UNITED STATES DEPARTMENT OF AGRICULTURE
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SUBJECT: **Design Guide for Sectionalizing Distribution Lines**

TO: All Electric Borrowers

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OFFICE OF PRIMARY INTEREST: Distribution Branch, Electric Staff Division

INSTRUCTIONS: This bulletin replaces Bulletin 61-2 which was rescinded in 1992.

AVAILABILITY: This bulletin can be accessed via Internet at:

http://www.usda.gov/rus/electric/bulletins.htm

PURPOSE: This bulletin provides guidance and assistance in sectionalizing distribution lines to protect them from faults.

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10/23/12
Date

TABLE OF CONTENTS

Exhibits

INDEX:

Sectionalizing Distribution Lines
Design Guide

ABBREVIATIONS

A	amperes (or amps)
AC	alternating current
ANSI	American National Standards Institute
BIL	basic impulse level
CLF	current-limiting fuse
CRN	Cooperative Research Network
DC	direct current
DG	distributed generation
DR	distributed resources
EEI	Edison Electric Institute
FCI	faulted circuit indicator
FERC	Federal Energy Regulatory Commission
G&T	generation and transmission cooperative
GIS	geographic information system
GPS	global positioning system
IED	intelligent electronic device
IEEE	Institute of Electronics and Electrical Engineers
IMT	impulse margin time
MFT	minimum fault time
NEMA	National Electrical Manufacturers Association
NERC	North American Electric Reliability Corporation
NRECA	National Rural Electric Cooperative Association
OCR	oil circuit recloser
P.U.	per unit
PLC	programmable logic control
ROT	relay operating time
SCADA	supervisory control and data acquisition
SF_6	sulfur hexafluoride
STD	substation transformer and distribution line
TCC	time-current characteristic
TCP/IP	Transmission Control Protocol/Internet Protocol

UPS	uninterruptible power supply
VAR	volt-amperes reactive
V	volts
Ω	ohms

1 INTRODUCTION

This bulletin is a guide for making sectionalizing and protection studies on electric distribution systems for rural electric cooperatives. It provides a revised and updated version of RUS Bulletin 61-2 which was rescinded in 1992. Specifically, the bulletin updates methods, examples, and tools relevant to radial distribution systems. As in the earlier publications, it is not intended to provide a complete and exhaustive discussion of the subject, but rather to present the reader with helpful information and examples that will typically be encountered.

Within the arena of sectionalizing, there are many aspects of the subject that are established, quantifiable, and part of national standards. Included in this body of information are specific time-current characteristics of fuses and relays, the methods of calculations for available short-circuit current, and the standard damage points for distribution transformers. There are also many aspects of sectionalizing that are more subjective, debatable, and influenced by experience. These include “fuse save” versus “fuse blow,” coordination margins, and transformer protection practices. This reflects the idea that system protection is partly science and partly art.

This bulletin concentrates on the “science” side of the subject and offers some well-established practices and conventions on the “art” side. In the end, it is the responsibility of a cooperative’s protection engineer to recognize the specific needs and goals of the cooperative and apply the principles herein to the available equipment and technology to accomplish the best combination of reliability and economics possible.

This bulletin is not intended to provide a detailed discussion of substation transformer protection. The document focuses on the distribution system beginning at the low-side connections of the substation transformer.

Arc Flash energy available on a distribution system will be affected by system protective device settings. Although it is beyond the scope of this Bulletin to address this issue, the protection engineer is encouraged to research and understand the relationship between system settings and arc flash energy.

2 PHILOSOPHY AND STUDY PREPARATION

a General. At a high level, sectionalizing is about compromises and creating the best combination of methods and practices that suits the individual cooperative. Goals and issues must be considered and evaluated and then implemented. Questions that must be considered include the following:

- Which is more of a problem, blinks or longer outages?
- How high can we (or should we) set protective devices?
- Are our equipment maintenance cycles adequate?
- Do right-of-way cycles affect our protection plans?
- What weather patterns affect our service area?

b System Reliability. The goal of all coordination philosophies is improved system reliability.

(1) Setting Service Priorities. Inherently, the installation of any coordination device sacrifices the electric service to the loads and customers downline for the greater good of maintaining service to the rest of the customers. The device may protect major or critical loads by dropping long exposures to noncritical loads during fault conditions. But one must remember that every sectionalizing device sets a priority of service because its operation stops electric service, even temporarily, to the downline customers in favor of the rest of the circuit customers.

(2) Protective Devices. The protection engineer must face a compromise: Higher settings for protective devices typically will improve reliability on a distribution system by reducing the number of nuisance operations while allowing for more downline devices to be applied. On the other hand, lower settings for protective devices can improve the security of the system by clearing higher-impedance faults (at the expense of increased operations).

(3) Different Approaches. No single approach is right for all systems and, many times, not even for all portions of one system. Urban and rural service areas have different characteristics and different approaches may be appropriate. This bulletin suggests an approach for determining settings for typical environments. It is important to understand the methodology and what can be achieved (as well as what cannot be achieved) rather than to use rote settings or values.

c Temporary and Permanent Faults. Faults can generally be categorized as temporary or permanent.

(1) System Protection. It is easy to agree on one thing in system protection: that permanent faults need to be disconnected or they will disconnect themselves through destruction of the system. Studies have shown that a majority of faults are temporary in nature. Historically, utilities have used devices (circuit breakers and reclosers) to clear temporary faults and restore service without manual intervention. These same devices also clear permanent faults, but require manual intervention to restore service afterward.

(2) Application of Fault Devices. The application of these devices, including how many to use, how to use them, and how to set them depends on the sectionalizing goals of the cooperative. Any fault or short circuit draws fault current depending on the system and fault impedance. Some electronically controlled reclosers record the magnitude of the fault which

occurred. Some faults are actually located by comparing the actual fault current level to areas that can develop a fault of that magnitude. Tolerance to temporary faults is discussed in Section 2E of this Design Guide, “Fuse Saving.”

d Zones of Protection. In developing a sectionalizing study, maximum and minimum fault currents must be calculated.

(1) Determining Fault Current Levels. Maximum fault current levels are used to ensure that interrupting devices have adequate capabilities and ratings to handle the full amount of fault current to which they may be exposed. Minimum fault current levels are used to determine the zone of protection for a particular device. Determining the minimum fault current is a challenge, as fault currents can be below load levels. Certain assumptions are required because of the variability of faults on distribution systems. Utilities have used such methods to estimate minimum fault current levels as:

- Assuming some percentage of maximum fault current,
- Assuming some multiple of load current, and
- Assuming some fault impedance (Z_f) level.

(2) Methods. Traditionally, cooperatives have used the fault impedance method successfully, and this method will be described in this manual. The question that has always been considered is “What fault impedance should be used?” The previous version of this bulletin suggested 30 to 40 Ω for overhead lines and 10 to 20 Ω for underground lines. This led to some confusion and concern about the use of 40 Ω of ground fault resistance to calculate the minimum fault current available for overhead construction on distribution systems under the jurisdiction of the Rural Utilities Service.

(3) Discussion. The following discussion (through the end of this subsection) is offered to clarify the issue and establish guidelines that can support sound electric system operations. Studies have shown that the actual fault impedance when an energized conductor is in contact with the earth can vary from zero to infinity.[1] Therefore, it is impossible, using current technology, to select a minimum pickup value that will both detect energized conductors in contact with the ground and allow normal load currents to flow without interfering with normal system operation.

The 40-Ω value described in RUS bulletins and literature has always been

[1] “Downed Power Lines: Why They Can’t Always Be Detected,” NRECA, February 22, 1989.

a compromise and was never intended to be an absolute value.[2] This is supported by the fact that Bulletin 61-2 was a guide bulletin before it was rescinded and by the fact that it suggested the use of 30 Ω under certain conditions.

From an engineering perspective, any ground fault resistance used in selecting minimum ground trip levels is a "design value" selected for calculation purposes only and should not be confused with the ground fault resistance that might occur. The values of 40 and 30 Ω have been used for many years on RUS systems. Surveys have shown that utilities frequently use values other than 40 Ω.[3,4] The actual value used (or method used, for that matter) should be determined by the cooperative's engineer or consultant. Such a practice of selecting a method that allows for the possible detection of low-level ground faults while considering system voltage, load current, phase unbalance, and system coordination is considered prudent and sound utility engineering.

e Fuse Saving. One method of system protection and sectionalizing is the proper application of power fuses on the distribution system. This is an economical method to provide additional sectionalizing locations, but has one major drawback.

(1) Drawback. When the fuse blows, a service technician must go to the location, determine the cause of the fault, and re-fuse. Automatic devices, such as reclosers and circuit breakers, will reset themselves after operating a few times short of lockout, but at a considerable added cost. Fuses, by their nature, are a time-current device. A given current for a given time will melt or "blow" the undamaged fuse. Temporary faults can also melt the fuse.

(2) Outage Solutions. To avoid an outage and the associated service technician's visit, the upline recloser may have a "quick-trip curve" enabled. This allows the upline device to quickly deenergize and reenergize the line with the intention to save the fuse from blowing. Unfortunately, this "blinks" the lights of a much larger portion of the system.

With today's demand for improved power quality, including fewer blinks, this fuse-saving philosophy is being avoided, for at least a portion of the time, by some systems. By disabling the reclosers' quick-trip operation and allowing the fuses to blow, the smallest possible portion of the system

[2] "Review of Sectionalizing Fundamentals," L.B. Crann, July 1972, REA National Field Conference.
[3] "Ground Fault Impedance Values for System Protection," NRECA CRN Project 96-05, August 1997.
[4] "IEEE Guide for Protective Relay Applications to Distribution Lines," IEEE Std 37.230-2007.

experiences the outage. But, unfortunately, when a lightning shower blows through, many fuses are blown that could have been saved. Some systems can switch from the fuse-blowing philosophy to the fuse-saving philosophy, and vice versa, by reenabling or disabling the quick trip feature with distribution automation systems.

Some systems accept the fact that blinks caused by temporary faults are the real world and that the power system cannot provide blink-free power to its customers. In such systems, it is strongly suggested that each customer provide its own voltage protection in the form of uninterruptible power supplies (UPS) to critical loads, including home personal computers, just as they must be protected from surges by surge suppressors.

f Frequency of Studies. Sectionalizing studies should be reviewed at frequent intervals to ensure that they are adequate.

(1) The frequency of review should be driven by the rate of change of the system itself. When load currents or system configurations experience significant changes, the sectionalizing study should be updated to review the impact on devices.

(2) Major system changes would also necessitate that a sectionalizing study be performed as part of the work. The following would typically determine the need for a new study:

- Constructing a new substation,
- Increasing substation transformer capacity,
- Adding new substation feeders,
- Changes in available fault current due to transmission and/or distribution improvements,
- Major reconductoring projects, whether increasing conductor size on existing three-phase lines or converting from single phase to three phase, or
- Conversion to a higher operating voltage.

g Summary of Steps in Making a Sectionalizing Study. The following is a list of individual steps involved in making a sectionalizing study. These steps provide an orderly overview of the process.

(1) Obtain complete data on the distribution system and determine all device types that are likely to be used in the study.
(2) Select preferred locations for sectionalizing devices or relocated sites for existing devices. Determination of locations is based on operational concerns, outage histories, and review of system configurations.
(3) Calculate all available fault current at each tentative sectionalizing device

location.

(4) Select feeder protection to provide optimum coverage on the feeder and adequate coordination with substation transformer protection.

(5) Starting at the substation feeder protection level, make sure each device meets the cooperative's goals for sectionalizing and coordination. Revise locations and settings as necessary.

(6) Check the selected devices for voltage rating, continuous current rating, interrupting current rating, and minimum pickup rating. Make sure each device is applied within its rating and will respond to minimum fault current within its zone of protection.

(7) Prepare written instructions for additions and changes to sectionalizing devices and update existing circuit diagrams.

h Data Necessary for Sectionalizing Study. The following data should be assembled and updated at the beginning of the study.

(1) Distribution System Information

(a) Circuit diagrams of the distribution system prepared in accordance with the appropriate RUS bulletins.

(b) Locations of critical and large power loads.

(c) Maximum load currents at the time of the study for each proposed sectionalizing point.

(d) An understanding of historical load growth and future anticipated load growth for respective feeders and areas.

(e) The distribution of meters along the circuit.

(2) Substation/Source Information. This information may vary, depending on whether the cooperative owns just distribution lines, or distribution lines and substation transformers, or distribution lines and substation transformers and transmission lines. In each scenario, the available fault currents at the appropriate location must be obtained or calculated.

(3) Equipment Information. Information about the sectionalizing equipment being used and to be added should be collected. Specific equipment information, such as make, type, ratings, and characteristic curves, should be assembled and available for use.

i Location of Sectionalizing Devices

(1) Determine Locations. After the basic data have been accumulated, the next step in the study is to determine tentative locations for sectionalizing devices. These locations may be revised after the short-circuit currents are calculated and load currents checked.

(2) Suggestions. Judgment and knowledge of one's system, including terrain, must be used for each case, but the following may be helpful:

(a) Number of Automatic Sectionalizing Devices. The number of automatic sectionalizing devices used in series should be kept to a reasonable level. There are obvious advantages and disadvantages to the number of devices in series. More devices can help reduce the number of affected customers, but more devices also can create greater coordination difficulties, causing misoperations. Non-automatic devices, such as disconnect switches, can be very helpful in restoration when used judiciously between automatic devices.

(b) High-Reliability Zones. "High-reliability zones" have been suggested to improve system performance. In these zones, efforts are focused on the feeder from the source to the first set of feeder devices. Within this zone, all taps are provided with some form of sectionalizing to reduce the possibility of feeder operations. Outside of this zone, more judgment may be used in weighing protection devices versus exposure.

(c) Visibility. Main sectionalizing devices should be visible and accessible from roads during any season of the year.

(d) Critical Placement. Sectionalizing devices should be located where they will not disrupt service to critical customers. Generally, such devices should be placed just beyond these customers.

j Suggested Outline for a Sectionalizing Study

(1) Scope of study.

(2) Tabulation of sectionalizing devices to be purchased.

(3) Sectionalizing device schedule for each substation area.

(4) Cost estimate (cost of new devices and their installation, plus changing or converting existing devices).

(5) Schematic diagram and coordination chart for substation protective devices for fault conditions.

(6) Detailed impedance fault current calculations for source and substation transformers up to load side bus, if appropriate.

(7) Examples of typical time current characteristic curves for devices used in the study.

(8) Instructions to the operations manager.

3 DETERMINATION OF FAULT CURRENTS

a General Information

(1) Assumptions. The discussion and the information in this Section of the Design Guide are based on the following assumptions:

(a) The frequency of the system is 60 hertz.

(b) All distribution lines have multigrounded neutral conductors.

(c) Underground lines are made up of direct-buried, single-phase jacked cables with aluminum or copper conductors and bare copper concentric neutrals. The voltage rating of the cable is 25 kV or less.

(d) The substation transformers are connected delta on the supply side and wye-grounded on the load side.

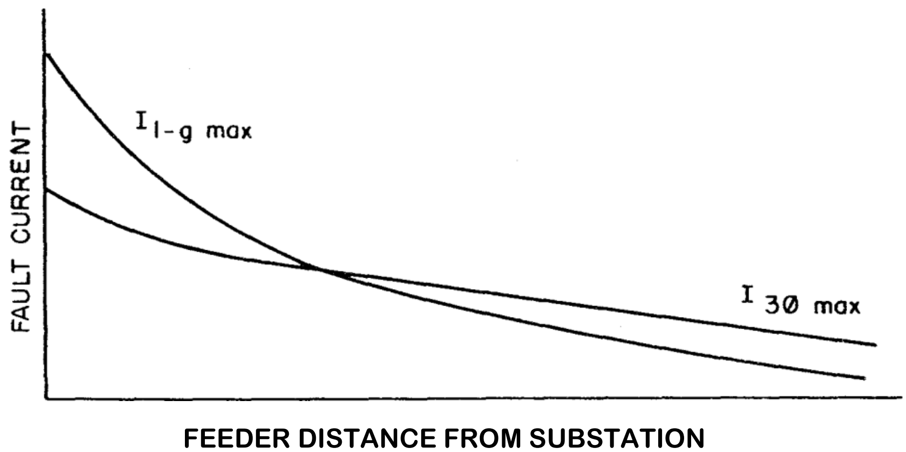
(e) The system is radial (i.e., no connected loops). If there is more than one source of supply, they are not interconnected.

(2) Fault Current. In a sectionalizing study, it is necessary to calculate both the maximum fault current and the minimum fault current at each sectionalizing point. In addition, the minimum fault current must be calculated for the end of each line. The method of calculating maximum and minimum fault currents will be given in Section 3B of this Design Guide.

(a) Types of Fault. There are four possible types of fault: three-phase, double line-to-ground, line-to-line, and single line-to-ground. Three-phase faults can occur only on three-phase circuits; line-to-line and double line-to-ground faults can occur on three-phase or V-phase circuits, and line-to-ground faults can occur on any type circuit. As a result of the multigrounded neutral construction of overhead lines, the line-to-ground fault is by far the most common, although other types do occur. For underground cables, the only type of fault that is likely to occur is a line-to-ground fault. However, the impedance of underground cable to three-phase and line-to-line faults is given in this bulletin because, for combined underground-overhead lines, where the overhead section is farther from the substation than the underground cable, it is possible that a fault on the overhead line could cause either line-to-line or three-phase fault current to pass through the cable.

(b) Maximum Fault Current for Three-Phase Lines. The three-phase fault current generally determines the maximum fault current level for three-phase lines. Near the substation, however, it is possible that a line-to-ground fault may produce a larger fault current. This is because line-to-ground faults see a lower source impedance with a delta/grounded-wye transformer connection, but a higher impedance per mile of line than three-phase faults. Thus, to determine the maximum fault current on a three-phase line, it is necessary to calculate the line-to-ground fault current as well as the three-phase fault current up to that point on the line where the line-to-ground current becomes equal to or less than the three-phase current. (See Figure 3.1.)

Figure 3.1. Fault Current on a Distribution Line Supplied by a Delta/Grounded-Wye Substation Transformer



For V-phase and single-phase lines, line-to-line and line-to-ground faults, respectively, yield the maximum fault current.

Double line-to-ground faults usually yield neither a maximum nor a minimum value for any type of line and, thus, do not normally need to be calculated. See *Symmetrical Components for Power Systems Engineering* by J. Lewis Blackburn (CRC Press, 1993) for further information.

Table 3.1 summarizes, for each type of line, what type of fault will yield the maximum and minimum fault current values. The table is applicable for overhead, underground, and combined overhead-underground lines.

Table 3.1. Fault Current Values for Various Types of Fault

Line Type	Fault Type That Yields	
	Maximum Fault Current	**Minimum Fault Current**
Three-Phase	Three-phase fault or Line-to-ground fault near substation.	Line-to-ground fault*
V- or Two-Phase Line	Line-to-line fault (line-to-ground fault near a substation)	Line-to-ground fault*
Single-phase	Line-to-ground fault	Line-to-ground fault*

*A value for fault resistance must be included.

A calculation method for determining fault current is presented in Section 3B of this Design Guide immediately below. There are various brands of engineering analysis software that will readily perform these calculations once an engineering model has been built and properly configured for the exact power system.

b Calculation Method for Determining Fault Currents

(1) General

(a) Since this bulletin was last updated, there have been many changes in computational equipment and methodologies. With the advent and widespread usage of personal computers and specialized engineering software, there has been less and less reliance on hand calculations. However, since this bulletin is written for technicians and engineers of various skill and experience levels, some hand calculation methods will be discussed. Furthermore, there is an extensive bibliography included for the serious practitioner. Tables containing formulas and other useful information are included in this section of the Design Guide.

(b) Tables 3.2 through 3.4 in this Design Guide contain the information necessary to hand calculate fault currents for line-to-ground (Table 3.2), three-phase (Table 3.3), and line-to-line (Table 3.4) faults. Additionally, the percent and per unit methods of calculating fault currents will be discussed in general.

Table 3.2. Information for Calculating Line-to-Ground Fault Current on Load Side of Substation

1. SOURCE IMPEDANCE (LOAD SIDE OF VOLTAGE BASE)

Type of Fault Current or Impedance Value Given	Formula to Determining Source Impedance Z_s
a. $I_{s(\text{L-L})}$, line-line fault current on source side of substation	$Z_s = \dfrac{E_L^2}{I_{s(\text{L-L})} E_{s(\text{L-L})}}$
b. I_{3s}, three-phase fault current on source side of substation	$Z_s = \left(\dfrac{2}{\sqrt{3}}\right)\left[\dfrac{E_L^2}{I_{3s} E_{s(\text{L-L})}}\right]$
c. Z_1, Positive-sequence impedance on source side of substation	$Z_s = 2Z_1 \dfrac{E_L}{E_{s(\text{L-L})}}$
Source impedance is available from power supplier.	

2. SUBSTATION TRANSFORMER IMPEDANCE

Formula to convert substation transformer impedance Z_t from percent to ohms:

$$Z_t\ (\Omega) = \frac{Z_t\ (\%)\ E_t^2}{(\text{kVA per phase})\ (100{,}000)}$$

R_t (resistive component of substation transfer) = $0.20Z_t$

(approximate)

X_t (reactive component of substation transformer) = $0.98Z_t$

(approximate)

3. DISTRIBUTION LINE IMPEDANCE (SINGLE-PHASE IMPEDANCE VALUES)

Overhead Lines*			Underground Lines†		
ACSR Conductor Size	Ω per mile R_L	Ω per mile X_L	Aluminum Conductor Cable Size	Ω per mile R_L	Ω per mile X_L
336.4 MCM	0.410	1.010	350 MCM	0.560	0.159
266.8 MCM	0.510	1.039	250 MCM	0.759	0.211
4/0	0.640	1.220	4/0	0.890	0.261
3/0	0.759	1.270	3/0	1.089	0.340
2/0	0.940	1.369	2/0	1.319	0.439
1/0	1.120	1.450	1.0	1.559	0.570
2	1.640	1.469	1	1.839	0.670
4	2.470	1.459	2	2.159	0.880
6	3.72	1.540			

4. CALCULATION OF FAULT CURRENT

Maximum line-to-ground fault current:

$$I_{\max} = \frac{E_L}{\sqrt{(R_s + R_t + R_{\text{dist}})^2 + (X_s + X_t + X_{\text{dist}})^2}}$$

*Standard C1-type construction is assumed.
†To obtain total distribution line impedance R_{dist} and reactance X_{dist} to any point, multiply the appropriate value below by the number of miles of line. For two or more conductor sizes, calculate resistance and reactance values separately for each conductor size and total value for the sizes together.
E_L = line-to-ground voltage on load side of substation.
$E_{s(\text{L-L})}$ = line-to-line voltage on supply side of substation.

Table 3.3. Information for Calculating Three-Phase Fault Current on Load Side of Substation

1. SOURCE OF IMPEDANCE (LOAD SIDE VOLTAGE BASE)	
Type of fault current of impedance value given	Formula to determine source impedance Z_s
a. $I_{s(\text{L-L})}$, line fault current on source side of substation	$Z_s = \left(\frac{3}{2}\right)\left(\frac{E_L^2}{I_{s(\text{L-L})} E_{s(\text{L-L})}}\right)$
b. I_{3s}, three-phase fault current on source side of substation	$Z_s = \sqrt{3}\left(\frac{E_L^2}{I_{3s} E_{s(\text{L-L})}}\right)$
c. Z_1, positive-sequence impedance on source side of substation	$Z_s = 3Z_1\left(\frac{E_L}{E_{s(\text{L-L})}}\right)^2$
Source impedance is available from power supplier.	

2. SUBSTATION TRANSFORMER IMPEDANCE
Formula to convert substation transformer impedance Z_t from percent to ohms:
$Z_s\ (\Omega) = \frac{Z_1\ (\text{percent})\ E_L^2}{(\text{kVA per phase})\ (100{,}000)}$
$\left.\begin{array}{l} R_t = \text{(resistive component of substation transformer} = 0.20Z_t \\ X_t = \text{(reactive component of substation transformer)} = 0.98Z_t \end{array}\right\}$ approximate

3. DISTRIBUTION LINE IMPEDANCE (THREE-PHASE IMPEDANCE VALUES)					
Overhead Lines*			Underground Cables†		
ACSR conductor size	Ω per mile		Aluminum conductor cable size	Ω per mile	
	R_L	X_L		R_L	X_L
336.4 MCM	0.278	0.632	350 MCM	0.298	0.180
266.8 MCM	0.350	0.653	250 MCM	0.410	0.256
4/0	0.441	0.712	4/0	0.606	0.271
3/0	0.557	0.727	3/0	0.741	0.293
2/0	0.702	0.742	2/0	0.941	0.311
1/0	0.885	0.756	1/0	1.363	0.349

2	1.409	0.780	1	1.363	0.349
4	2.240	0.805	2	1.844	0.385
6	3.509	0.853			
4. CALCULATION OF FAULT CURRENT					
Maximum three-phase fault current $I_{\max} = \dfrac{E_L}{\sqrt{(R_s + R_t + R_{\text{dist}})^2 + (X_s + X_t + X_{\text{dist}})^2}}$					

* Standard CI-type construction assumed.
† See manufacturer's technical literature for exact impedance values based on exact configuration, type of cable, neutral size, etc.
To obtain total distribution line impedance R_{dist} and reactance X_{dist} to any point, multiply the appropriate value below by the number of miles of line. For two or more conductor sizes, calculate resistance and reactance values separately for each conductor size and total value for the sizes together.
E_L = line-to-ground voltage on load side of substation.
$E_{s(\text{L-L})}$ = line-to-line voltage on supply side of substation.

Table 3.4. Information for Calculating Line-to-Line Fault Current on Load Side of Substation

1. SOURCE OF IMPEDANCE (LOAD SIDE VOLTAGE BASE)	
Type of Fault Current of Impedance Value Given	Formula to Determine Source Impedance Z_s
a. $I_{s(\text{L-L})}$, line-line fault current on source side of substation	$Z_s = \sqrt{3}\left(\dfrac{E_L^2}{I_{s(\text{L-L})}E_{s(\text{L-L})}}\right)$
b. I_{3s}, three-phase fault current on source side of substation	$Z_s = 2\left(\dfrac{E_L^2}{I_{3s}E_{s(\text{L-L})}}\right)$
c. Z_1, positive-sequence impedance on source side of substation	$Z_s = 2\sqrt{3}Z_1\left(\dfrac{E_L}{E_{s(\text{L-L})}}\right)^2$
Source impedance is available from power supplier.	
2. SUBSTATION TRANSFORMER IMPEDANCE	
Formula to convert substation transformer impedance Z_t from percent to ohms: $Z_s\ (\Omega) = \dfrac{Z_1\ (\text{percent})\ E_L^2}{(\text{kVA per phase})\ (100{,}000)}$ $\left.\begin{array}{l} R_t = \text{(resistive component of substation transformer} = 0.20Z_t \\ X_t = \text{(reactive component of substation transformer)} = 0.98Z_t \end{array}\right\}$ approximate	

3. DISTRIBUTION LINE IMPEDANCE (THREE-PHASE IMPEDANCE VALUES $\times 2\sqrt{3}$)			
Overhead Lines*		Underground Cables†	
ACSR Conductor	Ω per mile	Aluminum	Ω per mile

Size	R_L	X_L	Conductor Cable Size	R_L	X_L
336.4 MCM	0.516	1.176	350 MCM	0.552	0.335
266.8 MCM	0.650	1.213	250 MCM	0.764	0.380
4/0	0.819	1.323	4/0	0.898	0.399
3/0	1.033	1.353	3/0	1.102	0.434
2/0	1.305	1.379	2/0	1.393	0.460
1/0	1.641	1.405	1/0	1.720	0.516
2	2.623	1.450	1	2.172	0.544
4	4.167	1.498	2	2.735	0.570
6	3.509	0.853			

4. CALCULATION OF FAULT CURRENT

Maximum three-phase fault current

$$I_{\max} = \frac{E_L}{\sqrt{(R_s + R_t + R_{\text{dist}})^2 + (X_s + X_t + X_{\text{dist}})^2}}$$

* Standard CI-type construction assumed.
† To obtain total distribution line impedance R_{dist} and reactance X_{dist} to any point, multiply the appropriate value below by the number of miles of line. For two or more conductor sizes, calculate resistance and reactance values separately for each conductor size and total value for the sizes together.
E_L = line-to-ground voltage on load side of substation.
$E_{s(\text{L-L})}$ = line-to-line voltage on supply side of substation.

