# Improved Sensitivity and Security for Distribution Bus and Feeder Relays

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# IMPROVED SENSITIVITY AND SECURITY FOR DISTRIBUTION BUS AND FEEDER RELAYS

## INTRODUCTION

Almost all distribution buses and feeders are protected by phase and ground overcurrent relays. Maximum bus and feeder loads limit the sensitivity of phase overcurrent relay settings. The limit is especially serious for the bus relays, which see the combined load of many feeders and provide backup for feeder relays.

Introducing new logic and schemes to improve customer service has required panel modifications, additional relay elements, timers, and other equipment. These expenses often delay or prevent taking advantage of new ideas to improve customer service.

This paper presents two new relays for distribution bus and feeder protection which improve phase fault sensitivity with no loss of security and have great flexibility in protection scheme design without the expense of additional equipment.

Phase distance torque-control of the bus relay phase overcurrent elements permits more sensitive phase overcurrent settings. Negative-sequence overcurrent elements of the new distribution bus and feeder relays reject three-phase load to provide more sensitive coverage of phase-to-phase faults. Bus relay backup of the feeder relays is improved.

Programmable logic, extra timers and a wide range of relay elements give the relay protection engineer tools for innovative protection scheme design that can be adapted to future needs.

Specific applications of the distribution bus and feeder relays on the distribution system of British Columbia Hydro and Power Authority (B.C. Hydro) are presented.

## BRIEF OVERVIEW OF THE NEW DISTRIBUTION RELAYS

The new distribution bus and feeder relays have many features in common and a few unique characteristics.

### Common Protection Features

Phase and ground overcurrent elements provide traditional distribution system fault protection. The new negative-sequence overcurrent elements provide faster and more sensitive phase-to-phase fault protection, with no loss of security.

"Fast" or "electromechanical" reset can be selected for any of the time-overcurrent elements (phase, negative-sequence, or ground). The "electromechanical" reset option emulates the resetting of an electromechanical relay induction disc and can be applied to prevent a source-side electromechanical relay from tripping due to "ratcheting" for a fault beyond one of the new distribution relays. On the other hand, "fast" reset is compatible with other solid-state devices.

An undervoltage element can be used for loadshedding, to torque-control phase overcurrent elements, etc.

Both relays have user-programmable logic and multiple setting groups for the ultimate flexibility in protection scheme design, adaptation, and change.

## Feature Unique to the Distribution Bus Relay

The distribution bus relay contains a self-polarized mho phase distance element that can torque-control the distribution bus relay phase overcurrent elements. Torque-control permits more sensitive phase overcurrent element settings, since the mho elements help discriminate between fault current and heavy load.

## Features Unique to the Distribution Feeder Relay

The distribution feeder relay contains a multiple shot reclosing relay with sequence coordination.

The distribution feeder relay also contains a fault locator that is optimized for radial distribution systems (see Reference 1).

## Distribution System Arrangement and Protection

The relay voltage connections shown in Figure 1 are optional (relay voltage from the bus PT). They are needed for voltage and MW/MVAR metering, the undervoltage element, the phase distance element for the bus relay, and fault locating for the feeder relay.

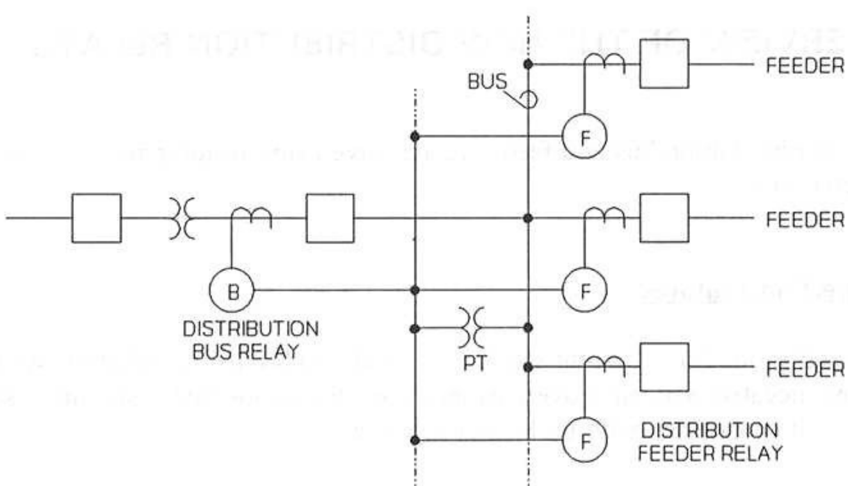



**Figure 1: Distribution System Arrangement and Protection**

## IMPROVED DISTRIBUTION RELAY DESIGN

A few important observations guided the improved design of the new distribution relays:

- Protection engineers develop new protection schemes.
- A limited number of relay inputs and output contacts are available.
- The distribution system is dynamic.
- Negative-sequence overcurrent elements are insensitive to balanced load.
- Relays cannot always be installed for convenient user access.

The following discussion explains how these observations resulted in new and improved distribution relay features.

### Programmable Logic

Protection schemes are constantly being modified and improved. Changing traditional protection schemes often requires purchasing and installing additional equipment.

References 2, 3, and 4 give examples of how some utilities changed their distribution protection schemes from fuse saving to trip saving (fuse blowing) schemes by installing additional timers. Future changes and enhancements in traditional installations will also require additional equipment.

Philosophy of distribution protection changes over time and differs from utility to utility; sometimes from area to area within the same utility. If a distribution relay meets one utility's requirements, it may not satisfy another's. Making factory modifications to satisfy different utilities is costly, time consuming, and results in "one-of-a-kind" relays.

Relay design engineers devised user-programmable logic for the new distribution relays. This logic handles future protection schemes as well as the multiplicity of protection schemes that protect different utilities' distribution systems. With these new relays, there is less need for additional equipment as protection schemes are enhanced.

The power of the programmable logic comes from ANDing, ORing, inverting, and timing of relay elements, using Boolean algebra logic equations. Relay elements are combined to make conditional logic for internal functions and output contacts. Relay element combinations can be run through independent timers. Relay elements such as overcurrent elements, reclosing relay states, and inputs are used in this programmable logic. The programmable logic replaces discrete timers, auxiliary relays, diodes, and external interconnections.

**Programmable Logic Example**

In the following example, relay opto-isolated input IN6 supervises the ground overcurrent elements (51NT and 50NLT) for tripping. Input IN6 can be de-energized during circuit paralleling operations to prevent the ground overcurrent elements from initiating a trip on temporary current unbalance.

| | |
|---|---|
| 51NT | is a ground time-overcurrent element. |
| 50NLT | is a ground definite-time overcurrent element. |
| IN6 | is a relay opto-isolated input. |
| 51T | is a phase time-overcurrent element. |
| A,E | are programmable variables equal to ORed combinations of relay elements. |
| V | is a programmable variable equal to ANDed combinations of other programmable variables ("A" and "E" are some of these "other programmable variables"). |
| + | is the logical OR operator. |
| * | is the logical AND operator. |

| | |
|---|---|
| A = 51NT+50NLT | ORing level of programmable logic. If 51NT or 50NLT assert, "A" asserts. |
| E = IN6 | ORing level of programmable logic (no ORing done in this case). If input IN6 is energized with nominal control voltage, "E" asserts. |
| V = A*E | ANDing level of programmable logic. If both "A" and "E" are asserted at the same time, "V" asserts.<br><br>Effectively, V=(51NT+50NLT)*IN6. |
| TR = 51T+V | TR is the TRIP output contact programmable trip variable.<br><br>Effectively, TR = 51T+[(51NT+50NLT)*IN6].<br><br>Close TRIP output contact = TR+ ... |

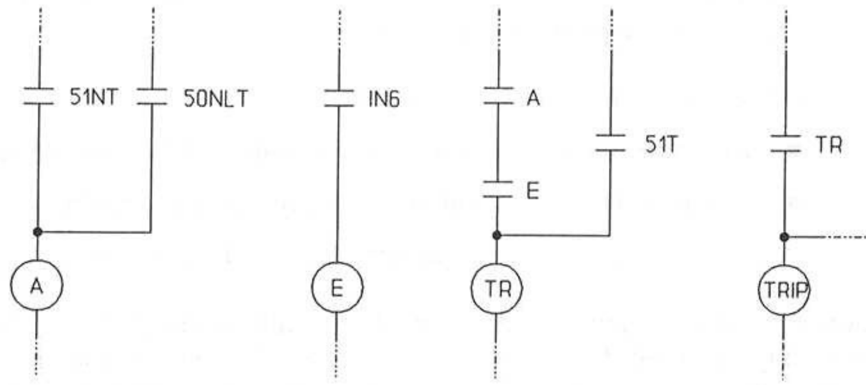



**Figure 2: Relay Logic Representation of Programmable Logic Example**

## Usable Inputs and Output Contacts

### Inputs

All opto-isolated inputs of the new distribution relays can be programmed to specific functions such as setting group selection, torque-control, circuit breaker status, reclose enable, and other functions. The relay protection engineer makes the most effective use of the inputs.

Some of the inputs appear in the programmable logic. These inputs can be used to supervise other relay elements, they can be time-qualified, etc.

### Output Contacts

The TRIP output contacts and the four auxiliary output contacts of the new distribution relays can be programmed with the programmable logic.

## The Dynamic Distribution System

An electric power distribution system changes hourly to seasonally:

- Scheduled switching for construction or maintenance projects
- Emergency switching for repairs
- Bus-tie breakers substituting for distribution feeder breakers
- Seasonal load transfers

The resulting system reconfigurations last from hours to months. Many reconfigurations are repeated. The following problems can result:

- Major changes in load or unbalance
- Large variations in fault duties, due to source and feeder changes
- Coordination problems with different protective equipment
- Increased fault duty on conductor, cable, and equipment

Traditional protective equipment does not adapt readily to distribution system reconfigurations. If new settings are needed they have to be manually changed: there are no settings in reserve. The time to make or enter and test new settings slows down emergency responses and risks human error. Sometimes relay settings are not changed for emergency or abnormal switching, because it takes too long or is too difficult. System protection is compromised.

