

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY)	
UTILITIES COMPANY FOR A CERTIFICATE OF)	
PUBLIC CONVENIENCE AND NECESSITY FOR)	CASE NO. 2022-00066
THE CONSTRUCTION OF TRANSMISSION)	
FACILITIES IN HARDIN COUNTY, KENTUCKY)	

RESPONSE OF
KENTUCKY UTILITIES COMPANY
TO
COMMISSION STAFF'S POST-HEARING REQUEST FOR INFORMATION
DATED JUNE 3, 2022

FILED: JUNE 10, 2022

KENTUCKY UTILITIES COMPANY

**Response to Commission Staff's Post-Hearing Request for Information
Dated June 3, 2022**

Case No. 2022-00066

Question No. 1

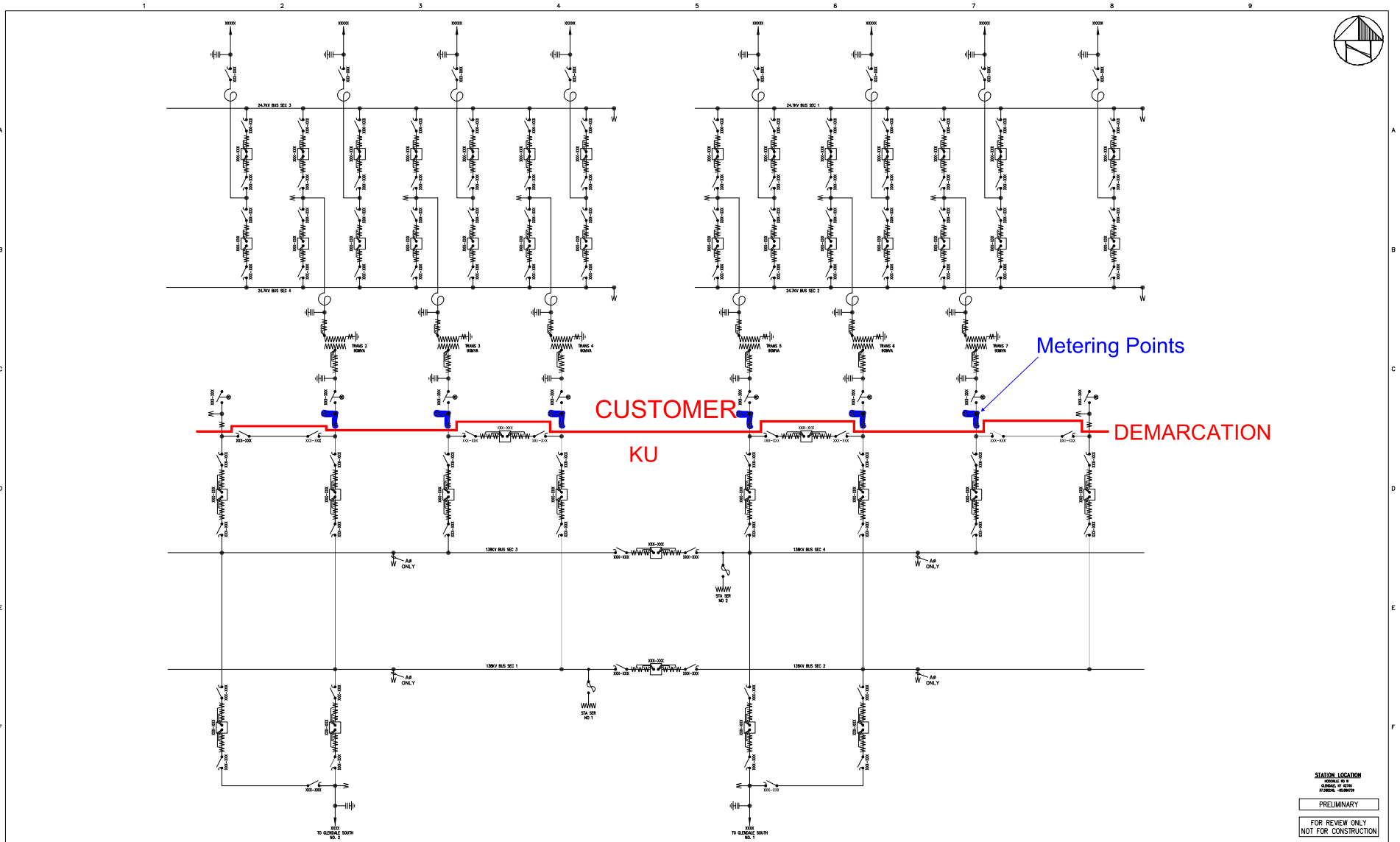
Responding Witness: Robert M. Conroy / Elizabeth J. McFarland