(2) Use of Fault Current Calculation Tables. Regardless of the type of fault, there are three main components of the impedance offered to the fault: the impedance of the source, the impedance of the substation, and the impedance of the distribution line up to the location of the fault. For the minimum fault current, a fourth impedance, the fault resistance component, is added.

(a) For most cases, the calculation of a fault current consists of determining these three impedance components (four for minimum fault current), finding the total impedance offered to the fault, and dividing the system line-to-ground voltage by this impedance. The steps below outline the procedure in detail and will be demonstrated in the sample problem in Section 8 of this Design Guide.

(b) If you are using an engineering analysis program, you will probably need to do the calculations in steps (2) and (3) below by hand and then insert those values into the program and let the program calculate the fault currents, etc., at the beginning and end of each line section in the database model.

(1) Refer to the appropriate table for the type of fault for which

values are to be calculated.

(2) The source impedance can be obtained from the power supplier. The format usually used is $R + jX$ % on the stated base. Convert this to $R + jX$ % on 100 MVA base as shown in the percent and per unit discussion.

(3) Determine the substation transformer size, voltage, and impedance in percent from the nameplate information or from the manufacturer. As in (2) above, the impedance should be resolved into its reactive and resistive components either by using the formulas given in the tables or by using a ratio based on judgment.

(4) To find the distribution line impedance to any point on the system, multiply the appropriate value from Section 3 of the tables by the number of miles of line from the substation to the point being considered. If two or more different-size conductors are used from the substation to the point, add the total resistance of the first size to the resistance of the next size to the point, then add the total reactance of the first size to the reactance of the next size, etc.

(5) As indicated in Section 4 of the tables, add up separately the resistance and reactance components determined in the steps above. (When calculating minimum line-to-ground fault current, be sure to include a fault resistance value.) Find the total impedance and divide the system line-to-ground voltage by this impedance value to determine fault current.

(3) Minimum Fault Current. It is necessary to calculate minimum fault currents for coordination purposes and also to define a maximum "reach" or "zone of protection" of an overcurrent protective device. To calculate minimum fault current, a value of fault resistance should be added to the resistance component of total system impedance up to the point of fault. The selection of fault resistance is discussed in Section 2D of this Design Guide.

(4) Distribution Substation Fault Current Calculations. Generally the power supplier will furnish the source impedance.

(a) These values—Z_1 (positive-sequence impedance), Z_2 (negative-sequence impedance), and Z_0 (zero-sequence impedance)—are usually given in $R + jX$ format as a percent or per unit (P.U.) value on a 100 MVA base (typically). The substation transformer size and impedance information is generally known and usually takes the form of a percent impedance on the transformer base rating. The source and substation transformer impedance are then usually converted to ohmic values.

These ohmic values are then inserted into a typical engineering analysis program to be used to calculate fault currents within the model at the end of each line section.

(b) A typical example will illustrate the procedure.

Transformer Impedance (Percent Method)

A transformer having 10% impedance on a 20 MVA rating would have 50% impedance on a 100 MVA base (See Table 3.5 of this Design Guide).

$$10\% \times \frac{100}{20} = 50\% \text{ on a 100-MVA base}$$

Source Impedance (Typical Format)

From the power supplier for Westland Substation (69 kV):

$$\left.\begin{aligned} Z_1 &= 7.82 + j20.8\% \\ Z_0 &= 16.60 + j58.78\% \end{aligned}\right\} \text{ on a 100-MVA base @ 69 kV}$$

Transformer Conversion

Formula to convert transformer impedance Z_t from percent to ohms (see Table 3.3 of this Design Guide):

$$Z_t\,(\Omega) = \frac{Z_t(\%)E_L^{\,2}}{(\text{kVA per phase})(100{,}000)}$$

$$= \frac{(7.09\%)\ (7{,}200)^2}{(3{,}333)\ (100{,}000)}$$

$$= \frac{3{,}675{,}456}{(3{,}333)\,(100{,}000)}$$

$$= 1.102747\ \Omega$$

Spread transformer impedance into its R and X components (Ω):

1.102495 Ω

$0.2 + j0.98$	approximate (use manufacturer's data)
$0.2205 + j1.080445$	Ω

Methodology and Formulas

1. Methodology and formulas to convert transformer impedance Z_t from percent on its own MVA base to percent on a 100 MVA base (see Table 3.5):

Transformer size	=	10/12/14 MVA
Transformer impedance	=	7.09%
Transformer voltage	=	69 kV HS and 7.2/12.47 kV LS

where HS = high side and LS = low side.

2. Convert transformer impedance to 100 MVA base:

$$\frac{100}{10} \times 7.09\% = 70.9\% \text{ on } 100 \text{ MVA base}$$

3. Spread transformer impedance into its R and X components (percent on 100 MVA):

70.9	% on 100 MVA
$0.2 + j0.98$	
$14.18 + j\,69.48$	% on 100 MVA

Source and Transformer Impedance (High Side)

Source	Z_1	=	7.82	$+ j20.87$	% on 100 MVA
Transformer	Z_t	=	14.18	$+ j69.48$	% on 100 MVA

Source plus Transformer Impedance (Assume Delta/Grounded-Wye Connection)

Total impedance at service point (percent on 100 MVA at low side):

$Z_{1LS} = Z_1 + Z_t =$	$22.0 + j90.352$	% on 100 MVA
$Z_0 = Z_t =$	$14.18 + j69.482$	% on 100 MVA

See constants for fault calculations. Multiply by 0.0155 Ω/%

Z_{1LS} = 22.0 + j90.352 % on 100 MVA

$$\frac{0.0155\ \Omega/\%}{0.341 + j1.40046\ \Omega}$$ Convert to ohms (see Table 3.6)

Z_0 = 14.18 + j69.482 % on 100 MVA

$$\frac{0.0155\ \Omega/\%}{0.220 + j1.080\ \Omega}$$ Convert to ohms (see Table 3.6)

Total impedance at service point at 12.47 kV:

$Z_1 = 0.3421 + j1.4049\ \Omega$
$Z_0 = 0.220 + j1.080\ \Omega$

Source plus Transformer Impedance

Positive-sequence impedance:

$$Z_1 = \sqrt{(0.3421)^2 + j(1.4049)^2}\ \Omega$$
$$= 1.4459\ \Omega$$

Impedance for phase-to-neutral faults:

$$Z_{PN} = \sqrt{\frac{(Z_1 + Z_2 + Z_0)^2}{3}}$$

$$= \sqrt{\frac{\begin{pmatrix} 0.3421 + j1.4049 \\ 0.3421 + j1.4049 \\ 0.220 + j1.080 \end{pmatrix}^2}{3}}$$

$$Z_{PN} = \sqrt{0.3014^2 + j1.2966^2}\ \Omega$$

$$= 1.3316\ \Omega$$

Fault Currents at the 7.2/12.47 kV Bus

Three-phase current = $E_{LL} \div (1.73)(Z_1) = \dfrac{12{,}470}{(1.73)\ (1.4459)}$ = 4985 A

Phase-to-phase current = $E_{LL} \div 2Z_1$ = 4322 A

Phase-to-neutral current = $(E_{LL})(1.73)(Z_{PN})$ = 5407 A

where E_{LL} = line-to-line voltage in volts (*not* kilovolts)

Three-Phase Fault Current at the 7.2/12.47 kV Bus

Three-Phase Fault Current by the Percent Method:

$$Z_1 = 22.0 + j90.352 \text{ \% on 100 MVA}$$

$$= 92.99 \text{ \% on 100 MVA}$$

Three-phase fault current $= \dfrac{100}{92.99\,\%}(4630 \text{ A}) = 4979$ A

Note: The difference between this value and the previous calculation is due to rounding off.

Line-Neutral Fault by the Percent Method

Line-neutral fault $= \dfrac{\sqrt{2Z_1 + Z_0}^{\,2}}{3}$

$$= \frac{\sqrt{\begin{pmatrix} 22.0 + j90.352 \\ 22.0 + j90.352 \\ 14.18 + j69.42 \end{pmatrix}^2}}{3} \text{ \% on 100 MVA}$$

$$= \frac{\sqrt{58.18^2 + j250.124^2}}{3} \text{ \% on 100 MVA}$$

$$= 19.393 + j83.3746\text{\% on 100 MVA}$$
$$= 85.60038\text{\% on 100 MVA}$$

$$= \left(\frac{100}{85.60038}\right)(4630 \text{ A})$$

$$= \quad 5409 \text{ A}$$

What about the Minimum Phase-to-Ground Fault Current?

Here is where we have to insert a fault impedance such as 25, 30, or 40 Ω or some other value determined by the application of education and experience, industry standards, research, etc.

Calculate Minimum Line-to-Ground Fault

Ground fault impedance = $R + j0$

Use engineering judgment and experience to determine R.

Z_{pg} = Z_{PN} + ground fault impedance

$$\begin{aligned} &= \quad 0.3014 + j1.2966 \\ &= \quad \underline{40.0 \quad\quad + j0} \\ &= \quad 40.3014 + j1.2966 \end{aligned}$$

$$Z_{pg} = \sqrt{(40.3014)^2 + j(1.2966)^2}$$

$$= \quad 40.322225$$

Phase-to-Ground Fault

$$\text{Phase-to-ground fault} = E \div (1.73)(Z_{pg})$$

$$= \frac{12.470}{(1.73)(40.32225)}$$

$$= \quad 178.8 \text{ A}$$

Minimum Phase-to-Ground Fault

If ground fault impedance = 30 Ω, then phase-to-ground fault = 237 A.

If ground fault impedance = 25 Ω, then phase-to-ground fault = 284 A.

Line-To-Ground Fault by the % Method

Z_{PG} = Z_{PN} + ground fault impedance

$$\begin{array}{rcll} & 19.393 & + & j83.3746 & \text{\% on 100 MVA base} \\ + & 2{,}572.400 & + & j0 & \text{\% on 100 MVA base (i.e., 40 } \Omega\text{)} \\ \hline & 2{,}591.793 & + & j83.3746 & \end{array}$$

= 2,593.1336 % on 100 MVA base

$$\text{Line-to-ground fault current} = \left(\frac{100}{2593.1336}\right)(4{,}630\ \text{A})$$

$$= 178.54\ \text{A}$$

Note: Use the constants for fault calculations to convert from ohms to percent impedance on a particular voltage base, e.g.,

$$\begin{array}{lll} 40 + j0\ \Omega & @ & 12.47\ \text{kV (line-to-line)} \\ \underline{\times\ 64.31\ \%/\Omega} & & \\ 2572.4 + j0\ \% & @ & 12.47\ \text{kV (line-to-line)} \end{array}$$

(5) Fault Current Calculations. While a complete discussion of per unit or percent quantities is beyond the scope of this bulletin, Table 3.5 gives a short review of the various quantities. Both the percent and per unit methods of calculation are simpler than using actual amperes, ohms, and volts.[5]

The discussion in Table 3.5 is based on the constants for fault current calculations for commonly encountered voltages in Table 3.6 of this Design Guide.

Table 3.5. Discussion of Per Unit and Percent Values

1. DEFINITION:
$\text{P.U. apples} = \dfrac{\text{actual \# of apples}}{\text{base \# of apples}}$ $\quad$ $\text{P.U. ohms} = \dfrac{\text{actual ohms}}{\text{base ohms}}$
$\text{P.U. current} = \dfrac{\text{actual amperes}}{\text{base amperes}}$

[5] *Power System Analysis* by John Grainger, Jr., and William Stevenson, McGraw-Hill, 1994.

P.U. values $\times$ 100 = % values

$\%V$ = P.U. I. $\times$ $\%Z$ P.U. V = P.U. I $\times$ P.U. Z

2. P.U. IMPEDANCE:

$$\text{P.U. } Z = \frac{\text{actual ohms}}{\text{base ohms}}$$

where

$$\text{Base ohms} = \frac{\text{rated voltage}}{\text{rated current}} = \frac{V_{LL}/\sqrt{3}}{\left(\dfrac{\text{base kVA}}{\sqrt{3}\,\text{kV}}\right)}$$

where V_{LL} is line-to-line voltage.

Then

$$\text{Base ohms} = \frac{1000\,(\text{kV})^2}{\text{base kVA}} = \frac{(\text{kV})^2}{\text{base MVA}}$$

$$\text{P.U. } Z = \frac{\text{actual ohms}}{\left[\dfrac{(\text{kV})^2}{\text{base MVA}}\right]} = \frac{\text{base MVA} \times \text{actual ohms}}{(\text{kV})^2}$$

Also

$$\text{P.U. } Z = \frac{\text{voltage drop across } Z \text{ at rated } I}{\text{rated voltage (per phase)}}$$

$$= \frac{Z\,\dfrac{\text{MVA} \times 1000}{\sqrt{3}\ \text{kV}}}{\dfrac{\text{kV}}{\sqrt{3}} \times 1000} = Z \times \frac{\text{MVA}}{\text{kV}^{2}}$$

Note: $\%Z$ varies directly with the MVA base and inversely with the square of the voltage.

Examples:

A transformer having 10% impedance on a 20 MVA rating would have 50% impedance on a 100 MVA base of

$$10\% \times \frac{100}{20} = 50\%$$

A 12.47-kV line having 1% resistance would have

$$\%R = 1\% \times \left(\frac{12.47}{13.8}\right)^2 = 0.816\%$$

if the base voltage were 13.8 kV.

3. P.U. CURRENT:

$$\text{P.U. } I = \frac{\text{actual amperes}}{\text{base amperes}} = \frac{\dfrac{\text{load MVA} \times 1000}{\sqrt{3}\ \text{load kV}}}{\dfrac{\text{base MVA} \times 1000}{\sqrt{3}\ \text{base } V_{\text{L-L}}\ (\text{in kV})}}$$

$$= \frac{\text{load MVA}}{\text{base MVA}} = \frac{1}{\text{P.U. voltage}}$$

Note: P.U. I = P.U. MVA if voltage is constant.

(6) Distribution Voltage Transformation. When a line is encountered that incorporates an autotransformer or two-winding transformer used for system voltage conversion (often 7.2 kV to 14.4 kV or vice versa), there are several additional steps that must be taken to find the fault current beyond these devices.

(a) Using the procedure outlined in steps 1 through 5 in Section 3B(2)(b) of this Design Guide, determine the resistance and reactance values of the total impedance (source, substation transformer, and distribution line) from the substation to the point on the line where the step-up or step-down transformer is located.

(b) Using the formula below, determine the impedance of the transformer in ohms. (For the purpose of this bulletin, it is assumed that only single-phase autotransformers or two-winding transformers will be encountered.)

Two-winding transformer or autotransformer

$$Z_t\ (\Omega) = \frac{\%Z_t (E_L)^2}{\text{kVA} \times 100{,}000}$$

where E_L is the line-to-neutral voltage on the load side of the transformer, $\%Z_t$ is the percent impedance of the transformer given at rated kVA and voltage, and kVA is the kVA rating of the transformer.

Resolve the impedance into its reactive and resistive components, either by using the formulas given below or by taking a ratio based on engineering judgment.

$$R_t = 0.2Z_t \qquad X_t = 0.98Z_t$$

(c) Reflect the source, substation transformer, and distribution line impedance (Z STD) determined in step a to the load side of the voltage transformation transformer by the appropriate method shown below.

(1) Step-up transformation:

$$Z \text{ STD load side } (\Omega) = (N^2)(Z \text{ STD source side } (\Omega))$$

(2) Step-down transformation:

$$Z \text{ STD load side } (\Omega) = (1/N^2)(Z \text{ STD source side } (\Omega))$$

where

$$N = \frac{\text{high side line-neutral voltage}}{\text{low side line-neutral voltage}}$$

(d) Add the distribution line resistance and reactance values from voltage transformation transformer location to the location of the fault to the R and X values obtained in steps b and c:

$$R \text{ total} = R \text{ STD load side} + R \text{ auto} + R \text{ dist}$$

$$X \text{ total} = X \text{ STD load side} + X \text{ auto} + X \text{ dist}$$

(e) Determine the fault current, using the formula below and the and R and X values determined in step d:

$$I_{\text{fault}} = \frac{E_{\text{line-to-ground}} \text{ (load side voltage)}}{\sqrt{(R_{\text{total}})^2 + (X_{\text{total}})^2}}$$

To find the fault current that would appear on the source side of the voltage transformation formula, use the appropriate formula below:

(1) Step-down voltage transformation:

Source-side fault current = (1/N) (load-side fault current)

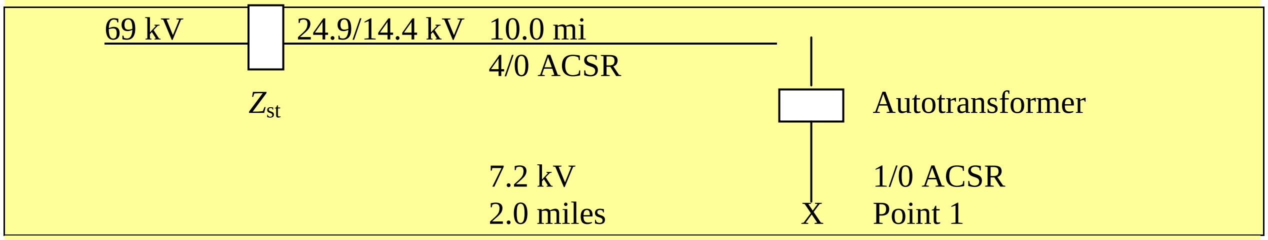
(2) Step-up voltage transformation:

Source-side fault current = (N) (load-side fault current)

An example of the method follows.

Sample Problem

Determine the three-phase fault current at point 1 in the diagram. The step-down autotransformer characteristics are 200 kVA, 14.4 to 7.2 kV, % Z = 2.63.



Z_{dist} = (0.441 + j0.712) (10) = 4.41 + j7.12 Ω, obtained from Table 3.3.

Step a:

$$
\begin{array}{lllll}
Z_{st} & = & 0 & + & j3.6 \quad \text{given by supplier} \\
Z_{dist} & = & \underline{4.41} & \underline{+} & \underline{j7.12} \\
Z_{std} & = & 4.41 & + & j10.72 \quad \Omega \ @ \ 14.4/24.9 \text{ kV}
\end{array}
$$

Step b:

$$
Z_{auto} \text{ load side} = \frac{(\%\ Z)\,(E_L)^2}{(\text{kVA})\,(100{,}000)} = \frac{(2.63)(7200)^2}{(200\ \text{kVA})(100{,}000)} = 6.82\ \Omega
$$

$$
\begin{array}{lll}
R_{auto} & = & (0.2)(Z_{auto}) = 1.36\ \Omega \\
X_{auto} & = & (0.98)(Z_{auto}) = 6.68\ \Omega \\
Z_{auto} & = & 1.36 + j6.68 \text{ ohms}
\end{array}
$$

Step c:

$$
Z_{std} \text{ loadside} = \frac{1}{N^2}(4.41 + j10.72) = \frac{1}{(2)^2}(4.41 + j10.72) = 1.1 + j2.68
$$

$$
\text{Where N} = \frac{14.4}{7.2} = 2
$$

Step d:

R_{dist} = (2.0 mi) (.855 ohms/mi) = 1.77 ohms

X_{dist} = (2.0 mi) (.756 ohms/mi) = 1.51 ohms

$$\begin{aligned} Z_{std} &= 1.10 + j2.68 \\ Z_{auto} &= 1.36 + j6.68 \\ Z_{dist} &= \underline{1.77 + j1.51} \\ Z_{total} &= 4.23 + j10.87 \end{aligned}$$

Step e:

$$I_{3\varphi\ fault} = 7200/\sqrt{(4.23)^2 + (10.87)^2} = \frac{7200}{11.664} = 617.3\ \text{A}$$

$I_{3\varphi}$ = 617.3 A

The same procedure should be followed for a step-up autotransformer or two-winding transformer.

(7) Fault Current on Supply Side. A fault anywhere on the load side of the substation causes a current to flow on the supply side. To determine the supply side current, use the following formulas. Note that I_s is not necessarily the same in all three phases. The formulas give the maximum supply currents in any one phase.

(a) For line-to-ground fault:

$$I_s = \frac{E_L I_L}{E_{s(\text{L-L})}}$$

(b) For three-phase fault:

$$I_s = \frac{E_L \sqrt{3} I_L}{E_{s(\text{L-L})}}$$

(c) For a line-to-line fault:

$$I_s = \frac{2 E_L I_L}{E_{s(\text{L-L})}}$$

(8) Plotting the Sectionalizing Circuit Diagram. After the calculation of short-circuit currents has been completed, the calculated values should be placed on the circuit diagram at each sectionalizing point and at the end of lines. The maximum three-phase fault current and the maximum line-to-ground fault current should be shown on the circuit diagram at every location where a sectionalizing device is installed. The minimum line-to-ground fault current should be shown at the end of each zone of protection and at the end of each single-phase and three-phase line.

Table 3.6. Constants for Fault Calculations

Voltage (kV), line-to-line or phase-to phase	Base amperes, Three-phase amperes/100 MVA	Percent/per Ohm	Ohms/1%
500 kV	$\frac{100{,}000\ KVA}{\sqrt{3} \times 500\ kV}$	$\frac{115.5A \times \sqrt{3}}{500{,}000} \times 100\%$	$\frac{1\ Ohm}{.0400\ \%}$
500	115.5	0.040	25.0
230	251	0.189	5.29
169	342	0.351	2.85
161	359	0.386	2.59
115	502	0.756	1.32
110	525	0.827	1.21
100	577	1.00	1.00
69	837	2.10	0.476
66	875	2.30	0.436
46	1255	4.73	0.212
44	1,312	5.17	0.194
38	1,519	6.92	0.144
34.5	1,673	8.4	0.11906
25	2,310	16.00	0.0625
24.9	2,319	16.13	0.06199
24	2,406	17.36	0.0576
20	2,887	25.00	0.0400
19	3,039	27.7	0.0361
18	3,208	30.87	0.0324
13.80	4,184	52.51	0.0190
12.47	4,630	64.31	0.0155
8	7,217	156.25	0.0064
7.20	8,019	192.9	0.00518
6.90	8,368	210.1	0.00476
6.60	8,748	229.6	0.00436
4.80	12,028	434.0	0.00230
4.16	13,879	577.9	0.00173
2.30	25,103	1,890	0.000529
0.600	96,228	27,778	0.0000360
0.575	100,412	30,246	0.0000331
0.480	120,285	43,403	0.0000230
0.240	240,570	173,611	0.00000576

4 TYPES OF SECTIONALIZING DEVICES

a Introduction. If the goal of sectionalizing is to economically minimize the number and duration of outages seen by customers, then the tools of sectionalizing must be understood and judiciously applied. "Economically minimize" would suggest that there is a point of diminishing return on investment to combat outages. It is impossible to eliminate outages completely, so the goal of the protection engineer and system planner is to understand and best apply the resources available. The following is a brief discussion of some of the most common tools used on rural distribution systems and their characteristics.

b Circuit Breakers. Circuit breakers can have vacuum, oil, SF_6 gas, or air as an interrupting medium. Currently, in the distribution market, a vast majority of breakers sold for feeder protection are vacuum interruption circuit breakers. The construction and testing by manufacturers for medium-voltage circuit breakers are defined by a number of national and industry standards (including ANSI, IEEE, NEMA, and others). When used for distribution feeder protection, they are normally controlled by time-overcurrent relays and reclosing relays. Circuit breakers require an external power source for closing and tripping. Advances in relaying have resulted in a marked increase in the functionality and information that relays can offer.

c Automatic Circuit Reclosers. Automatic circuit reclosers have been used successfully on rural circuits for many years. Reclosers are available with a wide range of current and voltage ratings and are suitable for use on virtually all distribution circuits.

(1) Series Coil Reclosers. The original concept of reclosers was to provide a self-contained, low-cost tripping and reclosing circuit interrupter, which could be used economically for pole-mounted protection of distribution feeders.

This type of recloser is commonly referred to as a "series-coil" recloser. These reclosers employ a series coil that causes tripping of the recloser at approximately two times the continuous current rating of the coil. They can be either single-phase or three-phase devices. They may employ either a hydraulic timing mechanism for time-delayed operating curves or may feature a hold-closed method of operation after the fast curve operations. Some of the heavy-duty three-phase or single-phase models may use a closing solenoid connected between phases or from phase to neutral. Series coil reclosers are used in both substation and line applications.

(2) Non-Series-Coil Reclosers. Some three-phase reclosers require an external power source for tripping and closing. This type of recloser is

commonly referred to as "non-series-coil" recloser. Reclosers that are electronically controlled are more versatile and more easily modified. They do require a power source for operation, which usually is an AC source if used on the line, or they may use DC from a battery bank if used in a station. This type of recloser closely resembles a circuit breaker in its function and operation. Three-phase reclosers with advanced controls are similar in functionality and information recording to electronic relays, and are routinely used in stations as feeder protection.

(3) Types of Electronically Controlled Units. Automatic circuit reclosers come in a variety of single-phase electronically controlled units, which offer a wide variety of coordination options and reporting functions. Likewise, electronically operated three-phase units are now available that can be configured for single- or three-phase trip or lock-out operations, and which offer improved flexibility in sectionalizing, reliability, and SCADA schemes.

d Automatic Line Sectionalizers. An automatic line sectionalizer is an oil, air, or vacuum switch that automatically opens to isolate a faulted section of line. It employs either a hydraulic or electronic counting mechanism, which is actuated by a system overcurrent and an upline circuit breaker or recloser tripping action. Unlike other overcurrent protection devices, a sectionalizer does not operate on a time-current curve.

(1) Automatic line sectionalizers are used principally in branch circuits where:

(a) Small loads or little circuit exposure will not justify reclosers (typically sectionalizers are less expensive than reclosers).

(b) It is desirable to establish an automatic sectionalizing point but time-current curve coordination with other sectionalizing devices would be difficult or impossible.

(2) Automatic line sectionalizers are available as either three-phase or single-phase devices. They are not rated to interrupt fault current and, therefore, must be used in conjunction with upline reclosers or circuit breakers capable of sensing and interrupting minimum fault currents beyond the sectionalizer. The recloser or circuit breaker must sense a fault and perform the circuit tripping and fault-clearing operation. The sectionalizer counts the preset number of recloser or breaker trips and senses minimum fault current through the sectionalizer. After both conditions are met, the sectionalizer automatically locks open during the open circuit time of the breaker or recloser. A sectionalizer may be used for switching loads within its load-interrupting rating.

e Line Switches. Line switches typically do not have overcurrent characteristics, but are extremely valuable in the operation of a distribution system, especially in the restoration of service. For very long or heavily loaded circuits, line switches can be used in conjunction with automatic circuit reclosers to help isolate problems and restore service to as many customers as possible.