The two new distribution relays handle distribution system reconfigurations with multiple setting groups. The setting groups can be accessed by command or by setting group selection inputs and can be programmed to cover many different contingencies. For example, in a bus-tie circuit breaker application, the bus-tie relay stores the settings for the feeder relays it replaces (see Figure 3).

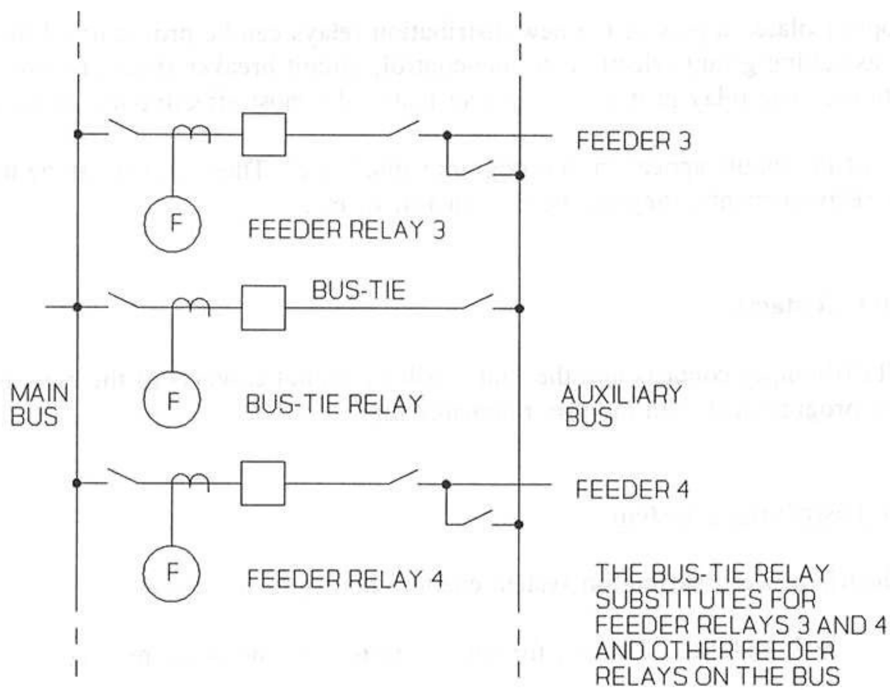



**Figure 3: Bus-tie Breaker Substitutes for Distribution Feeder Breakers**

References 5 and 6 describe the first relay with multiple setting groups. In the new distribution relays, the multiple setting group feature has been expanded to allow the programmable internal logic and output contact functions to change along with the relay element settings.

## Faster and More-Sensitive Phase-to-Phase Fault Protection

Negative-sequence overcurrent elements can be set to respond faster and more sensitively to phase-to-phase faults, because negative-sequence overcurrent elements do not respond to balanced load current. Like ground overcurrent elements, negative-sequence overcurrent elements can be set below load current levels. On the other hand, phase overcurrent relays must be set above load current levels.

Table 1 shows that negative-sequence currents are generated during unbalanced faults. With the new primary protection coverage offered by the negative-sequence overcurrent elements, phase overcurrent elements are needed for only three-phase faults.

The negative-sequence overcurrent elements can also cover phase-to-phase-to-ground faults where the ground fault resistance is high. High ground fault resistance makes a phase-to-phase-to-ground fault appear as a phase-to-phase fault to the relay.

**Table 1: Traditional and New Primary Protection Coverage Comparison**

| System Condition | Currents Generated | | | Traditional Primary Protection Coverage | | New Primary Protection Coverage | | |
|---|---|---|---|---|---|---|---|---|
| | Phase Current ($I_P$) | Negative-sequence Current ($I_2$) | Zero-sequence Current ($I_O$) | Phase Over-current Elements | Ground Over-current Elements | Phase Over-current Elements | Negative-sequence Over-current Elements | Ground Over-current Elements |
| LG Fault | X | X | X | | X | | | X |
| LLG Fault | X | X | X | X | X | | X | X |
| LL Fault | X | X | | X | | | X | |
| 3-Phase Fault | X | | | X | | X | | |
| Balanced Load | X | | | | | | | |

## Convenient Display

Relays cannot always be installed so that operators have easy access to a front panel display/interface. The solution is to separate the display/interface from the relay.

A new display/interface can be installed for easy access, and the relays can then be installed in more inaccessible places if necessary. The display/interface connects via communications cables to the relays. One display/interface handles up to four relays.

A liquid crystal display (LCD) and pushbuttons on the display/interface allow easy access to target information, metering, fault information, setting group selection, and other features of the new distribution relays.

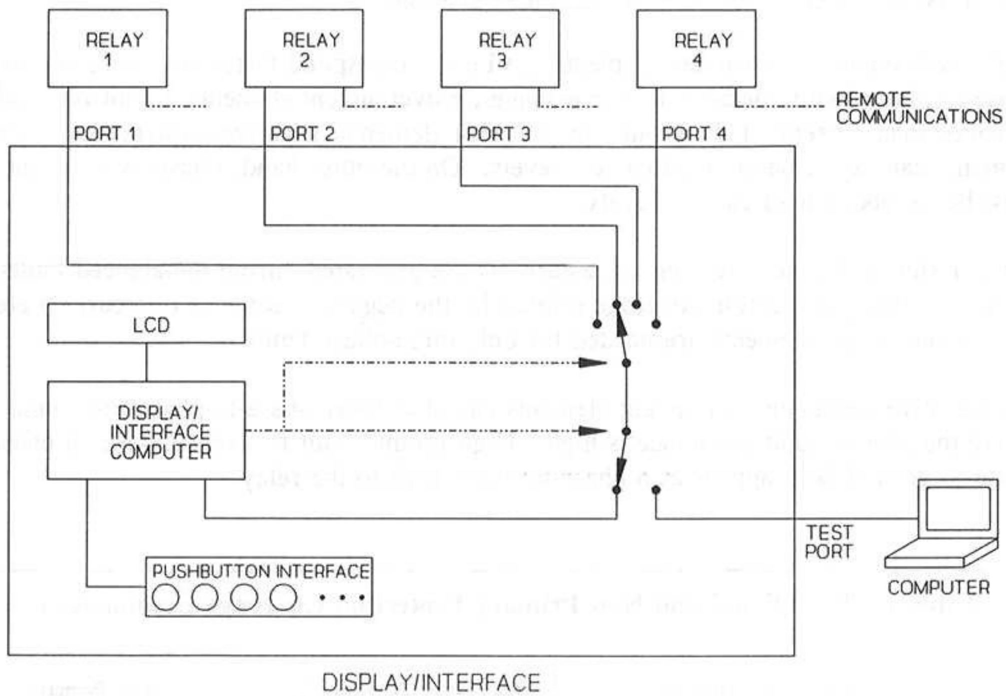



**Figure 4: Display/Interface Block Diagram**

# IMPROVING DISTRIBUTION SYSTEM PROTECTION AT B.C. HYDRO

## Traditional Distribution Protection Practice at B.C. Hydro

### Feeder Protection

Traditional distribution feeder protection at B.C. Hydro consists of three separate phase overcurrent relays and one ground overcurrent relay, all electromechanical. Three separate phase relays provide phase and ground protection redundancy (ground redundancy at a reduced sensitivity). Fuse saving (tripping the station breaker before the distribution fuse blows) and auto-reclose schemes are used in some B.C. Hydro regions and can be disabled by on/off switches. A simple breaker failure protection scheme consists of a timer initiated from the operation of the overcurrent relays and timed to override relay reset after successful opening of the feeder breaker. Analog demand ammeters are installed on all phases.

### Bus Protection

Like feeder protection, distribution bus protection consists of three phase overcurrent relays and one ground overcurrent relay (electromechanical), along with timed breaker failure protection. Analog demand ammeters are also installed on all phases.

The bus phase overcurrent relays often have to be torque-controlled when it is not possible to achieve a setting low enough to operate for minimum bus phase faults and high enough to allow maximum load with some margin for cold load pickup. Torque-control keeps an overcurrent element from operating until the controlling element has operated. Undervoltage or distance relays provide torque-control for bus phase overcurrent relays.

Appendix 2 explains the need for torque-control and why undervoltage relays cannot be used in some cases. In such cases, three phase-to-phase mho distance relays are used. Compensator distance relays are not adequate. Analysis by B.C. Hydro indicated that when bus load current is significant compared to fault current, the dependability of the polyphase distance relay becomes questionable. These results were later confirmed by a polyphase distance relay manufacturer (see Reference 7).

### Feeder Relay Backup

The bus ground relay is an effective backup for the feeder ground relay because it can be set just slightly higher than the feeder ground relay. The same does not hold true for the bus phase overcurrent relays. Even though bus phase overcurrent relays can be set below load using torque-control, their setting must still be much higher than the feeder phase relay setting. The higher setting is necessary for time coordination purposes because during a feeder fault the bus load causes the total bus phase current to be much higher than the faulted feeder phase current. This is especially true for low magnitude feeder phase faults where the bus voltage is high enough to supply substantial load to the unfaulted feeders. The lack of sensitive backup for the feeder phase relays was yet another reason to provide three separate phase overcurrent relays for feeder protection.

## Reasons for Change in Distribution Protection Practice

B.C. Hydro went through a major downsizing process during the recession of the early 1980's. During the subsequent recovery, management resisted rehire demands to meet increased work load. Instead, the company's emphasis was on efficiency. New corporate culture looked for ways to reduce demands put on the remaining manpower.

With the advent of microprocessor-based protective relays that allow remote access to metering and have self checking capability, thus allowing reduction in maintenance frequency, it became very desirable for B.C. Hydro to look into installing such relays on its distribution system. The protection features and principles mentioned previously were not to be lost or compromised by applying microprocessor-based protective relays and hopefully they would be enhanced, especially in the area of backup for feeder phase protection.