- Q-1. Provide a schematic of the substation, accompanying 138 kV lines and gas line on the Glendale Megasite property. Indicate where the meter(s) are and the demarcation point for financial responsibility of the lines and equipment that are Ford's responsibility, the responsibility of KU and estimated cost for each assigned item.
- A-1. For transmission lines and gas line, see the response to PSC 2-10 (and see pages 3-15 of 37 for transmission lines and page 36 of 37 for the gas line).

See the response to PSC 4-6 for network costs associated with the Glendale Industrial substation that represents the preliminary estimated costs for KU.

See attached for the schematic of the 138/24.7kV substation (Glendale Industrial) that indicates the line of demarcation and metering locations. The preliminary estimated costs for the "Behind the Meter" costs will be billed to the customer via the Excess Facilities Rider, while the assets will be owned and operated by KU. KU continues to work with Ford to finalize the details.

		<u>(\$,000,000)</u>
Engineering/PM		\$ 5.224
138.24.7kV Transformers	\$10.300	
24.7KV Breakers	\$ 2.335	
24.7kV Reactors	\$ 0.910	
24.7kV Disconnects	\$ 0.085	
24.5kV CTs/PTs	\$ 0.955	
Control House	\$ 1.300	
Grounding Materials (Lot)	\$ 2.000	
Steel (Lot)	\$ 2.600	
Aluminum Bus, connectors (Lot)	\$ 0.683	
Control Cable (Lot)	\$ 2.500	\$ 23.668
Labor		\$ 10.108
Total		<u>\$ 39.000</u>



DRAWING RELEASE RECORD				
REV.	DATE	PROJECT	DRAWN	APPROVED

DRAWING RELEASE RECORD				
REV.	DATE	PROJECT	DRAWN	APPROVED

Project	Drawn	By	03/04/2022	Approved	Scale	NONE
GLENDALE INDUSTRIAL SUBSTATION 138/24.7KV SUBSTATION SWITCHING DIAGRAM						

STATION LOCATION
INDICATED BY A
 TRIANGLE IN OTHER
 DRAWINGS.

PRELIMINARY

FOR REVIEW ONLY
 NOT FOR CONSTRUCTION

LGE KU.
 PPL companies

Drawing Number: **SD-470** Revision: **A**

DrawnDT Version 1.0

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Post-Hearing Request for Information Dated June 3, 2022

Case No. 2022-00066

Question No. 2

Responding Witness: Robert M. Conroy / Elizabeth J. McFarland

- Q-2. Refer to KU's response to Commission Staff's Third Request for Information, Item 3, page 35 of 36.
- a. Provide the size of the gas main and whether it will be able to support a future gas fired generation facility.
 - b. Provide the portion of the gas pipeline that will be Ford's expense.
 - c. Confirm that all gas facilities built will be covered by a gas facilities' rider or agreement.
- A-2.
- a. The main extension will be 16-inches. KU is not aware of current plans for a gas fired generation facility, but the ability to support a gas fired generation facility would depend on a host of variables that KU has not analyzed at this time.
 - b. The gas main extension to the demarcation point at the gas metering facility will be covered under LG&E's Gas Main Extension Rules found in LG&E's Gas tariff P.S.C. Gas No. 13, Original Sheet No. 106. Ford will be responsible for gas facilities beyond that point.
 - c. All gas facilities built will either be covered by LG&E's Gas Main Extension Rules found in LG&E's Gas tariff P.S.C. Gas No. 13, Original Sheet No. 106 or LG&E's Standard Facility Contribution Rider found in LG&E's Gas tariff P.S.C. Gas No. 13, Original Sheet No. 64. KU and Ford have not had discussions about whether any of the expenses would be eligible for LG&E's gas Standard Facility Contribution Rider.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Post-Hearing Request for Information Dated June 3, 2022