Sectionalizing studies should consider the prevention of outages as well as measures to partially restore service, especially along main feeders. Line switches can be individually operated or gang-operated, load-breaking or non-load-breaking, and manually operated or remotely operated through SCADA systems. Load-break gang-operated switches are typically located at open points between feeders and substations to facilitate switching load between areas for maintenance or restoration. Non-load-break switches are economically beneficial in locations where main feeders go cross country or through heavily treed rights-of-way or just past a load center; they can be used to isolate the part of a circuit requiring repair, allowing the feeder to be reenergized to that point.

f Fused Cutouts. Fused cutouts are the most economical means of isolating sections of faulted lines on rural distribution systems.

(1) Currently, the standard fused cutout is very popular and used for fusing line taps, underground take-offs, capacitor banks, and distribution transformers. The cutout is versatile:

(a) It can be used with one barrel for fuse applications under 100 A.

(b) With a larger fuse barrel, it can be used for applications of 100 A to 200 A.

(c) It accepts a solid blade that can be used as a line disconnect switch carrying up to 300 A of continuous current.

(2) Fused cutouts are also routinely used as a bypass mechanism for automatic circuit reclosers. While the cutout itself is a non-load-break device, a hotstick tool can be used to break load or the cutout can be purchased with a load-break attachment.

Typically, expulsion fuse links are used in cutouts because of their economy and versatility. Several types of expulsion fuses are available with differing curves for different applications. However, several manufacturers also provide a current-limiting fuse that can be used in a cutout for specific applications. There is available a sectionalizer (see functionality above) that fits in a cutout and opens after sensing a fault.

g Current-Limiting Fuses. Current-limiting fuses are relatively expensive compared to expulsion-fused cutouts. They are also more difficult to apply since the engineer must consider not only their continuous current rating, but also their maximum (and sometimes minimum) voltage rating and their ability to interrupt a current in less than one-half cycle. Industry standards define both "general purpose" and "backup" current-limiting fuses. In general, where current-limiting fuses are being considered, the backup type will usually prove more desirable than the general-purpose type unless the general-purpose fuses have time-current curves that nearly parallel those of expulsion fuses.

(1) Advantages of Backup Current-Limiting Fuses. The advantages of backup current-limiting fuses are:

(a) No changes in existing fusing principles or methods are required for coordination.

(b) The majority of faults should blow only the expulsion fuse, which is chosen to coordinate with the current-limiting fuse.

(2) Disadvantage of Backup Current-Limiting Fuses. A disadvantage of backup current-limiting fuses (CLF) is that it must be used with a coordinated expulsion fuse. If an expulsion fuse larger than the one for which the CLF has been designed to coordinate is employed, the CLF may attempt to interrupt a current below its ability to clear, resulting in a burned-up fuse and a likely system fault.

(3) Justification to Use Current-Limiting Fuses. Current-limiting fuses, even though they are expensive, can often be justified such as for:

(a) Fusing Distribution Transformers on Overhead Circuits Where Available Fault Current is High. Engineering judgment is required in this regard because the probability of disruptive transformer failure is related not only to the available fault current, but also to the rated interrupting current of a transformer internal under-oil expulsion fuse and/or the tank pressure withstand ability.

(b) Fusing Underground Cables and Associated Equipment. In the case of underground equipment, current-limiting fuses may be justified even where fault current is not high. Since a CLF operates without expulsion action, it can be placed in a confined space. For underground applications, either a general-purpose or a backup CLF with an under-oil expulsion link can be employed successfully.

h Power Fuses. Power fuses can be current-limiting, conventional expulsion, or boric acid types. They have higher interrupting ratings than distribution fused cutouts and are, therefore, seldom applied on distribution circuits unless the available fault current is extremely high. Power fuses find their largest application as transformer bank protection or the high-side fuse for relatively small distribution substation transformers. They usually have a maximum voltage rating of 138 kV and the fuse links are generally E rated.

i Circuit Switchers. A circuit switcher is a high-voltage load-switching and fault-interrupting device that usually—but not always—incorporates a disconnect switch function in the switching operation. Voltage ratings will generally cover all distribution power transformers.

(1) Limitations. It should be recognized that a circuit switcher is not a circuit breaker. It has a fault-interrupting rating less than the smallest standard rating for circuit breakers and it does not have high-speed reclosing ability. A further limitation is that there are no provisions for mounting current transformers.

(2) Usefulness. Even though a circuit switcher has some limitations, it is well-suited for protection of substation transformers against secondary and internal faults, switching transformer magnetizing current, load dropping, capacitor bank switching, cable switching, and switching both series and shunt reactors.

j Underground Sectionalizing Devices. Underground distribution systems are fed either directly out of a substation or fed from an overhead distribution line. These systems have evolved into almost distinct higher-current and lower-current systems. Manufacturers generally rate components at 200 or 600 A. There are exceptions, but for the most part these are the primary conventions.

(1) 600-A Underground System. The sectionalizing devices used in 600-A backbone underground systems are generally pad-mounted or submersible switches that may have fused or automatically opening tap points to connect to the 200-A system.

(2) 200-A Overhead System. When a 200-A system is fed directly from an overhead system, the most common sectionalizing device protecting the main line is a riser pole (or pothead) fuse. Occasionally, automatic devices such as reclosers are used to provide protection to the overhead system from underground faults when greater flexibility is desired (which comes at a substantially higher cost).

(3) 200-A Underground System. When a 200-A system is fed (tapped) from an underground 600-A system, a fuse scheme or automatic opening scheme within a pad-mounted or submersible switch is the primary sectionalizing device. Operationally, the sectionalizing device commonly used to manually isolate problems or equipment on 200-A systems is the dead front load-break elbow.

k Fault Indicators. Fault indicators can be extremely valuable tools in locating faults and restoration efforts. Fault indicators are typically available to fit certain diameters of wire and can be manually or automatically reset. For automatic reset indicators, typically current or voltage is used to determine if the fault is cleared. Various factors will determine which type is selected for specific applications. Fault indicators are especially helpful on underground systems in locating faults on the underground primary and allowing service to be restored to most or all of the remaining system.

l Intelligent Electronic Devices. Advances in solid-state relays have provided additional sectionalizing tools to the distribution engineer by making more information available to perform sectionalizing functions automatically or by remote control. For instance, intelligent electronic devices (IEDs) can approximate the location of a fault for faster response time. They have an infinite number of relay settings, e.g., curves, to make coordination more effective. These new devices also make it possible to dynamically change settings to suit a variety of conditions. Indirectly related to sectionalizing, they also record three-phase amperes, watts, and VARs; monitor power quality; and provide fault analysis information.

5 APPLICATIONS OF SECTIONALIZING DEVICES

a General Guidelines. In applying sectionalizing devices to electric distribution systems, four tasks need to be accomplished to assure safe and reliable electric operations:

- Choose appropriate locations for line devices.
- Select the proper type of device to handle the available fault duty (maximums and minimums).
- Select the proper size of device to handle the peak load currents.
- Select and set the time-current characteristics (TCC) to coordinate both with the upline sectionalizing devices and the downline devices.

(1) Prerequisites. In order to accomplish each of these tasks, an accurate map and validated computer model of the electric system model must be developed. Applying sectionalizing and protective devices without such information can result in inadequate system sectionalizing and protection. These prerequisites include the following:

- Maps showing the correct conductor sizes, lengths and phases, and normal open points.

- Maps showing the accurate location of large critical commercial and industrial loads with peak load conditions.

- Maps showing the current location of all sectionalizing devices and their sizes and types.

- Models with system fault calculations based on current source impedances and conductor sizes and lengths.

- Models with anticipated fault calculations for the next 3 to 4 years.

- Models with current loading conditions that have been validated by field measurements (e.g., feeder breaker or recloser ampere reading, line voltage regulator voltage and current readings, end-of-the-line voltage readings at peak conditions).

- Models with projected future loading conditions based on approved load forecast or power requirement studies.

(2) Device Location. Before applying any sectionalizing device to a system, the system engineer should identify the proper and appropriate locations for each device. This is more of an art than a set procedure. Choosing a location is based on many factors and the circumstances may change as the system operational characteristics change. Device placement is selected to isolate faulted portions of the system from the rest of the system and to assist operating personnel in the location of the fault.

(a) Line Fuses. Line fuses are typically applied at locations that are:

(1) Short single-phase taps off main three-phase feeder lines, or

(2) Single-phase lines with less than 20 amperes of peak load.

(b) Line Reclosers. Line reclosers are typically applied at locations that are:

(1) Single-phase lines with greater than 20 amperes of peak load,

(2) Three-phase branches,

(3) After large industrial and commercial loads, or

(4) Locations to cover the calculated minimum down-line fault conditions.

(c) Line Sectionalizers. Line sectionalizers are typically applied at locations that are:

(1) Downline from line reclosers where minimum fault

conditions are met, or

(2) Downline from line reclosers where normally a line recloser is installed and, generally, on the ends of feeders.

(d) Uses. Typically, single-phase reclosers are used on most moderately loaded line applications. Three-phase devices are usually utilized on heavily loaded three-phase lines where ground fault relays are needed to cover the minimum calculated fault conditions. A full discussion on locating devices is included in Section 5C(2)(b) in this Design Guide.

(3) Maximum and Minimum Fault Currents. A distribution system experiences both underground and overhead fault conditions regularly. It is neither economical nor practical to design a system that would eliminate all system faults. Faults can be caused by a number of sources, including—but not limited to—the following:

- Weather (e.g., wind, lightning, ice, high temperatures),
- Equipment failure,
- Trees,
- Public contacts with both overhead and underground lines (by digging, in the latter case),
- Animals,
- Automobile accidents, and
- Vandalism.

(a) Faulted Conditions. Faulted conditions can present a hazard to the public and utility personnel, and can cause damage to electric system equipment. Protective systems are applied to sense these faulted conditions and to limit the consequences by clearing the fault in a timely manner. Since most of the faulted conditions on a distribution system are temporary in nature, line devices are often applied that provide for reclosing. This results in improved system reliability and improved service to the ultimate consumer.

(b) Calculation of System Fault Conditions. System fault conditions are calculated on the basis of (1) the available source impedance from the power supplier (e.g., the G&T) and (2) the system impedance of all line devices to the point of the possible fault. The maximum fault conditions are calculated without any fault impedance and represent the highest level of current expected at a given line point. Such calculated levels can be used to establish the interrupting capability of the sectionalizing device that is to be applied.

For a typical electric distribution system served by a delta/wye power transformer, the maximum fault at the substation bus is the line-to-ground fault. Moving downline on the feeder, the maximum three-phase and phase-to-phase-to-ground faults are higher and are used for sizing sectionalizing devices.

(c) Minimum Fault Resistance. Minimum faults, as stated earlier, are calculated by adding an estimated fault resistance to the available source impedance. The fault resistance is based upon the judgment of the system engineer or consultant and will represent the minimum fault current levels that are expected on the system. This judgment is usually based on the history of high-resistance fault conditions experienced on the system. The minimum levels are utilized to establish necessary line protective device pickup levels.

See Exhibit A for a sample model printout showing the calculations of fault currents and loading conditions from an engineering model.

(4) Maximum Load Currents. The maximum load current levels on all system line components are typically based on the most recent peak loading conditions that occurred on the system. This is often called the "base system." These levels are based on peak-month consumer energy sales and allocated by using computer engineering model software. The resulting loading calculations should reflect the maximum loading conditions that have been experienced on the system.

(a) Planning the Sectionalizing System. In planning the sectionalizing system, one must not only use the maximum load calculations from the base system, the maximum conditions should also be calculated for the anticipated future load conditions. Such conditions are determined from the current approved load forecast. The future system peak conditions should identify the maximum anticipated loads that need to be served by the future sectionalizing system.

(b) Peak Conditions. It is not unusual for a distribution system to experience two annual peak conditions. One condition could be for the summer and one for the winter. If such peaks are long in duration (longer than 2 or 3 hours per year), they both should be modeled and reviewed for the proper sizing of the line devices.

When line devices for maximum load conditions are sized, device manufacturers should be contacted for the overloading capability of each device. Such ratings can be considered in the sizing of the line devices.

(5) Device Coordination. Device coordination means choosing characteristics for a line device so that it can experience a faulted condition *outside* its zone or range of protection without being tripped and still operate appropriately to clear the fault when it experiences a fault condition *inside* its zone of protection. Effective line sectionalizing requires that line device time-current characteristics have proper separation and devices work independently when faults are in their respective zones. Section 5C(4) in this Design Guide describes the separation requirements and how coordination can be achieved.

b Guidelines for Substation Overcurrent Protection. The following is information that highlights high-side devices used to protect distribution power transformers.

(1) Power Transformer Protection

(a) High-Side Devices. High-side devices are primarily used to protect distribution power transformers are fuses, circuit switchers, and breakers. Regardless of the protective device selected, the primary function of the device is to protect the transformer. The goal is to minimize the amount of time the transformer is subjected to fault current. The considerations that need to be taken into account in selecting a protective device are the size and voltage of the transformer and economics.

(1) Fuses. Fuses are the least expensive option but can be limited in performance. They are usually used on smaller units of 10,000 kVA or less and voltages of 69 kV or less. There are some applications where fuses are used for larger units and voltages, but these are less common.

(2) Circuit Switchers. The next option for transformer protection on the economic scale is the circuit switcher. The circuit switcher is considered a "dumb" device in that it does not contain the intelligence to operate by itself. These devices require relays to sense fault conditions and provide a trip signal to the circuit switcher before it will operate. The circuit switcher and relay combination is usun for ally used in substations with transformer sizes above 10,000 kVA and/or having high-side voltages of 69 kV or higher.

(3) Breakers. Breakers are the third and usually most expensive option for transformer protection. These devices, like the circuit switchers, are considered to be dumb and require relaying to provide detection and tripping

intelligence. Breakers are usually used on larger transformers and for higher voltages.

(b) Relaying Strategies. Relaying strategies used to protect transformers usually consist of a high-speed differential scheme as the primary protection and an overcurrent scheme to provide backup protection. Depending on the design scheme, the differential relay may protect only the transformer or may incorporate the secondary bus of the substation. Differential relays are based on the principle that power in is equal to the power out. When the power in does not equal the power out, and the resulting differential exceeds a certain threshold, then the relay trips.

(1) Overcurrent Relay Schemes. The overcurrent relay schemes commonly used consist of phase overcurrent relays on the high side of the transformer and a ground relay on the secondary side in the neutral of the transformer. The relays are usually set by taking into account the size of the transformer, its overload capability, and the coordination with the substation distribution feeder devices. Other considerations that should be taken into account consist of the amount of expected imbalance on the secondary side and the size of the regulators being used.

(2) Phase Overcurrent Relays. The phase overcurrent relays are usually set by taking into consideration the size and overload capability of the transformer; ANSI C57-91 provides valuable information. It should be kept in mind that not all transformers are the same. Substations utilizing autotransformers will not have as high an overload capability as two winding transformers. Because of their construction, autotransformers do not have the short-circuit through-fault capability of a two-winding transformer. In coordinating the phase overcurrent with the distribution feeder, the shift in the time-current curves for the devices due to the difference in the high-side and low-side voltages needs to be taken into account.

(3) Ground Overcurrent Relays. The ground overcurrent relay must be coordinated with the distribution feeder device ground protection. It also should take into account the single winding capability of the transformer. While the balancing of feeders is a goal of a well-operated distribution system, a certain amount of imbalance can be expected at the substation. Any expected imbalance should be taken into account in determining the setting for the

ground overcurrent relay to prevent the relay from tripping. The size of the voltage regulators should be considered in order to protect them from overcurrents.

(4) Other Relay Devices. Other devices that can be included in a scheme to protect the transformer are oil-level, sudden-pressure, and high-temperature relays. These relays are usually internal to the transformer and can be used to trip the high-side protective device. Settings for these relays are usually specified and set by the manufacturer at the time the transformer is specified.

(c) Low-Side Devices

(1) On the low side, bank or station breakers may be used. Some substation designs may utilize a secondary bus device. These may be fuses, reclosers, or breakers. If something other than a fuse is used, then the device is usually set up for one shot to lockout. A bus device must coordinate with the high-side protective device and the distribution feeder devices.

(2) Alternatively, low-side protection may consist of feeder breakers or reclosers only.

(d) Protective Relays. The choices are:

(1) Differential relays,
(2) Backup overcurrent relays,
(3) Sudden-pressure relays, and
(4) Combustible gas monitoring relays.

(2) Feeder Current Protection

(a) Breaker Versus Recloser Utilization

(1) A question that is often raised by the system engineer is what type of device should be utilized in the substation on the substation feeders. The options are generally either breakers or reclosers. The question then arises, “Which device is better?” The answer can be diverse when the various device manufacturers are asked. The real question is not which device is better but which device can handle the fault and peak load duty and which device is more economical.

(2) Breakers and reclosers are really two distinct device types manufactured under different ANSI standards. Breakers typically have higher current interrupting ratings and also can support much higher continuous load currents. Breakers typically are built as power class equipment with higher basic impulse levels (BILs) and, therefore, are usually larger in size than a recloser. Breakers have limitations on number of reclosures and, according to ANSI Standards, should be derated under certain operating conditions. Refer to the applicable ANSI breaker standard to identify their limitations.

(3) Reclosers have traditionally been more economical and offered more options for time-current characteristics (TCCs) with available electronic controls. With the introduction of intelligent electronic devices (IEDs), more TCC options are now available for breakers.

(b) Three-Phase Versus Single-Phase Reclosers

(1) Single-phase hydraulic reclosers are sometimes still being used by rural power distributors as feeder protection. They are inexpensive and reliable. Such practices are discouraged, however, as these devices do not provide the flexibility in coordination with downline devices nor do they provide the best protection for ground and minimum fault conditions.

(2) One argument that is given for using single-phase devices is that, if a fault is on one phase only, the other two phases can remain energized until the fault condition can be repaired. This improves system reliability. This is not a bad practice if it is limited to electric systems that have relatively low current levels and have no three-phase loads on the feeder.

Triple-single reclosers are now available with such flexibility and they come with ground-fault sensing and tripping.

(c) Coordination with the Source Device

(1) Most substation feeders utilize either single-phase reclosers or three-phase reclosers or breakers. In either case, coordination with the source protective device can be complicated and is influenced by many variables. For the

most part, the feeder device is required to coordinate with a protective fuse on the source side of the power transformer or with protective relaying that may be either electromechanical or electronic.

(2) Coordinating with high-side fuses can be accomplished by using a method based on time-current characteristics curves adjusted by multiplying factors to compensate for fuse preloading, ambient conditions, and the number of reclosures of the line protecting device. Source-side fuses are selected to protect the electric system from a power transformer fault and to protect the power transformer from a secondary bus fault. Once the fuse size has been determined, the feeder recloser or breaker curve or curves can be evaluated and selected.

(3) The circuit recloser or breaker must be selected to coordinate with the source-side fuse link so that the fuse does not blow for any fault on the load side of the feeder device. The cumulative heating effect of the recloser or breaker operations must be less than the damage characteristics curve (minimum melt) of the fuse link. This is accomplished through the use of multiplying factors on the recloser or breaker TCC curves that identify the damage or fatigue point of the fuse link. The modified delayed curve must be faster than the source-side fuse's minimum-melt curve.

(4) TCC curves are used to coordinate the feeder recloser or breaker with the source-side fuse link utilizing the following rule:

For the maximum available fault current at the recloser or breaker location, the minimum melting time of the fuse link on the transformer's source-side must be greater than the average clearing time of the recloser/breaker's slowest response curve(s), multiplied by a specific factor. The multiplying factors (often called "K" factors) for various reclosing intervals and operating sequences are published by fuse and recloser manufacturers. The factors range from 1.35 to 3.7 depending on the TCC curves of the recloser or breaker and the reclosing intervals selected.

(5) One other condition that needs to be considered in coordinating source-side fuses (and relay TCC curves as well) is when there is an unsymmetrical transformer

connection (delta/wye). The ratio of primary to secondary fault current will be different when plotting the TCC curves depending on the type of secondary fault realized (three-phase, phase-to-phase, and phase-to-ground). The following ratio factors are used to determine the amount to shift the fuse curve(s) to reflect the TCC response to the secondary of a delta/wye transformer:

Fault Type	Ratio Factor
Three-phase	N
Phase-to-Phase	0.87N
Phase-to-Ground	1.73N

"N" is defined as the power transformer ratio of the source phase-to-phase voltage to the load phase-to-phase voltage.

(6) Since the phase-to-phase fault condition will result in the tightest coordination with the source-side fuse, it should be used in assuring coordination between the devices and protecting the fuse for a secondary fault. Another way of saying this is that a secondary phase-to-phase fault produces the greater amount of source-side current for a given amount of secondary current. Therefore, plotting and reflecting the source-side fuse TCCs using the secondary phase-to-phase ratio factor produces a fuse TCC curve to the far left, resulting in the worst case condition where the minimum melt curve of the fuse should be protected.

(7) Similar steps are required when coordinating secondary reclosers or breakers with substation source-side backup overcurrent relays. As with fuses, the TCC curves of the relays are selected that will provide protection to the electric system for a power transformer fault as well as protection of the transformer for a secondary substation fault. Once the source-side relay TCCs have been selected, the feeder recloser or breaker TCC curves can be reviewed and selected for proper coordination.

(8) When source-side relays are used, generally the system engineer is required to coordinate the high-side overcurrent relays as well as backup ground relays off the neutral bushing of the power transformer. Care should be exercised if source-side instantaneous pickups have been selected. Normally, if instantaneous pickups have been chosen for the high-side backup overcurrent, they should be set for slightly less than the maximum reflected low-side

available phase-to-ground fault to assure coordination with the low-side feeder recloser or breaker settings. Also, it is recommended that NO instantaneous pickup be utilized for the backup ground relay. If used, miscoordination is likely to occur with the feeder protective devices unless set so high that the functionality of the instantaneous setting is questionable.

(9) One significant dilemma in coordinating with source-side electromechanical relays is dealing with relay disk movement, coasting, and reset times. When a fault occurs, the electromechanical relay disk moves toward the closed position, and it will "coast" for a short time if the fault is interrupted or removed by the downline protecting device. This additional movement is typically called coasting time or impulse margin time (IMT). Impulse margin times are published for various types of electromechanical relays and can vary from 0.03 to 0.06 seconds. This margin time needs to be allowed for in the relay response to assure proper coordination with the downline feeder recloser or breaker.

(10) The time that should be added to the relay response is called the "minimum fault time (MFT)." It is calculated using the following formula:

$$MFT = ROT - IMT$$

where ROT is relay operating time at a specific fault level or the maximum fault level, and IMT is impulse margin time. Once calculated, the MFT can be added to the source relay response time or the feeder device to check for proper clearance and coordination.

(11) Reset times of electromechanical relay disks are another matter that needs to be considered when defining feeder recloser or breaker settings. Electromechanical relay disks take an extraordinary amount of time to reset to their time lever or dial position. Depending on the manufacturing type and response speeds, the reset times vary from 25 to 35 seconds at the mid-time dial position. This is critical when multi-shot protection schemes are used, which is what most electric systems utilize for feeder protection.

(12) When checking coordination with source-side relays, several methods can be used, each having their own degree of complexity. For a single-shot (non-reclosing) feeder recloser or breaker condition, one method is to just add 0.3

seconds to the feeder device clearing time; the source relay time must have a greater response time than this. This is a conservative and more simplistic approach. A more accurate approach is to add minimum fault times to the clearing time of the feeder device and check for clearance and coordination. Either of these approaches allow for tolerances, variations due to temperature, plus any other variables.

(13) For coordinating multi-shot (reclosing) feeder or breaker plans with source-side electromechanical relays, the method of checking coordination is much more complicated and important. One simple and conservative method is first to add all times of the sequence and compare the sum to the relay curves. If the added feeder device responses are to the left of the source-relay on the TCC plots, coordination exists. This method is extremely conservative and does not account for resetting of the relay disk between operations. It may not be a realistic approach for many applications.

(14) A more accurate method is to calculate the actual relay disk travel for each trip and reclose operation of the feeder device, add recloser or breaker timing—plus impulse margin times—for each trip, and subtract the relay reset time for each reclosing interval. Calculating the total times as a percentage of relay travel will identify if coordination of the feeder recloser or breaker to the source-side relay will occur. If the total times are greater than 100%, the feeder recloser or breaker does not coordinate with the source-side relays and will result in the substation being tripped offline, causing an outage. This can be corrected by changing the last reclosing interval on the feeder device to a longer time, allowing the source electromechanical relay to reset more fully to attain adequate coordination between devices.

(15) Fortunately, with the development of static and/or electronic relays and controls, life for the system protection engineer is becoming somewhat simplified. The need to coordinate with electromechanical relays is declining greatly as the new “intelligent electronic devices” (IEDs) are replacing the old forms. With such devices, relay and device responses are much easier to predict and can be more easily modified to assure proper coordination between devices.

(16) As a rule of thumb—when not having to worry about electromechanical complexities, and where static or electronic relays are present—adequate coordination between a feeder recloser (or feeder breaker) and the source-side protective device can be attained if the minimum separation of the feeder response and the source-protecting device response is greater than 30 cycles (or 0.5 seconds). Closer separation can be allowed if more precise TCC studies are accomplished where curve tolerances, device responses, reclosing intervals, and other variables are included for the specific application being reviewed. A tool that can be used to attain such coordination is the instantaneous pickup function, if available in the feeder recloser or breaker controls, applied at the proper level to assure the desired separation mentioned above.

(17) When feeder protection devices are equipped with both phase and ground protection, another aspect of coordination of feeder devices to source-side devices is to realize the composite TCC response of the ground and phase trip settings. In other words, when checking and confirming coordination, it is not required to look individually at phase responses and ground responses. They should be viewed as TCC responses working together for the purposes intended. With a majority of line faults being phase-to-ground, the ground current relay is going to "see" the fault the same as the phase relay, and the ground relay will respond quicker. This means that the coordination of the phase relay by itself with the source-side device is not required and unnecessary.

(18) The system protection engineer is encouraged to refer to system protection manuals and standard methods for details of the processes described above, as such are beyond the scope of the guide.

(d) Coordination with the Load Device(s)

(1) As stated earlier, typical electric distribution substations utilize single-phase hydraulic reclosers or three-phase reclosers or breakers to protect substations from feeder faulted conditions. Over the last 10 years, electric systems have moved more and more away from the use of single-phase hydraulic reclosers. This is due to feeders having higher load currents and the need for ground trip protection.

(2) For substation feeders utilizing single-phase hydraulic reclosers, to assure proper coordination and no simultaneous operations, the separation between the feeder recloser and the downline single-phase recloser must be greater than 12 cycles at the maximum fault conditions at the downline device. From 2 to 12 cycles, possible simultaneous operations may occur. Less than 2 cycles separation means simultaneous operations will occur and there is not proper coordination.

(3) For feeder devices with electromechanical overcurrent relays, the same coordination steps described in the earlier section must be followed. Minimum fault times, relay operating times, impulse margin times, and disk reset times must all be used to assure proper coordination.

(4) For feeder reclosers or breakers with electronic or static relays or controls, coordination can more easily be set and established. Time current characteristics can be modified and set to adjust feeder device responses that will coordinate with whatever downline devices that may be in operation.

(5) As a rule of thumb—when not having to worry about electromechanical complexities and where static or electronic relays or controls are present—adequate coordination between a feeder recloser or breaker and the downline protective devices can be attained when there is a minimum separation or margin of the downline feeder device response and the source-protecting device response is greater than 21 cycles or 0.35 seconds for the maximum fault at the downline location. Closer separation can be allowed if more precise TCC studies are accomplished where curve tolerances, device responses, reclosing intervals, and other variables are included for the specific application being reviewed.

