 3PMRCD (Manual Close Reclaim Time Delay) timer has expired.

3PMRCD := 900 Manual Close Reclaim Time Delay (1–99999 cycles)

If Circuit Breaker 1 reclose supervision conditions (settings SP1CLS and 3P1CLS) fail to occur within 300 cycles after the three-pole open interval time delay expires, the auto-reclose logic goes to lockout.

BK1CLSD := 300 BK1 Reclose Supervision Delay (OFF, 1–99999 cycles)

If Circuit Breaker 2 reclose supervision conditions (settings SP2CLS and 3P2CLS) fail to occur within 300 cycles after the three-pole open interval time delay expires, the auto-reclose logic goes to lockout.

BK2CLSD := 300 BK2 Reclose Supervision Delay (OFF, 1–99999 cycles)

Single-Pole Auto-Reclose Logic

Initiate a single-pole auto-reclose cycle whenever the SEL-421 single-pole trips. Auto-reclose is blocked if a manual, time-delayed, bus, or circuit breaker failure trip occurs. None of these events generate a single-pole trip (see [Auto-Reclose Conditions on page A.1.141](#)).

Set the single-pole open interval time equal to one second.

SP0ID := 60 Single-Pole Open Interval Delay (1–99999 cycles)

Set the reclaim time following a single-pole auto-reclose cycle equal to 900 cycles.

SPRCD := 900 Single-Pole Reclaim Time Delay (1–99999 cycles)

Initiate a single-pole auto-reclose cycle whenever the SEL-421 single-pole trips.

SPRI := SPT AND (Z1G OR COMPRM) Single-Pole Reclose Initiation (SELOGIC Equation)

No supervision is required before Circuit Breaker 1 attempts a single-pole reclose. The SEL-421 auto-reclose logic only applies synchronism supervision during a single-pole auto-reclose cycle in this application example (setting cannot be set to NA or logical 0).

SPICLS := 1 Single-Pole BK1 Reclose Supervision (SELOGIC Equation)

No supervision is required before Circuit Breaker 2 attempts a single-pole reclose when this circuit breaker is the leader. The SEL-421 auto-reclose logic only applies synchronism supervision during a single-pole auto-reclose cycle in this application example (setting cannot be set to NA or logical 0).

SP2CLS := NOT LEADBK1 Single-Pole BK2 Reclose Supervision (SELOGIC Equation)

Three-Pole Auto-Reclose Logic

Set the three-pole open interval time equal to 30 cycles.

3P0ID1 := 30 Three-Pole Open Interval 1 Delay (1–99999 cycles)

There is no need to enable fast three-pole auto-reclose because we have already used the first and only three-pole shot for this purpose.

3PFARC := NA Three-Pole Fast ARC Enable (SELOGIC Equation)

Set the reclaim time following a three-pole auto-reclose cycle equal to 900 cycles.

3PRCD := 900 Three-Pole Reclaim Time Delay (1–99999 cycles)

Initiate a three-pole auto-reclose cycle when the SEL-421 three-pole trips because of Zone 1 phase distance protection or a communications-assisted trip. No manual, time-delayed, bus, or circuit breaker failure trips are included in the 3PRI SELOGIC control equation for this application example.

3PRI := 3PT AND (M1P OR COMPRM) Three-Pole Reclose Initiation (SELOGIC Equation)

You can force the auto-reclose logic to skip a three-pole shot. However, it is not necessary for this application example.

79SKP := NA Skip Reclosing Shot (SELOGIC Equation)

Only attempt to reclose Circuit Breaker 1 if Bus 1 is hot and the line is dead. The SEL-421 auto-reclose logic only applies this supervision during a three-pole auto-reclose cycle (you cannot set this setting to NA or logical 0; see [Voltage Elements on page A.1.138](#)).

3P1CLS := **DLLB1** Three Pole BK 1 Reclose Supervision (SELOGIC Equation)

Only attempt to reclose Circuit Breaker 2 if the synchronism check is successful or if Circuit Breaker 1 is out of service and the line is dead and Bus 2 is hot. The SEL-421 auto-reclose logic only applies synchronism supervision during a three-pole auto-reclose cycle in this application example (you cannot set this setting to NA or logical 0).

3P2CLS := **25A2BK2 OR (NOT LEADBK1 AND DLLB2)** Three Pole BK 2 Reclose Supervision (SELOGIC Equation)

Voltage Elements

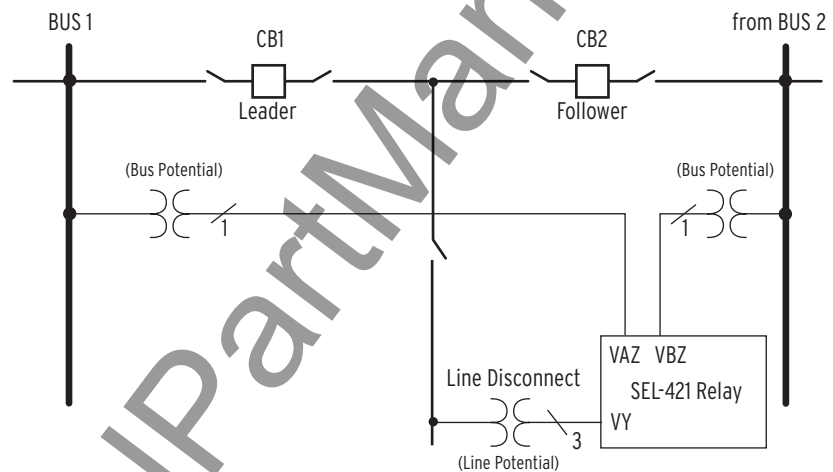


Figure 1.39 Potential Sources

Enable the voltage check elements.

EVCK := **Y** Reclosing Voltage Check (Y, N)

Set the dead line voltage threshold equal to 15 V secondary.

27LP := **15.0** Dead Line Voltage (1.0–200 V secondary)

Set the live line voltage threshold equal to 50 V secondary.

59LP := **50.0** Live Line Voltage (1.0–200 V secondary)

Set the dead bus voltage threshold for Circuit Breakers 1 and 2 equal to 15 volts secondary.

27BK1P := **15.0** Breaker 1 Dead Busbar Voltage (1.0–200 V secondary)

27BK2P := **15.0** Breaker 2 Dead Busbar Voltage (1.0–200 V secondary)

Set the live bus voltage threshold for Circuit Breakers 1 and 2 equal to 50 V secondary.

59BK1P := **50.0** Breaker 1 Live Busbar Voltage (1.0–200 V secondary)

59BK2P := **50.0** Breaker 2 Live Busbar Voltage (1.0–200 V secondary)

Trip Logic

If you want Circuit Breaker 2 to always three-pole trip, except when Circuit Breaker 2 is the leader, program SELOGIC control equation E3PT2 as follows:

E3PT2 := **NOT LEADBK2** Breaker 2 3PT (SELOGIC Equation)

Synchronism-Check Application

Reclose Circuit Breaker 1 following a three-pole trip if the line is dead and Bus 1 is hot. Reclose Circuit Breaker 2 following a three-pole trip if a synchronism check across the hot line to Bus 2 is successful or Circuit Breaker 1 is out of service and the line is dead and Bus 2 is hot.

In this application example, the relay does not perform a synchronism check on single-pole reclosing.

Synchronism-Check Solution

Apply the synchronism-check function as follows for Circuit Breaker 2:

- Use the A-Phase voltages from the line and Bus 2 for the synchronism check across Circuit Breaker 2.
- Select the high voltage magnitude and low voltage magnitude thresholds for the synchronism check.
- Select the maximum voltage angle difference allowed for both reclosing and manual closing.
- Select conditions that block the synchronism check.

Synchronism-Check Relay Settings

Select the relay settings for this application example.

Relay Configuration

Enable synchronism check for Circuit Breaker 2 only.

E25BK1 := **N** Synchronism Check for Breaker 1 (Y, N)

E25BK2 := **Y** Synchronism Check for Breaker 2 (Y, N)

Synchronism-Check Element Reference

Select A-Phase voltage from the line source for the synchronism check reference. VAY is the reference for the synchronism check because this analog input is connected to the line potential.

SYNCP := **VAY** Synch Reference (VAY, VBY, VCY, VAZ, VBZ, VCZ)

Set the low voltage threshold that supervises synchronism check equal to 60 V secondary.

25VL := **60.0** Voltage Window Low Threshold (20.0–200 V secondary)

Set the high voltage threshold that supervises synchronism check equal to 70 V secondary.

25VH := **70.0** Voltage Window High Threshold (20.0–200 V secondary)

Circuit Breaker 2 Synchronism Check

Select A-Phase voltage from Bus 2 for the synchronism check source. VBZ is the source for the synchronism check because this is the bus potential.

SYNCS2 := **VBZ** Synch Source 2 (VAY, VBY, VCY, VAZ, VBZ, VCZ)

Both the line reference and bus source voltages are measured line-to-neutral. Set the ratio factor equal to unity.

KS2M := **1.00** Synch Source 2 Ratio Factor (0.000–30)

You do not need to shift the angle of the synchronism check because both the source and reference voltage are measured A-Phase-to-neutral.

KS2A := **0** Synch Source 2 Angle Shift (0, 30, 60, 90, 120, 150, 180, 210, 240, 270, 300, 330 degrees)

There is no alternate synchronism source for Circuit Breaker 2 in this application example.

ALTS2 := **NA** Alternative Synch Source 2 (SELOGIC Equation)

Assume that there is no slip between the source and reference voltages.

25SFBK2 := **OFF** Maximum Slip Frequency—BK2 (OFF, 0.005–0.5 Hz)

Set the maximum allowable voltage angular difference between the source and reference voltages equal to 20 degrees when attempting to reclose Circuit Breaker 2.

ANG1BK2 := **20.0** Maximum Angle Difference 1—BK2 (3.0–80 degrees)

Set the maximum allowable voltage angular difference between the source and reference voltages equal to 20 degrees when attempting to manually close Circuit Breaker 2.

ANG2BK2 := **20.0** Maximum Angle Difference 2—BK2 (3.0–80 degrees)

The relay does not compensate the synchronism check to account for circuit breaker closing time because setting 25SFBK2 is OFF. Leave the close time compensation setting at the default.

TCLSBK2 := **1.00** Breaker 2 Close Time (1.00–30 cycles)

Block the synchronism check if Circuit Breaker 2 is closed.

BSYNBK2 := **52AA2 AND 52AB2 AND 52AC2** Block Synchronism Check—BK2 (SELOGIC Equation)

Example Complete

This completes the application example that describes setting the SEL-421 for one shot of high-speed single-pole reclosing and one shot of three-pole reclosing for two circuit breakers. This example showed a configuration for synchronism check, as well. Analyze your particular power system to determine the appropriate settings for your application.

Relay Settings

Table 1.40 provides a list of all the SEL-421 auto-reclose settings.

Table 1.40 Settings for Auto-Reclose and Synchronism Check Example
(Sheet 1 of 3)

Setting	Description	Entry
Recloser Closing (Group)		
E79	Reclosing (Y, Y1, N)	Y
NSPSHOT	Number of Single-Pole Reclosures (N, 1, 2)	1
ESPR1	Single-Pole Reclose Enable—BK1 (SELOGIC Equation)	IN205
ESPR2	Single-Pole Reclose Enable—BK2 (SELOGIC Equation)	IN206
N3PSHOT	Number of Three-Pole Reclosures (N, 1–4)	1
E3PR1	Three-Pole Reclose Enable—BK1 (SELOGIC Equation)	IN207
E3PR2	Three-Pole Reclose Enable—BK2 (SELOGIC Equation)	IN208
TBBKD	Time Between Breakers for Automatic Reclose (1–99999 cycles)	15
BKCFD	Breaker Close Failure Delay (OFF, 1–99999 cycles)	600
SLBK1	Lead Breaker = Breaker 1 (SELOGIC Equation)	IN107
SLBK2	Lead Breaker = Breaker 2 (SELOGIC Equation)	0
FBKCEN	Follower Breaker Closing Enable (SELOGIC Equation)	3POBK2 OR NOT LEADBK1
ULCL1	Unlatch Closing for Breaker 1 (SELOGIC Equation)	52AA1 AND 52AB1 AND 52AC1
ULCL2	Unlatch Closing for Breaker 2 (SELOGIC Equation)	52AA2 AND 52AB2 AND 52AC2
79DTL	Recloser Drive to Lockout (SELOGIC Equation)	LOP
79BRCT	Block Reclaim Timer (SELOGIC Equation)	NA
3PMRCD	Manual Close Reclaim Time Delay (1–99999 cycles)	900
BK1CLSD	BK1 Reclose Supervision Delay (OFF, 1–99999 cycles)	300
BK2CLSD	BK2 Reclose Supervision Delay (OFF, 1–99999 cycles)	300
Single-Pole Reclose (Group)		
SPOID	Single-Pole Open Interval Delay (1–99999 cycles)	60
SPRCD	Single-Pole Reclaim Time Delay (1–99999 cycles)	900
SPRI	Single-Pole Reclose Initiation (SELOGIC Equation)	SPT AND (Z1G AND COMPRM)
SP1CLS^a	Single-Pole BK1 Reclose Supervision (SELOGIC control equation)	1

Table 1.40 Settings for Auto-Reclose and Synchronism Check Example
(Sheet 2 of 3)

Setting	Description	Entry
SP2CLS^a	Single-Pole BK2 Reclose Supervision (SELOGIC Equation)	NOT LEADBK1
Three-Pole Reclose (Group)		
3POID1	Three-Pole Open Interval 1 Delay (1–99999 cycles)	30
3PFARC	Three-Pole Fast Auto-Reclose Enable (SELOGIC Equation)	NA
3PRCD	Three-Pole Reclaim Time Delay (1–99999 cycles)	900
3PRI	Three-Pole Auto-Reclose Initiate (SELOGIC Equation)	3PT AND (M1P OR COMPRM)
79SKP	Skip Reclosing Shot (SELOGIC Equation)	NA
3P1CLS^a	Three-Pole BK 1 Reclose Supervision (SELOGIC Equation)	DLLB1
3P2CLS^a	Three-Pole BK 2 Reclose Supervision (SELOGIC Equation)	25A2BK2 OR (NOT LEADBK1 AND DLLB2)
Voltage Elements (Group)		
EVCK	Reclosing Voltage Check (Y, N)	Y
27LP	Dead Line Voltage (1.0–200 V secondary)	15.0
59LP	Live Line Voltage (1.0–200 V secondary)	50.0
27BK1P	Breaker 1 Dead Busbar Voltage (1.0–200 V secondary)	15.0
59BK1P	Breaker 1 Live Busbar Voltage (1.0–200 V secondary)	50.0
27BK2P	Breaker 2 Dead Busbar Voltage (1.0–200 V secondary)	15.0
59BK2P	Breaker 2 Live Busbar Voltage (1.0–200 V secondary)	50.0
Trip Logic (Group)		
E3PT2	Breaker 2 3PT (SELOGIC Equation)	NOT LEADBK2
Relay Configuration (Group)		
E25BK1	Synchronism Check for Breaker 1 (Y, N)	N
E25BK2	Synchronism Check for Breaker 2 (Y, N)	Y
Synchronism-Check Element Reference (Group)		
SYNCP	Synchronism Reference (VAY, VBY, VCY, VAZ, VBZ, VCZ)	VAY
25VL	Voltage Window Low Threshold (20.0–200 V secondary)	60.0
25VH	Voltage Window High Threshold (20.0–200 V secondary)	70.0
Breaker 2 Synchronism Check (Group)		
SYNCS2	Synchronism Source 2 (VAY, VBY, VCY, VAZ, VBZ, VCZ)	VBZ
KS2M	Synchronism Source 2 Ratio Factor (0.10–3)	1.00

Table 1.40 Settings for Auto-Reclose and Synchronism Check Example
(Sheet 3 of 3)

Setting	Description	Entry
KS2A	Synchronism Source 2 Angle Shift (0, 30, 60, 90, 120, 150, 180, 210, 240, 270, 300, 330 degrees)	0
ALTS2	Alternative Synchronism Source 2 (SELOGIC Equation)	NA
25SFBK2	Maximum Slip Frequency—BK2 (OFF, 0.005–0.5 Hz)	OFF
ANG1BK2	Maximum Angle Difference 1—BK2 (3.0–80 degrees)	20.0
ANG2BK2	Maximum Angle Difference 2—BK2 (3.0–80 degrees)	20.0
TCLSBK2	Breaker 2 Close Time (1.00–30 cycles)	1.00
BSYNBK2	Block Synchronism Check—BK2 (SELOGIC Equation)	52AA2 AND 52AB2 AND 52AC2

^a These settings cannot be set to NA or logical 0.

Circuit Breaker Failure Application Examples

NOTE: The following discussion designates Circuit Breaker 1. For Circuit Breaker 2, replace the 1 with 2.

Under normal operating conditions, local station primary protection operates to remove faulted equipment from service. Zones of protection are arranged to minimize service disruption when local primary protection operates. Backup protection clears the fault when local protection fails to do so, typically removing more equipment from service than the primary protection would have removed for a correct operation.

Protection systems typically employ both local and remote backup protection. Local backup protection uses dedicated additional equipment to clear a fault if the local primary protection fails. Remote backup protection consists of overlapping, time-coordinated protection zones situated at remote locations with respect to the local terminal. Remote backup protection operates if a fault outside the local protection zone persists. Circuit breaker failure relaying is local backup protection.

The SEL-421 features four types of circuit breaker failure and retrip protection capability:

1. Failure to interrupt fault current for phase currents
2. No current/residual current circuit breaker failure protection
3. Failure to interrupt load current
4. Flashover circuit breaker failure protection

Protection against failure to interrupt fault current for phase currents is the most common implementation. This subsection describes failure to interrupt fault current circuit breaker failure protection.

Failure to Interrupt Fault Current for Phase Currents

The SEL-421 provides two schemes for failure to interrupt fault current for phase currents. Scheme 1 is protection for basic cases involving both multiphase faults and single-phase faults with a common breaker failure time delay. Scheme 2 is for more elaborate protection that discriminates between multiphase and single-phase faults and features separate circuit breaker failure time delays. Use Scheme 2 for separate circuit breaker failure timing for three-pole and single-pole faults.

Basic Operation—Scheme 1 and Scheme 2

NOTE: The following discussion specifies three elements. There is one element for each phase: $\phi = A, B,$ and C .

A trip output from the local primary or backup line protection typically initiates the failure to interrupt fault current circuit breaker failure scheme (BFI3P1 and BFI ϕ 1 for Scheme 1 or BFI ϕ 1 for Scheme 2). When initiated, the relay starts circuit breaker failure timing; the time delay is BFPU1 (Breaker Failure Time Delay—BK1). The SEL-421 does not require an external BFI contact when applied for local circuit breaker failure protection because the relay detects line faults. In addition, you can add external BFI from an input in parallel with the circuit breaker trip coil to capture additional trip initiations to increase scheme dependability.

Set the instantaneous overcurrent element pickup threshold 50FP1 to pick up for all line faults. The relay asserts Relay Word bit 50F ϕ 1 when the phase current exceeds the 50FP1 threshold. The 50F ϕ 1 element must reset quickly even during the presence of subsidence current at the circuit breaker opening.

If 50F ϕ 1 is asserted when timer BFPU1 expires, the relay asserts circuit breaker failure protection Relay Word bit FBF1 (Breaker 1 Breaker Failure). Assign FBF1 to SELOGIC control equation BFTR1 (Breaker Failure Trip—BK1) as one of the circuit breaker failure elements that can cause a circuit breaker failure trip. When SELOGIC control equation BFTR1 asserts, the relay asserts corresponding Relay Word bit BFTRIP1 (Breaker 1 Failure Trip Output). Assign BFTRIP1 to a high current interrupting control output to perform circuit breaker failure tripping or to a standard control output to operate an 86 lockout relay.

Scheme Components

The following are components of the circuit breaker failure schemes in the SEL-421:

- Circuit Breaker Failure Initiation (BFI3P1 or BFI ϕ 1)
- Phase Fault Current Pickup (50FP1)
- Breaker Failure Pickup Time Delay (BFPU1)

For a detailed description see [Circuit Breaker Failure Trip Logic on page R.1.131](#).

Circuit Breaker Failure Initiation (BFI3P1 or BFI ϕ 1)

All circuit breaker trips typically initiate the circuit breaker failure scheme. The SEL-421 detects power system faults; the relay does not need an external BFI contact for local circuit breaker failure protection applications.

Scheme 1. Scheme 1 uses initiation SELOGIC control equation BFI3P1 for three-pole tripping applications and BFI ϕ 1 for single-pole tripping applications.

Scheme 2. Scheme 2 uses initiation SELOGIC control equations BFI ϕ 1 for both three-pole (multiphase) and single-phase faults.

Phase Fault Current Pickup (50FP1)

Circuit breaker failure protection must pick up for all faults on the protected line. Two settings philosophies are prevalent. One philosophy is to set the instantaneous overcurrent element (50F ϕ 1) to pick up above load current and below the minimum fault current (under minimum generation), if possible ($I_{load\ max} < 50FP1 < I_{minimum\ fault}$). Another settings philosophy is to set the threshold to match the line protection sensitivity; this increases circuit breaker failure protection dependability.

In the following application examples, we use the first settings philosophy because this approach gives greater security. In either case, when input phase currents exceed the overcurrent element threshold, the relay asserts Relay Word bit 50F ϕ 1.

Subsidence current results from the energy trapped in the CT magnetizing branch after the circuit breaker opens to clear a fault or interrupt load. Subsidence current exponentially decays and delays resetting of instantaneous overcurrent elements. However, the open phase detection logic causes the SEL-421 50F ϕ 1 element to reset in less than one cycle during subsidence current conditions. The open phase detection logic determines that a pole is open during the presence of subsidence current and immediately resets the corresponding current level detectors.

Breaker Failure Pickup Time Delay (BFPU1)

Scheme 1. Relay Word bit FBF1 (Breaker 1 Breaker Failure) asserts when the time delay on pickup timer BFPU1 expires and the corresponding 50F01 element is asserted.

Scheme 2. Relay Word bit FBF1 (Breaker 1 Breaker Failure) asserts for these conditions:

- *A single phase-to-ground fault occurs:* FBF1 asserts when time delay on pickup timers BFPU1 (Breaker Failure Time Delay—BK1) followed by SPBFPU1 (SPT Breaker Failure Time Delay—BK1) expire. The corresponding 50F01 element and only one single-phase breaker failure initiation (for example, BFIA1) are asserted.
- *A multiphase fault occurs:* FBF1 asserts when time delay on pickup timer BFPU1 (Breaker Failure Time Delay—BK1) expires. The corresponding 50F01 elements and at least two single-phase breaker failure initiations (for example, BFIA1 and BFIB1) are asserted.

Timing Sequence

Figure 1.40 and *Figure 1.41* illustrate the timing sequence for circuit breaker failure schemes.

Scheme 1

Scheme 1 follows *Figure 1.40*.

Scheme 2

Scheme 2 uses both timing sequences in *Figure 1.40* and *Figure 1.41*, depending on the fault type (multiphase fault and single-phase fault, respectively).

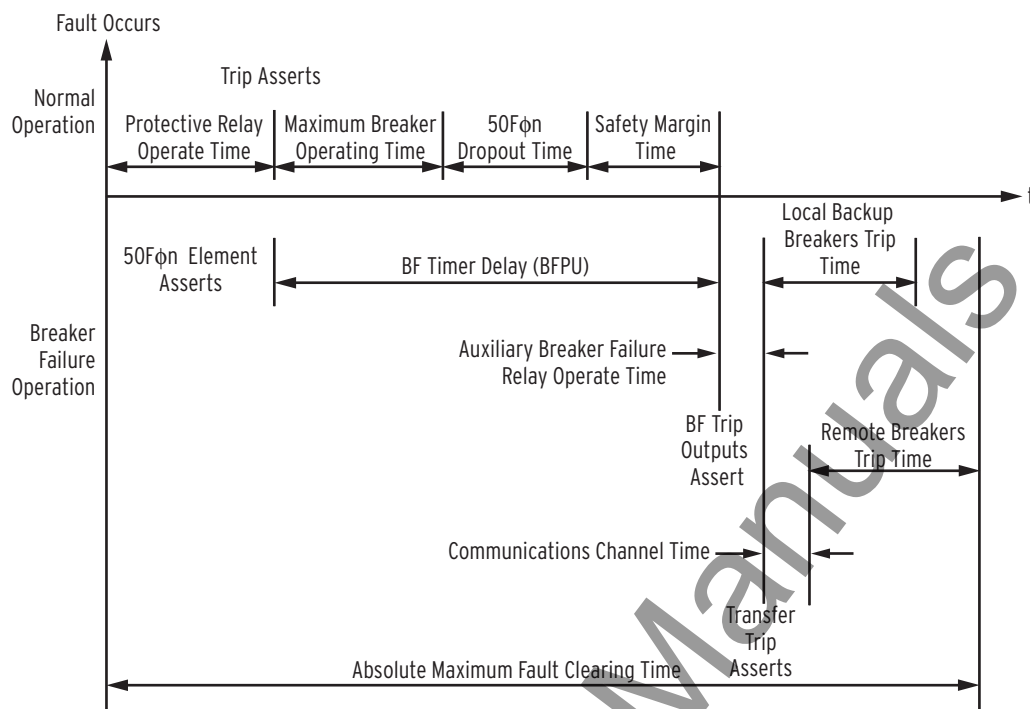


Figure 1.40 Scheme 1 All Faults and Scheme 2 Multiphase Fault Timing Diagram

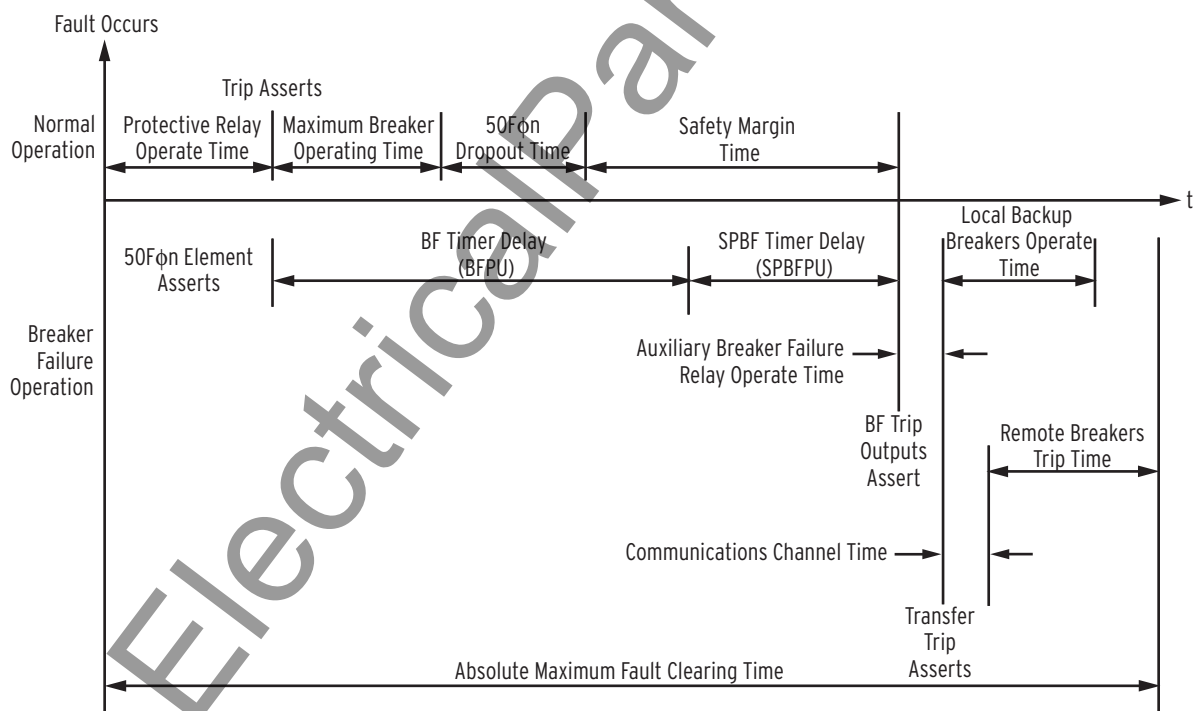


Figure 1.41 Scheme 2 Single-Phase Fault Timing Diagram

Circuit Breaker Failure Protection—Example 1

The absolute maximum fault clearing time depends on power system transient stability and the thermal withstand capability of the equipment. If a circuit breaker fails, the total time required to trip all electrically adjacent circuit breakers must be less than this absolute maximum clearing time. Set the time delay on pickup timer to allow time for the protected circuit breaker to operate and the instantaneous overcurrent element (50F ϕ 1) to reset. Always include a safety margin, remembering that the operating time of the line relays and the electrically adjacent circuit breakers limit this margin.

Use the SEL-421 to provide circuit breaker failure protection for one circuit breaker. This is a circuit breaker failure protection Scheme 1 application example for three-pole tripping circuit breakers (you can also use this scheme for single-pole tripping applications). For a single-pole tripping circuit breaker application example (Scheme 2), see [Circuit Breaker Failure Protection—Example 2 on page A.1.160](#). This example uses a 230 kV power system similar to the system in [230 kV Overhead Transmission Line Example on page A.1.2](#). [Figure 1.42](#) shows the SEL-421 at the S terminal of the two-terminal line between Harvard and Princeton. [Table 1.41](#) provides the related power system parameters.



Figure 1.42 230 kV Power System for Circuit Breaker Failure Scheme 1

Table 1.41 Secondary Quantities

Parameter	Value
Line impedances	
Z_{1L}	$1.95 \Omega \angle 84^\circ$ secondary
Z_{0L}	$6.2 \Omega \angle 81.5^\circ$ secondary
Source S impedances	
$Z_{1S} = Z_{0S}$	$2.5 \Omega \angle 86^\circ$ secondary
Source R impedances	
$Z_{1R} = Z_{0R}$	$2.5 \Omega \angle 86^\circ$ secondary
Nominal frequency (f_{nom})	60 Hz
Maximum operating current load (I_{load})	4.95 A secondary

Relay Configuration

Enable Scheme 1 circuit breaker failure protection for Circuit Breaker BK1.

EBFL1:=1 Breaker 1 Failure Logic (N, 1, 2)

Circuit Breaker 1 Failure Logic

Phase Current Level Detector

NOTE: This is one method for calculating setting 50FP1. Use your company practices and policies for determining the pickup setting for your particular application.

Set the phase current level detector equal to 120 percent of the maximum load current I_{load} . Check that this setting is less than the minimum fault current ($\phi\phi$ fault) with minimum generation. Circuit breaker failure protection for faults involving ground (SLG and $\phi\phi G$ faults) is covered in this application example by no current/residual current circuit breaker failure protection (see [Residual](#)

(Current Circuit Breaker Failure Protection on page A.1.165). This settings philosophy provides security for the circuit breaker failure protection. For this power system, the maximum load current is 4.95 A secondary and the minimum $\phi\phi$ fault current is 13.0 A secondary.

$$50FP1 = 120\% \cdot I_{load} = 120\% \cdot 4.95 \text{ A} = 5.94 \text{ A}$$

$$50FP1 := 5.94 \text{ Phase Fault Current Pickup—BK1 (0.50–50 A secondary)}$$

Circuit Breaker Failure Protection Time Delay

The recommended setting for BFPU1 (Breaker Failure Time Delay—BK1) is the sum of the following (see Figure 1.43):

- Maximum circuit breaker operating time
- 50FA1 maximum dropout time
- Safety margin

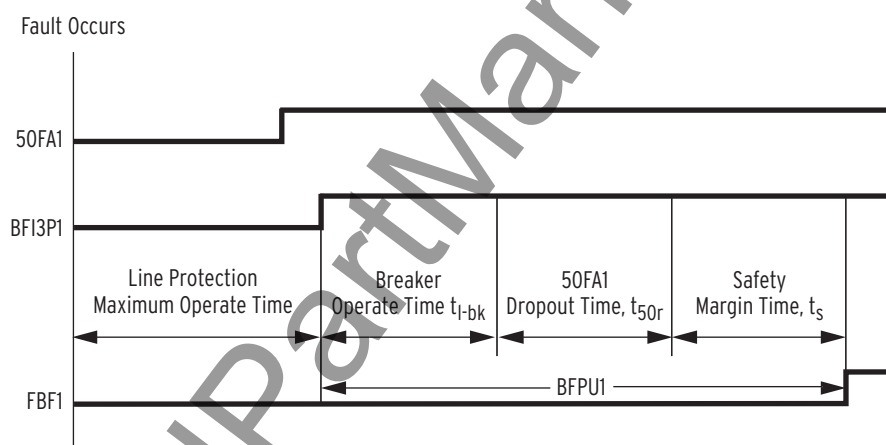


Figure 1.43 Timing Diagram for Setting BFPU1—Scheme 1

To maintain system stability, the relay must clear the fault within the total clearing time. Use the maximum operating time of the local and remote circuit breakers. The maximum operating time of the circuit breaker, t_{l-bk} , is 3 cycles for this example. Also, use the maximum dropout time for Relay Word bit 50FA1; the maximum dropout time of the phase current level detector, t_{50r} , is 1 cycle. You must also include the communications channel time, t_{ch} , for remote circuit breaker tripping.

To determine setting BFPU1, you must find the safety margin, t_s . Determine the safety margin from Figure 1.40:

$$\begin{aligned} t_s &= t_t - (t_{1r} + t_{1-bk} + t_{50r} + t_{86} + t_{ch} + t_{r-bk}) \\ &= 17 - (2 + 3 + 1 + 1 + 1 + 3) \\ &= 6 \text{ cycles} \end{aligned}$$

Equation 1.87

Where:

- t_s = safety margin
- t_t = total clearing time (17 cycles)
- t_{lr} = line protection maximum operating time (2 cycles)
- t_{l-bk} = local circuit breaker maximum operating time (3 cycles)
- t_{50r} = circuit breaker failure overcurrent element 50FA1 maximum reset time (1 cycle)
- t_{86} = auxiliary breaker failure relay operating time (1 cycle)
- t_{ch} = communications channel maximum operating time (1 cycle)
- t_{r-bk} = remote circuit breaker maximum operating time (3 cycles)

Use the safety margin result from [Equation 1.87](#) to calculate BFPUI:

$$\begin{aligned} \text{BFPUI} &= t_{l-bk} + t_{50r} + t_s \\ &= 3 + 1 + 6 \\ &= 10 \text{ cycles} \end{aligned} \quad \text{Equation 1.88}$$

BFPUI := **10.000** Breaker Failure Time Delay—BK1 (0.000–6000 cycles)

Retrip Time Delay

If the circuit breaker is equipped with two trip coils, the relay should attempt to retrip the protected circuit breaker before a circuit breaker failure trip asserts. Wait 4 cycles for the retrip.

RTPUI := **4.000** Retrip Time Delay—BK1 (0.000–6000 cycles)

Circuit Breaker Failure Protection Initiation

To initiate circuit breaker failure protection for Circuit Breaker BK1, assign the protection elements to Relay Word bit BFI3P1 (Three-Pole Breaker Failure Initiate—BK1). This protection example uses three-pole tripping only.

BFI3P1 := **3PT** Three-Pole Breaker Failure Initiate—BK1 (SELOGIC Equation)

BFI1A := **NA** A-Phase Breaker Failure Initiate—BK1 (SELOGIC Equation)

BFI1B := **NA** B-Phase Breaker Failure Initiate—BK1 (SELOGIC Equation)

BFI1C := **NA** C-Phase Breaker Failure Initiate—BK1 (SELOGIC Equation)

Circuit Breaker Failure Protection Initiation Dropout Delay

Set the circuit breaker failure initiate dropout time delay to zero. Disable this feature for this application example because this is not a dual circuit breaker scheme.

BFID01 := **0.000** Breaker Fail Initiate Dropout Delay—BK1 (0.000–1000 cycles)

Circuit Breaker Failure Protection Initiation Seal-In Delay

Set the latch logic circuit breaker failure pickup time delay to zero. Disable this feature for this application example. Relay Word bit 3PT internally initiates circuit breaker failure protection and has a minimum duration three-pole time delay on dropout (that is, TDUR3D).

BFISP1 := **0.000** Breaker Fail Initiate Seal-In Delay—BK1 (0.000–1000 cycles)

Residual Current Circuit Breaker Failure Protection

Enable no current/residual circuit breaker failure protection for Circuit Breaker BK1. Use this logic to detect a circuit breaker failure and take appropriate action when a weak source drives the fault or if the protected circuit breaker fails to trip during a high-resistance ground fault.

ENCBF1 := **Y** No Current/Residual Current Logic—BK1 (Y, N)

Residual Current Pickup

Set the pickup of the residual current level detector greater than maximum system unbalance; assume a 15 percent maximum unbalance.

$$50RP1 = 0.15 \cdot I_{\text{load}} = 0.15 \cdot 4.95 \text{ A} = 0.74 \text{ A}$$

50RP1 := **0.74** Residual Current Pickup—BK1 (0.25–50 A secondary)

Residual Current Circuit Breaker Failure Time Delay

Setting NPU1 is the time delay on pickup before the relay asserts a low current circuit breaker failure trip for Circuit Breaker BK1. You can set this delay greater than BFPU1; a high-resistance ground fault is not as much a threat to power system transient stability as is a phase fault, because synchronizing power still flows through the two unfaulted phases.

NPU1 := **12.000** No Current Breaker Failure Delay—BK1 (0.000–6000 cycles)

Residual Current Circuit Breaker Failure Initiation

This particular application uses the residual current circuit breaker failure scheme only to detect when the circuit breaker fails to trip during high-resistance ground faults. Set SELOGIC control equation BFIN1 (No Current Breaker Failure Initiate) to NA.

If you want to apply this scheme for no current conditions (e.g., weak source), assign the 52A contact from Circuit Breaker BK1 (52AA1) to the SELOGIC control equation BFIN1 (No Current Breaker Failure Initiate).

BFIN1 := **NA** No Current Breaker Failure Initiate—BK1 (SELOGIC Equation)

Load Current Circuit Breaker Failure Protection

Disable load current circuit breaker failure protection for Circuit Breaker BK1.

ELCBF1 := **N** Load Current Breaker Failure Logic—BK1 (Y, N)

Flashover Circuit Breaker Failure Protection

Disable flashover current circuit breaker failure protection for Circuit Breaker BK1.

EF0BF1 := **N** Flashover Breaker Failure Logic—BK1 (Y, N)

Circuit Breaker Failure Protection Trip Logic

Circuit Breaker 1 Failure Trip Equation

The SEL-421 has dedicated circuit breaker failure trip logic. Set SELOGIC control equation BFTR1 (Breaker Failure Trip—BK1) to assert for either Circuit Breaker BK1 circuit breaker failure trip or Circuit Breaker BK1 residual current circuit breaker failure trip. When this SELOGIC control equation asserts, the relay sets Relay Word bit BFTRIP1 to logical 1 until BFTR1 deasserts, the TDUR3D timer times out, and an unlatch or reset condition is active.

BFTR1 := **FBF1 OR NBF1** Breaker Failure Trip—BK1 (SELOGIC Equation)

Unlatch Circuit Breaker 1 Failure Trip Equation

Use SELOGIC control equation BFULTR1 (Breaker Failure Unlatch Trip—BK1) to define the conditions that unlatch the control outputs that assert during a circuit breaker failure trip. BFULTR1 unlatches the circuit breaker trip condition BFTRIP1 (Breaker Failure Trip for Circuit Breaker BK1). Assign a control input that is energized externally to signal the relay when the circuit breaker failure trip clears the fault successfully.

BFULTR1 := **IN104** Breaker Failure Unlatch Trip—BK1 (SELOGIC Equation)

Control Outputs

Use SELOGIC control equations to assign control outputs for tripping Circuit Breaker BK1, retripping Circuit Breaker BK1, and circuit breaker failure tripping. *Figure 1.44* shows dc connections for the circuit breaker failure trip and circuit breaker trip/retrip.

Use the main board high current interrupting control output for the retrip signal (RT1) because this output can interrupt large circuit breaker coil currents. There is no TDUR3D (3PT Minimum Trip Duration Time Delay) for RT1; the RT1 signal can drop out while there is current flowing through the trip coil, if the auxiliary circuit breaker contacts have not yet opened.

OUT101 := **3PT**

OUT103 := **RT1**

OUT107 := **BFTRIP1**

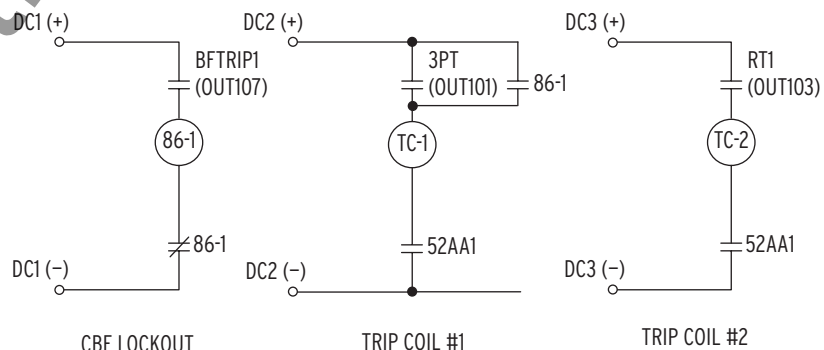


Figure 1.44 Circuit Breaker Failure Trip and Circuit Breaker Trip DC Connections

Example Completed

This completes the application example that describes setting of the SEL-421 for circuit breaker failure protection. Analyze your particular power system to determine the appropriate settings for your application.

Relay Settings

[Table 1.42](#) lists all protection relay settings applied for this example.

Table 1.42 Settings for Circuit Breaker Failure Example 1

Setting	Description	Entry
Relay Configuration (Group)		
EBFL1	Breaker 1 Failure Logic (N, 1, 2)	1
Breaker 1 Failure Logic (Group)		
50FP1	Phase Fault Current Pickup—BK1 (0.50–50 A secondary)	5.94
BFP1	Breaker Failure Time Delay—BK1 (0.000–6000 cycles)	10.000
RTP1	Retrip Time Delay—BK1 (0.000–6000 cycles)	4.000
BFI3P1	Three-Pole Breaker Failure Initiate—BK1 (SELOGIC Equation)	3PT
BFIA1	A-Phase Breaker Failure Initiate—BK1 (SELOGIC Equation)	NA
BFIB1	B-Phase Breaker Failure Initiate—BK1 (SELOGIC Equation)	NA
BFIC1	C-Phase Breaker Failure Initiate—BK1 (SELOGIC Equation)	NA
BFID1	Breaker Fail Initiate Dropout Delay—BK1 (0.000–1000 cycles)	0.000
BFIS1	Breaker Fail Initiate Seal-In Delay—BK1 (0.000–1000 cycles)	0.000
ENCBF1	No Current/Residual Current Logic—BK1 (Y, N)	Y
50R1	Residual Current Pickup—BK1 (0.25–50 A secondary)	0.74
NPU1	No Current Breaker Failure Delay—BK1 (0.000–6000 cycles)	12.000
BFIN1	No Current Breaker Failure Initiate—BK1 (SELOGIC Equation)	NA
ELCBF1	Load Current Breaker Failure Logic—BK1 (Y, N)	N
EFOB1	Flashover Breaker Failure Logic—BK1 (Y, N)	N
BFTR1	Breaker Failure Trip—BK1 (SELOGIC Equation)	FBF1 OR NBF1
BFULTR1	Breaker Failure Unlatch Trip—BK1 (SELOGIC Equation)	IN104
Main Board (Outputs)		
OUT101		3PT
OUT103		RT1
OUT107		BFTRIP1

Circuit Breaker Failure Protection—Example 2

Use the SEL-421 to provide circuit breaker failure protection for both circuit breakers in breaker-and-a-half schemes. This application example explains setting the relay for Circuit Breaker BK1 (see [Figure 1.45](#)). You can apply these same settings for Circuit Breaker BK2. You can apply circuit breaker failure Scheme 2 protection for single-pole trip circuit breakers. Scheme 2

provides separate timers for multiphase faults (BFPU1) and single-phase faults (SPBFPU1). For more information on Scheme 2 circuit breaker failure protection, see [Failure to Interrupt Fault Current: Scheme 2 on page R.1.126](#).

NOTE: This application example is for two circuit breakers. Apply the same settings for Circuit Breaker BK2 as for Circuit Breaker BK1. For Circuit Breaker BK2, substitute 2 for 1 in the following settings.

This example uses a 500 kV power system with single-pole tripping enabled (see [Figure 1.45](#)). [Table 1.43](#) provides the power system parameters.

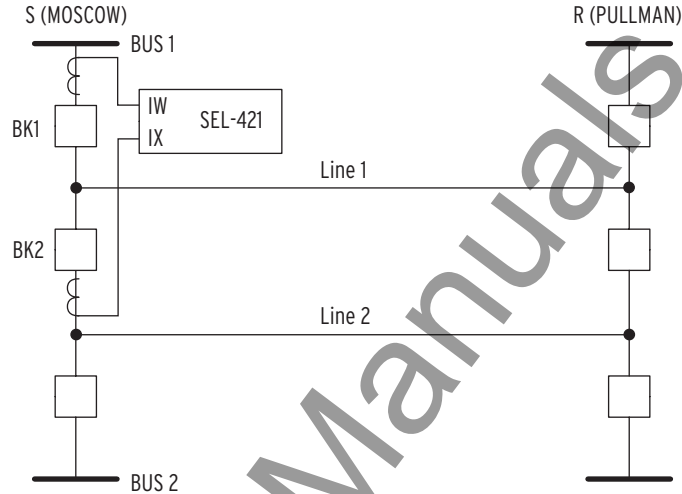


Figure 1.45 500 kV Power System for Circuit Breaker Failure Scheme 2

Table 1.43 Secondary Quantities

Parameter	Value
Line impedances	
Z_{1L1}	$3.98 \Omega \angle 87.6^\circ$ secondary
Z_{0L1}	$14.48 \Omega \angle 82.1^\circ$ secondary
Source S impedances	
$Z_{1S} = Z_{0S}$	$4.4 \Omega \angle 88^\circ$ secondary
Source R impedances	
$Z_{1R} = Z_{0R}$	$1.78 \Omega \angle 88^\circ$ secondary
Nominal frequency (f_{nom})	60 Hz
Maximum operating current (I_{load})	3.25 A secondary

Relay Configuration

Enable Scheme 2 circuit breaker failure protection for two circuit breakers.

EBFL1 := 2 Breaker 1 Failure Logic (N, 1, 2)

EBFL2 := 2 Breaker 2 Failure Logic (N, 1, 2)

Circuit Breaker 1 Failure Logic

Phase Current Level Detector

NOTE: This is one method for calculating setting 50FP1. Use your company practices and policies for determining the pickup setting for your particular application.

Set the phase fault current pickup greater than maximum load and less than the fault current that flows through Circuit Breaker BK1 ($I_{S(BK1)}$). Maximum load current, I_S , is 3.25 A secondary.



Assume that the total load current (I_S) supplied from Substation S flows through BK1 only; $I_{S(BK1)} = I_S$ (see [Figure 1.46](#)). Calculate setting 50FP1 with all the load current I_S through Circuit Breaker BK1.

$$\begin{aligned} 50\text{FP1} &= 120\% \cdot (\text{Percent Current} \cdot I_S) \\ &= 120\% \cdot (100\% \cdot 3.25 \text{ A}) \\ &= 3.91 \text{ A secondary} \end{aligned}$$

A fault study shows that the minimum ground fault current, $I_{\text{fault minimum}}$, is 4.2 A secondary when the parallel line is in service at minimum generation. Calculate the 50FP1 setting for dependability at 1/2 of the minimum fault current.

$$\begin{aligned} 50\text{FP1} &= 0.5 \cdot (\text{Percent Current} \cdot I_{\text{fault-minimum}}) \\ &= 0.5 \cdot (100\% \cdot 4.20 \text{ A}) \\ &= 2.10 \text{ A secondary} \end{aligned}$$

Although the result of this setting calculation is below maximum load (see [Equation 1.89](#)), use this calculation to set the 50FP1 element for dependability.

50FP1:= **2.10** Phase Fault Current Pickup—BK1 (0.50–50 A secondary)

Circuit Breaker Failure Time Delay

BFPU1 (Breaker Failure Time Delay—BK1) is the time delay on pickup for a circuit breaker trip following a multiphase fault. You can also add an additional delay, **SPBFPU1** (SPT Breaker Failure Time Delay—BK1).

The recommended setting for BFPU1 is the sum of the following (see [Figure 1.47](#)):

- Maximum circuit breaker operating time
- 50FA1 maximum dropout time
- Safety margin

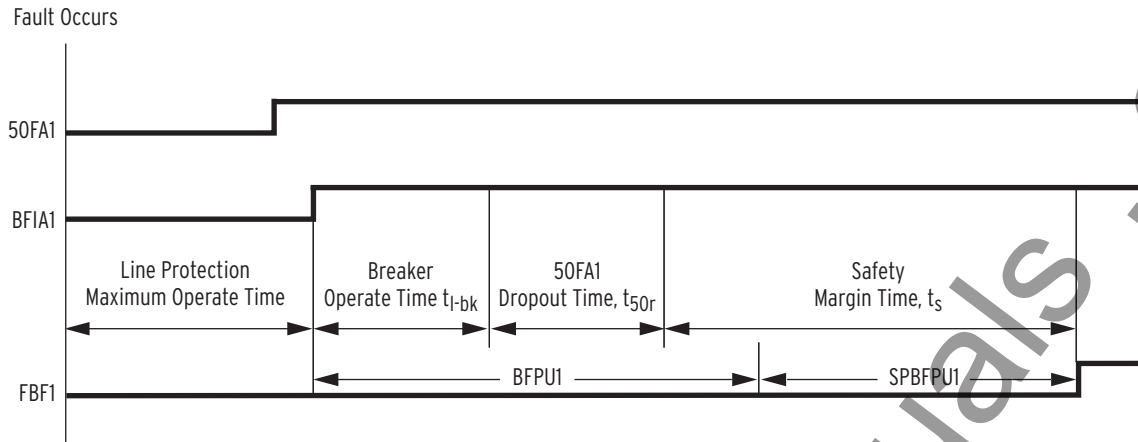


Figure 1.47 Timing Diagram for Setting BFPU1—Scheme 2

To maintain system stability, you must clear the fault within the total clearing time. Use the maximum operating time of the local and remote circuit breakers. The maximum operating time of the circuit breaker, t_{l-bk} , is 2 cycles for this example. Also use the maximum reset time of 50FA1; the maximum reset (dropout) time of the phase current level detector, t_{50r} , is 1 cycle. You must also include the communications channel time, t_{ch} , for remote circuit breaker tripping.

To determine setting BFPU1, you must find the safety margin, t_s . Determine the safety margin from [Figure 1.40](#).

$$\begin{aligned} t_s &= t_t - (t_{lr} + t_{l-bk} + t_{50r} + t_{86} + t_{ch} + t_{r-bk}) \\ &= 15 - (2 + 2 + 1 + 1 + 1 + 2) \\ &= 6 \text{ cycles} \end{aligned}$$

Equation 1.91

Where:

- t_s = safety margin
- t_t = total clearing time (15 cycles)
- t_{lr} = line protection maximum operating time (2 cycles)
- t_{l-bk} = local circuit breaker maximum operating time (2 cycles)
- t_{50r} = circuit breaker failure overcurrent element 50FA1 maximum reset time (1 cycle)
- t_{86} = auxiliary breaker failure relay operating time (1 cycle)
- t_{ch} = communications channel maximum operating time (1 cycle)
- t_{r-bk} = remote circuit breaker maximum operating time (2 cycles)

Use the safety margin result from [Equation 1.92](#) to calculate BFPU1:

$$\begin{aligned} \text{BFPU1} &= t_{l-bk} + t_{50r} + t_s \\ &= 3 + 1 + 6 \\ &= 10 \text{ cycles} \end{aligned}$$

Equation 1.92

BFPU1:= **10.000** Breaker Failure Time Delay—BK1 (0.000–6000 cycles)

SPBFPU1 is an additional delay you can cascade to BFPU1 for single-phase faults (see [Figure 1.48](#)). Set SPBFPU1 to extend breaker failure pickup time delay as long as the total clearing time $t_t = 15$ cycles.

SPBFPU1 := **5.000** SPT Breaker Failure Time Delay -BK1
(0.000–6000 cycles)

Retrip Time Delay

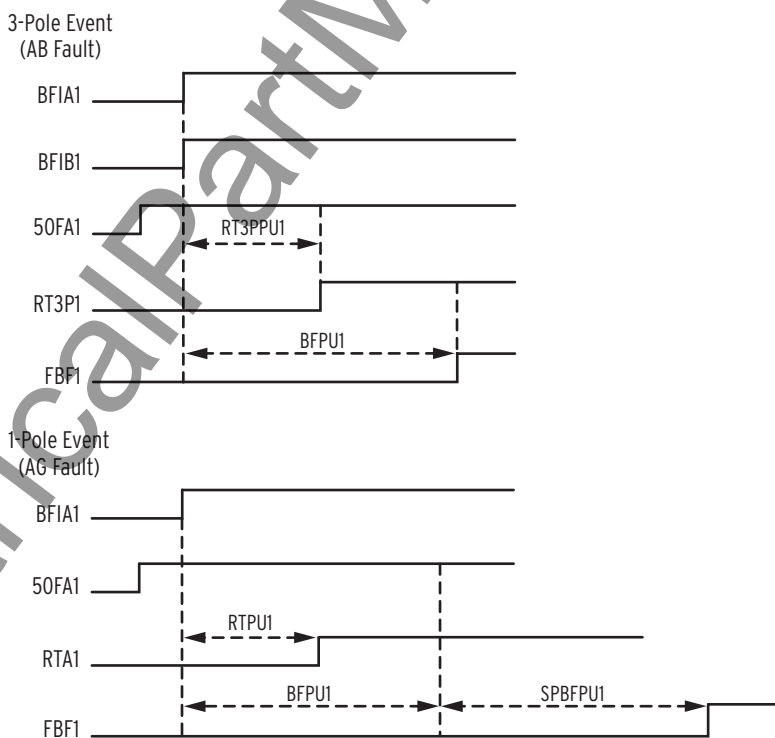
Scheme 2 provides retrip timers RT3PPU1 for multiphase faults and RTPU1 for single-phase faults. Set the retrip following a single-pole trip to occur 3 cycles after circuit breaker failure initiation.

RTPU1 := **3.000** Retrip Time Delay—BK1 (0.000–6000 cycles)

A three-pole retrip follows a three-pole trip. The relay should attempt to retrip the protected circuit breaker before a circuit breaker failure trip asserts. Apply the default setting for the three-pole retrip time delay on pickup.

RT3PPU1 := **3.000** Three-Pole Retrip Time Delay—BK1 (0.000–6000 cycles)

[Figure 1.48](#) compares the complete timing sequence for single-pole versus three-pole circuit breaker failure operations.