## Development of Distribution Protection Requirements

Many B.C. Hydro departments helped develop a list of requirements for a distribution relay. Departments with responsibilities in substations, distribution systems, and protective relays were asked to submit "wish lists" stating all the functions they would like in new distribution bus and feeder relays. B.C. Hydro forwarded a compiled but unedited "wish list" to relay suppliers who were then asked to make presentations to explain and discuss the features provided in their products. This effort took a few months to complete and, because none of the off-the-shelf products met most of the "wish list" demands, B.C. Hydro accepted Schweitzer Engineering Laboratories' (SEL) offer to develop two new relays:

- SEL-151C relay for distribution bus protection
- SEL-151 relay for distribution feeder protection

## The Most Significant Features in the New Distribution Relays

For B.C. Hydro applications, the most significant features in the new SEL distribution relays are:

- the negative-sequence overcurrent elements in both relays
- the phase distance element (self-polarized mho) included in the distribution bus relay for torque-control of phase overcurrent elements

Both features make the bus relay very effective in providing backup for the feeder relays. Therefore, there is no need to provide a second set of dedicated protection for each feeder to backup the microprocessor-based feeder protection.

### Improved Phase-to-Phase Fault Protection with Negative-Sequence Elements

Negative-sequence overcurrent elements can be set more sensitively than phase overcurrent elements to detect phase-to-phase faults because they are insensitive to balanced load current. However, there was concern that it would be difficult to coordinate the negative-sequence overcurrent elements with other protective devices in the substation and out on the feeder that operate on different electrical quantities (e.g., phase or residual currents). Moreover, since phase overcurrent elements are still needed for three-phase fault detection, the negative-sequence overcurrent elements would necessitate more work in settings calculations and coordination studies.

But because bus relay sensitivity for feeder backup is important, B.C. Hydro engineers studied the application of negative-sequence overcurrent elements more closely. Guided by SEL application ideas, a very simple method for setting the negative-sequence overcurrent elements was devised. After careful study of this setting concept to verify that it would coordinate with all upstream and downstream protective equipment for all types of faults, the negative-sequence overcurrent elements were used on both bus and feeder relays.

The setting realized for the bus negative-sequence overcurrent elements is as sensitive as the feeder phase overcurrent elements for effective backup for feeder phase-to-phase faults. Feeder relay sensitivity to feeder phase-to-phase faults improves, too, with the application of feeder negative-sequence overcurrent elements.

The simple method for setting the negative-sequence overcurrent elements is as follows:

1. Start with the most downstream negative-sequence overcurrent element (e.g., feeder relay).

2. Identify the phase overcurrent device (relay, line recloser, fuse, etc.) down-stream from the negative-sequence overcurrent element that is of greatest concern for coordination. This is usually the phase overcurrent device with the longest clearing time.

3. Consider the negative-sequence overcurrent element as an "equivalent" phase overcurrent element. Derive settings for this "equivalent" phase overcurrent element as any phase coordination would be done. The only difference is that the "equivalent" phase overcurrent element setting is only governed by coordination time and not by load or cold load pickup considerations.

4. Multiply the "equivalent" phase overcurrent element pickup setting by $\sqrt{3}$. The result is the negative-sequence overcurrent element pickup in terms of $3I_2$ current. Any time dial or time delay calculated for the "equivalent" phase overcurrent element is used for the negative-sequence overcurrent element with no conversion factor applied.

5. Set the next upstream negative-sequence overcurrent element to coordinate with the first downstream negative-sequence overcurrent element (and the third negative-sequence overcurrent element with the second and so on). Again, coordination is not influenced by load considerations.

Appendix 1 explains in detail how the $\sqrt{3}$ conversion factor is derived and how following this recommended setting procedure achieves coordination for all faults with no further analysis required.

When negative-sequence overcurrent elements are set per the above guidelines, they provide better sensitivity for phase-to-phase faults and phase-to-phase-to-ground faults with high ground resistance. Even though negative-sequence overcurrent elements also detect phase-to-ground faults and phase-to-phase-to-ground faults with low ground resistance, ground overcurrent elements provide much better sensitivity for these latter faults.

**Torque-Controlled Bus Phase Overcurrent Elements**

Even with a new distribution bus relay, the principles behind applying torque-control to the bus phase overcurrent elements remain essentially the same. The improvements achieved with the new relays are:

- Torque-controllable phase instantaneous overcurrent elements provided: These elements can also be torque-controlled by undervoltage or phase distance elements. Time delayed instantaneous elements (definite-time elements) significantly enhance the feeder relay backup function provided by the bus relay.

- Cost savings: The undervoltage or phase distance elements used in torque-controlling are in the same relay package as the phase overcurrent elements. The extra expense of separate undervoltage or distance relays is eliminated.

Appendix 3 gives examples of setting the bus phase overcurrent and distance elements.

## Other Important Protection Improvements

The numerous features and flexibility in the new distribution relays provide many other improvements. Some features offer solutions to a few outstanding protection and coordination problems:

### Multiple Setting Groups

At some substations, a phase instantaneous overcurrent element set for two transformers in service (normal case) cannot detect a bus fault when one of the two transformers is out of service. This shortcoming is significant for indoor substations where speed of clearing faults is critical. With multiple setting groups, a more sensitive instantaneous setting can be enabled when a transformer is out of service. A transformer breaker auxiliary contact wired to a selectable setting group input on the bus relay would switch the settings.

### Settable Feeder Unbalance Alarm

To monitor the feeder load unbalance an alarm from the neutral demand ammeter is initiated. The threshold for this alarm is settable. For feeders with very low unbalance, the setting for this neutral demand alarm could be very low. In effect, this could be considered a kind of "high impedance ground fault detection" scheme. The programming for this output contact alarm is shown in Appendix 4.

### Event Reports

Event reports make analyzing protection operations easy. Often, when the bus and feeder protection miscoordinated for a feeder fault, we had to guess the load conditions prior to the fault that might have contributed to the misoperation. This will no longer be necessary since all current, voltage, input, and output contact information prior to and during tripping is contained in the event reports.

## Material, Engineering and Operating Cost Savings

A comparison of material cost between the traditional and new schemes showed that the cost of providing protection for a feeder section, consisting of eight to ten feeders and two bus sections (four to five feeders for each bus section) is actually less with the new scheme than with the traditional one. This is mainly due to panel space savings and that separate undervoltage or distance relays are not needed to torque-control the bus phase overcurrent relays -- they are all in one new distribution bus relay package.

The savings in planning, engineering, operating and maintenance costs have not been assessed, but are expected to be significant. With a package where all possible protection needs can be selected by programming, standardization of application and design of distribution bus and feeder protection is possible. This reduces both engineering cost and planning lead time. Operating and maintenance cost savings result from remote access to feeder and bus load data, reduced maintenance frequency due to the self-checking feature, fault locating, and faster analysis of relay operations and system disturbances with event reports.

# CONCLUSIONS

The new distribution bus and feeder relays improve sensitivity, security, and reliability, yet remain compatible with current practice.

The new bus relay backs up the feeder relays, through the use of negative-sequence and torque-controlled phase overcurrent elements. This effective backup should alleviate concerns about converting from traditional, discrete relay schemes to one-package-per-feeder applications.

Negative-sequence overcurrent elements provide faster and more-sensitive phase-to-phase fault protection. A method for setting these elements with minimal coordination study effort is presented.

Advanced programmable logic replaces extra timers, auxiliary relays, and wiring that are frequently required in traditional installations.

Multiple setting groups (which include settings and logic) cover different distribution system contingencies, operating modes, and reconfigurations.

Close collaboration between B.C. Hydro and SEL resulted in two new relays having the advantages of new technology, while preserving the dependability of traditional electromechanical practice.

## APPENDIX 1

### Setting Negative-Sequence Overcurrent Elements

The following analysis is required to prove the validity of the setting concept introduced in the previous section, "Improved Phase-to-Phase Fault Protection with Negative-Sequence Elements."

The negative-sequence overcurrent elements in the SEL-151 and SEL-151C relays operate on $3I_2$ current. An analysis of the relative magnitude of phase current ($I_P$) versus negative-sequence current ($3I_2$) for phase-to-ground, phase-to-phase, and phase-to-phase-to ground faults is given in Figures 5, 6, and 7, respectively.

From Figures 5, 6, and 7, the highest $|3I_2/I_P|$ ratio is for the phase-to-phase fault condition:

$$|3I_2/I_P| = \sqrt{3}$$

The following important conclusion can be made:

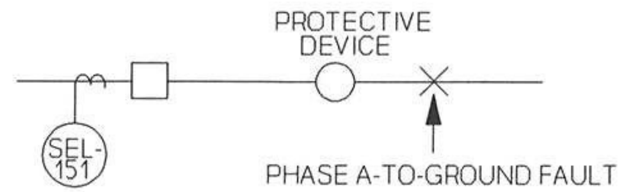
> A negative-sequence overcurrent element that operates on $3I_2$ current and has its pickup set to $\sqrt{3}$ times the pickup value of a phase overcurrent element will have the same sensitivity for phase-to-phase faults and less sensitivity to all other faults when compared to that phase overcurrent element.

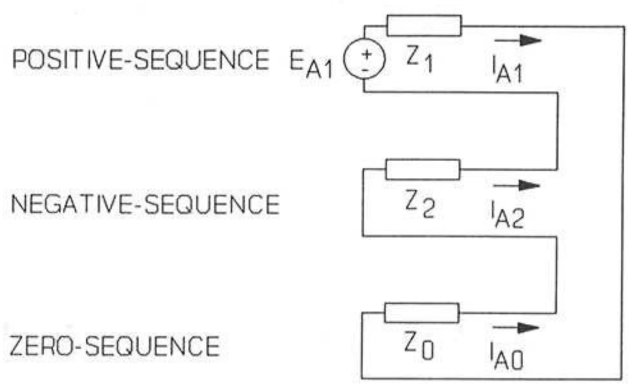
### Faults on the Secondary of Delta-Wye Transformers

Phase-to-ground and phase-to-phase faults on the wye secondary of a delta-wye transformer generate negative-sequence currents on the primary system. Figures 8 and 9 detail the relationship between the primary negative-sequence and phase current values for these fault cases.