(6) The system protection engineer is encouraged to refer to system protection manuals and standard methods for details of the processes described above, as such are beyond the scope of this guide.

c Guidelines for Overhead Line Protection. One of the key components of a reliable electric distribution system is the proper application of line sectionalizing devices. Proper application will assure reduced outage times and minimize system damage due to overcurrent conditions. The following comments provide guidelines in the proper application of line sectionalizing devices.

(1) Line Devices. There is a wide variety of line devices available to the system engineer for sectionalizing an electric distribution system. The devices are ever-changing, bringing operational and maintenance benefits as technology advances to fulfill the needs of the industry. Currently, the devices that are available are as follows:

- Line reclosers (single-phase and three-phase),
- Line sectionalizers (single-phase and three-phase),
- Line fuses (expulsion and current-limiting), and
- Line switches (single-blade and group-operated).

(a) Line Reclosers (Single-Phase and Three-Phase). Line reclosers are a self-contained device with the necessary circuit intelligence to sense overcurrent conditions, to time and interrupt the overcurrent, and to reclose automatically to reenergize the line. If the fault is “permanent,” the reloser will “lock open” after a predetermined number of operations (usually three or four) and, thereby, isolate the faulted section of distribution line from the main part or source of the system.

(1) Most faults on overhead distribution systems are temporary in nature and last only a few cycles or seconds. Statistical studies of distribution systems show that approximately 70 to 80% of overcurrent conditions on overhead lines are temporary in nature. Automatic line reclosers, with their trip and reclose capability, eliminate prolonged outages on distribution lines due to temporary faults or transient overcurrent conditions.

(2) Automatic line or circuit reclosers are classified on the basis of single- or three-phase, hydraulic or electronic controls, and oil or vacuum interrupters. Each type has its advantages.

(3) With the high cost associated with oil maintenance, there is a trend toward utilization of reclosers that have vacuum interrupters. Selecting vacuum interrupters increases the length of the maintenance cycle and reduces maintenance costs.

(4) Single-phase line reclosers are used typically for protection of single-phase lines, such as branches or taps off three-phase lines. They can also be used on three-phase circuits

where the load is predominantly single-phase. This allows, when a permanent phase-to-ground fault occurs, one phase to be locked out while service is maintained to the remaining two-thirds of the system.

(5) In the past, single-phase reclosers have been primarily hydraulically controlled. In recent years, more and more single-phase reclosers have been electronically controlled. Such configurations offer greater flexibility in line applications and coordinate more precisely with upline and downline devices. Such devices are considerably more expensive and have not been utilized extensively in the rural electric distribution industry. As technology improves and the costs become more reasonable, it is expected that more single-phase, electronically controlled reclosers will be utilized.

(6) As mentioned earlier, very often on rural electric distribution lines, three single phase reclosers are installed on three-phase lines. Such applications are on lines with relatively low peak loads, have very few large three-phase loads, and phase-to-ground fault levels are not very low.

(7) Three-phase line reclosers are used where lockout of all three phases is required for any permanent fault, to prevent single phasing of three-phase loads such as large three-phase motors. Three-phase reclosers with a ground trip accessory are also utilized when line load currents are high and minimum fault current levels are very low. In such cases, the three-phase reclosers are equipped with neutral sensing circuitry using current pickup levels much lower than the line phase currents. Three-phase reclosers have two modes of operation: single-phase trip/three-phase lockout and three-phase trip/three-phase lockout.

(8) Single-phase trip/three-phase lockout is obtained with three single-phase reclosers mounted in a single tank with mechanical interconnection for lockout only. Each phase operates independently for overcurrent tripping and reclosing. If any phase operates to the lockout condition, the mechanical linkage trips the other two phases open and locks them open. This then prevents extended single-phase energization of three-phase loads.

(9) Most other three-phase reclosers operate through the three-phase trip/three-phase lockout mode. For any fault, all

contacts open simultaneously for each trip operation. The three phases are mechanically linked for tripping and reclosing, and are operated by a common mechanism.

(10) Some manufacturers are now selling three-phase reclosers that can do single- or three-phase trip with single- or three-phase lockout. These are configured to the user's requirements through electronic controls.

(11) Reclosers can be purchased with hydraulic or electronic controls. The uses of three-phase hydraulically controlled reclosers have declined over the years. The industry has deferred to the electronically controlled devices, which offer improved flexibility in application (added time-current characteristics), provide for better ground fault protection, and are more precise in coordination with other line devices.

(b) Line Sectionalizers (Single-Phase and Three-Phase). A line sectionalizer is a protective device that automatically isolates faulted sections of line from a distribution system. Normally applied in conjunction with a backup recloser, a sectionalizer does not have any fault-interrupting capability of its own. Rather, it counts the operations of the backup device during faulted conditions and, after a preselected number of current-interrupting operations and while the source or backup device is open, the sectionalizer opens to isolate the faulted section of line. This allows the source or backup device to reclose into the remaining unfaulted portion of lines, thus restoring the lines to service.

If the fault is temporary, however, it will be cleared by the source/backup device prior to the sectionalizer count to lockout, and the sectionalizer will remain closed. Then the sectionalizer automatically resets to prepare for another complete cycle of operations should a new fault occur.

(1) Compared to fuse cutouts, which do, of course, have full interrupting capability, sectionalizers provide several advantages that, depending on the application and the particular utility's approach to overcurrent protection, can offset a higher initial cost. These advantages include application flexibility, convenience, and safety.

(2) After a permanent fault, for example, the fault-closing capability of a sectionalizer greatly simplifies testing of a circuit, and if the fault is still present, interruption takes

place safely at the backup recloser. Since replacing fuse links is not required, the line can be tested and restored to service with far more speed and convenience. Also, the possibility of error in selecting the size and type of fuse is eliminated.

(3) In addition to providing the general advantages just cited, sectionalizers are particularly suitable for two applications where time-current characteristics (which sectionalizers do not have) might pose coordination problems:

(a) Sectionalizers can be used between two protective devices with operating curves that are close together. This is a vital feature in locations where additional coordination steps are impractical or impossible.

(b) They can be used on close-in taps where high fault magnitude prevents coordination with fuses or use of expensive high-interrupting fault reclosers.

(4) Sectionalizers are available in single- and three-phase versions controlled by hydraulic or electronic counting mechanisms.

(5) Sectionalizers do have high momentary current ratings, providing for safe closing operations on faulted lines.

(c) Line Fuses (Expulsion and Current-Limiting). Line fuses are the most basic protective device available for line overcurrent protection on distribution systems. Their primary function is to serve as an inexpensive means to protect equipment against overloads and short circuits.

(1) Fuses are available in a variety of types, offering a wide variety of time-current characteristics. The basic types are expulsion fuses and current-limiting fuses. Expulsion fuses are utilized more extensively in distribution systems than current-limiting because of cost and operational needs.

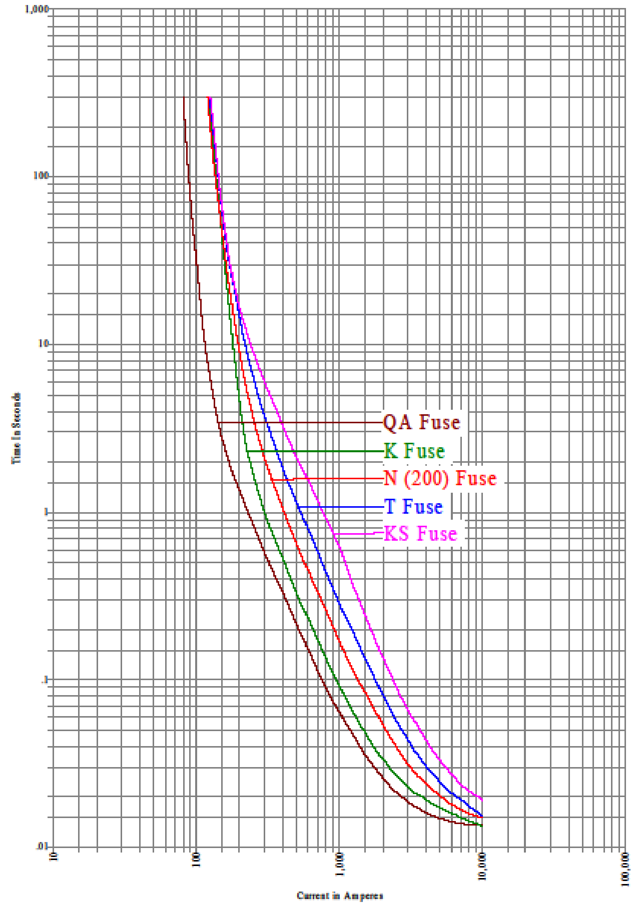
(2) Expulsion fuses serve as expendable, inexpensive “weak link” protective devices used on distribution lines with cutouts. That is, fuse links are components that are replaced after providing the desired protection to equipment and/or distribution lines. Properly coordinated with backup reclosers, fuses can help reduce the total cost

of sectionalizing equipment without reducing service reliability or increasing operational and maintenance expenses.

(3) Fuses follow basic time-current characteristics that are described in a set of two curves. Minimum melt curves describe the current and time characteristics that are necessary for melting of a fuse to begin. Once melting has occurred, the fuse is considered to be damaged and, therefore, can no longer be relied on to function in the manner that is expected of a new fuse. Total clear curves describe the current and time characteristics that are necessary for the fuse to fail, thus clearing a fault.

(4) Expulsion fuses can be grouped into types that have similar time-current characteristics. These types are typically designated by a letter. Often these types are referred to as the "speed" of a fuse. Typical fuse types used in the electric distribution industry, from the fastest to the slowest, are N, QA, K, T, S, and KS. Refer to Figure 5.1 for a summary of the total clear characteristics of a 50-A fuse for various speeds. The most popular fuse for coordinating with hydraulic line reclosers is the Type T.

Figure 5.1. Time Current Characteristics (50-Amp Fuse Comparisons)



(5) Current-limiting fuses (CLFs) are typically utilized on electric systems that have very high fault conditions. They are generally used to protect equipment such as distribution transformers, capacitor banks, and other devices on the system where available faults may result in catastrophic failures. With the improved design of distribution transformers and capacitor banks for applications at higher fault current locations, the use of CLFs has declined. For systems with loads very sensitive to voltage fluctuations, CLFs are used to limit fault current levels, reducing undesirable line voltage flicker. CLFs are generally very high in cost, so decisions to use them should be closely scrutinized.

(d) Line Switches (Single-Blade and Group-Operated). One does not usually find line switches listed as sectionalizing devices on electric distribution systems, but they are important sectionalizing tools for aiding in power restoration. One of the key objectives of proper sectionalizing is to provide a means for isolating system faults from the rest of the system so that power can be restored. Related to this objective is to have line switches located on the electric system where portions of the system can be clearly isolated (visible break) as well as to provide a means whereby loads can be transferred to other system sources until the faulted lines can be repaired. Single-phase and three-phase switches should be carefully placed on the system to allow for such system operations.

(2) Considerations for Sizing and Locating Devices

(a) Application Based on Valid System Model. Before considering the application of any line sectionalizing device, accurate knowledge of true system conditions must be determined and available to the system engineer. Without such information, system damage is sure to occur and service reliability will be poor.

(1) It is critical that the following system conditions are accurately determined and/or calculated before the installation of any sectionalizing device:

(a) System configuration (line conductor sizes, number phases, voltages, opens and substation boundaries, substation feeder numbers and service areas, etc.);
(b) Location of critical loads (e.g., large power, large commercial and industrial plants, hospitals, schools, nursing homes);
(c) Available fault currents; and
(d) Peak line/load currents.

(2) System configuration is demonstrated primarily from the mapping system. The mapping system provides information to help determine each of the above items. If the system is old and not adequately maintained, steps should be taken to update and field verify what the current electric system characteristics are. Geographic information systems (GIS) are available to help analyze electric system conditions and to aid in maintenance and management. This tool can be invaluable in the proper operation and maintenance of sectionalizing devices. In addition, GIS is constantly improving and, with improved communication techniques, live or real-time system monitoring can be attained, providing a means for quick responses to system outages and line problems.

(3) The location of critical loads and consumers can be determined generally from the service personnel in the field and the customer services department. These people can provide insight into where sectionalizing devices need to be

placed. In planning system protection and sectionalizing, knowledge of such locations is critical. Sectionalizing devices are placed to eliminate exposure of critical loads, assuring minimized interruption and reliability of service. Such loads should be clearly indicated on system maps for sectionalizing system planning and outage response. No system can guarantee 100% reliability, but every reasonable effort should be put forth to maintain service to priority consumers.

(4) Available fault currents are calculated from the source impedances as provided by the distributor's power supplier. Calculations of system conditions are based on this information, and the method for calculating such values is discussed earlier in Section 3B of this Design Guide. The important point here is that the information from the supplier should be current and validated by official means. "By official means" implies in written official form, and it is desireable that it be provided from a registered professional engineer. The information should include, as a minimum, the positive-, negative-, and zero-sequence impedances on, typically, a 100 MVA base at a specified point on the electrical system (i.e., high side of a substation, low side of substation, or point on a distribution meter point).

(5) In addition to requesting this information, inquiries should be made to the power supplier as to any impedance changes that are expected over the next 2, 3, or 4 years (typically the period of a construction work plan). Such information will enable the distribution system engineer to design the protection system for the future worst-case scenario. Source impedances can change dramatically when there are significant changes in the transmission system (i.e., conductor upgrades, loop feeds, new generating plants, etc.), as well as changes in the substation (i.e., power transformer uprating, source voltage change, low-side voltage change). Such changes should be included in the planning of a sectionalizing system and incorporated in all system improvements.

(6) Finally, the last critical aspect of the system that needs to be known is the line load currents. Often, such accurate information is the most difficult to secure. The reason is that the load currents vary with system conditions (i.e., summer, winter). Typically, the values are first calculated

from a system computer model built around an accurate mapping system, accurate consumer load data, and accurate substation service area boundaries for the time of the load data. The calculated values and model should then be validated from actual field-recorded peak voltages and currents. Such values can be recorded from installed digital recording voltmeters at selected key line locations (e.g., circuit extremities with high voltage drops, key circuit branch points) and from digital line voltage regulator controls. From the field-measured values, the system peak model conditions can be validated for use in the design of the protection system and application of sectionalizing devices. It is extremely important that the model accurately reflect the realities of the system.

(b) Location Selection

(1) After a valid system model has been developed, the preferred and best location of the overhead line sectionalizing devices can be determined. Starting from the substation feeder device to the end of the circuit, the following guidelines can be utilized in the location of line sectionalizing devices:

(a) Identify any zones of protection.

(b) Locate priority loads and install sectionalizing devices downline to eliminate exposure and improve reliability.

(c) Identify key branch points and install devices such that service to the higher load branch or both branches can be maintained.

(d) Locate points on the distribution feeder where the minimum calculated fault conditions are below substation feeder minimum ground pickup level and install a suitable device at that location or upline.

(e) Install devices at locations that are easily accessible for operations.

(f) Locate taps off main lines that are either long, through wooded areas, or inaccessible.

(2) Typically, sectionalizing devices are located on the electric

system for primarily two objectives:

(a) To eliminate line exposure for high loads or load groups (branch circuits), and

(b) To have enough devices on the system to aid in the location and isolation of faulted lines.

This will enable system operating and construction personnel to restore electric service in a timely fashion. Following the guidelines listed above will enable the system engineer to accomplish these objectives.

(3) After locating application points for reclosers, it is important to locate sites for the application of line switches. These points can be determined from the computer model and the mapping system. Sites where loads can be transferred to alternative sources should be identified and line switches installed to allow for easy transfer when line problems occur.

(4) The main purpose for the switches is to provide such operational flexibility, but also to provide visible breaks when line repairs are being made. A general guide is to locate these sites as follows:

(a) Adjoining substation circuit tie points,
(b) On main circuit branches,
(c) Just downline from key feeder loads, or
(d) Adjacent to feeder tie points.

(c) Selecting Equipment Type and Current Rating

(1) Once system conditions have been identified and validated with a computer model, and after locations have been selected to produce the desired operational results outlined above, the particular sectionalizing device can be selected. Typically, reclosers or sectionalizers are utilized on lines that have the highest loads, have the most customers, and justify the highest expenditures for reliability. Lines with the lowest loads and fewest consumers will use fuses. Reclosers and sectionalizers are also installed to aid in fault location and power restoration.

(2) Line reclosers (either three-phase or single-phase) are the most expensive sectionalizing device, with single-phase

sectionalizers being close behind, leaving fuses as the least expensive device.

(3) With such devices, the following conditions have to be met in selecting the type and size of the equipment.

(a) The device must have the insulation level suitable for the line voltage to which it is to be applied.

(b) The device must have the continuous current rating to carry the projected peak load conditions and any anticipated load shifts. The rating should be selected to allow for load growth over at least the next 3- to 5-year period.

(c) The device must be able to interrupt the maximum fault current calculated at the point of application.

(d) The device must respond to the minimum calculated line-to-ground fault to the end of the line or to the next downline device.

(e) The device must coordinate with downline devices.

(f) The device must coordinate with upline devices.

(4) Insulation levels are usually based on rated withstand test voltage, which is expressed as basic impulse level (BIL) in kilovolts. The typical ratings for distribution equipment are 95 kV BIL for 12.5 kV systems, 125 kV BIL for 25 kV systems, and 150 kV for 35 kV systems. Equipment with higher BIL can usually operate on lower-voltage systems. Engineers are encouraged to coordinate such applications with the manufacturer before equipment installation to identify any limitations and operational problems.

(5) When one discusses peak load conditions, questions usually arise as to what "peak" means. It could be the peak for winter, the peak for summer, the projected probable peak from the RUS load forecast, or even the extreme peak found in the RUS load forecast. It is the system engineer's task to select the peak that will adequately protect the system in conjunction with the duration of the peak. For systems that routinely experience extreme summer and winter conditions, sectionalizing devices should be applied for such a peak. However, if extreme peaks are infrequent

and have a duration that is very short, then the normal or probable peak projections could and should be utilized. Electric systems in the extreme south generally have extreme winter conditions that last only a few days or even hours. In such cases, applying sectionalizing equipment based on the normal/probable or extreme summer load projections is economical and practical. This means that, for short periods of time, line devices may have to be bypassed until the short-duration peak conditions have passed.

(6) Line devices also typically have overload factors identified by the manufacturers. If such factors have been identified by the manufacturers, short-term operation overloads can be allowed without serious damage occurring to or improper operation of the device. The system engineer is encouraged to be familiar with these overload factors before sizing any sectionalizing device.

(7) One of the most serious mistakes in the application of sectionalizing devices is to install them at locations where they do not have the interrupting rating to clear the maximum calculated fault. Such actions can result in rupture of the device, possible fire on the pole and the ground, and possible injury of individuals who might be standing below the device or in the vicinity. It is important that the system engineer carefully apply sectionalizing devices so that they have the capacity to safely interrupt the maximum fault calculated.

(3) Time-Current Curve Selection

(a) Protective devices are said to be coordinated when the device closest to the fault location interrupts the line fault current without causing upline devices to permanently open or lock out. Coordination is achieved by proper selection of fuse size, trip coil ratings for hydraulic reclosers, or minimum trip current values in electronic and relay-controlled reclosers. The selection of the proper fuse size, trip ratings, or settings is determined by comparing the time-current curves (TCCs) of the upline and downline devices.

(b) Time-current curves of fuses and hydraulically controlled reclosers are generally of similar shapes, which can simplify the coordination process. However, the limited selection of these curves can also make it harder to achieve the desired level of coordination. Relay-controlled and electronically controlled reclosers have a large variety of settings and can be closely coordinated with other devices, but the wide range of settings can make the process more complicated.

(c) Several of the major protective device manufacturers publish reference manuals that discuss device characteristics and coordination methods in detail. Contact your manufacturer's representative to obtain copies of the texts and carefully review them before beginning a coordination study.

(4) Coordination

(a) Relay and Electronic Control

(1) Relay Control. Electromechanical or electronic relays are used with three-phase breakers in substations or other applications that require devices capable of interrupting high levels of fault current. Electromechanical relays have several characteristics that must be considered for coordination with a downline device.

For time-delayed tripping, the relay contains a disk that begins moving toward the closed position when line current exceeds the relay's minimum trip setting. When the disk fully rotates, it closes a set of contacts that causes the breaker to trip. When timing for a fault current, the relay disk moves toward the closed position, and it will continue to rotate (coast) for a short time after it is deenergized if the fault is interrupted by a downline device. This additional rotation is called the *coasting time* or *impulse margin time*. The downline device must clear the fault in sufficient time to prevent the coasting action of the disk from causing the relay to unnecessarily trip.

Likewise, electromechanical relays typically do not reset immediately after deenergization because the disk requires time to return to its original position. If the downline device is a recloser, the relay disk may not have time to fully reset during the reclosing interval. Under this condition, the disk will accumulate, or advance its rotation, toward contact closure with each reclose action, also causing the relay to unnecessarily trip. Downline reclosers must allow a sufficient reclosing interval to allow the relay to reset, or allowances must be made in the relay settings to compensate for the accumulated disk travel.

One commonly overlooked characteristic of relay-controlled devices is the control response curve associated with the interrupting device clearing time. The clearing time of the interrupting device (also called the *interrupting time*) must be added to the control response time to determine the average clearing time. Relay trip settings can be adjusted using current tap and time dial settings to produce a variety of time-current characteristics. Refer to the relay manufacturer's literature to determine the available settings, including the coasting and reset times, for the relay in question.

(2) Electronically Controlled Reclosers. Electronically controlled reclosers are available for single- and three-phase applications. They are commonly used not only in substations but throughout the distribution system. These devices can be coordinated closely with downline devices since there is no coasting or override in the electronic device. If the downline device, with its plus tolerance, clears faster than the response time of the electronic control with its negative tolerance, then the devices will coordinate.

As with relay-controlled devices, the clearing time of the interrupting device (also called the interrupting time) must be added to the control response time to determine the average clearing time.

For coordination with downline devices, it should be understood that when the control response curve of an electronic control is exceeded, the interrupting device has been committed to trip, regardless of the total clearing time. Thus, control response curves of both fast (instantaneous) and time-delay curves should be compared with downline sectionalizing device operating curves. As an example, the control response curve, including tolerance of the time-delay curve, must lie above the maximum clearing curve, including tolerance, of a load-side recloser or fuse if coordination is required.

When an electronic recloser is coordinated with an upline device, the clearing time of the interrupting device must be added to the control response time, plus tolerances, to check coordination with the upline device. Clearing times and TCC tolerances are usually listed on the manufacturer's TCC sheet for the device.

Reclosing intervals and resetting intervals may require coordination with other devices in applying electronic reclosers. When the recloser is used downline of a fuse, for example (in a substation application), the reclosing time may need to be lengthened to allow fuse cooling between recloser operations.

(b) Single-Phase Recloser with Single-Phase Recloser

(1) The simplest method of coordinating reclosers in series is to choose the same make and style of recloser and then to select reclosers in descending coil sizes. Usually, adjacent coil sizes will coordinate satisfactorily if the reclosers are not spaced too closely. However, if load current or fault current at the substation is high, it may be uneconomical to use the higher-interrupting-rated recloser throughout the entire circuit. When reclosers of different make or type are used in series, it will be necessary to plot the time-current characteristic (TCC) curves of each recloser in order to determine coordination.

(2) Coordination by merely selecting adjacent coil sizes can frequently be achieved with hydraulic reclosers of different make or type. However, this should be checked by comparing TCC curves. The fast curves may have different slopes and speeds but, in most cases, it is usually not possible to coordinate fast curves on hydraulic reclosers.

(3) When comparing TCC curves of adjacent reclosers, it is important to maintain sufficient separation between the curves to avoid simultaneous operation of the two devices. Generally, separation of less than 2 cycles will result in simultaneous operation; separation of 2 to 12 cycles *may* result in simultaneous operation; and separation of more than 12 cycles will assure coordination. Refer to the manufacturer’s recommendations to ensure that the coordination will be achieved for the devices in question.

(4) It is possible to coordinate series reclosers by electing different time-delay operating curves or a different number of operating sequences. This generally is not recommended, however, except in special cases where coordination cannot be achieved otherwise. It is good practice to standardize on a particular time-delay curve and operating sequence for all line reclosers on a system. (This

does not necessarily apply to substation reclosers. The demanding requirement of substation protection and coordination can often be met by special selection of curves and sequences for each station or feeder.) Experience has indicated that a sequence of two fast curve operations followed by two time-delay curve operations followed by lockout is a good choice for line reclosers. However, some system operators may wish to standardize on one fast and either two or three time-delay curves. In high-lightning-incidence areas, it may be advantageous to use three fast curves followed by a time-delay curve.

(c) Single-Phase Recloser with Fuses. Coordination of reclosers with source-side fuse links is most often encountered when the fuse is protecting the high-voltage side of a transformer and the recloser is on the low-voltage side.

(1) To coordinate the recloser with an upline fuse, the cumulative heating effect of the recloser operations must be less than the minimum-melting curve (or damage curve) of the fuse. The time value of the recloser delayed curve is multiplied by a heating factor (also called the *K* factor) to account for the heating effect. The *K* factor will vary with the reclose timing and the fast-slow sequence of the recloser. Refer to the recloser manufacturer's data to determine the *K* factor for the device in question.

(2) Coordination of reclosers with load-side fuse links is usually done to permit the recloser to clear temporary faults beyond the fuse and to force the fuse to blow on permanent faults. This is commonly referred to as "fuse saving." Coordination is determined by plotting the time-current curves of both the recloser and fuse. As previously discussed, the reclose operations of the recloser will cause heating in the fuse, therefore the time value of the recloser's fast curve must be shifted to account for the heating effect.

(3) If only one fast curve is used on the recloser, a 1.25 multiplying factor is used. If two fast curves are used, a 1.35 multiplier is used for reclose times of 60 cycles or longer and a 1.8 multiplier for reclose times less than 60 cycles. Both fuse curves, minimum melt and maximum clearing, should be plotted. The fuse curves should lie between the shifted fast curve and the time-delay curve over all or most of the range of available fault current.

Tolerance should be allowed for recloser time-delay curves. Because of the shape of the curves, it may not be possible to achieve perfect coordination over the entire fault current range. In general, EEI-NEMA Type T fuse links provide the widest range of coordination with hydraulic reclosers.

(4) It is desirable to employ recloser fuse combinations that will allow the recloser to sense a minimum calculated fault at the end of the line. However, if this is not practical, the fuse should melt for an end-of-the-line minimum fault in approximately 20 seconds or less.

(d) Fuse Link to Fuse Link Coordination. Many branch lines can be most economically protected by fused cutouts.

(1) It is desirable that they be coordinated with and protected by reclosers as previously described. It is sometimes practical to apply, in series, two fuse links with different ratings protected by one recloser.

(2) At other locations, it may be more economical to provide only permanent fault protection by coordinating fuse links in series. It is best to limit the number of branch line sectionalizing fuses in series to two or three.

(3) It is recommended that the same make or type fuse link be used throughout a system. The EEI-NEMA Type K or T links are preferable, since they are standardized and are available from several suppliers.

(4) When coordinating sectionalizing line fuses in series, the following factors should be considered:

(a) Peak load currents at the point of application should be less than the fuse link rating. The fuse link must be large enough to withstand inrush currents to motors, capacitor banks, and transformer banks. In addition to these transients, which last only a few cycles, consideration should be given to cold-load pickup, which can last several seconds to several minutes. Some fuses are rated for a higher continuous current than the name might suggest. Therefore, it is important to consult the manufacturer's specifications regarding fuses.