**Figure 1.48 Timing Sequences for
Circuit Breaker Failure Protection Scheme 2**

Circuit Breaker Failure Initiation

Scheme 2 does not use Relay Word bit BFI3P1 to initiate failure to interrupt fault current circuit breaker failure protection.

BFI3P1 := **NA** Three-Pole Breaker Failure Initiate—BK1 (SELOGIC Equation)

Assign the protection elements to Relay Word bits BFIA1, BFIB1, and BFIC1 to initiate single-pole trip circuit breaker failure protection for Circuit Breaker BK1. For a complete description of circuit breaker failure initiation, see [Circuit Breaker Failure Protection on page R.1.125](#). This application example uses the POTT tripping scheme, step-distance backup protection, and SOTF protection.

BFIA1 := **BFIA1 OR TPA1** A-Phase Breaker Failure Initiate—BK1
(SELOGIC Equation)

BFIB1 := **BFIB1 OR TPB1** B-Phase Breaker Failure Initiate—BK1
(SELOGIC Equation)

BFIC1 := **BFIC1 OR TPC1** C-Phase Breaker Failure Initiate—BK1
(SELOGIC Equation)

Relay Word bits BFIAT1, BFIBT1, and BFICT1 (Circuit Breaker 1 Latched Single-Pole Circuit Breaker Failure Initiation) latch the BFIA1, BFIB1, and BFIC1 inputs to the circuit breaker failure protection.

Circuit Breaker Failure Protection Initiation Dropout Delay

Set the circuit breaker failure initiate time delay on dropout to stretch a short pulsed circuit breaker failure initiation. Enable this feature for this application example because you are protecting dual circuit breakers.

BFIDO1 := **3.000** Breaker Failure Initiate Dropout Delay—BK1
(0.000–1000 cycles)

Circuit Breaker Failure Protection Initiation Seal-In Delay

Set the circuit breaker failure initiate time delay on pickup for the latch logic to qualify extended circuit breaker failure initiation latch seal-in.

BFISP1 := **4.000** Breaker Failure Initiate Seal-In Delay—BK1
(0.000–1000 cycles)

For these BFIDO1 and BFISP1 settings, if the circuit breaker failure initiate is 1 cycle or more, the relay seals in the circuit breaker failure extended initiation after the initiate signal deasserts until the BFIDO1 time (3 cycles) expires and all 50F01 elements deassert.

Residual Current Circuit Breaker Failure Protection

Disable residual current circuit breaker failure protection for Circuit Breaker BK1 because a strong source drives this terminal.

ENCBF1 := **N** No Current/Residual Current Logic—BK1 (Y, N)

Load Current Circuit Breaker Failure Protection

Disable load current circuit breaker failure protection for Circuit Breaker BK1.

ELCBF1 := **N** Load Current Breaker Failure Logic—BK1 (Y, N)

Flashover Circuit Breaker Failure Protection

Disable flashover current circuit breaker failure protection for Circuit Breaker BK1.

EF0BF1 := **N** Flashover Breaker Failure Logic—BK1 (Y, N)

Circuit Breaker Failure Protection Trip Logic

Circuit Breaker 1 Failure Trip Equation

The SEL-421 has dedicated circuit breaker failure trip logic. Set SELOGIC control equation BFTR1 (Breaker Failure Trip—BK1) to assert for a Circuit Breaker BK1 circuit breaker failure trip. When this SELOGIC control equation asserts, the relay sets Relay Word bit BFTRIP1 to logical 1 until BFTR1 deasserts, the TDUR1D timer times out, and an unlatch or reset condition is active.

BFTR1 := **FBF1** Breaker Failure Trip—BK1 (SELOGIC Equation)

Unlatch Circuit Breaker Failure Trip Equation

Use SELOGIC control equation BFULTR1 (Breaker Failure Unlatch Trip—BK1) to define the conditions that unlatch the control outputs that assert during a circuit breaker failure trip. BFULTR1 unlatches the circuit breaker trip condition BFTRIP1 (Breaker Failure Trip for Circuit Breaker 1). Assign a control input that is energized externally to signal the relay when the circuit breaker failure trip clears the fault successfully.

BFULTR1 := **IN104** Breaker Failure Unlatch Trip—BK1 (SELOGIC Equation)

Use the same input signal to unlatch the circuit breaker failure trip on Circuit Breaker BK2.

Control Outputs

Use SELOGIC control equations to assign the control outputs for tripping and retripping Circuit Breaker BK1 and Circuit Breaker BK2 and circuit breaker failure tripping. These output assignments are for the SEL-421 with an additional INT6 I/O interface board (see [I/O Interface Boards on page U.2.14](#)).

NOTE: The symbol ϕ indicates A, B, and C for A-phase, B-phase, or C-phase of the power system.

Assign the trip outputs to the hybrid (high current interrupting) control outputs. Use the high current interrupting control outputs for the retrip signal (RT ϕ 1) because these outputs can interrupt large circuit breaker coil currents. There is no TDUR3D (3PT Minimum Trip Duration Time Delay) for RT ϕ 1; the RT ϕ 1 signal can drop out while there is current flowing through the trip coil, if the auxiliary circuit breaker contacts have not yet opened.

OUT101 := **TPA1**
OUT102 := **TPB1**
OUT103 := **TPC1**
OUT107 := **BFTRIP1**
OUT201 := **TPA2**
OUT202 := **TPB2**
OUT203 := **TPC2**
OUT204 := **RTA1**
OUT205 := **RTB1**
OUT206 := **RTC1**
OUT207 := **RTA2**
OUT208 := **RTB2**
OUT209 := **RTC2**

Figure 1.49 illustrates the corresponding dc connections for Circuit Breaker BK1. Circuit Breaker BK2 connections are similar.

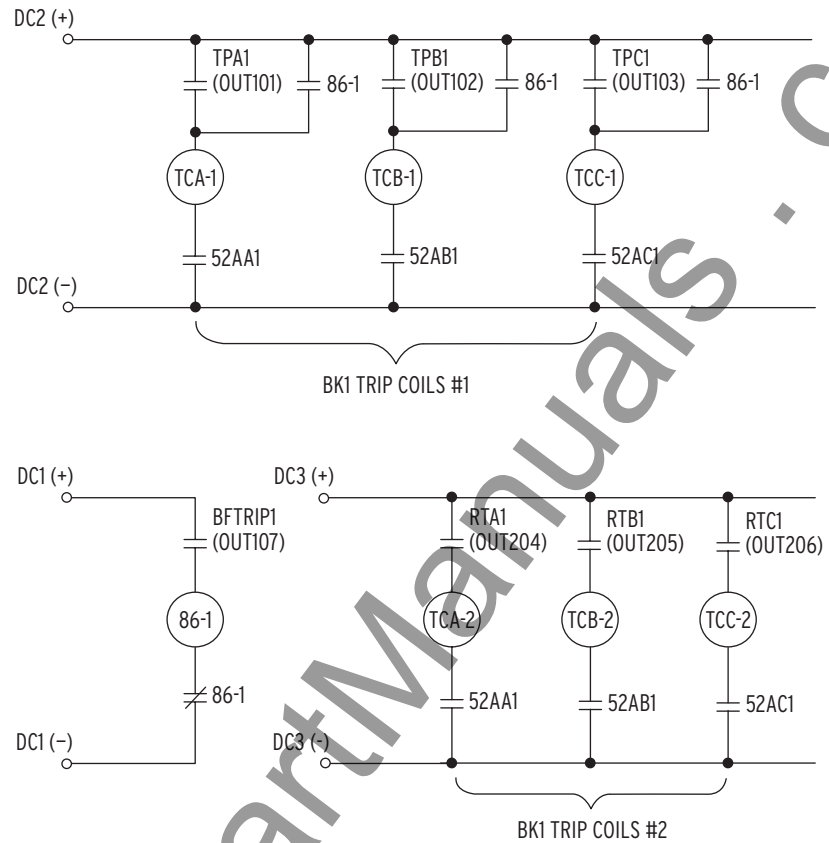


Figure 1.49 Circuit Breaker BK1 DC Connections (Two Trip Coils)

Example Completed

This completes the application example that describes setting the SEL-421 for Scheme 2 circuit breaker failure protection. Analyze your particular power system to determine the appropriate settings for your application.

Relay Settings

Table 1.44 lists all protection relay settings applied for this example. These settings are for Circuit Breaker BK1; settings for Circuit Breaker BK2 are similar unless otherwise noted.

Table 1.44 Settings for Circuit Breaker Failure Example 2 (Sheet 1 of 2)

Setting	Description	Entry
Relay Configuration (Group)		
EBFL1	Breaker 1 Failure Logic (N, 1, 2)	2
EBFL2	Breaker 2 Failure Logic (N, 1, 2)	2
Breaker 1 Failure Logic (Group)		
50FP1	Phase Fault Current Pickup—BK1 (0.50–50 A secondary)	2.10
BFPUI	Breaker Failure Time Delay—BK1 (0.000–6000 cycles)	10.000
SPBFUI	SPT Breaker Failure Time Delay—BK1 (0.000–6000 cycles)	5.000
RTPUI	Retrip Time Delay—BK1 (0.000–6000 cycles)	3.000
RT3PPUI	Three-Pole Retrip Time Delay—BK1 (0.000–6000 cycles)	3.000

Table 1.44 Settings for Circuit Breaker Failure Example 2 (Sheet 2 of 2)

Setting	Description	Entry
BFI3P1	Three-Pole Breaker Failure Initiate—BK1	NA
BFIAI	A-Phase Breaker Failure Initiate—BK1 (SELOGIC Equation)	BFIA1 OR TPA1
BFIB1	B-Phase Breaker Failure Initiate—BK1 (SELOGIC Equation)	BFIB1 OR TPB1
BFIC1	C-Phase Breaker Failure Initiate—BK1 (SELOGIC Equation)	BFIC1 OR TPC1
BFIDO1	Breaker Fail Initiate Dropout Delay—BK1 (0.000–1000 cycles)	3.000
BFISP1	Breaker Fail Initiate Seal-In Delay—BK1 (0.000–1000 cycles)	4.000
ENCBF1	No Current/Residual Current Logic—BK1 (Y, N)	N
ELCBF1	Load Current Breaker Failure Logic—BK1 (Y, N)	N
EFOBF1	Flashover Breaker Failure Logic—BK1 (Y, N)	N
BFTR1	Breaker Failure Trip—BK1 (SELOGIC Equation)	FBF1
BFULTR1	Breaker Failure Unlatch Trip—BK1 (SELOGIC Equation)	IN104
Control Outputs		
OUT101		TPA1
OUT102		TPB1
OUT103		TPC1
OUT107		BFTRIP1
OUT201		TPA2
OUT202		TPB2
OUT203		TPC2
OUT204		RTA1
OUT205		RTB1
OUT206		RTC1
OUT207		RTA2
OUT208		RTB2
OUT209		RTC2

Section 2

Monitoring and Metering

The SEL-421 Relay provides extensive capabilities for monitoring substation components and metering important power system parameters. The relay provides the following useful features:

- *Circuit Breaker Monitor on page A.2.2*
- *Station DC Battery System Monitor on page A.2.22*
- *Metering on page A.2.28*

This section explains each of these features and gives practical examples for applying these features in the power system.

Circuit Breaker Monitor

The SEL-421 features advanced circuit breaker monitoring.

This subsection is organized as follows:

- [Overview](#)
- [Enabling the Circuit Breaker Monitor on page A.2.3](#)
- [Circuit Breaker Contact Wear Monitor on page A.2.3](#)
- [Other Circuit Breaker Monitor Functions on page A.2.10](#)
- [BREAKER Command on page A.2.18](#)

Overview

NOTE: This section lists settings for Circuit Breaker 1; settings for Circuit Breaker 2 are similar; replace 1 in the setting with 2.

The SEL-421 features advanced circuit breaker monitoring. [Figure 2.1](#) shows that the relay processes phase currents, circuit breaker auxiliary contacts, and the substation dc battery voltages to detect out-of-tolerance and maximum life circuit breaker parameters. These parameters include current interrupted, operating times, and contact wear. By using SEL-421 monitoring, maintenance personnel can determine the extent of a developing circuit breaker problem and select an appropriate response to correct the problem. These monitoring features are available online in real-time; you can detect impending problems immediately. The result is better power system reliability and improved circuit breaker life expectancy.

One of the many circuit breaker monitor features is the circuit breaker contact wear monitor. The SEL-421 tracks the number of circuit breaker close-open operations and respective fault interrupting levels for each of two circuit breakers. The relay uses data from the circuit breaker manufacturer to compare the recorded operational data with the manufacturer's recommended maintenance requirements. The SEL-421 notifies you when each set of circuit breaker pole contacts exceeds preset wear thresholds. Using this information, you can operate your substation more economically by accurately scheduling circuit breaker maintenance.

You can also collect the following data on these circuit breaker parameters:

- Electrical operating time
- Mechanical operating time
- Circuit breaker inactivity time
- Interrupted current
- Pole scatter
- Pole discrepancy
- Motor run time

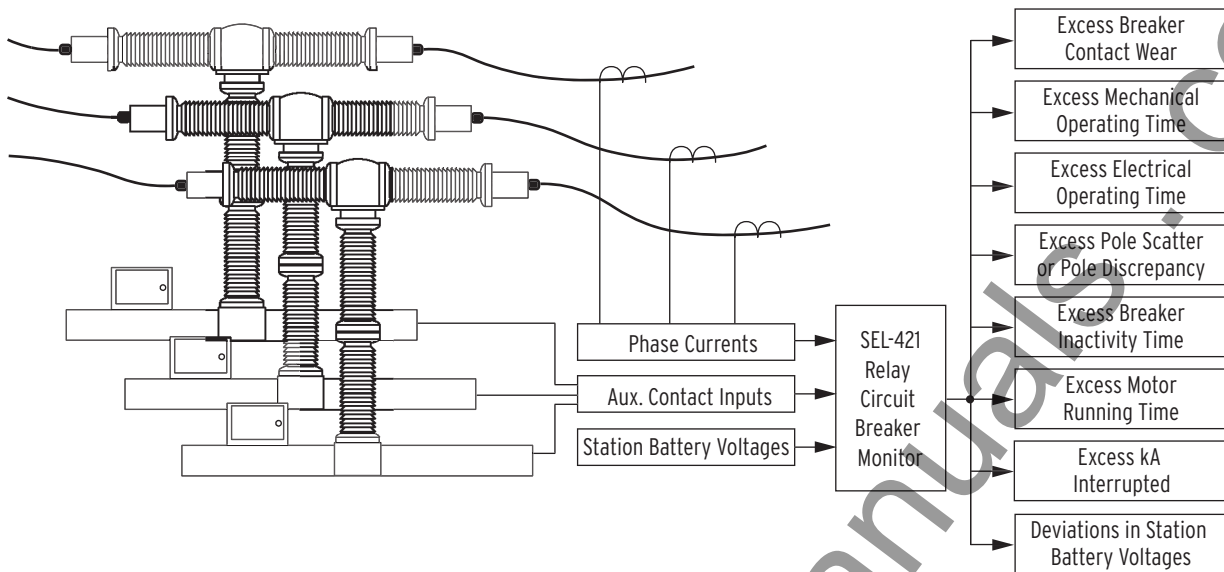


Figure 2.1 SEL-421 Intelligent Circuit Breaker Monitor

You can program the relay to alarm when any of the above quantities exceed a preset threshold. In addition, the relay stores a 128-event circuit breaker history in nonvolatile memory. The circuit breaker history report includes circuit breaker mechanical operation times, electrical operation times, interrupted currents, and other important parameters. The alarm and reporting features help you operate your substation safely and reliably.

Enabling the Circuit Breaker Monitor

Enable and configure the SEL-421 circuit breaker monitor by using the settings listed in [Table 2.1](#) for each of two possible circuit breakers. Power system circuit breakers are either single-pole tripping or three-pole tripping circuit breakers; set the relay for the circuit breaker type that the relay controls. For a single pole tripping circuit breaker, set BK1TYP := 1, and for a three-pole tripping circuit breaker, set BK1TYP := 3. The factory default setting is BK1TYP := 1. Be sure to configure the relay with the settings that match your circuit breakers.

Table 2.1 Circuit Breaker Monitor Configuration

Name	Description	Range	Default
EB1MON	Enable Circuit Breaker 1 monitoring	Y, N	N
BK1TYP	Circuit Breaker 1 type	1, 3	1
EB2MON	Enable Circuit Breaker 2 monitoring	Y, N	N
BK2TYP	Circuit Breaker 2 type	1, 3	1

Circuit Breaker Contact Wear Monitor

The circuit breaker contact wear monitor in the SEL-421 provides information that helps you schedule circuit breaker maintenance. This monitoring function accumulates the number of close-open operations and integrates the per-phase current during each opening operation. The SEL-421 compares this information to a predefined circuit breaker maintenance curve to calculate the percent contact wear on a per-pole basis.

The circuit breaker maintenance curve also incorporates the accumulated fault current arcing time (ΣI^2t), assuming an identical arcing time for each trip. You can obtain the one-cycle arcing time from circuit breaker manufacturer data.

The SEL-421 updates and stores the contact wear information and the number of trip operations in nonvolatile memory. You can view this information through any communications port.

Any phase wear percentage that exceeds the threshold setting B1BCWAT asserts the alarm Relay Word bit, B1BCWAL, for Circuit Breaker 1. You can use this Relay Word bit in a SELOGIC® control equation to alert operations personnel, or you can control other functions such as blocking reclosing. The relay clips or limits the maximum reported circuit breaker wear percentage at 150 percent.

NOTE: In the following discussion, three elements are specified, one for each phase: $\phi = A, B,$ and C .

The SEL-421 integrates currents and increments the trip counters for the contact wear monitor each time the SELOGIC control equation BM1TRP ϕ asserts. Set the logic for this function from a communications port with the **SET M** ASCII command, with the ACSELERATOR® QuickSet™ SEL-5030 software program **Breaker Monitor Settings** tree view, or by using the front-panel **SET/SHOW** menu. (See [Making Simple Settings Changes on page U.4.17](#) for information on setting the relay using these methods.) The default settings cause the contact wear monitor to integrate and increment each time the SEL-421 trip logic asserts.

Using the Circuit Breaker Contact Wear Monitor

Perform the following specific steps to use the circuit breaker contact wear monitor:

- Step 1. Enable the circuit breaker monitor.
- Step 2. Load the manufacturer's circuit breaker maintenance data.
- Step 3. Preload any existing circuit breaker wear (if setting up the contact wear monitor on a circuit breaker with preexisting service time).
- Step 4. Program the SELOGIC control equations for trip and close conditions.

Enable the Circuit Breaker Monitor

NOTE: If you want to enable the circuit breaker monitor on Circuit Breaker 2, confirm that the relay is set for two-circuit breaker operation; setting NUMBK must be 2. Once you have set NUMBK := 2, you can set the Circuit Breaker 2 monitor settings, including EB2MON.

You must enable the circuit breaker monitor before you load the manufacturer's data, preload any existing circuit breaker wear, and set the trip initiate and close initiate SELOGIC control equations. Set the circuit breaker monitor enable setting EB1MON to Y (for Yes). You can set EB1MON by using ASCII command **SET M**, the ACSELERATOR QuickSet **Breaker Monitor** branch of the **Settings** tree view, or with the front-panel **SET/SHOW** submenu.

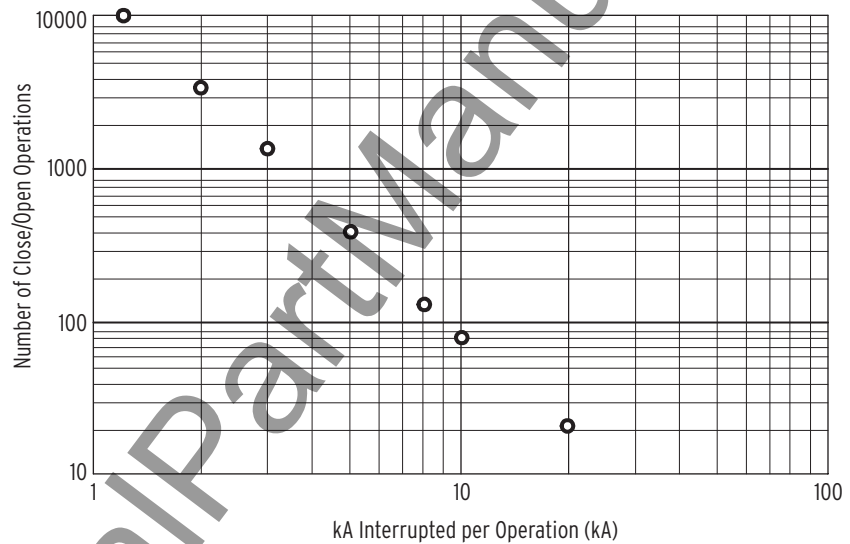
Load Manufacturer Circuit Breaker Maintenance Data

Load the maintenance data supplied by the circuit breaker manufacturer. Circuit breaker maintenance information lists the number of permissible operating cycles (close/open operations) for a given current interruption level. [Table 2.1](#) shows typical circuit breaker maintenance information from an actual SF6 circuit breaker. The log/log plot of [Figure 2.2](#) is the circuit breaker maintenance curve, produced from the [Table 2.2](#) data.

Table 2.2 Circuit Breaker Maintenance Information—Example

Current Interruption Level (kA)	Permissible Close/Open Operations ^a
0.00–1.2	10000
2.00	3700
3.00	1500
5.00	400
8.00	150
10.00	85
20.00	12

^a The action of a circuit breaker closing and then later opening is considered one close/open operation.

**Figure 2.2 Circuit Breaker Maintenance Curve (Manufacturer's Data)**

The three set points necessary to reproduce this circuit breaker maintenance curve in the SEL-421 are listed in [Table 2.3](#) for Circuit Breaker 1. This circuit breaker contact wear curve is shown in [Figure 2.3](#).

Table 2.3 Contact Wear Monitor Settings—Circuit Breaker 1

Setting	Definition	Range
B1COSP1	Close/Open set point 1—max	0–65000 close/open operations
B1COSP2	Close/Open set point 2—mid	0–65000 close/open operations
B1COSP3	Close/Open set point 3—min	0–65000 close/open operations
B1KASP1 ^a	kA Interrupted set point 1—min	1.0–999 kA in 0.1 kA steps
B1KASP2	kA Interrupted set point 2—mid	1.0–999 kA in 0.1 kA steps
B1KASP3 ^a	kA Interrupted set point 3—max	1.0–999 kA in 0.1 kA steps

^a The ratio of settings B1KASP3/B1KASP1 must be in the range: $5 \leq \text{B1KASP3/B1KASP1} \leq 100$.

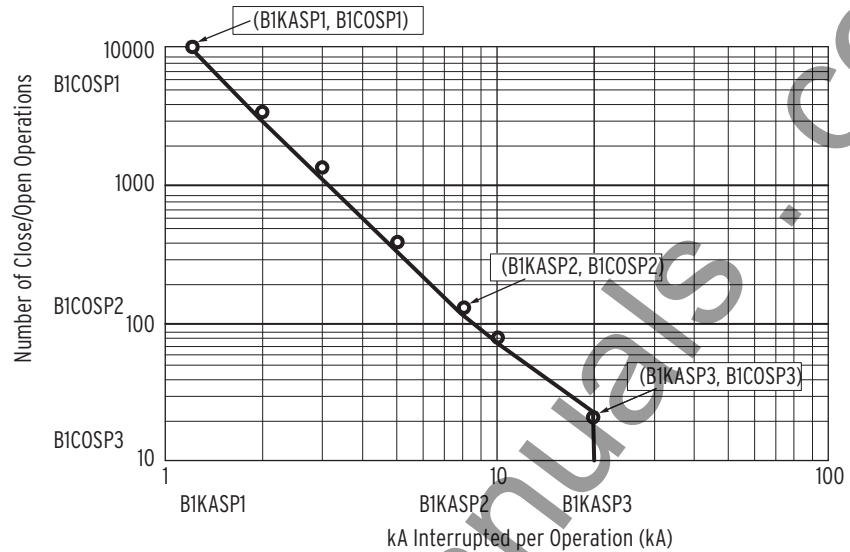


Figure 2.3 Circuit Breaker Contact Wear Curve With SEL-421 Settings

Circuit Breaker Contact Wear Curve Details. Circuit breaker maintenance information from the two end values of [Table 2.2](#) or [Figure 2.2](#) determine set point (B1KASP1, B1COSP1) and set point (B1KASP3, B1COSP3) for the contact wear curve of [Figure 2.3](#). Set point (B1KASP2, B1COSP2) is the middle maintenance point in these data. There are two philosophies for selecting the middle set point. One method places the middle set point to provide the best “curve-fit” for your plot of the manufacturer’s circuit breaker maintenance data of [Figure 2.2](#). Another philosophy is to set the middle point based on actual experience or fault studies of the typical system faults.

EXAMPLE 2.1 Creating the Circuit Breaker Contact Wear Curve

Acquire the manufacturer’s maintenance information (this example uses the data of [Table 2.2](#) for Circuit Breaker 1). If you receive the data in tabular form, plot the manufacturer’s maintenance information on log/log paper in a manner similar to [Figure 2.2](#).

Choose the left and right set points from the extremes of the curve you just plotted. Select the left set point on the contact wear curve corresponding to (B1KASP1, B1COSP1) by setting B1KASP1 := 1.2 and B1COSP1 := 10000. Plot the right set point (B1KASP3, B1COSP3) by setting B1KASP3 := 20.0 and B1COSP3 := 12.

Choose the midpoint of the contact wear curve based on your experience and system fault studies. The majority of operations for a typical circuit breaker are to interrupt single-line-to-ground faults. Therefore, plot the midpoint (B1KASP2, B1COSP2) by setting B1KASP2 at or slightly greater than the expected single-line-to-ground fault current: B1KASP2 := 8.0 and B1COSP2 := 150.

There are two other notable portions of the circuit breaker contact wear curve in [Figure 2.3](#). The curve is horizontal below the left set point (B1KASP1, B1COSP1). This is the close/open operation limit regardless of interrupted current value (for the [Example 2.1](#) circuit breaker, this is at B1COSP1 := 10000). Some manufacturers call this point the mechanical circuit breaker service life.

Another part of the circuit breaker maintenance curve falls vertically at the right set point (B1KASP3, B1COSP3). This is the maximum interrupted current limit (for the [Example 2.1](#) circuit breaker, this is at B1KASP3 := 20.0). If the interrupted current exceeds setting B1KASP3, the relay sets contact wear at 105 percent.

EXAMPLE 2.2 I²t Criteria Application

Some circuit breaker manufacturers do not provide a circuit breaker maintenance curve, but specify the accumulated fault current arcing time ($\sum I^2 t$) for circuit breaker maintenance. For example, manufacturer's data specify $\sum I^2 t$ per phase at 750 kA²-seconds for a particular circuit breaker, at a rated arcing duration for each trip of 1 cycle. The circuit breaker maximum interrupting current rating is 40 kA, and the continuous load current rating is 2 kA.

You can construct the contact wear curve for this circuit breaker from the specified $\sum I^2 t$. Choose B1KASP1 := 2.0 (the continuous current rating) and B1KASP3 := 40.0 (the maximum interrupting current rating). Choose the middle of the contact wear curve based on experience and system fault studies. The majority of faults a typical circuit breaker interrupts are single-line-to-ground faults. Therefore, set nKASP2 at or slightly greater than the expected single-line-to-ground fault current (B1KASP2 := 10.0 kA in this example). From the following equations, calculate these settings points to obtain the number of close/open operations:

$$B1COSP1 = \frac{\sum I^2 t}{(B1KASP1)^2 \cdot t_{arc}} = \frac{750}{2^2 \cdot (0.01667 \cdot 1)} := 11250 \quad \text{Equation 2.1}$$

$$B1COSP2 = \frac{\sum I^2 t}{(B1KASP2)^2 \cdot t_{arc}} = \frac{750}{10^2 \cdot (0.01667 \cdot 1)} := 450 \quad \text{Equation 2.2}$$

$$B1COSP3 = \frac{\sum I^2 t}{(B1KASP3)^2 \cdot t_{arc}} = \frac{750}{40^2 \cdot (0.01667 \cdot 1)} := 28 \quad \text{Equation 2.3}$$

In these equations, t_{arc} is the arcing time in seconds; $t_{arc} = (1/f_{nom}) \cdot$ (arc duration in cycles); f_{nom} is the nominal power system frequency (50 Hz or 60 Hz). These calculations show the number of close/open operations rounded to the nearest unit.

Preloading Contact Wear Data

Upon the first commissioning of the SEL-421, the associated circuit breakers can already have some wear. You can preload a separate amount of wear for each pole of each circuit breaker (see [Preload Breaker Wear on page A.2.20](#) to preload existing contact wear data). The relay accepts integer values of percentage wear as great as 100 percent. The relay adds the incremental contact wear at the next circuit breaker monitor initiation (and at all subsequent initiations) to the preloaded value to obtain a total wear value. The limit for reporting circuit breaker contact wear is 150 percent for each pole.

Program the SELOGIC Control Equations for Trip and Close Conditions

NOTE: In the following discussion, three elements are specified. There is one element for each phase: ϕ = A, B, and C).

Circuit Breaker Monitor Trip Initiation Settings: BM1TRP ϕ . The SEL-421 employs SELOGIC control equations to initiate the circuit breaker monitor. For Circuit Breaker 1, this setting is BM1TRP ϕ . These SELOGIC control equations use Relay Word bits to determine when the circuit breaker monitor accumulates circuit breaker operating parameters from phases A, B, and C. When detecting a rising edge (a transition from logical 0 to logical 1) of the initiation settings, the relay accumulates the interrupted rms currents

NOTE: Factory defaults differ for single-pole tripping and three-pole tripping. Three-pole tripping uses the single setting BM1TRPA for all three poles.

and advances the trip counter by one count. There are separate current accumulators and trip counters for each circuit breaker pole. [Table 2.4](#) shows the factory default settings for circuit breaker monitor initiation.

Table 2.4 Circuit Breaker Monitor Initiate SELogic Control Equations

Name	Description	Default	Comment ^a
BM1TRPA	BK1 Monitor initiate equation	3PT	If BK1TYP := 3
BM1TRPA	A-phase BK1 Monitor initiate equation	TPA1	If BK1TYP := 1
BM1TRPB	B-phase BK1 Monitor initiate equation	BM1TRPA	If BK1TYP := 1
BM1TRPC	C-phase BK1 Monitor initiate equation	BM1TRPA	If BK1TYP := 1

^a See [Table 2.1](#).

Initiation settings can include both internal and external tripping conditions. In order to capture trip information initiated by devices other than the SEL-421, you must program the SELOGIC control equation BM1TRPφ to sense these trips.

EXAMPLE 2.3 Circuit Breaker Monitor External Trip Initiation

Connect external trip signals to the relay control inputs. This example uses input IN201; you can use any control inputs that are appropriate for your installation. Control Input IN201 is located on the SEL-421 I/O Interface Board #1, and is either a direct-coupled or optoisolated input, depending on the specific I/O board that was ordered. Make the control input settings as explained in [Control Inputs on page U.2.6](#).

If you want Circuit Breaker Monitor 1 to initiate for the trip elements TPA1, TPB1, and TPC1, or for external trips, set these SELOGIC control equations from the **SET M ASCII** command or the ACSELEATOR QuickSet **Breaker Monitor Settings** tree view:

BK1TYP := 1 Breaker 1 Trip Type (Single Pole = 1, Three Pole = 3)

BM1TRPA := TPA1 OR IN201 Breaker Monitor A-Phase Trip Initiate-BK1

BM1TRPB := TPB1 OR IN202 Breaker Monitor B-Phase Trip Initiate-BK1

BM1TRPC := TPC1 OR IN203 Breaker Monitor C-Phase Trip Initiate-BK1

EXAMPLE 2.4 Using a Control Input to Capture External and Internal Trip Commands

You can also capture all trip information for circuit breaker trips by using a relay control input to monitor the trip bus for the given circuit breaker. [Figure 2.4](#) shows an illustration of this method in which IN106 connects to the Circuit Breaker 1 A-phase trip bus (via a parallel connection across the trip bus), and asserts for any trip from any source. This example uses inputs IN106; you can use any control inputs that are appropriate for your installation. Vdc for this example is 125 Vdc.

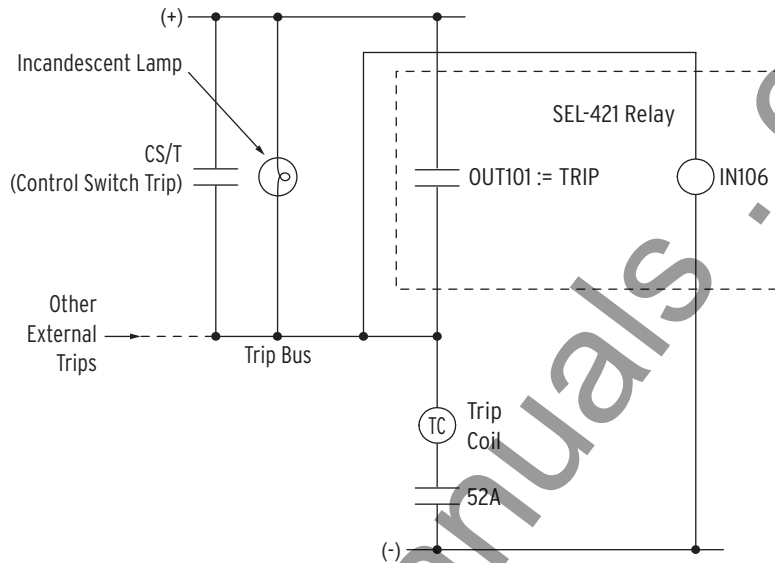


Figure 2.4 Trip Bus Sensing With Relay Input IN106

NOTE: See [Control Inputs on page U.2.6](#) for recommended control input settings.

Many U.S. substation trip bus configurations have an incandescent trip indicator lamp from the battery + terminal to the trip bus. This lamp presents an impedance that can provide sufficient “pull-up” on the trip bus to falsely assert the control input. The worst case for this condition occurs when the circuit breaker is open (auxiliary circuit breaker (52A) contact in [Figure 2.4](#) is open). Use the input assertion level setting IN106P to set the sensitivity of the control input. In most applications, set this input pickup level at 80 percent of the station battery voltage. See [Table 2.1 on page U.2.6](#) for other recommended settings. You can also change the input debounce time IN106D for slow or noisy mechanical switches; the default debounce time of 1/8 cycle should be sufficient for most trip bus arrangements.

For a 125-Vdc station battery system, compute the assertion level as follows:

$$\text{IN106P} = 80\% \cdot 125 \text{ Vdc} = 100 \text{ Vdc}$$

In the **SET G (GLOBAL)** command or in the ACSELERATOR QuickSet **Global > Control Inputs Settings** tree view, confirm that the assertion level (setting IN106P) and the debounce time (setting IN106PU and IN106DO) are correct for your trip bus control voltage. You must enable independent control input conditioning by using Global setting EICIS. Enter these settings:

EICIS := **Y** Independent Control Input Settings (Y, N)

IN106P := **100** Input IN106 Pickup Level (15-265 Vdc)

IN106PU := **0.1250** Input IN106 Pickup Delay (0.0000-5 cyc)

IN106DO := **0.1250** Input IN106 Dropout Delay (0.0000-5 cyc)

BM1TRPA := **IN106** Breaker Monitor Trip-BK1 (SELogic Equation)

Use this procedure to cause the circuit breaker monitor to initiate for either external or internal Circuit Breaker 1 A-phase trips.

NOTE: In the following discussion, three elements are specified. There is one element for each phase: ϕ = A, B, and C).

Circuit Breaker Monitor Close Initiation Settings: BM1CLS ϕ . The SEL-421 employs SELOGIC control equations to initiate the circuit breaker monitor duration timers for close functions. For Circuit Breaker 1, this setting is BM1CLS ϕ . These SELOGIC control equations use Relay Word bits to determine when the circuit breaker monitor times mechanical closing, electrical closing, and pole scatter. [Table 2.5](#) shows the factory default settings for circuit breaker monitor close initiation.

Table 2.5 Circuit Breaker Monitor Close SELogic Control Equations

Name	Description	Default	Comment ^a
BM1CLSA	Breaker Monitor 1 close equation	BK1CL	If BK1TYP := 3
BM1CLSA	Breaker Monitor 1 A-phase close equation	BK1CL	If BK1TYP := 1
BM1CLSB	Breaker Monitor 1 B-phase close equation	BM1CLSA	If BK1TYP := 1
BM1CLSC	Breaker Monitor 1 C-phase close equation	BM1CLSA	If BK1TYP := 1

^a See Table 2.1.

As in [Example 2.4](#) (connection of the trip bus to a control input), you can also capture the circuit breaker close information by using a relay input to monitor the close bus for the given circuit breaker.

Other Circuit Breaker Monitor Functions

kA Interrupt Monitoring

The SEL-421 monitors the amount of phase current that each pole of the circuit breaker interrupts at each trip operation. The relay records the interrupted current as a percentage of the circuit breaker maximum interrupting rating specified by the manufacturer. Set the maximum interruption current with setting B1MKAI (Maximum kA Interrupt Rating—BK1). If the percent of current interrupt that the relay records exceeds threshold setting B1KAIAT (kA Interrupt Capacity Alarm Thresh—BK1), the relay asserts breaker monitor alarm Relay Word bit B1KAIAL.

Mechanical Operating Time

NOTE: This section lists settings for Circuit Breaker 1; settings for Circuit Breaker 2 are similar; replace 1 in the setting with 2.

The mechanical operating time is the time between trip initiation or close initiation and the associated phase circuit breaker 52A normally-open contact status change. (Assertion of 52Aφ1 indicates that a particular circuit breaker phase has closed). The SEL-421 measures the tripping times for each phase from the assertion of the respective BM1TRPφ Relay Word bit to the dropout of the respective 52Aφ1 Relay Word bit. Similarly, for mechanical closing time, the relay measures the closing times for each phase from the assertion of the BM1CLSφ Relay Word bit to the pickup of the 52Aφ1 Relay Word bit. The relay compares these tripping or closing times to the mechanical slow operation time thresholds for tripping and closing, B1MSTRT and B1MSCLT, respectively. The SEL-421 issues a mechanical slow operation alarm, B1MSOAL, for 5 seconds when trip or close times exceed these thresholds. See [Figure 2.5](#) for a Circuit Breaker 1 A-phase timing diagram.

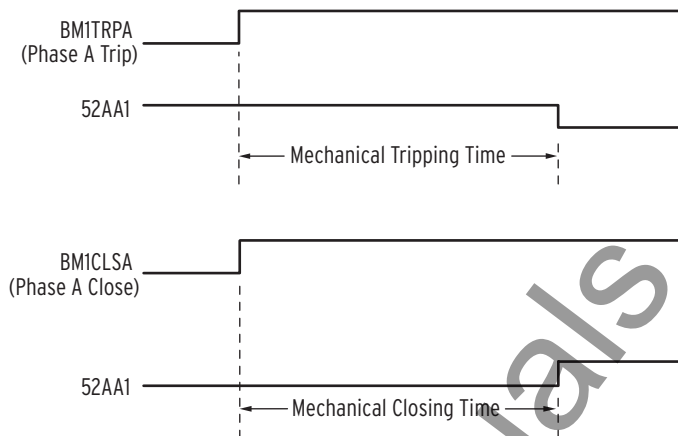


Figure 2.5 Mechanical Operating Time for Circuit Breaker 1 A-Phase

EXAMPLE 2.5 Mechanical Operating Time Settings

Use Circuit Breaker 1, a single-pole tripping circuit breaker, for this example. Connect the circuit breaker normally-open 52A contacts through station battery power to IN101, IN102, and IN103. This example uses inputs IN101, IN102, and IN103 for phases A, B, and C, respectively; you can use any control inputs that are appropriate for your installation. The control voltage for this example is 125 Vdc.

Control Inputs IN101-IN103 are located on the SEL-421 main board and are direct-coupled inputs. Make the control input pickup, dropout, and debounce timer settings as explained in [Control Inputs on page U.2.6](#).

Set the Relay Word bits to respond to these inputs.

52AA1 := **IN101** A-Phase N/O Control Input-BK1 (SELogic Equation)

52AB1 := **IN102** B-Phase N/O Control Input-BK1 (SELogic Equation)

52AC1 := **IN103** A-Phase N/O Control Input-BK1 (SELogic Equation)

Connect external trip signals to IN201, IN202, and IN203, and external close signals to IN204, IN205, and IN206 for the A, B, and C phases, respectively. Use the default settings for input conditioning (debounce time and assertion level), as with inputs IN101 to IN103 above.

Set the mechanical operating time threshold for the slow trip alarm (B1MSTRT) at 30 ms, and the slow close alarm threshold (B1MSCLT) at 70 ms. Use your company standard practices to determine these settings for your application. For this example, enter the following settings:

B1MSTRT := **30** Mechanical Slow Trip Alarm Threshold-BK1
(1-999 ms)

B1MSCLT := **70** Mechanical Slow Close Alarm Threshold-BK1
(1-999 ms)

EB1MON := **Y** Breaker 1 Monitoring (Y, N)

BK1TYP := **1** Breaker 1 Trip Type (Single Pole = 1, Three Pole = 3)

BM1TRPA := **TPA1 OR IN201** Breaker Monitor A-Phase Trip-BK1
(SELogic Equation)

BM1TRPB := **TPB1 OR IN202** Breaker Monitor B-Phase Trip-BK1
(SELogic Equation)

BM1TRPC := **TPC1 OR IN203** Breaker Monitor C-Phase Trip-BK1
(SELogic Equation)

BM1CLSA := **BK1CL OR IN204** Breaker Monitor A-Phase Close-BK1
(SELogic Equation)

BM1CLSB := **BK1CL OR IN205** Breaker Monitor B-Phase Close-BK1
(SELogic Equation)

BM1CLSC := **BK1CL OR IN206** Breaker Monitor C-Phase Close-BK1
(SELogic Equation)

Assertion of the Relay Word bit B1MSOAL indicates any one of the following four conditions:

- The mechanical operating time for a trip operation exceeds 30 ms (the slow trip alarm setting)
- The mechanical operating time for a close operation exceeds 70 ms (the slow close setting)
- No 52A ϕ 1 status change occurred during the time B1MSTRT plus approximately 100 ms after trip initiation (a trip time-out condition)
- No 52A ϕ 1 status change occurred during the time B1MSCLT plus approximately 100 ms after close initiation (a close time-out condition)

The relay makes a further check on the auxiliary circuit breaker (52A) contacts by testing whether these circuit breaker contacts have changed state within approximately 100 ms after the end of the trip or close threshold times. Thus, this additional check serves as the trip time-out and close time-out condition. This check verifies that the circuit breaker actually closed or opened, and it alerts you if maintenance is required on the circuit breaker mechanical linkages or auxiliary (52) contacts.

Electrical Operating Time

The electrical operating time is the time between trip or close initiation and an open phase status change. For both circuit breakers, the relay measures the tripping time for each phase from the assertion of the BM1TRP ϕ Relay Word bit to the time the relay detects an open phase condition. Similarly, the relay measures electrical operating time for closing each phase from the assertion of BM1CLS ϕ to the restoration of phase quantities. The relay compares these tripping or closing times to the electrical slow operation time thresholds for tripping and closing, B1ESTRT and B1ESCLT, respectively. The SEL-421 issues an electrical slow operation alarm, B1ESOAL, for 5 seconds when trip or close times exceed these thresholds. [Figure 2.6](#) shows the timing diagram for A-phase pole of Circuit Breaker 1.

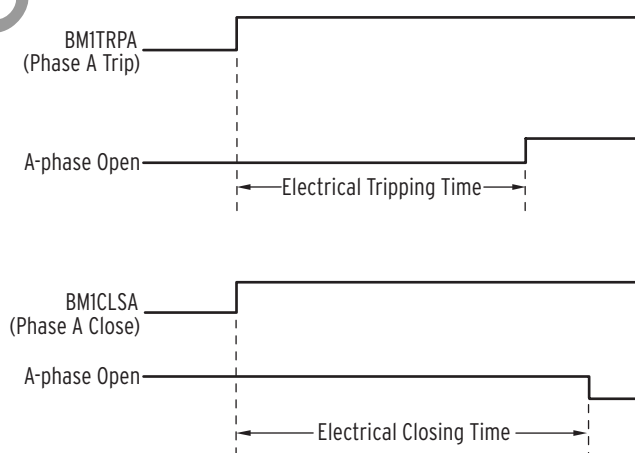


Figure 2.6 Electrical Operating Time for Circuit Breaker 1 A-Phase

Primary load/fault current can indicate contact closing, contact opening, and arc extinction, depending upon the actual circuit breaker monitor setup. You can detect problems within the circuit breaker arcing chamber by timing the interval from trip/close initiation to electric arc extinction.

EXAMPLE 2.6 Electrical Operating Time Settings

Use Circuit Breaker 1, a single-pole tripping circuit breaker, for this example. Connect external trip signals to IN201, IN202, and IN203, and external close signals to IN204, IN205, and IN206 for the A-, B-, and C-phases, respectively. This example uses control inputs IN201 through IN206; you can use any control inputs that are appropriate for your installation. The control voltage for this example is 125 Vdc.

Control Inputs IN201-IN206 are located on the SEL-421 I/O Interface board #1 and are either direct-coupled or optoisolated inputs, depending on the specific I/O Interface board that was ordered. Make the control input settings as explained in [Control Inputs on page U.2.6](#).

Set the electrical operating time threshold for the slow trip alarm (BIESTRT) at 25 ms, and the slow close alarm threshold (BIESCLT) at 65 ms. Use your company standard practices to determine these settings for your application. For this example, enter the following settings:

BIESTRT := **25** Electrical Slow Trip Alarm Threshold-BK1 (1-999 ms)

BIESCLT := **65** Electrical Slow Close Alarm Threshold-BK1 (1-999 ms)

EBIMON := **Y** Breaker 1 Monitoring (Y, N)

BKITYP := **1** Breaker 1 Trip Type (Single Pole = 1, Three Pole = 3)

BMITRPA := **TPA1 OR IN201** Breaker Monitor A-Phase Trip-BK1 (SELogic Equation)

BMITRPB := **TPB1 OR IN202** Breaker Monitor B-Phase Trip-BK1 (SELogic Equation)

BMITRPC := **TPC1 OR IN203** Breaker Monitor C-Phase Trip-BK1 (SELogic Equation)

BMICLSA := **BK1CL OR IN204** Breaker Monitor A-Phase Close-BK1 (SELogic Equation)

BMICLSB := **BK1CL OR IN205** Breaker Monitor B-Phase Close-BK1 (SELogic Equation)

BMICLSC := **BK1CL OR IN206** Breaker Monitor C-Phase Close-BK1 (SELogic Equation)

Assertion of the Relay Word bit B1ESOAL indicates any one of the following four conditions:

- The electrical operating time for a trip operation exceeds 25 ms (the slow trip alarm setting)
- The electrical operating time for a close operation exceeds 65 ms (the slow close setting)
- No pole-open logic status change occurred during the time B1ESTRT plus approximately 100 ms after trip initiation (a trip time-out condition)
- No pole-open logic status change occurred during the time B1ESCLT plus approximately 100 ms after close initiation (a close time-out condition)

The relay further checks the circuit breaker by testing whether the circuit breaker has interrupted or restored current within 100 ms after the end of the trip or close threshold times. Thus, this additional check serves as the trip time-out and close time-out condition. This verifies that the circuit breaker actually closed or opened, and alerts you if maintenance is required on circuit breaker mechanical linkages.

Pole Scatter

NOTE: Pole scatter applies only to single-pole mechanism circuit breakers (BK1TYP := 1). These circuit breakers have an auxiliary circuit breaker (52A) contact for each phase.

The SEL-421 records and compares the operation time of each circuit breaker pole to detect time deviations between pairs of circuit breaker poles when tripping and closing all three poles simultaneously on single-pole-capable circuit breakers. The relay measures the differences in operating times resulting from auxiliary circuit breaker (52A) contact status changes. The logic compares the operation time of each individual circuit breaker pole against the time for each of the other poles. The relay triggers an alarm, B1PSAL, for any time deviation greater than the preset time threshold settings B1PSTRT and B1PSCLT for Circuit Breaker 1.

Figure 2.7 shows the operating time for each pole (A, B, and C) of Circuit Breaker 1. TAB represents the operating time deviation between poles A and B. TBC is the time between B and C, and TCA is the time between C and A. Once activated, the pole scatter alarm remains asserted for five seconds.

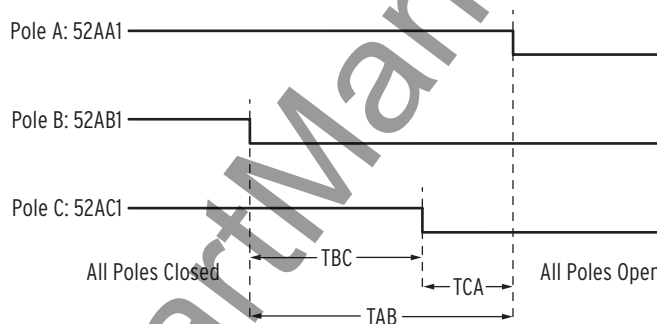


Figure 2.7 Timing Illustration for Pole Scatter at Trip

EXAMPLE 2.7 Pole Scatter Settings

Use Circuit Breaker 1, a single-pole tripping circuit breaker, for this example. This example uses control inputs IN101, IN102, and IN103 for the A-, B-, and C-phases, respectively; you can use any control inputs that are appropriate for your installation.

The control voltage for this example is 125 Vdc. Control Inputs IN101-IN103 are located on the SEL-421 main board and are direct-coupled inputs. Make the control input pickup, dropout, and debounce timer settings as explained in [Control Inputs on page U.2.6](#). Connect the circuit breaker normally-open auxiliary circuit breaker (52A) contacts through station battery power to IN101, IN102, and IN103.

Set the relay to respond to these inputs by using the ACSELERATOR QuickSet **Breaker Monitor (SET M)** settings:

52AA1 := **IN101** A-Phase Normally Open Control Input-BK1 (SELogic Equation)

52AB1 := **IN102** B-Phase Normally Open Control Input-BK1 (SELogic Equation)

52AC1 := **IN103** C-Phase Normally Open Control Input-BK1 (SELogic Equation)

Connect external trip signals to IN201, IN202, and IN203, and external close signals to IN204, IN205, and IN206 for the A-, B-, and C-phases, respectively. This example uses control inputs IN201 through IN206; you can use any control inputs that are appropriate for your installation. Use the default settings for conditioning inputs IN201 through IN206.

Set the pole scatter trip alarm time threshold (B1PSTRT) at 4 ms, the pole scatter close alarm time threshold (B1PSCLT) at 6 ms, and the pole discrepancy time delay (B1PDD) at 1400 ms. (See [Pole](#)

Discrepancy on page A.2.15 for information on setting B1PDD). Use your company standard practices to determine these settings for your application. For this example, enter the following settings:

B1PSTRT := **4** Pole Scatter Trip Alarm Threshold–BK1 (1–999 ms)
 B1PSCLT := **6** Pole Scatter Close Alarm Threshold–BK1 (1–999 ms)
 B1PDD := **1400** Pole Discrepancy Time Delay–BK1 (1–9999 ms)
 EBIMON := **Y** Breaker 1 Monitoring (Y, N)
 BK1TYP := **1** Breaker 1 Trip Type (Single Pole = 1, Three Pole = 3)
 BMITRPA := **TPA1 OR IN201** Breaker Monitor A-Phase Trip–BK1 (SELogic Equation)
 BMITRPB := **TPB1 OR IN202** Breaker Monitor B-Phase Trip–BK1 (SELogic Equation)
 BMITRPC := **TPC1 OR IN203** Breaker Monitor C-Phase Trip–BK1 (SELogic Equation)
 BMICLSA := **BK1CL OR IN204** Breaker Monitor A-Phase Close–BK1 (SELogic Equation)
 BMICLSB := **BK1CL OR IN205** Breaker Monitor B-Phase Close–BK1 (SELogic Equation)
 BMICLSC := **BK1CL OR IN206** Breaker Monitor C-Phase Close–BK1 (SELogic Equation)

If any of the pole-open times (TAB, TBC, and TCA in Figure 2.7) exceed 4 ms, or if any of the pole close times exceed 6 ms, the relay asserts the Relay Word bit B1PSAL. Assertion of B1PSAL indicates any one of the following four conditions:

- The pole scatter time for trip operation exceeds the alarm setting time (4 ms)
- The pole scatter time for close operation exceeds the alarm setting time (6 ms)
- One phase auxiliary circuit breaker (52A) contact status change exceeds B1PSTRT plus approximately 5 ms after the trip initiation
- One phase auxiliary circuit breaker (52A) contact status change exceeds B1PSCLT plus approximately 5 ms after the close initiation

Note that the relay provides a time out of approximately 200 ms after the trip or 300 ms after the close threshold to end detection of pole scatter alarms.

Pole Discrepancy

NOTE: Pole discrepancy applies only to single-pole mechanism circuit breakers (BK1TYP := 1). These circuit breakers have an auxiliary circuit breaker (52A) contact output for each phase.

The SEL-421 continuously monitors the status of each circuit breaker pole to detect open or close deviations among the three poles. In addition, at tripping and closing, the relay measures the differences in operating times during the auxiliary circuit breaker (52A) contact status changes or open phase logic operation. The relay triggers an alarm Relay Word bit, B1PDAL, if the status of any pole compared to another pole exceeds the time window setting B1PDD for the circuit breaker.

You can set the relay to use the current flowing through the circuit breaker to supervise pole discrepancy timing of the auxiliary circuit breaker (52A) contacts. Enable this supervision by setting E1PDCS to Y for Circuit Breaker 1.

Pole discrepancy setting B1PDD should be longer than the single-pole reclosing dead time.

$$B1PDD := (SPOID + \text{circuit breaker pole operating time} + \text{contact latency}) \cdot 1.2 \quad \text{Equation 2.4}$$

Where:

SPOID is the single-pole open interval time and the factor 1.2 is a safety factor.

Round this time to the next higher hundreds of milliseconds value to give the pole discrepancy setting. See [Auto-Reclosing and Synchronism Check on page R.2.1](#) for information on setting the SEL-421 recloser.

[Figure 2.8](#) shows a Circuit Breaker 1 operation where Pole B closes first, followed by Pole C; Pole A closes slowly. If the time from a change in 52AB1 to the change in 52AA1 exceeds the pole discrepancy time threshold setting B1PDD, then the relay asserts the B1PDAL alarm. Once activated, the relay asserts the pole discrepancy alarm for five seconds.