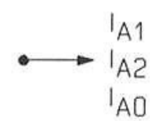
Neither Figure 8 nor Figure 9 has a $3I_2/I_P$ ratio greater than $\sqrt{3}$. Negative-sequence overcurrent elements set with respect to the guidelines given in "Improved Phase-to-Phase Fault Protection with Negative-Sequence Elements" achieve coordination for these cases, also.

Further study of Figure 9 shows that primary phase B has twice the magnitude of fault current as compared to primary phases A or C. After phase B fuse blows, no fault current flows in primary phases A and C. Thus, coordination is still achieved.

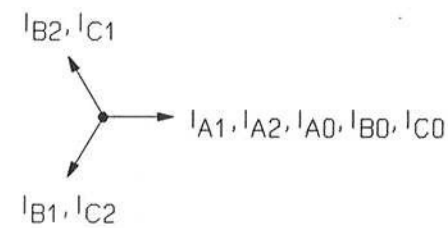



$$I_{A1} = I_{A2} = I_{A0}$$
$$I_2 = I_0$$
$$\therefore 3I_2 = 3I_0$$

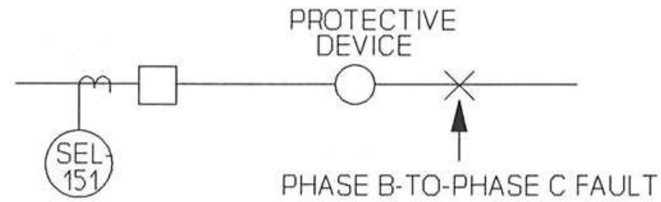


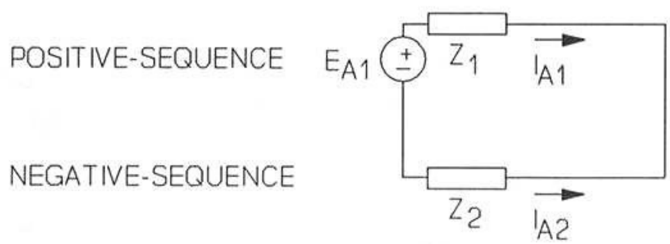
$$I_A = I_{A1} + I_{A2} + I_{A0}$$
$$I_B = I_{B1} + I_{B2} + I_{B0} = 0$$
$$I_C = I_{C1} + I_{C2} + I_{C0} = 0$$



$$3I_{A2} = I_A = 3I_{A0}$$
$$3I_2 = I_P$$
$$\therefore \boxed{\frac{3I_2}{I_P} = 1}$$

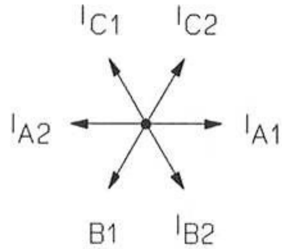
**Figure 5: Phase-to-Ground Fault on a Radial System**




$$I_{A2} = -I_{A1}$$


$$I_A = I_{A1} + I_{A2} = 0$$
$$I_B = I_{B1} + I_{B2}$$
$$I_C = I_{C1} + I_{C2}$$




$$\sqrt{3}\,|I_{B2}| = |I_B|$$
$$\sqrt{3}\,|I_{C2}| = |I_C|$$

$$\sqrt{3}\, I_2 = I_P$$
$$3\, I_2 = \sqrt{3}\, I_P$$

$$\therefore \boxed{\frac{3\, I_2}{I_P} = \sqrt{3}}$$

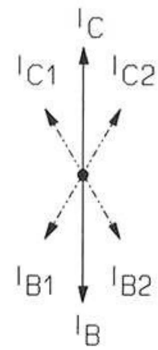
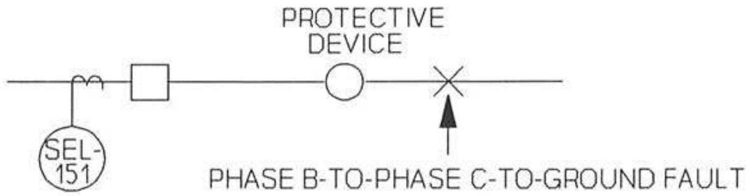
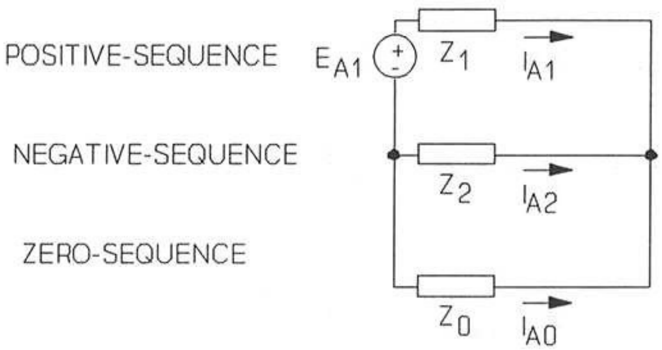



**Figure 6: Phase-to-Phase Fault on a Radial System**




$$I_{A2} = -I_{A1} \frac{Z_0}{Z_0 + Z_2}$$

$$I_{A0} = -I_{A1} \frac{Z_2}{Z_0 + Z_2}$$

$$I_B = a^2 I_{A1} + a I_{A2} + I_{A0}$$

$$a = 1 \angle 120^\circ$$

FROM THE ABOVE EQUATIONS, THE FOLLOWING EQUATION CAN BE DERIVED:

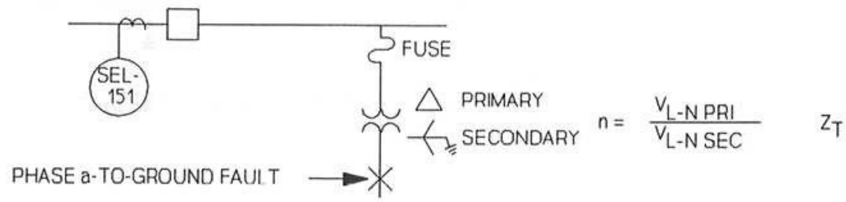
$$\left|\frac{3I_2}{I_P}\right| = \left|\sqrt{\frac{3}{1 + \frac{Z_2}{Z_0} + \left(\frac{Z_2}{Z_0}\right)^2}}\right|$$

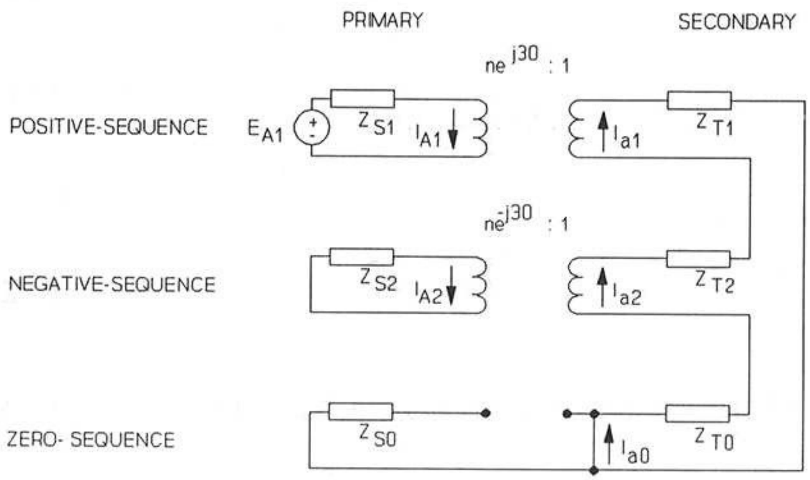
$Z_0$ INCLUDES GROUND FAULT RESISTANCE, IF PRESENT

| $\left\lvert\frac{Z_0}{Z_2}\right\rvert$ | $\left\lvert\frac{3I_2}{I_P}\right\rvert$ | $\left\lvert\frac{3I_2}{3I_0}\right\rvert$ |
|---|---|---|
| 0.00 | 0.00 | 0.00 |
| $\downarrow$ | $\downarrow$ | $\downarrow$ |
| $\infty$ | $\therefore \boxed{1.73 = \sqrt{3}}$ | $\infty$ |

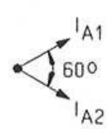
$$\left|\frac{Z_0}{Z_2}\right| \Rightarrow \infty \text{ (AS GROUND FAULT RESISTANCE INCREASES)}$$

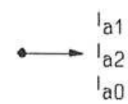
**Figure 7: Phase-to-Phase-to-Ground Fault on a Radial System**



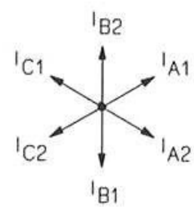

$$|I_{A1}| = |I_{A2}|$$



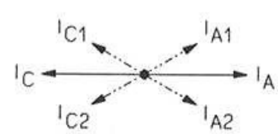




$$I_{a1} = I_{a2} = I_{a0}$$

$$I_A = I_{A1} + I_{A2}$$
$$I_B = I_{B1} + I_{B2} = 0$$
$$I_C = I_{C1} + I_{C2}$$




$$\sqrt{3}\,|I_{A2}| = |I_A|$$
$$\sqrt{3}\,|I_{C2}| = |I_C|$$




$$\sqrt{3}\, I_2 = I_P$$
$$3\, I_2 = \sqrt{3}\, I_P$$
$$\therefore \boxed{\frac{3\, I_2}{I_P} = \sqrt{3}}$$