Case No. 2022-00066

Question No. 3

Responding Witness: Elizabeth J. McFarland

- Q-3. Refer to KU's response to Commission Staff's Second Request for Information (Staff's Second Request), Item 1a.
- a. Explain whether the cost of removing the existing 2.7-mile segment of the Brown North-Hardin County line between the two proposed tap points is included in the cost of constructing the proposed East and West 345 kV lines. Include in the response the cost of removing the line segment.
 - b. Explain why the line segment is being removed once the East and West 345 kV taps are completed.
 - c. Explain whether KU is relinquishing its existing right-of-way once the line segment is removed.
- A-3.
- a. Yes. See the response to PSC 3-7. Also, in the response to PSC 4-7, the price breakdown is provided for the construction of the 345 kV West Route. The last line contains a cost "Removal Labor (Existing Line Segment)" of \$1.700M. This is for the removal costs associated with the Brown North – Hardin County 345 kV line between the 345 kV East Route and 345 kV West Route.
 - b. The Hardin County to Brown North 345 kV line will be configured breaker to breaker, in and out of Glendale South Substation. This creates two independent circuits and eliminates the need for the 2.7 mile section between the tap points. Removal of the unneeded segment eliminates ongoing maintenance for the segment and allows for removal of easements that would be required if the line were to remain in place once the reroute is complete.
 - c. KU intends to release its easement rights between the 345 kV West route tap point and 345 kV East route tap point, on the Brown North – Hardin County 345 kV line, once both new lines are constructed and energized. This easement release will take place upon the completion of the removal work.

KENTUCKY UTILITIES COMPANY

**Response to Commission Staff's Post-Hearing Request for Information
Dated June 3, 2022**

Case No. 2022-00066

Question No. 4

Responding Witness: Elizabeth J. McFarland

- Q-4. Refer to KU's response to Staff's Second Request, Item 5a.
- a. Provide further explanation of what a three terminal line is and how that differs from the existing Daviess County–Hardin County and Brown North-Hardin County line terminal. That existing tap has a short line segment to the substation just to the north and three terminal points at the tap, two (2) Brown North–Hardin County line segments on either side of the tap and the Daviess County–Hardin County line. Reconcile how this is not the same situation as KU is attempting to avoid on the Western Route as proposed with the parallel section.
 - b. Explain why the line segment of the proposed Western Route 345 kV line running parallel to the Daviess County–Hardin County 345 kV line does not represent wasteful duplication of service.
 - c. Provide a transmission study for the example discussed on part c above showing that thermal, voltage, or other issues result in either single or double faults that render tapping the West Route on the Daviess County–Hardin County line not good utility practice.
- A-4.
- a. A two-terminal line is one that connects two substations directly together, typically with a circuit breaker(s) on each end of the line. The “existing Daviess County-Hardin County and Brown North-Hardin County line terminal” referenced in the question are each two-terminal lines. The existing Daviess County-Hardin County line is a unique independent 345kV circuit with two terminals, one at Daviess County and one at Hardin County. The existing Brown North-Hardin County line is a separate, different, and unique independent 345kV circuit with two terminals, one at Brown North and one at Hardin County. Please see Attachment 1. Note that the red (Daviess County-Hardin County line) and blue (Brown North-Hardin County line) lines are unique and separate, and this is *not* a three-terminal situation.