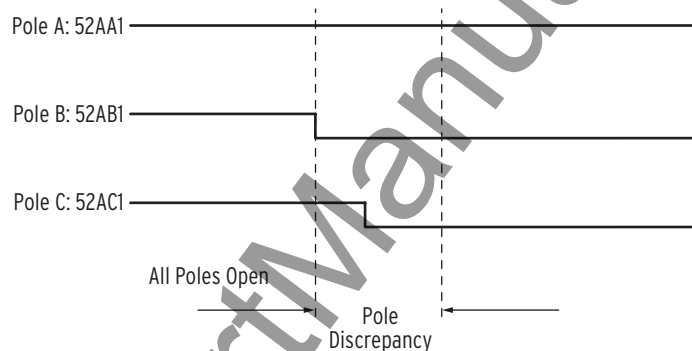


Figure 2.8 Pole Discrepancy Measurement

EXAMPLE 2.8 Pole Discrepancy Alarm for Circuit Breaker 1—No Other Circuit Breaker Monitor Functions

Use Circuit Breaker 1, a single-pole tripping circuit breaker, for this example. This example uses control inputs IN101, IN102, and IN103 for the A-, B-, and C-phases, respectively; you can use any control inputs that are appropriate for your installation.

The control voltage for this example is 125 Vdc. Control Inputs IN101–IN103 are located on the SEL-421 main board and are direct-coupled inputs. Make the control input pickup, dropout, and debounce timer settings as explained in [Control Inputs on page U.2.6](#). Connect the circuit breaker normally-open auxiliary circuit breaker (52A) contacts through station battery power to IN101, IN102, and IN103.

Set the relay internal Relay Word bits to respond to these inputs by using the ACCELERATOR QuickSet **Breaker Monitor (SET M)** settings:

52AA1 := **IN101** A-Phase Normally Open Control Input–BK1 (SELogic Equation)

52AB1 := **IN102** B-Phase Normally Open Control Input–BK1 (SELogic Equation)

52AC1 := **IN103** C-Phase Normally Open Control Input–BK1 (SELogic Equation)

Connect external trip signals to IN201, IN202, and IN203, and external close signals to IN204, IN205, and IN206 for the A, B, and C phases, respectively. This example uses control inputs IN201 through IN206; you can use any control inputs that are appropriate for your installation.

Use the default relay Global settings for conditioning inputs IN101 to IN103. Set the pole discrepancy time delay (B1PDD) at 1400 ms. This time delay assumes a dead time of 1000 ms plus a pole closing time of 100 ms (including contact latency), plus 20 percent (for security), rounded to the next higher hundreds of milliseconds value. This pole

discrepancy time is longer than the single-pole open interval time default of 900 ms; confirm that this is the case for your application settings.

Enter the following settings:

B1PDD := **1400** Pole Discrepancy Time Delay-BK1 (1-9999 ms)

EB1MON := **Y** Breaker 1 Monitoring (Y, N)

BK1TYP := **1** Breaker 1 Trip Type (Single Pole = 1, Three Pole = 3)

The pole discrepancy timing window is B1PDD := 1400 (ms). Assertion of the Relay Word bit B1PDAL indicates that the status of the three Circuit Breaker 1 poles disagrees for 1400 ms or longer.

Circuit Breaker Inactivity Time Elapsed

The SEL-421 circuit breaker inactivity time monitor detects the elapsed time (measured in days) since the last trip or close operation of a circuit breaker. Use setting B1ITAT to set the circuit breaker inactivity time. An alarm Relay Word bit, B1BITAL, asserts if the elapsed time exceeds a predefined setting. This alarm is useful to detect circuit breakers that are not operated on a regular basis. These circuit breakers can fail to operate when needed to perform a protection trip.

EXAMPLE 2.9 Inactivity Time Settings

Use Circuit Breaker 1 for this example. To assert an alarm if Circuit Breaker 1 has not operated within the last 365 days, enter the following settings:

EB1MON := **Y** Breaker 1 Monitoring (Y, N)

B1ITAT := **365** Inactivity Time Alarm Thresh-BK1 (N, 1-9999 days)

Assertion of the Relay Word bit B1BITAL indicates that it has been more than 365 days since the last Circuit Breaker 1 operation.

When testing the inactivity timer, you must measure actual relay clock transitions across time 00:00:00.000 (to increment the day counter). If you set the relay to a specific date, enable the circuit breaker monitor (EB1MON := Y), then advance the date setting to a new date, the inactivity timer shows only 1 day of elapsed time.

Motor Running Time

The SEL-421 circuit breaker monitor measures circuit breaker motor running time. Depending on your particular circuit breaker, you can use the motor running time to monitor the charge time of the circuit breaker springs or the running time of the compressed air motor. An alarm asserts if the elapsed motor running time exceeds the predefined threshold setting B1MRTAT.

Setting B1MRTIN is a SELOGIC control equation to activate the motor-running timer. The rising edge of B1MRTIN indicates the motor starting time; a falling edge indicates the motor stop time. The motor running time logic asserts the alarm Relay Word bit, B1MRTAL, for 5 seconds when the motor running time exceeds the predefined threshold. Setting B1MRTIN to logical 0 disables the motor running time feature of the circuit breaker monitor.

EXAMPLE 2.10 Motor Running Time Settings

Use Circuit Breaker 1 for this example.

Connect the motor control contact to IN207. This example uses control input IN207; you can use any control inputs that are appropriate for your installation.

To determine the motor run time value, take the circuit breaker out of service using your company standard circuit breaker maintenance policy. Issue a trip and close command while you measure the time that the circuit breaker motor requires for recharging the spring or reestablishing the return air pressure to normal. Add 20 percent to this time measurement to avoid false alarms. Use the resulting time value for the motor running time alarm setting B1MRTAL.

The control voltage for this example is 125 Vdc. Control Input IN207 is located on the SEL-421 I/O Interface board #1 and is either a direct-coupled or an optoisolated input, depending on the specific I/O Interface board that was ordered. Make the control input settings as explained in [Control Inputs on page U.2.6](#).

The recharge time measurement for this circuit breaker was 20 seconds; add 20 percent (4 seconds) to give an alarm time of 24 seconds. To set the motor running time alarm threshold at 24 seconds, enter the following settings:

EBIMON := **Y** Breaker 1 Monitoring (Y, N)

B1MRTIN := **IN207** Motor Run Time Control Input-BK1 (SELogic Equation)

B1MRTAT := **24** Motor Run Time Alarm Threshold-BK1 (1-9999 seconds)

Assertion of the Relay Word bit B1MRTAL indicates the following condition: motor running time exceeds 24 seconds because IN207 was asserted for more than 24 seconds.

BREAKER Command

Use the **BRE** command to access vital information about the condition of substation circuit breakers and preset or reset circuit breaker monitor data. The SEL-421 monitors two separate circuit breakers; you must specify Circuit Breaker 1 and Circuit Breaker 2 for most **BRE** commands. [Table 2.6](#) shows the SEL-421 **BRE** commands. For more information on the **BRE** command, see [BREAKER on page R.9.2](#).

Table 2.6 BRE Command^a

Command	Description	Access Level
BRE C A	Clear all circuit breaker monitor data to zero.	B, P, A, O, 2
BRE R A	Clear all circuit breaker monitor data to zero.	B, P, A, O, 2
BRE n C	Clear Circuit Breaker <i>n</i> data to zero.	B, P, A, O, 2
BRE n R	Clear Circuit Breaker <i>n</i> data to zero.	B, P, A, O, 2
BRE n	Display the breaker report for the most recent Circuit Breaker <i>n</i> operation.	1, B, P, A, O, 2
BRE n H	Display history data for the last 128 Circuit Breaker <i>n</i> operations.	1, B, P, A, O, 2
BRE n P	Preload previously accumulated Circuit Breaker <i>n</i> data.	B, P, A, O, 2

^a *n* is 1 or 2, representing Circuit Breaker 1 and Circuit Breaker 2, respectively.

The **BRE 1 C**, **BRE 2 C**, **BRE 1 R**, and **BRE 2 R** commands reset the accumulated circuit breaker monitor data for Circuit Breaker 1 or Circuit Breaker 2, respectively. If you do not specify Circuit Breaker 1 or Circuit Breaker 2, the clear commands **BRE C A** and **BRE R A** clear all data for both circuit breakers.

The **BRE 1** or **BRE 2** commands display the circuit breaker report for the most recent Circuit Breaker 1 or Circuit Breaker 2 operation, respectively.

The relay also displays the operation summary and the circuit breaker alarms. When the circuit breaker maintenance curve reaches 150 percent for a particular pole, the percentage wear for this pole remains at 150 percent (even if additional current is interrupted) until reset. However, the relay continues to advance the operation counter to as many as 9999999 operations per pole until reset. Accumulated circuit breaker wear/operations data are retained if the relay loses power or if the circuit breaker monitor is disabled (EB1MON := N and EB2MON := N).

Circuit Breaker Report

Figure 2.9 is a sample breaker report (shown with typical data). The relay reports DC battery monitor voltages for the minimum dc voltage during a 20-cycle period at circuit breaker monitor trip initiation (BM1TRP ϕ) and for a 30-cycle window at circuit breaker monitor close initiation (BM1CLS ϕ). The circuit breaker report contains data only for options that you have enabled. For example, if you set EDCMON := 1, then the relay does not show the row labeled Last Op Minimum DC2 (V).

```
=>BRE 1 <Enter>
```

Relay 1	Date: 03/20/2001	Time: 17:21:42.577
Station A	Serial Number: 2001001234	

Breaker 1
Breaker 1 Report

	Trip A	Trip B	Trip C	Cls A	Cls B	Cls C
Avg Elect Op Time (ms)				5.8	7.5	8.4
Last Elect Op Time (ms)	18.2	20.0	17.9	8.4	10.4	8.4
Avg Mech Op Time (ms)						
Last Mech Op Time (ms)	25.8	24.4	26.5	30.1	26.3	34.2
Inactivity Time (days)	1	1	1	1	1	1
	3 Pole Trip			3 Pole Close		
	AB	BC	CA	AB	BC	CA
Max Pole Scatter (ms)	5.1	3.1	5.0	6.3	4.1	2.1
Last Pole Scatter (ms)	2.1	1.0	3.1	4.1	2.1	2.1
	Pole A	Pole B	Pole C			
Accum Pri Current (kA)	3.13657	0.43533	0.41785			
Accum Contact Wear (%)	0.5	0.5	0.5			
Max Interrupted Current (%)	1.6	0.2	0.2			
Last Interrupted Current(%)	1.6	0.2	0.2			
Number of Operations	5	5	5			
	Alarm	Total Count				
Mechanical Operating Time	MSOAL	4				
Electrical Operating Time	ESOAL	3				
Breaker Inactivity Time	BITAL	0				
Pole Scatter	PSAL	2				
Pole Discrepancy	PDAL	1				
Current (kA) Interrupted	KAIAL	0				
LAST BREAKER MONITOR RESET	03/15/2001	07:21:31.067				

```
=>>
```

Figure 2.9 Breaker Report
(For the most recent operation)

Breaker History

The SEL-421 displays the circuit breaker history report when you issue the **BRE 1 H** or **BRE 2 H** commands. The report consists of as many as 128 circuit breaker monitor events stored in nonvolatile memory. These events are determined by settings BM1TRP ϕ and BM1CLS ϕ (see [Program the SELOGIC Control Equations for Trip and Close Conditions on page A.2.7](#)). The breaker history report is similar to [Figure 2.10](#) (shown with typical data).

```

=>BRE 1 H <Enter>
Breaker 1 History Report

Relay 1                               Date: 03/15/2001  Time: 07:19:27.156
Station A                             Serial Number: 01001234

```

No.	Date	Time	Bkr.Op	Op Time(ms)	Pri I (A)	VDC1 (V)	VDC2 (V)
			Elect	Mech			
1	06/01/2000	12:24:36.216	Trp A	26 28	5460	119	118
2	06/01/2000	12:24:36.216	Trp B	26 28	5260	119	118
3	06/01/2000	12:24:36.216	Trp C	26 28	5160	119	119
4	09/26/1999	16:24:36.214	Cls A	39 35	1020	118	118
5	09/26/1999	16:24:36.214	Cls B	39 35	990	118	118
6	09/26/1999	16:24:36.214	Cls C	39 35	1010	118	118
7	03/26/1999	11:24:36.218	Cls C	39 35	1100	117	115
8	03/26/1999	11:24:31.218	Trp C	26 28	3460	116	112

```

128
=>

```

Figure 2.10 Breaker History Report

Preload Breaker Wear

You can preload a separate contact wear value for each pole of each circuit breaker by using the commands **BRE 1 P** or **BRE 2 P** for Circuit Breaker 1 and Circuit Breaker 2, respectively. The relay adds the incremental contact wear at all subsequent circuit breaker monitor initiations to your preloaded value to obtain a total wear value. You can enter integer values of percentage wear from 1 percent to 100 percent. In addition to preloading contact wear data, you can enter values for previous operations and accumulated currents. The maximum number of operations or accumulated primary current (in kA) you can enter is 9999999. The circuit breaker preload terminal screen is similar to [Figure 2.11](#) for both the terminal and ACSELERATOR QuickSet.

```

=>BRE 1 P <Enter>

```

Accum Contact Wear (%)	A-phase % := 5 ? 12 <Enter>
	B-phase % := 10 ? 15 <Enter>
	C-phase % := 7 ? 10 <Enter>
Accum Num of Operations:	A-phase := 25 ? 11 <Enter>
	B-phase := 25 ? 11 <Enter>
	C-phase := 25 ? 11 <Enter>
Accum Pri Current (kA)	Trip A := 99.0 ? 299 <Enter>
	Trip B := 98.0 ? 254 <Enter>
	Trip C := 98.0 ? 257 <Enter>
	Pole A Pole B Pole C
Accum Contact Wear (%)	12 15 10
Accum Num of Operations	11 11 11
Accum Pri Current (kA)	299 254 257

Figure 2.11 Circuit Breaker Preload Data

When performing circuit breaker testing, capture the **BRE 1 P** information (write the date or use a terminal screen capture) before testing. Test the circuit breaker, then enter the previously recorded preload data with the **BRE 1 P** command. Using this method, you can eliminate testing operations from actual usage data in the circuit breaker monitor.

Compressed ASCII Circuit Breaker Report

You can retrieve a Compressed ASCII circuit breaker report by using the **CBR** command from any communications port. See [CBREAKER on page R.9.4](#) for more information on the **CBR** command.

The relay arranges items in the Compressed ASCII circuit breaker report in a special order. For the purpose of improving products and services, SEL sometimes changes the items and item order.

The information presented below explains the message and serves as a guide to the items in a Compressed ASCII configuration circuit breaker report.

The format of the Compressed ASCII **CBR** message is the following:

```

"RID","SID","FID","yyyy"
relayid,stationid,fidstring,"yyyy"
"BID","yyyy"
breakerid,"yyyy"
"AVG_TR_ELEC","LAST_TR_ELEC","AVG_TR_MECH","LAST_TR_MECH","LAST_TR_MINDC2","TR_INAC(
days)","MAX_TR_SCAT(ms)","LAST_TR_SCAT(ms)","yyyy"
fff,fff,fff,fff,fff,fff,fff,fff,fff,fff,"yyyy"
fff,fff,fff,fff,fff,fff,fff,fff,fff,fff,"yyyy"
fff,fff,fff,fff,fff,fff,fff,fff,fff,fff,"yyyy"
"AVG_CL_ELEC","LAST_CL_ELEC","AVG_CL_MECH","LAST_CL_MECH","LAST_CL_MINDC2","CL_INAC(
days)","MAX_CL_SCAT(ms)","LAST_CL_SCAT(ms)","yyyy"
fff,fff,fff,fff,fff,fff,fff,fff,fff,fff,"yyyy"
fff,fff,fff,fff,fff,fff,fff,fff,fff,fff,"yyyy"
fff,fff,fff,fff,fff,fff,fff,fff,fff,fff,"yyyy"
"ACC_CURR(KA)","ACC_WEAR(%)","MAX_INT_CURR(%)","LAST_INT_CURR(%)","NUM_OPERS","yyyy"
fff,fff,fff,fff,fff,fff,fff,fff,fff,fff,"yyyy"
fff,fff,fff,fff,fff,fff,fff,fff,fff,fff,"yyyy"
fff,fff,fff,fff,fff,fff,fff,fff,fff,fff,"yyyy"
"AVG_MOT_RUNTIME","LAST_MOT_RUNTIME","RESET_MONTH","RESET_DAY","RESET_YEAR","RESET_H
OUR","RESET_MIN","RESET_SEC","yyyy"
fff,fff,fff,fff,fff,fff,fff,fff,fff,fff,"yyyy"

```

Definitions for the items and fields in the Compressed ASCII configuration are the following:

- yyyy is the checksum
- iii is an integer value
- fff is a floating-point value

The relay reports the data as A-phase in the first line, B-phase in the second line, and C-phase in the third line. Pole scatter data are slightly different: TAB is in the first line, TBC is in the second line, and TCA is in the third line.

Station DC Battery System Monitor

NOTE: This section lists settings for Station DC Battery Monitor 1; settings for Station DC Battery Monitor 2 are similar; replace 1 in the setting with 2.

The SEL-421 automatically monitors station battery system health by measuring the dc voltage, ac ripple, and voltage between each battery terminal and ground. The relay provides two dc monitor channels, Vdc1 and Vdc2. Four voltage thresholds give you the ability to create five sensing zones (low failure, low warning, normal, high warning, and high failure) for the dc voltage.

The ac ripple quantity indicates battery charger health. When configuring the ac ripple setting DC1RP, we can define the ripple content of a dc supply as the peak-to-peak ac component of the output supply waveform.

The relay also makes measurements between the battery terminal voltages and station ground to detect positive and negative dc ground faults. [Figure 2.12](#) shows a typical dual-battery dc system.

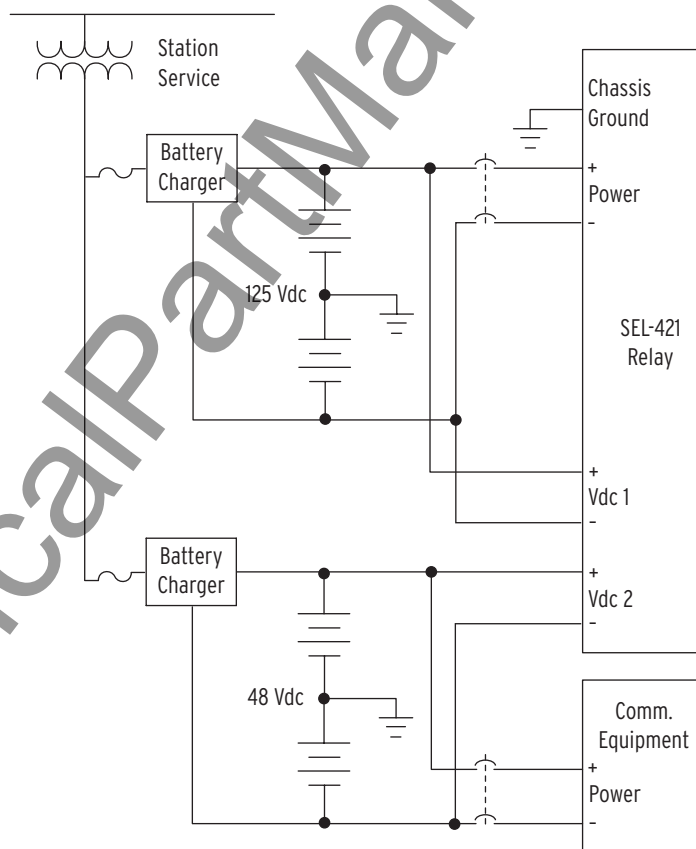


Figure 2.12 Typical Station DC Battery System

The dc battery monitor measures the station battery voltage applied at the rear-panel terminals labeled Vdc1 (+ and –) and Vdc2 (+ and –). Monitoring dc voltage during circuit breaker operation gives a quick test of the battery system, which includes wiring and junctions from the batteries to the circuit breaker. In the breaker report and in the breaker history report, the relay displays the minimum value of station battery voltage during circuit breaker operation on a per-pole basis (see [Circuit Breaker Report on page A.2.19](#)).

NOTE: First enable Station DC Monitoring (with the Global setting EDCMON) to access station dc battery monitor settings.

[Table 2.7](#) lists the station dc battery monitor settings and the corresponding Relay Word bits that assert when battery quantities exceed these settings thresholds. Use the **SET G ASCII** command from a terminal or use the ACSELERATOR QuickSet **Global > Station DC Monitoring** branch of the **Settings** tree view to access the DC Monitor settings.

Table 2.7 DC Monitor Settings^a and Relay Word Bit Alarms

Setting	Definition	Relay Word Bit
DC1LFP	Low Level Fail Pickup (OFF, 15–300 Vdc) ^b	DC1F
DC1LWP	Low Level Warn Pickup (OFF, 15–300 Vdc) ^a	DC1W
DC1HWP	High Level Warn Pickup (OFF, 15–300 Vdc) ^a	DC1W
DC1HFP	High Level Fail Pickup (OFF, 15–300 Vdc) ^a	DC1F
DC1RP	Peak to Peak AC Ripple Pickup (1–300 Vac) ^a	DC1R
DC1GF	Ground Detection Factor (1.00–2.00) (advanced setting)	DC1G

^a For DC2 Monitor Settings and Relay Word bit Alarms, substitute 2 for 1 in the setting names and Relay Word bit names.

^b Minimum setting step size is 1 V for voltage settings.

Station DC Battery System Monitor Application

Not only does the station dc monitor provide a view of how much the station dc battery voltage dips when tripping, closing, and when other dc control functions occur, the dc monitor also alarms for undervoltage or overvoltage dc battery conditions in five sensing regions. The following describes how to apply the dc battery monitor to a typical 125-Vdc protection battery system with a 48-Vdc communication equipment battery system. Adjust the values used here to meet the specifications of your company.

Battery Voltage

When setting the station dc battery monitor, you must determine the minimum and maximum dc levels in the battery system. In addition, you must also establish the threshold levels for different battery system states or conditions. The following voltage levels describe these battery system conditions:

- Trip/Close—the lowest dc voltage point at which circuit breaker trip and close operations occur
- Open-circuit—the dc battery voltage when all cells are fully charged and not connected to the battery charger
- Float low—the lowest charging voltage supplied by the battery charger
- Float high—the highest charging voltage supplied by the battery charger
- Equalize mode—a procedure during which the batteries are overcharged intentionally for a pre-selected time in order to bring all cells to a uniform output

Set the low end of the allowable dc battery system voltage according to the recommendations of C37.90–1989 (R1994) IEEE Standard for Relays and Relay Systems Associated with Electric Power. *Section 6.4* in this standard is titled *Allowable Variation from Rated Voltage for Voltage Operated Auxiliary Relays*. This section calls for an 80 percent low-end voltage and 28, 56, 140, or 280-Vdc high-end voltages for the popular nominal station battery voltages. [Table 2.8](#) lists expected battery voltages under various conditions using commonly accepted per-cell voltages.

Table 2.8 Example DC Battery Voltage Conditions

Condition	Calculation	Battery Voltage (Vdc)
Trip/Close	80% • 125 Vdc	100.0
Open-Circuit	60 (cells) • 2.06 (volts/cell)	123.6
Float Low	60 (cells) • 2.15 (volts/cell)	129.0
Float High	60 (cells) • 2.23 (volts/cell)	133.8
Equalize Mode	60 (cells) • 2.33 (volts/cell)	139.8
Trip/Close	80% • 48 Vdc	38.4
Open Circuit	24 (cells) • 2.06 (volts/cell)	49.4
Float Low	24 (cells) • 2.15 (volts/cell)	51.6
Float High	24 (cells) • 2.23 (volts/cell)	53.5
Equalize Mode	24 (cells) • 2.33 (volts/cell)	55.9
Trip/Close	80% • 24 Vdc	19.2
Open Circuit	12 (cells) • 2.06 (volts/cell)	24.7
Float Low	12 (cells) • 2.15 (volts/cell)	25.8
Float High	12 (cells) • 2.23 (volts/cell)	26.8
Equalize Mode	12 (cells) • 2.33 (volts/cell)	28.0

Use the expected battery voltages of [Table 2.9](#) to determine the SEL-421 station dc battery monitor threshold settings. [Table 2.9](#) shows these threshold settings for a nominal 125-Vdc battery system (the Vdc1 input) and a nominal 48-Vdc battery system (the Vdc2 input).

Table 2.9 Example DC Battery Monitor Settings—125 Vdc for Vdc1 and 48 Vdc for Vdc2

Setting	Description	Indication	Value (Vdc)
DC1LFP	Low-fail threshold, Mon. 1	Poor battery performance	100
DC1LWP	Low-warning threshold, Mon. 1	Charger malfunction	127
DC1HWP	High-warning threshold, Mon. 1	Equalization	137
DC1HFP	High-fail threshold, Mon. 1	Charger malfunction	142
DC2LFP	Low-fail threshold, Mon. 2	Poor battery performance	38
DC2LWP	Low-warning threshold, Mon. 2	Charger malfunction	50
DC2HWP	High-warning threshold, Mon. 2	Equalization	55
DC2HFP	High-fail threshold, Mon. 2	Charger malfunction	57

AC Ripple

Another method for determining whether the substation battery charger has failed is to monitor the amount of ac ripple on the station dc battery system. The *IEEE C37.90-1989* standard also identifies an “*Allowable AC Component in DC Control Voltage Supply*” (Section 6.5) as an alternating component (ripple) of 5 percent peak or less. (This definition is valid if the minimum instantaneous voltage is not less than 80 percent of the rated voltage.) The SEL-421 measures ac ripple as a peak-to-peak waveform, consequently, DC1RP and DC2RP should be set at or greater than 10 percent ($2 \cdot 5\%$ peak) of the equalizing voltage. [Table 2.10](#) shows the ac ripple threshold settings for this example.

Table 2.10 Example DC Battery Monitor Settings–AC Ripple Voltages

Setting	Description	Indication	Value (Vac)
DC1RP	AC ripple threshold, Mon. 1	Charger malfunction	14
DC2RP	AC ripple threshold, Mon. 2	Charger malfunction	6

DC Ground

If a battery system is centered around chassis ground, then the magnitude of the voltage measured from the positive terminal to ground and from the negative terminal of the battery to ground should be approximately one half of the nominal battery system voltage. The ratio of the positive-to-ground battery voltage to the negative-to-ground battery voltage is 1 to 1, or 1.00.

[Equation 2.5](#) is the balanced (no grounding) ratio for a 125-Vdc battery system.

$$k = \frac{V_{dc1_{pos}}}{V_{dc1_{neg}}} = \frac{62.50 \text{ V}}{62.50 \text{ V}} = 1.00 \quad \text{Equation 2.5}$$

If either terminal is partially or completely shorted to chassis ground, then the terminal voltage will be less than the nominal terminal-to-ground voltage.

This causes the ratio of positive voltage to negative voltage to differ from 1.00.

[Equation 2.6](#) is an example of the unbalanced (grounding) ratio for a partial short circuit to ground on the negative side of a 125-Vdc battery system.

$$k = \frac{V_{dc1_{pos}}}{V_{dc1_{neg}}} = \frac{62.50 \text{ V}}{59.10 \text{ V}} = 1.06 \quad \text{Equation 2.6}$$

The SEL-421 uses this voltage ratio to calculate a ground detection factor.

[Figure 2.13](#) shows a graphical representation of the ground detection factor setting and battery system performance.

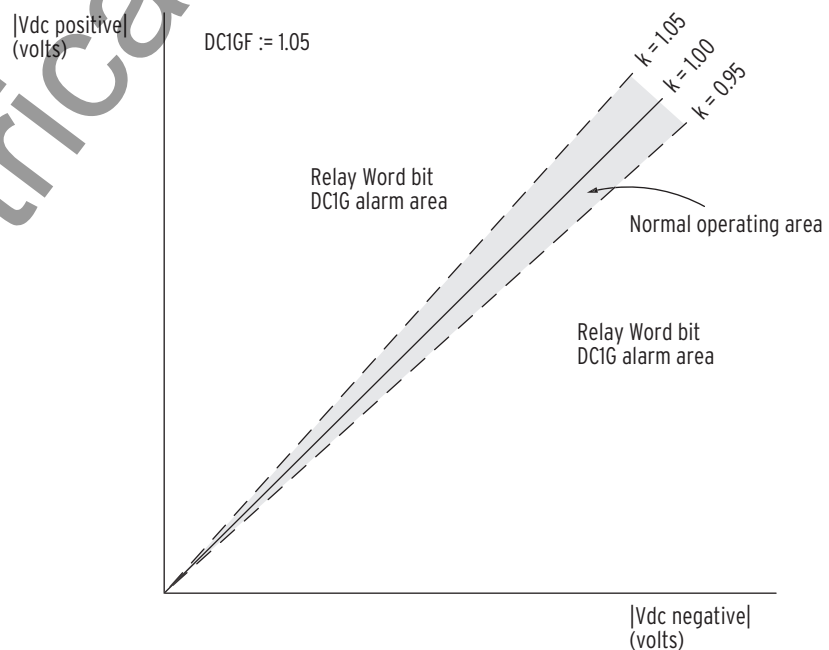


Figure 2.13 Ground Detection Factor Areas

NOTE: Only the upper ground detection factor in [Figure 2.12](#) is entered as a setting. The SEL-421 calculates the lower factor by taking the reciprocal of the upper factor: $1/1.05 = 0.952$ in this case.

If the ground detection factor ratio exceeds a setting threshold, the relay asserts the DCIG Relay Word bit. To set the ground detection factor threshold, enable the advanced Global settings (set $EGADVS := Y$), and set the DC1GF and the DC2GF thresholds at a value close to 1.05 (the factory default setting) to allow for some slight battery system unbalance of around 5 percent.

[Table 2.11](#) lists the ground detection factor threshold settings for this example.

Table 2.11 Example DC Battery Monitor Settings—Ground Detection Factor ($EGADVS := Y$)

Setting	Description	Indication	Value
DC1GF	Ground detection factor, Mon. 1	Battery wiring ground(s)	1.05
DC2GF	Ground detection factor, Mon. 2	Battery wiring ground(s)	1.05

DC Battery Monitor Alarm

You can use the battery monitor Relay Word bits to alert operators for out-of-tolerance conditions in the battery systems. Add the appropriate Relay Word bit to the SELOGIC control equation that drives the relay control output you have selected for alarms. For example, use the b contact of control output OUT108. Set the SELOGIC control equation to include the battery monitor thresholds:

OUT108 := NOT (HALARM OR SALARM OR DC1F OR DC1W OR DC1R OR DC1G)
(Output SELOGIC Equation)

This is one method; you can implement many other methods as well. See [Alarm Output on page U.2.45](#) for more information.

DC Battery Monitor Metering

The SEL-421 monitors battery system voltages and records time stamps for voltage excursions. In addition, the relay records maximum and minimum battery voltages. [Figure 2.14](#) shows a sample dc battery monitor meter report. Use the **MET BAT** command from a communications terminal to obtain this report. For more information on the **MET** commands, see [METER on page R.9.27](#).

->MET BAT<Enter>							
Relay 1				Date: 03/22/2001 Time: 09:37:10.035			
Station A				Serial Number: 2001001234			
Station Battery		VDC	VDCP0	VDCNE	VAC		
VDC1 (V)		24.17	11.98	-12.19	0.01		
VDC2 (V)		47.68	23.80	-23.88	0.02		
	VDC1(V)	Date	Time	VDC2(V)	Date	Time	
Minimum	20.12	03/15/2001	14:28:59.172	41.64	03/22/2001	08:46:25.726	
Enter L-Zone		03/15/2001	14:28:51.490		03/18/2001	18:46:23.868	
Exit L-Zone		03/15/2001	14:29:05.035		03/18/2001	18:47:55.441	
Maximum	27.19	03/19/2001	08:34:49.761	50.84	03/22/2001	08:34:55.490	
Enter H-Zone		03/19/2001	08:34:27.172		03/22/2001	08:34:27.172	
Exit H-Zone		03/19/2001	08:37:01.041		03/22/2001	08:35:00.912	
LAST DC RESET: 03/15/2001 12:30:30.492							
->							

Figure 2.14 Battery Metering: Terminal

Any battery voltage between setting DCnLWP and the dc battery monitor low limit of 15 Vdc is in the L-Zone. Battery voltages in the H-Zone are voltages between setting DCnHWP and the dc battery monitor high limit of 300 Vdc.

Reset DC Battery Monitor Metering

Use the **MET RBM** command from a communications terminal to reset the dc battery monitor. The relay sets the Relay Word bit RST_BAT to reset the dc battery monitor, and clears RST_BAT when the reset has been successfully completed. You can program a SELOGIC control equation RST_BAT (in Global settings) to control dc battery monitor reset. Enable data reset control with global setting EDRSTC := Y.

Metering

The SEL-421 provides five metering modes for measuring power system operations:

- [Instantaneous Metering on page A.2.29](#)
- [Maximum/ Minimum Metering on page A.2.33](#)
- [Demand Metering on page A.2.35](#)
- [Energy Metering on page A.2.39](#)
- [Time-Synchronized Metering on page A.2.40](#)

Monitor present power system operating conditions with instantaneous metering. Maximum/Minimum metering displays the largest and smallest system deviations since the last reset. Demand metering includes either thermal or rolling analyses of the power system and peak demand metering. Energy metering displays the megawatt-hours imported, megawatt-hours exported, and total megawatt-hours. Time-synchronized metering displays the line voltage and current synchrophasors.

The SEL-421 processes three sets of current quantities: LINE, BK1, and BK2 (when configured for two circuit breakers). In one configuration using two circuit breakers, Terminal W is usually connected as BK1, and Terminal X is generally connected as BK2. The line voltage from Terminal Y (V ϕ Y) provides the voltage quantities for LINE. See [Current and Voltage Source Selection on page R.1.3](#) for more information on configuring the SEL-421 inputs.

Use the **MET** command to access the metering functions. Issuing the **MET** command with no options returns the fundamental frequency measurement quantities listed in [Table 2.13](#). The **MET** command followed by a number, **MET k**, specifies the number of times the command will repeat (k can range from 1 to 32767). This is useful for troubleshooting or investigating uncharacteristic power system conditions. With other command options, you can view currents from either circuit breaker. For example, you can monitor the fundamental currents on Circuit Breaker 1 or Circuit Breaker 2 by entering **MET BK1** or **MET BK2**, respectively. Additionally, the **MET PM** command provides time-synchronized phasor measurements at a specific time, e.g., **MET PM 12:00:00**.

[Table 2.12](#) lists **MET** command variants for instantaneous, maximum/minimum, demand, and energy metering. The [METER on page R.9.27](#) describes these and other **MET** command options. Other **MET** command options are for viewing protection and automation variables (see [SELOGIC Control Equation Programming on page R.3.5](#)); analog values from MIRRORED BITS[®] communications (see [SEL MIRRORED BITS Communications on page R.5.17](#)); and synchronism check (see [Section 2: Auto-Reclosing and Synchronism Check in the Reference Manual](#)).

Table 2.12 MET Command^a

Name	Description
MET	Display Fundamental Line metering information
MET BK n	Display Fundamental Circuit Breaker n metering information
MET RMS	Display rms Line metering information
MET BK n RMS	Display rms Circuit Breaker n metering information
MET M	Display Line Maximum/Minimum metering information
MET BK n M	Display Circuit Breaker n Maximum/Minimum metering information
MET RM	Reset Line Maximum/Minimum metering information
MET BK n RM	Reset Circuit Breaker n Maximum/Minimum metering information
MET D	Display Demand Line metering information
MET RD	Reset Demand Line metering information
MET RP	Reset Peak Demand Line metering information
MET E	Display Energy Line metering information
MET RE	Reset Energy Line metering information
MET SYN	Display Synchronism Check voltage and slip angle/frequency information
MET BAT	Display DC Battery Monitor information (see Figure 2.14)
MET PM	Display Phasor Measurement (Synchrophasor) metering information

^a n is 1 or 2, representing Circuit Breaker 1 and Circuit Breaker 2, respectively.

Instantaneous Metering

Use instantaneous metering to monitor power system parameters in real time. The SEL-421 provides these fundamental frequency readings:

- Fundamental frequency phase voltages and currents
- Phase-to-phase voltages
- Sequence voltages and currents
- Fundamental real, reactive, and apparent power
- Displacement power factor

You can also monitor these real-time rms quantities (with harmonics included):

- RMS phase voltages and currents
- Real and apparent rms power
- True power factor

Both the fundamental and the rms-metered quantities are available for the LINE input. The relay also provides both the fundamental and rms circuit breaker currents for circuit breakers BK1 and BK2.

Voltages, Currents, Frequency

[Table 2.13](#) summarizes the metered voltage, current, and frequency quantities available in the SEL-421. The relay reports all instantaneous voltage magnitudes, current magnitudes, and frequency as absolute value 10-cycle averages (for example, the LINE A-phase filtered magnitude LIAFM_10c; see [Appendix B: Analog Quantities in the Reference Manual](#)). Instantaneous

metering also reports sequence quantities referenced to A-phase. The SEL-421 references angle measurements to positive-sequence quantities. The relay reports angle measurements in the range of ± 180.00 degrees.

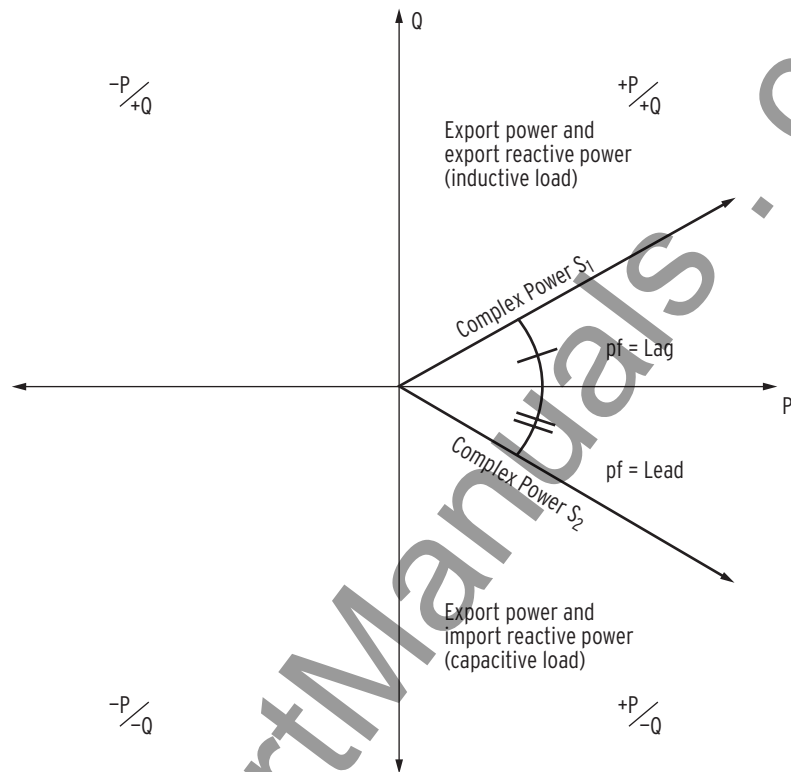
Table 2.13 Instantaneous Metering Quantities—Voltages, Currents, Frequency

Metered Quantity	Symbol	Fundamental	RMS
Phase voltage magnitude	$ V_\phi $	X	X
Phase voltage angle	$\angle(V_\phi)$	X	
Phase current magnitude	$ I_\phi $	X	X
Phase current angle	$\angle(I_\phi)$	X	
Phase-to-phase voltage magnitude	$ V_{\phi\phi} $	X	X
Phase-to-phase voltage angle	$\angle(V_{\phi\phi})$	X	
Positive-sequence voltage magnitude	$ V_1 $	X	
Positive-sequence voltage angle	$\angle(V_1)$	X	
Negative-sequence voltage magnitude	$ 3V_2 $	X	
Negative-sequence voltage angle	$\angle(3V_2)$	X	
Zero-sequence voltage magnitude	$ 3V_0 $	X	
Zero-sequence voltage angle	$\angle(3V_0)$	X	
Positive-sequence current magnitude	$ I_1 $	X	
Positive-sequence current angle	$\angle(I_1)$	X	
Negative-sequence current magnitude	$ 3I_2 $	X	
Negative-sequence current angle	$\angle(3I_2)$	X	
Zero-sequence current magnitude	$ 3I_0 $	X	
Zero-sequence current angle	$\angle(3I_0)$	X	
Battery voltages	Vdc	X	
Frequency	f	X	X
Circuit breaker current magnitudes	$ I_\phi $	X	X
Circuit breaker current angles	$\angle(I_\phi)$	X	

Power

Table 2.14 shows the power quantities that the relay measures. The instantaneous power measurements are derived from 10-cycle averages that the SEL-421 reports by using the generator condition of the positive power flow convention; for example, real and reactive power flowing out (export) is positive, and real and reactive power flowing in (import) is negative (see Figure 2.15).

For power factor, LAG and LEAD refer to whether the current lags or leads the applied voltage. The reactive power Q is positive when the voltage angle is greater than the current angle ($\theta_V > \theta_I$), which is the case for inductive loads where the current *lags* the applied voltage. Conversely, Q is negative when the voltage angle is less than the current angle ($\theta_V < \theta_I$); this is when the current *leads* the voltage, as in the case of capacitive loads.

**Figure 2.15 Complex Power (P/Q) Plane****Table 2.14 Instantaneous Metering Quantities—Powers**

Metered Quantity	Symbol	Fundamental (50 Hz/ 60 Hz Only)	RMS (Harmonics Included)
Per-phase fundamental real power	$P_{\phi 1}$	X	
Per-phase true real power	$P_{\phi rms}$		X
Per-phase reactive power	$Q_{\phi 1}$	X	X
Per-phase fundamental apparent power	$S_{\phi 1}$	X	
Per-phase true apparent power	$U_{\phi rms}$		X
Three-phase fundamental real power	$3P_1$	X	
Three-phase true real power	$3P_{rms}$		X
Three-phase reactive power	$3Q_1$	X	X
Three-phase fundamental apparent power	$3S_1$	X	
Three-phase true apparent power	$3U_{rms}$		X
Per-phase displacement power factor	$PF_{\phi 1}$	X	
Per-phase true power factor	PF_{ϕ}		X
Three-phase displacement power factor	$3PF_1$	X	
Three-phase true power factor	$3PF$		X

High-Accuracy Instantaneous Metering

The SEL-421 is a high-accuracy metering instrument. [Table 2.15](#) and [Table 2.16](#) show the metering accuracy for the relay instantaneous metering quantities at nominal power system frequency and at 20°C. Use a method similar to that in [Example 2.11](#) to compute exact error coefficients.

Table 2.15 Instantaneous Metering Accuracy—Voltages, Currents, and Frequency

Quantity	Magnitude Accuracy		Phase Accuracy
	Range	Specification	
$V_{\phi}, V_{\phi\phi}$	33.5 – 200 V _{L-N}	$\pm 0.1\%$	$\pm 0.05^\circ$
3V0, V1, 3V2	33.5 – 200 V _{L-N}	$\pm 0.15\%$	$\pm 0.10^\circ$
I_{ϕ}	$(0.5 - 3) \cdot I_{nom}$	$\pm 0.2\% \pm (0.8 \text{ mA}) \cdot I_{nom}$	$\pm 0.20^\circ$
3I0, I1, 3I2	$(0.5 - 3) \cdot I_{nom}$	$\pm 0.3\% \pm (1.0 \text{ mA}) \cdot I_{nom}$	$\pm 0.30^\circ$
f	40–65 Hz	$\pm 0.01 \text{ Hz}$	

Table 2.16 Instantaneous Metering Accuracy—Power^a

Quantity	Description	Power Factor	Accuracy (%)
At $0.1 \cdot I_{nom}$			
3P	Three-phase rms real power	Unity	± 0.40
		–0.5 or +0.5	± 0.70
3Q ₁	Reactive power	–0.5 or +0.5	± 0.50
At $1.0 \cdot I_{nom}$			
3P	Three-phase fundamental real power	Unity	± 0.40
		–0.5 or +0.5	± 0.40
3Q ₁	Reactive power	–0.5 or +0.5	± 0.40

^a Power accuracy is valid for applied currents in the range $(0.1-1.2) \cdot I_{nom}$, and applied voltages from 33.5–75 V.

EXAMPLE 2.11 Calculating Exact Error Coefficients

Consider the case of a 5 A relay during normal operating conditions. The secondary current in the CT is 1.0 A for nominal system operation. Noting that this current is greater than 10 percent of I_{nom} ($1 \text{ A} > 0.5 \text{ A}$), calculate the error coefficient:

$$\begin{aligned}
 \text{error} &= \pm(0.2\% \cdot 1.0 \text{ A}) \pm (0.8 \text{ mA} \cdot I_{nom}) \\
 &= \pm(0.002 \cdot 1.0 \text{ A}) \pm (0.008 \text{ A} \cdot 5) \\
 &= \pm(0.002 \text{ A} \pm 0.04 \text{ A}) \\
 &= +0.002 \text{ A to } +0.006 \text{ A} \\
 &\text{and} \\
 &= -0.006 \text{ A to } -0.002 \text{ A}
 \end{aligned}$$

Equation 2.7

[Figure 2.16](#) represents the calculated accuracy range. The error is very small, indicating that the SEL-421 measures normal operating currents accurately.

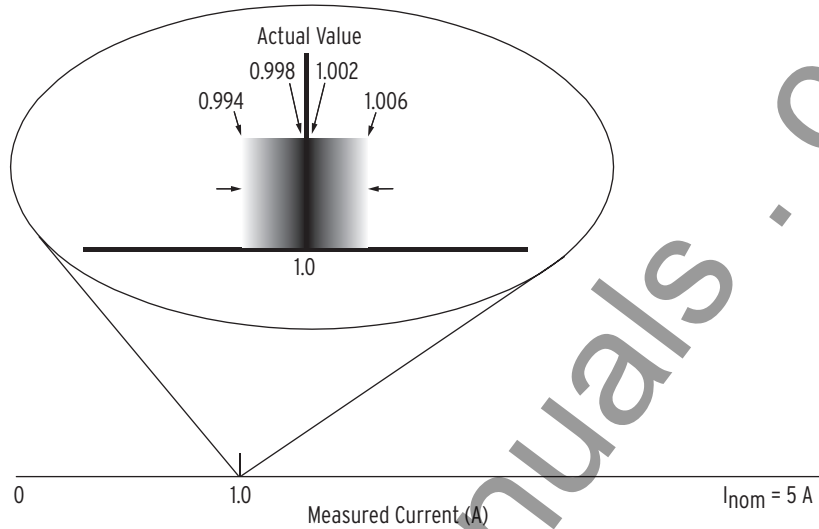


Figure 2.16 Typical Current Measuring Accuracy

When you use [Equation 2.7](#), you add an error amount related to the nominal current rating of the relay, I_{nom} . Use just the numeric portion of I_{nom} , either “5” for a 5 A relay or “1” for a 1 A relay; do not use the unit (A). The errors in [Example 2.11](#) are very small and qualify the SEL-421 as a high-accuracy meter.

Maximum/ Minimum Metering

The SEL-421 measures and retains the deviations of the power system since the last maximum/minimum reset. Knowing these maximum and minimum quantities can help you operate your power system more effectively in a variety of ways. For example, you can benefit from maximum/minimum metering information by using it to track power flow for troubleshooting, planning future expansion, and scheduling maintenance.

The relay provides maximum/minimum metering for LINE input rms voltages, rms currents, rms powers, and frequency; it also conveys the maximum/minimum rms currents for circuit breakers BK1 and BK2, as well as both dc battery voltage maximums and minimums. The SEL-421 also records the maximum values of the sequence voltages and sequence currents. [Table 2.17](#) lists these quantities.

**Table 2.17 Maximum/Minimum Metering Quantities—
Voltages, Currents, Frequency, and Powers (Sheet 1 of 2)**

Metered Quantity	Symbol
RMS phase voltage	$V_{\phi rms}$
RMS phase current	$I_{\phi rms}$
Positive-sequence voltage magnitude ^a	$ V_1 $
Negative-sequence voltage magnitude ^a	$ 3V_2 $
Zero-sequence voltage magnitude ^a	$ 3V_0 $
DC battery voltage	VDC1, VDC2
Positive-sequence current magnitude ^a	$ I_1 $
Negative-sequence current magnitude ^a	$ 3I_2 $
Zero-sequence current magnitude ^a	$ 3I_0 $
Frequency	f
Circuit breaker rms current	$I_{\phi rms}$

**Table 2.17 Maximum/Minimum Metering Quantities—
Voltages, Currents, Frequency, and Powers (Sheet 2 of 2)**

Metered Quantity	Symbol
Three-phase true real power	$3P_{rms}$
Three-phase reactive power	$3Q_1$
Three-phase true apparent power	$3U_{rms}$

^a Sequence components are maximum values only.

Maximum/Minimum Metering Accuracy

The accuracy of the maximum/minimum metering quantities is the same as the equivalent instantaneous metering accuracies listed in [Table 2.17](#) and [Table 2.16](#). The SEL-421 maximum/minimum metering values are a true reflection of the extremes that occur in the power system.

View or Reset Maximum/Minimum Metering Information

The relay shows time stamped maximum/minimum quantities when you use a communications port or ACSELERATOR QuickSet to view these quantities. See [Examining Metering Quantities on page U.4.37](#) for an introduction to reading metering quantities. In addition, you can read the maximum/minimum quantities on the SEL-421 front-panel LCD screen. For more information on using the front panel to view metering quantities, see [Meter on page U.5.16](#).

To reset the maximum/minimum values, use the **MET RM** command from a communications terminal, or use the {RESET} button in the ACSELERATOR QuickSet **HMI > Meter and Control > Maximum/Minimum** window, or answer Y and press {ENT} at the Maximum/Minimum submenu reset prompt on the front-panel LCD screen. You can also reset maximum/minimum metering with Global settings RSTMML, RSTMMB1, and RSTMMB2 (for line, Circuit Breaker 1, and Circuit Breaker 2) when EDRSTC (Data Reset Control) is Y.

Find more information on these methods in [METER on page R.9.27](#) and [Meter on page U.5.16](#).

Maximum/Minimum Metering Updating and Storage

The SEL-421 updates maximum/minimum values once per power system cycle. The relay stores maximum/minimum values and the corresponding dates and times to nonvolatile storage once per day. If greater than a previously stored maximum or less than a previously stored minimum, the new value overwrites the previous value. Should the relay lose control power, it will restore the maximum/minimum information saved at 23:50 hours on the previous day.

The relay updates maximum/minimum values under the following conditions:

- DFAULT is deasserted (equals logical 0)
- The metering value is greater than the previous maximum, or less than the previous minimum, for 2 cycles
- Voltage input is greater than 13 V secondary
- Current input is greater than $0.05 \cdot I_{nom}$ (in secondary amps)

Megawatt and megavar maximum/minimum values are subject to the above voltage thresholds, current thresholds, and conditions.

FAULT SELogic Control Equation

The relay suspends updating maximum/minimum metering when SELOGIC control equation FAULT asserts to logical 1. If there is a fault, the elements programmed in FAULT pick up and assert Relay Word bit DFAULT (Delayed FAULT Suspend). This Relay Word bit remains asserted for one minute after SELOGIC control equation FAULT deasserts. While DFAULT is asserted, the relay does not record maximum/minimum data.

The factory default setting for SELOGIC control equation FAULT includes specific time-overcurrent and distance elements pickups: FAULT := 50P1 OR 51S1 OR M2P OR Z2G OR M3P OR Z3G.

In addition, the relay also suspends demand metering during the time that Relay Word Bit DFAULT is asserted (see [Demand Metering Updating and Storage on page A.2.39](#)).

Demand Metering

Economic operation of the power system involves the proper allocation of the load demand among the available generating units. By knowing the demand requirements at different points in the system and at different times of the day you can optimize your system generation resources or your consumption of electric power. The SEL-421 provides you this demand information and enables you to operate your power system with an effective economic strategy.

Demand metering and peak demand metering are available only for the LINE quantities. The relay uses longer-term accumulations of the metering quantities for reliable demand data. [Table 2.18](#) lists the quantities used for demand and peak demand metering.

Table 2.18 Demand and Peak Demand Metering Quantities—(LINE)^a

Symbol	Units	Description
$I_{\phi rms}$	A, primary	Input rms currents
$I_{G rms}$	A, primary	Residual ground rms current
$3I_2$	A, primary	Negative-sequence current
P_{ϕ}	MW, primary	Single-phase real powers (with harmonics)
Q_{ϕ}	MVAR, primary	Single-phase reactive powers
U_{ϕ}	MVA, primary	Single-phase total powers (with harmonics)
3P	MW, primary	Three-phase real power (with harmonics)
3Q	MVAR, primary	Three-phase reactive power
3U	MVA, primary	Three-phase total power (with harmonics)

^a ($I_G = 3I_0 = I_A + I_B + I_C$)

Thermal Demand and Rolling Demand

Two methods exist for measuring power system current and power demand. These methods are thermal demand metering and rolling demand metering. [Figure 2.17](#) and [Figure 2.18](#) illustrate the step input response of the two demand measuring methods with setting DMTC (demand meter time constant) at 15 minutes.

Thermal Demand

Thermal demand is a continuous exponentially increasing or decreasing accumulation of metered quantities. Thermal demand measurement is similar to parallel RC network integration. Thermal demand metering response is at 90 percent (0.9 per unit) of the full applied value after a period equal to the DMTC setting (15 minutes in [Figure 2.17](#)).