**Figure 8: Phase-to-Ground Fault on the Secondary of a Delta-Wye Transformer**

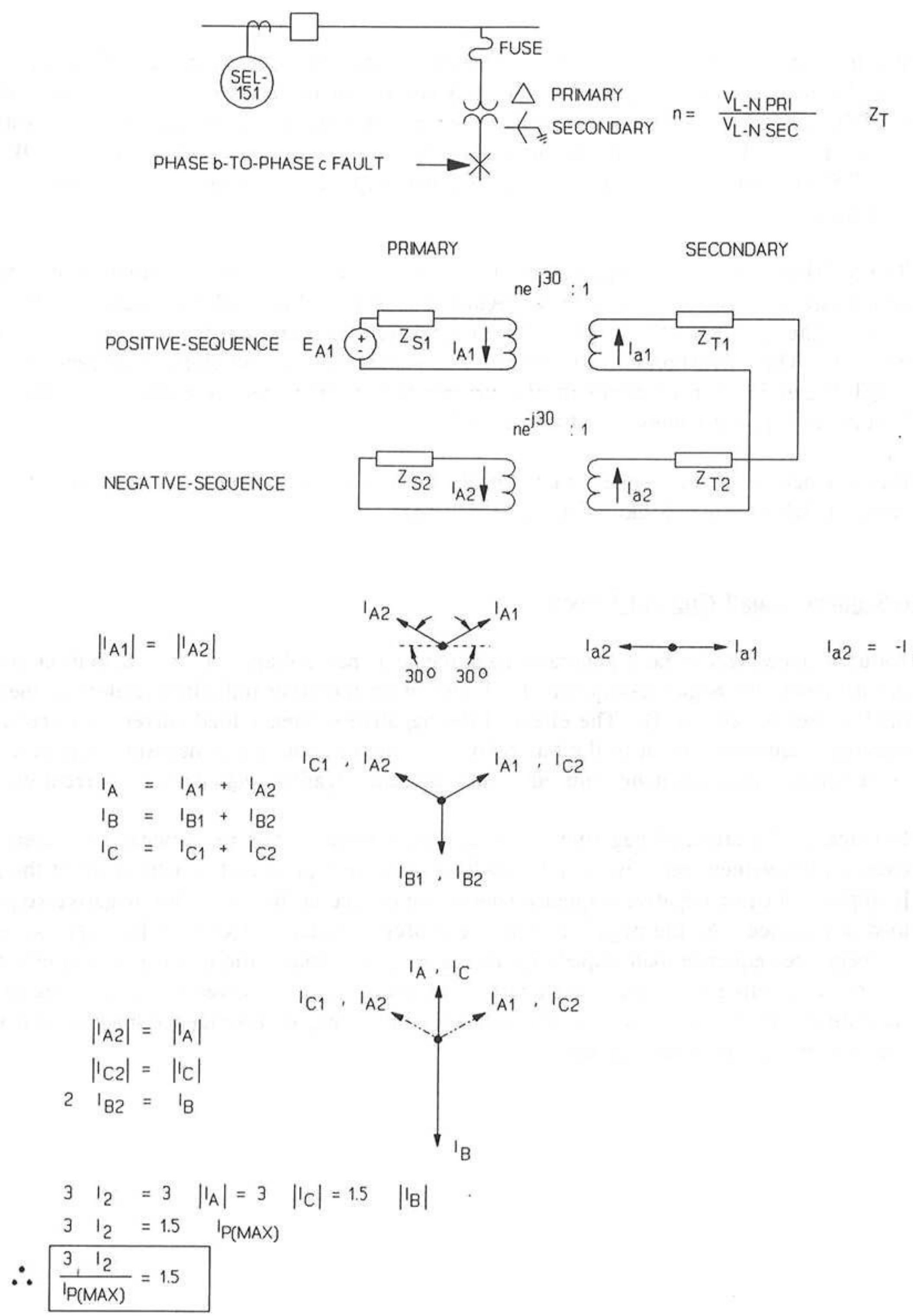



**Figure 9: Phase-to-Phase Fault on the Secondary of a Delta-Wye Transformer**

## Negative-Sequence Overcurrent Element Coordination Example

Bus-to-feeder-to-fuse coordination for phase-to-phase faults for a typical B.C. Hydro installation is shown in Figure 10. The bus and feeder phase time-overcurrent elements (51T-B and 51T-F, respectively) have to be set with load and cold load pickup conditions in mind. But the bus and feeder negative-sequence time-overcurrent elements (51QT-B and 51QT-F, respectively) do not have to be set with regard to load or cold load pickup conditions.

The 51QT-F curve is the "equivalent" feeder phase time-overcurrent element that is set to coordinate with 100T fuses, with no regard to feeder load or cold load pickup. The 51QT-B curve is the "equivalent" bus phase time-overcurrent element that is set to coordinate with 51QT-F. The corresponding true negative-sequence overcurrent element current values for 51QT-B and 51QT-F (in terms of $3I_2$ current) can be calculated by multiplying their "equivalent" phase values by a factor of $\sqrt{3}$.

Improvement in phase-to-phase fault sensitivity is evident in Figure 10, especially for the bus relay, which provides backup for the feeder relay.

## Negative-Sequence Load Current Effects

An unbalanced feeder fault generates negative-sequence voltage on the distribution bus which in turn generates negative-sequence load current on the other unfaulted feeders connected to the bus (see Reference 7). The effect of the negative-sequence load current is to reduce the negative-sequence current to the bus relay, i.e., help the bus relay negative-sequence overcurrent elements coordinate with other downstream negative-sequence overcurrent elements.

Practically, the effect of negative-sequence load current on bus relay negative-sequence overcurrent element sensitivity and coordination is negligible and is a function of the ratio [complex ratio] of negative-sequence source impedance at the bus to the negative-sequence load impedance. As the negative-sequence source impedance decreases [stronger source] or the negative-sequence load impedance increases [lower load], the desensitization effect on the bus relay negative-sequence overcurrent elements is reduced. Over a typical range of this ratio on the B.C. Hydro system, the reduction in bus negative-sequence load current was found to be less than ten percent.

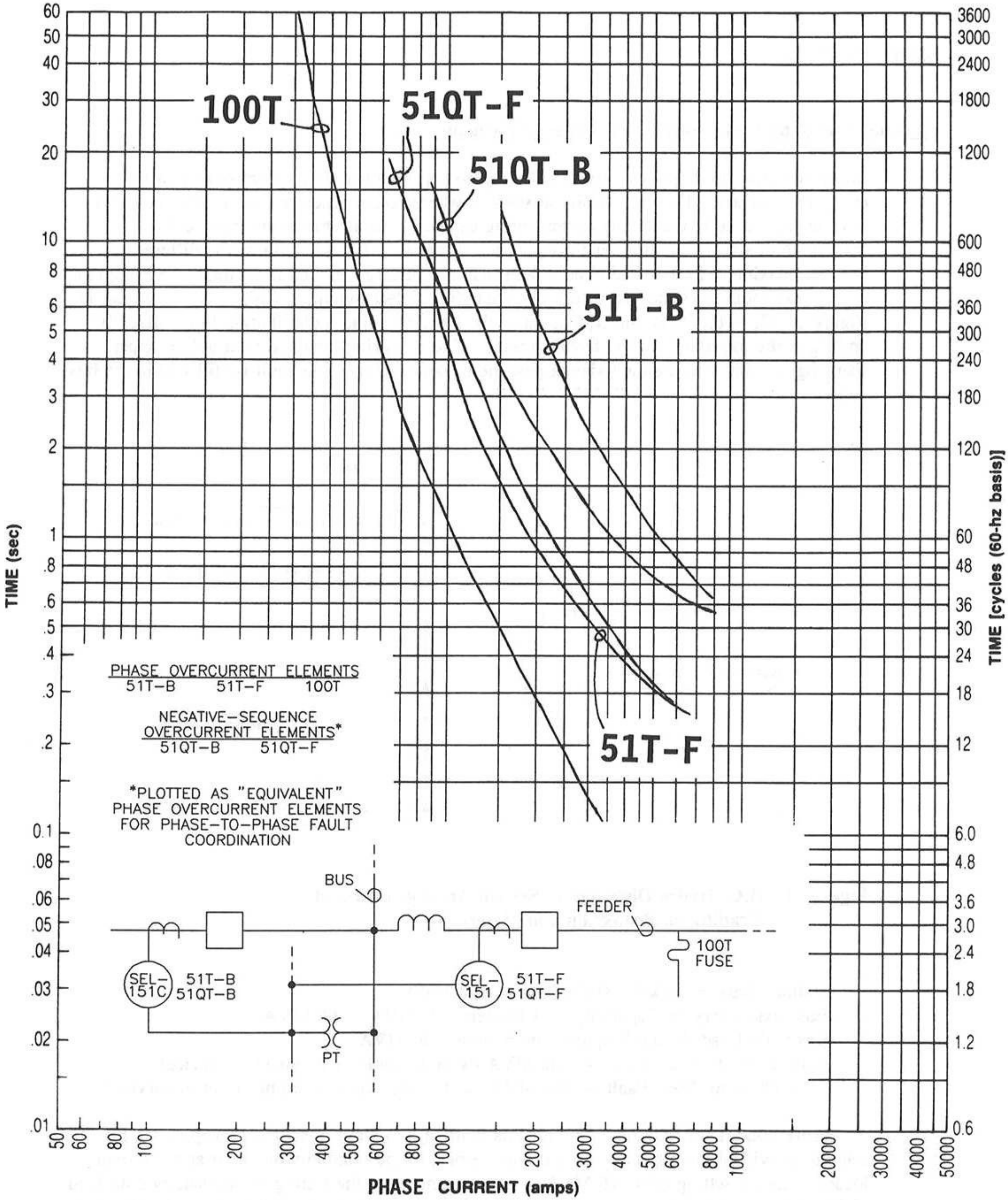



**Figure 10: Phase-to-Phase Fault Coordination**

# APPENDIX 2

**Torque-Control by Undervoltage and Distance Elements**

Many bus protection applications on B.C. Hydro's system use torque-control of phase overcurrent relays. This is typically at stations where feeder reactors limit feeder fault levels in order to reduce feeder breaker interrupting capability requirements and reduce the magnitude of station transformer through fault currents. At these stations, the difference between maximum load and minimum fault may not be large enough to facilitate a setting that allows maximum load and yet is sensitive enough to detect minimum faults. For example, in Figure 11, $Z_S$ is the Thévenin equivalent of the system behind a distribution low voltage bus and $Z_R$ is the impedance of the feeder reactor. The following load and fault values apply. Fault figures apply to the fault shown past the feeder reactor. This fault is still within the bus zone.