(b) The fuses should be coordinated with each other by applying the 75% rule. This means that the load-side fuse maximum clearing curve should not exceed 75% of the source-side fuse minimum melting curve.

(c) The fuse links should be coordinated with the burn-down characteristic of the conductors in the fuse zone of protection.

(d) A fuse link should melt in approximately 20 seconds or faster for a minimum fault in its zone of protection.

(5) Identification of High-Reliability Zones

(a) Because of the widespread use of microprocessor-based devices in homes and businesses, consumers are highly sensitive to the momentary outages that occur during recloser operations. These outages can cause clocks to reset, digital controls to malfunction, and computer systems to crash. Although recloser operations are a normal, and necessary, part of the protection scheme, many consumers find them objectionable and will begin to question the reliability of the electric system if they occur too frequently.

(b) To increase the reliability of a particular feeder, efforts must be made to decrease the number of momentary outages affecting the circuit. However, as noted in Section 5C(4)(c) of this Design Guide, downline reclosers or fuses can cause the upline main feeder recloser to operate on its fast curves before the downline device clears the fault. These additional operations increase the number of momentary outages and decrease the reliability of the entire downline circuit. Therefore, a high-reliability zone can be established beginning with the substation feeder recloser and extending downline to the first mainline recloser.

(c) To begin establishing a high-reliability zone, the substation protection device should utilize an electronic control with sequence coordination features. Sequence coordination enables the recloser to suppress its fast-trip operations in response to a fault beyond a downline recloser. All taps in this zone need to be protected by a fuse or recloser. The substation fast trip curves and all tap fuses should be coordinated to cause the fuse to blow before the recloser trips on its fast curve. This scheme is known as “trip-saving,” as opposed to the fuse-saving scheme discussed in Section 5C(4)(c) of this Design Guide. A trip-saving scheme will cause a permanent outage on the tap for faults beyond the fuse, but will not cause the upline recloser to operate.

(d) Another tool available for use in a high-reliability zone is the single-phase electronic recloser. These devices are available with sequence coordination, and can be configured for single-phase trip with three-phase lockout, single-phase trip with single-phase lockout, or three-phase trip with three-phase lockout. Because these devices can operate in single-phase mode, faults affecting one or two phases will not cause momentary outages on the unaffected phases, resulting in better overall reliability.

(e) This high-reliability zone concept can be extended out on the feeder. As noted, it will require use of electronic reclosers capable of sequence coordination and careful selection of recloser trip curves and fuse curves to achieve trip-saving coordination.

d Guidelines for Underground Overcurrent Protection

(1) All-Underground Circuits

(a) If a circuit is completely underground, it should be assumed that there can be almost no temporary faults on that circuit. Therefore, there is little justification for automatic-reclosing overcurrent protective devices for the purpose of clearing temporary faults. Reclosing on an underground fault can worsen the damage to the faulted cable and can conceivably damage a sound adjacent cable. A one-shot sectionalizing plan using fuses, fault interrupters, or a combination of both can be considered, provided selective coordination of the devices in series can be attained.

(b) Fusing is the best solution for many underground sectionalizing applications with relatively few consumers and/or lower load current. However, for higher loads and larger numbers of consumers, pad- and pole-mounted electronic fault interrupters offer a good alternative to fusing. As electronically controlled devices, these units offer a wider range of coordination than fuses. In addition, if ferroresonance is anticipated, or if single phasing of three-phase loads would be a problem, electronic three-phase fault interrupters can be used. A combination of fuses and fault interrupters is certainly a possibility for an all-underground sectionalizing plan.

(c) If coordination between fuses or older-style nonelectronic one-shot devices cannot be assured because of load current or fault current conditions, consider the use of electronic fault interrupters or use electronically controlled reclosers set to one-shot operation. As previously stated, these devices offer much more flexibility than do fuses or hydraulically controlled sectionalizers. If electronic fault interrupters or reclosers are not available, and coordination must be achieved, consider using a hydraulic recloser. In this case, the reclosers would not be used for the purpose of clearing temporary faults, but instead would be used to assure selective coordination of sectionalizing devices.

(d) While it is true that reclosing on an underground fault can exacerbate the damage to a faulted cable and can conceivably damage a sound adjacent cable, it is felt that an overriding consideration is to selectively sectionalize the smallest section of cable, thereby rendering better service to consumers. The general rule of thumb is that it is not necessary to reclose on an underground fault. However, if in the judgment of the engineer, better service reliability to the most consumers can be expected by choosing an automatic reclosing device, it is preferable to do so. The number of reclosing operations should be held to a minimum. Usually one or at most two reclose operations will be all that will be required for coordination with other devices.

(2) <u>Overhead to Underground Circuits</u>

(a) Circuits with both overhead and underground construction present different sectionalizing problems than either a total underground circuit or a completely overhead circuit. It is not unusual for circuits to exit from a distribution substation with underground cable. The underground exit may extend for several hundred feet or for several miles before it reaches an overhead transition point. Overhead distribution circuits can also dip underground at any point and reemerge again to continue as an overhead line. Considerable engineering judgment should be exercised in selecting sectionalizing devices for these combination lines. If the majority of the line is underground with a small percentage overhead, the line can be considered similar to an all-underground circuit. The converse is also true. If the line is predominately overhead with a small part of it underground, it can be considered as a completely overhead system in choosing overcurrent protective devices.

(b) It is usually not possible to install fuses between reclosers, although it may seem desirable to do so in certain overhead-underground circuits. An attempt to do this usually results in fuses and reclosers being larger than would ordinarily be selected. This, in turn, results in the entire coordination of time-current curves back to the substation being undesirably high.

(c) A three-phase automatic line sectionalizer can be installed between three-phase reclosers, provided the sectionalizer is equipped with the sensing required to permit it to count only the backup recloser operations. This is sometimes described as "voltage restraint." The advantage of a sectionalizer is that it does not operate on a time-current curve. The disadvantage of a sectionalizer is that it would probably be set for one count and is, therefore, a high-cost device compared to a fuse.

(d) If the expense of three-phase sectionalizers and three-phase reclosers cannot be justified, the alternative is to treat the underground section of line as if it were an overhead line.

(e) Underground taps off main overhead lines usually present no unusual overcurrent coordination problems. They can be economically fused. If coordination with fuses cannot be achieved, consideration should be given to electronic fault interrupters.

(3) <u>Use of Fault Indicators</u>

(a) Although underground cable faults are usually rare occurrences, the time required to locate, switch lines, or repair the cable can result in an extended outage for the consumers. The proper use of faulted circuit indicators (FCIs) will enable quick identification of a faulted cable section and significantly reduce outage time. The FCI is easily affixed to the cable or elbow, and contains a sensor that causes a built-in target or indicator to operate when current exceeds a preset level. Operating personnel can quickly check each FCI on the circuit to determine the last point at which fault current was detected. Using this information, they can then isolate the faulted section and begin restoration work.

(b) FCI devices should be placed along the circuit at strategic points that will allow operating personnel to determine the location of the faulted section and switch lines to restore service to the maximum number of consumers. The number and cost of placement of the FCI devices along a circuit should be weighed against the number of consumers and level of desired reliability.

(c) A number of manufacturers produce FCI devices in a variety of configurations for overhead and underground use. FCIs are generally selected according to load current levels and reset methods. Devices can be reset manually, or configured for time-delay, voltage, or current reset. Most FCI manufacturers provide detailed application notes for their products. Take advantage of this information to achieve the best results from these devices.

6 EQUIPMENT UTILIZATION AND MAINTENANCE

a Utilization Guidelines

(1) Tripping and Reclosing Practices

(a) In past years, rural electric distribution systems have typically utilized three reclosures to lockout (or four trips to lockout). This has been for substation feeder circuit breakers or reclosers as well as line circuit reclosers. If substation feeder circuit breakers were used, instantaneous reclosure was utilized after the first trip. Time-current characteristics for recloser tripping have typically been two fast operations and two slow operations. Over the years, such practices have been evaluated and scrutinized. The results show that changes appear to be warranted.

(b) According to a paper presented by the Power System Relaying Committee of the IEEE Power Engineering Society, the practice of allowing instantaneous reclosures and four trips to lockout on substation circuit breakers is not a sound sectionalizing practice and, in fact, is detrimental to system operations.[6] The study concluded that:

(1) With instantaneous reclosure on a circuit breaker, often the breaker closes back into a temporary faulted line condition before the fault clears itself, and

(2) The third reclosure is generally unsuccessful, contributing to unnecessary through faults on substation power transformers and should be eliminated.

(c) On the basis of the conclusions made in this study, the practice of having instantaneous reclosures on substation distribution feeders is not recommended. Also, it is strongly recommended that all substation feeder breakers or reclosers have only two reclosures to lockout (or three trips to lockout). For further details, see the IEEE paper.

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[6] "An Analysis of VEPCO's 34.5-kV Distribution Feeder Faults as Related to Through Fault Failures of Substation Transformers," approved by the IEEE Power System Relaying Committee and presented at the 1978 IEEE Power Engineering Society Winter Power Meeting.

(d) As mentioned earlier, with the use of digital clocks, microwaves, videocassette recorders, DVD players, computers, and other electronic conveniences, there has been a trend to reduce feeder operations by eliminating the fast TCC response and allowing the downline fuses to clear the fault lines. This concept removes any fuse-saving policy, deferring to the elimination of nuisance—and often frequent—operations of substation feeder breakers or reclosers. This practice is in line with the high-reliability zone policy mentioned above. Such a policy is strongly recommended to the system engineer in the development of a sectionalizing system.

(2) Use of Relay and Control Targets. Whenever there is an outage on the line, operational personnel are anxious to get the power back on as soon as possible. Often valuable information is ignored or lost in the process, information that can be obtained by reading and recording of relay and control targets that are on substation relays and feeder controls. Noting such information can provide valuable information in the location and identification of faulted conditions. Timely location can result in timely power restoration. It is strongly recommended that the system engineer establish a policy that, whenever there is an outage anywhere within a distribution substation, all targets on relays and controls be noted and recorded for current and future use.

(3) Fault Locating. New circuit breakers and reclosers are being purchased with new intelligent electronic devices (IEDs). Such devices provide event information regarding the faulted condition and can aid operating personnel in the type and location of the fault. System engineers are encouraged to purchase such devices for their feeder breakers and reclosers and to utilize the information provided with the device.

b Recloser Maintenance Guidelines

(1) Oil Versus Vacuum Interruption. Line circuit reclosers have served distribution systems well for decades. Most of the reclosers used in the past have been reclosers that utilized oil as the interrupting medium. Utilizing oil for interrupting over time contaminates the oil, causing different TCC responses and, eventually, costly maintenance. Over the last 10 years, vacuum interruption technology has improved and, currently, vacuum interrupting devices are considered to be a more economical means for sectionalizing. Vacuum line reclosers have greater duty cycles than oil interrupting devices and should hold their designed TCCs longer than devices that use oil interruption. When purchasing new line reclosers, the system engineer is encouraged to compare the life cycle economics of oil versus vacuum. Vacuum devices have proven economical because of their longer duty cycle and reduced maintenance

costs.

(2) Maintenance and Scheduling

(a) Substation Breakers and Reclosers with Electromechanical Relay and/or Electronic Controls

To maintain reliable electric service, routine testing, inspection, and maintenance are required on all sectionalizing equipment. This is especially true when it comes to substation equipment and the protective relays and controls utilized. If these devices are not routinely checked and tested, major outages are sure to occur. Major equipment damage is also likely to occur, costing hundreds of thousands of dollars. Power transformer failures have been known to occur as a result of inadequate equipment maintenance. It is a priority that should be established by the system engineer.

Typical circuit breakers and circuit reclosers should be tested and maintained about every 4 to 5 years. Generally speaking, over that period of time, electromechanical devices drift and require recalibration. Also, batteries in electronically controlled reclosers require testing and/or replacement. So a 4- to 5-year maintenance cycle is good for planning purposes on substation equipment.

Generally, there are two ways that such maintenance can occur:

(1) Method 1: Full system maintenance every duty cycle period. Method 1 calls for the substation equipment to be tested and maintained every established duty cycle (e.g., every 4 or 5 years). Under such a method, the maintenance costs can be very high for the scheduled year and may take a considerable time to complete, depending on the number of substations that the cooperative has. It normally takes approximately a week to test and check out two or three substations. Under such a method, if financial constraints require a delay, such maintenance is often delayed.

(2) Method 2: Partial system maintenance every year. Method 2 calls for a percentage of the system substations to be tested and maintained every year. The percentage is determined by the established duty cycle period. For example, if the duty cycle has been established at 5 years, then 20% of the system substations are to be tested and maintained every year. If a system has 12 substations, then three substations should be scheduled each year.

If Method 2 is selected, it is important that it be started after having completely testing all substations. This will assure safe and proper operation of the equipment for the duty cycle, which is necessary for reliable electric service. Method 2 also spreads the maintenance costs over the duty cycle period, which greatly helps the cooperative's financial bottom line.

(b) Line Reclosers. One sectionalizing dilemma that has to be addressed by the system engineer is how to maintain all the line reclosers on the system. Recloser manufacturers typically recommend that line reclosers be removed and maintained about every 5 to 6 years. Line recloser maintenance is typically accomplished under one of the following plans:

(1) Plan A: Maintain reclosers by substation service areas. Under Plan A, reclosers are removed and replaced from designated substation service areas every year. If a cooperative has established a 6-year duty cycle, then approximately 17% (1/6 = 16.7%) of the substation service area reclosers need to be removed and replaced every year. If the cooperative has 12 substations on the system, then two substation service area reclosers are to the replaced and maintained annually.

(2) Plan B: Maintain reclosers as needed according to established duty cycles for each recloser type. Under Plan B, individual reclosers are monitored and maintained as needed. The need is established by two parameters: (1) the number of operations, and (2) the number of years since the recloser was last maintained. If a recloser has exceeded the established number of operations (operations duty cycle), it should be marked for maintenance. Also, if a recloser has not exceeded its established operations duty cycle but has not been checked in the established maintenance year cycle (device interval duty cycle), then it should be maintained.

Under this plan, recloser counts need to be recorded and reclosers need to be closely monitored when maintained in order that acceptable operation duty cycles can be established for each recloser type. It is not unusual for the higher-interrupting-type reclosers to have a considerably longer operation duty cycle than the lower-capacity interrupting devices. It is also characteristic that operation duty cycles vary between cooperatives. This is because of device loading and available fault currents on the system.

(3) Plan C: Maintain reclosers when they fail to operate properly. Plan C is considered to be an unacceptable method for line recloser maintenance and is not recommended.

Plans A and B are considered to be acceptable approaches to maintaining line reclosers. Each plan has its own advantage and disadvantages. They are summarized in Table 6.1.

Table 6.1. Advantages and Disadvantages of Maintenance Plans

Advantages	Disadvantages
Plan A	
1. Does not require recording counts of device operations. 2. Work order/staking sheets can be simplified.	1. Requires a large number of spare reclosers. 2. Recloser maintenance does not necessarily follow scheduled substation service areas. 3. Construction work plan needs as a result of growth do not occur by scheduled substation service areas. 4. Maintenance costs are higher because of some reclosers being maintained unnecessarily. 5. Reclosers may not operate properly because they are not actually monitored individually.
Plan B	
1. Maintenance costs are lower because recloser maintenance is based on need, not service area. 2. Fewer spare reclosers are needed. 3. Reclosers are more likely to be working properly because they are monitored individually. 4. Maintenance fits very well with construction work plan system improvement items.	1. Device operations count needs to be determined by field measurement. 2. Reclosers for maintenance are scattered over the entire system and will require more precise work order/staking sheets.

(3) Maintenance Specifications. A system engineer can have the best designed sectionalizing system but if it is not adequately maintained, the full goal of service protection and system reliability will not be attained. It is estimated that approximately 75% of all electric distribution

cooperatives outsource their line recloser maintenance. Often, such maintenance has consisted of an oil change or flush and cheap paint job. With the high cost of labor, test equipment, parts, and supplies, recloser maintenance shops have found the need to cut corners and do not provide maintenance to the reclosers to the quality needed.

To help prevent such activities, an example program, "Line Recloser Maintenance Specifications," is presented here as Exhibit B. The specifications are for system engineers to use as needed. Revisions are encouraged to fit system and financial needs. The maximum maintenance costs should be updated to current system conditions.

Test data are called for in the specifications. Such information can aid the system engineer in determining operation duty cycles as well as device interval duty cycles.

7 SPECIAL CONSIDERATIONS

a Grid Stability. The stability of the transmission system or grid has rarely been a consideration in designing distribution system protection. The Northeastern U.S. blackout of 2003 brought more recommendations and regulations, some of which are yet to be implemented. Regardless of the cause of the Northeast blackout, there have been increasing demands with minimal transmission system improvements, resulting in increasing load curtailments or rolling blackouts. National and regional reliability requirements vary greatly, but most contain some form of load curtailment or load shedding to prevent the collapse of the transmission system. In January 2007, the North American Electric Reliability Council and the North American Electric Reliability Corporation merged into the single entity, NERC Corporation (see www.nerc.com/about), which was certified as the "electric reliability organization" by the Federal Energy Regulatory Commission (FERC) in July 2006. The extent of reliability requirements imposed on distribution system operators are still being determined; however, it is clear that additional requirements for the system operators, even distributors, are very likely to be imposed.

Many bulk power suppliers have some method of load curtailment in place, which may contain a staged curtailment plan, including escalating load controls such as requesting voluntary load reduction, the interruption of nonfirm loads, and rolling blackouts coordinated by the distributors. In more extreme cases, underfrequency relays may be installed at selected substations to automatically shed load in the event of system instability. Undervoltage relaying may also be used to ensure automated load shedding.

b Loading Considerations

(1) Critical Loads. The load served by a distribution system often affects not

only the mechanics of system protection but also the sectionalizing philosophy. Critical loads such as health care, emergency response, communications, and other infrastructure services require special consideration to minimize the chance for outages. Although it is not always physically or economically feasible, distribution system protection devices should be located downline of critical loads. Although modern motor controls monitor and protect for the loss of one or more phases, consideration should be given to using three-phase or gang-operated devices for critical three-phase loads to prevent damage to customers' equipment.

(2) Cold Load Pickup. Cold load pickup refers to the restoration of loads that have been unserved for some time period. Cold load pickup typically is divided into two types: inrush controlled and thermostatically controlled. Inrush currents result from a number of factors, such as distribution transformer energization, motor starting currents, and motor accelerating currents. These inrush currents can easily last several cycles and exceed nominal load currents by up to 10 times. Thermostatically controlled cold load pickup is the increase in load due to increased heating or cooling loads, such as air conditioning, heating, and water heating. Inrush cold load pickup is the primary relaying consideration.

When fast curves or operations are used in system protection schemes, nuisance trips are not uncommon. Generally, inrush currents will stabilize within a few cycles, and even in the event of a fast curve trip and reclose, the sectionalizing device will generally reclose successfully when it utilizes the slow curve. Some electronic reclosers support operator-enabled cold load pickup, which simply advances the control to the slow time-current curve. More advanced relays may utilize harmonic analysis (typically second and third harmonics) to identify inrush currents and suppress trips due to inrush. Although this type of relay is more prominent in substations' transformer protection relays, newer intelligent devices have the ability to perform a similar function.

Cold load pickup due to thermal recovery and loss of diversity of heating and cooling systems can remain from a few minutes to several hours, and can easily reach 3 to 5 times normal load currents. These increased load levels, due to the loss of diversity, often require incremental load pickup. Although this method extends outage times, it provides better protection than increasing trip settings or bypassing sectionalizing equipment.

(3) Load Imbalance. Maintaining a well-balanced load is a never-ending challenge, particularly in rural areas served by long single-phase lines. Seasonal loading can also complicate maintaining good load balance. Although electricity is often the most practical cooling method, efficient and cost-effective heating may be accomplished a number of ways. In

climates where customers can use either gas or electricity for heating, loads can swing from balanced to imbalanced each season, depending on the distribution and location of the electric and nonelectric loads.

Frequent monitoring of load imbalances at major sectionalizing points is important to detect potential problems. Ground relays are one of the best ways to detect high-impedance phase-to-ground faults. Consequently, the better balanced the load, the lower the neutral current and the more sensitive the ground relays can be set. At the same time, consideration must be given to the load imbalance resulting from single-phase sectionalizing. Keeping single-phase loads as small as possible is ideal, but is simply not economically feasible or practical in all cases. Another consequence of load imbalances is inrush currents. In the case of a load imbalance that causes only 40 amperes of neutral current, an inrush situation may cause five times that amount for several cycles. This resulting 200 Amps of neutral current could easily operate a 180-Amp fast curve. Herein lies the “art” of system protection: finding a practical compromise between reliability and protection.

c Sympathetic Tripping. Sympathetic tripping may be a factor in protection analysis, particularly on weak or higher-impedance systems. Sympathetic tripping typically occurs at substations where protective devices are on the same bus. If a high-current fault occurs on a feeder served by a high-impedance source, the bus voltage drops proportionally to the fault current and system impedance. In some cases, the load can respond to the lower voltage with higher currents, exceeding the trip values set in the protective relay. Newer protection analysis software can calculate voltages throughout the distribution system for a given fault type and location, which can help quantify expected voltages for given faults. However, the load’s response to the lower voltage depends highly on the type of load. A purely resistive load would have a decreasing current with a decreasing voltage, while motor loads would typically respond with higher currents as they attempt to do the work with less voltage.

d Voltage Conversions. Many utilities continue to increase system voltages, primarily to serve increasing loads with existing conductors, with the added benefit of reducing losses. Voltage conversions typically double system voltages, such as a conversion from 12.47 kV to 24.94 kV.

Only in rare instances can an entire feeder be converted to a higher voltage. Therefore, step transformers are often used to convert portions of a feeder. Often, voltage conversions occur over several years, so step transformers are an integral part of the distribution system. Most often voltage conversions start at the substation and extend downline over time. However, some situations—such as very long single-phase lines with loading near the end—may be best served by a voltage conversion at the load end of a line rather than the source end.

While higher operational voltages lower load currents and increase fault currents, the values don't always double or halve as expected. Some utilities specify step transformers with higher impedances to reduce through-fault currents, thereby increasing system impedance and further reducing fault currents.

Analysis software becomes very important when developing protection schemes on mixed voltage systems. The following example shows why. A 25-kV feeder with a 40-Ω ground impedance would result in a minimum phase-to-ground current of 360 A. On the 12-kV (load) side of a step transformer, the minimum phase-to-ground current in the 12-kV area would be 180 A. However, if a protective device is located in the 25-kV area, but its protection zone extends into the 12-kV area, the device will only see half of the 180-A minimum fault current in the 12-kV area, or 90 A. Although it may be intuitive that the minimum fault current for a 25-kV sectionalizing device (with a 40-Ω fault impedance) is 360 A, if its protection zone includes, and extends beyond, a step transformer, the minimum fault current it needs to detect and clear is actually only 90 A. Similarly, where a step transformer is used to step up rather than down, the minimum source (12-kV) fault currents increase when the fault is in the higher voltage (25-kV) area.

e Intelligent Devices. As technologies continue to advance and become commonplace, sectionalizing devices increase in functionality while costs decrease. This provides the opportunity to extend advanced protection, as well as additional functionality, further into the distribution system. Although once limited to transmission grade relays, programmable controls have now migrated down to the single-phase recloser control.

(1) Programmable Logic Control. Many programmable sectionalizing devices now contain some form of programmable logic control (PLC). The electronics can be as simple as user-selectable time-current curve (TCC) selection and programmable time delays, or as complex as user-customized TCCs, thereby allowing better coordination responses. Beyond simple data entry of settings, many devices also support ladder logic or logical equations to control sectionalizing devices' tripping schemes. Although somewhat more complicated than electromechanical devices, these devices provide many more options to protection engineers.

In the most extreme applications, the combination of PLC-type programmability coupled with remote communications can yield a very dynamic and flexible protection system for increasingly complex distribution networks. Even in the most simple radial applications, user-defined TCCs may allow the protection engineer to move from a lockout coordination to a trip coordination scheme while utilizing a combination of older hydraulic devices and newer programmable electronic devices. Programmable logic can also be used to set up and configure sequence-of-events recorders or load interval data logging.

(2) Alternative Settings. Alternative settings are, as the name implies, an alternative set of tripping set points. They are most useful when a device may be operated in multiple scenarios. A common and simple application of alternative settings is in a substation feeder relay or recloser that could serve as a secondary source to predetermined critical load. In the event the primary source to the critical load is lost, the backup feeder may be required to serve the load.

It is likely that, in many cases, the secondary source device's setting would be too low and would require an increase in trip currents to serve both normal and contingency loads. Using alternative settings is a method by which the protection engineer can "pre-engineer" settings for known contingency cases, while simplifying the tasks of field personnel. Another application of alternative settings is providing seasonal settings where load variations dictate. The alternative trip settings are a field-selectable control that relieves the protection engineer from having to reprogram field devices.

(3) Additional Data Collection. The data acquisition capability of newer sectionalizing devices provides a number of advantages to the protection engineer as well as other functions within the electric utility. Power quality, diagnostic, and design information can be obtained from the newer intelligent electronic devices (IEDs).

(a) Time Stamps. Time stamping of electric system events is becoming ever more important. Although most of today's newer smart devices now contain Global Positioning System (GPS) synchronized clock capability, it is an option, and many legacy electronic devices do not support high-accuracy time stamping. Anyone who has tried to re-create a sequence of events utilizing multiple devices' event reports with unsynchronized clocks knows just how important time-stamping synchronization becomes. There have been discussions about regulatory requirements mandating high-accuracy time stamping of system monitoring equipment.

(b) Fault Data. Obviously, the magnitude of fault currents during an event is important to the protection engineer for a number of reasons. Fault magnitudes, in combination with fault location from operations personal, and other system configuration parameters can help validate the accuracy of the engineering model used to perform the protection study. Higher-end devices can also perform waveform captures, which allow an even more detailed analysis by defining the exact cycle level timing of a fault as well as protective equipment response times. The former allows analysis of the symmetrical and asymmetrical contribution to the fault as well. Probably the most useful application of fault data is the analysis of duty cycles. Equipment duty cycles are the primary driver of performing maintenance. Many of today's smarter devices can be programmed to record duty cycle information and indicate to the operator when a particular device is nearing time for maintenance. Analysis of duty cycles provides the opportunity to perform more cost-effective, just-in-time maintenance rather than cyclical or reactive maintenance of protection equipment.

(c) Load Data. Load data is another component of the sectionalizing and coordination equations. Load data collected by IEDs can be used not only for coordination studies, but also for system planning studies or rate studies. Load interval data collection should be configured at the device level to support access to this data for the various engineering studies. Some legacy devices may store only 24 hours of data, while newer devices can store several months of data, depending on what metered values are configured.

In general, most devices can monitor and record maximum currents, while many now support voltage inputs in addition to the currents, which allows meter quality data collection of parameters, such as power, reactive power, and power factor with a single device. The voltages can also be used to increase the functionality of the protective device by providing under- or overvoltage protection or even single-phasing protection of downline equipment.

(4) Relay Failure Considerations. One of the biggest drawbacks to intelligent electronic devices is exposure to failure, simply because of the nature of electronics. Where an electromechanical device may have only a handful of active parts, electronically controlled devices have literally thousands of components. As a result, the mean time before failure is much shorter for electronic devices then for electromechanical devices and, to some extent, hydraulic devices. Because of this weakness, the protection engineer must plan for more frequent failures of protection equipment.