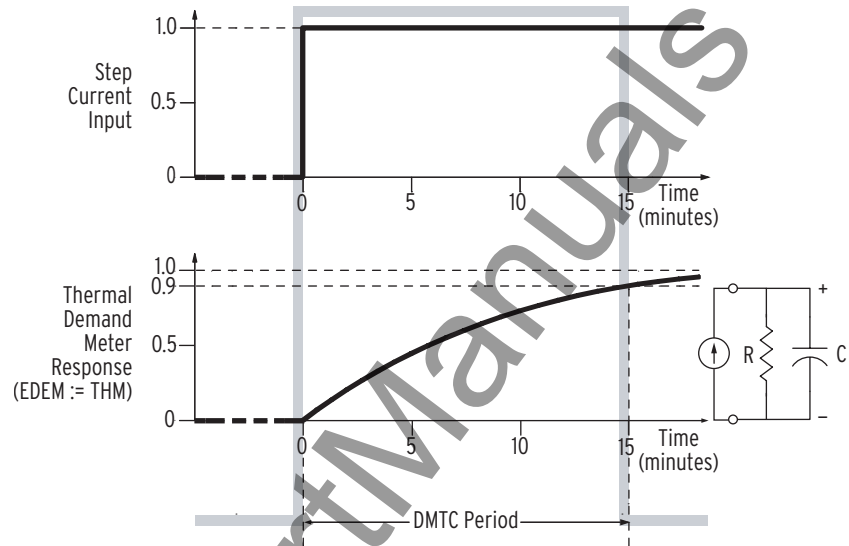


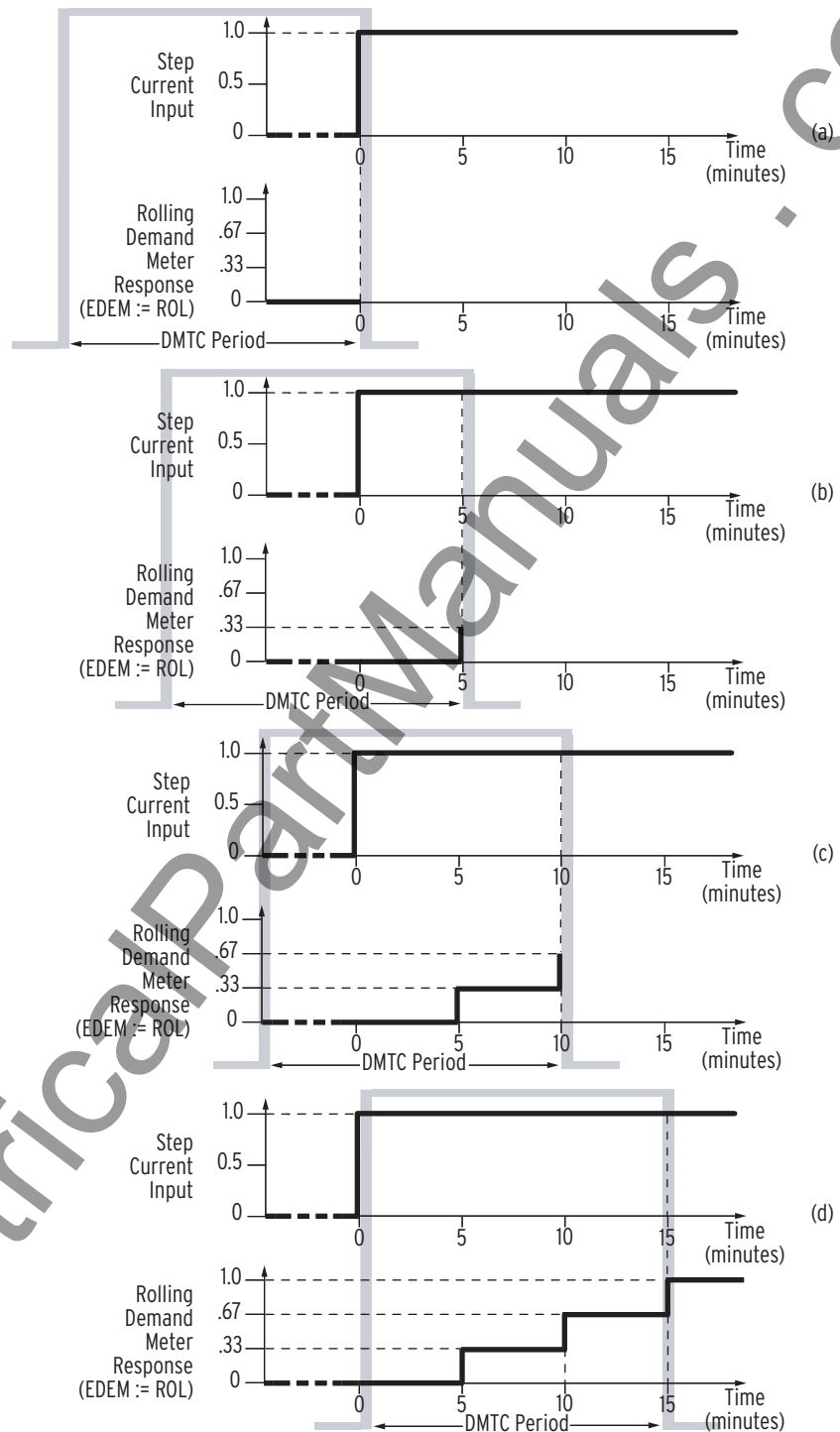
Figure 2.17 Thermal Demand Metering

Rolling Demand

Rolling demand is a sliding time-window arithmetic average. Rolling demand measurement is similar to a step-sampled A/D conversion system. [Figure 2.18](#) shows the rolling demand response for a step input for a demand meter time constant of 15 minutes (DMTC := 15). The relay divides the DMTC period into three 5-minute intervals and averages the three DMTC sub-interval samples every DMTC period. [Table 2.19](#) lists the rolling demand response for four DMTC periods shown in [Figure 2.18](#). Rolling demand metering response is at 100 percent (1.0 per unit) of the full applied value after a time equal to the fourth DMTC period (see (d) in [Figure 2.18](#)).

Table 2.19 Rolling Demand Calculations

DMTC Period (see Figure 2.18)	1/3 DMTC Interval (minutes)	Interval Sample (per unit)	Rolling Demand Total	Rolling Demand Calculation	Rolling Demand Response (per unit)
(a)	–5 to 0	0	0	0 / 3	0
(b)	0 to 5	1	1	1 / 3	0.33
(c)	5 to 10	1	2	2 / 3	0.67
(d)	10 to 15	1	3	3 / 3	1.00

**Figure 2.18 Rolling Demand Metering**

Demand Metering Settings

Use the demand metering enable setting EDEM to select the demand metering type (thermal or rolling) appropriate to your needs. Use demand pickup settings PDEMP, QDEMP, and GDEMP to set alarm thresholds to notify you when demand currents exceed preset operational points. [Table 2.20](#) shows the demand metering settings.

Table 2.20 Demand Metering Settings^a

Setting	Description	Range	Default
EDEM	Demand meter type	N, THM = Thermal, ROL = Rolling	N
DMTC	Demand meter time constant	5, 10, 15, ..., 300 minutes	15 minutes
PDEMP	Phase demand current pickup	OFF, $(0.10-3.20) \cdot I_{nom}$, secondary	$2.00 \cdot I_{nom}$
GDEMP	Residual ground demand current pickup	OFF, $(0.10-3.20) \cdot I_{nom}$, secondary	$0.40 \cdot I_{nom}$
QDEMP	Negative-sequence demand current pickup	OFF, $(0.10-3.20) \cdot I_{nom}$, secondary	$0.40 \cdot I_{nom}$

^a Current pickup settings are in steps of 0.01 A, secondary.

NOTE: Changing EDEM or DMTC resets the demand meter values to zero. This also applies to changing the active settings group where either setting EDEM or DMTC is different in the new active settings group. (Changing demand current pickup settings PDEMP, GDEMP, and QDEMP will not affect the demand meters.)

Figure 2.19 shows how the SEL-421 applies the demand current pickup settings of Table 2.20 over time. When residual ground demand current $I_{G(DEM)}$ exceeds the corresponding demand pickup setting GDEMP, Relay Word bit GDEM asserts to logical 1. Use these demand current logic outputs (PDEM, GDEM, and QDEM) for control or alarm for high loading or unbalance conditions.

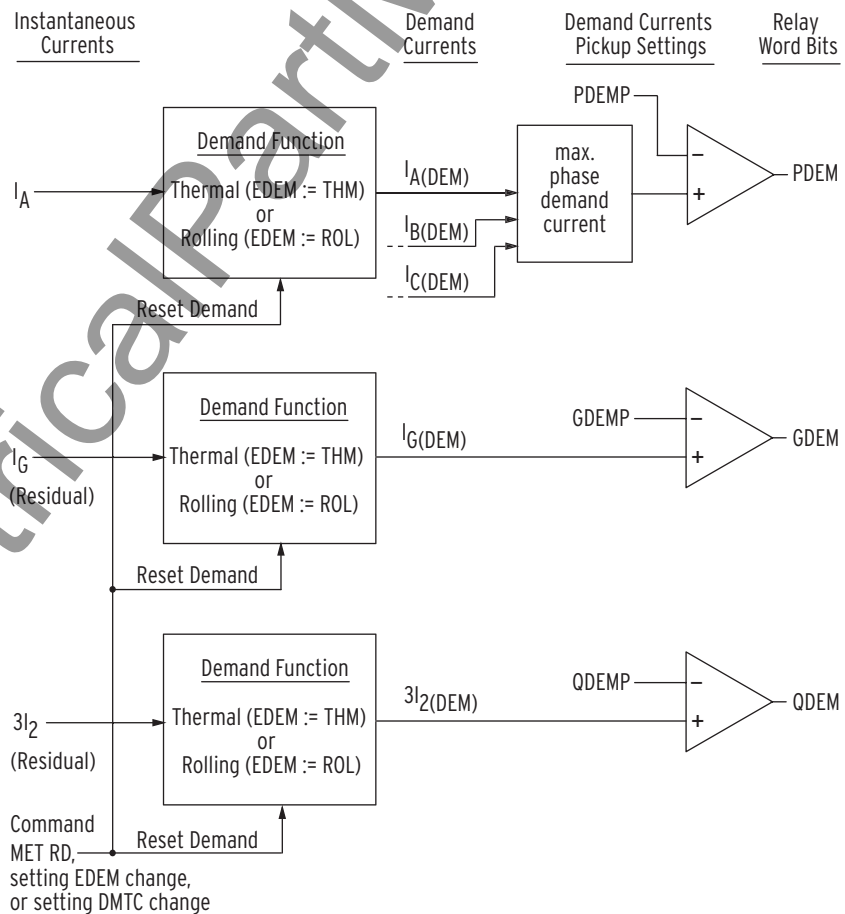


Figure 2.19 Demand Current Logic Outputs

View or Reset Demand Metering Information

The relay shows demand metering quantities and time-stamped peak demand quantities when you use a communications port or ACSELERATOR QuickSet to view these quantities. See [Section 4: Basic Relay Operations in the User's Guide](#) for an introduction to reading metering quantities. In addition, you can read the demand and peak demand quantities on the SEL-421 front-panel LCD screen. For more information on using the front panel to view metering quantities, see [Meter on page U.5.16](#).

To reset the demand metering values use the **MET RD** command from a communications terminal, or use the {RESET} button in the ACSELERATOR QuickSet **HMI > Meter and Control > Demand/Peak** window, or answer Y and press {ENT} at the Demand Submenu reset demand prompt on the front-panel LCD screen. The relay begins the demand meter sampling period from the time of the demand meter reset.

To reset the peak demand metering values, enter the **MET RP** command from a communications terminal, or use the {RESET} button in the ACSELERATOR QuickSet **HMI > Meter and Control > Demand/Peak** window, or answer Y and press {ENT} at the Demand Submenu reset peak demand prompt on the front-panel LCD screen. You can also reset demand metering with Global settings RST_DEM and RST_PDM (for demand and peak demand) when EDRSTC (Data Reset Control) is Y.

Find more information on these methods in [METER on page R.9.27](#) and [Meter on page U.5.16](#).

Demand Metering Updating and Storage

The SEL-421 updates demand and peak demand values once per second. The relay also stores peak demand values and the date and time these occurred to nonvolatile storage once per day (it overwrites the previous stored value if it is exceeded). Should the relay lose control power, it will restore the peak demand information saved at 23:50 hours on the previous day.

Demand metering updating and peak recording is suspended during the time that SELOGIC control equation FAULT asserts Relay Word bit DFAULT (Delayed FAULT Suspend). (See [FAULT SELOGIC Control Equation on page A.2.35](#) for more information.)

Energy Metering

Energy is the power consumed or developed in the electric power system measured over time. You can use accurate accounting of power system energy flow to manage billing revenues, whether your system is a net energy producer or consumer. Time-synchronized demand and energy measurements make demand and energy metering information even more useful for power system status applications. See [Section 4: Time-Synchronized Measurements in the Applications Handbook](#) for more information on high-accuracy timing applications.

The SEL-421 integrates energy imported and exported on a per-phase basis every second. As in demand metering, the relay uses the longer-term accumulations of rms or true real power for reliable energy data. Also similar to demand metering, energy metering is available only for the LINE data. [Table 2.21](#) lists the energy metering quantities that the relay displays.

Table 2.21 Energy Metering Quantities--(LINE)

Analog Quantity	Units	Description
MWH ϕ OUT	MWh, primary	Single-phase energy export
MWH ϕ IN	MWh, primary	Single-phase energy import
MWH ϕ T	MWh, primary	Single-phase energy total
3MWHOUT	MWh, primary	Three-phase energy export
3MWHIN	MWh, primary	Three-phase energy import
3MWH3T	MWh, primary	Three-phase energy total

Energy Metering Accuracy

At low currents ($0.1 \cdot I_{nom}$), energy metering accuracy at near-unity power factors is ± 0.5 percent. At power factors of 0.5 lagging or leading, energy metering accuracy is ± 0.7 percent. At high currents ($1.0 \cdot I_{nom}$), energy metering accuracy at near unity power factors is ± 0.4 percent. At power factors of 0.5 lagging or leading, energy metering accuracy is ± 0.4 percent.

View or Reset Energy Metering Information

You can read the energy metering quantities by using a communications port, ACSELERATOR QuickSet, or the SEL-421 front-panel LCD screen. See [Section 4: Basic Relay Operations in the User's Guide](#) for an introduction to reading metering quantities. For more information on using the front panel to view metering quantities, see [Section 5: Front-Panel Operations in the User's Guide](#). The ACSELERATOR QuickSet HMI also displays the energy metering data; see [Section 3: PC Software in the User's Guide](#).

To reset the energy values, use the **MET RE** command from a communications terminal, or use the **{RESET}** button in the ACSELERATOR QuickSet **HMI > Meter and Control > Energy** window, or answer Y and press **{ENT}** at the Energy Meter submenu reset prompt on the front-panel LCD screen. You can also reset energy metering with Global setting RST_ENE when EDRSTC (Data Reset Control) is Y.

Find more information on these methods in [METER on page R.9.27](#) and in [Meter on page U.5.16](#).

Energy Metering Updating and Storage

The SEL-421 updates energy values once per second. The relay also stores energy values to nonvolatile storage once every four hours, referenced from 23:50 hours (it overwrites the previously stored value if it is exceeded). Should the relay lose control power, it restores the energy values saved at the end of the last four-hour period.

The SEL-421 provides synchrophasor measurement with an angle reference according to IEEE C37.118. See [Section 7: Synchrophasors in the Reference Manual](#) for more information on synchrophasor application. The relay

Time-Synchronized Metering

calculates the phasor measurement quantities 50 or 60 times per second, depending on the nominal system frequency contained in Global setting NFREQ.

When you issue the **MET PM *time*** command, the SEL-421 captures the time-synchronized data for the given trigger time (specify *time* in 24-hour format). The relay displays the synchrophasor data immediately after the time trigger.

See [Figure 7.5 on page R.7.20](#) for a sample **MET PM** command response.

The SEL-421 Synchrophasor measurements are only valid when a suitable high-accuracy IRIG-B time source is connected to the relay, as indicated by Relay Word bit TSOK = logical 1. See [Configuring High-Accuracy Timekeeping on page U.4.77](#) for detailed information.

The **MET PM** command is only available when the SEL-421 is configured for phasor measurement functions (Global settings) and the relay is in high-accuracy timekeeping mode.

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Section 3

Analyzing Data

The SEL-421 Relay features comprehensive power system data analysis capabilities. The relay provides these useful analysis tools:

- [Data Processing on page A.3.2](#)
- [Triggering Data Captures and Event Reports on page A.3.4](#)
- [Duration of Data Captures and Event Reports on page A.3.6](#)
- [Oscillography on page A.3.8](#)
- [Event Reports, Event Summaries, and Event Histories on page A.3.12](#)
- [SER \(Sequential Events Recorder\) on page A.3.34](#)

An event is a representation of the operating conditions of the power system at a specific time. Events include instances such as a relay trip, an abnormal situation in the power system that triggers a relay element, or an event capture command.

Information from oscillograms, relay event reports, and SER data is very valuable if you are responsible for outage analysis, outage management, or relay settings coordination.

The SEL-421 accepts an IRIG-B clock input for high-accuracy timing. When a suitable external clock is used (such as the SEL-2407), the SEL-421 synchronizes the data acquisition system to the received signal. Knowledge of the precise time of sampling (as shown in COMTRADE files) allows comparisons of data across the power system. Use a coordinated network of SEL-421 relays to create moment-in-time “snapshots” of the power system. These data are useful for determining power system dynamic voltage and current phasors, impedances, load flow, and system states. For more information on this feature, see [Section 4: Time-Synchronized Measurements in the Applications Handbook](#).

The SEL-421 can also perform the PMU (Phasor Measurement Unit) function of gathering synchrophasor data when the relay is in high-accuracy timekeeping mode (HIRIG). See [Section 7: Synchrophasors in the Reference Manual](#).

Data Processing

The SEL-421 is a numeric, or microprocessor-based, relay that samples power system conditions via the CT and PT inputs. The relay converts these analog inputs to digital information for processing to determine relaying quantities for protection and automation. [Figure 3.1](#) shows a general overview of the input processing diagram for the SEL-421.

Raw and Filtered Data

The SEL-421 outputs two types of analytical data: high-resolution raw data and filtered data. [Figure 3.1](#) shows the path a power system signal takes through relay input processing. A CT or PT analog input begins at hardware acquisition and sampling, continues through software filtering, and progresses to protection and automation processing. The initial hardware low-pass filter half-power or -3 dB point is 3.0 kHz. Next, the relay samples the power system voltage or current with an 8000 samples/second A/D (analog to digital) converter. This is the tap point for high-resolution raw data captures. You can select 8000 samples/second, 4000 samples/second, 2000 samples/second, and 1000 samples/second effective sampling rates for presentation and storage of the high-resolution raw data in binary COMTRADE format (see [Oscillography on page A.3.8](#)).

The software portion of input signal processing receives the high-resolution raw data sampled quantities and passes these to the Anti-Aliasing Digital Filter. The half-power or -3 dB point of the anti-aliasing filter is 640 Hz. Subsequent processing decimates the sampled data to eight samples per power system cycle using additional digital filtering. This 8-samples/cycle information is the filtered data for event reports and other relay functions. The relay selects every other sample of 8-samples/cycle filtered data to present 4-samples/cycle event reports.

The SEL-421 samples the control inputs at a rate of 16 samples per cycle. There are two types of control inputs: direct-coupled and optoisolated, and these are processed differently.

The SEL-421 Main Board A and INT1, INT5, and INT6 I/O Interface boards have direct-coupled control inputs with analog-to-digital converters that measure the applied voltage. These analog sample values are available in COMTRADE files and as analog quantities (labeled IN101A–IN107A or IN201A–IN208A or IN301A–IN308A). The relay compares the sampled data against setting-defined pickup and dropout voltage thresholds to create the raw contact status information. This raw digital data can be included in high-resolution (COMTRADE) data files. Contact bounce may be visible when the raw data is viewed.

The SEL-421 Main Board B and INT2, INT3, INT4, INT7, and INT8 I/O Interface boards have optoisolated control inputs with fixed pickup voltages. Optoisolated inputs are ordered with one of six available pickup voltage ratings. No analog voltage information is available. The raw input digital status is available in high-resolution (COMTRADE) data files. Contact bounce may be visible when the raw data is viewed.

The SEL-421 filters both types of control inputs with settable debounce timers, and updates the resulting Relay Word bits 8 times per cycle. Event reports can include the filtered control input Relay Word bits.

Control input state changes will appear to occur faster in COMTRADE oscillography files than in event reports (**EVE** command) or Sequential Events Recorder reports (**SER** command) because of the control input debounce time delays.

See [Control Input Assignment on page U.4.70](#) and [Control Inputs on page U.2.6](#) for details on control inputs.

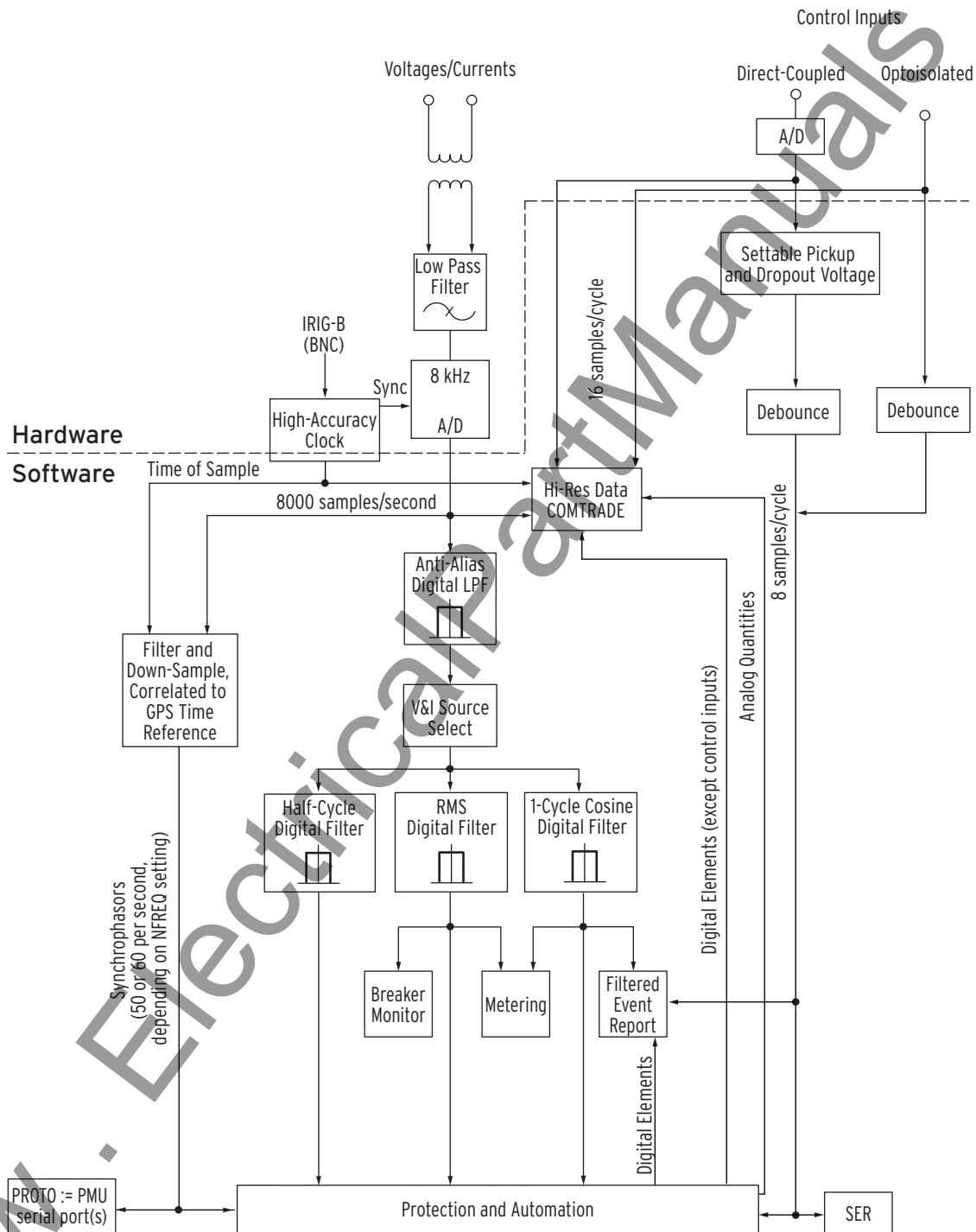


Figure 3.1 SEL-421 Input Processing

Triggering Data Captures and Event Reports

The SEL-421 displays power system data from oscillograms, event reports, event summaries, event histories, and SER data. For information on the SER, see [SER \(Sequential Events Recorder\) on page A.3.34](#). All of these features, except the SER, require sampled or filtered data from the power system, and are triggered both internally and externally depending on the event trigger that you program in the relay.

Use an event trigger to initiate capturing power system data. Both high-resolution raw data oscillography and event reports use the same triggering methods. The trigger for data captures comes from three possible sources:

- Relay Word bit TRIP assertions
- SELOGIC® control equation ER (Event Report Trigger)
- TRI command

In previous SEL relays, the **PUL** command initiated event recording. If you want the **PUL** command to initiate data capture, add the Relay Word bit TESTPUL to the SELOGIC control equation ER (see [SELOGIC Control Equation ER](#) and [Example 3.2](#)). For more information on the **PUL** command, see [PULSE on page R.9.36](#) and [Operating the Relay Inputs and Outputs on page U.4.61](#).

Relay Word Bit TRIP

If Relay Word bit TRIP asserts, the relay automatically generates a data capture event trigger on the rising edge of the TRIP Relay Word bit state change. In every instance, TRIP causes the relay to begin recording data. You therefore do not have to enter any condition that causes a trip in the ER SELOGIC control equation. For information on Relay Word bit TRIP see [Trip Logic on page R.1.115](#).

SELogic Control Equation ER

Program the SELOGIC control equation ER to trigger high-resolution raw data oscillography and standard event reports for conditions other than TRIP conditions. When ER asserts, the SEL-421 begins recording data if the relay is not already capturing data initiated by another trigger.

EXAMPLE 3.1 Triggering Event Report/Data Capture Using the ER SELogic Control Equation

This example shows how the elements in the ER SELogic control equation initiate relay data capture. See [Section 3: SELogic Control Equation Programming in the Reference Manual](#) for more information on rising-edge operators and SELogic control equations.

The factory default setting for Group setting SELogic control equation ER is

ER := R_TRIG M2P OR R_TRIG Z2G OR R_TRIG 51S1 OR R_TRIG M3P OR R_TRIG Z3G Event Report Trigger Equation (SELogic Equation)

The element transitions in this setting are from the following Relay Word bits:

- M2P, M3P: Zone 2 mho phase distance element, Zone 3 mho phase distance element
- Z2G, Z3G: Zone 2 mho ground distance element, Zone 3 mho ground distance element
- 51S1: Selectable operating quantity time overcurrent element

The rising-edge operator, R_TRIG, occurs in front of each of the elements in the factory default ER equation. Rising-edge operators are especially useful for generating an event report at fault inception. The triggering element causes ER to assert, then clears the way for other elements to assert ER because the relay uses only the beginning of a long element assertion. The starting element in a continuously occurring fault does not mask other possible element triggers. This allows another rising-edge sensitive element to generate another event report later in that same continuously occurring fault (such as an overcurrent situation with the R_TRIG 51S1 element).

In the factory default ER SELoGic control equation, if the Z3G element remains asserted for the duration of the ground fault, the rising-edge operator, R_TRIG, in front of Z3G causes ER to assert for only one processing interval (a 1/8-cycle pulse). Other elements in the ER SELoGic control equation can trigger event reports while the Z3G element remains asserted throughout the fault duration.

You can also use the falling-edge operator, F_TRIG, to initiate data captures. See [Section 3: SELoGic Control Equation Programming in the Reference Manual](#) for more information on falling edge operators.

EXAMPLE 3.2 Including PUL Command Triggering in the ER SELoGic Control Equation

This example shows you how to add the effect of the **PUL** command to emulate previous SEL relays. The relay asserts Relay Word bit, TESTPUL, when any output pulses via the **PUL** command. For more information on the **PUL** command, see [PULSE on page R.9.36](#).

Program the Group settings SELoGic control equation ER as follows:

ER := R_TRIG M2P OR R_TRIG Z2G OR R_TRIG 51S1 OR R_TRIG M3P OR R_TRIG
Z3G OR TESTPUL Event Report Trigger Equation (SELoGic
Equation)

TRI (Trigger Event Report) Command

Use the **TRI** command from any communications port to trigger the SEL-421 to begin recording high-resolution raw data and event report data. When testing with the **TRI** command, you can gain a glimpse of power system operating conditions that occur immediately after you issue the **TRI** command. See [TRIGGER on page R.9.56](#) and [Triggering an Event on page U.4.46](#) for more information on the **TRI** command.

Duration of Data Captures and Event Reports

The SEL-421 stores high-resolution raw data and filtered data. The number of stored high-resolution raw data captures and event reports is a function of the amount of data contained in each capture. You can configure the relay to record long data captures at high sampling rates, although this reduces the total number of stored events you can retrieve from the relay.

To use the data capture functions, select the effective sampling rate and data capture times. Relay setting SRATE, listed in [Table 3.1](#), determines the number of data points the relay records per second. You can set SRATE to 8 kHz, 4 kHz, 2 kHz, and 1 kHz. The effective sampling rate and the event report length are related:

- 8 kHz sampling—2.00 seconds total event report
- 4 kHz sampling—3.00 seconds total event report
- 2 kHz sampling—4.00 seconds total event report
- 1 kHz sampling—5.00 seconds total event report

The length of the data capture/event report (setting LER) and the pretrigger or prefault time (setting PRE) are related, as shown in [Figure 3.2](#). The LER setting is the overall length of the event report data capture; the PRE setting determines the time reserved in the LER period when the relay records pretrigger (prefault) data. Typically, you set the PRE time to 20 percent of the total LER period. [Table 3.1](#) shows the relay settings for the data capture recording times at each effective sampling rate.

Table 3.1 Report Settings

Label	Description	Range	Default
SRATE	Effective sample rate of event report	1, 2, 4, 8 kHz	2 kHz
SRATE = 8 kHz			
LER	Length of event report	0.25–2.00 seconds	0.5 seconds
PRE	Length of prefault	0.05–1.95 seconds	0.1 seconds
SRATE = 4 kHz			
LER	Length of event report	0.25–3.00 seconds	0.5 seconds
PRE	Length of prefault	0.05–2.95 seconds	0.1 seconds
SRATE = 2 kHz			
LER	Length of event report	0.25–4.00 seconds	0.5 seconds
PRE	Length of prefault	0.05–3.95 seconds	0.1 seconds
SRATE = 1 kHz			
LER	Length of event report	0.25–5.00 seconds	0.5 seconds
PRE	Length of prefault	0.05–4.95 seconds	0.1 seconds

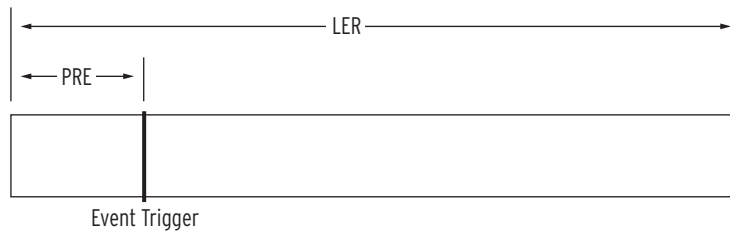


Figure 3.2 Data Capture/Event Report Times

The relay stores all data captures to volatile RAM and then moves these data to nonvolatile memory storage. There is enough volatile RAM to store one maximum length capture (maximum LER time) for a given SRATE. No data captures can be triggered while the volatile RAM is full; the relay must move at least one data capture to non-volatile storage to reenale data capture triggering. Thus, to record sequential events, you must set LER to half or less than half of the maximum LER setting. The relay stores more sequential data captures as you set LER smaller.

[Table 3.2](#) lists the maximum number of data captures/event reports the relay stores in nonvolatile memory for various report lengths and sample rates. The relay automatically overwrites the oldest events with the newest events when the nonvolatile storage capacity is exceeded.

NOTE: Consider the total capture time when choosing a value for setting LER at the SRATE := 8 kHz. At LER := 0.5 or LER := 1.0 the relay records at least two data captures. These and smaller LER settings are sufficient for most power system disturbances.

The relay stores approximately six seconds of high-resolution raw or filtered data in nonvolatile memory at the maximum resolution (8000 samples/second effective sampling rate). If you have selected LER at 0.5 seconds (30 cycles at 60 Hz or 25 cycles at 50 Hz), you can store eleven 1/2-second reports. These 11 reports are at 8000 samples/second resolution (approximately eight times more resolution than the SEL-300 series relays.) [Table 3.2](#) lists the storage capability of the SEL-421 for common event report lengths:

The lower rows of [Table 3.2](#) show the number of event reports the relay stores at the maximum data capture times for each SRATE sampling rate setting. Table entries are the maximum number of stored events; these can vary by 10 percent according to relay memory usage.

Table 3.2 Event Report Nonvolatile Storage Capability

Event Report Length	Maximum Number of Stored Reports			
	8 kHz	4 kHz	2 kHz	1 kHz
0.25 seconds	18-20	25-27	31-33	36-39
0.50 seconds	11	16	18-20	23-25
1.0 seconds	6	8	11	15
2.0 seconds	3	4	6	8
3.0 seconds	N/A	3	4	5
4.0 seconds	N/A	N/A	3	4
5.0 seconds	N/A	N/A	N/A	3

Oscillography

The SEL-421 features two types of oscillography:

- Raw data oscillography—effective sampling rate as fast as 8000 samples/second
- Event report oscillography from filtered data—either 8 samples/cycle or 4 samples/cycle

Use high-resolution raw data oscillography to view transient conditions in the power system. You can set the relay to report these high-resolution oscillograms at 8000 samples/second, 4000 samples/second, 2000 samples/second, and 1000 samples/second effective sampling rates (see [Duration of Data Captures and Event Reports on page A.3.6](#)). The high-resolution raw data oscillograms are available as files through the use of Ymodem file transfer and FTP (file transfer protocol) in the binary COMTRADE file format output (*IEEE Standard Common Format for Transient Data Exchange (COMTRADE) for Power Systems, IEEE C37.111–1999*).

The filtered data oscillograms at 8 samples/cycle and 4 samples/cycle give you accurate information on the relay protection and automation processing quantities. The relay outputs 8-samples/cycle and 4-samples/cycle filtered event reports through a terminal or as files in ASCII format, Compressed ASCII format, and binary FTP and Ymodem file outputs. [Figure 3.3](#) shows a sample filtered-data oscillogram.

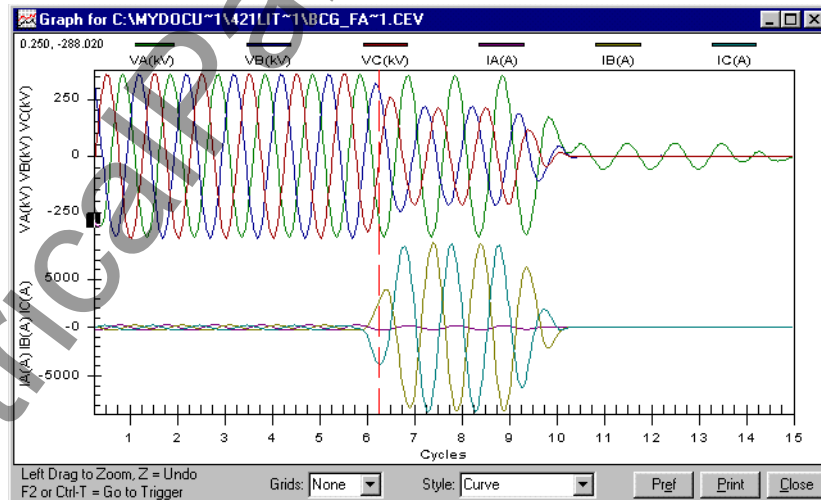


Figure 3.3 Sample SEL-421 Oscillogram

Raw Data Oscillography

Raw data oscillography produces oscillograms that track power system anomalies that occur outside relay digital filtering. Raw data oscillography captures data with content ranging from dc to greater than 3.0 kHz; the –3 dB point of the single-order low-pass analog input filter is 3.0 kHz (with response rolling off at –20 dB per decade).

COMTRADE files include all eight Relay Word bits from each row of the Relay Word that has at least one element included in the event report digital elements setting—see [Table 10.91 on page R.10.48](#).

The SEL-421 stores high-resolution raw data oscillography in binary format and uses COMTRADE file types to output these data:

- .HDR—header file
- .CFG—configuration file
- .DAT—high-resolution raw data file

The .HDR file contains summary information about the event in ASCII format. The .CFG file is an ASCII configuration file that describes the layout of the .DAT file. The .DAT file is in binary format and contains the values for each input channel for each sample in the record. These data conform to the IEEE C37.111-1999 COMTRADE standard.

.HDR File

The .HDR file contains the summary and relay settings information that appears in the event report for the data capture (see [Event Summary Section of the Event Report on page A.3.23](#) and [Settings Section of the Event Report on page A.3.23](#)). The settings portion is in a comma-delimited format as illustrated in [Figure 3.4](#).

Relay 1										Date: 03/15/2001	Time: 23:30:49.026	
Station A										Serial Number: 2001001234		
Event: BCG T										Location: 48.17		Time Source: OTHER
Event Number#: 10007										Shot 1P: 0		Shot 3P: 0
Targets: INST TIME ZONE_1										B_PHASE C_PHASE bk1rs		Freq: 60.01
Breaker 1: OPEN										Trip Time: 23:30:49.026		Group: 1
Breaker 2: OPEN										Trip Time: 23:30:49.026		
PreFault: IA IB IC IG 3I2										VA	VB	VC
MAG(A/kV)										276	262	246
ANG(DEG)										22.1	-91.7	138.2
Fault:										5.1	178.5	0.0
MAG(A/kV)										217	8892	8727
ANG(DEG)										-17.0	167.3	24.8
										5586	11403	361.421
										95.6	94.4	0.1
											-129.9	218.687
											126.7	214.239
												321.083
												0.2
SET_G1.TXT										VImem		
[INFO]												
RELAYTYPE=421												
FID=SEL-421-R101-V0-Z001001-D20010315												
BFID=SLBT-4XX-R100-V0-Z001001-D20010315												
PARTNO=04210415X125XHX												
[IOBOARDS]												
.												
.												
.												
[IOBOARDS]												
.,.,8,8,0,0,1												
[COMCARDS]												
[G1]												
"SID","Station A"												
"RID","Relay 1"												
"TIDW","Breaker 1"												
"TIDX","Breaker 2"												
"NUMBK",2												
"BID1","Breaker 1"												
"BID2","Breaker 2"												
"NFREQ",60												

Summary Event
Information

Relay Settings

Figure 3.4 Sample COMTRADE .HDR Header File

.CFG File

The .CFG file contains data such as sample rates, number of channels, line frequency, channel information, and transformer ratios (see [Figure 3.5](#)). A <CR><LF> follows each line. If control inputs or control outputs are not available because of board loading and configuration, the relay does not report these inputs and outputs in the analog and digital sections of the .CFG file.

```

Station A,FID=SEL-421-R101-V0-Z001001-D20010315,1999
373,29A,344D
1,IAW,A,,A,0.007553,0,0,-32767,32767,400.0,1,P
2,IBW,B,,A,0.007553,0,0,-32767,32767,400.0,1,P
3,ICW,C,,A,0.007553,0,0,-32767,32767,400.0,1,P
4,IAX,A,,A,0.007553,0,0,-32767,32767,400.0,1,P
5,IBX,B,,A,0.007553,0,0,-32767,32767,400.0,1,P
6,ICX,C,,A,0.007553,0,0,-32767,32767,400.0,1,P
7,VAY,A,,kV,0.015107,0,0,-32767,32767,3636.0,1,P
8,VBY,B,,kV,0.015107,0,0,-32767,32767,3636.0,1,P
9,VCY,C,,kV,0.015107,0,0,-32767,32767,3636.0,1,P
10,VAZ,A,,kV,0.015107,0,0,-32767,32767,3636.0,1,P
11,VBZ,B,,kV,0.015107,0,0,-32767,32767,3636.0,1,P
12,VCZ,C,,kV,0.015107,0,0,-32767,32767,3636.0,1,P
13,VDC1,,,V,1.000000,0,0,-32767,32767,1,1,P
14,VDC2,,,V,1.000000,0,0,-32767,32767,1,1,P
15,IN101,,,V,1.000000,0,0,-32767,32767,1,1,P
16,IN102,,,V,1.000000,0,0,-32767,32767,1,1,P
17,IN103,,,V,1.000000,0,0,-32767,32767,1,1,P
18,IN104,,,V,1.000000,0,0,-32767,32767,1,1,P
19,IN105,,,V,1.000000,0,0,-32767,32767,1,1,P
20,IN106,,,V,1.000000,0,0,-32767,32767,1,1,P
21,IN107,,,V,1.000000,0,0,-32767,32767,1,1,P
22,IN201,,,V,1.000000,0,0,-32767,32767,1,1,P
23,IN202,,,V,1.000000,0,0,-32767,32767,1,1,P
24,IN203,,,V,1.000000,0,0,-32767,32767,1,1,P
25,IN204,,,V,1.000000,0,0,-32767,32767,1,1,P
26,IN205,,,V,1.000000,0,0,-32767,32767,1,1,P
27,IN206,,,V,1.000000,0,0,-32767,32767,1,1,P
28,IN207,,,V,1.000000,0,0,-32767,32767,1,1,P
29,IN208,,,V,1.000000,0,0,-32767,32767,1,1,P
1,27BP0,,,0
2,27AP0,,,0
3,3P0,,,0
4,SPO,,,0
5,SPOC,,,0
6,SPOB,,,0
7,SPOA,,,0
.
.
.
337,OUT101,,,0
338,OUT102,,,0
339,OUT103,,,0
340,OUT104,,,0
341,OUT105,,,0
342,OUT106,,,0
343,OUT107,,,0
344,OUT108,,,0
60
1
2000,1000
15/03/2001,23:30:48.925200
15/03/2001,23:30:49.026800
BINARY
1

```

COMTRADE Standard
Total Channels, Analog, Digital

Analog Channel Data

Digital (Status)
Channel Data

First Data Point
Trigger Point

Figure 3.5 COMTRADE .CFG Configuration File Data

The configuration file has the following format:

- Station name, device identification, COMTRADE standard year
- Number and type of channels
- Channel name units and conversion factors
- Line frequency
- Sample rate and number of samples
- Date and time of first data point
- Date and time of trigger point
- Data file type
- Time stamp multiplication factor

.DAT File

The .DAT file follows the COMTRADE binary standard. The format of the binary data files is sample number, time stamp, data value for each analog channel, and grouped status channel data for each sample in the file. There are no data separators in the binary file, and the file contains no carriage return/line feed characters. The sequential position of the data in the binary file determines the data translation. Refer to the *IEEE Standard Common Format for Transient Data Exchange (COMTRADE) for Power Systems, IEEE C37.111-1999* for more information. Many programs read the binary COMTRADE files. These programs include the SEL-5601 Analytic Assistant and the ACSELERATOR® QuickSet™ SEL-5030 software program.

Generating Raw Data Oscillograms

To use high-resolution raw data oscillography, select the type of triggering event and use a trigger event method described in [Triggering Data Captures and Event Reports on page A.3.4](#). Use the settings SRATE, LER, and PRE to set the SEL-421 for the appropriate data sampling rate and data capture time (see [Duration of Data Captures and Event Reports on page A.3.6](#)).

Retrieving Raw Data Oscillograms

Use a computer terminal emulation program and the **FILE** commands at any communications port to retrieve the stored high-resolution raw data capture from the relay file structure. See [Retrieving High-Resolution COMTRADE Data: Terminal on page U.4.50](#) for the method of identifying and downloading COMTRADE files. You can also use ACSELERATOR QuickSet (see [Retrieving High Resolution COMTRADE Data: ACSELERATOR QuickSet on page U.4.51](#)).

Event Report Oscillography

Use a terminal or SEL-supplied PC software to retrieve filtered event report files stored in the relay and transfer these files to your computer. Both ACSELERATOR QuickSet and the SEL-5601 Analytic Assistant read the compressed event files that the relay generates for an event. See [Analyze Events on page U.3.19](#) for instructions on viewing event report oscillography with ACSELERATOR QuickSet.

Event Reports, Event Summaries, and Event Histories

Event reports simplify postfault analysis and help you improve your understanding of protection scheme operations. Event reports also aid in testing and troubleshooting relay settings and protection schemes because these reports contain detailed data on voltage, current, and relay element status. For further analysis assistance, the relay appends the active relay settings to each event report. The relay stores event reports in nonvolatile memory, and you can clear the event report memory on a port-by-port basis (see the **EVE** command in [EVENT on page R.9.17](#)).

You decide the amount of information and length in an event report (see [Duration of Data Captures and Event Reports on page A.3.6](#)).

The SEL-421 records the filtered power system data that the relay uses in protection and automation processing. You can view filtered information about an event in one or more of the following forms:

- Event report
- Event summary
- Event history

Alias Names

NOTE: if Alias names were changed after an event was recorded, the relay uses the present alias names in subsequent event reports.

To customize your event report, rename any Relay Word bit, analog quantity, or default terminal name with more meaningful names to improve the readability of fault analysis and customized programming. After renaming the primitive quantities, the alias names rather than the primitive names appear in the event reports and SER. The primitive names of the analog channels still appear in the event reports.

Event Report

The relay generates event reports to display analog data, digital data (control inputs, control outputs, and the state of Relay Word bits), and relay settings. The event report is a complete description of the data that the relay recorded in response to an event trigger. Each event report includes these components:

- Report header and analog section
 - Currents, voltages, polarizing voltage (V1MEM)
- Digital section
 - Relay Word bit elements, control outputs, control inputs
- Event summary
- Settings
 - Group settings
 - Global settings
 - Output settings
 - SELOGIC control equations protection logic

Viewing the Event Report

Access event reports from the communications ports and communications cards at Access Level 1 and higher. (You cannot view event reports at the front panel, although you can view event summary information at the front-panel

display; see [Events on page U.5.19](#).) You can independently acknowledge the oldest event report at each communications port (**EVE ACK** command) so that you and users at other ports (SCADA, Engineering, etc.) can retrieve complete sets of event reports. To acknowledge the oldest event report, you must first view that event report at a particular port by using the **EVE N(EXT)** command (see [EVENT on page R.9.17](#)).

You can use the **EVE** command and a terminal to retrieve event reports by event order or by event serial number. (The relay labels each new event with a unique serial number as reported in the **HIS** command history report; see [Event History on page A.3.31](#).)

Event Numbering

Use the **EVE *n*** command to access particular event reports. When parameter *n* is 1 through 9999, *n* indicates the order of the event report. The most recent event report is 1, the next most recent report is 2, and so on. When parameter *n* is 10000 through 42767, *n* indicates the absolute serial number of the event report.

You can retrieve only analog or digital information, and you can exclude the summary or settings portions of the report. The default **EVE** command event report data resolution is 4 samples/cycle and the default report length is 0.5 seconds (30 cycles at 60 Hz or 25 cycles at 50 Hz) with the factory default setting for LER.

[Table 3.3](#) lists a summary of **EVE** commands (see [EVENT on page R.9.17](#) for complete information on the **EVE** command). [Table 3.4](#) shows a few examples of command options that you can use with the **EVE** command. The **EVE L** and **EVE C** commands provide compatibility with older command sets.

Table 3.3 EVE Command^{a, b, c} (Sheet 1 of 2)

Command	Description
EVE	Return the most recent event report (including settings and summary) at full length with 4-samples/cycle data.
EVE <i>n</i>	Return a particular <i>n</i> event report (including settings and summary) at full length with 4-samples/cycle data.
EVE A	Return only the analog information for the most recent event report.
EVE ACK	Acknowledge the oldest unacknowledged event at the present communications port.
EVE C <i>n</i>	Return a particular <i>n</i> event report at a 15-cycle length with 8-samples/cycle data.
EVE D <i>n</i>	Return only the digital information for a particular <i>n</i> event report.
EVE <i>n</i> L	Return a particular <i>n</i> event report at full length with 8-samples/cycle sampling.
EVE <i>n</i> Lyyy	Return yyy cycles of a particular <i>n</i> event report with 4-samples/cycle data.
EVE N	Return the oldest unacknowledged event report with 4-samples/cycle data (N = next).
EVE <i>n</i> NSET	Return a particular <i>n</i> event report without settings at full length with 4-samples/cycle data.
EVE <i>n</i> NSUM	Return a particular <i>n</i> event report without the event summary at full length with 4-samples/cycle data.

Table 3.3 EVE Command^{a, b, c} (Sheet 2 of 2)

Command	Description
EVE <i>n</i> S <i>x</i>	Return a particular <i>n</i> event report at full length with <i>x</i> -samples/cycle data.
EVE <i>n</i> TE	Return a particular <i>n</i> event report at full length without the report header with 4-samples/cycle data.

- ^a The optional parameter *n* indicates event order or serial number (see [Event Numbering](#)).
^b The parameter *x* is 4 or 8 to represent data resolution of 4 samples/cycle and 8 samples/cycle, respectively.
^c The parameter *yyy* represents an event length in cycles.

Table 3.4 EVE Command Examples

Example	Description
EVE L10 S8	Return 10 cycles of an 8-samples/cycle event report for the most recent event.
EVE L010 A	Return 10 cycles of the analog portion only of the most recent event report at 4-samples/cycle resolution.
EVE 2 NSET	For the second most recent event, return the event report with no settings at 4-samples/cycle data.

You can retrieve event reports with the ACSELERATOR QuickSet **Analysis > View Event History** menu. The **Analysis > View Event Files** menu gives you oscillogram/element displays, phasor displays, harmonic analysis, and an event summary for each event you select in the **Event History** dialog box. See [Analyze Events on page U.3.19](#), and [Reading the Event History on page U.4.48](#) for more information on viewing event reports with ACSELERATOR QuickSet.

You can also download event report files from the relay. Use a terminal emulation program with file transfer capability. At an Access Level 1 prompt or higher, type **FILE READ EVENTS E8 _nnnnn.TXT <Enter>** for the 8-samples/cycle event report and type **FILE READ EVENTS E4 _nnnnn.TXT <Enter>** for the 4-samples/cycle event report (*nnnnn* is the event serial number). Start the terminal download routine to store the file on your computer. If you want the Compressed ASCII file, use the C8 _nnnnn.TXT and C4 _nnnnn.TXT file names for the 8-samples/cycle and 4-samples/cycle Compressed ASCII event reports, respectively. See [Retrieving Event Report Data Files: Terminal on page U.4.54](#) for file download procedures.

The following discussion shows sample portions of an event report that you download from the relay using a terminal and the **EVE** command. An event report contains analog, digital, summary, and settings sections without breaks.

Report Header and Analog Section of the Event Report

The first portion of an event report is the report header and the analog section. See [Figure 3.6](#) for the location of items included in a sample analog section of an event report. If you want to view only the analog portion of an event report, use the **EVE A** command.

The report header is the standard SEL-421 header listing the relay identifiers, date, and time. Report headers help you organize report data. Each event report begins with information about the relay and the event. The report lists the RID setting (Relay ID) and the SID setting (Station ID). The FID string identifies the relay model, flash firmware version, and the date code of the firmware. See [Firmware Version Number on page U.6.41](#) for a description of

the FID string. The relay reports a date and time stamp to indicate the internal clock time when the relay triggered the event. The relay reports the firmware checksum as CID.

The event report column labels follow the header. The data underneath the analog column labels contain samples of power system voltages and currents in primary kilovolts and primary amps, respectively. These quantities are instantaneous values scaled by $\sqrt{2/2}$ (0.707) and are described in [Table 3.5](#). To obtain phasor rms values, use the methods illustrated in [Obtaining RMS Phasors From 4-Samples/Cycle Event Reports](#) on page A.3.16, [Figure 3.7](#), and [Figure 3.8](#).

Relay 1				Date: 03/15/2001 Time: 23:30:49.026				Header			
Station A				Serial Number: 2001001234				Firmware ID			
FID=SEL-421-R101-V0-Z001001-D20010315				Event Number = 10007				CID=0x3425			
Currents (Amps Pri)				Voltages (kV Pri)							
IA	IB	IC	IG	VA	VB	VC	VS1	VS2	Vlmem		
[1]											
-267	167	44	-56	-288.0	337.7	-47.8	215.3	144.9	-287.9	One Cycle of Data	
-76	-203	241	-37	-223.7	-138.4	361.3	-290.5	331.3	-223.7		
266	-166	-45	55	288.2	-337.5	47.5	-215.2	-145.0	288.1		
76	202	-242	36	223.4	138.7	-361.4	290.5	-331.2	223.5		
•											
•											
•											
[6]											
-269	167	46	-56	-289.3	336.9	-45.8	215.5	144.7	-289.4	Trigger	
-74	-202	240	-35	-222.2	-140.2	361.5	-290.2	331.4	-221.8		
268	-165	-45	57	289.4	-336.7	45.6	-215.4	-144.6	289.5		
93	151	-888	-643	221.1	133.5	-335.0	290.2	-331.4	220.8		
[7]											
-208	2701	-3760	-1267	-288.7	293.7	-24.1	215.5	144.5	-286.3	Largest Current (to Event Summary)	
-146	2941	173	2968	-219.6	-87.6	261.6	-290.1	331.4	-214.0		
134	-5748	8310	2696	286.9	-232.4	3.5	-215.6	-144.4	273.3		
179	-6677	1811	-4688	219.8	47.4	-214.2	290.0	-331.5	202.8		
[8]											
-125	5661	-8506	-2971	-286.1	213.6	-3.8	215.8	144.2	-256.5	Circuit Breaker Open	
-177	6857	-1950	4730	-220.8	-46.9	214.2	-289.9	331.6	-193.2*		
129	-5508	8382	3003	286.9	-213.8	3.6	-216.0	-144.0	243.9		
174	-6726	1839	-4712	220.4	47.2	-214.2	289.8	-331.6	185.9		
[9]											
-128	5623	-8479	-2984	-287.1	213.9	-3.5	216.1	143.8	-234.5		
-173	6821	-1924	4724	-219.8	-47.3	214.0	-289.7	331.7	-180.4		
126	-5540	8404	2990	286.6	-213.7	3.5	-216.3	-143.7	227.3		
177	-6749	1860	-4713	220.0	47.4	-212.9	289.6	-331.8	176.2		
[10]											
-126	4616	-6204	-1714	-282.9	178.6	41.9	216.4	143.5	-222.1		
-106	4288	-1047	3135	-231.6	-64.5	95.3	-289.4	331.9	-162.6		
65	-1722	1878	221	140.2	-72.1	-43.6	-216.6	-143.3	194.6		
16	-807	4	-786	105.1	41.3	10.5	289.2	-332.0	130.7		
[11]											
-1	-1	-2	-5	13.8	1.1	0.3	216.8	143.1	-147.1		
2	3	4	9	54.8	-0.7	-0.3	-289.1	332.1	-93.5		
1	1	2	5	-8.1	-1.6	-1.1	-217.0	-142.8	109.8		
-2	-2	-3	-8	-58.2	0.2	0.2	289.0	-332.2	65.3		

Figure 3.6 Analog Section of the Event Report

Table 3.5 Event Report Metered Analog Quantities (Sheet 1 of 2)

Quantity	Description
IA	Instantaneous filtered line current, A-phase
IB	Instantaneous filtered line current, B-phase
IC	Instantaneous filtered line current, C-phase
IG	Instantaneous filtered line current, residual (or ground)
VA	Instantaneous filtered A-phase voltage
VB	Instantaneous filtered B-phase voltage
VC	Instantaneous filtered C-phase voltage

Table 3.5 Event Report Metered Analog Quantities (Sheet 2 of 2)

Quantity	Description
VS1	Instantaneous filtered synchronization Source 1 voltage
VS2	Instantaneous filtered synchronization Source 2 voltage
V1Mem	Instantaneous memorized positive-sequence polarization voltage

Figure 3.6 contains selected data from the analog section of a 4-samples/cycle event report for a BCG fault on a 400 kV line with CT ratio := 400/1 and PT ratio := 3636/1. The bracketed numbers at the left of the report (for example, [11]) indicate the cycle number; *Figure 3.6* presents seven cycles of 4-samples/cycle data.

The trigger row includes a > character following immediately after the V1Mem column to indicate the trigger point. This is the dividing point between the prefault or PRE time and the fault or remainder of the data capture.

The row that the relay uses for the currents in the event summary is the row with the largest current magnitudes; the relay marks this row on the event report with an asterisk (*) character immediately after the V1Mem column. The (*) takes precedence over the > if both occur on the same row in the analog section of the event report.