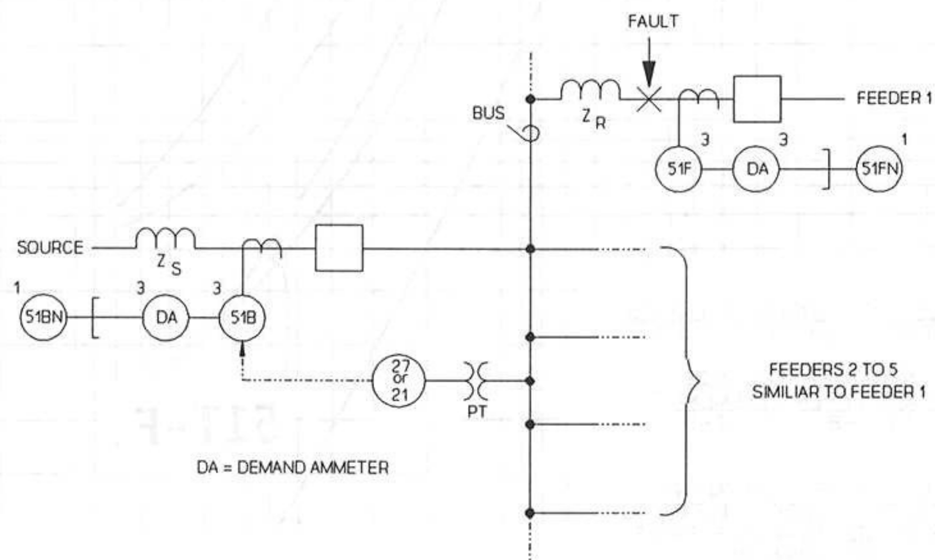



**Figure 11: B.C. Hydro Distribution System Arrangement and Traditional Protection and Metering**

Voltage Base = 25 kV; MVA Base = 100 MVA
Bus Load Carrying Capability = 5 Feeders x 12MVA = 60 MVA
Bus Cold Load Pickup Requirement = 90 to 120 MVA
Max. Phase-to-Phase Fault = 286 MVA (with all station equipment in service)
Min. Phase-to-Phase Fault = 190 MVA (with some station equipment out of service)

To ensure operation of the bus relay for this fault, it is desired to set the pickup of the bus relay to provide a margin of 2.5 to 3.0 with respect to the minimum bus fault at the shown location (i.e., a setting of 63-76 MVA). At the same time, the setting should satisfy cold load pickup requirements. It becomes clear that a satisfactory setting is not possible. A solution to this problem is to use another element that operates on fault but not on load and have this element control the bus overcurrent relay. With this solution a setting of say, 70 MVA could be applied to satisfy the fault sensitivity requirements.

Note that "control" and not "supervision" is used. By control, it is meant that the overcurrent element does not start timing until the controlling element has operated. Control is more secure than supervision. In supervision, the overcurrent element can time-out, but tripping is held pending operation of the supervising element. If a transient operates the supervising element, false tripping can result if the overcurrent element has already operated on load.

In most applications, undervoltage relays, connected phase-to-phase to the bus PT's shown in Figure 11 are used to provide the torque-control feature. But, in stations where the source behind the bus is very strong (i.e., $Z_S$ is very small) the voltage drop at the bus due to a three-phase fault at the shown location may not be enough to allow a reasonable undervoltage relay setting. For example, for this fault, if $Z_S = 0.06$ pu and $Z_R = 0.29$ pu, the bus voltage would drop to $\approx 0.83$ pu $[0.29/(0.29 + 0.06) = 0.83]$. This would not provide a good margin for positive operation of an undervoltage relay set (typically) to dropout at $\approx 0.85$ pu. For these substations, a distance, rather than undervoltage relay is applied to provide the torque-control. The distance relay would then be set to cover to the fault location shown with enough margin.

## APPENDIX 3

### Development of Bus Phase Element Settings

In order to provide effective backup for feeder phase overcurrent elements, the bus phase overcurrent elements must be set as sensitive and as fast as possible, while maintaining proper coordination with the feeder relay. The best way to illustrate our strategy for bus relay phase overcurrent settings is to show it through an example for a typical installation on the B.C. Hydro system.

Figure 12 shows a typical 25 kV feeder section consisting of two bus sections, where each bus section supplies four feeders and a feeder tie. The feeder tie is provided for emergency feeder supply on loss or maintenance of a feeder breaker or a bus section. Each feeder has a feeder reactor to limit maximum feeder fault levels to approximately 7000A. This configuration is typical of an urban substation where feeder settings must coordinate with the maximum distribution fuse size on our system, 100T.

With feeder loading up to 300A, the feeder phase overcurrent elements are set at 600A to provide some cold load pickup margin, and time dial #2 on a "very inverse" characteristic to provide coordination with the 100T fuse. The feeder bus relay must allow for the load of four feeders, with some margin for cold load pickup, and of eight feeders (for loss of one bus section) with little or no margin for cold load pickup. A setting of more than 2000A is required. Even if this setting is adequate for bus faults, it is by no means acceptable for satisfactory backup for feeder faults. Torque-control of the bus phase overcurrent relays is required.

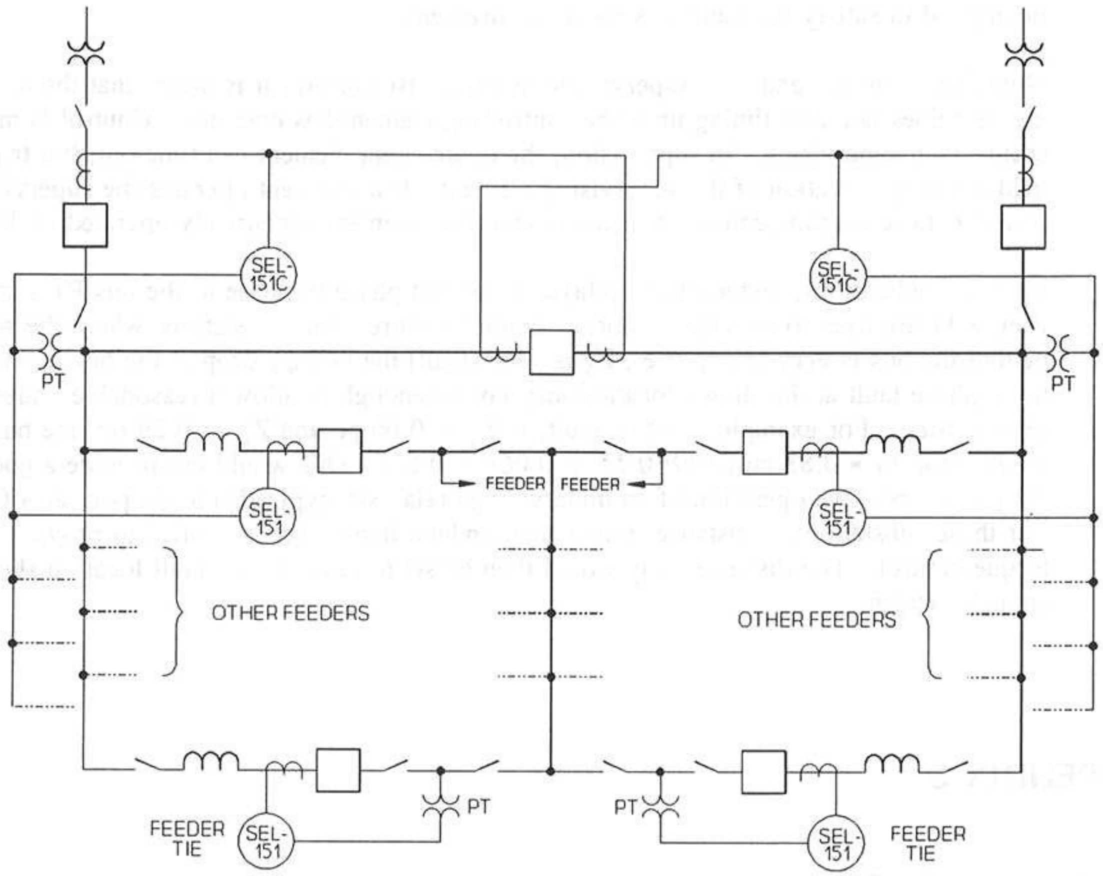



**Figure 12: B.C. Hydro 25 kV Feeder Section**

With torque-control, a bus phase overcurrent relay set as close as possible to 600A (feeder relay setting) while also coordinating with the feeder phase element is desirable. Our fault studies indicated that the minimum setting for the bus relay to coordinate with the feeder relay was about 1000A. This takes into account that for remote feeder faults, the bus phase element senses much higher currents than the feeder phase element, since the bus relay carries load currents plus feeder fault currents. Since a phase time-overcurrent element set to pickup at 1000A takes a long time to operate at low multiples of pickup current, a torque-controlled definite-time phase overcurrent element set to 1000A pickup is used in conjunction with the phase time-overcurrent element. The phase time-overcurrent element alone was not considered adequate enough to provide the feeder relay backup feature. In the SEL-151C and SEL-151 relays, both instantaneous overcurrent and time-overcurrent elements can be torque-controlled. Definite-time overcurrent elements are derived from instantaneous overcurrent elements and so definite-time elements can be torque-controlled, too.