A three-terminal line is one that connects three substations directly together, typically with a circuit breaker(s) at each of the three ends. Relay protection of a three-terminal line is more complex and makes it more susceptible to protection system misoperations (resulting in an unintended outage) as compared to a two-terminal line. As discussed in the response to PSC 2-5, terminating the proposed western 345 kV line from the new Glendale South Substation into the existing Daviess County–Hardin County 345 kV line creates an undesired three-terminal line with a short terminal (the three terminal ends would be at the: 1) Hardin County Substation, 2) Daviess County Substation, and 3) the new Glendale South Substation thus creating the “three-terminal line”). Please see Attachment 2, which is a hypothetical three-terminal circuit.

The “short line segment to the substation” referenced in this question actually represents two independent 345 kV circuits, each with two terminals as referenced in the paragraph above. Both existing lines originate at Hardin County Substation, each having their own circuit breakers, and terminate at different remote substations, Daviess County and Brown North. These existing 345kV lines are built on double circuit lattice steel towers in the short line segment referenced. They are two completely unique and separate 345kV two-terminal lines and thus not a three-terminal line.

The Company’s proposed 345 kV West Route will tap the Hardin County – Brown North 345 kV line and go to the Glendale South 345 kV substation, keeping a preferred two-terminal line configuration. Please see Attachment 3.

- b. The two 345 kV lines in parallel, Hardin County – Daviess County 345 kV line and Hardin County – Glendale South 345 kV line, are two independent circuits. There is no duplication since each line terminates at separate substations, Hardin County to Glendale South and Hardin County to Daviess County. The 345 kV eastern route will continue the connectivity to Brown North substation. As discussed in response to PSC 2-5, terminating the proposed western 345 kV line to Glendale South Substation into the Daviess County – Hardin County 345 kV line would create an undesired three-terminal line with a short terminal.
- c. Consistent with prudent and reliable relaying protection engineering practice, LG&E and KU avoid constructing 3-terminal lines if at all possible. On the LG&E/KU 345kV Bulk Electric System there are no 3-terminal lines with 345kV sources at all three terminals.

While the complexities and difficulties developing protection for 3-terminal lines are well known and documented,^{1,2} studies are not typically performed that would demonstrate the problems associated with 3-terminal lines because they are dependent on many varying parameters such as exact loading conditions and voltage conditions at a specific point in time as well as exact physical location along the line. Simplicity and reliability for the bulk electric system are key considerations and are primary considerations in the two-terminal configuration proposed.

The following references demonstrate the challenges and complexities with 3-terminal systems:

A paper from 2021 written by Schweitzer Engineering Laboratories entitled “Application Considerations for Protecting Three-Terminal Transmission Lines”³ stating in part that, “Three-terminal transmission lines pose protection challenges not encountered with more familiar two-terminal lines.” This indicates a more complex and less reliable system for 3-terminal lines as compared to 2-terminal lines.