Obtaining RMS Phasors From 4-Samples/Cycle Event Reports

Use the column data in an event report to calculate rms values. You can use a calculator to convert rectangular data to phasor data, or use hand-calculations to separately determine the magnitude and angle of the rms phasor.

Hand Calculation Method. The procedure in the following steps explains a method for obtaining a current phasor from the IA channel data in the event report of *Figure 3.6*. You can process voltage data columns similarly. The drawings in *Figure 3.7* and *Figure 3.8* show one cycle of A-phase current in detail. *Figure 3.7* shows how to relate the event report ac current column data to the sampled waveform and rms values. *Figure 3.8* shows how to find the phasor angle. If you use the larger 8-samples/cycle event report, take every other sample and apply those values in this procedure.

This example demonstrates using a terminal or terminal emulation program. A more convenient method is to use ACSELERATOR QuickSet or the SEL-5601 Analytic Assistant. These programs automate the analysis process presented in this example and provide you with voltage and current phasors as software outputs.

This example assumes that you have successfully established communication with the relay; see *Making an EIA-232 Serial Port Connection on page U.4.7* for step-by-step instructions. In addition, you must understand relay access levels and passwords. See *Changing the Default Passwords on page U.4.9* to change the default access level passwords.

Step 1. Prepare to monitor the relay at Access Level 1:

- Using a communications terminal, type **ACC <Enter>**.
- Type the Access Level 1 password and press **<Enter>**.
You will see the Access Level 1 => prompt.

Step 2. Identify an event:

- Type **HIS <Enter>**.

The **HIS** command gives a quick, one-row listing of relay-stored events (see *Event History on page A.3.31* for more information).

This example uses the latest captured event.

- b. If no events are available, use the **TRI** command to generate an event (see *Triggering Data Captures and Event Reports on page A.3.4*).

Step 3. Gather data from the event report:

- a. Enable terminal data capture (usually a **Transfer > Capture Text** menu) in your terminal or terminal emulation program.
- b. Type **EVE <Enter>** at the Access Level 1 => prompt to obtain an event report similar to *Figure 3.6*.
(See *Table 3.3* or *EVENT on page R.9.17* for a summary of **EVENT** commands.)

The relay responds with the entire event report.

Step 4. Calculate the phasor magnitude:

- a. Select a cycle of data from the IA column of the event report.

Figure 3.6 Cycle [1] data for this example are shown in *Figure 3.7*.

There are three pairs of scaled instantaneous current samples from Cycle [1].

- b. Compute phasor magnitude using the following expression:

$$\sqrt{X^2 + Y^2} = |\text{Phasor}| \quad \text{Equation 3.1}$$

In *Equation 3.1*, Y is the first row of IA column current of a data pair, and the next row is X, the present value of the pair.

For this example, the computation shown in *Figure 3.7* yields 277.0 A.

- c. Compute phasor magnitudes from the remaining data pairs for Cycle [1].
- d. Confirm that all values are similar.

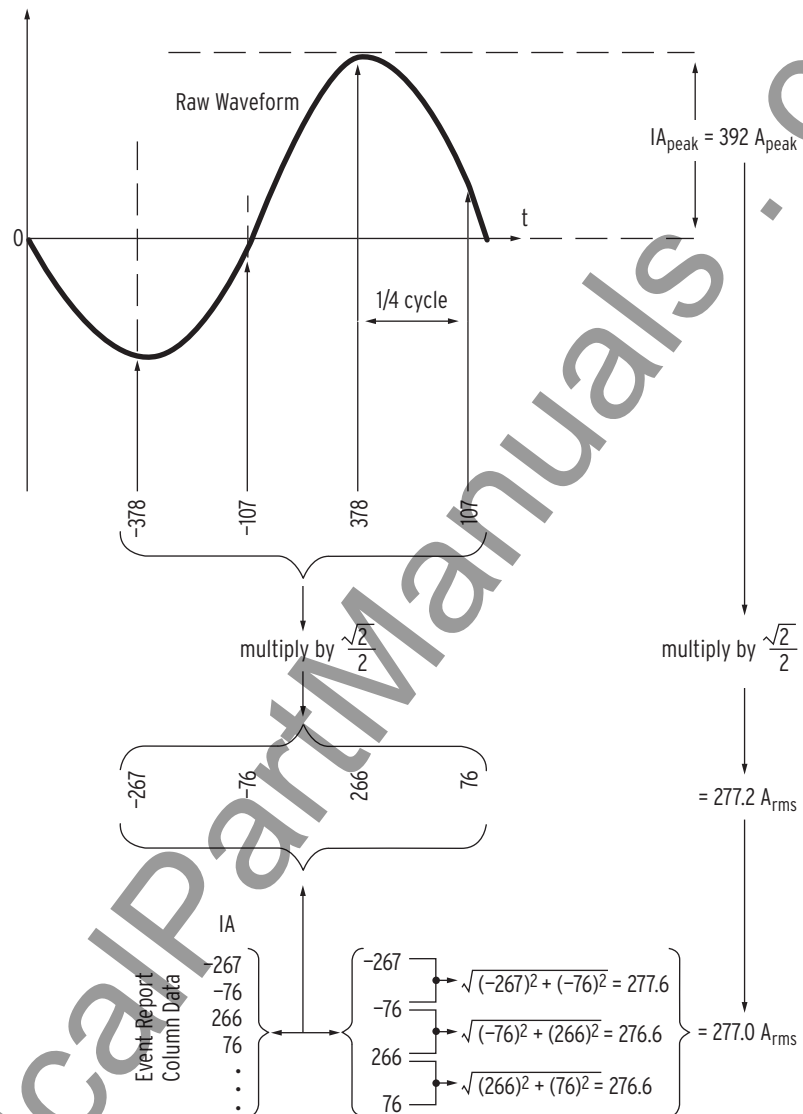


Figure 3.7 Event Report Current Column Data and RMS Current Magnitude

Step 5. Calculate the immediate phase angle:

- Select the same cycle of data from the IA column of the event report as you did when finding the magnitude (Cycle [1] data for this example).
- Compute phasor angle using the following expression:

$$\theta = \arctan\left(\frac{Y}{X}\right) = \angle \text{Phasor}$$

Equation 3.2

In Equation 3.2, Y is the first (or previous value) IA column current of a data pair, and X is the present value of the pair.

For this example, the computation shown in Figure 3.8 yields -105.9 degrees.

- Compute phasor angles from the remaining data pairs for Cycle [1].

NOTE: The arctan function of many calculators and computing programs does not return the correct angle for the second and third quadrants (when X is negative). When in doubt, graph the X and Y quantities to confirm that the angle that your calculator reports is correct.

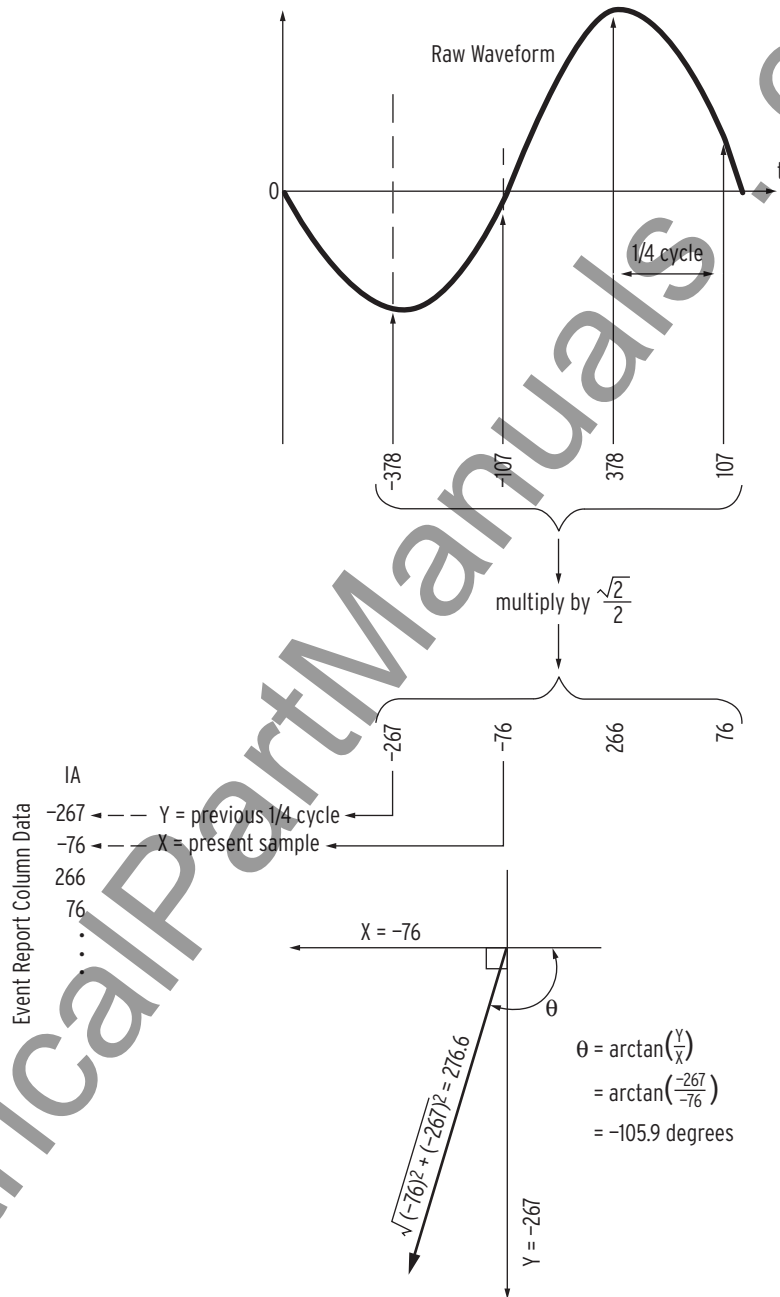


Figure 3.8 Event Report Current Column Data and RMS Current Angle

- Step 6. Calculate the reference phase angle. Usually, you compare power system angles to a reference phasor (positive-sequence A-phase voltage, for example):
- Repeat [Step 5](#) for the row data in the VA column that correspond to the IA column data values you used in [Step 5](#).

The angle calculation for the VA data is the following:

$$\begin{aligned}\theta &= \angle VA \\ &= \arctan\left(\frac{Y}{X}\right) \\ &= \arctan\left(\frac{-288.0}{-223.7}\right) \\ &= -127.8^\circ\end{aligned}\quad \text{Equation 3.3}$$

(This is an example of an arctan calculation that yields the incorrect answer from some calculators and math programs.)

Step 7. Calculate the absolute phase angle:

- Subtract the IA angle from the VA angle to obtain the A-phase-referenced phasor angle for IA.

$$\angle VA - \angle IA = -127.8^\circ - (-105.9^\circ) = -21.9^\circ \quad \text{Equation 3.4}$$

I_A leads V_A ; thus, the rms phasor for current IA at the present sample is 277.0 A $\angle 21.9^\circ$, referenced to V_A .

In the procedure above, you use two rows of current data from the event report to calculate an rms phasor current. At the first sample pair of Cycle [1], the rms phasor is $I_A = 277.0 \text{ A } \angle -105.9^\circ$.

The present sample of the sample pair ($X = -76$) is a scaled instantaneous current value (not an rms quantity) that relates to the rms phasor current value by the expression

$$X = -76 = 277.0 \cdot \cos(-105.9^\circ) \quad \text{Equation 3.5}$$

Polar Calculator Method. A method for finding the phasor magnitude and angle from event report quarter-cycle data pairs is to use a polar-capable calculator or computer program. Many calculators and computer programs convert Cartesian (X and Y) coordinate data to polar data. Key or enter the X value (present value or lower value of a column pair) and the Y value (later value or upper value in a column pair) as Cartesian (rectangular) coordinates. Perform the keystrokes necessary for your calculator or computing program to convert to polar coordinates. This is the phasor value for the data pair.

Digital Section of the Event Report

The second portion of an event report is the digital section. Inspect the digital data to evaluate relay element response during an event. See [Figure 3.9](#) for the locations of items in a sample event report digital section. If you want to view only the digital portion of an event report, use the **EVE D** command (see [Table 3.3](#) or [Section 9: ASCII Command Reference in the Reference Manual](#) for details). In the digital portion of the event report, the relay indicates deasserted elements with a period (.) and asserted elements with an asterisk (*) character.

The element and digital information labels are single character columns. Read these columns from top to bottom. The trigger row includes a > character following immediately after the last digital element column to indicate the trigger point. The relay marks the row used to report the maximum fault current with an asterisk (*) character at the right of the last digital element

column. Event reports that are 4-samples/cycle reports show the OR combination of digital elements in the two 8-samples/cycle rows to make the quarter-cycle entry.

The digital report arranges the event report digital settings into 79 column pages. For every 79 columns, the relay generates a new report that follows the previous report.

The report displays the digital label header for each column in a vertical fashion, aligned on the last character. For example, if the first digital section elements are IN101, #, RMBA5, M2P, LOKA, #, OUT203, OUT204, and HALARM, the header appears as in [Figure 3.10](#). If the Relay Word bits included in the header were assigned aliases, the alias names appear in the report.

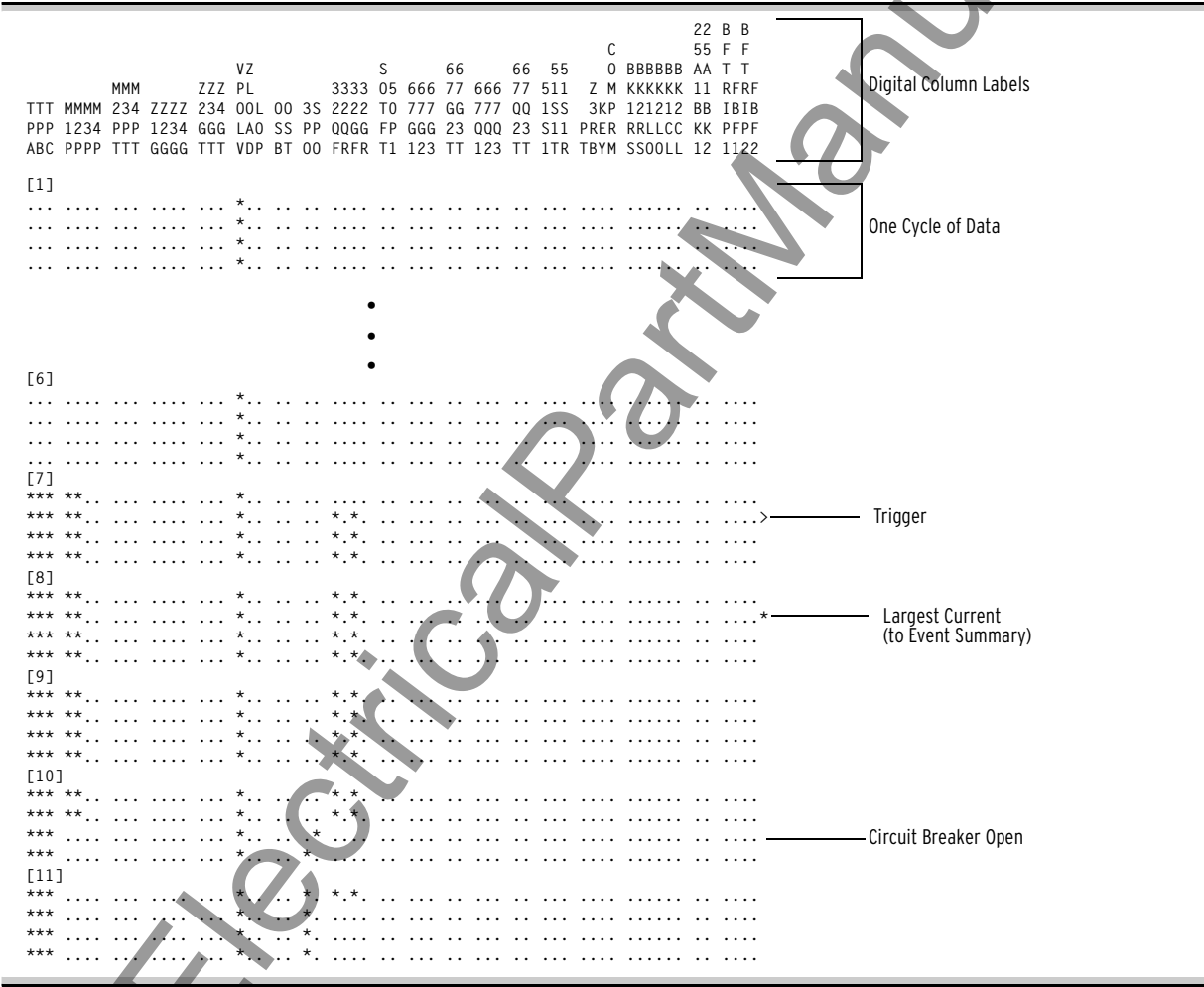


Figure 3.9 Digital Section of the Event Report



This example shows how to read the digital event report shown in [Figure 3.9](#). The sample digital event report shows seven cycles of 4-samples/cycle data for a BCG fault that trips a single-pole-capable circuit breaker.

In the next reported sample (the second sample of Cycle [7]), the digital event report shows that the relay has asserted the negative-sequence directional element, 32QF, and the ground directional element, 32GF.

Approximately three cycles later, the digital event report shows that the circuit breaker has tripped. In Cycle [10], Relay Word bit SPO indicates that the relay has detected a single-pole open; one of the poles of the circuit breaker has opened. The remaining poles open and the relay asserts Relay Word bit, 3PO, (Three-Pole Open). Note that the relay polarizing voltage for element security, VPOLV, is always available.

Selecting Event Digital Elements

Specify the digital elements in the digital section of the event report by using the Event Reporting Digital Elements settings found in the Report settings (the **SET R** command from a terminal or the **Report** branch of the **Settings** tree view of ACSELERATOR QuickSet). You can enter as many as 800 Relay Word bits from 100 target rows. The # symbol places a blank column in the digital report. Use the # symbol to organize the digital section of the event report. See *Report Settings on page R.10.47* for a list of the default programmed digital elements.

Digital Section INnnn Times

Reported assertion times for input digital elements differ, although these elements have the same name in both high-resolution raw data reports and in the filtered event reports. When you enter an input (INnnn) in the event digitals list, the relay displays the filtered input with time latency in the event

NOTE: The SEL-421 compressed event reports and COMTRADE files may contain additional digital elements as compared to standard (ASCII) event reports. See [CEVENT on page A.3.24](#).

report and the Compressed ASCII event report. However, in the binary COMTRADE file event report, the relay reports the actual high-sample rate capture time for relay inputs.

Event Summary Section of the Event Report

The third portion of an event report is the summary section. See [Figure 3.11](#) for the locations of items included in a sample summary section of an event report. If you want to exclude the summary portion from an event report, use the **EVE NSUM** command (see [EVENT on page R.9.17](#)).

The information in the summary portion of the event report is the same information in the event summary, except that the report header does not appear immediately before the event information when you view a summary in the event report. See [Event Summary on page A.3.28](#) for a description of the items in the summary portion of the event report.

Event: BCG T										Location: 48.17				Time Source: OTHER				Event Information			
Event Number#: 10007										Shot 1P: 0				Shot 3P: 0					Prefault Data		
Targets: INST TIME_ZONE_1										A_PHASE				B_PHASE bk1rs							
Breaker 1: OPEN										Trip Time: 23:30:49.026											
Breaker 2: OPEN										Trip Time: 23:30:49.026								Fault Data			
Prefault:		IA	IB	IC	IG	3I2	VA	VB	VC	Vmem											
MAG(A/kV)		276	262	246	65	17	364.704	364.903	364.452	364.614											
ANG(DEG)		22.1	-91.7	138.2	5.1	178.5	0.0	-119.9	120.3	0.2											
Fault:																		MIRRORED BITS Channel Status			
MAG(A/kV)		217	8892	8727	5586	11403	361.421	218.687	214.239	321.083											
ANG(DEG)		-17.0	167.3	24.8	95.6	94.4	0.1	-129.9	126.7	0.7											
														L C R		L C R					
														B B B R		B B B R					
														O A A O		O A A O					
														K D D K		K D D K					
														A A A A		B B B B					
														0 0 0 0		0 0 0 0					
MB:8->1																					
TRIG		RMBB		TMBB		RMBB		TMBB													
		00000000		00000000		00000000		00000000													
																		</			

<p>Group 1</p> <p>Line Configuration</p> <p>CTRW := 400 CTRX := 400 PTRY := 3636 VNOMY := 115 PTRZ := 3636 VNOMZ := 115 ZIMAG := 4.72 ZIANG := 82.60 ZOMAG := 14.50 ZOANG := 75.70 EFLOC := Y LL := 100.00</p> <p>•</p> <p>•</p> <p>•</p>	Active Group Settings
<p>Global</p> <p>General Global Settings</p> <p>SID := "Station A" RID := "Relay 1" NUMBK := 2 BID1 := "Breaker 1" BID2 := "Breaker 2" NFREQ := 60 PHROT := ABC DATE_F := MDY FAULT := NA</p> <p>•</p> <p>•</p> <p>•</p>	Global Settings
<p>Output</p> <p>Main Board</p> <p>OUT101 := 3PT OUT102 := BK1CL OUT103 := BK2CL OUT104 := NA OUT105 := NA OUT106 := NA OUT107 := NA OUT108 := NA</p> <p>•</p> <p>•</p> <p>•</p>	Output Settings
<p>Protection 1</p> <p>Freeform Protection SELogic</p> <p>1: ### PROTECTION FREEFORM AUTOMATION EXAMPLE 2: ### 3: ### SET CONTROL VARIABLE 1 4: ### ASSERTS WHEN PRIMARY POSITIVE SEQUENCE IS 5: ### GREATER THAN 90% OF 230 KV DIVIDED BY SQRT 3 6: PSV01 := V1M >= 119.5 #90% OF 230 KV DIVIDED BY SQRT 3</p> <p>Alias</p> <p>Relay Aliases (Relay Word Bit or Analog Quantity name, 7 Character Alias [0-9 A-Z _])</p> <p>1: EN,"REL_EN"</p>	Active Protection Logic Settings
	Alias Settings

Figure 3.12 Settings Section of the Event Report

CEVENT

The relay provides a Compressed ASCII event report for SCADA and other automation applications. ACSELERATOR QuickSet uses Compressed ASCII commands to gather event report data. If you want to view the Compressed ASCII event report data, use a terminal to issue ASCII command **CEV**. A sample of the report appears in [Figure 3.13](#); this is a comma-delimited ASCII file. The relay appends a four-digit hex checksum at the end of the lines in the Compressed ASCII report.

Items included in the Compressed ASCII event report are similar to the event report, although the relay reports the items in a special order. CEV files (and COMTRADE files) include all eight Relay Word bits from each row of the

See *SEL Compressed ASCII Commands on page R.5.6* and *ASCII Command Reference on page R.9.1* for more information on the Compressed ASCII command set.

[illegible]

Date Code 20080110

- Trigger

Event Data (Cycle 6-11)

Largest Current
(to Event Summary)

(Continued on next page)

SEL-421 Relay

```
"SETTINGS", "02E1"  
"Group 1"
```

Active Group Settings

Global Settings

Global Settings

Global Settings

Output Settings

Output Settings

Output Settings

Active Protection Logic Settings

Active Protection Logic Settings

Active Protection Logic Settings

Alias Settings

Alias Settings

Alias Settings

Alias Settings

Figure 3.13 Sample Compressed ASCII Event Report

The order of the labels in the digital portion of the Column Labels field matches the order of the HEX-ASCII Relay Word. Each numeral in the HEX-ASCII Relay Word reflects the status of four Relay Word bits from the Digital Column Labels field of the Compressed ASCII event report. The HEX-ASCII Relay Word from the first sample of Cycle [7], the trigger cycle, is the following:

```
"000200c00000000000000000000000fbf3fc0000000080000400000000000000002700000000000000000001"
```

In this HEX-ASCII Relay Word, the seventh numeral in the HEX-ASCII Relay Word is C. In binary, this is 1100. Mapping the labels to the digital Column Labels yields the following:

M1P	M2P	M3P	M4P
1	1	0	0

M1P and M2P are elements that picked up at the first sample of Cycle [7] (see [Figure 3.9](#)).

Event Files Download

You can download the event file from the relay and save these files to a PC to keep as a record or examine later. Use a terminal emulation program with file transfer capability. For example, type **FILE READ EVENTS E4_10007.TXT** <Enter> at an Access Level 1 prompt or higher to download a 4-samples/cycle event report with serial number 10007. Start the terminal download routine to store the file on your computer. Use Y modem protocol.

If you want the Compressed ASCII file, type **FILE READ EVENTS C4_10007.TXT** <Enter>. In addition, you can use ACSELERATOR QuickSet to download event files. See [Retrieving Event Report Data Files: Terminal on page U.4.54](#) for more information on event report file download procedures.

Event Summary

You can retrieve a shortened version of stored event reports as event summaries. These short-form reports present vital information about a triggered event. The relay generates an event in response to power system faults and other trigger events (see [Triggering Data Captures and Event Reports on page A.3.4](#)). See [Figure 3.14](#) for a sample event summary.

The SEL-421 can be configured to automatically send an event summary—see [Automatic Messages on page R.5.9](#).

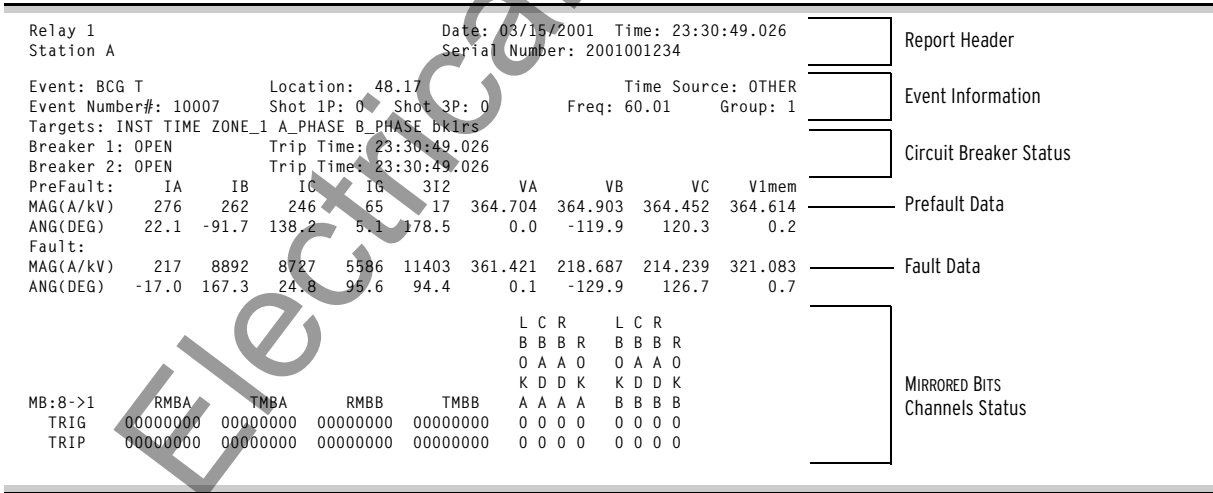


Figure 3.14 Sample Event Summary Report

The event summary contains the following information:

- Standard report header
 - Relay and terminal identification
 - Event date and time
- Event type
- Location of fault (if applicable)
- Time source (HIRIG or OTHER)
- Event number
- Recloser shot counter at the trigger time
- System frequency
- Active group at trigger time
- Targets
- Circuit breaker trip and close times; and auxiliary contact(s) status
- Prefault and fault voltages, currents, and sequence current (from the event report row with the largest current)
- MIRRORED BITS® communications channel status (if enabled)

The relay derives the summary target information and circuit breaker trip and close times from the rising edge of relevant Relay Word bits during the event. If no trip or circuit breaker element asserted during the event, the relay uses the last row of the event.

Fault location data can be indeterminate (for example, when there is no fault on the power system). If this is the case, the relay displays “\$\$\$\$. \$\$” for the Location entry in the event summary. You will also see the “\$\$\$\$. \$\$” display if the fault location enable setting EFLOC is N.

The SEL-421 reports the event type according to the output of the fault location algorithm. [Table 3.6](#) lists event types in fault reporting priority. Fault event types (AG, BG, and BCG, for example) have reporting priority over indeterminate fault events. For example, you can trigger an event when there is no fault condition on the power system by using the **TRI** command. In this case, when there is no fault, the relay reports the event type as TRIG.

Table 3.6 Event Types

Event	Event Trigger
AG, BG, CG, ABC, AB, BC, CA, ABG, BCG, CAG	The relay reports phase involvement. If Relay Word bit TRIP asserts at any time during the event, the relay appends a T to the phase (AG T, for example).
TRIP	The event report includes the rising edge of Relay Word bit TRIP, but phase involvement is indeterminate.
ER	The relay generates the event with elements in the SELOGIC control equation ER, but phase involvement is indeterminate.
TRIG	The relay generates the event in response to the TRI command.

Viewing the Event Summary

Access the event summary from the communications ports and communications cards. View and download history reports from Access Level 1 and higher. You can independently acknowledge a summary (with the **SUM ACK** command) at each communications port so that you and users at other ports (SCADA, Engineering, etc.) can retrieve a complete set of summary reports. To acknowledge and remove a summary, you must first use the **SUM N(EXT)** command to view that summary.

You can use the **SUM** command to retrieve event summaries by date or date range, and by event number. (The relay labels each new event with a unique number as reported in the **HIS** command history report; see [Event History on page A.3.31](#).)

[Table 3.7](#) lists the **SUM** commands. See [SUMMARY on page R.9.48](#) for complete information on the **SUM** command.

Table 3.7 SUM Command

Command	Description
SUM	Return the most recent event summary (with header).
SUM n	Return a particular <i>n</i> ^a event summary (with header).
SUM ACK	Acknowledge the event summary on the present communications port.
SUM N	View the oldest unacknowledged event summary (N = next).

^a The parameter *n* indicates event order or serial number (see [Event Numbering on page A.3.13](#)).

You can retrieve event summaries with ACSELERATOR QuickSet. The **Event Waveform View > Summary Data** menu item gives you summary information for each event you select in the **Event History** dialog box. Access the **Relay Event History** dialog box via the **Analysis > View Event Files** menu. See [Analyze Events on page U.3.19](#) for information and examples.

CSUMMARY

The relay outputs a Compressed ASCII summary report for SCADA and other automation applications. Issue ASCII command **CSU** to view the Compressed ASCII summary report. A sample of the summary report appears in [Figure 3.15](#); this is a comma-delimited ASCII file. The relay appends a four-digit hex checksum at the end of the lines in the Compressed ASCII report.

Items included in the Compressed ASCII summary report are similar to those included in the summary report, although the relay reports the items in a special order. For the purpose of improving products and services, SEL sometimes changes the items and item order.

See [SEL Compressed ASCII Commands on page R.5.6](#) and [ASCII Command Reference on page R.9.1](#) for more information on the Compressed ASCII command set.

"RID","SID","FID","03e2"		Report Header
"Relay 1","Station A","SEL-421-R101-V0-Z001001-D20010315","0dfc"		
"EVENT_NUM","MONTH","DAY","YEAR","MIN","SEC","MSEC","USEC","EVENT","LOCAT ION","TIME_SOURCE","SHOT_1P","SHOT_3P","FREQUENCY","GROUP","BREAKER1","HOUR_T1", "MIN_T1","SEC_T1","MSEC_T1","HOUR_C1","MIN_C1","SEC_C1","MSEC_C1","BREAKER2","HO UR_T2","MIN_T2","SEC_T2","MSEC_T2","HOUR_C2","MIN_C2","SEC_C2","MSEC_C2","T_LED" ,"TARGETS","MB_TRIGGER","MB_TRIP","IA_PF","IA_DEG_PF","IB_PF","IB_DEG_PF","IC_PF ","IC_DEG_PF","IG_PF","IG_DEG_PF","3I2_PF","3I2_DEG_PF","I1_PF","I1_DEG_PF","VA_ PF","VA_DEG_PF","VB_PF","VB_DEG_PF","VC_PF","VC_DEG_PF","VS1_PF","VS1_DEG_PF","V S2_PF","VS2_DEG_PF","VIMEM_PF","VIMEM_DEG_PF","VO_PF","VO_DEG_PF","V2_PF","V2_DE G_PF","V1_PF","V1_DEG_PF","IA","IA_DEG","IB","IB_DEG","IC","IC_DEG","IG","IG_DEG ","3I2","3I2_DEG","I1","I1_DEG","VA","VA_DEG","VB","VB_DEG","VC","VC_DEG","VS1", "VS1_DEG","VS2","VS2_DEG","VIMEM","VIMEM_DEG","VO","VO_DEG","V2","V2_DEG","V1", V1_DEG","D94E"		Report Labels
10007,3,15,2001,23,30,49,026,900,"BCG T",48.17,"OTHER",0,0.60,01,1,"OPEN",23,30,49,26,...,"OPEN",23,30,49,26,...,28872, INST TIME ZONE_1 A_PHASE B_PHASE bklrs","0000000000",276,22.05,262, -91.71,246,138.23,784,68.57,17,178.47,261,22.93,365,0.00,365,-119.87,364,120.30, 361,-88.78,362,151.39,365,-0.01,0,-43.94,365,0.14,217,- 16.99,8727,24.82,17836,175.10,11403,94.44,361,0.07,219,- 129.89,214,126.73,321,0.75,31,2.67,321,0.75,31,2.67,67,2.55,263,-0.87,"49C7"		Report Data

Figure 3.15 Sample Compressed ASCII Summary

Event History

The event history gives you a quick look at recent relay activity. The relay labels each new event with a unique number from 10000 to 42767. (At 42767, the top of the numbering range, the relay returns to 10000 for the next event number and then continues to increment.) See [Figure 3.16](#) for a sample event history.

The event history contains the following:

- Standard report header
 - Relay and terminal identification
 - Date and time of report
- Event number
- Event date and time
- Event type
- Location of fault (if applicable)
- Maximum phase current from summary fault data
- Active group at the trigger instant
- Targets

[Figure 3.16](#) is a sample event history from a terminal.

Relay 1		Date: 03/16/2001 Time: 11:57:27.803					
Station A		Serial Number: 2001001234					
#	DATE	TIME	EVENT	LOCAT	CURR	GRP	TARGETS
10007	03/15/2001	23:30:49.026	BCG T	48.17	8892	1	INST TIME ZONE_1 B_PHASE
10006	03/15/2001	07:15:00.635	ABC T	22.82	8203	1	INST ZONE_1 A_PHASE bklrs
10005	03/15/2001	06:43:53.428	TRIG	\$\$\$\$. \$\$	0	1	

Figure 3.16 Sample Event History

Fault location data can be indeterminate (for example, when you trigger an event and there is no fault on the power system). If this is the case, the relay displays \$\$\$\$.\$\$ for the Location entry in the event history. You will also see the \$\$\$\$.\$\$ display if the fault location enable setting EFLOC is N.

The event types in the event history are the same as the event types in the event summary (see [Table 3.6](#) for event types).

The event history report indicates events stored in relay nonvolatile memory. The relay places a blank row in the history report output; items that are above the blank row are available for viewing (use the **EVE** and **CEV** commands). Items that are below the blank row are no longer in relay memory; these events appear in the history report to indicate past power system performance. The relay does not ordinarily modify the numerical or time order in the history report. However, if an event report is corrupted (power was lost during storage, for example), the relay lists the history report line for this event after the blank row.

Viewing the Event History

Access the history report from the communications ports and communications cards. View and download history reports from Access Level 1 and higher. You can also clear or reset history data from Access Levels 1 and higher. You can independently clear/reset history data at each communications port so that you and users at other ports (SCADA, Engineering, etc.) can retrieve complete history reports. You can also clear all history data from all ports (with the **HIS CA** and **HIS RA** commands).

Use the **HIS** command from a terminal to obtain the event history. You can view event histories by date or by date range, or you can specify the number of the most recent events that the relay returns. See [HISTORY on page R.9.22](#) for information on the **HIS** command. [Table 3.8](#) lists the **HIS** commands.

Table 3.8 HIS Command

Command	Description
HIS	Return event histories with the oldest at the bottom of the list and the most recent at the top of the list.
HIS k	Return the <i>k</i> most recent event summaries with the oldest at the bottom of the list and the most recent at the top of the list.
HIS date1	Return the event summaries on date <i>date1</i> ^a .
HIS date1 date2	Return the event summaries from <i>date1</i> to <i>date2</i> , with <i>date1</i> at the bottom of the list and <i>date2</i> at the top of the list.
HIS C	Clear all event data on the present port.
HIS R	Clear all event data on the present port.
HIS CA	Clear event data for all ports.
HIS RA	Clear event data for all ports.

^a Use the same date format as Global setting DATE_F.

You can use ACSELERATOR QuickSet to retrieve the relay event history. Use the **Analysis > View Event History** menu to view the **Event History** dialog box. See [Analyze Events on page U.3.19](#) for information and examples.



Figure 3.17 Sample Compressed ASCII History Report

CHISTORY

The relay outputs a Compressed ASCII history report for SCADA and other automation applications. Issue the **CHI** command to view the Compressed ASCII history report. A sample of the report appears in [Figure 3.17](#); this is a comma-delimited ASCII file. The relay appends a four-digit hex checksum at the end of each history in the Compressed ASCII history report.

Items included in the Compressed ASCII history report are similar to those included in the history report, although the relay reports the items in a special order. For the purpose of improving products and services, SEL sometimes changes the items and item order.

See *SEL Compressed ASCII Commands* on page R.5.6 and *Section 9: ASCII Command Reference in the Reference Manual* for more information on the Compressed ASCII command set.

History File Download

You can also download the history report file from the relay. Use a terminal emulation program with file transfer capability. At an Access Level 1 prompt or higher type **FILE READ REPORTS HISTORY.TXT <Enter>**. Start the terminal download routine to store the file on your computer. If you want the Compressed ASCII file, type **FILE READ REPORTS CHISTORY.TXT <Enter>**. In addition, you can use ACSELERATOR QuickSet to download history files. See [*Retrieving Event Report Data Files: Terminal on page U.4.54*](#) for file download procedures.

SER (Sequential Events Recorder)

The SEL-421 SER (Sequential Events Recorder) gives you detailed information on relay states and relay element operation. The SER captures and time-tags state changes of Relay Word bit elements and relay conditions. These conditions include power-up, relay enable and disable, group changes, settings changes, memory overflow, diagnostic restarts, and SER autoremoval/reinsertion. The SEL-421 stores the latest 1000 SER entries to nonvolatile memory. [Figure 3.18](#) is a sample SEL-421 SER report.

The SER report contains the following:

- Standard report header
 - Relay and terminal identification
 - Date and time of report
- SER number
- SER date and time
- Relay element or condition
- Element state

Relay 1			Date: 03/16/2001 Time: 13:09:29.341		
Station A			Serial Number: 2001001234		
FID=SEL-421-R101-V0-Z001001-D20010315					
#	DATE	TIME	ELEMENT	STATE	
6	03/15/2001	00:00:00.004	Power-up	Group 1	
5	03/15/2001	00:00:00.022	Relay	Enabled	
4	03/15/2001	00:30:00.021	GROUND O/C 1 LINE 1	51S1 PICKED UP	
3	03/15/2001	00:30:03.221	GROUND O/C 1 LINE 1	51S1 TIMEOUT	
2	03/15/2001	00:32:00.114	GROUND O/C 1 LINE 1	51S1 RESET	
1	03/15/2001	00:32:00.114	GROUND O/C 1 LINE 1	51S1 DROPOUT	

SER

Number

Relay Element

or Condition

Figure 3.18 Sample SER Report

In the SER report, the oldest information has the highest number. The newest information is always #1. When using a terminal you can order the positions of the SER records in the SER report (see [Table 3.9](#) or the [SER on page R.9.36](#)).

Viewing the SER Report

The relay displays the SER records in ASCII and binary formats. For more information on binary SER messaging, see [SEL Communications Protocols on page R.5.1](#).

Access the SER report from the communications ports and communications cards in Access Level 1 and higher. You can independently clear/reset already viewed SER data at each communications port (with the **SER CV** or **SER RV** command) so that users at other ports (SCADA, Engineering, for example) can retrieve complete SER reports. The **SER CV** or **SER RV** command will not clear any SER data that has been recorded, but not viewed, on a particular serial port. To clear all SER data on a serial port, use the **SER C** or **SER R** command.

To clear all SER data from all serial ports, use the **SER CA** or **SER RA** command, available only from Access Levels P, A, O, and 2. This procedure would normally be used after relay commissioning or testing.

Use an ASCII terminal or ACSELERATOR QuickSet to examine SER records. You can use the **SER** command to view the SER report by date, date range, SER number, or SER number range. The relay labels each new SER record with a unique number. See [Table 3.9](#) or [Section 9: ASCII Command Reference in the Reference Manual](#) for more information on the **SER** command.

Table 3.9 SER Commands^a

Command	Description
SER	Return the 20 most recent records from the SER, with the oldest (highest number) at the top of the list and the most recent (lowest number) at the bottom of the list.
SER <i>k</i>	Return the <i>k</i> most recent records from the SER, with the oldest (highest number) at the top of the list and the most recent (lowest number) at the bottom of the list.
SER <i>m n</i>	Return the SER records from <i>m</i> to <i>n</i> . If <i>m</i> is greater than <i>n</i> , records appear with the oldest (highest number) at the top of the list and the most recent (lowest number) at the bottom of the list. If <i>m</i> is less than <i>n</i> , records appear with the most recent (lowest number) at the top of the list and the oldest (highest number) at the bottom of the list.
SER <i>date1</i>^b	Return the SER records on date <i>date1</i> .
SER <i>date1 date2</i>	Return the SER records from <i>date1</i> at the top of the list to <i>date2</i> at the bottom of the list.
SER C and SER R	Clear SER records on the present port.
SER CA and SER RA	Clear SER data for all ports.
SER CV and SER RV	Clear viewed SER records on the present port.
SER D	List chattering SER elements that the relay is removing from the SER records.

^a The parameters *m* and *n* indicate SER numbers that the relay assigns at each SER trigger.

^b Use the same date format as Global setting DATE_F.

You can retrieve SER records with ACSELERATOR QuickSet. The **HMI > Meter and Control** menu item gives you the SER report. See [Viewing SER Records on page U.4.54](#) for information and examples. The latest 200 SER events are viewable on the front-panel display through the front-panel EVENTS MENU (see [Section 5: Front-Panel Operations in the User's Guide](#)).

CSER

The relay outputs a Compressed ASCII SER report for SCADA and other automation applications. Issue the **CSE** command to view the Compressed ASCII SER report. A sample of the SER report appears in [Figure 3.19](#); this is a comma-delimited ASCII file. The relay appends a four-digit hex checksum at the end of the lines in the Compressed ASCII report.

Items included in the Compressed ASCII SER report are similar to the SER report, although the relay reports the items in a special order. For the purpose of improving products and services, SEL sometimes changes the items and item order.

See [SEL Compressed ASCII Commands on page R.5.6](#) and [CSER on page R.9.13](#) for more information on the Compressed ASCII command set.

"RID","SID","FID","03e2"		Report Header
"Relay 1","Station A","SEL-421-R101-V0-Z001001-D20010315","0dfc"		
"#","MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC","ELEMENT","STATE","0FC8"		
1,3,15,2001,00,32,00,114,"GROUND_O/C_1_LINE_1","51S1_DROPOUT","09D2"		
2,3,15,2001,00,32,00,114,"GROUND_O/C_1_LINE_1","51S1_RESET","08E7"		
3,3,15,2001,00,30,03,221,"GROUND_O/C_1_LINE_1","51S1_TIMEOUT","09B0"		SER Data (6 records)
4,3,15,2001,00,30,00,021,"GROUND_O/C_1_LINE_1","51S1_PICK_UP","097B"		
5,3,15,2001,00,00,00,222,"Relay","Enabled","09BA"		
6,3,15,2001,00,00,00,004,"Power-up","Group 1","0A0A"		

Figure 3.19 Sample Compressed ASCII SER Report

SER File Download

You can also download the SER data as a file from the relay. Use a terminal emulation program with file transfer capability. At an Access Level 1 prompt or higher type **FILE READ REPORTS SER.TXT <Enter>**. Start the terminal download routine to store the file on your computer. If you want the Compressed ASCII file, type **FILE READ REPORTS CSER.TXT <Enter>**. See [Downloading an SER Report File on page U.4.59](#) for SER file download procedures.

Setting SER Point and Aliases

You program the relay elements that trigger an SER record. You can select as many as 250 elements. These triggers, or points, can include control input and control output state changes, element pickups and dropouts, recloser state changes, and so on. You can also change the names of the elements and set aliases for the element clear and set states. Use the **SET R** command from a terminal, or use ACCELERATOR QuickSet **Report** branch of the **Settings** tree view to enter **SER Points and Aliases**.

Use the text-edit line mode settings method to enter or delete SER elements (see [Text-Edit Mode Line Editing on page U.4.22](#)). To set an SER element, enter the five items of this comma-delimited string (all but the first parameter are optional):

Relay Word Bit, Reporting Name, Set State Name, Clear State Name, HMI Alarm

Names or aliases can contain any printable ASCII character. See [Viewing SER Records on page U.4.54](#) for examples of entering SER data.

The relay defaults to the element name when you do not provide a reporting name. The default names for the set and clear states are Asserted and Deasserted, respectively. By default, SER Points are not configured for HMI alarm display. The relay always creates an SER record for power-up, relay enable and relay disable, any group change and settings change, diagnostic restart, and memory overflow. For a setting example, see [Viewing SER Records on page U.4.54](#).

Automatic Deletion and Reinsertion

The SER also includes an automatic deletion and reinsertion function. The relay automatically deletes oscillating SER items from SER recording. This function prevents overfilling the SER buffer with “chattering” information. Set Report setting ESERDEL (Enable SER Delete) to Y to enable this function, and select values for the setting SRDLCNT (SER Delete Count) and the setting SRDLTIM (SER Delete Time) that mask the chattering SER element. The relay removes an item from all SER recordings once a point has changed state more than SRDLCNT times in an SRDLTIM period. Once deleted from SER recording, the relay ignores the item for a 10 • SRDLTIM

period. At the end of this period, the relay checks the chatter criteria and, if the point does not exceed the criteria, the relay automatically reinserts the item into SER recording. To see a list of deleted SER points, use the **SER D** command (see [SER on page R.9.36](#)).

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Section 4

Time-Synchronized Measurements

The SEL-421 Relay records power system events with very high accuracy when you provide high-accuracy clock input signals, such as from a GPS receiver. SEL-421 relays placed at key substations can give you information on power system operating conditions in real time.

Based on the high-accuracy time input, the relay calculates synchrophasors for currents and line voltages (for each phase and for positive-sequence), as specified in IEEE C37.118, Standard for Synchrophasors for Power Systems. You can then perform detailed analysis and calculate load flow from the synchrophasors.

See [Section 7: Synchrophasors](#) in the [Reference Manual](#) for more information about phasor measurement functions in the SEL-421.

This section presents details on these measurements as well as suggestions for further application areas. This section covers:

- [Relay Configuration for High-Accuracy Timekeeping on page A.4.2](#)
- [Fault Analysis on page A.4.7](#)
- [Power Flow Analysis on page A.4.8](#)
- [State Estimation Verification on page A.4.11](#)

Relay Configuration for High-Accuracy Timekeeping

The SEL-421 features two IRIG-B timekeeping modes, IRIG and high-accuracy IRIG, called HIRIG.

The HIRIG mode replaces the PPS mode in previous SEL-421 relays, which required a separate 1k PPS time input in firmware versions R111 and earlier. Relay Word bit TSOK asserts when the SEL-421 is in HIRIG mode (see [Table 4.9 on page U.4.77](#)).

The SEL-421 must be in the HIRIG mode in order for the synchrophasor features to operate (see [Section 7: Synchrophasors in the Reference Manual](#)).

See [Configuring High-Accuracy Timekeeping on page U.4.77](#) for details on the time-source connections of the SEL-421, including the changes made to the SEL-421 hardware and firmware version R112.

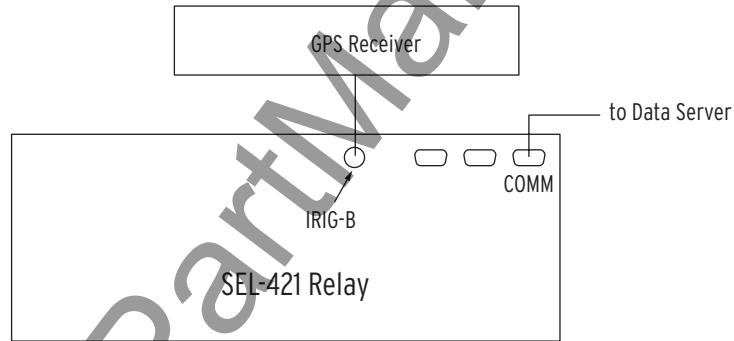


Figure 4.1 High-Accuracy Timekeeping Connections

Time-Synchronized Triggers

Program the SEL-421 to perform data captures at *specific* times. Relays that are time-locked using HIRIG mode provide high-accuracy time-synchronized data captures. When you use this method on multiple relays, the actual trigger times can differ by as much as 5 ms, but the information in the binary COMTRADE file outputs from each relay is time-stamped at very high accuracy. Do not assume that the relay triggers are locked with high accuracy; rather, compare corresponding time-stamped data points from each COMTRADE file.

Time Triggering the SEL-421

NOTE: The **MET PM time** command can be used to capture synchrophasor data at a specific time, if synchrophasors are enabled with Global setting EPMU := Y. See [View Synchrophasors by Using the MET PM Command on page R.7.19](#).

Perform the following steps to trigger an event data capture in the SEL-421 at a specific time. These settings cause the relay to initiate a data capture at 12:00:30 p.m. Use other SELOGIC® control equations in a similar manner to trigger relay event recordings.

You should be familiar with the ACSELERATOR® SEL-5030 Software Program. See [Section 3: PC Software in the User's Guide](#) and [Section 4: Basic Relay Operations in the User's Guide](#) for ACSELERATOR operational information.

This example assumes that you have successfully established communication with the relay (see [Establishing Communication on page U.4.6](#) for a step-by-step procedure). In addition, you should be familiar with relay access levels

and passwords. See [Changing the Default Passwords on page U.4.9](#) to change the default access level passwords.

Step 1. Configure the communications port:

- a. Start the ACSELERATOR® QuickSet™ SEL-5030 software.
- b. On the top toolbar, click **Communication > Parameters**.
You will see the **Communication Parameters** dialog box.
- c. Select the **Data Speed, Data Bits, Stop Bits, Parity,** and **RTS/CTS** that match the relay settings. The defaults are **9600, 8, 1, None, Off**, respectively.
- d. Click **OK** to update the ACSELERATOR QuickSet communications parameters.
- e. Type **<Ctrl + T>** to use the serial communications terminal.
- f. Type **<Enter>** to see whether the communications link is active between ACSELERATOR QuickSet and the relay.
You will see the Access Level 0 = prompt in the terminal window.
- g. Exit the terminal window.

Step 2. Confirm the correct ACSELERATOR passwords:

- a. Reopen the **Communication** menu and click **Port Parameters**.
- b. Enter your Access Level 1 password in the **Level One Password** text box and your Access Level 2 password in the **Level Two Password** text box.
- c. Click **OK**.

Step 3. Click **Settings > Read** to read the present configuration in the SEL-421.


The relay sends all configuration and settings data to ACSELERATOR.

Step 4. Click the + mark next to the **Group** you want to program on the **Settings** tree view.

This example uses **Group 1**.

You will see the **Protection Free-Form Logic Settings** dialog box.

Step 5. Enter time trigger settings:

- a. Click the  button beside the first unused Protection SELOGIC row entry field to start the **Expression Builder**.
- b. On the left side of the SELOGIC control equation, select **Math Variables** and double-click **PMV64**.
- c. On the right side of the equation, select **Analog Quantities > Date and Time**.
- d. Double click **THR** (Time in Hours).

- e. Use the # character to add a comment to the line.
- f. When finished, click **Accept**.

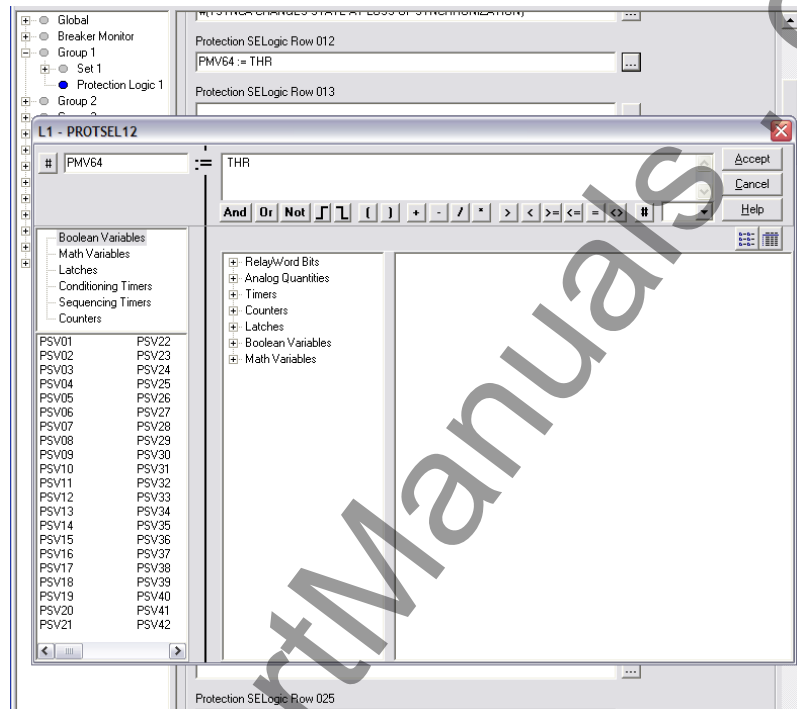


Figure 4.2 Setting PMV64 with the Expression Builder Dialog Box

- Step 6. In a similar manner, build a free-form SELOGIC program in Protection Logic that causes protection free-form SELOGIC control equation variable PSV02 to assert to logical 1 at 12:00:30.005 p.m. Use the following expressions:

PMV64 := THR # Clock hours

PMV63 := TMIN # Clock minutes

PMV62 := TSEC # Clock seconds

PSV02 := (PMV64=12) AND (PMV63=00) AND (PMV62=30) # Set PSV02 at 12:00:30

NOTE: In this example, the event report trigger will occur between 12:30:00.002 and 12:30:00.005 because of the method of SEL-421 protection logic processing.

- Step 7. Select settings:

- a. Click the + mark next to **Relay Configuration** as shown in [Figure 4.3](#).
- b. Click the **Trip Logic** and **ER Trigger** branch.
You will see the **Trip Logic** and **ER Trigger Settings** dialog box (see [Figure 4.3](#)).