Undervoltage relays cannot be used for torque-control in this case, for reasons explained in Appendix 2. Even at stations with no feeder reactor and with weaker sources, undervoltage relays for torque-control are not appropriate. This is because the feeder impedance dominates, resulting in little voltage drop at the station for remote feeder faults. A distance relay, on the other hand, can cover to the desired fault location, but load encroachment must be assessed.

The bus distance element setting must satisfy two requirements:

- operate for a 1000A fault on the feeder (bus phase time-overcurrent and definite-time element pickup settings = 1000A)
- have a limited reach along the load angle to allow the load carrying capability of the bus

To allow more load, the maximum torque angle (MTA) of the relay was set at 85 degrees. With this angle, it was possible to maintain the desired reach along the feeder angle (60 degrees), and at the same time, limit the reach along the feeder load angle (25 degrees assumed). Figure 13(a) illustrates the effect of increasing the MTA on permissible load. Circle 2 with MTA of 85 degrees has less reach along the feeder load angle than circle 1 with MTA matching the feeder angle. This solution allows a large increase in the distance element load carrying capability, but not enough to carry the maximum load of 8-10 feeders per feeder section.

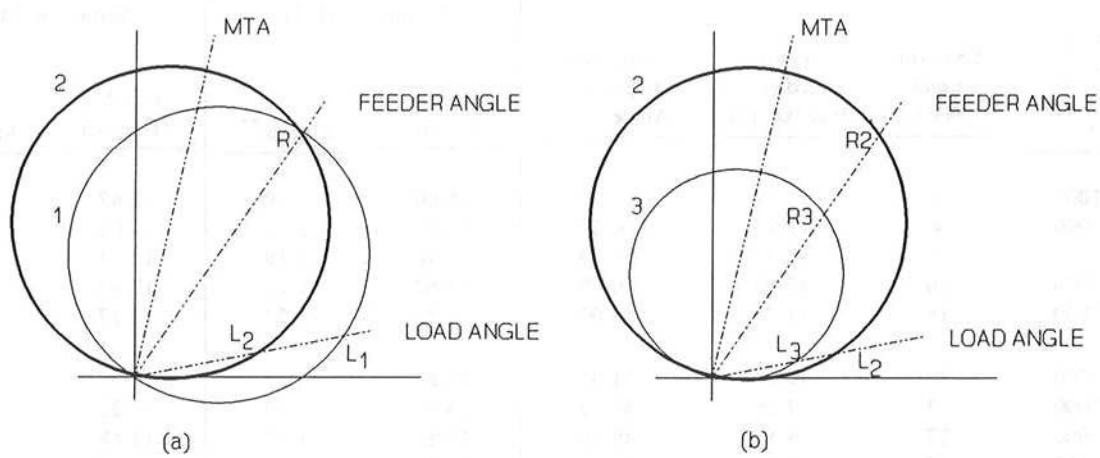



**Figure 13: (a) Increase MTA to Carry More Bus Load**
**(b) Decrease Setting with Help of Load**

A further increase in distance element load carrying capability is achieved by taking advantage of the effect of load on distance element reach. Because of bus load, the total current to the bus relay is larger than the fault current. This makes the apparent impedance to the feeder fault, as seen by the bus distance element, smaller than its actual value. As can be seen from Figure 13(b), if the distance element is set to cover to point R2 on the feeder, without considering load, then the setting will be as per the larger mho circle. If the station load is high enough to make location R2 appear to the distance element to be at location R3, then the element could be set to cover to location R3 (smaller mho circle) without compromising the coverage required. The shorter setting allows more load carrying capability for the distance element.

Table 2 shows the two settings that will be used for the distance element. The more sensitive setting (16.71 ohms) will be used when there are no more than five feeders on the feeder section. This setting has 76 MVA load carrying capability (at 25 deg. load angle), thus allowing some margin for cold load pickup. When more feeders are added, the shorter distance relay reach will be applied. At that time there would be enough bus load to improve the coverage provided by the distance element. The setting of 14.43 Ohms at 85 degree MTA has a load carrying capability of 88 MVA, allowing a small cold load pickup factor.

Table 2 lists the result of a fault study. It shows the apparent impedance to the feeder bus, for a feeder fault and a specific bus load. As indicated on the table, the fault locations were selected to result in feeder fault current of 1000A and 1100A, in order to assess the margin of coverage provided by the distance element settings.

**Table 2: Effective Bus Distance Element Reach for Feeder Phase Fault**

| | | | | (Distance Element Settings: MTA = 85 degrees; Setting in Ω, primary) | | | |
|---|---|---|---|---|---|---|---|
| | | | | Setting = 16.71 | | Setting = 14.43 | |
| Feeder Fault Current (A) | Total Bus Load (MVA) | Apparent Impedance at Bus (Ω, pri.) | Apparent Impedance Angle (deg.) | Reach* (Ω, pri.) | Margin** | Reach* (Ω, pri.) | Margin** |
| 1000 | 0 | 14.19 | 64.00 | 15.60 | 1.10 | 13.47 | 0.95 |
| 1000 | 4 | 13.25 | 60.00 | 15.15 | 1.14 | 13.08 | 0.99 |
| 1000 | 8 | 12.39 | 57.00 | 14.76 | 1.19 | 12.74 | 1.03 |
| 1000 | 10 | 11.99 | 56.00 | 14.62 | 1.22 | 12.62 | 1.05 |
| 1000 | 14 | 11.26 | 54.00 | 14.32 | 1.27 | 12.37 | 1.10 |
| 1000 | 20 | 10.29 | 51.00 | 13.85 | 1.35 | 11.97 | 1.16 |
| 1000 | 23 | 9.86 | 50.00 | 13.69 | 1.39 | 11.82 | 1.20 |
| 1000 | 27 | 9.33 | 49.00 | 13.52 | 1.45 | 11.68 | 1.25 |
| 1000 | 35 | 8.41 | 46.00 | 12.99 | 1.54 | 11.22 | 1.33 |
| 1000 | 40 | 7.92 | 45.00 | 12.80 | 1.62 | 11.06 | 1.40 |
| 1100 | 0 | 12.86 | 63.00 | 15.49 | 1.20 | 13.38 | 1.04 |
| 1100 | 6 | 11.72 | 59.00 | 15.02 | 1.28 | 12.97 | 1.11 |
| 1100 | 10 | 11.04 | 57.00 | 14.76 | 1.34 | 12.74 | 1.15 |
| 1100 | 20 | 9.59 | 52.00 | 14.02 | 1.46 | 12.10 | 1.26 |
| 1100 | 30 | 8.44 | 49.00 | 13.52 | 1.60 | 11.68 | 1.38 |

* Reach = (Distance element setting in Ω, primary) x cos(85° - Apparent Impedance Angle)
= Effective distance element reach for fault (Ω, primary)

** Margin = Reach/Apparent Impedance at Bus

25 kV Voltage Base

## APPENDIX 4

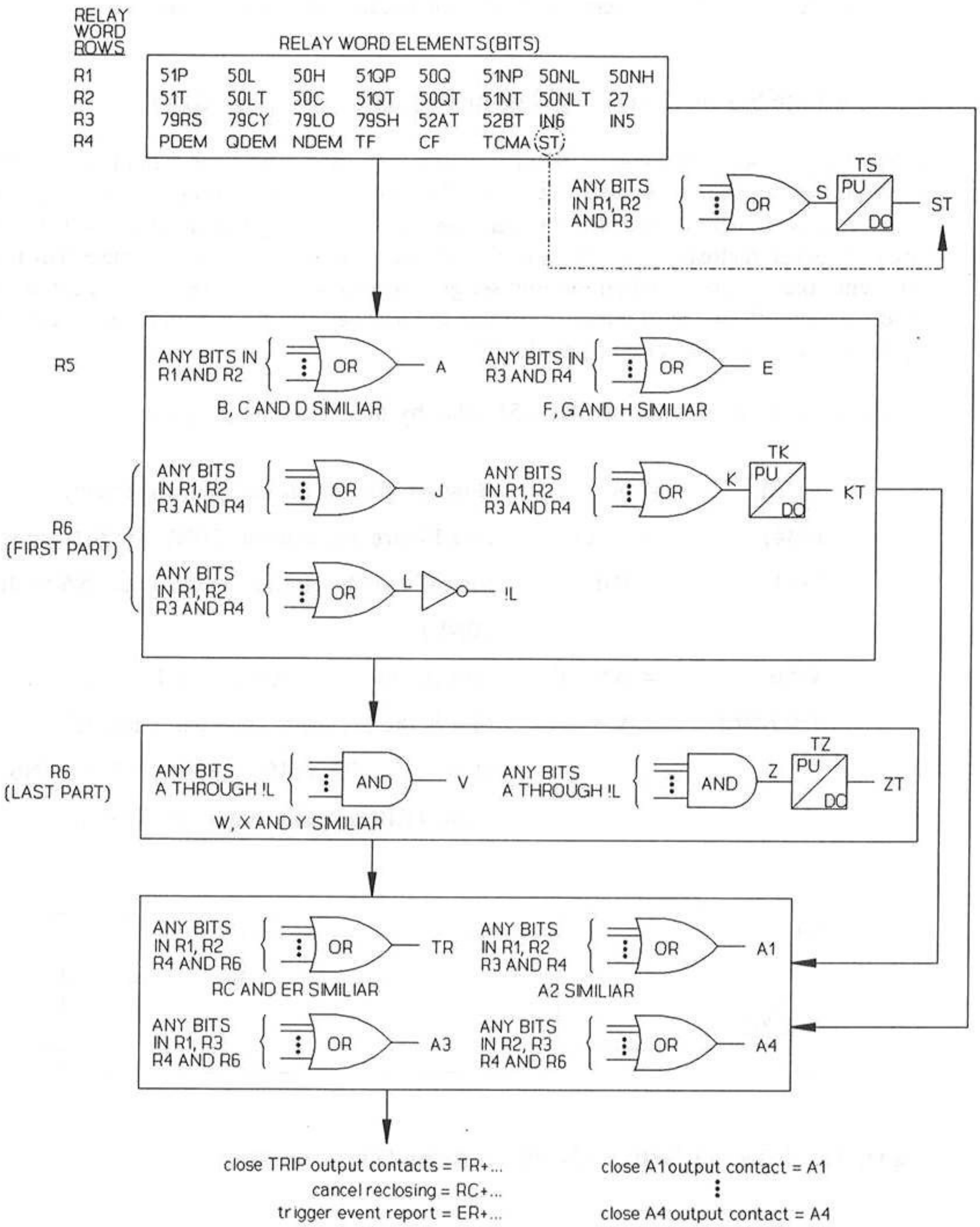



**Figure 14: Programmable Logic Block Diagram (SEL-151 Relay)**

## B.C. Hydro Logic Programming for the SEL-151 and SEL-151C Relays

In the following examples, the numbers in parenthesis following a programmable element [e.g., A(12)] indicate what Relay Word rows can be accessed for programming the element. This is how they appear in the actual programming procedure. The parentheses are not shown with the programmable elements in Figure 14 because of space constraints.