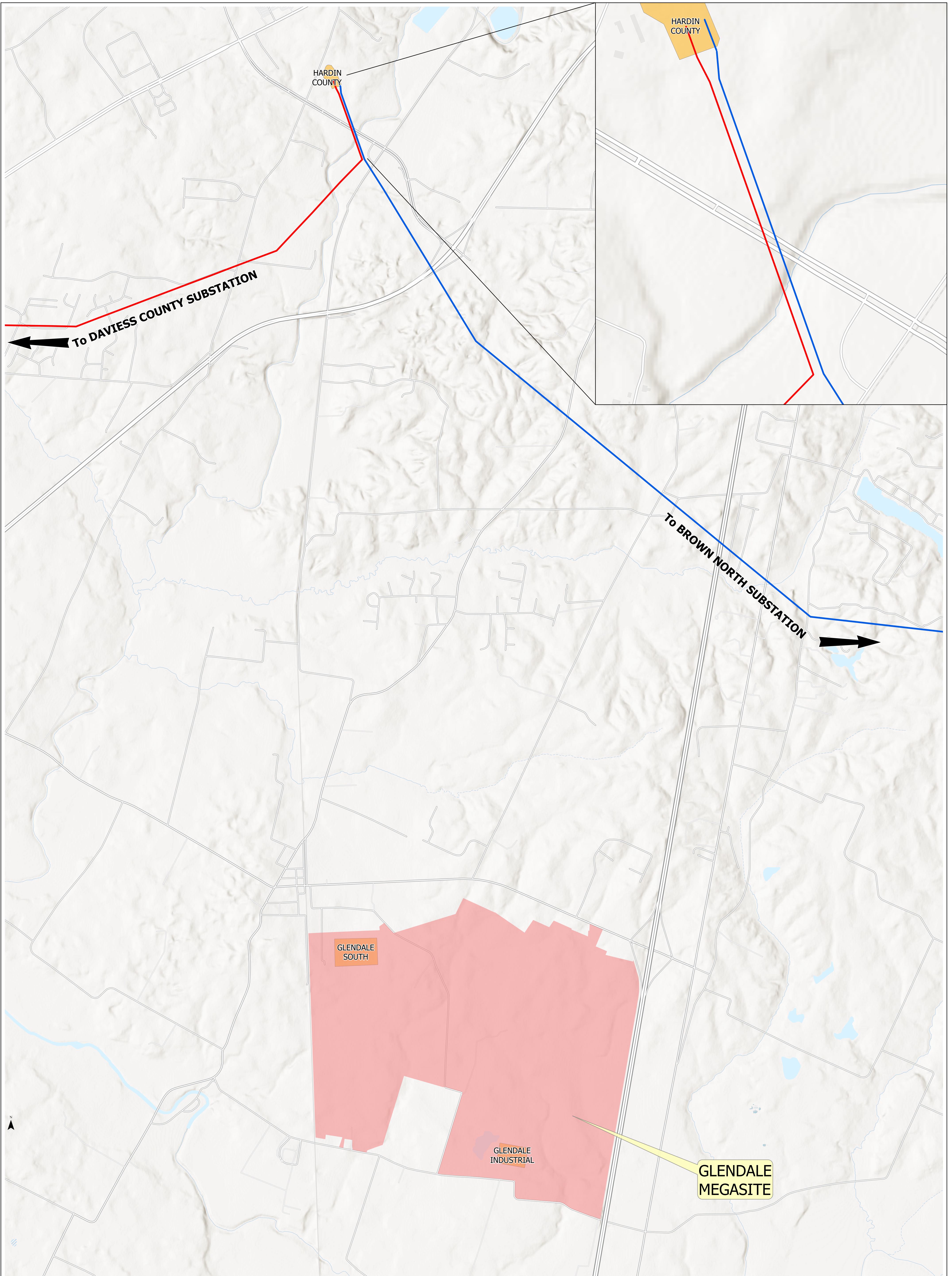
A paper from September 13, 2006 by the North American Electric Reliability Council entitled “The Complexity of Protecting Three-Terminal Transmission Lines”⁴ stating in part that “Three terminal and other multi-terminal line construction projects are generally a trade-off of planning economics and protection complexities, and can, sometimes, lead to compromises in reliability.”

¹ IEEE Std C37.113™-2015 “IEEE Guide for Protective Relay Applications to Transmission Lines”, The Institute of Electrical and Electronics Engineers, Inc.: NY. P. 96 (see Attachment 4).

² Blackburn, J. Lewis, & Domin, Thomas J. (2007). *Protective Relaying: Principles and Applications, Third Edition*. CRC Press (see Attachment 5).

³ See Attachment 6.

⁴ See Attachment 7.