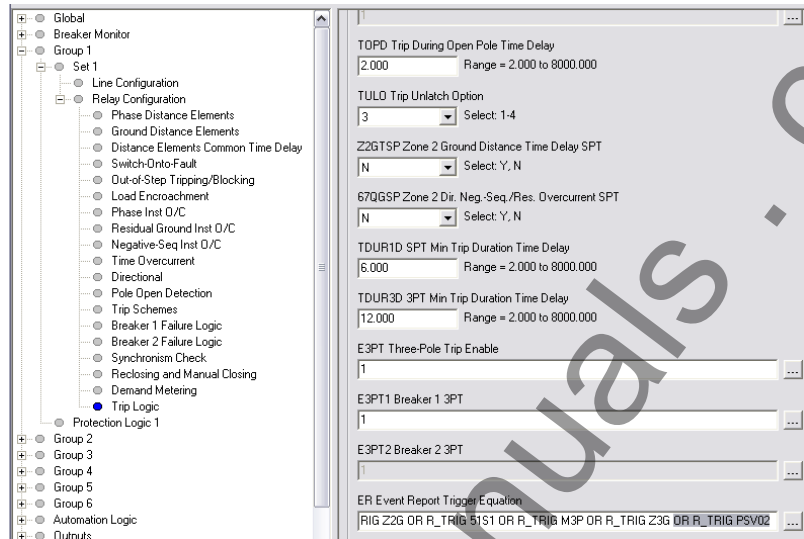


Figure 4.3 Selecting Trip Logic and ER Trigger Settings in ACSELERATOR

Step 8. Click in the **ER Event Report Trigger Equation (SELOGIC)** text box and add **OR R_TRIG PSV02** to the end of elements already in this SELOGIC control equation.

Step 9. Click **File > Save** to save the new settings in ACSELERATOR.

Step 10. Upload the new settings to the SEL-421:

- a. Click **File > Send**.

ACSELERATOR prompts you for the settings class or instance you want to send to the relay, as shown in the first dialog box in [Figure 4.4](#).

- b. Click the check box for **Group 1** (or the settings group that you are programming).
- c. Click **OK**.

The relay responds with the second dialog box shown in [Figure 4.4](#).

If you see no error message, the new settings are loaded in the relay.

NOTE: The **Relay Editor** dialog boxes shown in [Figure 4.4](#) are for the SEL-421. The SEL-421-1 and the SEL-421-2 dialog boxes do not contain Automation 2 through Automation 10 setting instances.



Figure 4.4 Uploading Group Settings to the SEL-421

COMTRADE File Information

Retrieve the COMTRADE files for the time-triggered data captures from each relay with the **FILE READ EVENTS** command. See [Reading Oscillograms, Event Reports, and SER on page U.4.46](#) for methods to retrieve these files.

Parse the binary COMTRADE data for the power system currents and voltages you need to calculate system quantities. See [Raw Data Oscillography on page A.3.8](#) for more information on the COMTRADE file format.

Fault Analysis

Power System Measurements

Use the SEL-421 measurement and communications capabilities to obtain precise simultaneous measurements from the power system at different locations. Combining system measurements from a number of key substations gives you a snapshot picture of the phasor relationships in the power system at a particular time. You can perform extensive fault analysis by evaluating the simultaneous measurements gathered at a central computer or data server.

Install at least two SEL-421 relays in the power system to implement dynamic phasor determination. [Figure 4.5](#) shows an example of a 230 kV overhead transmission line with a SEL-421 at each terminal. Connect GPS clocks (such as the SEL-2407) at each substation to provide very high-accuracy time signal inputs for each relay. See [Configuring High-Accuracy Timekeeping on page U.4.77](#) for details on the IRIG-B connections required for high-accuracy IRIG (HIRIG) timekeeping in the SEL-421.

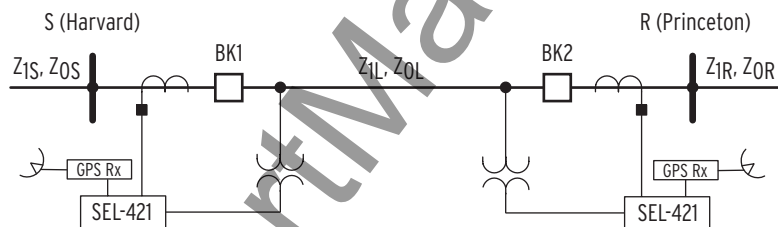


Figure 4.5 230 kV Transmission Line System

With synchronized and time-stamped binary COMTRADE data, you can develop automated computer algorithms for comparing these data from different locations in the power system.

In particular, you can use fault data extracted from two relays. Use third-party software to filter the binary COMTRADE data so that the signals are composed of fundamental quantities only (50 Hz or 60 Hz). You can also use third-party software to convert the binary COMTRADE data to ASCII COMTRADE files. Use the Phasor Diagram in the SEL-5601 Analytic Assistant to select the appropriate prefault and post-fault quantities.

Power Flow Analysis

Use the SEL-421 to develop instantaneous power flow data. Obtain the voltage and current phasors from different power system buses at the same instant and use these measurements to determine power flow at that instant. Use the synchronized phasor measurement capabilities of the relay and the **METER PM** command or a synchrophasor protocol to collect synchronized voltage and current data. Use this information to confirm your power flow models.

Four SEL-421 relays are installed in the power system shown in [Figure 4.6](#). Substations S and R provide generation for the load at Substation T.

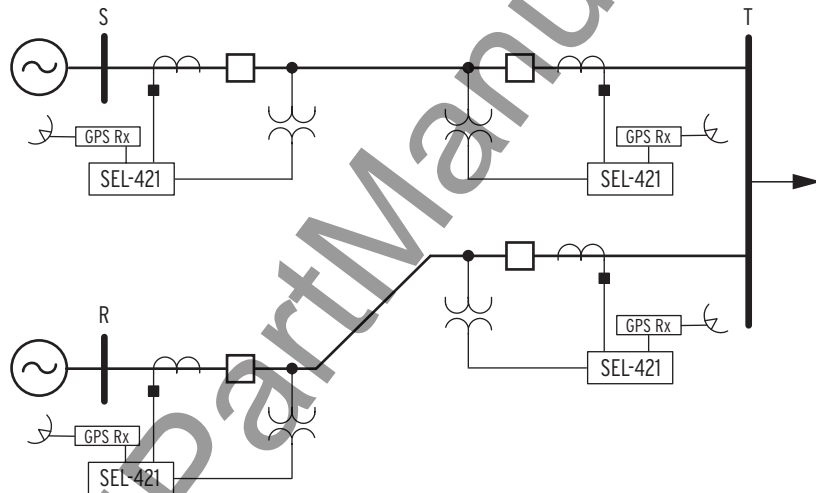


Figure 4.6 500 kV Three Bus Power System

[Table 4.1](#) lists the voltage and current measured by the four SEL-421 relays at one particular time.

Table 4.1 SEL-421 Voltage and Current Measurement (Sheet 1 of 2)

Voltage		Current	
SEL-421 at Substation S			
V_{AS}	288.675 kV $\angle 0^\circ$	I_{AS}	238.995 A $\angle 41.9^\circ$
V_{BS}	288.675 kV $\angle 240^\circ$	I_{BS}	238.995 A $\angle -78.1^\circ$
V_{CS}	288.675 kV $\angle 120^\circ$	I_{CS}	238.995 A $\angle 161.9^\circ$
SEL-421 at Substation R			
V_{AR}	303.109 kV $\angle -0.2^\circ$	I_{AR}	234.036 A $\angle -44.2^\circ$
V_{BR}	303.109 kV $\angle 239.8^\circ$	I_{BR}	234.036 A $\angle 195.8^\circ$
V_{CR}	303.109 kV $\angle 119.8^\circ$	I_{CR}	234.036 A $\angle 75.8^\circ$
SEL-421 at Substation T Looking Towards Substation S			
V_{AT-S}	295.603 kV $\angle -1.6^\circ$	I_{AT-S}	238.995 A $\angle -138.1^\circ$
V_{BT-S}	295.603 kV $\angle 238.4^\circ$	I_{BT-S}	238.995 A $\angle 101.9^\circ$
V_{CT-S}	295.603 kV $\angle 118.4^\circ$	I_{CT-S}	238.995 A $\angle -18.1^\circ$
SEL-421 at Substation T Looking Towards Substation R			
V_{AT-R}	295.603 kV $\angle -1.6^\circ$	I_{AT-R}	234.036 A $\angle 135.8^\circ$

Table 4.1 SEL-421 Voltage and Current Measurement (Sheet 2 of 2)

Voltage		Current	
V _{BT-R}	295.603 kV ∠238.4°	I _{BT-R}	234.036 A ∠15.8°
V _{CT-R}	295.603 kV ∠118.4°	I _{CT-R}	234.036 A ∠-104.2°

Use [Equation 4.1](#) to calculate the generation supplied from Substation S and Substation R, plus the load at Substation T.

$$\begin{aligned}
 S_{3\phi} &= P_{3\phi} + jQ_{3\phi} \\
 &= \sqrt{3} \cdot V_{pp} \cdot I_L^* \\
 &= 3 \cdot V_p \cdot I_L^*
 \end{aligned}
 \tag{Equation 4.1}$$

Where:

- S_{3φ} = Three-phase complex power (MVA)
- P_{3φ} = Three-phase real power (MW)
- Q_{3φ} = Three-phase imaginary power (MVAR)
- V_{pp} = Phase-to-phase voltage
- V_p = Phase-to-neutral voltage
- I_L^{*} = Complex conjugate of the line current

The complex power generation supplied by Substation S is:

$$\begin{aligned}
 S_S &= (3 \cdot 288.675 \text{ kV} \angle 0^\circ) \cdot (238.995 \text{ A} \angle -41.9^\circ) \\
 &= 154.1 \text{ MW} - j138.2 \text{ MVAR}
 \end{aligned}$$

The complex power generation supplied by Substation R is:

$$\begin{aligned}
 S_R &= (3 \cdot 303.109 \text{ kV} \angle -0.2^\circ) \cdot (234.036 \text{ A} \angle 44.2^\circ) \\
 &= 152.6 \text{ MW} + j148.3 \text{ MVAR}
 \end{aligned}$$

The load at Substation T supplied by Substation S is:

$$\begin{aligned}
 S_{T-S} &= (3 \cdot 295.603 \text{ kV} \angle -1.6^\circ) \cdot (238.995 \text{ A} \angle 138.1^\circ) \\
 &= -153.7 \text{ MW} + j145.9 \text{ MVAR}
 \end{aligned}$$

The load at Substation T supplied by Substation R is:

$$\begin{aligned}
 S_{T-R} &= (3 \cdot 295.603 \text{ kV} \angle -1.6^\circ) \cdot (234.036 \text{ A} \angle -135.8^\circ) \\
 &= -152.8 \text{ MW} - j140.5 \text{ MVAR}
 \end{aligned}$$

The total load at Substation T is:

$$\begin{aligned}
 S_T &= S_{T-S} + S_{T-R} \\
 &= -306.5 \text{ MW} + j5.4 \text{ MVAR}
 \end{aligned}$$

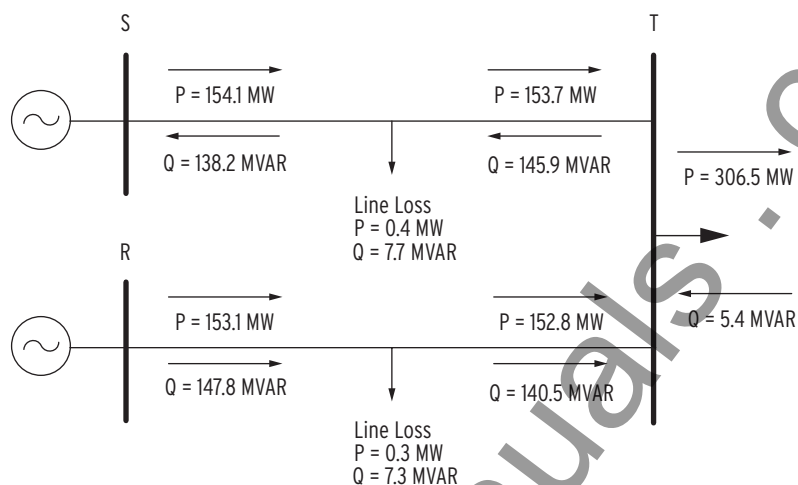


Figure 4.7 Power Flow Solution

Use the power flow solution to verify the instantaneous positive-sequence impedances of your system transmission lines.

State Estimation Verification

Electric utility control centers have used state estimation to monitor the state of the power system for the past 20 years. The state estimator calculates the state of the power system using measurements such as complex power, voltage magnitudes, and current magnitudes received from different substations. State estimation uses an iterative, nonlinear estimation technique. The state of the power system is the set of all positive-sequence voltage phasors in the network. Typically, several seconds or minutes elapse from the time of the first measurement to the time of the first estimation. Therefore, state estimation is a steady-state representation of the power system.

Consider using precise simultaneous positive-sequence voltage measurements from the power system to verify your state estimation model. Take time-synchronized high-resolution positive-sequence voltage measurements at all substations. Send the SEL-421 Fast Messages to a central database to determine the power system state.

Use Synchrophasors for State Measurement, Not Estimation

Power system contingency analysis models rely on state-estimation techniques, and may have inaccuracies caused by incorrect present-state information, or errors in system characteristics, such as incorrect line and source impedance estimates. The simultaneous event-report triggering technique described earlier in this section can be used to verify present models.

With Phasor Measurement Units (PMUs) such as the SEL-421 installed in several substations, synchrophasor measurements can be transmitted to a central processor in near real-time, providing very accurate snapshots of the power system. This type of data processing system provides system-state measurements that are a few seconds old, rather than state estimates that may be several minutes old. In addition, the synchrophasor results are real measurements, rather than estimates.

See [Section 7: Synchrophasors in the Reference Manual](#) for information on the PMU settings and the communications protocols available for synchrophasor data collection.

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Section 5

Substation Automatic Restoration

Many electric utilities tap overhead transmission lines with bulk power transformers. A tapped line with three terminals presents more operating constraints and line protection complications than does a two-terminal line. Use an automatic restoration scheme to reduce the decision-making burden on operations and dispatch personnel during equipment failures, system events, and lightning-induced line operations.

This section contains the following:

- [*230 kV Tapped Transmission Line Application Example on page A.5.2*](#)

with subsections:

- [*Philosophy on page A.5.3*](#)
- [*SEL-421 Configuration on page A.5.5*](#)
- [*SEL-421 Settings at Substation T on page A.5.6*](#)

This section assumes that you are familiar with line protection. Find supporting material for the information in this section in [*Section 2: Auto-Reclosing and Synchronism Check in the Reference Manual*](#), [*Section 3: SELOGIC Control Equation Programming in the Reference Manual*](#), and [*Section 5: SEL Communications Protocols in the Reference Manual*](#).

230 kV Tapped Transmission Line Application Example

This example shows you how to automate the complete restoration sequence, including auto-reclose and synchronism check, **for the tapped 230/115 kV autotransformer located at Substation T.** Figure 5.1 shows a one-line diagram of the tapped 230 kV overhead transmission line.

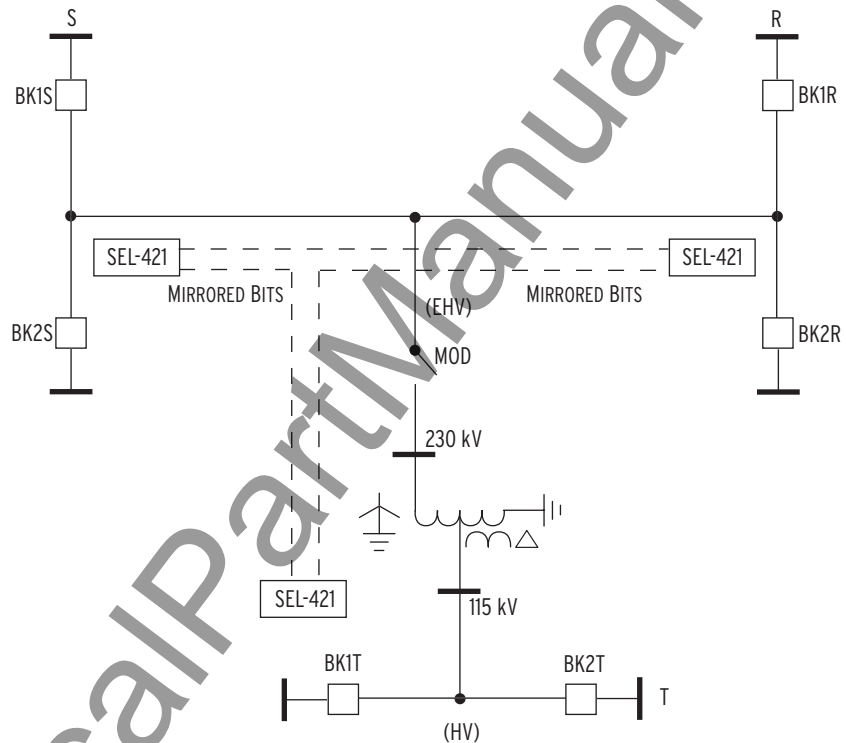


Figure 5.1 230 kV Tapped Overhead Transmission Line

The tapped autotransformer at Substation T has a high-side MOD (motor-operated disconnect) and two low-side circuit breakers. Whenever an internal fault occurs on the 230 kV overhead transmission line, the SEL-421 relays at each of the three terminals open all of the circuit breakers, followed by the high-side MOD at Substation T. The SEL-421 relays replace separate line relays, discrete reclosing and synchronism check relays, timers, latching relays, and extensive wiring for this particular example.

Use the SEL-421 protection free-form SELOGIC control equations in Table 5.4 to automate the following actions at Substation T:

- Restore tapped Substation T to service after a successful 230 kV overhead transmission line auto-reclose operation.
- Restore the 230 kV overhead transmission line to service after an autotransformer failure or a low-side circuit breaker failure operation.
- Restore Substation T station service and 115 kV bus continuity after an unsuccessful automatic line reclose operation or a remote 230 kV circuit breaker failure trip.

Philosophy

System Protection Philosophy

SEL-421 relays located at each of the three 230 kV terminals protect the tapped 230 kV transmission line; the relays operate in the DCB (directional comparison blocking) trip scheme. Zone 1 distance protection also operates in the DUTT (direct underreaching transfer trip) scheme. When the high-side MOD is closed, the SEL-421 at Substation T direct transfer trips the other two terminals if a 115 kV circuit breaker fails to operate or an autotransformer failure occurs; the SEL-421 at Substation T also receives direct transfer trip commands from Substations S and R.

Auto-Reclose Philosophy

Refer to [Figure 5.2](#) for a timing diagram of the complete auto-reclose cycle.

Use the SEL-421 to provide auto-reclose at Substation T as follows.

Circuit Breaker BK1T

- If the high-side MOD is closed and the synchronism check across Circuit Breaker BK1T with respect to the 230 kV potential is successful for at least four seconds, the SEL-421 recloses Circuit Breaker BK1T in five seconds total.
- If the high-side MOD is open and the 115 kV system has been energized for at least four seconds, the relay recloses Circuit Breaker BK1T in five seconds total.

Circuit Breaker BK2T

- If Circuit Breaker BK1T recloses and the synchronism check is successful across Circuit Breaker BK2T with respect to the 230 kV potential for at least four seconds, the SEL-421 recloses Circuit Breaker BK2T in five seconds total.
- If the high-side MOD is open, Circuit Breaker BK1T recloses, and the 115 kV system has been energized for at least four seconds, the relay recloses Circuit Breaker BK2T in five seconds total.

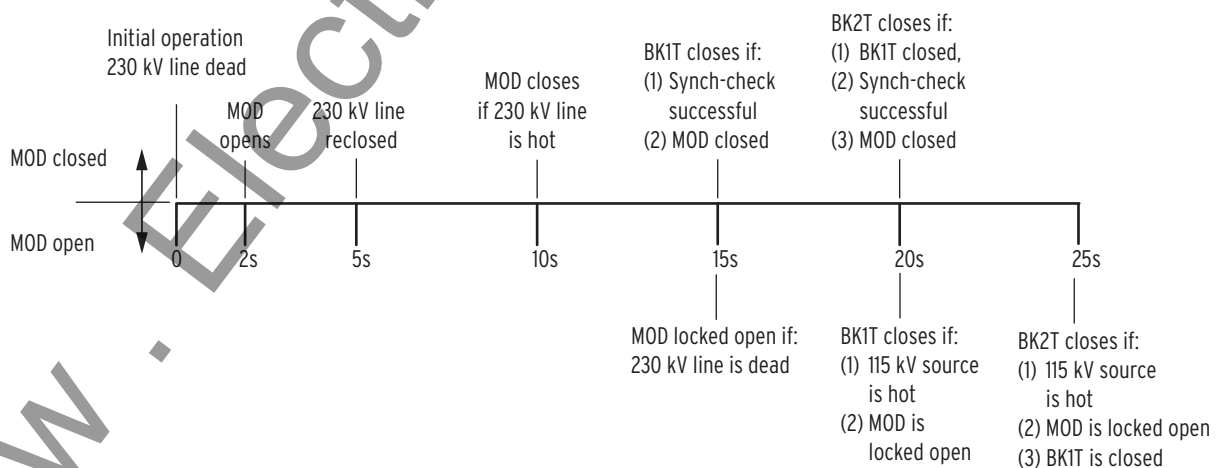


Figure 5.2 Automatic Restoration Timing Diagram

Automatic Restoration Philosophy

Refer to [Figure 5.2](#) for a timing diagram of the complete automatic restoration cycle. The SEL-421 at Substation T automatically restores service in response to the following system conditions:

- Low-side circuit breaker or autotransformer failure at Substation T
- Successful 230 kV line reclose
- Permanent 230 kV line fault or circuit breaker failure at Substations S or R

Transmission Line Faults or Circuit Breaker/Autotransformer Failure

The SEL-421 at Substation T responds to a 230 kV transmission line fault, low-side circuit breaker failure or autotransformer failure at the local substation, and any circuit breaker failure at Substations S and R. For these situations, the relay does the following:

- Sends a pulsed open command to the high-side MOD. The 230 kV transmission line must be dead for two seconds, and the relay must have successfully opened the 115 kV circuit breakers.
- Disables DTT (direct transfer trip) via MIRRORRED BITS® communications (issued at Substation T) when the high-side MOD is open
- Inhibits reception of any DTT via MIRRORRED BITS communications from any of the two remote 230 kV terminals when the high-side MOD is open

Low-Side Circuit Breaker or Autotransformer Failure. The following actions occur if a low-side circuit breaker or autotransformer failure occurs at Substation T:

- Substation S and R reclose five seconds later.
- Lockout relays at Substation T locks out the high-side MOD and low-side circuit breakers. The relay uses an external lockout relay (86 a and 86 b contacts in the breaker trip and close circuits, and an 86 b contact in the MOD close circuit); Substation T remains locked out pending further action from operations or field personnel.

Successful 230 kV Line Reclose. The SEL-421 at Substation T issues the following actions if the 230 kV transmission line auto-reclose is successful at Substations S and R:

- Sends a pulsed close command to the high-side MOD at Substation T to energize the autotransformer if the relay measures balanced nominal voltage from the high-side PTs for five seconds and the low-side circuit breakers are open; the tertiary windings of the autotransformer restore station service.
- Recloses Circuit Breaker BK1T five seconds after the high-side MOD closes, if the voltage is nominal and synchronized.
- Recloses Circuit Breaker BK2T five seconds later if the voltage is still nominal and synchronized.

Thus, the local SEL-421 restores the 115 kV system at Substation T.

Permanent 230 kV Line Fault Or Circuit Breaker Failure. If a permanent 230 kV line fault or circuit breaker failure operation occurs at Substations S or R, the SEL-421 at Substation T executes the following actions:

- Locks open the high-side MOD if there is no voltage on the 230 kV side for 13 seconds. (You can implement this logically via a timer and latch bit combination.) The latch resets if the 230 kV system is hot for 60 seconds and both low-side circuit breakers (BK1T and BK2T) are open.
- Recloses Circuit Breaker BK1T after five seconds if there is nominal voltage on the 115 kV side and the high-side MOD is locked open.
- Recloses Circuit Breaker BK2T five seconds later if there is nominal voltage on the 115 kV side, the high-side MOD is locked open, and Circuit Breaker BK1T reclosed successfully.

These actions restore station service and low-side continuity at Substation T. Substation T operates in this configuration until operations or field personnel take further action.

SEL-421 Configuration

In this example, the SEL-421 at Substation T measures a single set of three-phase potentials (input VY) and a single set of three-phase currents (input IW) on the 230 kV side of the autotransformer. The relay uses single-phase potential inputs VAZ and VBZ to provide synchronism check across the low-side circuit breakers. [Figure 5.3](#) shows the connection diagram.

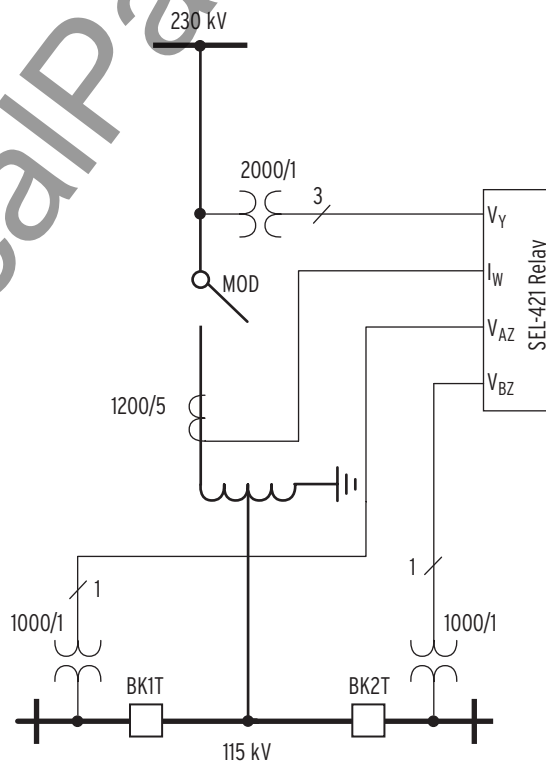


Figure 5.3 SEL-421 Inputs

SEL-421 Settings at Substation T

The settings in [Table 5.1](#) through [Table 5.6](#) provide 230 kV transmission line protection, auto-reclose, and substation restoration at Substation T as described in this application example.

Protection free-form SELOGIC control equations appear in tabular form (see [Table 5.4](#)). These equations, which are the free-form settings extracted from a SEL-421, are also shown in [Figure 5.4](#).

Global Settings

Table 5.1 Global Settings^a

Setting	Description	Entry
General Global Settings		
SID	Station Identifier	Station T
RID	Relay Identifier	SEL-421
NUMBK	Number of Breakers in Scheme	2
BID1	Breaker 1 Identifier	Circuit Breaker 1–115 kV
BID2	Breaker 2 Identifier	Circuit Breaker 2–115 kV
NFREQ	Nominal System Frequency (Hz)	60
PHROT	System Phase Rotation	ABC
Current and Voltage Source Selection		
ESS	Current and Voltage Source Selection	Y
LINEI	Line Current Source	IW
BK1I	Breaker 1 Current Source	NA
BK2I	Breaker 2 Current Source	NA

^a This table shows only the global settings relevant to this particular application example.

Breaker Monitor

Table 5.2 Breaker Monitor Settings^a

Setting	Description	Entry
Breaker Configuration		
BK1TYP	Breaker 1 Trip Type (Single-Pole = 1, Three-Pole = 3)	3
BK2TYP	Breaker 2 Trip Type (Single-Pole = 1, Three-Pole = 3)	3
Breaker 1 Inputs		
52AA1	N/O Contact Input—BK1 (SELOGIC)	NOT IN101
Breaker 2 Inputs		
52AA2	N/O Contact Input—BK2 (SELOGIC)	NOT IN102

^a This table shows only the breaker monitor settings relevant to this particular application example.

Group Settings

Table 5.3 Group Settings (Sheet 1 of 3)

Setting	Description	Entry
Line Configuration		
CTRW	CT Ratio—Input W	240
CTRX	CT Ratio—Input X	240

Table 5.3 Group Settings (Sheet 2 of 3)

Setting	Description	Entry
PTRY	PT Ratio—Input Y	2000
VNOMY	PT Nominal Voltage (L-L)—Input Y	115
PTRZ	PT Ratio—Input Z	1000
VNOMZ	PT Nominal Voltage (L-L)—Input Z	115
DCB Trip Scheme^a		
BT	Block Trip	RMB1A OR RMB1B
Synchronism-Check Element Reference (Group)		
SYNCP	Synch Reference	VAY
25VL	Voltage Window Low Threshold (volts)	60.0
25VH	Voltage Window High Threshold (volts)	70.0
Breaker 1 Synchronism Check (Group)		
SYNCS1	Synch Source 1	VAZ
KS1M	Synch Source 1 Ratio Factor	1.00
KS1A	Synch Source 1 Angle Shift (degrees)	0.00
25SFBK1	Maximum Slip Frequency—BK1	OFF
ANG1BK1	Maximum Angle Difference 1—BK1(degrees)	20.00
ANG2BK1	Maximum Angle Difference 2—BK1 (degrees)	20.00
BSYNBK1	Block Synch Check—BK1 (SELOGIC)	NA
Breaker 2 Synchronism Check (Group)		
SYNCS2	Synch Source 2	VBZ
KS2M	Synch Source 2 Ratio Factor	1.00
KS2A	Synch Source 2 Angle Shift (degrees)	0.00
ALTS2	Alternative Synch Source 2 (SELOGIC)	NA
25SFBK2	Maximum Slip Frequency—BK2	OFF
ANG1BK2	Maximum Angle Difference 1—BK2 (degrees)	20.00
ANG2BK2	Maximum Angle Difference 2—BK2 (degrees)	20.00
BSYNBK2	Block Synch Check—BK2 (SELOGIC)	NA
Recloser and Manual Closing		
NSPSHOT	Number of Single-Pole Reclosures	N
N3PSHOT	Number of Three-Pole Reclosures	1
E3PRI1	Three-Pole Reclose Enable—BK1 (SELOGIC)	1
E3PRI2	Three-Pole Reclose Enable—BK2 (SELOGIC)	NOT LEADBK2
TBBKD	Time Between Breakers for ARC (cycles)	300
BKCFD	Breaker Close Failure Delay (cycles)	300
SLBK1	Leader = Circuit Breaker 1 (SELOGIC)	1
SLBK2	Leader = Circuit Breaker 2 (SELOGIC)	0
FBKCEN	Follower Breaker Closing Enable (SELOGIC)	52AA1
ULCL1	Unlatch Closing for Breaker 1 (SELOGIC)	52AA1
ULCL2	Unlatch Closing for Breaker 2 (SELOGIC)	52AA2
79DTL	Recloser Drive to Lockout (SELOGIC)	NA
79BRCT	Block Reclaim Timer (SELOGIC)	NA

Table 5.3 Group Settings (Sheet 3 of 3)

Setting	Description	Entry
BK1CLSD	BK1 Reclose Supervision Delay (cycles)	1200
BK2CLSD	BK2 Reclose Supervision Delay (cycles)	1200
Three-Pole Reclose Settings (Group)		
3POID1	Three-Pole Open Interval 1 Delay (cycles)	300
3PFARC	Three-Pole Fast ARC Enable (SELOGIC)	NA
3PRCD	Three-Pole Reclaim Time Delay (cycles)	1200
3PRI	Three-Pole Reclose Initiation (SELOGIC)	M1P OR Z1G OR RXPRM
79SKP	Skip Reclosing Shot (SELOGIC)	NA
3P1CLS	Three-Pole BK1 Reclose Supervision (SELOGIC)	PCT01Q
3P2CLS	Three-Pole BK2 Reclose Supervision (SELOGIC)	PCT02Q
Trip Logic^a		
TR	Zone 1 direct transfer trip	RMB2A OR RMB2B OR
	Step-distance or time-overcurrent protection	Z1T OR Z2T OR 51S1T OR
	Direct transfer trip if MOD closed	(RMB3A OR RMB3B) AND NOT IN103...

^a This portion of the table shows all of the receive MIRRORED BITS (RMBn) communications assignments.

Protection Free-Form SELogic Control Equations

Table 5.4 Protection Free-Form SELogic Control Equations (Sheet 1 of 3)

Setting	Description	Entry	Comments
PSV01	Protection Comparison 1	PSV01 := V1M >= 119.500	Logical 1 if V ₁ greater than or equal to 90% nominal voltage
PSV02	Protection Comparison 2	PSV02 := V1M < 26.500	Logical 1 if V ₁ is less than 20% nominal voltage
PLT01S	Protection Latch 1 set	PLT01S := R_TRIG PST02Q AND NOT PLT01	MOD latch set
PLT01R	Protection Latch 1 reset	PLT01R := R_TRIG PST03Q AND PLT01	MOD latch reset
PST01PT	Protection Sequence Timer 1 preset	PST01PT := 150.00	Pulse open the MOD if:
PST01R	Protection Sequence Timer 1 reset	PST01R := NOT PSV02 OR NOT IN101 OR NOT IN102 OR PST01Q OR IN103	230 kV bus is not dead OR BK1T OR BK2T is closed OR PST01 output equals logical 1 OR MOD is open
PST01IN	Protection Sequence Timer 1 enable	PST01IN := PSV02 AND IN101 AND IN102 AND NOT IN103	230 kV bus is dead AND BK1T AND BK2T are open AND MOD is closed

Table 5.4 Protection Free-Form SELogic Control Equations (Sheet 2 of 3)

Setting	Description	Entry	Comments
OUT103 ^a	Output 103	PST01ET > 120.00 AND NOT PCN01Q	MOD open command
PST02PT	Protection Sequence Timer 2 preset	PST02PT := 780.00	MOD latch is set if: 230 kV bus is dead AND MOD is open
PST02R	Protection Sequence Timer 2 reset	PST02R := PLT01	
PST02IN	Protection Sequence Timer 2 enable	PST02IN := PSV02 AND IN103	
PST03PT	Protection Sequence Timer 3 preset	PST03PT := 3600.00	MOD latch reset if: 230 kV bus is hot AND BK1T AND BK2T are open for 60 s
PST03R	Protection Sequence Timer 3 reset	PST03R := NOT PLT01	
PST03IN	Protection Sequence Timer 3 enable	PST03IN := PSV01 AND IN101 AND IN102	
PST04PT	Protection Sequence Timer 4 preset	PST04PT := 330.00	Pulse close the MOD if: 230 kV bus is not hot OR BK1T OR BK2T is closed OR MOD is closed OR PST04 output equals logi- cal 1
PST04R	Protection Sequence Timer 4 reset	PST04R := NOT PSV01 OR NOT IN101 OR NOT IN102 OR NOT IN103 OR PLT01 OR PST04Q	
PST04IN	Protection Sequence Timer 4 enable	PST04IN := PSV01 AND IN101 AND IN102 AND IN103 AND NOT PLT01	
OUT106*	Output 106 AND NOT PCN02Q	PST04ET > 300.00 AND NOT PCN02Q	MOD close command
PCN01PV	Protection Counter 1 preset	PCN01PV := 2	MOD block trip if: Two trips without MOD open
PCN01R	Protection Counter 1 reset	PCN01R := IN103	
PCN01IN	Protection Counter 1 enable	PCN01IN := OUT103	
PCN02PV	Protection Counter 2 preset	PCN02PV := 2	MOD block close if: Two closes without MOD closed
PCN02R	Protection Counter 2 reset	PCN02R := NOT IN103	
PCN02IN	Protection Counter 2 enable	PCN02IN := OUT106	
PCT01PU	Protection Condition- ing Timer 1 Pickup	240.00	MOD is closed AND syn- chronized OR MOD latch set AND MOD is open AND BK1T bus is hot for 4 s
PCT01DO	Protection Condition- ing Timer 1 Dropout	0.00	
PCT01IN	Protection Condition- ing Timer 1 Enable	NOT IN103 AND 25A1BK1 OR PLT01 AND IN103 AND 59VS1	

Table 5.4 Protection Free-Form SELogic Control Equations (Sheet 3 of 3)

Setting	Description	Entry	Comments
PCT02PU	Protection Conditioning Timer 2 Pickup	240.00	
PCT02DO	Protection Conditioning Timer 2 Dropout	0.00	
PCT02IN	Protection Conditioning Timer 2 Enable	NOT IN103 AND 25A1BK2 AND NOT IN101 OR PLT01 AND IN103 AND 59VS2 AND NOT IN101	MOD is closed AND synchronized AND BK1T is closed OR MOD latch set AND MOD is open AND BK2T bus is hot AND BK11T is closed for 4 s

^a This control output assignment is not a protection free-form SELogic control equation, but appears in this table for continuity of the overall logic.

=>> SH0 L <Enter>

Protection 1

Free-Form Protection SELogic

```

1: ### PROTECTION FREE-FORM AUTOMATION EXAMPLE
2: ###
3: ### SET CONTROL VARIABLE 1
4: ### ASSERTS WHEN PRIMARY POSITIVE SEQUENCE VOLTAGE IS
5: ### GREATER THAN 90% OF NOMINAL
6: PSV01 := VIM >= 119.500 # 90% OF 230 KV DIVIDED BY SQRT 3
7: ###
8: ### SET CONTROL VARIABLE 2
9: ### ASSERTS WHEN PRIMARY POSITIVE SEQUENCE VOLTAGE IS
10: ### LESS THAN 20% OF NOMINAL
11: PSV02 := VIM < 26.500 # 20% OF 230 KV DIVIDED BY SQRT 3
12: ###
13: ### SET LATCH 1
14: PLT01S := R_TRIG PST02Q AND NOT PLT01 # SET LATCH WITH TIMER 2 OUTPUT
15: PLT01R := R_TRIG PST03Q AND PLT01 # RESET LATCH WITH TIMER 3 OUTPUT
16: ###
17: ### SET SEQUENCING TIMER 1
18: ### TIMES IF PSV02 IS ASSERTED, BREAKER 1 AND 2 ARE OPEN, AND
19: ### THE MOD IS CLOSED. RESETS IF PSV02 IS NOT ASSERTED, OR BREAKER
20: ### 1 OR 2 IS CLOSED, OR MOD IS OPEN, OR TIMER 1 OUTPUT ASSERTED
21: PST01PT := 150.00 # TIMER 1 PICKUP 150 CYCLES
22: PST01R := NOT PSV02 OR NOT IN101 OR NOT IN102 OR IN103 OR PST01Q
23: PST01IN := PSV02 AND IN101 AND IN102 AND NOT IN103
24: ###
25: ### SET SEQUENCING TIMER 2
26: ### TIMES IF PSV02 IS ASSERTED AND THE MOD IS OPEN. RESETS IF
27: ### LATCH 1 IS SET
28: PST02PT := 780.00 # TIMER 2 PICKUP 780 CYCLES
29: PST02R := PLT01
30: PST02IN := PSV02 AND IN103
31: ###
32: ### SET SEQUENCING TIMER 3
33: ### TIMES IF PSV01 IS ASSERTED AND BREAKER 1 AND 2 ARE OPEN
34: ### RESETS WHEN LATCH 1 IS RESET
35: PST03PT := 3600.00 # TIMER 3 PICKUP 3600 CYCLES
36: PST03R := NOT PLT01
37: PST03IN := PSV01 AND IN101 AND IN102
38: ###
39: ### SET SEQUENCING TIMER 4
40: ### TIMES IF PSV01 IS ASSERTED AND BREAKER 1 AND 2 ARE OPEN
41: ### THE MOD IS OPEN, AND LATCH 1 IS NOT SET. RESET IF PSV01 NOT
42: ### ASSERTED, OR BREAKER 1 OR 2 NOT OPEN, OR MOD NOT OPEN
43: ### OR LATCH 1 SET, OR TIMER 4 OUTPUT ASSERTED
44: PST04PT := 330.00 # TIMER 4 PICKUP 330 CYCLES
45: PST04R := NOT PSV01 OR NOT IN101 OR NOT IN102 OR NOT IN103 OR PLT01 OR \
    PST04Q
46: PST04IN := PSV01 AND IN101 AND IN102 AND NOT PLT01 AND IN103
47: ###
48: ### SET COUNTER 1
49: ### MOD TRIP ANTI-PUMP, TWO TRIPS WITHOUT AN OPEN LOCKS OUT TRIP
50: PCN01PV := 2.00 # A TWO COUNT COUNTER
51: PCN01R := IN103 # AN OPEN MOD RESETS COUNTER
52: PCN01IN := OUT103 # COUNTS ON THE RISING EDGE OF AN MOD TRIP
53: ###
54: ### SET COUNTER 2
55: ### MOD CLOSE ANTI-PUMP, TWO CLOSES WITHOUT A CLOSE LOCKS OUT CLOSE
56: PCN02PV := 2.00 # A TWO COUNT COUNTER
57: PCN02R := NOT IN103 # A CLOSED MOD RESETS THE COUNTER
58: PCN02IN := OUT106 # COUNTS ON THE RISING EDGE OF AN MOD CLOSE
59: ###
60: ### SET CONDITIONING TIMER 1
61: ### SUPERVISES BK1 RECLOSING, ASSERTS IF MOD IS CLOSED AND IN SYNC. OR
62: ### MOD LATCH SET AND MOD OPEN AND BK1 BUS HOT FOR FOUR SECONDS
63: PCT01PU := 240.00 # FOUR SECOND PICKUP TIME
64: PCT01DO := 0.0 # NO DELAY ON DROPOUT
65: PCT01IN := NOT IN103 AND 25A1BK1 OR PLT01 AND IN103 AND 59VS1
66: ###
67: ### SET CONDITIONING TIMER 2
68: ### SUPERVISES BK2 RECLOSING, ASSERTS IF MOD IS CLOSED AND IN SYNC. AND BK1
69: ### CLOSED OR MOD LATCH SET AND MOD OPEN AND BK2 BUS HOT AND BK1 CLOSED
70: ### FOR FOUR SECONDS
71: PCT02PU := 240.00 # FOUR SECOND PICKUP TIME
72: PCT02DO := 0.0 # NO DELAY ON DROPOUT
73: PCT02IN := NOT IN103 AND 25A1BK2 AND NOT IN101 OR PLT01 AND IN103 AND \
    59VS2 AND NOT IN101

```

Figure 5.4 Protection Free-Form SELogic Control Equations

Control Inputs

Connect the relay control inputs as specified in [Table 5.5](#). This table shows the substation equipment that each control input monitors.

Table 5.5 Control Inputs

Input	Monitor Condition
IN101	115 kV BK1T 52 b contact
IN102	115 kV BK2T 52 b contact
IN103	230 kV MOD b contact
IN104	Circuit breaker and autotransformer failure lockouts (86)

Control Outputs

Table 5.6 Control Outputs (SELogic Control Equations)

Setting	Function	Entry
Main Board		
OUT101	Trip BK1T	TRIP
OUT102	Trip BK2T	TRIP
OUT103	Trip MOD	PST01ET > 120.00 AND NOT PCN01Q
OUT104	Close BK1T	BK1CL
OUT105	Close BK2T	BK2CL
OUT106	Close MOD	PST04ET > 300.00 AND NOT PCN02Q
OUT107	General alarm	NOT HALARM OR NOT SALARM OR NOT ILOP
MIRRORED BITS Transmit Equations (SELogic Control Equations)		
TMB1A	Blocking signal	M3P OR Z3G OR DSTRT
TMB2A	Zone 1 direct underreaching transfer trip	M1P OR Z1G
TMB3A	Direct transfer trip: 86BF or 86T and MOD closed	NOT IN103 AND IN104
TMB1B	Blocking signal	M3P OR Z3G OR DSTRT
TMB2B	Zone 1 direct underreaching transfer trip	M1P OR Z1G
TMB3B	Direct transfer trip: 86BF or 86T and MOD closed	NOT IN103 AND IN104

[Figure 5.5](#) and [Figure 5.6](#) are logical representations of the free-form protection SELOGIC control equations.

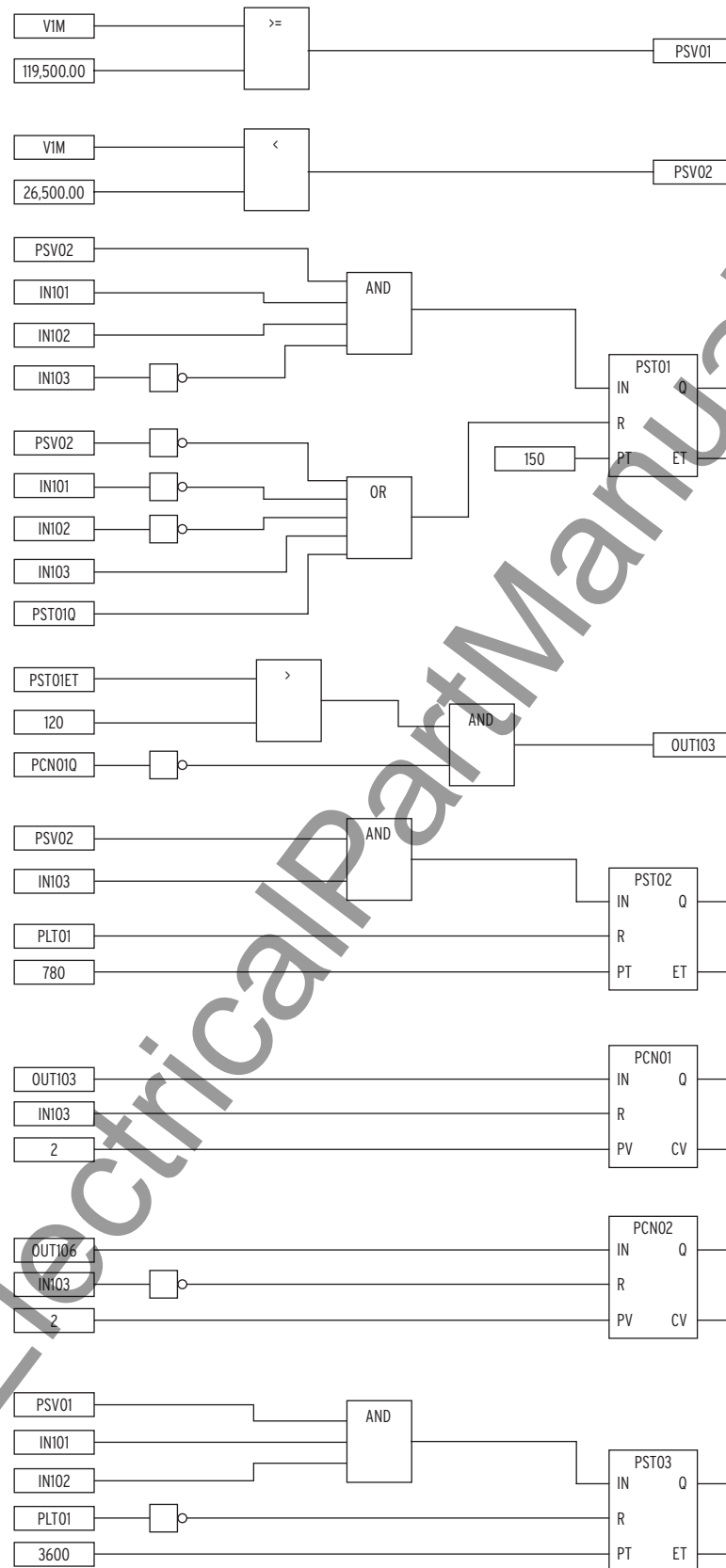


Figure 5.5 Protection Free-Form SELLogic Control Equations

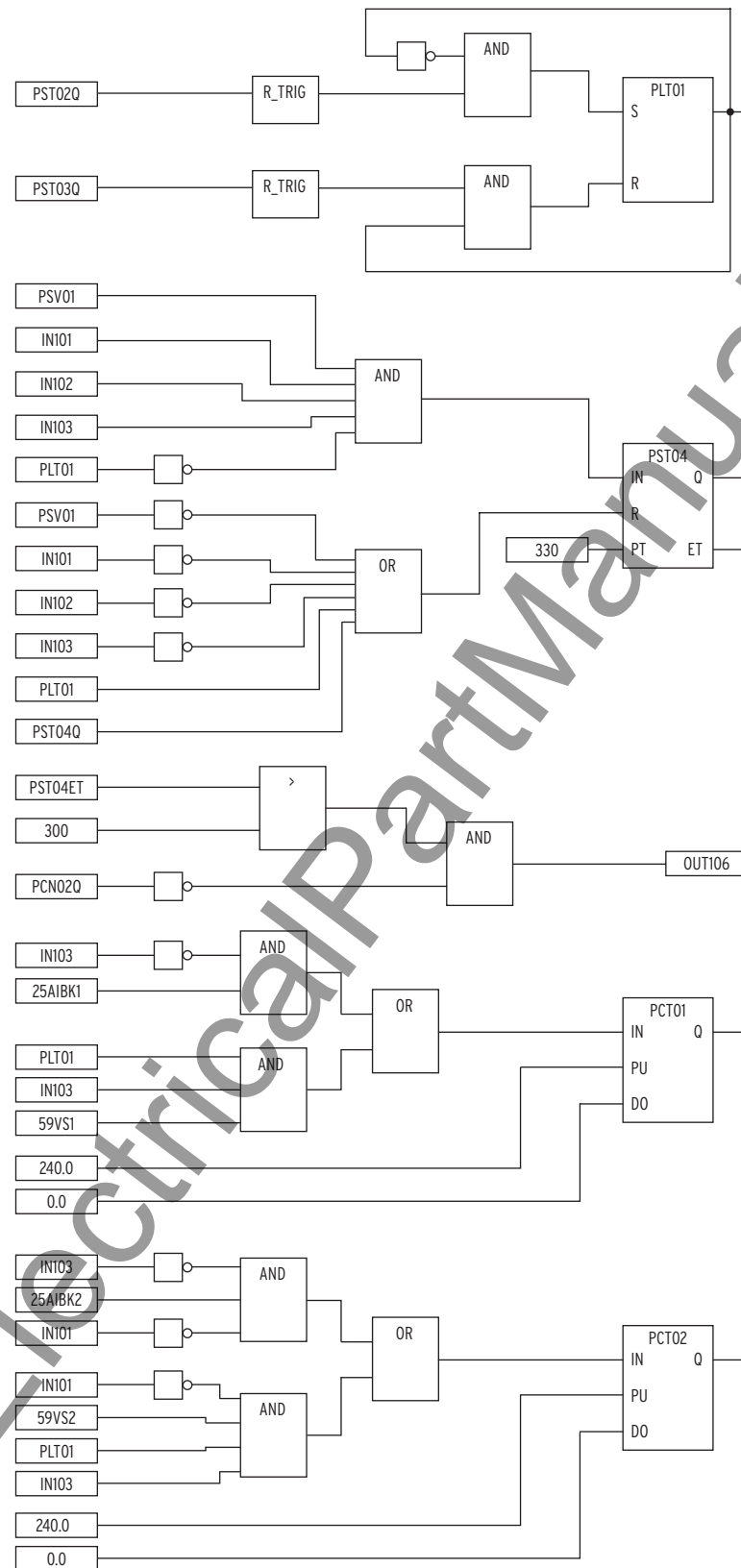


Figure 5.5 Protection Free-Form SLogic Control Equations (continued)

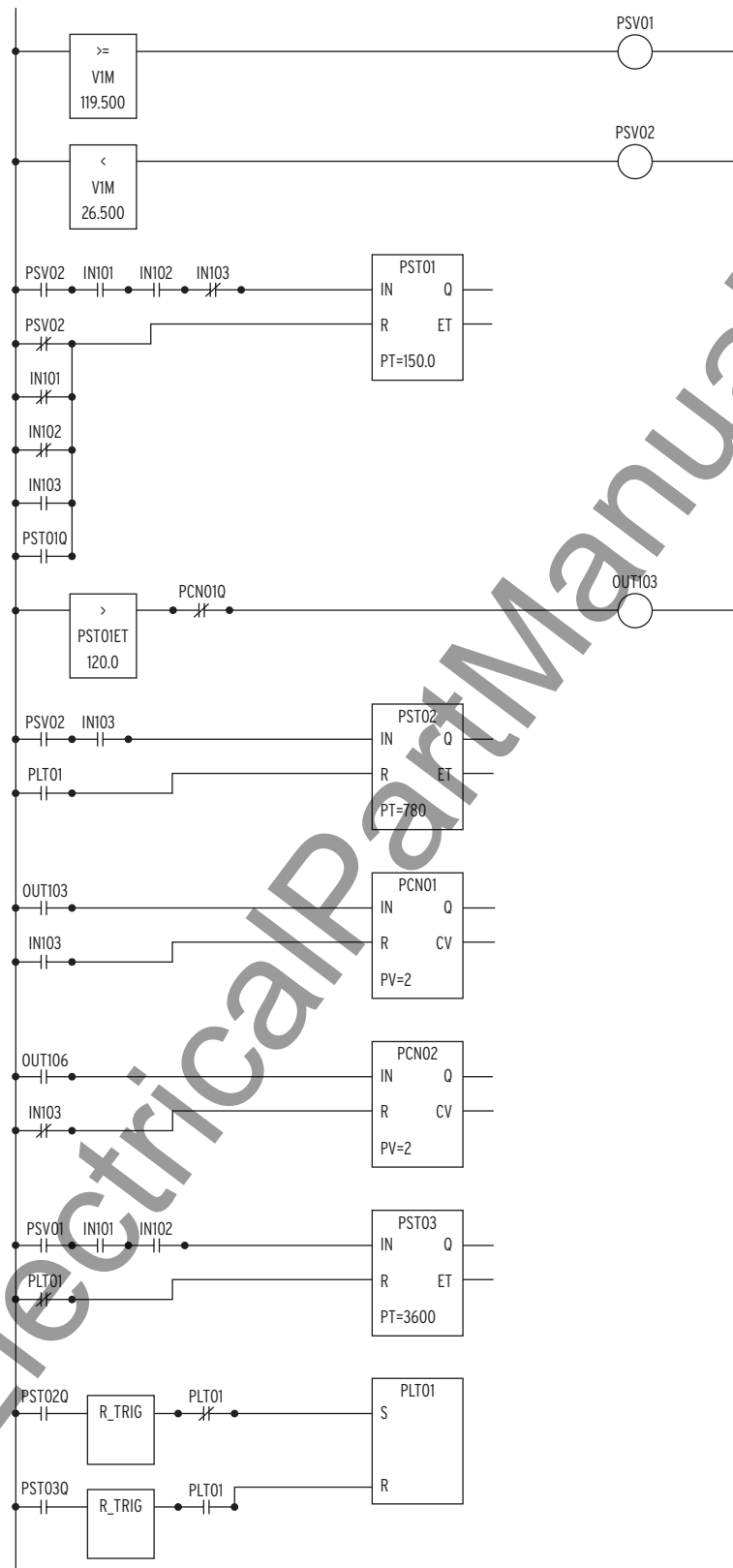


Figure 5.6 Ladder Logic Representation, Protection Free-Form SELlogic Control Equations

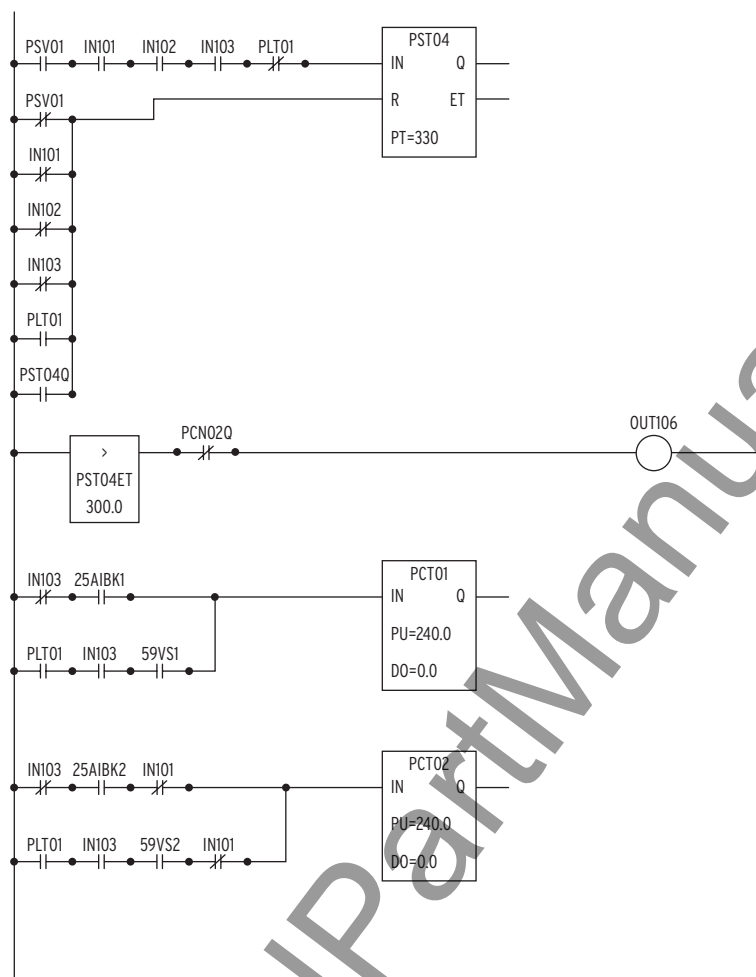


Figure 5.6 Ladder Logic Representation, Protection Free-Form SEL logic Control Equations (continued)

Section 6

SEL Communications Processor Applications

This section describes applications where the SEL-421 Relay is applied in a system integration architecture that includes SEL Communications Processors, the SEL-2032, SEL-2030, and SEL-2020. This section addresses the following topics:

- [*SEL Communications Processors on page A.6.2*](#)
- [*SEL Communications Processor and Relay Architecture on page A.6.4*](#)
- [*SEL Communications Processor Example on page A.6.6*](#)

For detailed application examples using the SEL-2032, SEL-2030, and SEL-2020 Communications Processors, see the SEL library of Application Guides on our website at www.selinc.com.