## Programming a Fuse Saving Scheme for Feeder Protection (SEL-151 Relay)

A low-set ground instantaneous element attempts to save a fuse for a fault beyond the fuse only once at the start of a reclosing cycle (first trip). Upon tripping of the feeder circuit breaker, this element is disabled and remains disabled for a set time after the subsequent circuit breaker reclosure. If the fault beyond the fuse is permanent, the fuse will blow following the reclosure, when the low-set ground instantaneous element is disabled for the set time. An on-off switch is wired to disable the low-set ground instantaneous element, if necessary (e.g., during circuit paralleling).

This scheme is realized in the SEL-151 relay by the following program:

| | | |
|---|---|---|
| A(12) | = 50NL | (low-set ground instantaneous element) |
| E(34) | = 52AT | (see Figure 16; disables 50NL for fuse saving) |
| F(34) | = IN6 | (on-off switch wired to relay input IN6 to disable 50NL) |
| V(56) | = A*E*F | (effectively, V = 50NL*52AT*IN6) |
| TR(1246) | = V+... | (TR is the programmable trip variable) |
| | | effectively, TR(1246) = (50NL*52AT*IN6)+... |
| | | close TRIP output contacts = TR+... |

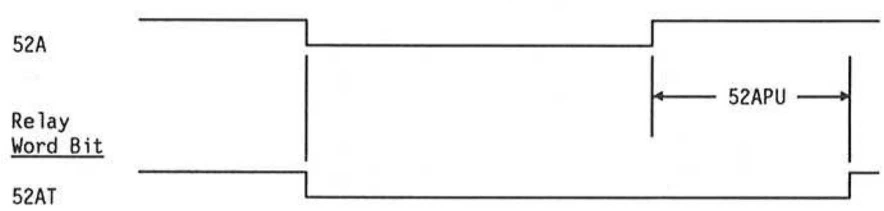



**Figure 15: Effect of Setting 52APU on Relay Word Bit 52AT**

The 52APU time period provides the set time that 50NL continues to be disabled after the circuit breaker is reclosed.

## Programming for Undervoltage Tripping

At B.C. Hydro diesel stations, feeder and bus protection is provided by undervoltage and overcurrent relays with the undervoltage relays tripping through timers. Overcurrent relaying alone is not dependable because the rotating machine impedance dominates and can reach the steady state value before the overcurrent relays operate. Depending on the bus PT location, tripping the bus may result in loss-of-potential to the PT's feeding the undervoltage elements. Tripping from these elements would be held, thus preventing re-energization of the bus. In this case, another timer is provided to disable tripping from the undervoltage elements, after a set time. The SEL-151 relay can be programmed to accomplish the undervoltage trip and trip reset as follows.

| | | |
|---|---|---|
| S(123) | = 27 | (undervoltage element, 27, initiates timer TS) |
| K(1234) | = 27 | (undervoltage element, 27, initiates timer TK; output of timer TK is time-qualified undervoltage condition) |
| L(1234) | = ST | (L set equal to output of timer TS) |
| W(56) | = KT*!L | (effectively, W = KT*NOT(L); the output of timer TK is limited in time duration by !L) |
| TR(1246) | = W+... | (TR(1246) is the programmable trip variable) |
| | | effectively, TR(1246) = (KT*!L)+... |
| | | close TRIP output contacts = TR+... |

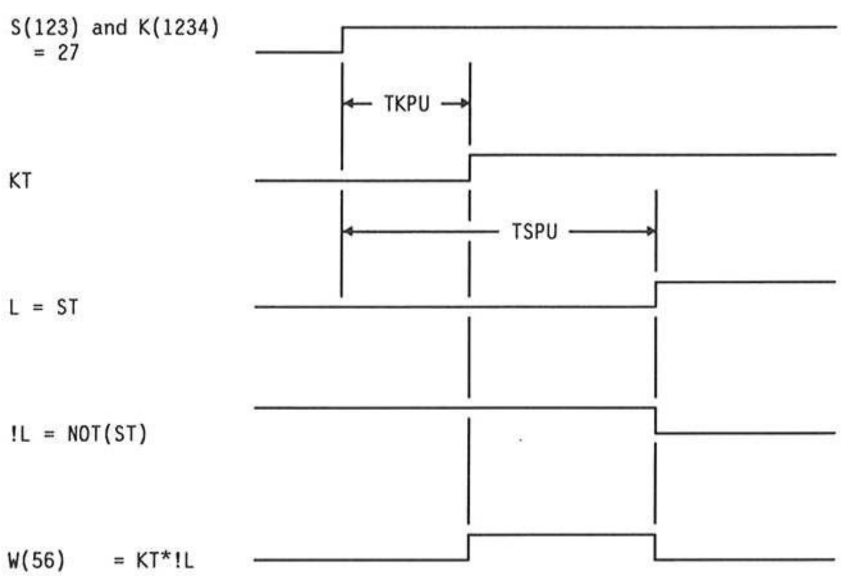



**Figure 16: Undervoltage Trip Condition Time Duration Limit**

By setting timer TS longer than timer TK, tripping from the undervoltage elements will be a pulse type whose duration is adjustable, thus achieving both the tripping and the resetting of the trip pulse.

<u>Programming the Output Contacts</u>

Typically the following output contacts will be used for the feeder relay.

TR(1246) = 50H+51QT+50NH+51T+51NT+V

(TR(1246) is the programmable trip variable; V is from the fuse saving scheme)

close TRIP output contacts = TR+...

A1(1234) = TF (feeder breaker failure output wired to trip adjacent bus zone)

A2(1234) = NDEM (Excessive feeder neutral demand current to initiate an alarm)

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# BIOGRAPHICAL SKETCHES

## Edmund O. Schweitzer III

Edmund O. Schweitzer received his BSEE at Purdue University in 1968 and MSEE at Purdue in 1971. He earned his PhD at Washington State University in 1977. His professional experience includes electrical engineering work at Probe Systems in California and the National Security Agency in Maryland. He served as an assistant professor at Ohio University and Washington State University and an associate professor at Washington State University. Since 1983, he has directed the activities of Schweitzer Engineering Laboratories, Inc., the company he founded in Pullman, Washington. SEL designs, manufactures, and markets digital protective relays for power system protection.

Schweitzer started investigating digital relays during PhD studies at Washington State University in 1976. This investigation produced his doctoral dissertation and Schweitzer Engineering Laboratories, Inc. Schweitzer's university research was supported by Bonneville Power Administration, Electric Power Research Institute, and various utilities. Although the company has grown significantly, Schweitzer is still involved in the development of new relays and auxiliary equipment.

Last year, Schweitzer was elected a Fellow of the Institute of Electrical and Electronic Engineers (IEEE), an honor accorded less than one percent of electrical and electronic engineers. Schweitzer is a member of Eta Kappa Nu and Tau Beta Pi and has authored or co-authored 30 technical papers. He was among four finalists for the 1991 High Technology Entrepreneur of the Year, an award sponsored by a consortium of six major Washington businesses and associations. Schweitzer was chosen as the speaker for Washington State University's 1991 Lanning Distinguished Lecture during National Engineer's Week.

## Ahmed F. Elneweihi

Graduated in 1964 from Faculty of Engineering, Cairo University, Egypt with B.S.C. in Electrical Power Engineering.

From 1964-1971, worked for the Aswan Dam Authority, Egypt on 500 kV transmission design and construction as well as Equipment Purchasing and Inspection.

Immigrated to Canada and joined B.C. Hydro in 1971.

| | |
|---|---|
| 1971 - 1974 | Protection and Control Engineer with Production Group |
| 1974 - 1975 | Scheduling Engineer at a Control Centre with Production Group |
| 1975 - Present | Senior System Protection Engineer, Protection Planning Department |

Is a member of IEEE and serves on two Working Groups: "Static Var Compensator Protection" W.G. as Vice-Chairman, and "Use of Expert Systems in Protection" W.G. as a member.

**Mark W. Feltis**

Mark W. Feltis received his BSEE degree at Montana State University in 1984. He earned his MSEE degree at Washington State University in 1990, under fellowship from Schweitzer Engineering Laboratories, Inc., Pullman, Washington.

Mr. Feltis' professional experience includes working for four years (1984-1988) for the Pacific Gas and Electric Company in Santa Cruz, California in distribution planning, protection, and operations. From 1990 to the present, he has been working at Schweitzer Engineering Laboratories, Inc. as a development engineer in protective relay design.

Mr. Feltis is a member of Tau Beta Pi, the IEEE Power Engineering Society, and is a registered professional engineer in the state of California.

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Communications, Computers and Power in the
Modern Environment.

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