The engineer must also weigh the cost versus benefit of designing some redundancy into the system. Although it certainly makes sense to provide redundant or backup protection for substation transformer protection relays, it is not likely cost-justified to install a secondary or backup controller for a single-phase recloser in a rural area. Although there are many philosophies related to how much redundancy or how much overreach is built into a protection scheme, the use of downline electronic devices may drive the engineer to more closely consider building in more overreach than has been done in the past. Each situation is different, and there is no hard-and-fast set of rules than would work for every situation. It is the protection engineer's duty to establish a philosophy, implementing it where possible, but applying it practically and accepting limitations where the situation dictates.

(5) Breaker Failure Considerations. Another utilization of the intelligence of today's newer devices is in breaker failure operations. Newer devices can detect breaker or interrupter failures either directly or indirectly. For example, in the event of an SF_6 leak, a "smart" circuit breaker can give a status indication to the relay, which will, in turn, cause an alarm and dictate that the relay inhibit tripping signals to the breaker to prevent catastrophic failure in the device. A relay may also indirectly detect breaker failure by evaluating the magnitude and duration of a fault versus the expected interruption time, even when a tripped status is given back to the relay. Breaker failure detection may be used to expedite the tripping of a backup device, thereby minimizing the fault clearing time and equipment damage.

f Remote Monitoring and Control. There are a number of ways to remotely monitor and control sectionalizing equipment. Legacy SCADA systems provided quite a bit of real-time and sequence-of-events types of information to system operators; however, these systems were generally dedicated to real-time control and feedback, with less emphasis on data acquisition. Today, most intelligent devices incorporate many times more data collection and internal storage capacity than did traditional SCADA systems, while simultaneously supporting SCADA monitoring and diagnostic communications. These advanced communications options also open the door to better management of the electrical system.

(1) Communications. The traditional method of communication has been through discrete inputs and outputs (contact closures) and analog inputs (current transformers and potential transformers). This traditional method generally used a SCADA system to monitor the equipment and provide the information back to a central location. Today, serial data streams and protocol "standards" have become a quasi-standard method of communicating to intelligent devices. Most newer devices now come equipped with multiple communication ports, and can often support simultaneous communication to various systems.

Serial communication can be achieved through a number of media and communications methods. In general, IEDs contain RS-232 or RS-485 ports that can reach transmission speeds of up to a few kilobytes per second. Most advances in recent years have been made in the backhaul systems. Media converters allow RS-232 communications to be encapsulated over various backhaul systems, including dial-up, fiber-optic, wired Ethernet, licensed radio, unlicensed radio, satellite, and wireless Ethernet. With the ever-increasing popularity of the Internet and TCP/IP-based protocols, newer devices can also utilize these systems, whether directly or through protocol and media converters. Unfortunately for most rural utilities, high-speed—or any speed—communication backhaul systems are still only wishful thinking, or quite expensive. This is especially true when communication to distributed downline devices is considered.

(2) SCADA. Supervisory control and data acquisition (SCADA) systems have been around for a long time. Early SCADA systems were often developed independently by utilities, resulting in hundreds of proprietary systems and protocols that could not communicate with one another. Today, there are only a handful of quasi-standard protocols such as DNP 3.0, UCA, and MODBUS, and most equipment and SCADA vendors can support these protocols, although some still view proprietary protocols as a "good thing," since they are generally more efficient. However, given today's improved bandwidths, the increase in efficiency is not worth being tied to a proprietary or single-source solution.

(3) Maintenance. Most newer IEDs record and store more information than the average cooperative engineer has time to look at; however, that information is there when it is needed. Fault and operations data are often used to calculate duty cycles, which dictate when equipment maintenance should be performed. Most newer devices support simultaneous SCADA monitoring and diagnostic communication. Often, vendor-specific software can be used remotely to read and change settings, download data, and control the device without any SCADA system, so long as there is a communication system available.

The data contained in IEDs can often help monitor other maintenance issues in addition to equipment maintenance. Upline devices can often monitor and collect fault information for nonintelligent downline devices. Since the fault current flows through the IED, all duty-cycle-related information can be captured in the upline IED. Combining outage reporting or "dumb" operation counters with upline intelligent data collection can provide the same duty cycle information for lower-cost downline devices. Fault magnitudes can also be utilized to help locate other maintenance issues, such as burning rights-of-way, failing insulators, and bad lightning arrestors when combined with fault analysis software packages.

g Distribution Automation. With the advent of lower-cost communications, better standardization of communication protocols, and more-intelligent sectionalizing devices, much more sophisticated protection schemes can be developed. Although distribution automation can improve the performance from the protection perspective, it is perhaps more important in providing the ability to provide automatic restoration to critical loads. Very often, distribution automation can be cost-justified only in high-density or high load-factor areas. Availability of alternative power sources, as well as communications systems, is often a limiting factor as well.

(1) Transfer Trip Schemes. Transfer trip schemes are often used in multisource environments. They are used primarily when a protective device needs to ensure than an alternative source or distributed resource has been isolated. Transfer trip schemes can also be utilized as a backup protection scheme under breaker failure modes of operation.

In a distribution network, the availability of communications and the signal latency become important design considerations. Dedicated fiber optics is the ideal communication medium; however, other communication technologies have been used successfully in recent years.

(2) Flip-Flop Schemes. Flip-flop schemes are most often used for critical load applications. When two sources are available to a critical load and the primary source is lost, the primary source can be isolated, allowing the load to be switched to the secondary source. Very often, the equipment used to isolate one source and switch to the other source has to be located in close proximity. However, with the advent of improved communications and a larger installed base of fiber optic communication cables in municipal areas, this equipment may be installed farther apart.

(3) Sectionalizing Switches. In recent years, improved sensing technologies and microprocessors have made it possible to develop intelligent, automated switches. The most common application of these switches is to use them in the place of traditional sectionalizers by sensing faults, upline operations, and subsequent switch openings via motor operations. More advanced operational schemes can be implemented when these devices are enabled with communications.

h Fault Location. There are a number of ways to perform fault location. The traditional method has been to use mechanically activated devices installed on the primary conductor that trigger or trip a target when a predetermined current is exceeded. This method has been used on transmission and distribution systems for years. Fault locators can often be used successfully in a system protection scheme, especially to minimize patrol times, particularly in challenging terrain. In transmission systems, lines are generally long and made of the same type conductor for many miles. Therefore, line impedance is very predictable as a function of distance from the source or protective relay. Distance relays have been used successfully for many years on transmission lines to locate faults. However, distribution networks have a multitude of taps and varying sizes of conductors in most areas, thereby making the line impedance—and, therefore, fault current—the same at many locations on the same feeder. This would result in multiple possible targets for a fault.

(1) Fault Locators. Today there are several varieties of both mechanical and electronic fault locators. The biggest drawback to mechanical devices is the predefined "setting," or trigger levels, which limit the application of the devices to certain load and fault conditions. Mechanical locators also occasionally give false positive and false negative indications because of such things as improper sizing, inrush currents, and double faults (one fault causing another fault). The advantages of mechanical devices are lower cost and virtually no maintenance.

There are a few electronic fault locators on the market. They vary from replacements for mechanical locators to expensive IEDs capable of load interval and waveform capture in addition to local and remote fault indications. Vendors claim that the electronic devices are more accurate than mechanical devices and give 10+ years of maintenance-free service.

(2) Distance Relays. Distance relays essentially work on the principle of predictable line impedance over the distance of the line. Often line impedance values are programmed into the devices, allowing the relay to calculate the distance to the fault once a fault is detected. On transmission lines, these relays work well with most faults; however, in rare cases, higher impedance or nonbolted faults may give erroneous distance indications.

The same principle doesn't work as well for a distribution network. Compared to transmission systems, distribution systems are short and, thus, provide less variation in fault currents over the entire line segment. Resolving a fault location within ½ mile is very good on a 50-mile transmission system, but is not quite as good on a 5-mile distribution system. Also, by their nature, a distribution network has many paths that will provide the same fault impedance, so although distance to fault may work well for an express feeder, it won't work very well in a more complex area.

(3) Distribution Analysis Software. Distribution fault analysis software can calculate the fault magnitude at any point along a modeled distribution network. Therefore, fault information from smart reclosers and relays can be used in combination with the analysis software to identify areas with matching fault currents, yielding one or more possible fault areas. This method is probably best used as a diagnostic tool, although it has been successfully integrated into some outage management systems. It has been used successfully to find nuisance tripping causes with magnitude-only fault data to within ½ mile, even without more detailed fault data, such as waveform capture and symmetrical and asymmetrical fault contribution factors.

i Distributed Generation. The popularity of distributed generation (DG), or distributed resources (DR), is increasing because of technological advances, system benefits, and economic improvements in the cost of connecting such systems to the distribution system. Installing DG will have an impact on the distribution system, and special provisions should be made for it. A thorough analysis of DG systems and their impact on distribution systems is in IEEE Standard 1547, *Standard for Interconnecting Distributed Resources with Electric Power Systems*. In this bulletin, the special provisions reviewed are coordination, isolation, and islanding.

(1) Coordination. The addition of DG will affect the coordination of a distribution system, depending on the DG size, configuration, and location, as well as the location of upline and downline protective devices. DG should be considered as a second source to the distribution system, potentially resulting in higher fault currents and two-way power flow. Modifying the coordination of protective devices to support the higher fault currents may result in overreaching devices, thereby increasing the outage exposure to the existing distribution system. Bidirectional power flow devices can be also utilized to optimize the coordination; however, the addition of these devices and their associated components may be cost-prohibitive for the utility and/or DG owner.

(2) Isolation. Depending on the DG location, size, and local protection equipment, this second source could serve as a hazard to utility maintenance personnel by backfeeding the distribution system during planned or unplanned outages. It is recommended that a means of disconnecting the DG from the distribution system be required so that the DG can be isolated during maintenance or restoration activities by utility personnel.

(3) Islanding. Islanding of the DG can result when the upline protective device operates, isolating the circuit so that the DG serves the load normally fed by the distribution system. Damage to equipment may result should the upline protective device reclose out-of-synch with the DG. To address these issues, provision should be made to remove the DG from the distribution system automatically on operation of an upline protective device. Many smaller DG systems such as residential photovoltaic systems integrate islanding protection as a part of the inverter design.

8 SAMPLE PROBLEM: SMALL SUBSTATION

This sample problem is representative of the procedures and equipment used for overcurrent protection of small rural electric substations and their feeders. Typically, these substations include either three single-phase or one three-phase power transformer (generally ≤10 MVA) with power fuses for primary overcurrent protection. Each substation feeder is protected by single-phase or three-phase reclosers. Additional reclosers and fuse cutouts are used to provide protection out on the feeder and at taps.

a Problem. A 69-kV to 12.5/7.2-kV distribution substation has been experiencing load growth due to the addition of several housing developments on the east feeder. Load projections indicate that the existing transformer (1-3750 kVA) will need to be replaced in the next 24 to 36 months. In addition to replacing the transformers, the cooperative intends to replace the single-phase hydraulic reclosers (3-70L) for this feeder with a three-phase electronic recloser. Using the following data, select a primary fuse for the new substation transformer, determine appropriate settings for the new recloser on the east feeder, and verify that the existing reclosers on this feeder are appropriately sized.

A circuit diagram of the east feeder and the substation are shown in Figures 8.1 and 8.2.

Figure 8.1. Circuit Diagram of East Feeder

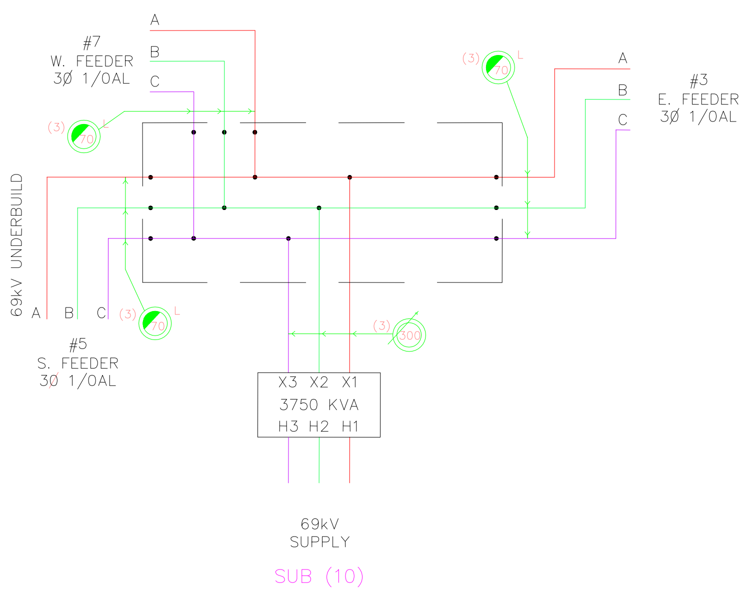
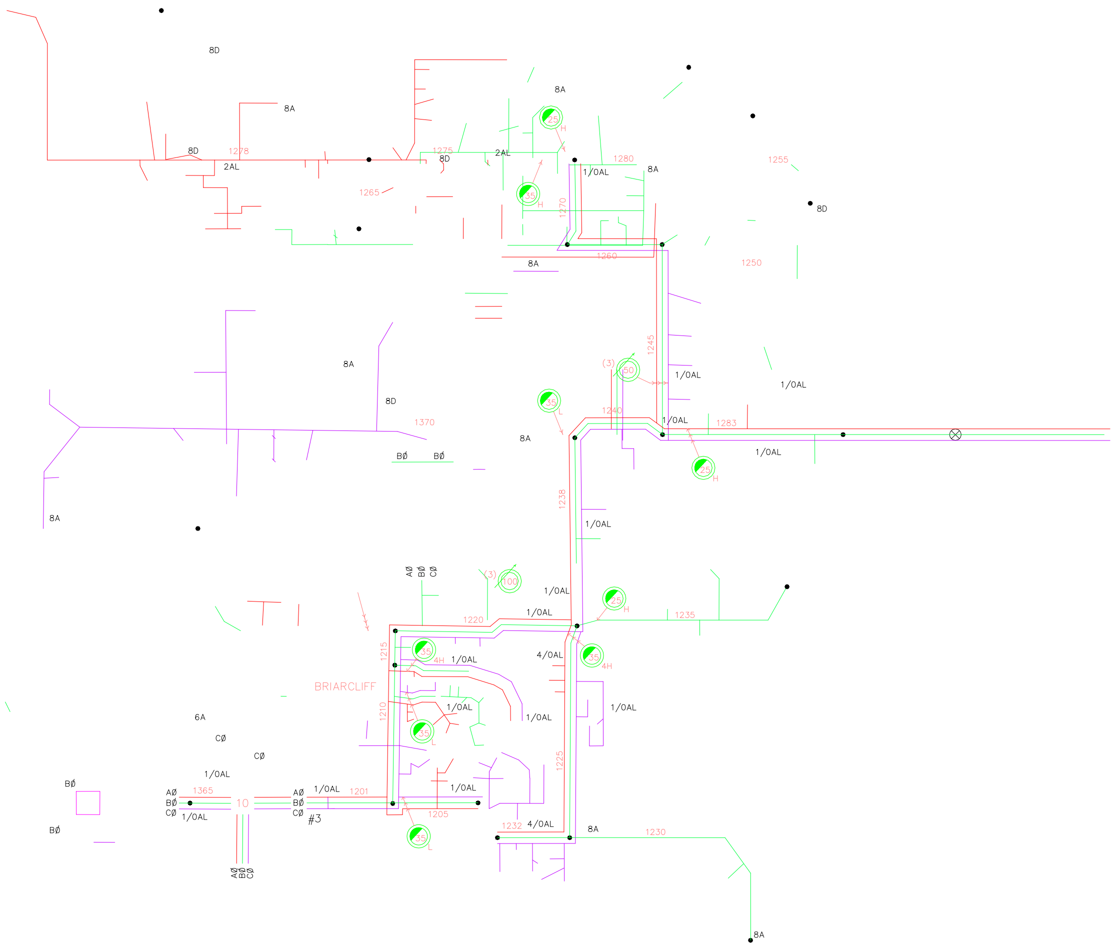


Figure 8.2. Circuit Diagram of Substation



The following data are applicable to the problem.

System Impedance (High Side of Transformer):
$Z_1 = 1.32 + j6.47\ \Omega$
$Z_0 = 2.76 + j13.42\ \Omega$
I_f (3-phase) = 6036 A

New Transformer Data:
67 kV to 13.090Y/7560 kV
5000/7000 kVA
$Z = 7.5\%$

b Selecting the Transformer Primary Fuse

(1) In selecting a fuse for the new transformer, the following factors must be considered:

- System voltage,

- Available fault current,
- Expected transformer loading (including peak and emergency loads),
- Inrush currents (including transformer magnetizing inrush and hot and cold load pickup),
- Transformer protection from damaging overcurrents,
- Coordination with other overcurrent protective devices, and
- Protection of other equipment (conductors, regulators, bus work, etc.).

(2) In the substation for this example, the nominal system voltage is 69 kV. The fuse selected for this application should have a voltage rating that meets or exceeds the maximum phase-to-phase operating voltage of the system.

(3) The available symmetrical fault current at the fuse location is just over 6,000 A. The fuse selected for this application should have an interrupting rating that meets or exceeds the maximum available fault current. It is a good practice to include sufficient margin in the interrupting rating to allow for future system growth and improvements.

(4) The fuse ampere rating and speed characteristic should be selected to accommodate the expected normal and emergency load current. It is common practice to use the transformer rating as a basis for the normal load current. This allows for future system growth up to the transformer capacity without having to replace the fuses. The primary full load current based on the rated capacity of the transformer in this example is calculated as follows:

$$I_{fl} \qquad \frac{\text{kVA rating}}{-\ \ \text{kV rating}} \qquad \frac{7{,}000}{-\ \ 67} \qquad 60\text{A}$$

It is important to note that the continuous loading capability of an E-rated fuse is greater than its ampere rating. As seen in Table 8.1 below, any fuse larger than 40E has a continuous capability that meets or exceeds the rated load current of the transformer.

Table 8.1. Primary Fuse Current-Carrying Capability

Rating, A ↓	**Peak-Load Capability, A**										
		Daily					**Emergency**				
Time, Hours →	**Continuous**	**½**	**1**	**2**	**4**	**8**	**½**	**1**	**2**	**4**	**8**
5E	7.5	7.7	7.6	7.5	7.5	7.5	8.0	7.8	7.7	7.7	7.7
7E	10.5	10.8	10.8	10.6	10.5	10.5	11.2	11.0	10.8	10.8	10.8
10E	15.0	15.5	15.2	15.0	15.0	15.0	16.0	16.7	16.5	16.5	16.5
13E	19.5	20.1	19.7	19.5	19.5	19.5	20.6	20.4	20.1	20.1	20.1
15E	22.6	23.2	22.8	22.5	22.5	22.5	24.0	23.5	23.2	23.2	23.2

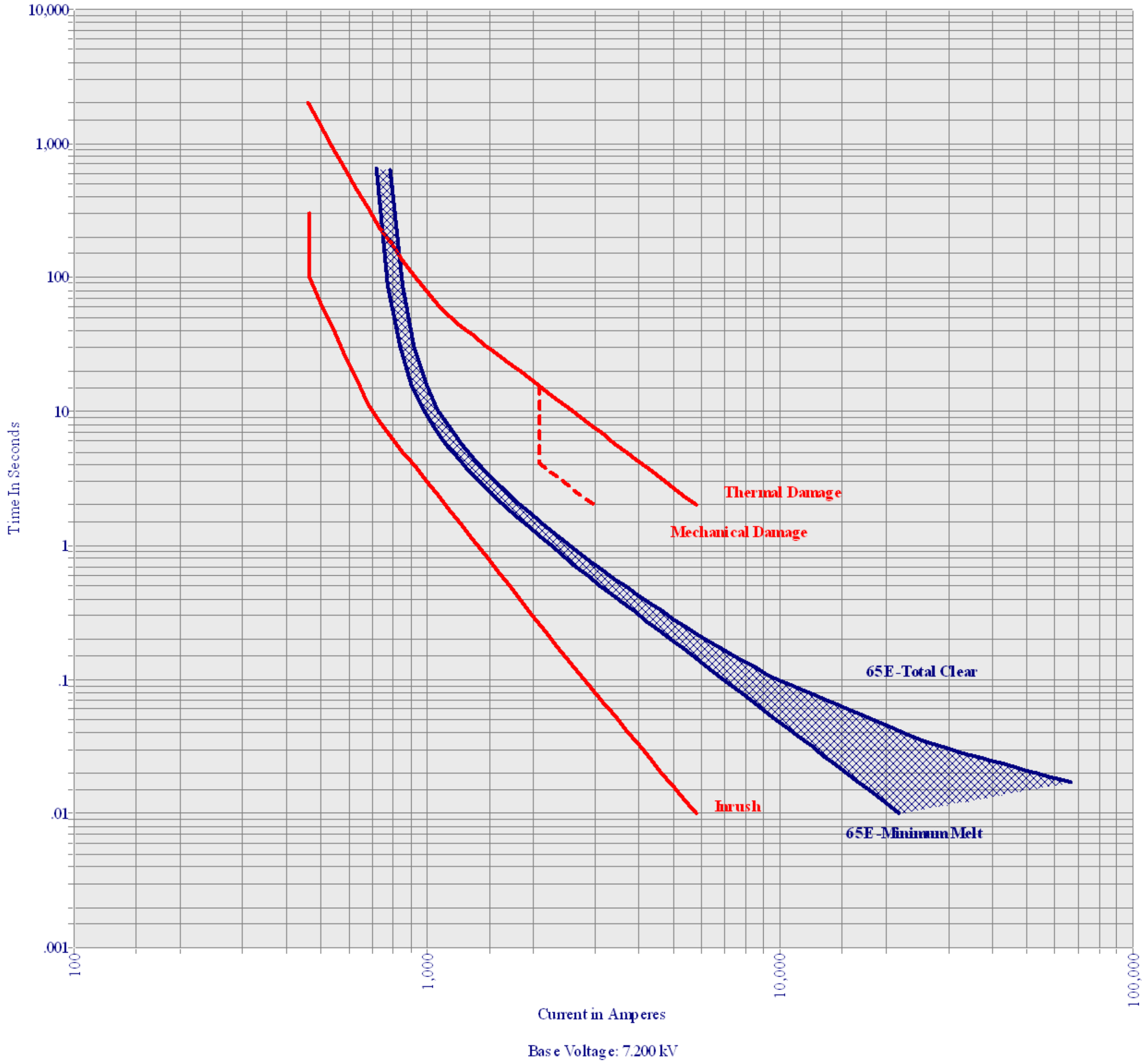
20E	30.0	31.0	30.4	30.0	30.0	30.0	32.0	31.4	31.0	31.0	31.0
25E	37.5	38.8	38.0	37.5	37.5	37.5	40.0	39.2	38.8	38.8	38.8
30E	45.0	46.5	45.6	45.0	45.0	45.0	48.8	47.0	46.5	46.5	46.5
40E	60	62	61	60	60	60	64	63	62	62	62
50E	75	78	76	75	75	75	80	79	78	78	78
65E	87	98	95	92	91	89	104	101	99	98	95
80E	96	108	104	101	99	98	116	112	109	107	105
100E	115	126	121	119	118	117	135	131	129	128	127
125E	137	150	145	143	141	140	162	157	155	153	152
150E	157	172	166	163	162	160	187	181	178	177	175
175E	192	210	204	199	197	196	245	238	231	226	224
200E	200	224	216	208	206	204	260	250	244	238	236

(5) In addition to daily and peak loads, the selected fuse must also accommodate emergency loading conditions, transformer magnetizing inrush, hot load pickup, and cold load pickup. (For a detailed discussion which these factors reference, see “Selection Guide for Transformer Primary Fuses in Medium- and High-Voltage Utility and Industrial Substations,” *S&C Data Bulletin 210-110*, October 10, 2005.)

For this application, we have selected an SMD-1A, 50E, slow-speed fuse. The transformer damage curve and the characteristic curves for this fuse are shown in the Figure 8.3.

We also note that this fuse will protect the conductors and bus and voltage regulators on the secondary side of the power transformer. A quick look at the damage curves for the conductor jumpers and bus reveals that there is adequate protection (not displayed in this example but available from various sources). Reviewing ANSI C57.15, we see that the damage point for voltage regulators is 40 times the base current for 15 cycles and that this fuse is adequate protection for that point.

Figure 8.3. Transformer Damage Curve with Primary Fuse



c	<u>Selecting the Substation Feeder Protection</u>

(1)	We have decided to install an electronically controlled three-phase recloser on this feeder. We will select a recloser that meets the following criteria:

- Has the correct voltage rating for the application,
- Can handle the expected load current (plus some for growth), and
- Has an adequate interrupting rating (plus some for inevitable increases).

(2)	The electronically controlled recloser will have a phase overcurrent setting and a ground overcurrent setting. As discussed in Section 5 of this Design Guide, the following considerations determine these settings:

(a) The most important constraint is the first upline protective device, which is the substation transformer 69-kV fuse. By converting this fuse to a 12-kV base, we can compare different curves available for use with our recloser control.

(b) The peak load on this feeder is expected to be about 100 A per phase. We need to select phase trip settings high enough to accommodate the expected load and inrush. A commonly used convention is to set the phase trip at 1.5 to 2.5 times the expected peak load current to handle inrush.

(c) We need to check to make sure that the phase setting protects the main feeder conductor from damage. The phase setting should be below the time-current damage curve for the smallest conductor protected by the station feeder device. (Note that this setting may be above the continuous current rating of the feeder conductor. Typically, the phase setting is not used to keep the conductor from becoming overloaded; rather, metering is used to monitor overload.)

(d) A ground setting should be selected that is sensitive enough to respond to high-impedance faults at the end of the line, open point, or the next protective device on the feeder, but will allow normal system operation of downline devices without false trips. The minimum fault at the end of the three-phase line (section 1279) is 162 A. In this example, we are fusing all single-phase laterals off the three-phase line.

(e) Phase and ground settings should be high enough to accommodate needed or expected feeder devices, such as fuses and reclosers.

(3) To select a phase setting, we start by looking at the load current times 1.5 to 2.5, or 150 to 250 A. We will lean toward the middle of this range in this example. Because this is an electronic control, we have a wide variety of current settings and curves available. Using a standard, extremely inverse curve available in the recloser control library, we will tentatively select 200 A, which fits well with the high-side fuse. Next, a comparison of the time current damage curve for 1/0 ACSR shows that this setting will be adequate for conductor protection. Figure 8.2 shows the high-side fuse curve, the conductor damage curve, and the feeder recloser phase curve.

(4) To select a ground setting, we start by looking at the calculated minimum fault currents in Table 8.2. Selecting 40 Ω as our fault impedance for the calculation, we see that the end of section 1270 will have a minimum fault value of 162 A. So the ground setting must be below 162 for coverage of this value. Looking ahead, we also find that there is a problem with the oil

circuit recloser at the source of section 1275. The expected load is 47 A on a 35H recloser, so we elect to increase the recloser rating to 50H. This constrains our ground setting to be above the curve of a 50H and below 162 A. We pick a point between the two values of 120 A, using a standard, extremely inverse curve, which gives us the recommended separation discussed in Section 5 of this Design Guide.