SEL Communications Processors

NOTE: The IRIG-B time signal available from SEL communications processors is not suitable for high-accuracy IRIG (HIRIG) timekeeping mode, which is required for synchrophasor functions. See [Configuring High-Accuracy Timekeeping on page U.4.77](#) for details.

SEL offers Communications Processors, the SEL-2032, SEL-2030, and SEL-2020, powerful tools for system integration and automation. These devices provide a single point of contact for integration networks with a star topology as shown in [Figure 6.1](#).

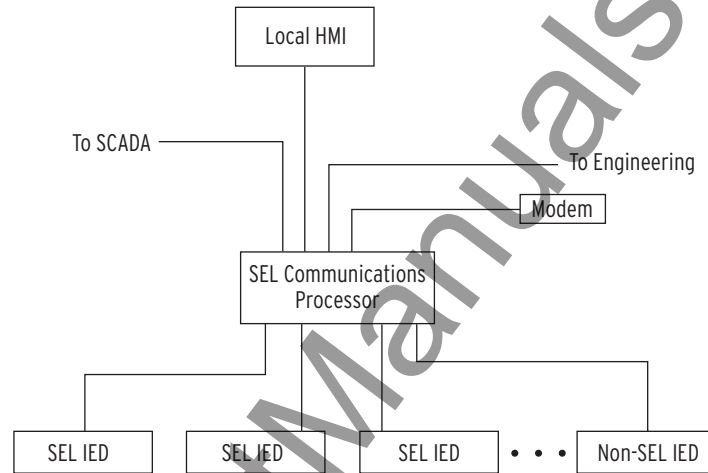


Figure 6.1 SEL Communications Processor Star Integration Network

In the star topology network in [Figure 6.1](#) the SEL Communications Processor offers the following substation integration functions:

- Collection of real-time data from SEL and non-SEL IEDs
- Calculation, concentration, and aggregation of real-time IED data into databases for SCADA, HMI, and other data consumers
- Access to the IEDs for engineering functions including configuration, report data retrieval, and control through local serial, remote dial-in, and Ethernet network connections
- Simultaneous collection of SCADA data and engineering connection to SEL IEDs over a single cable
- Distribution of IRIG-B time synchronization signal to IEDs based on external IRIG-B input, internal clock, or protocol interface
- Automated dial-out on alarms

The SEL Communications Processors have 16 serial ports plus a front port. This port configuration does not limit the size of a substation integration project, because you can create a multitiered solution as shown in [Figure 6.2](#). In this multitiered system, the lower-tier SEL Communications Processors forward data to the upper-tier SEL Communications Processor that serves as the central point of access to substation data and station IEDs.

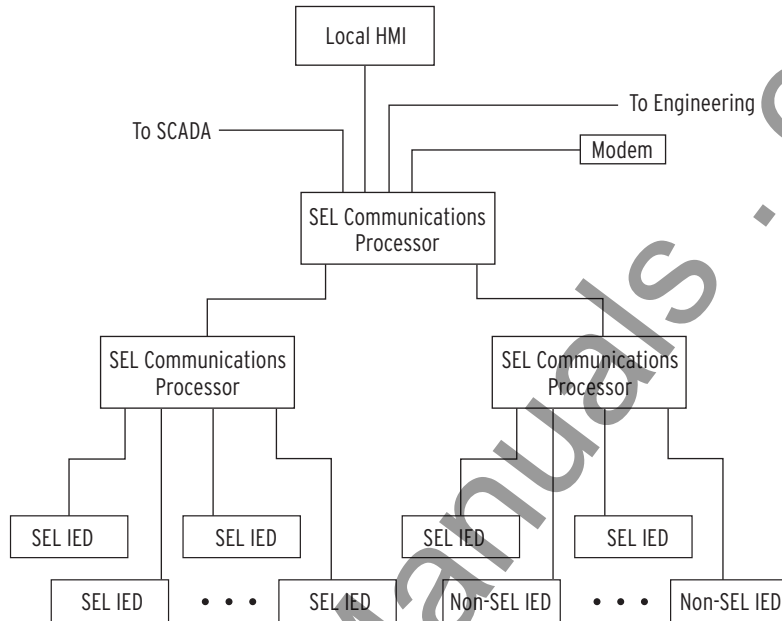


Figure 6.2 Multitiered SEL Communications Processor Architecture

You can add additional communications processors to provide redundancy and eliminate possible single points of failure. The SEL Communications Processors provide an integration solution with a reliability comparable to that of SEL relays. In terms of MTBF (mean time between failures), the SEL Communications Processors are 100 to 1000 times more reliable than computer-based and industrial technology-based solutions.

Configuration of an SEL communications processor is different from other general-purpose integration platforms. You can configure the SEL Communications Processors with a system of communication-specific keywords and data movement commands rather than programming in C or another general-purpose computer language. The SEL Communications Processors offer the protocol interfaces listed in [Table 6.1](#).

Table 6.1 SEL Communications Processors Protocol Interfaces

Protocol	Connect to
DNP3 Level 2 Slave	DNP3 masters (serial)
Modbus® RTU	Modbus masters
SEL ASCII/Fast Message Slave	SEL protocol masters
SEL ASCII/Fast Message Master	SEL protocol slaves including other communications processors and SEL relays
ASCII and Binary auto messaging	SEL and non-SEL IED master and slave devices
Modbus Plus ^a	Modbus Plus peers with global data and Modbus Plus masters
FTP (File Transfer Protocol) ^b	FTP clients
Telnet ^b	Telnet servers and clients
UCA2 GOMSFE ^b	UCA2 protocol masters
UCA2 GOOSE ^b	UCA2 protocol and peers
DNP3 Level 2 Slave (Ethernet) ^b	DNP3 masters (Ethernet)

^a Requires SEL-2711 Modbus Plus protocol card.

^b Requires Ethernet card.

SEL Communications Processor and Relay Architecture

Developing Star Networks

You can apply the SEL communications processors and SEL relays in a limitless variety of applications that integrate, automate, and improve station operation. Most of the system integration architectures using SEL communications processors involve either developing a star network or enhancing a multidrop network.

The simplest architecture using both the SEL-421 and an SEL communications processor is shown in [Figure 6.1](#). In this architecture, the SEL communications processor collects data from the SEL-421 and other station IEDs. The SEL communications processor acts as a single point of access for local and remote data consumers (local HMI, SCADA, engineers). The communications processor also provides a single point of access for engineering operations including configuration and the collection of report-based information.

By configuring a data set optimized to each data consumer, you can significantly increase the utilization efficiency on each link. A system that uses the SEL communications processors to provide a protocol interface to an RTU will have a shorter lag time (data latency); communication overhead is much less for a single data exchange conversation to collect all substation data (from a communications processor) than for many conversations required to collect data directly from each individual IED. You can further reduce data latency by connecting the SEL communications processor directly to the SCADA master and eliminating redundant communication processing in the RTU.

The SEL communications processor is responsible for the protocol interface, so you can install, test, and even upgrade the system in the future without disturbing protective relays and other station IEDs. This insulation of the protective devices from the communications interface assists greatly in situations where different departments are responsible for SCADA operation, communication, and protection.

NOTE: The communications processor Ethernet card supports components of UCA2 as a subset of IEC 61850.

You can equip SEL communications processors with an Ethernet card to provide a UCA2 interface to serial IEDs, including the standard SEL-421. The communications processor presents the SEL-421 data as models in a virtual device domain similar to the way they would appear if the SEL-421 was connected directly to the UCA2 network. The SEL communications processor and the Ethernet card offer a significant cost savings to customers who wish to continue using serial IEDs. For full details on applying the SEL communications processor with an optional Ethernet card, see the *SEL-2032* or *SEL-2030 Communications Processor Instruction Manual*.

The engineering connection can use either an Ethernet network connection through the communications processor Ethernet card or a serial port connection. This versatility will accommodate the channel that is available between the station and the engineering center. SEL software, including the ACSELERATOR® QuickSet™ SEL-5030 software program, can use either a serial port connection or an Ethernet network connection from an engineering workstation to the relays in the field.

Enhancing Multidrop Networks

You can also use the SEL communications processor to enhance a multidrop architecture similar to the one shown in [Figure 6.3](#). In this example, the SEL communications processor enhances a system that uses the SEL-2701 with an Ethernet HMI multidrop network. In the example, there are two Ethernet networks, the SCADA LAN and the Engineering LAN. The SCADA LAN provides real-time data directly to the SCADA Control Center via a protocol gateway and to the HMI (Human Machine Interface).

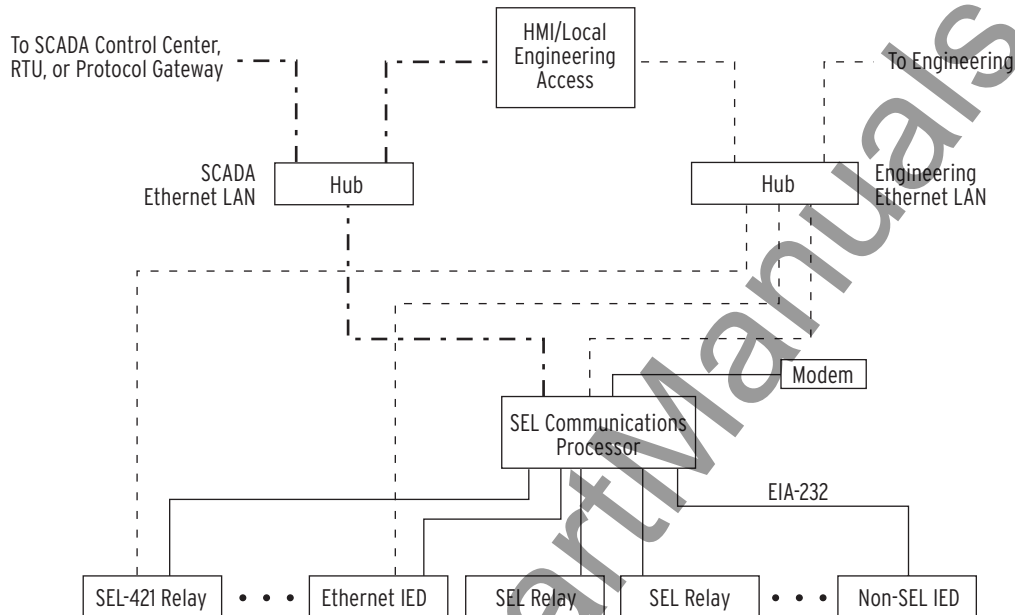


Figure 6.3 Enhancing Multidrop Networks With the SEL Communications Processors

In this example, the SEL communications processor provides the following enhancements when compared to a system that employs only the multidrop network:

- Ethernet access for IEDs with serial ports
- Backup engineering access through the dial-in modem
- IRIG-B time signal distribution to all station IEDs
- Integration of IEDs without Ethernet
- Single point of access for real-time data for SCADA, HMI, and other uses
- Significant cost savings by use of existing IEDs with serial ports

SEL Communications Processor Example

This example demonstrates the data and control points available in the SEL communications processor when you connect an SEL-421. The physical configuration used in this example is shown in [Figure 6.4](#).

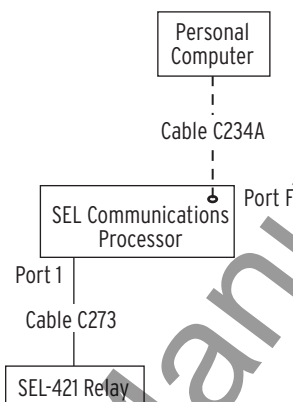


Figure 6.4 Example SEL Relay and SEL Communications Processors Configuration

[Table 6.2](#) shows the PORT 1 settings for the SEL communications processor.

Table 6.2 SEL Communications Processors Port 1 Settings

Setting Name	Setting	Description
DEVICE	S	Connected device is an SEL device
CONFIG	Y	Allow autoconfiguration for this device
PORTID	“Relay 1”	Name of connected relay ^a
BAUD	19200	Channel speed of 19200 bits per second ^a
DATABIT	8	Eight data bits ^a
STOPBIT	1	One stop bit
PARITY	N	No parity
RTS_CTS	Y	Hardware flow control enabled
TIMEOUT	5	Idle timeout that terminates transparent connections of 5 minutes

^a Automatically collected by the SEL communications processor during autoconfiguration.

Data Collection

Table 6.3 lists the automatic messages that are available in the SEL-421.

Table 6.3 SEL Communications Processor Data Collection Automessages

Message	Collection Mode	Data Collected
20METER	Binary	Power system metering data
20METER2	Binary	METER database region
20TARGET	Binary	Selected Relay Word bit elements
20TARGET2	Binary	TARGET database region
20DEMAND	Binary	Demand metering data
20DEMAND2	Binary	DEMAND database region
20STATUS	ASCII	Relay diagnostics
20STATUS2	Binary	STATUS database region
20HISTORY	ASCII	Relay event history
20HISTORY2	Binary	HISTORY database region
20BREAKER	ASCII	Circuit breaker monitor data
20BREAKER2	Binary	BREAKER database region
20EVENTL	ASCII	Long (16 samples/cycle) event report stored in a literal format (see the <i>SEL-2030 Instruction Manual</i>)
20LOCAL2	Binary	LOCAL database region
20ANALOGS2	Binary	ANALOGS database region
20D12	Binary	D1 270x DNP database region

Table 6.4 shows the automessage (Set A) settings for the SEL communications processor. In this example, the SEL communications processor is configured to collect metering and target data from the SEL-421 via the three automatic messages: 20TARGET, 20METER, and 20DEMAND.

Table 6.4 SEL Communications Processor Port 1 Automatic Messaging Settings (Sheet 1 of 2)

Setting Name	Setting	Description
AUTOBUF	Y	Save unsolicited messages
STARTUP	"ACC\nOTTER\n"	Automatically log-in at Access Level 1
SEND_OPER	Y	Send Fast Operate messages for remote bit and breaker bit control
REC_SER	N	Automatic sequential event recorder data collection disabled
NOCONN	NA	No SELOGIC control equation entered to selectively block connections to this port
MSG_CNT	3	Three automessages
ISSUE1	P00:00:01.0	Issue Message 1 every second
MESG1	20METER	Collect metering data
ISSUE2	P00:00:01.0	Issue Message 2 every second
MESG2	20TARGET	Collect Relay Word bit data
ISSUE3	P00:01:00.0	Issue Message 3 every minute
MESG3	20DEMAND	Collect demand metering data

Table 6.4 SEL Communications Processor Port 1 Automatic Messaging Settings (Sheet 2 of 2)

Setting Name	Setting	Description
ARCH_EN	N	Archive memory disabled
USER	0	No USER region registers reserved

Table 6.5 shows the map of regions in the SEL communications processor for data collected from the SEL-421 in the example.

Table 6.5 SEL Communications Processor Port 1 Region Map

Region	Data Collection Message Type	Region Name	Description
D1	Binary	METER	Relay metering data
D2	Binary	TARGET	Relay Word bit data
D3	Binary	DEMAND	Demand metering data
D4–D8	n/a	n/a	Unused
A1–A3	n/a	n/a	Unused
USER	n/a	n/a	Unused

Table 6.6 shows the list of meter data available in the SEL communications processor and the location and data type for the memory areas within D1 (Data Region 1). The type field indicates the data type and size. The type “int” is a 16-bit integer. The type “float” is a 32-bit IEEE floating point number.

NOTE: Communications processors using 20METER may misinterpret any analog quantities, AMV001 through AMV004, that contain a negative number. Use the math functions in your communications processor to handle these instances, or restrict AMV001 – AMV004 to positive values within the SEL-421 free-form automation logic.

The first four automation math variables (AMV001–AMV004) are reported to the communications processor as part of relay meter data. The communications processor treats these as vector quantities. Consequently, if one of these has a negative value, the communications processor will report the value as its magnitude (its absolute value) at an angle of 180 degrees.

See *Application Guide 2002-14: SEL-421 Relay Fast Messages* for more information on using the SEL Fast Meter and Fast Message protocols with the SEL-421.

Table 6.6 SEL Communications Processor METER Region Map (Sheet 1 of 2)

Item	Starting Address	Type
_YEAR	2000h	int
DAY_OF_YEAR	2001h	int
TIME(ms)	2002h	int[2]
MONTH	2004h	char
DATE	2005h	char
YEAR	2006h	char
HOUR	2007h	char
MIN	2008h	char
SECONDS	2009h	char
MSEC	200Ah	int
IA1	200Bh	float[2] ^a
IB1	200Fh	float[2] ^a
IC1	2013h	float[2] ^a

Table 6.6 SEL Communications Processor METER Region Map (Sheet 2 of 2)

Item	Starting Address	Type
IA2	2017h	float[2] ^a
IB2	201Bh	float[2] ^a
IC2	201Fh	float[2] ^a
IA3	2023h	float[2] ^a
IB3	2027h	float[2] ^a
IC3	202Bh	float[2] ^a
VA	202Fh	float[2] ^a
VB	2033h	float[2] ^a
VC	2037h	float[2] ^a
FREQ	203Bh	float[2] ^b
AMV001	203Fh	float[2] ^b
AMV002	2043h	float[2] ^b
AMV003	2047h	float[2] ^b
AMV004	204Bh	float[2] ^b
IAB(A)	204Fh	float[2] ^a
IBC(A)	2053h	float[2] ^a
ICA(A)	2057h	float[2] ^a
VAB(V)	205Bh	float[2] ^a
VBC(V)	205Fh	float[2] ^a
VCA(V)	2063h	float[2] ^a
PA(MW)	2067h	float
QA(MVAR)	2069h	float
PB(MW)	206Bh	float
QB(MVAR)	206Dh	float
PC(MW)	206Fh	float
QC(MVAR)	2071h	float
P(MW)	2073h	float
Q(MVAR)	2075h	float
I0(A)	2077h	float[2] ^a
I1(A)	207Bh	float[2] ^a
I2(A)	207Fh	float[2] ^a
V0(V)	2083h	float[2] ^a
V1(V)	2087h	float[2] ^a
V2(V)	208Bh	float[2] ^a

^a The first two addresses contain quantity; the second two addresses contain angle in degrees. Both values in IEEE 32-bit floating point format.

^b The first two addresses contain the quantity in IEEE 32-bit floating point format; the second two addresses always contain 0.

[Table 6.7](#) lists the Relay Word bit data available in the SEL communications processor for the memory area within D2 (Data Region 2).

Table 6.7 SEL Communications Processor TARGET Region (Sheet 1 of 3)

Address	Relay Word Bits (in Bits 7-0)							
	7	6	5	4	3	2	1	0
2804h	TEST	FMTEST	STSET	STCSET	STFAIL	STWARN	STRSET	STGSET
2805h	EN	TRIPLED	*	*	*	*	*	*
2806h	TLED_1	TLED_2	TLED_3	TLED_4	TLED_5	TLED_6	TLED_7	TLED_8
2807h	TLED_9	TLED_10	TLED_11	TLED_12	TLED_13	TLED_14	TLED_15	TLED_16
2808h	3POBK2	3POLINE	3PLSHT	BK1RS	BK2RS	79CY1	79CY3	BK1LO
2809h	BK2LO	BK1CL	BK2CL	LEADBK0	LEADBK1	LEADBK2	FOLBK0	FOLBK1
280Ah	B1OPHA	B1OPHB	B1OPHC	B2OPHA	B2OPHB	B2OPHC	LOPHA	LOPHB
280Bh	LOPHC	SPOA	SPOB	SPOC	SPO	3PO	27APO	27BPO
280Ch	27CPO	*	*	*	*	*	*	*
280Dh	52ACL1	52BCL1	52CCL1	52AAL1	52BAL1	52CAL1	52AA1	52AB1
280Eh	52AC1	*	52ACL2	52BCL2	52CCL2	52AAL2	52BAL2	52CAL2
280Fh	52AA2	52AB2	52AC2	*	*	*	*	*
2810h	*	*	*	*	*	*	*	*
2811h	*	*	*	*	*	*	*	*
2812h	*	*	*	*	*	*	*	*
2813h	*	*	*	*	*	*	*	*
2814h	BM1TRPA	BM1TRPB	BM1TRPC	BM1CLSA	BM1CLSB	BM1CLSC	B1BCWAL	B1MRTIN
2815h	*	B1MSOAL	B1ESOAL	B1PSAL	B1PDAL	B1BITAL	B1MRTAL	B1KAIAL
2816h	BM2TRPA	BM2TRPB	BM2TRPC	BM2CLSA	BM2CLSB	BM2CLSC	B2BCWAL	B2MRTIN
2817h	*	B2MSOAL	B2ESOAL	B2PSAL	B2PDAL	B2BITAL	B2MRTAL	B2KAIAL
2818h	RTD08ST	RTD07ST	RTD06ST	RTD05ST	RTD04ST	RTD03ST	RTD02ST	RTD01ST
2819h	RTDIN	RTDCOMF	RTDFL	*	RTD12ST	RTD11ST	RTD10ST	RTD09ST
281Ah	DC1F	DC1W	DC1G	DC1R	DC2F	DC2W	DC2G	DC2R
281Bh	PDEM	QDEM	GDEM	*	*	*	*	*
281Ch	RB25	RB26	RB27	RB28	RB29	RB30	RB31	RB32
281Dh	RB17	RB18	RB19	RB20	RB21	RB22	RB23	RB24
281Eh	RB09	RB10	RB11	RB12	RB13	RB14	RB15	RB16
281Fh	RB01	RB02	RB03	RB04	RB05	RB06	RB07	RB08
2820h	SG6	SG5	SG4	SG3	SG2	SG1	CHSG	*
2821h	*	IN107	IN106	IN105	IN104	IN103	IN102	IN101
2822h	IN208	IN207	IN206	IN205	IN204	IN203	IN202	IN201
2823h	IN216	IN215	IN214	IN213	IN212	IN211	IN210	IN209
2824h	IN224	IN223	IN222	IN221	IN220	IN219	IN218	IN217
2825h	IN308	IN307	IN306	IN305	IN304	IN303	IN302	IN301
2826h	IN316	IN315	IN314	IN313	IN312	IN311	IN310	IN309
2827h	IN324	IN323	IN322	IN321	IN320	IN319	IN318	IN317
2828h	PSV08	PSV07	PSV06	PSV05	PSV04	PSV03	PSV02	PSV01
2829h	PSV16	PSV15	PSV14	PSV13	PSV12	PSV11	PSV10	PSV09
282Ah	PSV24	PSV23	PSV22	PSV21	PSV20	PSV19	PSV18	PSV17
282Bh	PSV32	PSV31	PSV30	PSV29	PSV28	PSV27	PSV26	PSV25

Table 6.7 SEL Communications Processor TARGET Region (Sheet 2 of 3)

Address	Relay Word Bits (in Bits 7-0)							
	7	6	5	4	3	2	1	0
282Ch	PLT08	PLT07	PLT06	PLT05	PLT04	PLT03	PLT02	PLT01
282Dh	PLT16	PLT15	PLT14	PLT13	PLT12	PLT11	PLT10	PLT09
282Eh	PCT08Q	PCT07Q	PCT06Q	PCT05Q	PCT04Q	PCT03Q	PCT02Q	PCT01Q
282Fh	PCT16Q	PCT15Q	PCT14Q	PCT13Q	PCT12Q	PCT11Q	PCT10Q	PCT09Q
2830h	PST08Q	PST07Q	PST06Q	PST05Q	PST04Q	PST03Q	PST02Q	PST01Q
2831h	PST16Q	PST15Q	PST14Q	PST13Q	PST12Q	PST11Q	PST10Q	PST09Q
2832h	PCN08Q	PCN07Q	PCN06Q	PCN05Q	PCN04Q	PCN03Q	PCN02Q	PCN01Q
2833h	PCN16Q	PCN15Q	PCN14Q	PCN13Q	PCN12Q	PCN11Q	PCN10Q	PCN09Q
2834h	ASV008	ASV007	ASV006	ASV005	ASV004	ASV003	ASV002	ASV001
2835h	ASV016	ASV015	ASV014	ASV013	ASV012	ASV011	ASV010	ASV009
2836h	ASV024	ASV023	ASV022	ASV021	ASV020	ASV019	ASV018	ASV017
2837h	ASV032	ASV031	ASV030	ASV029	ASV028	ASV027	ASV026	ASV025
2838h	ALT08	ALT07	ALT06	ALT05	ALT04	ALT03	ALT02	ALT01
2839h	ALT16	ALT15	ALT14	ALT13	ALT12	ALT11	ALT10	ALT09
283Ah	AST08Q	AST07Q	AST06Q	AST05Q	AST04Q	AST03Q	AST02Q	AST01Q
283Bh	AST16Q	AST15Q	AST14Q	AST13Q	AST12Q	AST11Q	AST10Q	AST09Q
283Ch	ACN08Q	ACN07Q	ACN06Q	ACN05Q	ACN04Q	ACN03Q	ACN02Q	ACN01Q
283Dh	ACN16Q	ACN15Q	ACN14Q	ACN13Q	ACN12Q	ACN11Q	ACN10Q	ACN09Q
283Eh	PUNRLBL	PFRTEX	MATHERR	*	*	*	*	*
283Fh	AUNRLBL	AFRTEXP	AFRTEXA	*	*	*	*	*
2840h	SALARM	HALARM	BADPASS	CCALARM	*	*	*	*
2841h	*	*	*	*	*	*	*	*
2842h	*	*	*	*	*	*	*	*
2843h	*	*	TIRIG	TUPDH	TSYNCA	TSOK	PMDOK	FREQOK
2844h	OUT108	OUT107	OUT106	OUT105	OUT104	OUT103	OUT102	OUT101
2845h	OUT208	OUT207	OUT206	OUT205	OUT204	OUT203	OUT202	OUT201
2846h	*	OUT215	OUT214	OUT213	OUT212	OUT211	OUT210	OUT209
2847h	OUT308	OUT307	OUT306	OUT305	OUT304	OUT303	OUT302	OUT301
2848h	*	OUT315	OUT314	OUT313	OUT312	OUT311	OUT310	OUT309
2849h	PB1_LED	PB2_LED	PB3_LED	PB4_LED	PB5_LED	PB6_LED	PB7_LED	PB8_LED
284Ah	RMB8A	RMB7A	RMB6A	RMB5A	RMB4A	RMB3A	RMB2A	RMB1A
284Bh	TMB8A	TMB7A	TMB6A	TMB5A	TMB4A	TMB3A	TMB2A	TMB1A
284Ch	RMB8B	RMB7B	RMB6B	RMB5B	RMB4B	RMB3B	RMB2B	RMB1B
284Dh	TMB8B	TMB7B	TMB6B	TMB5B	TMB4B	TMB3B	TMB2B	TMB1B
284Eh	ROKA	RBADA	CBADA	LBOKA	ANOKA	DOKA	*	*
284Fh	ROKB	RBADB	CBADB	LBOKB	ANOKB	DOKB	*	*
2850h	TESTDNP	TESTDB	TESTFM	TESTPUL	*	*	*	*
2851h	CCIN25	CCIN26	CCIN27	CCIN28	CCIN29	CCIN30	CCIN31	CCIN32
2852h	CCIN17	CCIN18	CCIN19	CCIN20	CCIN21	CCIN22	CCIN23	CCIN24
2853h	CCIN09	CCIN10	CCIN11	CCIN12	CCIN13	CCIN14	CCIN15	CCIN16

Table 6.7 SEL Communications Processor TARGET Region (Sheet 3 of 3)

Address	Relay Word Bits (in Bits 7-0)							
	7	6	5	4	3	2	1	0
2854h	CCIN01	CCIN02	CCIN03	CCIN04	CCIN05	CCIN06	CCIN07	CCIN08
2855h	CCOUT25	CCOUT26	CCOUT27	CCOUT28	CCOUT29	CCOUT30	CCOUT31	CCOUT32
2856h	CCOUT17	CCOUT18	CCOUT19	CCOUT20	CCOUT21	CCOUT22	CCOUT23	CCOUT24
2857h	CCOUT09	CCOUT10	CCOUT11	CCOUT12	CCOUT13	CCOUT14	CCOUT15	CCOUT16
2858h	CCOUT01	CCOUT02	CCOUT03	CCOUT04	CCOUT05	CCOUT06	CCOUT07	CCOUT08
2859h	CCSTA01	CCSTA02	CCSTA03	CCSTA04	CCSTA05	CCSTA06	CCSTA07	CCSTA08
285Ah	CCSTA09	CCSTA10	CCSTA11	CCSTA12	CCSTA13	CCSTA14	CCSTA15	CCSTA16
285Bh	CCSTA17	CCSTA18	CCSTA19	CCSTA20	CCSTA21	CCSTA22	CCSTA23	CCSTA24
285Ch	CCSTA25	CCSTA26	CCSTA27	CCSTA28	CCSTA29	CCSTA30	CCSTA31	CCSTA32
285Dh	FSERP1	FSERP2	FSERP3	FSERP4	*	*	*	*
285Eh	ALTI	ALTV	ALTS2	DELAY	*	*	*	*
285Fh	TLED_17	TLED_18	TLED_19	TLED_20	TLED_21	TLED_22	TLED_23	TLED_24
2860h	PB9_LED	PB10LED	PB11LED	PB12LED	*	*	*	*

Control Points

The SEL communications processor can automatically pass control messages, called Fast Operate messages, to the SEL-421. You must enable Fast Operate messages using the FASTOP setting in the SEL-421 port settings for the port connected to the communications processor. You must also enable Fast Operate messages in the SEL communications processor by setting the automessage setting SEND_OPER equal to Y.

When you enable Fast Operate functions, the SEL communications processor automatically sends messages to the relay for changes in remote bits RB1–RB16 or breaker bits BR1 and BR2 on the corresponding communications processor port. In this example, if you set RB1 on Port 1 in the SEL communications processor, it automatically sets RB01 in the SEL-421.

Breaker bits BR1 and BR2 operate differently than remote bits. There are no breaker bits in the SEL-421. For Circuit Breaker 1, when you set BR1, the SEL communications processor sends a message to the SEL-421 that asserts the manual open command bit OC1 for one processing interval. If you clear BR1, the SEL communications processor sends a message to the SEL-421 that asserts the close command bit CC1 for one processing interval. If you are using the default settings, OC1 will open the circuit breaker and CC1 will close the circuit breaker. You can control and condition the effect of OC1 and CC1 by changing the manual trip and close settings (BK1MTR, BK2MTR, BK1MCL, BK2MCL) in the SEL-421. Operation for Circuit Breaker 2 with BR2, OC2, and CC2 is similar.

Section 7

Direct Network Communication

This section describes applications in which the SEL-421 Relay connects directly to a communications network via an Ethernet card or a serial port connection. This section includes the following topics:

- [Direct Network Communication on page A.7.2](#)
- [Serial Networking on page A.7.3](#)
- [Ethernet Card on page A.7.5](#)
- [Direct Networking Example on page A.7.8](#)

Direct Network Communication

You can establish direct network communication with the SEL-421 either by serial port or through an optional protocol card. The protocols available on the serial ports are DNP3 and the SEL suite of ASCII and binary protocols. The protocol card presently available for the SEL-421 is an Ethernet card with FTP, Telnet, DNP3, IEC 61850, and synchrophasor protocols. This is a factory-installed option available at the time of purchase of a new SEL-421 or as a factory-installed conversion to an existing relay.

The SEL-421 includes a protocol card slot. This slot supports an SEL standard interface for network protocol cards. Communication between the SEL-421 and an installed protocol card is automatic; you do not need any configuration or driver software. You can access any configuration settings you need for protocol parameters or network operation through the SEL-421. Each protocol card contains a processor responsible for network interface operation.

Unlike a protocol card installed in a computer, a protocol card installed in the SEL-421 is responsible for all network message and protocol processing. This means that network traffic volumes and network failures do not affect protection processing.

Because SEL relays have more than one port, you can establish direct networking and a communications processor star network simultaneously. Combine an SEL-2032 or SEL-2030 Communications Processor with a direct networking application to add the following system capabilities:

- Distribution of IRIG-B time synchronization signal
- Single point of access for IEDs through an Ethernet network or serial connection
- Nonvolatile logging of data collected from several IEDs
- Single point for central substation database access
- Single point of access for Fast SER (Sequential Events Recorder) data

Please see [Section 6: SEL Communications Processor Applications](#) for more information regarding use of the SEL-2032, SEL-2030, or SEL-2020 Communications Processor with the SEL-421.

NOTE: The IRIG-B time signal available from SEL communications processors is not suitable for high-accuracy IRIG (HIRIG) timekeeping mode, which is required for synchrophasor functions. See [Configuring High-Accuracy Timekeeping on page U.4.77](#) for details.

Serial Networking

The protocols available on the SEL-421 serial ports are either SEL protocols or standard protocols. While the standard protocols offer connectivity without a specific SEL support in other integration products, the SEL protocols offer features not included in standard protocols. These features provide additional capabilities that can significantly enhance your application.

SEL Protocols

SEL protocols are described in detail in [Section 5: SEL Communications Protocols in the Reference Manual](#). SEL protocols include Fast Meter, Fast Operate, Fast SER, MIRRORING BITS® communications, and SEL ASCII.

DNP3

DNP3 is a protocol that provides an interface for retrieving SCADA data. The DNP User's Group is responsible for maintaining and distributing the DNP3 specifications.

This section describes the serial networking features of DNP3. The DNP3 Ethernet interface is discussed briefly in [Ethernet Card on page A.7.5](#).

NOTE: In order to use DNP3 features, including virtual terminal connections, your DNP3 master device must support the required standard DNP3 objects and operations.

The DNP3 settings and operation are described in [Section 6: DNP3 Communications in the Reference Manual](#). The DNP3 interface has the capabilities summarized in [Table 7.1](#).

Table 7.1 DNP3 Serial Feature Summary

Feature	Application
DNP event data reporting	More efficient polling through event collection or unsolicited data
Time tagged events	Time-stamped SER data
Control output relay blocks	Operator-initiated control through remote bits
Write analog setpoint	Change the active protection settings group
Time synchronization	Set the relay time from the master station or automatically request time synchronization from the master
Custom mapping	Increase communication efficiency by organizing data and reducing available data to what you need for your application
Modem support	Reduce the cost of the communications channel by either master dialing to relay or relay dialing to master
Virtual terminal	Establish an engineering connection across a DNP3 network
TEST DNP command	Test DNP3 interface without disturbing protection

You can build a DNP3 network using either a multidrop or star topology. Each DNP3 network has a DNP3 master and DNP3 remotes or slaves. [Figure 7.1](#) shows the DNP3 multidrop network topology while [Figure 7.2](#) shows the DNP3 star network topology.

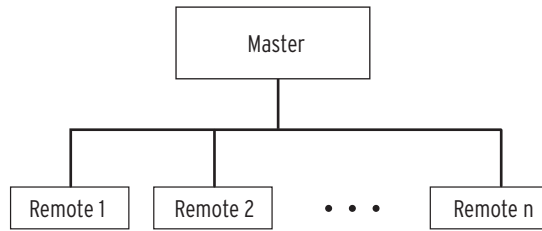


Figure 7.1 DNP3 Multidrop Network Topology

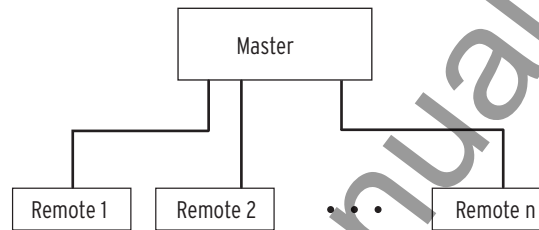


Figure 7.2 DNP3 Star Network Topology

DNP3 multidrop networks that are used within substations often use an EIA-485 physical layer. The multidrop network is vulnerable to the failure of a single transmitter. If any one transmitter fails in a state that disrupts signals on the network, the network will fail. The DNP3 star network topology eliminates the network transmitters and other single points of failure related to the physical medium.

If you are planning either a DNP3 star or network topology, you should consider the benefits of including an SEL communications processor in your design. A network with a communications processor is shown in [Figure 7.3](#). A DNP3 network that includes a communications processor has a lower data latency and shorter scan time than comparable networks through two primary mechanisms. First, the communications processor collects data from all remotes in parallel rather than one-by-one. Second, the master can collect all data with one message and response, drastically reducing message overhead.

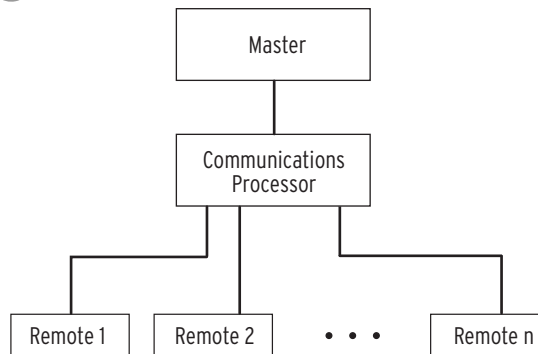


Figure 7.3 DNP3 Network with Communications Processor

In the communications processor DNP3 network you can also collect data from devices that do not have DNP3 protocol. The communications processor can collect data and present it to the master as DNP3 data regardless of the protocol between the communications processor and the remote device.

Ethernet Card

The SEL-421 Ethernet card is an optional protocol card that you can purchase as a factory-installed option. In order to exchange data over this interface, you must choose a data exchange protocol that operates over the Ethernet network link. The Ethernet card supports Telnet, DNP3, FTP, and IEC 61850 data exchange protocols.

You should carefully design your Ethernet network to maximize reliability, minimize system administration effort, and provide adequate security. Work with a networking professional to design your substation Ethernet network.

Ethernet

The SEL-421 Ethernet card provides Ethernet networking support with the popular physical and data-link standards listed in [Table 7.2](#).

Table 7.2 Ethernet Connection Options

Name	Connector	Media
10BASE-T/100BASE-TX selectable	RJ-45	CAT 5 (Category 5 twisted pair) cable
10BASE-F	Standard ST	Multimode fiber-optic cable
100BASE-FX	Standard ST	Multimode fiber-optic cable

FTP

Use FTP (File Transfer Protocol) to access data stored in files in the SEL-421. FTP is a standard TCP/IP protocol for exchanging files. A free FTP application is included with most web browser software. You can also obtain a free or inexpensive FTP application from the Internet.

When you connect to the SEL-421 Ethernet card, you will find files stored in directories. At the root or top level, you will find three directories, one for the Ethernet card and two for the SEL-421. One SEL-421 directory contains snapshots of data regions within the SEL-421 database. The other SEL-421 directory contains the files and subdirectories included in the virtual file interface described in [Section 5: SEL Communications Protocols in the Reference Manual](#).

Files associated with the Ethernet card are in the SEL-2702 directory. This directory contains the file DIAGNOSTICS.TXT, which contains a log of Ethernet card system failures. The time and date of the diagnostics file correspond to the time and date of the last system failure event. The SEL-2702 directory may also contain custom mapping files for the DNP3 LAN/WAN protocol.

If the IEC 61850 protocol is installed and enabled, the following files will be found in the root directory:

- CID (Configured IED Description) file—contains the IEC 61850 SCL configuration for the SEL-421
- ERR.TXT file—contains any errors encountered during the CID file download
- CFG.XML file—contains the Ethernet card and SEL-421 configuration information

Telnet

Use Telnet to connect to the SEL-421 ASCII interface and work with the relay. Telnet is a terminal connection across a TCP/IP network that operates in a manner very similar to a direct serial port connection to one of the relay ports. As with FTP, Telnet is a part of TCP/IP. A free Telnet application is included with most computer operating systems, or you can obtain low-cost or free Telnet applications on the Internet.

When you connect with Telnet and log-in to the relay, you can use all of the ASCII and Compressed ASCII commands described in [Section 9: ASCII Command Reference in the Reference Manual](#) to configure and interact with the relay. You can also use the SEL binary Fast Meter and Fast Operate commands described in [Section 5: SEL Communications Protocols in the Reference Manual](#).

IEC 61850

The IEC 61850 standard is a superset of UCA2 and contains most of the UCA2 specification plus additional functionality. The standard describes client/server and peer-to-peer communications, substation design and configuration, testing, and project standards.

UCA2 utilized GOMSFE to present data from station IEDs as a series of objects called models or bricks. The IEC working group incorporated GOMSFE concepts into the standard, with some modifications to terminology; one change was the renaming of bricks to logical nodes. Each logical node represents a group of data (controls, status, measurements, etc.) associated with a particular function. For example, the MMXU logical node (polyphase measurement unit) contains measurement data and other points associated with three-phase metering including voltages and currents. Each IED may contain many functions such as protection, metering, and control. Multiple logical nodes represent the functions in multifunction devices.

The GOOSE object within IEC 61850 is for high-speed control messaging. IEC 61850 GOOSE objects can quickly and conveniently transfer status, controls, and measured values between peers on an IEC 61850 network.

MMS provides services for the application-layer transfer of real-time data within a substation LAN. MMS was developed as a network independent data exchange protocol for industrial networks in the 1980s and standardized as ISO 9506. MMS supports complex named objects and flexible services that enable the mapping to IEC 61850 in a straightforward manner. It was for this reason that the UCA users group utilized MMS for UCA from the start, and why the IEC chose to keep it for IEC 61850.

See [Section 8: IEC 61850 Communications in the Reference Manual](#) for important information regarding IEC 61850.

DNP3

Installation of the Ethernet card in an SEL-421 relay provides a high performance DNP3 Level 2 slave network interface designed for operation in a substation environment.

The DNP3 Ethernet interface has the capabilities summarized in [Table 7.3](#).

Table 7.3 Ethernet DNP3 Feature Summary (Sheet 1 of 2)

Feature	Key Features
DNP3 Event data reporting	More efficient polling through event collection or unsolicited data
Time tagged events	Time-stamped SER data directly from the SEL-421, not an intermediate device

Table 7.3 Ethernet DNP3 Feature Summary (Sheet 2 of 2)

Feature	Key Features
Control output relay blocks	Operator-initiated control through remote bits
Custom mapping	Increase communication efficiency by organizing and/or reducing available data to what is needed with 5 custom data maps for up to 10 different sessions
Analog deadband settings per session	Deadbands may be set to different values per session depending on desired application

Customized DNP3 data within the SEL-421 relay is available to any of ten DNP3 master sessions configured in the Ethernet card. Configuration and implementation of DNP3 over the Ethernet interface is entirely independent of any serial DNP3 settings that might exist in the SEL-421.

See [Section 6: DNP3 Communications](#) in the *Reference Manual* for information on configuring and using DNP LAN/WAN for the SEL-421.

SEL Software

The SEL-421 configuration software, ACSELERATOR® QuickSet™ SEL-5030 Software, can connect to, configure, and control an SEL-421 with an Ethernet card. You can use ACSELERATOR QuickSet software to choose a connection type and provide the required information for a network connection. With this capability, you can configure and control SEL-421 relays from a local substation LAN (Local Area Network) or from an engineering workstation across a WAN (Wide Area Network). The ACSELERATOR QuickSet® Architect™ SEL-5032 Software will be included with your purchase of the IEC 61850 option. The ACSELERATOR QuickSet Architect software enables protection and integration engineers to design and commission IEC 61850 substations containing SEL IEDs.

Other SEL software includes Ethernet network connection capabilities, so you can use an Ethernet network for engineering connections to SEL protection and integration products. Check the documentation of your specific software for more information on Ethernet network connection capabilities.

Direct Networking Example

This direct networking example demonstrates direct networking to the SEL-421 using the Ethernet card. [Figure 7.4](#) shows the Ethernet network topology.

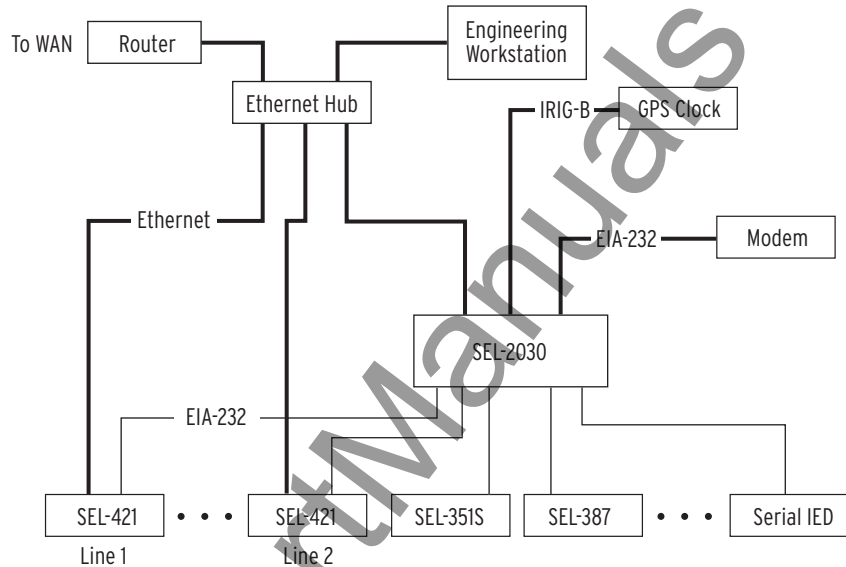


Figure 7.4 Example Direct Networking Topology

Application

In this application, all IEDs connect to the Ethernet network. The SEL-421 relays and the SEL-2030 each have an Ethernet card installed. In this example, the Ethernet network is used primarily for an engineering connection to the devices in the substation either across the WAN or from the local computer. The engineer can use FTP to collect settings, oscillography, and other file data directly from the SEL-421 relays. The engineer can also use Telnet to establish a terminal connection to the SEL-421 relays or through the SEL-2030 to one of the serial IEDs in order to configure these devices or obtain diagnostic information.

NOTE: The IRIG-B time signal available from SEL communications processors is not suitable for high-accuracy IRIG (HIRIG) timekeeping mode, which is required for synchrophasor functions. See [Configuring High-Accuracy Timekeeping on page U.4.77](#) for details.

There is a serial cable from the SEL-2030 to the SEL-421 relays. This cable provides IRIG-B time synchronization from the SEL-2030 that is synchronized by the GPS clock attached to the SEL-2030. The SEL-2030 provides its output synchronization signal from its internal clock, so that loss of the signal from the GPS will not result in a loss of synchronization between substation devices as they will all be synchronized to the SEL-2030 clock. During long periods of loss of synchronization, the SEL-2030 clock drift will become noticeable, but all substation devices will remain synchronized relative to each other and the SEL-2030 clock. The serial cables also allow the SEL-2030 to provide a single point for dial-in communications with the substation IEDs avoiding the high cost of high bandwidth connections (for example, ISDN or DSL) for this backup to the Ethernet network engineering connection.

Settings

This example focuses on the relay labeled Line 1 shown in [Figure 7.4](#). **PORT 5** settings for the SEL-421 configure the Ethernet card. **PORT 5** settings for this example are shown in [Table 7.4](#).

Table 7.4 SEL-421 PORT 5 Direct Networking Settings (Sheet 1 of 2)

Setting Name	Setting	Description
TIMEOUT	5	Port inactivity time-out in minutes (drops to Access Level 0 on Telnet connections when this expires)
AUTO	N	Automessage disabled because engineering connection will not require unsolicited messages from SEL-2030
FASTOP	N	Fast Operate messages disabled because they are not required on engineering connection
TERTIM1	1	Length of time the channel must be idle before checking for the termination string in seconds
TERSTRN	\005	Transparent communication termination string default of CTRL + E
TERTIM2	0	Length of time the channel must be idle before accepting the termination string in seconds
IPADDR	10.201.0.112	IP network address
SUBNETM	255.255.0.0	IP network subnet mask
DEFRTR	10.201.0.1	Default router
ETCPKA	N	Disable TCP keep-alive functionality (IEC 61850 only)
KAIDLE	10	Length of time to wait with no detected activity before sending a keep-alive packet (must be greater than or equal to KAINTV)
KAINTV	1	Length of time to wait between sending keep-alive packets after receiving no response for the prior keep-alive packet (must be less than or equal to KAIDLE)
KACNT	6	Maximum number of keep-alive packets to send
NETPORT	A	Primary network port selected to Port A
FAILOVR	N	Automatic fail-over disabled, forcing network operation on Port A only
FTIME	5	Fail over time-out; not used in this application
NETASPD	A	Automatically detect network speed on Port A
NETBSPD	A	Automatically detect network speed on Port B; not used in this application
FTPSERV	Y	FTP sessions enabled
FTPCBAN	FTP SERVER:	FTP connect banner
FTPIDLE	5	FTP connection time-out in minutes
FTPANMS	N	Anonymous log-in disabled so that passwords are required for all FTP users
FTPAUSR	""	Host user from which anonymous FTP client inherits access rights; not used in this application
T1CBAN	HOST TERMINAL SERVER:	Host Telnet connect banner
T1INIT	N	Telnet session from Ethernet card enable; not used in this application
T1RECV	Y	Telnet session to SEL-421 enable
T1PNUM	23	Host Telnet TCP/IP port

Table 7.4 SEL-421 PORT 5 Direct Networking Settings (Sheet 2 of 2)

Setting Name	Setting	Description
T2CBAN	CARD TERMINAL SERVER:	Ethernet card Telnet connect banner
T2RECV	Y	Telnet session to Ethernet card enable
T2PNUM	1024	Ethernet card Telnet TCP/IP port
TIDLE	5	Telnet connection time-out in minutes

FTP Session

Figure 7.6 is a screen capture of an FTP session with the relay. The FTP client used for this example is included with the Windows NT® operating system and accessible through a command prompt window. The operator connects to the relay, moves to the SETTINGS directory, and collects the **PORT 5** settings. *Figure 7.7* shows a portion of the **PORT 5** settings in the SET_P5.TXT file.

Telnet Session

This section contains screen captures of a Telnet session with the Line 1 SEL-421. The Telnet application shown is included with the Windows NT operating system. *Figure 7.5* shows the log-in dialog box and the entries required to connect to the SEL-421.

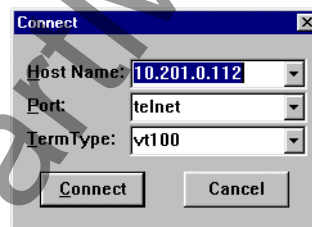


Figure 7.5 Telnet Connection Dialog Box

Figure 7.8 is a screen capture of a Telnet session with the relay. The operator connects to the relay, and displays the **PORT 5** settings. Only a portion of the **PORT 5** settings are shown.

```
C:\>ftp 10.201.0.112 <Enter>

Connected to 10.201.0.112.
220 SEL-2701 FTP SERVER:

User (10.201.0.112:(none)): 2AC
331 User name okay, need password.
Password:
230 User logged in, proceed.

ftp> ls <Enter>
200 PORT Command okay.
150 File status okay; about to open data connection.
SEL-421
SEL-2701
DD01_SEL-421
CFG.TXT
226 Closing data connection.
42 bytes received in 0.00 seconds (42000.00 Kbytes/sec)

ftp> cd SEL-421 <Enter>
250 CWD requested file action okay, completed.

ftp> ls <Enter>
200 PORT Command okay.
150 File status okay; about to open data connection.
CFG.TXT
EVENTS
REPORTS
SETTINGS
226 Closing data connection.
36 bytes received in 0.08 seconds (0.45 Kbytes/sec)

ftp> cd SETTINGS <Enter>
250 CWD requested file action okay, completed.

ftp> ls <Enter>
200 PORT Command okay.
150 File status okay; about to open data connection.
ERR.TXT
SET_A1.TXT
SET_A10.TXT
SET_A2.TXT
SET_A3.TXT
SET_A4.TXT
SET_A5.TXT
SET_A6.TXT
SET_A7.TXT
SET_A8.TXT
SET_A9.TXT
SET_ALL.TXT
SET_D1.TXT
SET_F1.TXT
SET_G1.TXT
SET_L1.TXT
SET_L2.TXT
SET_L3.TXT
SET_L4.TXT
SET_L5.TXT
SET_L6.TXT
SET_O1.TXT
SET_P1.TXT
SET_P2.TXT
SET_P3.TXT
SET_P5.TXT
SET_PF.TXT
SET_R1.TXT
SET_S1.TXT
SET_S2.TXT
SET_S3.TXT
SET_S4.TXT
SET_S5.TXT
SET_S6.TXT
SET_SM.TXT
226 Closing data connection.
419 bytes received in 0.73 seconds (0.57 Kbytes/sec)

ftp> get SET_P5.TXT <Enter>
200 PORT Command okay.
150 File status okay; about to open data connection.
226 Closing data connection.
2392 bytes received in 1.58 seconds (1.51 Kbytes/sec)

ftp> user entry <Enter>
221 Goodbye.
C:\>
```

Figure 7.6 Example FTP Session

```
[INFO]
RELAYTYPE=SEL
FID=SEL-421-X045-V0-Z001001-D20010106
BFID=SLBT-CFS-X000
PARTNO=SEL-400H1234
[IOBOARDS]
[COMCARDS]
, SEL-2701-X061-V0-Z000000-D20010117, SLBT-2701-X021-V0-Z000000-D20010109, 1
[P5]
"TIMEOUT",5
"AUTO",Y
"FASTOP",N
"TERTIM1",1
"TERSTRN","\005"
"TERTIM2",0
"IPADDR","10.201.0.112"
"SUBNETM","255.255.0.0"
"DEFRTR","10.201.0.1"
"NETPORT","A"
"FAILOVR","N"
"FTIME",5
"NETASPD","A"
"NETBSPD","A"
"FTPSERV","Y"
"FTPCBAN","FTP SERVER:"
"FTPIDLE",5
"FTPANMS","N"
"FTPUSR","ACC"
"T1CBAN","HOST TERMINAL SERVER:"
"T1INIT","N"
"T1RECV","Y"
"T1PNUM",23
"T2CBAN","CARD TERMINAL SERVER:"
"T2RECV","Y"
"T2PNUM",1024
"TIDLE",5
```

Remaining settings not shown

Figure 7.7 Partial Contents of SET_P5.TXT

```

HOST TERMINAL SERVER:

Relay 1                               Date: 01/19/2001  Time: 15:35:57.644
Station A                             Serial Number: 00000000

->ACC <Enter>

Password: ?*****

Relay 1                               Date: 01/19/2001  Time: 15:36:12.856
Station A                             Serial Number: 00000000

Level 1

->2AC <Enter>

Password: ?****

Relay 1                               Date: 01/19/2001  Time: 15:36:16.887
Station A                             Serial Number: 00000000

Level 2

->>>SHO P 5 <Enter>

Port 5

SEL Protocol Settings

TIMEOUT := 5          AUTO := N          FASTOP := N          TERTIM1 := 1
TERSTRN := "\005"
TERTIM2 := 0

Protocol Card Settings

IPADDR := "10.201.0.112"
SUBNETM := "255.255.0.0"
DEFRTR := "10.201.0.1"
NETPORT := "A"
FAILOVR := "N"
FTIME := 5
NETASPD := "A"
NETBSPD := "A"
FTPSERV := "Y"
FTPCBAN := "FTP SERVER:"
FTPIDLE := 5
FTPANMS := "N"
FTPAUSR := ""
T1CBAN := "HOST TERMINAL SERVER:"
T1INIT := "N"
T1RECV := "Y"
T1PNUM := 23
T2CBAN := "CARD TERMINAL SERVER:"
T2RECV := "Y"
T2PNUM := 1024      TIDLE := 5
Settings HOST1-CTRLB64 Not Shown

->>>QUI <Enter>

Host connection terminated, terminating Network connection.

```

Figure 7.8 Example Telnet Session

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Glossary

“a” Contact	A breaker auxiliary contact (ANSI Standard Device Number 52A) that closes when the breaker is closed and opens when the breaker is open.
“a” Output	A relay control output that closes when the output relay asserts.
“b” Contact	A breaker auxiliary contact (ANSI Standard Device Number 52B) that opens when the breaker is closed and closes when the breaker is open.
“b” Output	A relay control output that opens when the output relay asserts.
“c” Contact	A breaker auxiliary contact that can be set to serve either as an “a” contact or as a “b” contact.
“c” Output	An output with both an “a” output and “b” output sharing a common post.
3U, 4U, 5U	The designation of the vertical height of a device in rack units. One rack unit, U, is approximately 1.75 inches or 44.45 mm.
A	Abbreviation for amps or amperes; unit of electrical current flow.
ABS Operator	An operator in math SELOGIC [®] control equations that provides absolute value.
AC Ripple	The peak-to-peak ac component of a signal or waveform. In the station dc battery system, monitoring ac ripple provides an indication of whether the substation battery charger has failed.
Acceptance Testing	Testing that confirms that the relay meets published critical performance specifications and requirements of the intended application. Such testing involves testing protection elements and logic functions when qualifying a relay model for use on the utility system.
Access Level	A relay command level with a specified set of relay information and commands. Except for Access Level 0, you must have the correct password to enter an access level.
Access Level 0	The least secure and most limited access level. No password protects this level. From this level, you must enter a password to go to a higher level.
Access Level 1	A relay command level you use to monitor (view) relay information. The default access level for the relay front panel.
Access Level 2	The most secure access level where you have total relay functionality and control of all settings types.
Access Level A	A relay command level you use to access all Access Level 1 and Access Level B (Breaker) functions plus Automation, Alias, Global, Front Panel, Report, Port, and DNP settings.
Access Level B	A relay command level you use for Access Level 1 functions plus circuit breaker control and data.

Access Level O	A relay command level you use to access all Access Level 1 and Access Level B (Breaker) functions plus Output, Alias, Global, Front Panel, Report, Port, and DNP settings.																												
Access Level P	A relay command level you use to access all Access Level 1 and Access Level B (Breaker) functions plus Protection, SELOGIC, Alias, Global, Group, Breaker Monitor, Front Panel, Report, Port, and DNP settings.																												
ACSELERATOR[®] Architect[™]	ACSELERATOR Architect is an add-on to the ACSELERATOR Suite that utilizes the IEC 61850 Substation Configuration Language to configure SEL IEDs.																												
ACSELERATOR[®] QuickSet[™]	ACSELERATOR QuickSet SEL-5030 software program: A Windows [®] -based program that simplifies settings and provides analysis support.																												
ACSI	Abstract Communications Service Interface for the IEC 61850 protocol. Defines a set of objects, a set of services to manipulate and access those objects, and a base set of data types for describing objects.																												
Active Settings Group	The settings group that the SEL-421 is presently using from among six settings groups available in the relay.																												
Admittance	The reciprocal of impedance; I/V .																												
Advanced Settings	Settings for customizing protection functions; these settings are hidden unless you set EADVS := Y and EGADVS := Y.																												
Analog Quantities	Variables represented by such fluctuating measurable quantities as temperature, frequency, current, and voltage.																												
AND Operator	Logical AND. An operator in Boolean SELOGIC control equations that requires fulfillment of conditions on both sides of the operator before the equation is true.																												
ANSI Standard Device Numbers	<p>A list of standard numbers used to represent electrical protection and control relays. The standard device numbers used in this instruction manual include the following:</p> <table> <tr><td>21</td><td>Distance element</td></tr> <tr><td>25</td><td>Synchronism-check element</td></tr> <tr><td>27</td><td>Undervoltage Element</td></tr> <tr><td>32</td><td>Directional Elements</td></tr> <tr><td>50</td><td>Overcurrent Element</td></tr> <tr><td>51</td><td>Inverse-Time Overcurrent Element</td></tr> <tr><td>52</td><td>AC Circuit Breaker</td></tr> <tr><td>59</td><td>Overvoltage Element</td></tr> <tr><td>67</td><td>Definite Time Overcurrent</td></tr> <tr><td>79</td><td>Recloser</td></tr> <tr><td>86</td><td>Breaker Failure Lockout</td></tr> <tr><td>89</td><td>Disconnect</td></tr> </table> <p>These numbers are frequently used within a suffix letter to further designate their application. The suffix letters used in this instruction manual include the following:</p> <table> <tr><td>P</td><td>Phase Element</td></tr> <tr><td>G</td><td>Residual/Ground Element</td></tr> </table>	21	Distance element	25	Synchronism-check element	27	Undervoltage Element	32	Directional Elements	50	Overcurrent Element	51	Inverse-Time Overcurrent Element	52	AC Circuit Breaker	59	Overvoltage Element	67	Definite Time Overcurrent	79	Recloser	86	Breaker Failure Lockout	89	Disconnect	P	Phase Element	G	Residual/Ground Element
21	Distance element																												
25	Synchronism-check element																												
27	Undervoltage Element																												
32	Directional Elements																												
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52	AC Circuit Breaker																												
59	Overvoltage Element																												
67	Definite Time Overcurrent																												
79	Recloser																												
86	Breaker Failure Lockout																												
89	Disconnect																												
P	Phase Element																												
G	Residual/Ground Element																												

- N Neutral/Ground Element
- Q Negative-Sequence (3I2) Element

Anti-Aliasing Filter	A low pass filter that blocks frequencies too high for the given sampling rate to accurately reproduce.
Apparent Power, S	Complex power expressed in units of volt-amps (VA), kilovolt-amps (kVA), or megavolt-amps (MVA). Accounts for both real (P) and reactive (Q) power dissipated in a circuit: $S = P + jQ$. This is power at the fundamental frequency only; no harmonics are included in this quantity.
Arcing Resistance	The resistance in the arc resulting from a power line fault.
ASCII	Abbreviation for American Standard Code for Information Interchange. Defines a standard set of text characters. The SEL-421 uses ASCII text characters to communicate using front-panel and rear-panel EIA-232 serial ports on the relay and through virtual serial ports.
ASCII Terminal	A terminal without built-in logic or local processing capability that can only send and receive information.
Assert	To activate. To fulfill the logic or electrical requirements needed to operate a device. To set a logic condition to the true state (logical 1) of that condition. To apply a closed contact to an SEL-421 input. To close a normally open output contact. To open a normally closed output contact.
AT Modem Command Set Dialing String Standard	The command language standard that Hayes Microcomputer Products, Inc. developed to control auto-dial modems from an ASCII terminal (usually EIA-232 connected) or a PC (personal computer) containing software allowing emulation of such a terminal.
Autoconfiguration	The ability to determine relay type, model number, metering capability, port ID, baud rate, passwords, relay elements, and other information that an IED (an SEL-2020/2030 communications processor) needs to automatically communicate with relays.
Automatic Messages	Messages including status failure and status warning messages that the relay generates at the serial ports and displays automatically on the front-panel LCD.
Automatic Reclose	Automatic closing of a circuit breaker after a breaker trip by a protective relay.
Automation Variables	Variables that you include in automation SELOGIC control equations.
Auto-Reclose-Drive-to-Lockout	A logical condition that drives the auto-reclose function out of service with respect to a specific circuit breaker.
Autotransformer	A transformer with at least two common windings.
AX-S4 MMS	“Access for MMS” is an IEC 61850, UCA2, and MMS client application produced by SISCO, Inc., for real-time data integration in Microsoft Windows-based systems supporting OPC and DDE. Included with AX-S4 MMS is the interactive MMS Object Explorer for browser-like access to IEC 61850 / UCA2 and MMS device objects.
Bandpass Filter	A filter that passes frequencies within a certain range and blocks all frequencies outside this range.

Best Choice Ground Directional Supervision™ logic	An SEL logic that determines the directional element that the relay uses for ground faults.
Bit Label	The identifier for a particular bit.
Bit Value	Logical 0 or logical 1.
Block Trip Extension	Continuing the blocking signal at the receiving relay by delaying the dropout of Relay Word bit BT.
Blocking Signal Extension	The blocking signal for the DCB (directional comparison blocking) trip scheme is extended by a time delay on dropout timer to prevent unwanted tripping following current reversals.
Bolted Fault	A fault with essentially zero impedance or resistance between the shorted conductors.
Boolean Logic Statements	Statements consisting of variables that behave according to Boolean logic operators such as AND, NOT, and OR.
Breaker Auxiliary Contact	An electrical contact associated with a circuit breaker that opens or closes to indicate the breaker position. A form-a breaker auxiliary contact (ANSI Standard Device Number 52A) closes when the breaker is closed and opens when the breaker is open. A form-b breaker auxiliary contact (ANSI Standard Device Number 52B) opens when the breaker is closed and closes when the breaker is open.
Breaker-and-a-half Configuration	A switching station arrangement of three circuit breakers per two circuits; the two circuits share one of the circuit breakers.
Buffered Report	IEC 61850 IEDs can issue buffered reports of internal events (caused by trigger options data-change, quality-change, and data-update). These event reports can be sent immediately or buffered (to some practical limit) for transmission, such that values of data are not lost due to transport flow control constraints or loss of connection. Buffered reporting provides sequence-of-events (SOE) functionality.
C37.118	IEEE C37.118, Standard for Synchrophasors for Power Systems
Category	A collection of similar relay settings.
CCVT	Coupling-capacitor voltage transformer that uses a capacitive voltage divider to reduce transmission voltage to a level safe for metering and relaying devices. See CVT.
Checksum	A method for checking the accuracy of data transmission involving summation of a group of digits and comparison of this sum to a previously calculated value.
CID	Checksum identification of the firmware.
CID File	IEC 61850 Configured IED Description file. XML file that contains the configuration for a specific IED.
Circuit Breaker Failure Logic	This logic within the SEL-421 detects and warns of failure or incomplete operation of a circuit breaker in clearing a fault or in performing a trip or close sequence.

Circuit Breaker History Report	A concise circuit breaker event history that contains as many as 128 events. This breaker history report includes circuit breaker mechanical operation times, electrical operation times, interrupted currents, and dc battery monitor voltages.
Circuit Breaker Report	A full report of breaker parameters for the most recent operation. These parameters include interrupted currents, number of operations, and mechanical and electrical operating times among many parameters.
Class	The first level of the relay settings structure including Global, Group, Breaker Monitor, Port, Report, Front Panel, DNP settings, Protection SELOGIC control equations, Automation SELOGIC control equations, and Output SELOGIC control equations.
Cold Start	Beginning a system from power up without carryover of previous system activities.
Commissioning Testing	Testing that serves to validate all system ac and dc connections and confirm that the relay, auxiliary equipment, and SCADA interface all function as intended with your settings. Perform such testing when installing a new protection system.
Common Class Components	Composite data objects that contain instances of UCA standard data types.
Common Data Class	IEC 61850 grouping of data objects that model substation functions. Common Data Classes include Status information, Measured information, Controllable status, Controllable analog, Status settings, Analog settings, and Description information.
Common Inputs	Relay control inputs that share a common terminal.
Common Time Delay	Both ground and phase distance protection follow a common time delay on pickup.
Common Zone Timing	Both ground and phase distance protection follow a common time delay on pickup.
Communications Protocol	A language for communication between devices.
Communications-Assisted Tripping	Circuit breaker tripping resulting from the transmission of a control signal over a communications medium.
Comparison	Boolean SELOGIC control equation operation that compares two numerical values. Compares floating-point values such as currents, total counts, and other measured and calculated quantities.
COMTRADE	Abbreviation for Common Format for Transient Data Exchange. The SEL-421 supports the IEEE Standard Common Format for Transient Data Exchange (COMTRADE) for Power Systems, IEEE C37.111-1999.
Conditioning Timers	Timers for conditioning Boolean values. Conditioning timers either stretch incoming pulses or allow you to require that an input take a state for a certain period before reacting to the new state.
Contact Input	See Control input.
Contact Output	See Control output.

Coordination Timer	A timer that delays an overreaching element so that a downstream device has time to operate.
Control Input	Relay inputs for monitoring the state of external circuits. Connect auxiliary relay and circuit breaker contacts to the control inputs.
Control Output	Relay outputs that affect the state of other equipment. Connect control outputs to circuit breaker trip and close coils, breaker failure auxiliary relays, communications-assisted tripping circuits, and SCADA systems.
COS Operator	Operator in math SELOGIC control equations that provides the cosine function.
Counter	Variable or device such as a register or storage location that either records or represents the number of times an event occurs.
Cross-country fault	A cross-country fault consists of simultaneous separate single phase-to-ground faults on parallel lines.
CT	Current transformer.
CT Subsidence Current	Subsidence current appears as a small exponentially decaying dc current with a long time constant. This current results from the energy trapped in the CT magnetizing branch after the circuit breaker opens to clear a fault or interrupt load.
CTR	Current transformer ratio.
Current Reversal Guard Logic	Under this logic, the relay does not key the transmitter and ignores reception of a permissive signal from the remote terminal when a reverse-looking element detects an external fault.
Current Transformer Saturation	The point of maximum current input to a current transformer; any change of input beyond the saturation point fails to produce any appreciable change in output.
CVT	Capacitive voltage transformer that uses a capacitive voltage divider to reduce transmission voltage to a level safe for metering and relaying devices. See CCVT.
CVT Transient Blocking	Logic that prevents transient errors on capacitive voltage transformers from causing false operation of Zone 1 mho elements.
CVT Transient Detection Logic	Logic that detects transient errors on capacitive voltage transformers.
Data Attribute	In the IEC 61850 protocol, the name, format, range of possible values, and representation of values being communicated.
Data Bit	A single unit of information that can assume a value of either logical 0 or logical 1 and can convey control, address, information, or frame check sequence data.
Data Class	In the IEC 61850 protocol, an aggregation of classes or data attributes.
Data Label	The identifier for a particular data item.

Data Object	In the IEC 61850 protocol, part of a logical node representing specific information (status or measurement, for example). From an object-oriented point of view, a data object is an instance of a data class.
DC Offset	A dc component of fault current that results from the physical phenomenon preventing an instantaneous change of current in an inductive circuit.
DCB (Directional Comparison Blocking)	A communications-assisted protection scheme. A fault occurring behind a sending relay causes the sending relay to transmit a blocking signal to a remote relay; the blocking signal interrupts the tripping circuit of the remote relay and prevents tripping of the protected line.
DCE Devices	Data communication equipment devices (modems).
DCUB (Directional Comparison Unblocking)	A communications-assisted tripping scheme with logic added to a POTT scheme that allows high-speed tripping of overreaching elements for a brief time during a loss of channel. The logic then blocks trip permission until the communications channel guard returns for a set time.
Deadband	The range of variation an analog quantity can traverse before causing a response.
Deassert	To deactivate. To remove the logic or electrical requirements needed to operate a device. To clear a logic condition to its false state (logical 0). To open the circuit or open the contacts across an SEL-421 input. To open a normally open output contact. To close a normally closed output contact.
Debounce Time	The time that masks the period when relay contacts continue to move after closing; debounce time covers this indeterminate state.
Default Data Map	The default map of objects and indices that the SEL-421 uses in DNP protocol.
Delta	A phase-to-phase series connection of circuit elements, particularly voltage transformers or loads.
Demand Meter	A measuring function that calculates a rolling average or thermal average of instantaneous measurements over time.
Direct Tripping	Local or remote protection elements provide tripping without any additional supervision.
Directional Start	A blocking signal provided by reverse reaching elements to a remote terminal used in DCB communications-assisted tripping schemes. If the fault is internal (on the protected line), the directional start elements do not see the fault and do not send a blocking signal. If the fault is external (not on the protected line), the directional start elements start sending the block signal.
Directional Supervision	The relay uses directional elements to determine whether protective elements operate based on the direction of a fault relative to the relay.
Disabling Time Delay	A DCUB scheme timer (UBDURD) that prevents high-speed tripping following a loss-of-channel condition.
Distance Calculation Smoothness	A relay algorithm that determines whether the distance-to-fault calculation varies significantly or is constant.

Distance Protection Zone	The area of a power system where a fault or other application-specific abnormal condition should cause operation of a protective relay.
DMTC Period	The time of the demand meter time constant in demand metering.
DNP (Distributed Network Protocol)	Manufacturer-developed, hardware-independent communications protocol.
Dropout Time	The time measured from the removal of an input signal until the output signal deasserts. You can set the time, in the case of a logic variable timer, or the dropout time can be a result of the characteristics of an element algorithm, as in the case of an overcurrent element dropout time.
DTE Devices	Data terminal equipment (computers, terminals, printers, relays, etc.).
DTT (Direct Transfer Trip)	A communications-assisted tripping scheme. A relay at one end of a line sends a tripping signal to the relay at the opposite end of the line.
Dumb Terminal	See ASCII terminal.
DUTT (Direct Underreaching Transfer Trip)	A communications-assisted tripping scheme. Detection of a Zone 1 fault at either end of a line causes tripping of the local circuit breaker as well as simultaneous transmission of a tripping signal to the relay at the opposite end of the line. The scheme is said to be underreaching because the Zone 1 relays at both ends of the line reach only 80 percent (typically) of the entire line length.
Echo	The action of a local relay returning (echoing) the remote terminal permissive signal to the remote terminal when the local breaker is open or a weak infeed condition exists.
Echo Block Time Delay	A time delay that blocks the echo logic after dropout of local permissive elements.
Echo Duration Time Delay	A time delay that limits the duration of the echoed permissive signal.
ECTT (Echo Conversion to Trip)	An element that allows a weak terminal, after satisfaction of specific conditions, to trip by converting an echoed permissive signal to a trip signal.
EEPROM	Electrically Erasable Programmable Read-Only Memory. Nonvolatile memory where relay settings, event reports, SER records, and other nonvolatile data are stored.
EHV	Extra high voltage. Voltages greater than 230 kV.
EIA-232	Electrical definition for point-to-point serial data communications interfaces, based on the standard EIA/TIA-232. Formerly known as RS-232.
EIA-485	Electrical standard for multidrop serial data communications interfaces, based on the standard EIA/TIA-485. Formerly known as RS-485.
Electrical Operating Time	Time between trip or close initiation and an open phase status change.
Electromechanical Reset	Setting of the relay to match the reset characteristics of an electromechanical overcurrent relay.
End-Zone Fault	A fault at the farthest end of a zone that a relay is required to protect.

Energy Metering	Energy metering provides a look at imported power, exported power, and net usage over time; measured in MWh (megawatt hours).
Equalize Mode	A procedure where substation batteries are overcharged intentionally for a preselected time in order to bring all cells to a uniform output.
ESD (Electrostatic Discharge)	The sudden transfer of charge between objects at different potentials caused by direct contact or induced by an electrostatic field.
Ethernet	A network physical and data link layer defined by IEEE 802.2 and IEEE 802.3.
Event History	A quick look at recent relay activity that includes a standard report header; event number, date, time, and type; fault location; maximum fault phase current; active group at the trigger instant; and targets.
Event Report	A text-based collection of data stored by the relay in response to a triggering condition, such as a fault or ASCII TRI command. The data show relay measurements before and after the trigger, in addition to the states of protection elements, relay inputs, and relay outputs each processing interval. After an electrical system fault, use event reports to analyze relay and system performance.
Event Summary	<p>A shortened version of stored event reports. An event summary includes items such as event date and time, event type, fault location, time source, recloser shot counter, prefault and fault voltages, currents, and sequence current, and MİRRORED BITS® communications channel status (if enabled).</p> <p>The relay sends an event report summary (if auto messaging is enabled) to the relay serial port a few seconds after an event.</p>
EXP Operator	Math SELOGIC control equation operator that provides exponentiation.
F_TRIG	Falling-edge trigger. Boolean SELOGIC control equation operator that triggers an operation upon logic detection of a falling edge.
Fail-Safe	Refers to an output that is open during normal relay operation and closed when relay power is removed or if the relay fails. Configure alarm outputs for fail-safe operation.
Falling Edge	Transition from logical 1 to logical 0.
Fast Hybrid Control Output	A control output similar to, but faster than, the hybrid control output. The fast hybrid output uses an insulated gate bipolar junction transistor (IGBT) to interrupt (break) high inductive dc currents and to very rapidly make and hold the current until a metallic contact operates, at which time the IGBT turns off and the metallic contact holds the current. Unlike the hybrid control output, this output is not polarity sensitive; reversed polarity causes no misoperations.
Fast Meter	SEL binary serial port command used to collect metering data with SEL relays.
Fast Operate	SEL binary serial port command used to perform control with SEL relays.
Fast Message	SEL binary serial port protocol used for Fast SER, Fast Message Synchronphasors, and RTD communications.
Fault Type Identification Selection	Logic the relay uses to identify balanced and unbalanced faults (FIDS).

FID	Relay firmware identification string. Lists the relay model, firmware version and date code, and other information that uniquely identifies the firmware installed in a particular relay.
Firmware	The nonvolatile program stored in the relay that defines relay operation.
Flash Memory	A type of nonvolatile relay memory used for storing large blocks of nonvolatile data.
Flashover	A disruptive discharge over the surface of a solid dielectric in a gas or liquid.
Float High	The highest charging voltage supplied by a battery charger.
Float Low	The lowest charging voltage supplied by a battery charger.
Free-Form Logic	Custom logic creation and execution order.
Free-Form SELLOGIC Control Equations	Free-form relay programming that includes mathematical operations, custom logic execution order, extended relay customization, and automated operation.
FTP	File transfer protocol.
Function	<p>In IEC 61850, task(s) performed by the substation automation system, i.e., by application functions. Generally, functions exchange data with other functions. Details are dependent on the functions involved.</p> <p>Functions are performed by IEDs (physical devices). A function may be split into parts residing in different IEDs but communicating with each other (distributed function) and with parts of other functions. These communicating parts are called logical nodes.</p>
Function Code	A code that defines how you manipulate an object in DNP3 protocol.
Functional Component	Portion of a UCA GOMSFE brick dedicated to a particular function including status, control, and descriptive tags.
Fundamental Frequency	The component of the measured electrical signal with a frequency equal to the normal electrical system frequency, usually 50 Hz or 60 Hz. Generally used to differentiate between the normal system frequency and any harmonic frequencies present.
Global Settings	General settings including those for relay and station identifiers, number of breakers, date format, phase rotation, nominal system frequency, enables, station dc monitoring, control inputs, settings group selection, data reset controls, frequency tracking, time and date management, and current and voltage source selection.
GOMSFE	Generic Object Model for Substation and Feeder Equipment; a system for presenting and exchanging IED data.
GOOSE	IEC 61850 Generic Object Oriented Substation Event. GOOSE objects can quickly and conveniently transfer status, controls, and measured values among peers on an IEC 61850 network.
GPS	Global Positioning System. Source of position and high-accuracy time information.
Ground Directional Element Priority	The order the relay uses to select directional elements to provide ground directional decisions; relay setting ORDER.

Ground Distance Element	A mho or quadrilateral distance element the relay uses to detect faults involving ground along a transmission line.
Ground Fault Loop Impedance	The impedance in a fault-caused electric circuit connecting two or more points through ground conduction paths.
Ground Overcurrent Elements	Elements that operate by comparing a residual ground calculation of the three-phase inputs with the residual overcurrent threshold setting. The relay asserts ground overcurrent elements when a relay residual current calculation exceeds ground current setting thresholds.
Ground Quadrilateral Distance Protection	Ground distance protection consisting of a four-sided characteristic on an R-X diagram.
Ground Return Resistance	Fault resistance that can consist of ground path resistance typically in tower footing resistance and tree resistance.
Guard-Present Delay	A timer that determines the minimum time before the relay reinstates permissive tripping following a loss-of-channel condition in the DCUB communications-assisted tripping scheme; relay setting GARD1D.
GUI	Graphical user interface.
Hexadecimal Address	A register address consisting of a numeral with an “h” suffix or a “0x” prefix.
High-Resolution Data Capture	Reporting of 3 kHz low-pass analog filtered data from the power system at each event trigger or trip at high sample rates of 8000 samples/second, 4000 samples/second, 2000 samples/second, and 1000 samples/second.
HMI	Human machine interface.
Homogeneous System	A power system with nearly the same angle (<5 ° difference) for the impedance angles of the local source, the protected line, and the remote source.
HV	High voltage. System voltage greater than or equal to 100 kV and less than 230 kV.
Hybrid Control Output	Contacts that use an insulated gate bipolar junction transistor (IGBT) in parallel with a mechanical contact to interrupt (break) high inductive dc currents. The contacts can carry continuous current, while eliminating the need for heat sinking and providing security against voltage transients. These contacts are polarity dependent and cannot be used to switch ac control signals.
IA, IB, IC	Measured A-phase, B-phase, and C-phase currents.
ICD File	IEC 61850 IED Capability Description file. XML file that describes IED capabilities, including information on logical node and GOOSE support.
IEC 61850	Internationally standardized method of communications and integration conceived with the goal of supporting systems of multivendor IEDs networked together to perform protection, monitoring, automation, metering, and control.
IED	Intelligent electronic device.
IEEE	Institute of Electrical and Electronics Engineers, Inc.

IG	Residual current, calculated from the sum of the phase currents. In normal, balanced operation, this current is very small or zero.
IGBT	Insulated gate bipolar junction transistor.
Independent Zone Timing	The provision of separate zone timers for phase and ground distance elements.
Infinite Bus	A constant-voltage bus.
Input Conditioning	The establishment of debounce time and assertion level.
Instance	A subdivision of a relay settings class. Group settings have several subdivisions (Group 1–Group 6), while the Global settings class has one instance.
Instantaneous Meter	Type of meter data presented by the SEL-421 that includes the present values measured at the relay ac inputs. The word “Instantaneous” is used to differentiate these values from the measurements presented by the demand, thermal, energy, and other meter types.
IP Address	An identifier for a computer or device on a TCP/IP network. Networks using the TCP/IP protocol route messages based on the IP address of the destination. The format of an IP address is a 32-bit numeric address written as four numbers separated by periods. Each number can be zero to 255. For example, 1.160.10.240 could be an IP address.
IRIG-B	A time code input that the relay can use to set the internal relay clock.
Jitter	Time, amplitude, frequency, or phase-related abrupt, spurious variations in duration, magnitude, or frequency.
L/R	Circuit inductive/resistive ratio.
Latch Bits	Nonvolatile storage locations for binary information.
LED	Light-emitting diode. Used as indicators on the relay front panel.
Left-Side Value	LVALUE. Result storage location of a SELOGIC control equation.
Line Impedance	The phasor sum of resistance and reactance in the form of positive-sequence, negative-sequence, and zero-sequence impedances of the protected line.
LMD	SEL distributed port switch protocol.
LN Operator	Math SELOGIC control equation operator that provides natural logarithm.
Load Encroachment	The load-encroachment feature allows setting of phase overcurrent elements and phase distance elements independent of load levels.
Local Bits	The Relay Word bit outputs of local control switches that you access through the SEL-421 front panel. Local control switches replace traditional panel-mounted control switches.
Lockout Relay	An auxiliary relay that prevents operation of associated devices until it is reset either electrically or by hand.
Logical 0	A false logic condition, dropped out element, or deasserted control input or control output.

Logical 1	A true logic condition, picked up element, or asserted control input or control output.
Logical Node	In IEC 61850, the smallest part of a function that exchanges data. A logical node (LN) is an object defined by its data and methods. Each logical node represents a group of data (controls, status, measurements, etc.) associated with a particular function.
Loss of Channel	Loss of guard and no permissive signal from communications gear in a DCUB (directional comparison unblocking scheme) for either two or three terminal lines.
Loss of Guard	No guard signal from communications gear.
Loss of Potential	Loss of one or more phase voltage inputs to the relay secondary inputs.
Low-Level Test Interface	An interface that provides a means for interrupting the connection between the relay input transformers and the input processing module and allows inserting reduced-scale test quantities for relay testing.
MAC Address	The Media Access Control (hardware) address of a device connected to a shared network medium, most often used with Ethernet networks.
Maintenance Testing	Testing that confirms that the relay is measuring ac quantities accurately and verifies correct functioning of auxiliary equipment, scheme logic, and protection elements.
Math Operations	Calculations for automation or extended protection functions.
Math Operators	Operators that you use in the construction of math SELOGIC control equations to manipulate numerical values and provide a numerical base-10 result.
Maximum Dropout Time	The maximum time interval following a change of input conditions between the deassertion of the input and the deassertion of the output.
Maximum/Minimum Meter	Type of meter data presented by the SEL-421 that includes a record of the maximum and minimum of each value, along with the date and time that each maximum and minimum occurred.
Mechanical Operating Time	Time between trip initiation or close initiation and the change in status of an associated circuit breaker auxiliary 52A normally open contacts.
Mho Characteristic	A directional distance relay characteristic that plots a circle for the basic relay operation characteristic on an R-X diagram.
MIRRORED BITS® Communications	Patented relay-to-relay communications technique that sends internal logic status, encoded in a digital message, from one relay to the other. Eliminates the need for some communications hardware.
MMS	Manufacturing Messaging Specification, a data exchange protocol used by UCA.
MOD	Motor-operated disconnect.
Model	Model of device (or component of a device) including the data, control access, and other features in UCA protocol.

Motor Running Time	The circuit breaker motor running time. Depending on your particular circuit breaker, you can use the motor running time to monitor the charge time of the circuit breaker springs or the running time of the compressor motor.
MOV	Metal-oxide varistor.
Negation Operator	A SELOGIC control equation math operator that changes the sign of the argument. The argument of the negation operation is multiplied by –1.
Negative-Sequence	A configuration of three-phase currents and voltages. The currents and voltages have equal magnitude and a phase displacement of 120°, and have clockwise phase rotation with current and voltage maxima that occur differently from that for positive-sequence configuration. If positive-sequence maxima occur as ABC, negative-sequence maxima occur as ACB.
Negative-Sequence Current Supervision Pickup	An element allowed to operate only when a negative-sequence current exceeds a threshold.
Negative-Sequence Directional Element	An element that provides directivity by the sign, plus or minus, of the measured negative-sequence impedance.
Negative-Sequence Impedance	Impedance of a device or circuit that results in current flow with a balanced negative-sequence set of voltage sources.
Negative-Sequence Overcurrent Elements	Elements that operate by comparing a negative-sequence calculation of the three-phase secondary inputs with negative-sequence overcurrent setting thresholds. The relay asserts these elements when a relay negative-sequence calculation exceeds negative-sequence current setting thresholds.
Negative-Sequence Voltage-Polarized Directional Element	These directional elements are 32QG and 32Q. 32QG supervises the ground distance elements and residual directional overcurrent elements; 32Q supervises the phase distance elements.
NEMA	National Electrical Manufacturers' Association.
Neutral Impedance	An impedance from neutral to ground on a device such as a generator or transformer.
No Current/Residual Current Circuit Breaker Failure Protection Logic	Logic for detecting and initiating circuit breaker failure protection with a logic transition, or when a weak source drives the fault or a high-resistance ground fault occurs.
Nondirectional Start	A blocking signal provided by nondirectional overcurrent elements to a remote terminal used in DCB communications-assisted tripping schemes. The nondirectional start elements start sending the block signal.
Nonhomogeneous System	A power system with a large angle difference (>5° difference) for the impedance angles of the local source, the protected line, and the remote source.
Nonvolatile Memory	Relay memory that persists over time to maintain the contained data even when the relay is deenergized.
NOT Operator	A logical operator that produces the inverse value.

OR Operator	Logical OR. A Boolean SELOGIC control equation operator that compares two Boolean values and yields either a logical 1 if either compared Boolean value is logical 1 or a logical 0 if both compared Boolean values are logical 0.
OSI	Open Systems Interconnect. A model for describing communications protocols. Also an ISO suite of protocols designed to this model.
Out-of-Step Blocking	Blocks the operation of phase distance elements during power swings.
Out-of-Step Tripping	Trips the circuit breaker(s) during power swings.
Override Values	Test values you enter in Fast Meter, DNP, and communications card database storage.
Parentheses Operator	Math operator. Use paired parentheses to control the execution of operations in a SELOGIC control equation.
PC	Personal computer.
Peak Demand Metering	Maximum demand and a time stamp for phase currents, negative-sequence and zero-sequence currents, and powers. The SEL-421 stores peak demand values and the date and time these occurred to nonvolatile storage once per day, overwriting the previously stored value if the new value is larger. Should the relay lose control power, the relay restores the peak demand information saved at 23:50 hours on the previous day.
Phase Distance Element	A mho distance element the relay uses to detect phase-to-phase and three-phase faults at a set reach along a transmission line.
Phase Overcurrent Element	Elements that operate by comparing the phase current applied to the secondary current inputs with the phase overcurrent setting. The relay asserts these elements when any combination of the phase currents exceeds phase current setting thresholds.
Phase Rotation	The sequence of voltage or current phasors in a multiphase electrical system. In an ABC phase rotation system, the B-phase voltage lags the A-phase voltage by 120°, and the C-phase voltage lags B-phase voltage by 120°. In an ACB phase rotation system, the C-phase voltage lags the A-phase voltage by 120°, and the B-phase voltage lags the C-phase voltage by 120°.
Phase Selection	Ability of the relay to determine the faulted phase or phases.
Pickup Time	The time measured from the application of an input signal until the output signal asserts. You can set the time, as in the case of a logic variable timer, or the pickup time can be a result of the characteristics of an element algorithm, as in the case of an overcurrent element pickup time.
Pinout	The definition or assignment of each electrical connection at an interface. Typically refers to a cable, connector, or jumper.
Polarizing Memory	A circuit that provides a polarizing source for a period after the polarizing quantity has changed or gone to zero.
Pole Discrepancy	A difference in the open/closed status of circuit breaker poles. The relay continuously monitors the status of each circuit breaker pole to detect open or close conditions among the three poles.

Pole-Open Logic	Logic that determines the conditions that the relay uses to indicate an open circuit breaker pole.
Pole Scatter	Deviation in operating time between pairs of circuit breaker poles.
Port Settings	Communications port settings such as Data Bits, Speed, and Stop Bits.
Positive-Sequence	A configuration of three-phase currents and voltages. The currents and voltages have equal magnitude and a phase displacement of 120°. With conventional rotation in the counter-clockwise direction, the positive-sequence current and voltage maxima occur in ABC order.
Positive-Sequence Current Restraint Factor, a2	This factor compensates for highly unbalanced systems with many untransposed lines and helps prevent misoperation during current transformer saturation. The a2 factor is the ratio of the magnitude of negative-sequence current to the magnitude of positive-sequence current (I_2/I_1).
Positive-Sequence Current Supervision Pickup	An element that operates only when a positive-sequence current exceeds a threshold.
Positive-Sequence Impedance	Impedance of a device or circuit that results in current flow with a balanced positive-sequence set of voltage sources.
POTT (Permissive Overreaching Transfer Trip)	A communications-assisted line protection scheme. At least two overreaching protective relays must receive a permissive signal from the other terminal(s) before all relays trip and isolate the protected line.
Power Factor	The cosine of the angle by which phase current lags or leads phase voltage in an ac electrical circuit. Power factor equals 1.0 for power flowing to a pure resistive load.
PPS	Pulse per second from a GPS receiver. Previous SEL-421 relays had a TIME 1k PPS input.
Protection and Automation Separation	Segregation of protection and automation processing and settings.
Protection Settings Group	Individual scheme settings for as many as six different schemes (or instances).
Protection-Disabled State	Suspension of relay protection element and trip/close logic processing and deenergization of all control outputs.
PT	Potential transformer. Also referred to as a voltage transformer or VT.
PTR	Potential transformer ratio.
Quadrilateral Characteristic	A distance relay characteristic on an R-X diagram consisting of a directional measurement, reactance measurement, and two resistive measurements.
Qualifier Code	Specifies type of range for DNP3 objects. With the help of qualifier codes, DNP master devices can compose the shortest, most concise messages.
R_TRIG	Rising-edge trigger. Boolean SELOGIC control equation operator that triggers an operation upon logic detection of a rising edge.
RAM	Random Access Memory. Volatile memory where the relay stores intermediate calculation results, Relay Word bits, and other data.

Reactance Reach	The reach of a distance element in the reactive (X) direction in the R-X plane.
Real Power	Power that produces actual work. The portion of apparent power that is real, not imaginary.
Reclose	The act of automatically closing breaker contacts after a protective relay trip has opened the circuit breaker contacts and interrupted current through the breaker.
Relay Word Bit	A single relay element or logic result. A Relay Word bit can equal either logical 1 or logical 0. Logical 1 represents a true logic condition, picked up element, or asserted control input or control output. Logical 0 represents a false logic condition, dropped out element, or deasserted control input or control output. Use Relay Word bits in SELOGIC control equations.
Remapping	The process of selecting data from the default map and configuring new indices to form a smaller data set optimized to your application.
Remote Bit	A Relay Word bit with a state that is controlled by serial port commands, including the CONTROL command, a binary Fast Operate command, DNP binary output operation, or a UCA control operation.
Report Settings	Event report and Sequential Events Recorder settings.
Residual Current	The sum of the measured phase currents. In normal, balanced operation, this current is very small or zero.
Residual Directional Overcurrent Element	A residual overcurrent element allowed to operate in only the forward or reverse direction.
Residual Overcurrent Protection	Overcurrent protection that operates at conditions exceeding a threshold of system unbalance ($3I_0 = I_A + I_B + I_C$).
Resistance Blinder	An operate boundary in the resistive direction of a ground quadrilateral distance element.
Resistive Reach	The reach of a distance element in the resistive (R) direction in the R-X plane.
Retrip	A subsequent act of attempting to open the contacts of a circuit breaker after the failure of an initial attempt to open these contacts.
Reverse Fault	A fault operation behind a relay terminal.
Rising Edge	Transition from logical 0 to logical 1, or the beginning of an operation.
RMS	Root-mean-square. This is the effective value of the current and voltage measured by the relay, accounting for the fundamental frequency and higher-order harmonics in the signal.
Rolling Demand	A sliding time-window arithmetic average in demand metering.
RTD	Resistance Temperature Detector
RTU	Remote Terminal Unit.
RXD	Received data.
SCADA	Supervisory control and data acquisition.

SCD File	IEC 61850 Substation Configuration Description file. XML file that contains information on all IEDs within a substation, communications configuration data, and a substation description.
SCL	IEC 61850 Substation Configuration Language. An XML-based configuration language that supports the exchange of database configuration data among different software tools that can be from different manufacturers. There are four types of SCL files used within IEC 61850: CID, ICD, SCD, and SSD.
Self-Description	A feature of GOMSFE in the UCA2 protocol. A master device can request a description of all of the GOMSFE models and data within the IED.
Self-Test	A function that verifies the correct operation of a critical device subsystem and indicates detection of an out-of-tolerance condition. The SEL-421 has self-tests that validate the relay power supply, microprocessor, memory, and other critical systems.
SELOGIC Expression Builder	A rules-based editor within the ACSELERATOR QuickSet software program for programming SELOGIC control equations.
SELOGIC Math Variables	Math calculation result storage locations.
SELOGIC Control Equation	A relay setting that allows you to control a relay function (such as a control output) using a logical combination of relay element outputs and fixed logic outputs.
Sequencing Timers	Timers designed for sequencing automated operations.
Sequential Events Recorder	A relay function that stores a record of the date and time of each assertion and deassertion of every Relay Word bit in a list that you set in the relay. SER provides a useful way to determine the order and timing of events of a relay operation.
SER	Sequential Events Recorder or the relay serial port command to request a report of the latest 1000 sequential events.
Series-Compensated Line	A power line on which the addition of series capacitance compensates for excessive inductive line impedance.
Settle/Settling Time	Time required for an input signal to result in an unvarying output signal within a specified range.
Shot Counter	A counter that records the number of times a recloser attempts to close a circuit breaker.
Shunt Admittance	The admittance resulting from the presence of a device in parallel across other devices or apparatus that diverts some current away from these devices or apparatus.
Shunt Capacitance	The capacitance between a network connection and any existing ground.
Shunt Current	The current that a parallel-connected high-resistance or high-impedance device diverts away from devices or apparatus.
SIN Operator	Operator in math SELOGIC control equations that provides the sine function.
Single-Pole Trip	A circuit breaker trip operation that occurs when one pole of the three poles of a circuit breaker opens independently of the other poles.

SIR	Source-to-line impedance ratio.
SOTF (Switch-Onto-Fault Protection Logic)	Logic that provides tripping if a circuit breaker closes into a zero voltage bolted fault, such as would happen if protective grounds remained on the line following maintenance.
Source Impedance	The impedance of an energy source at the input terminals of a device or network.
SQRT Operator	Math SELOGIC control equation operator that provides square root.
SSD File	IEC 61850 System Specification Description file. XML file that describes the single-line diagram of the substation and the required logical nodes.
Stable Power Swing	A change in the electrical angle between power systems. A control action can return the angular separation between systems to less than the critical angle.
Status Failure	A severe out-of-tolerance internal operating condition. The relay issues a status failure message and enters a protection-disabled state.
Status Warning	Out-of-tolerance internal operating conditions that do not compromise relay protection, yet are beyond expected limits. The relay issues a status warning message and continues to operate.
Strong Password	A mix of valid password characters in a six-character combination that does not spell common words in any portion of the password. Valid password characters are numbers, upper- and lower-case alphabetic characters, “.” (period), and “-” (hyphen).
Subnet Mask	The subnet mask divides the local node IP address into two parts, a network number and a node address on that network. A subnet mask is four bytes of information and is expressed in the same format as an IP address.
Subsidence Current	See CT subsidence current.
Synch Reference	A phasor the relay uses as a polarizing quantity for synchronism check calculations.
Synchronism Check	Verification by the relay that system components operate within a preset frequency difference and within a preset phase angle displacement between voltages.
Synchronized Phasor	A phasor calculated from data samples using an absolute time signal as the reference for the sampling process. The phasors from remote sites have a defined common phase relationship. Also known as Synchrophasor.
Telnet	An Internet protocol for exchanging terminal data that connects a computer to a network server and allows control of that server and communication with other servers on the network.
Terminal Emulation Software	Software such as Microsoft® HyperTerminal® or ProComm Plus® that can be used to send and receive ASCII text messages and files via a computer serial port.
Thermal Demand	Thermal demand is a continuous exponentially increasing or decreasing accumulation of metered quantities; used in demand metering.

Thermal Withstand Capability	The capability of equipment to withstand a predetermined temperature value for a specified time.
Three-Phase Fault	A fault involving all three phases of a three-phase power system.
Three-Pole Trip	A circuit breaker operation that occurs when the circuit breaker opens all three poles at the same time.
Time Delay on Pickup	The time interval between initiation of a signal at one point and detection of the same signal at another point.
Time Dial	A control that governs the time scale of the time-overcurrent characteristic of a relay. Use the time-dial setting to vary relay operating time.
Time-Delayed Tripping	Tripping that occurs after expiration of a pre-determined time.
Time Error	A measurement of how much time an ac powered clock would be ahead or behind a reference clock, as determined from system frequency measurements.
Time-Overcurrent Element	An element that operates according to an inverse relationship between input current and time, with higher current causing faster relay operation.
Time Quality	An indication from a GPS clock receiver that specifies the maximum error in the time information. Defined in IEEE C37.118.
Torque Control	A method of using one relay element to supervise the operation of another.
Total Clearing Time	The time interval from the beginning of a fault condition to final interruption of the circuit.
Tower Footing Resistance	The resistance between true ground and the grounding system of a tower.
Transformer Impedance	The resistive and reactive parameters of a transformer looking in to the transformer primary or secondary windings. Use industry accepted open-circuit and short-circuit tests to determine these transformer equivalent circuit parameters.
Tree Resistance	Resistance resulting from a tree in contact with a power line.
TVE	Total Vector Error. A measurement of accuracy for phasor quantities that combines magnitude and angle errors into one quantity. Defined in IEEE C37.118.
TXD	Transmitted data.
UCA2	Utility Communications Architecture. A network-independent protocol suite that serves as an interface for individual intelligent electronic devices.
Unbalanced Fault	All faults that do not include all three phases of a system.
Unbuffered Report	IEC 61850 IEDs can issue immediate unbuffered reports of internal events (caused by trigger options data-change, quality-change, and data-update) on a “best efforts” basis. If no association exists, or if the transport data flow is not fast enough to support it, events may be lost.
Unconditional Tripping	Protection element tripping that occurs apart from conditions such as those involving communication, switch-onto-fault logic, etc.

Unstable Power Swing	A change in the electrical angle between power systems for which a control action cannot return the angular separation between systems to an angle less than the critical angle.
Untransposed Line	A transmission line with phase conductors that are not regularly transposed. The result is an imbalance in the mutual impedances between phases.
User ST	Region in GOOSE for user-specified applications.
VA, VB, VC	Measured A-phase-to-neutral, B-phase-to-neutral, and C-phase-to-neutral voltages.
VAB, VBC, VCA	Measured or calculated phase-to-phase voltages.
VG	Residual voltage calculated from the sum of the three phase-to-neutral voltages, if connected.
Virtual Terminal Connection	A mechanism that uses a virtual serial port to provide the equivalent functions of a dedicated serial port and a terminal.
Volatile Storage	A storage device that cannot retain data following removal of relay power.
VT	Voltage transformer. Also referred to as a potential transformer or PT.
Warm Start	The reset of a running system without removing and restoring power.
Weak Infeed Logic	Logic that permits rapid tripping for internal faults when a line terminal has insufficient fault current to operate protective elements.
Wye	A phase-to-neutral connection of circuit elements, particularly voltage transformers or loads. To form a wye connection using transformers, connect the nonpolarity side of each of three voltage transformer secondaries in common (the neutral), and take phase to neutral voltages from each of the remaining three leads. When properly phased, these leads represent the A-phase-, B-phase-, and C-phase-to-neutral voltages. This connection is frequently called 'four-wire wye,' alluding to the three phase leads plus the neutral lead.
XML	Extensible Markup Language. This specification developed by the W3C (World Wide Web Consortium) is a pared-down version of SGML designed especially for web documents. It allows designers to create their own customized tags, enabling the definition, transmission, validation, and interpretation of data among applications and organizations.
Zero-Sequence	A configuration of three-phase currents and voltages with currents and voltages that occur simultaneously, are always in phase, and have equal magnitude ($3I_0 = I_A + I_B + I_C$).
Zero-Sequence Compensation Factor	A factor based on the zero-sequence and positive-sequence impedance of a line that modifies a ground distance element to have the same reach as a phase distance element.
Zero-Sequence Impedance	Impedance of a device or circuit resulting in current flow when a single voltage source is applied to all phases.
Zero-Sequence Mutual Coupling	Zero-sequence current in an unbalanced circuit in close proximity to a second circuit induces voltage into the second circuit. When not controlled by

protection system design and relay settings, this situation can cause improper operation of relays in both systems.

**Zero-Sequence
Overcurrent Element**

Overcurrent protection that operates at conditions exceeding a threshold of system unbalance.

**Zero-Sequence
Voltage-Polarized
Directional Element**

An element that provides directionality by the sign, plus or minus, of the measured zero-sequence impedance.

Z-Number

That portion of the relay FID string that identifies the proper ACSELERATOR QuickSet software relay driver version and HMI driver version when creating or editing relay settings files.

Zone Time Delay

Time delay associated with the forward or reverse step distance and zone protection.

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SEL-421 Relay Command Summary

SEL-421 Relay Commands^{a, b} (Sheet 1 of 2)

Command	Description
2ACCESS	Go to Access Level 2 (complete relay monitoring and control)
AACCESS	Go to Access Level A (automation control)
ACCESS	Go to Access Level 1 (monitor relay)
BACCESS	Go to Access Level B (monitor relay and control circuit breakers)
BNAME	ASCII names of all relay status bits (Fast Meter)
BREAKER <i>n</i>	Display the circuit breaker report and breaker history; preload and reset breaker monitor data (<i>n</i> = 1 is BK1; <i>n</i> = 2 is BK2)
CASCII	Generate the Compressed ASCII response configuration message
CBREAKER	BREAKER command for the Compressed ASCII response
CEVENT	EVENT command for the Compressed ASCII response
CHISTORY	HISTORY command for the Compressed ASCII response
CLOSE <i>n</i>	Close the circuit breaker (<i>n</i> = 1 is BK1; <i>n</i> = 2 is BK2)
COMM <i>c</i>	Display relay-to-relay MIRRORING BITS communications data (<i>c</i> = A is channel A; <i>c</i> = B is channel B; <i>c</i> = M is either enabled single channel)
CONTROL <i>nm</i>	Set, clear, or pulse an internal remote bit (<i>nm</i> is the remote bit number from 01–32)
COPY <i>m n</i>	Copy settings between instances in the same class (<i>m</i> and <i>n</i> are instance numbers; for example: <i>m</i> = 1 is Group 1; <i>n</i> = 2 is Group 2)
CSER	SER command for the Compressed ASCII response
CSTATUS	STATUS command for the Compressed ASCII response
CSUMMARY	SUMMARY command for the Compressed ASCII response
DATE	Display and set the date
DNAME X	ASCII names of all relay digital I/O (Fast Meter)
DNP	Access or modify serial port DNP3 settings (similar to SHOW D and SET D)
EVENT	Display and acknowledge event reports
FILE	Transfer data between the relay and external software
GROUP	Display the active group number or select the active group
HELP	Display available commands or command help at each access level
HISTORY	View event summaries/histories; clear event data
ID	Display the firmware id, user id, device code, part number, and configuration information
LOOPBACK	Connect MIRRORING BITS data from transmit to receive on the same port
MAP 1	Analyze the communications card database
METER	Display metering data and internal relay operating variables
OACCESS	Go to Access Level O (output control)
OPEN <i>n</i>	Open the circuit breaker (<i>n</i> = 1 is BK1; <i>n</i> = 2 is BK2)
PACCESS	Go to Access Level P (protection control)
PASSWORD	Display or change relay passwords
PORT	Connect to a remote relay via MIRRORING BITS virtual terminal (for port number <i>p</i> = 1–3, and F), or the Ethernet card (port <i>p</i> = 5)

SEL-421 Relay Commands^{a, b} (Sheet 2 of 2)

Command	Description
PULSE OUTnnn	Pulse a relay control output (OUT nnn is a control output number)
QUIT	Reduce access level to Access Level 0 (exit relay control)
SER	View Sequential Events Recorder reports
SET^c	Enter relay settings
SHOW^c	Display relay settings
SNS	Display Sequential Events Recorder settings name strings (Fast SER)
STATUS	Report or clear relay status and SELOGIC control equation errors
SUMMARY	View summary event reports
TARGET	Display relay elements for a row in the Relay Word table
TEC	Display time-error estimate; display or modify time-error correction value.
TEST DB	Display or place values in the communications card database (useful for Ethernet protocol read tests)
TEST DNP	Display or place values in the serial port DNP3 object map
TEST FM	Display or place values in metering database (Fast Meter)
TIME	Display and set the internal clock
TRIGGER	Initiate a data capture and record an event report
VERSION	Display the relay hardware and software configurations
VIEW 1	View data from the communications card database

^a See [Section 9: ASCII Command Reference in the Reference Manual](#).

^b For help on a specific command, type **HELP [command] <Enter>** at an ASCII terminal communicating with the relay.

^c See the table below for SET/SHOW options.

SET/SHOW Command Options

Option	Setting Type	Description
[S] n	Group Settings 1–6	Particular application settings
A n^a	Automation Logic Block 1–10	Automation SELOGIC control equations
D	DNP3	Direct Network Protocol remapping (serial port only)
F	Front Panel	Front-panel HMI settings
G	Global 1–6	Relay-wide settings
L n	Protection Logic Group 1–6	Protection SELOGIC control equations
M	Breaker Monitor	Circuit breaker monitor settings
O	Outputs	Output SELOGIC control equations
P n	Port 1–3, F, 5	Communications port settings
R	Report	Event report and SER settings
T	Alias	Alias names for analog quantities and Relay Word bits

^a The SEL-421-1 and the SEL-421-2 have only one instance of automation logic settings.