Table 8.2. Circuit Load and Available Fault Currents

Location	Through Current, A	Maximum Fault Current, A	Minimum Fault Current, A
East Feeder	96	3070	196
1201	96	2430	191
1205	11	2030	188
1210	85	1974	188
1211	82	1921	187
1215	64	1822	186
1220	64	1440	180
1225	9	1237	177
1230	2	583	156
1232	0	1156	175
1235	10	955	176
1238	47	1185	175
1240	35	1044	171
1245	32	901	166
1250	18	591	154
1255	14	447	146
1260	21	842	164
1265	14	455	149
1270	18	791	162
1275	47	506	155
1278	0	409	145
1280	0	480	151
1283	2	900	166
1370	30	454	145

9 SAMPLE PROBLEM: LARGE SUBSTATION

This sample problem illustrates a method to sectionalize the system when the substation transformer is larger than 10,000 kVA and the available fault current is high. It is assumed that the substation is under construction and a complete sectionalizing study is needed. For simplicity, only a major feeder will be sectionalized to simplify the results. The configuration developed in this example is not the only way the system can be sectionalized; the particular method will depend on the preferences and experiences of the engineer, circuit configuration, and the historical preferences of the utility.

To get the greatest long-term benefit out of the sectionalizing study, the load current calculations for each feeder are based on the projected peak load of the substation. The system and estimated loads are shown in Figure 9.1 in this Design Guide.

There are numerous software programs capable of calculating maximum and minimum fault currents once the data is either entered into an engineering analysis program or imported from a GIS system. The various devices can be coordinated by using a software program, or the coordination can be done manually from the manufacturers' time-current curves; however, drawing the TCC curves manually is almost a thing of the past.

In general, the high-side protection at a large substation will be either a circuit switcher or a circuit breaker, since either of these devices will protect the transformer better than fuses. With the larger transformer, a differential relay scheme will be utilized, along with a backup overcurrent relay scheme. The differential scheme can protect just the transformer through the use of high- and low-side bushing current transformers, or it can also protect the low-side bus if current transformers are available on the low-side bus. This scheme is designed to minimize the transformer damage if an internal fault occurs. The backup overcurrent scheme is based on the upper rating of the transformer and is set to protect the transformer from overload situations. The differential relays' calculations and settings are complex and are best left to an engineer who specializes in transformer protection settings and/or substation protection.

a Basic Data

(1) Source Information. The power supplier to the substation provided the following information about the source:

$Z(+) = Z(-) = 0.14 + j4.39\%$ on 100 MVA base
$Z(0) = 3.44 + j14.65\%$ on 100 MVA base
Three-phase fault: 2253.1 MVA = 13,008 A @ 100 kV
Single-phase fault: 1255.0 MVA = 7,246 A @ 100 kV

(2) Transformer Information. The transformer manufacturer should supply a damage curve for the transformer. If one is unavailable, use ANSI standard curves. The transformer information is as follows:

Transformer impedance	7.45%
Transformer rating	15,000 kVA
Transformer turns ratios	100 kV—13.2/7.62 kV

(3) Nameplate Information. The following information is supplied by the manufacturer or is obtained from the transformer's nameplate:

Three phase, 15 MVA
High side 100 kV

Low side 13.2/7.62 kV
Impedance 7.45%

(4) Transformer Impedance. To determine the transformer impedance (ohmic) to a three-phase fault referred to the low-side base, see Table 3.3 in Section 3 of this Design Guide. To find the impedance of the transformer to a line-to-line fault, see Table 3.4 in Section 3 of this Design Guide. To find the impedance of the transformer to a line-to-ground fault, see Table 3.2 in Section 3 of this Design Guide.

(5) Circuit Breaker/Recloser Information. The manufacturers of the circuit breakers/reclosers should supply the following information:

- High-side breaker rating;
- Low-side breaker or recloser ratings;
- Time-current curves for the high- and low-side relays;
- Ratings and time-current curves for the distribution recloser; and
- Ratings and time-current curves of the distribution fuses.

(6) Three-Phase Transformer Impedance. From the co-op’s records, obtain a circuit diagram of the substation and circuits showing proposed sectionalizing points, conductor sizes, length of conductors between protection devices, and full-load currents.

(a) Calculation of Three-Phase Transformer Impedance

Using the % or per unit method:

$$\left(\frac{100 \text{ MVA}}{15 \text{ MVA}}\right)(7.45\%) = 49.667\% \quad \text{on } 100 \text{ MVA base}$$

On larger transformers, the assumption is made to spread the transformer into its resistance and reactance components by using the approximation 0.1 + j1.0.

Thus the transformer impedance becomes:

$$(49.667\%)(0.1 + j1.0) = 4.9667 + j49.667\% \text{ on } 100 \text{ MVA base}$$

The 3∅ transformer impedance can be converted to an ohmic value by the following calculation (See Table 9.1 below, the Constants for Fault Calculations Data Sheet).

$$(49.667\% \text{ on } 100 \text{ MVA Base})(0.01742 \text{ Ohms}/1\%) = 0.8652\ \Omega \text{ @ } 13.2 \text{ kV}$$

(b) Calculation of Three-Phase Transformer Impedance (Ohmic Method)

$$Z(t) = \frac{Z(t)\% \times E(L)^2}{(\text{kVA per phase}) \times 100{,}000}$$

$$= \frac{7.45 \times 7620^2}{5000 \times 100{,}000}$$

$$= 0.8652\ \Omega$$

Table 9.1. Constants for Fault Calculations Data Sheet

	100,000KVA / SQRT(3)*500KV	{115.5AMP*SQRT(3) / 500,000V} *100%	1-OHM/0.040
VOLTAGE- KV L toL	BASE AMPS or 3ph-Amps/100MVA	PER CENT/PER OHM	OHMS/1%
500	115.5	0.040	25
230	251	0.189	5.29
169	342	0.350	2.86
161	359	0.386	2.59
138	418	0.525	1.90
115	502	0.756	1.32
110	525	0.826	1.21
100	577	1.000	1.00
69	837	2.10	0.476
66	875	2.30	0.436
46	1255	4.73	0.212
44	1312	5.17	0.194
38	1519	6.93	0.144
34.5	1673	8.40	0.119
25	2309	16.0	0.063
24.9	2319	16.1	0.062
24	2406	17.4	0.058
20	2887	25.0	0.04
19	3039	27.7	0.0361
18	3208	30.9	0.0324
13.8	4184	52.5	0.01904
13.2	4374	57.4	0.01742
12.47	4630	64.3	0.01555
8	7217	156.3	0.0064
7.62	7577	172.2	0.005806
7.2	8019	192.9	0.005184
6.9	8367	210.0	0.004761
6.6	8748	229.6	0.004356
4.8	12028	434.0	0.002304
4.16	13879	577.8	0.00173056
2.3	25102	1890.4	0.000529
0.600	96225	27777.8	0.000036
0.575	100409	30245.7	0.00003306
0.480	120281	43402.8	0.00002304
0.240	240563	173611.1	0.00000576

(c) Calculation of Fault Currents. Maximum fault current is calculated at each proposed sectionalizing location. Minimum fault currents are calculated for each device at the end of the section of line the device is designed to protect, i.e., device's zone of protection.

(1) *3∅ Low-Side Fault Calculations*

Source Impedance Z(+) (High Side) = 0.14 + j 4.39% on 100 MVA

Transformer Impedance Z_T = 4.9667 + j 49.667% on 100 MVA

Low Side Source Impedance (Z_1) = 5.1067 + j 54.057 % on 100 MVA

= 54.2976% on 100 MVA

$$3\varnothing \text{ Low-Side Fault} = \left(\frac{100}{54.2976}\right)(4374 \text{ Amps}) = 8056 \text{ Amps}$$

[See Table 9.1 above, the Constants for Fault Calculations Data Sheet, for the derivation of the 4,374 Amps, i.e., Base Amps or 3 phase Amps/100 MVA = 4,374 Amps at 13.2 kV (line to line)]

(2) *Single-Phase Low-Side Fault*

Calculations:

Single-Phase Fault Impedance = $(2Z^* + Z_0)/3$
Low-Side Source Impedance Z(1) = 5.0167 + j 54.057 on 100 MVA
Source Impedance Z(1) = 5.1067 + j 54.057 on 100 MVA
Transformer Impedance Z_0 = $\underline{4.9667 + j\ 49.667}$ on 100 MVA

Total Low-Side Impedance = (15.1801 + 157.781)/3 % on 100 MVA
= 5.060 + j 52.5937 % on 100 MVA
= 52.8366 % on 100 MVA Base

Single-Phase Maximum Low-Side Fault =

$$\left(\frac{100}{52.8366}\right)(4374 \ \mathit{Amps}) = 8{,}278 \ \mathit{Amps}$$

(d) Distribution Line Impedance

(1) The last impedance to be calculated is the distribution line impedance. To determine the impedances for three-phase faults, refer to Table 3.3 in Section 3 of this Design Guide; for line-to-line faults, refer to Table 3.4 in Section 3 of this

Design Guide; for line-to-ground faults, refer to Table 3.2 in Section 3 of this Design Guide.

(2) Multiply each of the values obtained from the appropriate table by the number of feet or miles of each conductor size from the substation to the protection device or the end of the circuit as shown in the example below (Figure 9.1).

(3) The line impedance calculation is generally performed by the engineering analysis model. Since the way the impedance model is calculated, there can be differences from the traditional line impedance calculations shown in the various RUS (REA), other references, and more modern impedance models that take into account the inductive and capacitive coupling using various matrix manipulation methods. The example shown in Figure 9.1 of this Design Guide was developed using a commercially available engineering analysis program and, thus, the fault current results are not easily exactly duplicated by hand calculations.

(4) The same procedure is used for each line section for three-phase, line-to-line, and line-to-ground faults. The results are recorded on the spreadsheet or they can be read from the engineering analysis package software.

(e) Computation of Fault Currents. Calculating the fault current I_f is a simple matter of summing up the respective impedances vectorially from the fault location back to the source using the following equation:

$$I(\text{fault}) = \frac{E(L)}{[(R_s + R_t + R_{\text{dist}} + R_f)^2 + (X_s + X_t + X_{\text{dist}})^2]^{1/2}}$$

When calculating the maximum fault current, assume $R_f = 0$.

When calculating the minimum fault current, use the assumed value for fault current resistance, R_f. It has been assumed that the R_f for large substations is 30 Ω and 40 Ω for small substations. The selection of these values of fault current resistance has been extensively discussed in earlier sections of this bulletin.

Generally, on three-phase lines, only the three-phase and single phase fault currents need to be calculated, since a line-to-line fault usually will result in neither a maximum or minimum value. However, on V-phase lines, the line-to-line fault will yield the maximum value at some distance away from the substation and should be calculated.

(f) Selection of Sectionalizing Devices

(1) The transformer damage curve should be obtained from the manufacturer and plotted. Then, the high-side breaker relay settings should be chosen to protect the transformer from damage but be set high enough to carry expected load current along with cold load pickup ability. This curve should be plotted.

(2) To coordinate the high-side protection with the substation transformer damage curve, the high-side time-current curves are referenced to the distribution voltage level for line-to-line and line-to-ground faults. The following factors can be used:

Line-to-line faults: $$\frac{E_{s\,(\mathrm{L\text{-}L})}}{2E_L}$$

Line-to-ground faults: $$\frac{E_{s\,(L-L)}}{E_L}$$

(3) The next step is to determine the substation breaker or recloser relay settings. From the previous steps, the maximum available fault current on the low side is 8,056 Amps. The peak load current will have to be determined and the minimum fault current to the next set of protection devices will have to be calculated.

(4) The relays or electronic reclosers will have to be set to carry the full-load current, any load transfers that might occur during emergencies, and cold load pickup. The low-side protection will also have to coordinate with the high-side protection scheme. Reclosers and fuses on the distribution circuits will then have to coordinate with the low-side breaker. The low-side ground protective devices will have to be set to take care of the minimum available fault current. Care must be taken to ensure that the load current of the largest single-phase device is not greater than the minimum ground trip setting.

(5) The engineer will also have to decide whether to utilize a fuse-saving scheme or to minimize the momentary

interruptions and sacrifice fuses. Single-phase reclosers can be coordinated as long as the same sequence of either two fast and two slow operations or one fast and three slow operations is selected. To obtain the best coordination between reclosers, the engineer should skip a size, using, for example three 70-Amp, oil circuit reclosers (OCRs) on a three-phase line and then a 35-Amp OCR on a single-phase tap. This is not always possible because of the length of line on some distribution circuits. If you skip a size, you can generally achieve trip coordination, but if you are not always able to skip a size, you can still generally achieve lockout coordination.

(6) The maximum and minimum fault currents will need to be calculated at each protection device to ensure that the device will clear the maximum available fault current, carry the expected load current, and interrupt the minimum fault current at the end of the section the device is designed to protect.

(7) On large substations with feeders of 3∅, 336 ACSR and larger conductor, it is not uncommon to have a 560-Amp continuous-rated microprocessor-controlled recloser, an 800-Amp continuous-rated microprocessor-controlled recloser, or even a 1,200-Amp continuous-rated breaker with an electronic relay or other microprocessor control on each of the substation feeders.

(8) Since single-phase devices are typically rated no more than 4,000 Amps interrupting ability, they will have to be used downline. Fuses, single-phase electronic sectionalizers, or 3∅ electronic sectionalizers will have to be used on all taps in the high-fault current areas.

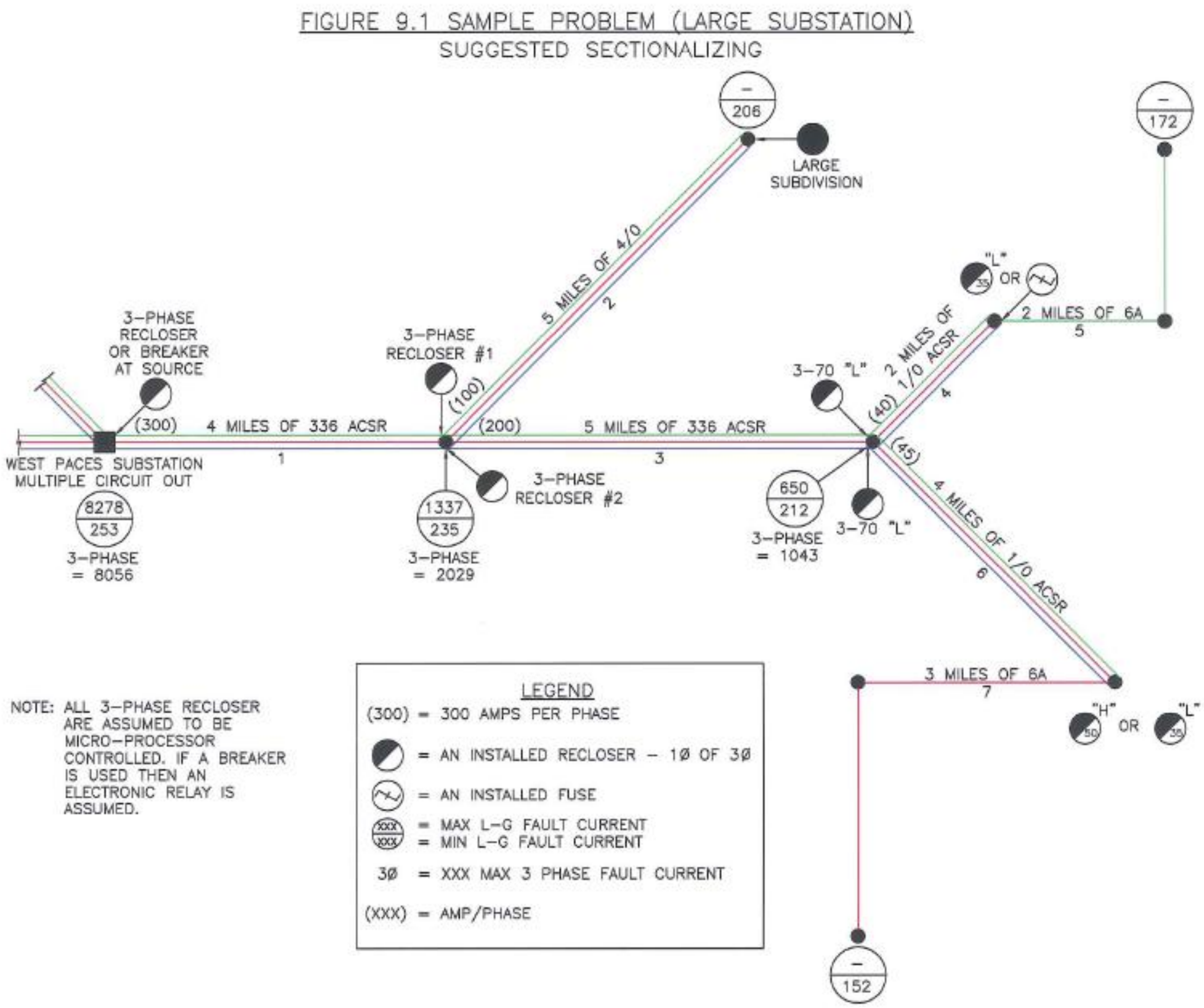
(9) Additionally, downline 3∅ electronic reclosers can be used in the mainline to adequately sectionalize the circuit while observing all of the fault current, load current, and minimum fault current issues discussed in this bulletin. The TCC curves in Figure 9.2 and Figure 9.3 show both the phase coordination for a 560-Amp phase trip recloser at the substation and a 300-Amp phase trip electronic recloser downline. Also shown are the ground trip settings for each device with the station recloser set on 140 Amps and the downline device set on 100 Amps.

(10) Using engineering judgment and minimum fault current

calculations, you can set the substation feeder recloser ground trip to a higher value than 140 Amps if the calculations show that the substation device will "see" to the downline recloser for a line-to-ground fault.

(11) The setting of the downline recloser's ground trip to a value less than 100 Amps is generally not recommended since during fault conditions there may be enough imbalance caused by a single-phase-to-ground fault to trip the downline electronic recloser out. This will create a larger outage that is more difficult to troubleshoot.

Figure 9.1. Diagram of the Substation and Circuits



b Solution

In this sample problem for large substations, the fault currents have been calculated and the load currents have been calculated and both of these values have been put on the circuit diagram (Figure 9.1) in their respective places. Voltage drops are not placed upon the sectionalizing circuit diagram since they should have already been considered, evaluated, and corrected, if necessary, so they are not needed in the sectionalizing analysis. As can be seen, the station had maximum fault current exceeding 8,100 Amps. The peak load current for the circuit shown is 300 Amps per phase. The zone of protection for the recloser/breaker at the substation is Section #1. The minimum fault current at the end of Section #1 using a 30 ohms fault resistance is 235 Amps L to G minimum. A suggested setting for the feeder recloser/ breaker is, thus, 560 Amps phase trip and 200 Amps (approximately) for the ground trip setting.

Using engineering judgment as a good rule of thumb for the phase trip setting is 150% to 200% of the projected peak loading. Again, using engineering judgment, we could set the ground trip anywhere from 100 Amps to 235 Amps. To provide selective coordination, generally we want to set the ground trip of the feeder recloser/breaker high enough and with the correct TCC so that the downline devices will clear the fault long before the feeder recloser/breaker has to operate.

However, for faults in Section #1 in Figure 9.1, we want the phase—and especially the ground trip—set sensitively enough that the device will operate but not trip out on nuisance problems.

For Recloser #1 in Figure 9.1, we have a three-phase tap serving a large subdivision at the end of the line. A suggested setting for that device could be 200 to 250 Amps on the phase trip and 140 Amps on the ground trip. With a judicious and experienced selection of TCC curves, this Recloser #1 would provide selective coordination with the upline feeder recloser/breaker. Selective coordination is defined, generally, as the condition in which Recloser #1 trips for a fault downline from its location WITHOUT the feeder recloser tripping out or blinking whatsoever.

For Recloser #2 in Figure 9.1, which is on the main line, the distribution engineer could choose to eliminate this recloser and let the feeder recloser/breaker "see" to the end of Section #3 depending upon the exposure of the circuit, i.e., ROW condition, topography, accessibility, etc. If the distribution engineer chooses to put in Recloser #2, the suggested setting for that phase trip could be 300 to 400 Amps and, for the ground trip, a range of 140 Amps to 200 Amps could be used. Again, with careful selection of TCC curves and trip settings, selective coordination could be achieved between the feeder recloser/breaker and the downline Recloser #3. From the load end of Section #3 to the end of the circuit, standard sectionalizing techniques could be used.

Figure 9.2. Time Current Characteristic Curves—Phase Trip

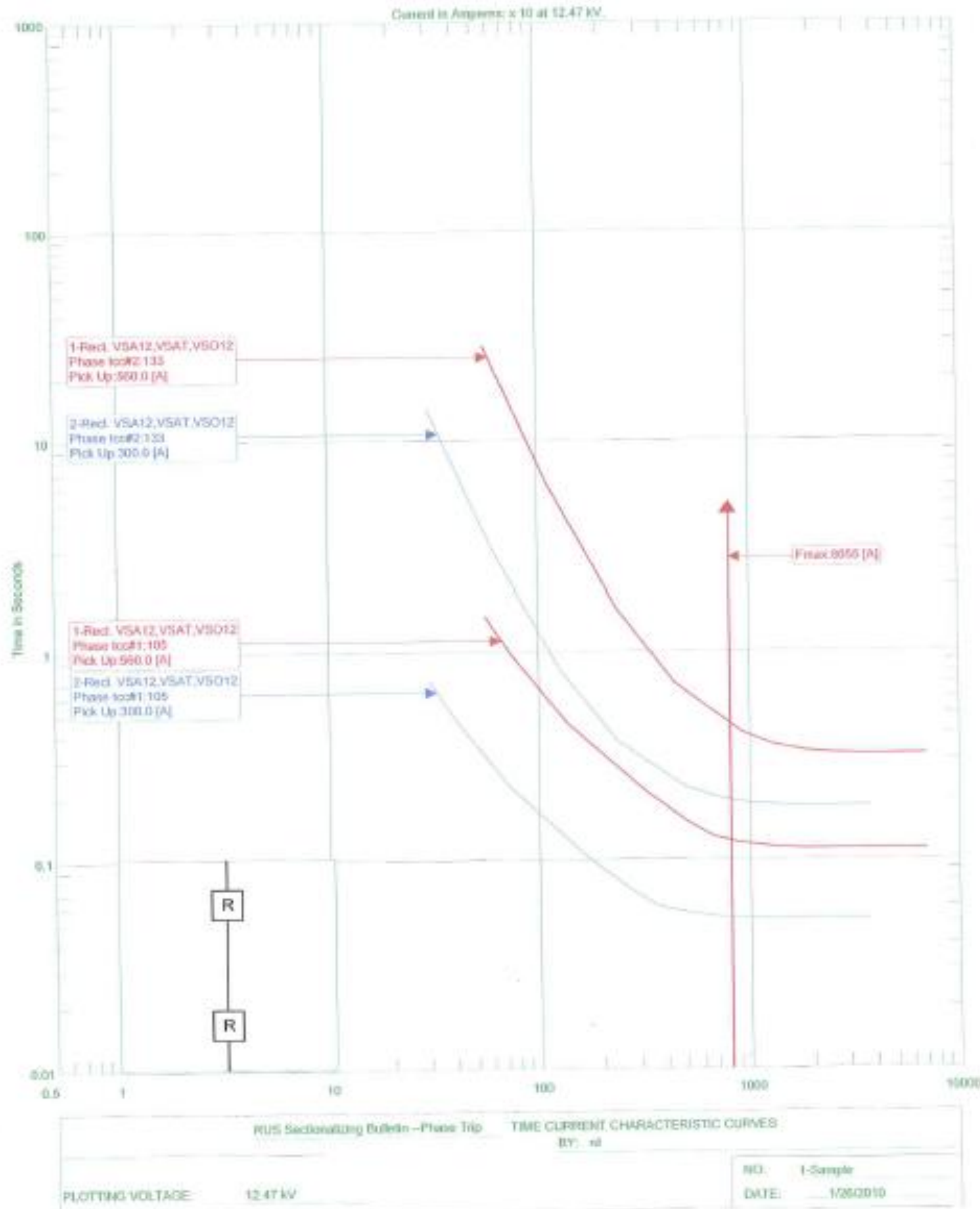
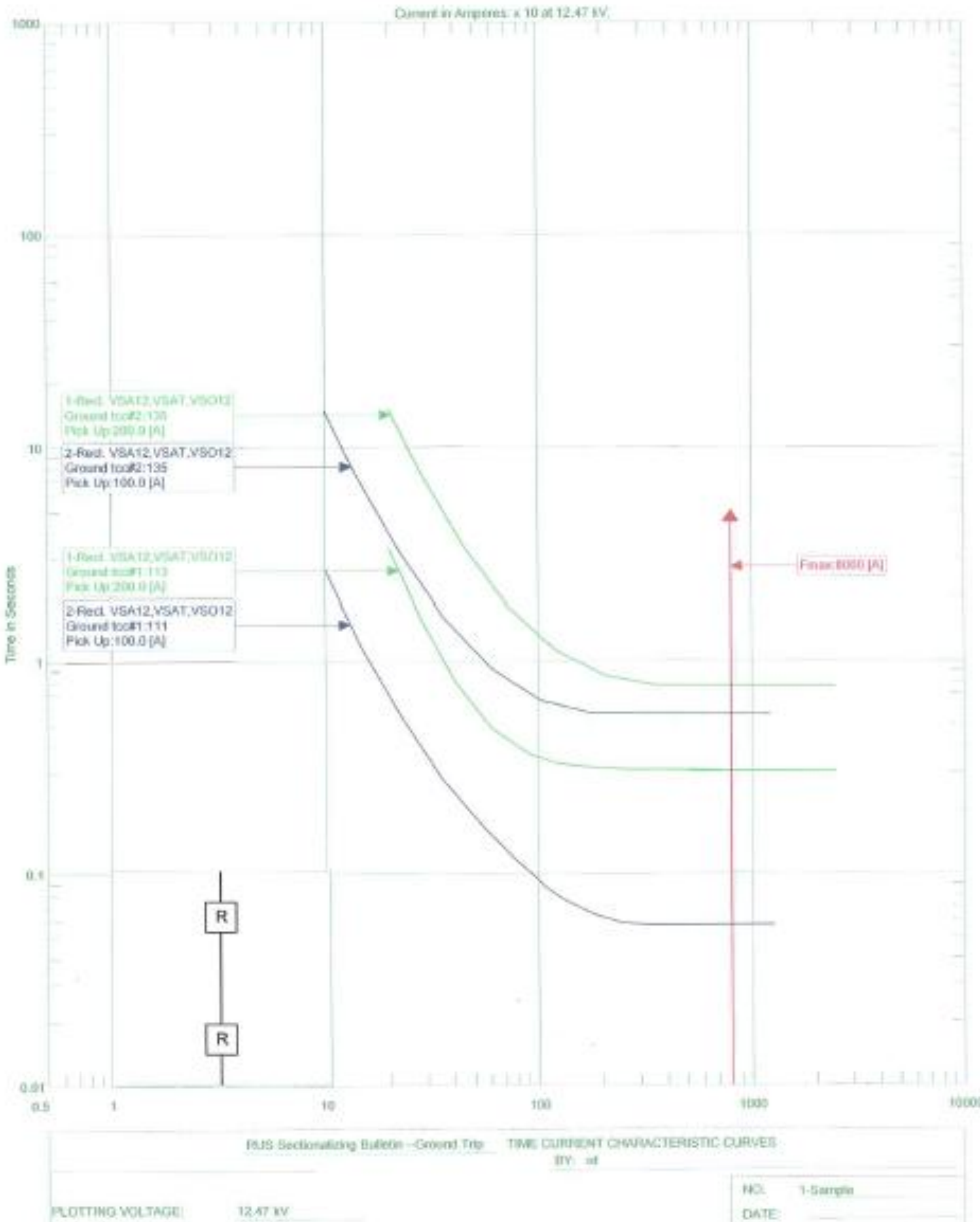


Figure 9.3. Time Current Characteristic Curves—Ground Trip



Coordination margins between curves are as discussed earlier in the bulletin and reference material, combined with engineering judgment and field experience. All electronic devices should be equipped with sequence coordination capability to enhance the probability of selective coordination.

Additional tricks of the trade to achieve selective coordination are to use similarly shaped but different curves on electronic reclosers in service, change the operations sequence, modifying both the phase and the ground trip curves by using a constant time adder, a curve multiplier, or for the ambitious engineer, simply digitizing a custom curve into the microprocessor recloser/relay. All of these techniques are contained in the references but most require extensive study and experience to implement.

EXHIBIT A
SAMPLE MODEL PRINTOUT SHOWING CALCULATIONS OF FAULT CURRENTS AND LOADING CONDITIONS

Case: Example Primary Analysis

LINE SECT	PRIOR SECT	MILES	PHS CONS	WIRE CONSTR-N	MX 3P FAULT	MX LLG FAULT	MX LG FAULT	MN LG FAULT	TOTAL KW	EQUIV AMPS	% CAP	LINE DROP	TOTAL DROP	LINE LOSS
SUB 4, CKT 1														
4-01	SUB (4)	0.00	240 3-	BKR-560-VWVE	3595	3910	3962	178	2431	115	21	0.00	0.00	0
42765	4-01	0.05	240 3-	#ACSR336	3528	3786	3830	178	2431	115	22	0.05	0.05	126
SW370-B	42765	0.05	240 3-	Closed	3528	3786	3830	178	2430	115	0	0.00	0.05	0
SW370-A	SW370-B	0.05	240 3-	Closed	3528	3786	3830	178	2430	115	0	0.00	0.05	0
43384	SW370-A	0.74	240 3-	#ACSR336	2855	2808	2703	176	2430	115	22	0.67	0.72	1557
44590	43384	0.74	0 3-	#ACSR336	2855	2807	2703	176	0	0	0	0.00	0.72	0
SW362-B	44590	0.74	0 3-	Open	2855	2807	2703	176	0	0	0	0.00	0.72	0
43385	43384	0.78	238 3-	#ACSR336	2823	2768	2656	176	2389	113	21	0.04	0.76	93
42763	43385	0.80	238 3-	#ACSR1/0	2798	2740	2624	176	2389	113	49	0.05	0.81	161
SW369-B	42763	0.80	238 3-	Closed	2798	2740	2624	176	2388	113	0	0.00	0.81	0
SW369-A	SW369-B	0.80	238 3-	Closed	2798	2740	2624	176	2388	113	0	0.00	0.81	0
43162	SW369-A	1.05	238 3-	#ACSR1/0	2507	2425	2268	174	2388	113	49	0.64	1.45	2049
42761	43162	1.11	135 3-	#ACSR1/0	2445	2361	2196	174	1316	60	26	0.08	1.53	141
SW368-B	42761	1.11	135 3-	Closed	2445	2361	2196	174	1315	60	0	0.00	1.53	0
SW368-A	SW368-B	1.11	135 3-	Closed	2445	2361	2196	174	1315	60	0	0.00	1.53	0
42759	SW368-A	1.93	135 3-	#ACSR1/0	1803	1725	1513	169	1315	60	26	1.09	2.62	1952
SW367-B	42759	1.93	135 3-	Closed	1803	1725	1513	169	1305	60	0	0.00	2.62	0
SW367-A	SW367-B	1.93	135 3-	Closed	1803	1725	1513	169	1305	60	0	0.00	2.62	0
42757	SW367-A	2.49	134 3-	#ACSR1/0	1517	1452	1241	166	1302	60	26	0.74	3.35	1195
SW366-B	42757	2.49	132 3-	Closed	1517	1452	1241	166	1257	58	0	0.00	3.35	0
SW366-A	SW366-B	2.49	132 3-	Closed	1517	1452	1241	166	1257	58	0	0.00	3.35	0
43337	SW366-A	3.36	132 3-	#ACSR1/0	1218	1167	972	161	1256	58	26	1.09	4.44	1744
42755	43337	3.36	130 3-	#HD6	1216	1166	971	161	1222	57	48	0.01	4.45	18
SW365-B	42755	3.36	130 3-	Closed	1216	1166	971	161	1222	57	0	0.00	4.45	0
SW365-A	SW365-B	3.36	130 3-	Closed	1216	1166	971	161	1222	57	0	0.00	4.45	0
43321	SW365-A	4.34	123 3-	#HD6	885	865	710	152	1156	55	46	2.29	6.74	731
42753	43321	4.35	123 3-	#ACSR4/0	885	864	709	152	1152	55	16	0.00	6.74	4
SW364-B	42753	4.35	123 3-	Closed	885	864	709	152	1152	55	0	0.00	6.74	0
SW364-A	SW364-B	4.35	123 3-	Closed	885	864	709	152	1152	55	0	0.00	6.74	0
42754	SW364-A	4.38	123 3-	#ACSR4/0	882	861	706	152	1152	55	16	0.02	6.76	30
C166	42754	4.38	0 3-	100 KVAR	882	861	706	152	0	-13	0	0.00	6.76	0
42951	42754	4.42	123 3-	#ACSR4/0	878	857	702	151	1152	59	18	0.04	6.80	51
42988	42951	4.52	119 3-	#ACSR4/0	867	846	692	151	1119	58	17	0.09	6.88	115
43025	42988	6.06	109 3-	#ACSR4/0	736	712	567	146	1035	54	16	1.24	8.12	711
D1796	43025	6.06	108 3-	REC-50-H	736	712	567	146	1018	53	107	0.00	8.12	0
42751	D1796	6.17	99 3-	#ACSR4/0	728	704	560	146	931	48	14	0.08	8.20	42
SW363-B	42751	6.17	99 3-	Closed	728	704	560	146	931	48	0	0.00	8.20	0
SW363-A	SW363-B	6.17	99 3-	Closed	728	704	560	146	931	48	0	0.00	8.20	0
43031	SW363-A	6.50	99 3-	#ACSR4/0	705	681	539	145	931	48	14	0.24	8.44	268
C165	43031	6.50	0 3-	100 KVAR	705	681	539	145	0	0	0	0.00	8.44	0
43064	43031	7.47	84 3-	#ACSR4/0	646	621	486	142	786	41	12	0.64	9.08	116
43066	43064	7.63	64 3-	#ACSR4/0	637	613	479	142	642	33	10	0.07	9.15	56
43223	43066	9.98	5 3-	#ACSR4/0	530	507	388	135	82	4	1	0.31	9.46	0
43127	43223	10.35	2 3-	#ACSR4/0	517	493	377	134	6	0	0	0.00	9.46	0
SW331-B	43127	10.35	0 3-	Open	517	493	377	134	0	0	0	0.00	9.46	0
43120	43223	10.16	1 1-	#ACSR4	0	0	378	133	5	0	1	0.00	9.46	0
43067	43066	7.70	36 1-	#HD6	0	0	473	141	352	55	47	0.19	9.34	107
D1794	43067	7.70	35 1-	REC-35-H	0	0	473	141	341	54	155	0.00	9.34	0
NODE42	D1794	8.49	5 1-	#HD6	0	0	413	135	37	5	5	0.59	9.93	3
43129	43064	7.65	16 1-	#HD6	0	0	471	141	111	17	15	0.13	9.20	20
NODE43	43129	8.02	6 1-	#ACSR4	0	0	439	138	41	6	5	0.07	9.28	3
43000	42988	5.24	3 3-	#HD6	720	709	578	145	6	0	0	0.02	6.90	0
43001	43000	5.31	2 1-	#HD6	0	0	567	144	5	0	1	0.00	6.91	0
NODE55	43001	5.43	1 1-	#ACSR4	0	0	553	143	1	0	0	0.00	6.91	0
42954	42951	4.53	4 3-	#ACSR1/0	861	840	688	151	32	1	1	0.00	6.80	0
D1797	42954	4.53	4 3-	REC-50-L	861	840	688	151	32	1	3	0.00	6.80	0
43317	D1797	4.65	4 3-	#ACSR1/0	844	824	673	150	32	1	1	0.00	6.81	0
43429	43317	4.95	2 3-	#ACSR4	776	761	621	148	0	0	0	0.01	6.82	0
42971	43429	4.98	2 3-	#HD6	769	754	615	147	0	0	0	0.00	6.82	0
43177	42971	5.57	0 3-	#ACSR4	663	655	534	142	0	0	0	0.00	6.82	0

(continued)

Substation Power Factor: 0.95 Load Factor: 0.50 Loss Factor: 0.29 Cost: 0.0750 per kWh
Run Date:

Exhibit A, *continued*

LINE SECT	PRIOR SECT	MILES	CONS	PHS	WIRE CONSTR-N	MX 3P FAULT	MX LLG FAULT	MX LG FAULT	MN LG FAULT	TOTAL KW	EQUIV AMPS	% CAP	LINE DROP	TOTAL DROP	LINE LOSS
NODE54	43177	5.79	0	3-	#ACSR4	630	624	509	140	0	0	0	0.00	6.82	0
42985	43177	5.86	0	3-	#ACSR4	620	614	501	140	0	0	0	0.00	6.82	0
42749	43317	5.64	0	3-	#ACSR1/0	726	708	573	146	0	0	0	0.00	6.81	0
SW361-A	42749	5.64	0	3-	Open	726	708	573	146	0	0	0	0.00	6.81	0
43163	43162	1.08	102	3-	#ACSR1/0	2468	2385	2222	174	1046	52	23	0.04	1.49	65
D1795	43163	1.08	102	1-	REC-50-L	0	0	2222	174	1046	156	314	0.00	1.49	0
42875	D1795	1.52	94	1-	#HD6	0	0	1662	169	941	144	120	3.23	4.72	1179
43375	42875	2.09	93	1-	#ACSR4	0	0	1199	163	926	142	102	4.35	9.07	6262
42770	43375	2.57	87	1-	#HD6	0	0	976	158	830	135	113	3.29	12.36	1461
43413	42770	3.11	85	1-	#ACSR4	0	0	799	153	814	133	96	3.79	16.15	5130
43405	43413	4.32	63	1-	#ACSR1/0	0	0	637	147	598	104	46	4.45	20.60	548
NODE69	43405	6.36	3	1-	#HD6	0	0	416	131	24	4	4	5.00	25.60	0
CKT	**1 total losses:**	**$25,938**													
<u>SUB4, CKT 2</u>															
4-02	SUB (4)	0.00	18	3-	BKR-560-VWVE	3595	3910	3962	178	182	8	2	0.00	0.00	0
43500	4-02	0.06	18	3-	#ACSR336	3527	3784	3828	178	182	8	2	0.00	0.00	0
SW371-B	43500	0.06	18	3-	Closed	3527	3784	3828	178	182	8	0	0.00	0.00	0
SW371-A	SW371-B	0.06	18	3-	Closed	3527	3784	3828	178	182	8	0	0.00	0.00	0
43449	SW371-A	0.74	18	3-	#ACSR336	2855	2807	2702	176	182	8	2	0.06	0.06	10
44589	43449	0.74	0	3-	#ACSR336	2854	2806	2702	176	0	0	0	0.00	0.06	0
SW362-A	44589	0.74	0	3-	Open	2854	2806	2702	176	0	0	0	0.00	0.06	0
43451	43449	0.85	18	3-	#ACSR336	2767	2701	2576	176	182	8	2	0.01	0.07	0
43499	43451	2.20	15	3-	#ACSR1/0	1672	1598	1383	168	125	6	3	0.23	0.30	17
43474	43499	2.25	15	1-	#ACSR4	0	0	1344	167	125	18	13	0.05	0.36	10
D1802	43474	2.25	14	1-	REC-35-L	0	0	1344	167	124	18	52	0.00	0.36	0
43482	D1802	2.73	1	1-	#ACSR4	0	0	1076	162	14	2	1	0.26	0.62	0
43505	43482	2.74	0	1-	#UG25KV1/0	0	0	1072	362	0	0	0	0.00	0.62	0
NODE68	43505	2.79	0	1-	#ACSR4	0	0	1047	161	0	0	0	0.00	0.62	0
CKT	**2 total losses:**	**$37**													
<u>SUB4, CKT 3</u>															
4-03	SUB (4)	0.00	2	3-	BKR-560-VWVE	3595	3910	3962	178	20	14	3	0.00	0.00	0
44538	4-03	0.01	2	3-	#ACSR336	3581	3883	3933	178	20	14	3	0.00	0.00	0
SW375-B	44538	0.01	2	3-	Closed	3581	3883	3933	178	20	14	0	0.00	0.00	0
SW375-A	SW375-B	0.01	2	3-	Closed	3581	3883	3933	178	20	14	0	0.00	0.00	0
43727	SW375-A	0.12	2	3-	#ACSR336	3455	3660	3693	177	20	14	3	-0.02	-0.02	4
44588	43727	0.12	0	3-	#ACSR336	3455	3660	3692	177	0	0	0	0.00	-0.02	0
SW372-B	44588	0.12	0	3-	Open	3455	3660	3692	177	0	0	0	0.00	-0.02	0
44540	43727	0.45	2	3-	#ACSR336	3101	3125	3080	177	20	14	3	-0.05	-0.07	0
SW376-B	44540	0.45	2	3-	Closed	3101	3125	3080	177	20	14	0	0.00	-0.07	0
SW376-A	SW376-B	0.45	2	3-	Closed	3101	3125	3080	177	20	14	0	0.00	-0.07	0
44284	44581	9.19	0	3-	#ACSR336	844	769	578	156	0	0	0	0.00	-1.25	0
44318	44284	10.02	0	3-	#ACSR336	789	719	537	154	0	0	0	0.00	-1.25	0
C168	44318	10.02	0	3-	200 KVAR	789	719	537	154	0	0	0	0.00	-1.25	0
44323	44318	10.38	0	3-	#ACSR336	768	699	521	153	0	0	0	0.00	-1.25	0
44345	44323	10.94	0	3-	#HD6	693	640	475	148	0	0	0	0.00	-1.25	0
44377	44345	12.15	0	3-	#ACSR4	554	524	391	137	0	0	0	0.00	-1.25	0
44382	44377	12.33	0	3-	#HD6	537	510	381	136	0	0	0	0.00	-1.25	0
SW383-A	44382	12.33	0	3-	Open	537	510	381	136	0	0	0	0.00	-1.25	0
NODE65	44284	9.87	0	3-	#ACSR1/0	768	705	528	152	0	0	0	0.00	-1.25	0
44122	44120	8.19	0	1-	#HD6	0	0	635	158	0	0	0	0.00	-1.24	0
D1835	44122	8.19	0	1-	REC-25-H	0	0	635	158	0	0	0	0.00	-1.24	0
44034	D1835	8.69	0	1-	#HD6	0	0	573	153	0	0	0	0.00	-1.24	0
44047	44034	9.07	0	1-	#ACSR4	0	0	531	149	0	0	0	0.00	-1.24	0
44205	44047	9.24	0	1-	#HD6	0	0	514	148	0	0	0	0.00	-1.24	0
44209	44205	9.32	0	1-	#ACSR4	0	0	506	147	0	0	0	0.00	-1.24	0
NODE60	44205	9.28	0	1-	#HD6	0	0	511	147	0	0	0	0.00	-1.24	0
43828	44547	4.44	1	3-	#ACSR336	1397	1285	1036	167	18	0	0	0.00	-0.65	0
C169	43828	4.44	0	3-	100 KVAR	1397	1285	1036	167	0	0	0	0.00	-0.65	0
43840	43828	4.55	1	3-	#ACSR336	1376	1266	1017	167	18	0	0	0.00	-0.65	0
D1843	43840	4.55	1	3-	REC-50-H	1376	1266	1017	167	18	0	2	0.00	-0.65	0
43850	D1843	4.84	1	3-	#ACSR336	1325	1217	972	166	18	0	0	0.00	-0.64	0
44414	43850	4.99	0	3-	#ACSR1/0	1282	1179	938	166	0	0	0	0.00	-0.64	0
NODE53	44414	5.78	0	3-	#ACSR4	998	945	740	157	0	0	0	0.00	-0.64	0
44464	43850	5.78	1	3-	#ACSR336	1180	1081	848	164	18	0	0	0.01	-0.64	0
43859	44464	5.80	1	1-	#ACSR4	0	0	841	164	18	2	2	0.00	-0.63	0

(continued)

Substation Power Factor: 0.95 Load Factor: 0.50 Loss Factor: 0.29 Cost: 0.0750 per kWh
Run Date:

Exhibit A, *continued*

LINE SECT	PRIOR SECT	MILES	PHS CONS	WIRE CONSTR-N	MX 3P FAULT	MX LLG FAULT	MX LG FAULT	MN LG FAULT	TOTAL KW	EQUIV AMPS	% CAP	LINE DROP	TOTAL DROP	LINE LOSS
D1838	43859	5.80	1 1-	REC-25-H	0	0	841	164	18	2	11	0.00	-0.63	0
43864	D1838	6.15	1 1-	#ACSR4	0	0	764	160	18	2	2	0.05	-0.58	0
43868	43864	6.46	1 1-	#HD6	0	0	706	157	18	2	2	0.04	-0.54	0
NODE52	43868	6.70	1 1-	#ACSR4	0	0	664	154	18	2	2	0.02	-0.52	0
44443	44464	6.52	0 3-	#ACSR336	1086	993	770	162	0	0	0	0.00	-0.64	0
43916	44443	6.58	0 1-	#ACSR4	0	0	759	162	0	0	0	0.00	-0.64	0
D1836	43916	6.58	0 1-	REC-25-99	0	0	759	162	0	0	0	0.00	-0.64	0
44439	D1836	6.96	0 1-	#ACSR4	0	0	688	158	0	0	0	0.00	-0.64	0
43970	44439	8.45	0 1-	#HD6	0	0	501	144	0	0	0	0.00	-0.64	0
NODE45	43970	8.96	0 1-	#ACSR4	0	0	455	140	0	0	0	0.00	-0.64	0
43816	43814	3.84	0 1-	#ACSR4	0	0	1144	168	0	0	0	0.00	-0.56	0
D1839	43816	3.84	0 1-	REC-35-H	0	0	1144	168	0	0	0	0.00	-0.56	0
NODE58	D1839	4.30	0 1-	#ACSR4	0	0	965	163	0	0	0	0.00	-0.56	0
43752	43741	1.83	0 3-	#ACSR4	1851	1790	1565	169	0	0	0	0.00	-0.20	0
42750	43752	1.83	0 3-	#ACSR1/0	1848	1787	1562	169	0	0	0	0.00	-0.20	0
SW361-B	42750	1.83	0 3-	Open	1848	1787	1562	169	0	0	0	0.00	-0.20	0
CKT	**3 total losses:**	**$79**												
<u>SUB4, CKT 4</u>														
4-04	SUB (4)	0.00	76 3-	BKR-560-VWVE	3595	3910	3962	178	726	35	6	0.00	0.00	0
43717	4-04	0.01	76 3-	#ACSR336	3584	3889	3940	178	726	35	7	0.00	0.00	2
SW373-B	43717	0.01	76 3-	Closed	3584	3889	3940	178	726	35	0	0.00	0.00	0
SW373-A	SW373-B	0.01	76 3-	Closed	3584	3889	3940	178	726	35	0	0.00	0.00	0
43508	SW373-A	0.12	76 3-	#ACSR336	3453	3656	3688	177	726	35	7	0.04	0.04	24
43520	43508	0.45	67 3-	#ACSR336	3100	3124	3079	177	564	27	5	0.10	0.14	14
43719	43520	0.46	6 3-	#HD6	3093	3115	3068	177	71	3	3	0.00	0.14	0
SW374-B	43719	0.46	6 3-	Closed	3093	3115	3068	177	71	3	0	0.00	0.14	0
SW374-A	SW374-B	0.46	6 3-	Closed	3093	3115	3068	177	71	3	0	0.00	0.14	0
43612	SW374-A	0.99	6 3-	#HD6	2164	2129	1958	171	71	3	3	0.08	0.22	9
NODE66	43612	1.96	2 3-	#ACSR4	1270	1266	1100	160	47	2	2	0.08	0.30	0
43521	43520	0.51	57 1-	#HD6	0	0	2929	176	466	68	57	0.19	0.33	129
D1807	43521	0.51	9 1-	REC-35-L	0	0	2929	176	65	9	27	0.00	0.33	0
43533	D1807	0.88	9 1-	#HD6	0	0	2124	172	65	9	8	0.11	0.44	8
NODE67	43533	2.73	0 1-	#ACSR4	0	0	803	152	0	0	0	0.13	0.57	0
43524	43521	0.57	47 1-	#ACSR1/0	0	0	2807	176	397	58	26	0.11	0.44	55
D1806	43524	0.57	47 1-	REC-50-L	0	0	2807	176	397	58	118	0.00	0.44	0
43662	D1806	2.15	47 1-	#ACSR1/0	0	0	1324	166	392	58	26	2.78	3.22	588
43576	43662	2.35	41 1-	#ACSR4	0	0	1199	164	355	53	38	0.58	3.80	109
43606	43576	3.67	7 1-	#HD6	0	0	740	151	53	8	7	1.71	5.52	6
43710	43606	3.94	5 1-	#ACSR4	0	0	682	149	44	6	5	0.08	5.60	5
NODE64	43710	4.73	0 1-	#HD6	0	0	559	142	0	0	0	0.06	5.66	0
43640	43508	0.12	0 3-	#ACSR336	3452	3656	3688	177	0	0	0	0.00	0.04	0
SW372-A	43640	0.12	0 3-	Open	3452	3656	3688	177	0	0	0	0.00	0.04	0
CKT	**4 total losses:**	**$949**												
SUB	**4 total losses:**	**$27,003**												

Substation Power Factor: 0.95 Load Factor: 0.50 Loss Factor: 0.29 Cost: 0.0750 per kWh
Run Date:

EXHIBIT B
LINE RECLOSER MAINTENANCE SPECIFICATIONS

August 1, 2005
(Revision 1 – August 5, 2006)

PURPOSE: To detail the minimum requirements for refurbishment of single-phase line sectionalizing reclosers regardless of type, size, or manufacturer.

LIMITED SCOPE:

1. The requirements set forth herein are in no way intended to limit those steps necessary to bring a used recloser up to proper operating status.

2. No warranty is written or implied by the compliance of the requirements included herein. The user is to refer to the warranty provided by the organization or contractor actually performing the recloser maintenance.

REQUIREMENTS:

1. Prior to any recloser maintenance, a full operational and functional test shall be accomplished. Any dysfunctional aspect of the recloser operation shall be documented. The test is to determine also the actual pickup current level and time-current characteristics of the device. The pickup values and counter reading, as found, shall be included in the recloser final test report.

   NOTE: All testing required by this specification shall be accomplished by using alternating current (AC) operating equipment only. Direct current (DC) or battery operational tests are *not* acceptable.

2. All internal parts of the recloser shall be disassembled, inspected, and thoroughly washed. All gaskets and tank liners are to be replaced if there are significant signs of deterioration. Other mechanism parts are to be replaced at the discretion of the maintenance contractor.

3. All operation counters are to be checked for proper operation. Counters with "small-sized numbers" are to be replaced with the "larger-sized numbers" as manufactured by ___________________________.

4. Reclosers having an estimated maintenance cost of more than 50% of a new purchase price are to be scrapped. The maintenance contractor can give credit for parts where appropriate. The maximum maintenance cost for each type of recloser is as follows:

   Type H or equivalent = $____
   Type L or equivalent = $____

Type E or equivalent	=	$____
Type 4H or equivalent	=	$____

5. After the preceding steps are accomplished, each recloser is to be tested for proper operation in accordance with published specifications of the manufacturer. The minimum tests to be performed are as follows:

   - Insulation resistance or hipot,
   - Minimum pickup current level,
   - Functional tests of operating handle, nonreclosing switch, and lockout indicator, and
   - Calibration of time-current characteristics.

   NOTE: A minimum of two test points per operating curve, not including the pickup current point, are to be used to determine that the recloser is properly operating. Suggested test points are 400% and 600% of rated *pickup* current (or 800% and 1200% of rated *load* current). Points other than these are to be approved by the owner. Any test results that are not within 10% of the manufacturer's published data should be noted and reviewed with the owner for possible scrapping of the unit.

6. After testing, each unit is to be thoroughly sandblasted or cleaned and painted with a good quality ANSI No. 70 gray paint.

7. Each unit shall also be externally labeled in the manner prescribed by the owner. The labeling shall be on the tank side, opposite the mounting bracket. The lettering shall be a minimum 3 inches high, shall include both the recloser type and size, and is to be done using a paint that will *not* deteriorate in sunlight.

8. Refurbished units are to be safely shipped back to the owner on containers that adequately support and protect the devices during shipment. The vendor has responsibility for units during shipment.

9. A report shall also be provided on each refurbished recloser unit. The report may be supplied electronically and by email. The report, at a minimum, shall include the following:

   - Manufacturer, type, size, kilovolt basic impulse level (BIL), and serial number;
   - Coil size found at start and coil size left;
   - Counter reading found at start and reading left;
   - Operations sequence as found and sequence left;
   - Timing test results as found and as calibrated;
   - Old oil batch number traceable to depository;
   - New oil batch number traceable to source for non-PCB verification;
   - Itemized list of parts installed, including invoice costs;
   - Date of repair and individuals performing the repairs and tests; and
   - Vendor comments on the timeliness of maintenance.

10. Prior to shipment, the maintenance contractor is to notify the owner that refurbishment has been completed and that the units are available for inspection. The owner then has the option of going to the contractor's facilities to inspect the refurbished units. At that time, the owner can request a sample of 10% of total units shipped for retesting observation. A price per unit for retesting is to be provided to the owner when annual unit price estimates are offered. If no such price is offered, it is assumed that the retesting will be accomplished by the contractor at no cost. It is further understood that all retested units found to be in nonconformance with the test reports will not be charged to the owner.

11. Shipped units may be retested by the owner after receipt. If a shipped unit is found to be not in conformance with contractor's test report, the unit will be returned to the contractor at contractor's expense for correction.

    NOTE: The method of the owner's test is to be compatible with the contractor's.

COMMENTS AND QUESTIONS:

Comments and questions regarding these specifications are encouraged and should be addressed to the cooperative system engineer or his designated consultant. The system engineer is ______________________, whose contact information is as follows:

Office phone: XXX-XXX-XXXX
FAX: YYY-YYY-YYYY
Email: sysengineer@coopabc.com

EXHIBIT C
BIBLIOGRAPHY AND REFERENCES

1. “Procedure for Making a Sectionalizing Study on Rural Electric Systems.” Technical Standards Bulletin #4A (December 1945), Rural Electrification Administration.

2. “Guide for Making a Sectionalizing Study on Rural Electric Systems.” REA Bulletin 61-2, March 1958.

3. “Review of Sectionalizing Fundamentals,” L.B. Crann. REA Field Conference Denver, Colorado, October 20, 1972.

4. “Guide for Making a Sectionalizing Study on Rural Electric Systems.” REA Bulletin 61-2, March 1978 (Reprinted January 1982).

5. “Downed Power Lines: Why They Can’t Always Be Detected.” IEEE Power Engineering Society, February 22, 1989.

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9. “Symmetrical Components,” Wagner and Evans. McGraw-Hill Book Company, 1933.

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12. “Applied Protective Relaying.” Westinghouse Electric Corporation, 1976.

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14. “Symmetrical Components for Power Systems Engineering,” J. Lewis Blackburn. CRC Press, 1993.