Existing KU 345kV Circuit Configuration



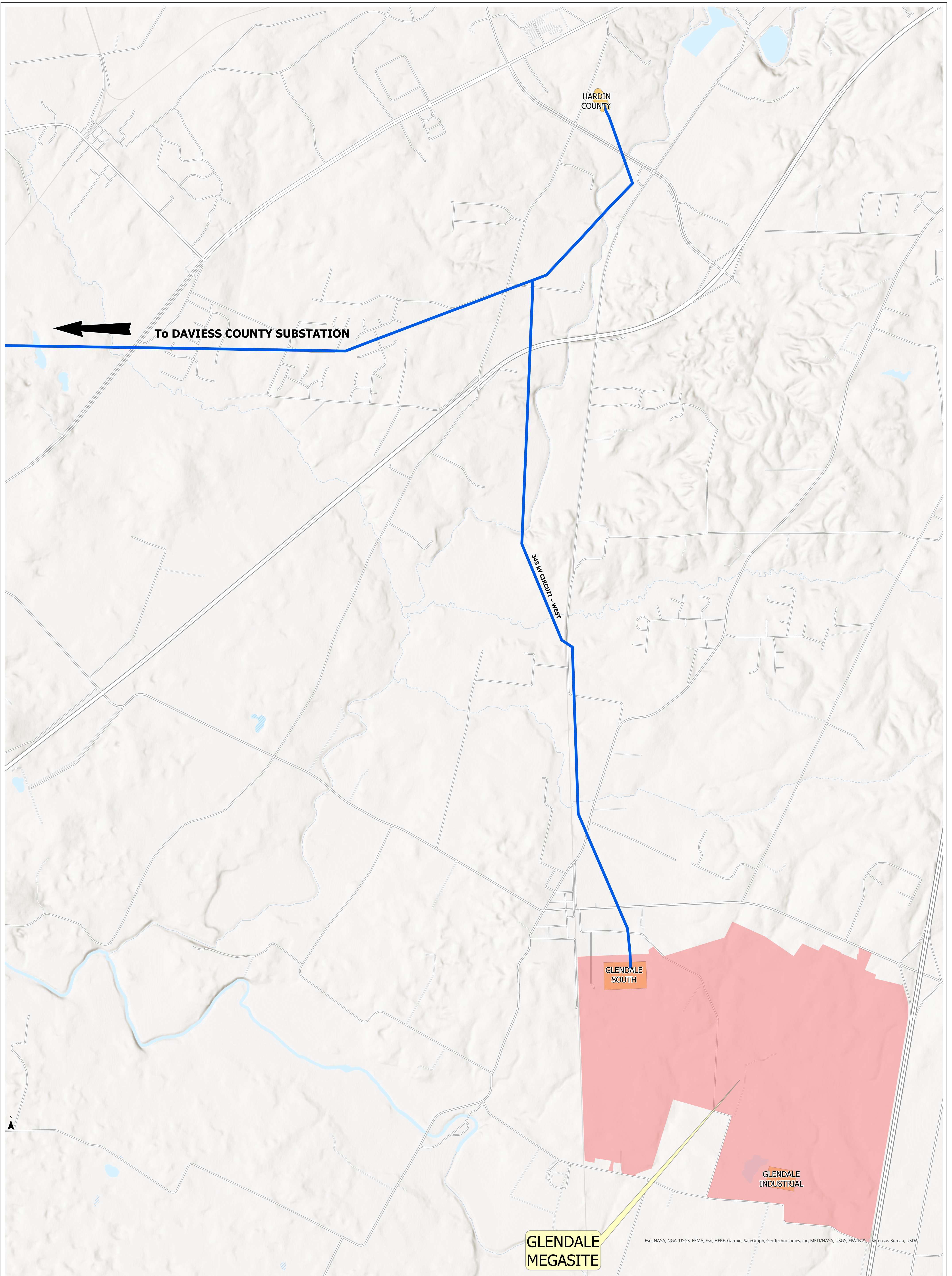
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0 0.13 0.25 0.5 Miles

6/9/2022

- Legend**
- Transmission Circuits
 - Blue line: Brown North - Hardin County
 - Red line: Daviess County - Hardin County
 - Red shaded area: Glendale Megaste
 - Orange shaded area: Electric Substation Boundary



Kentucky Utilities Hypothetical Three Terminal Circuit

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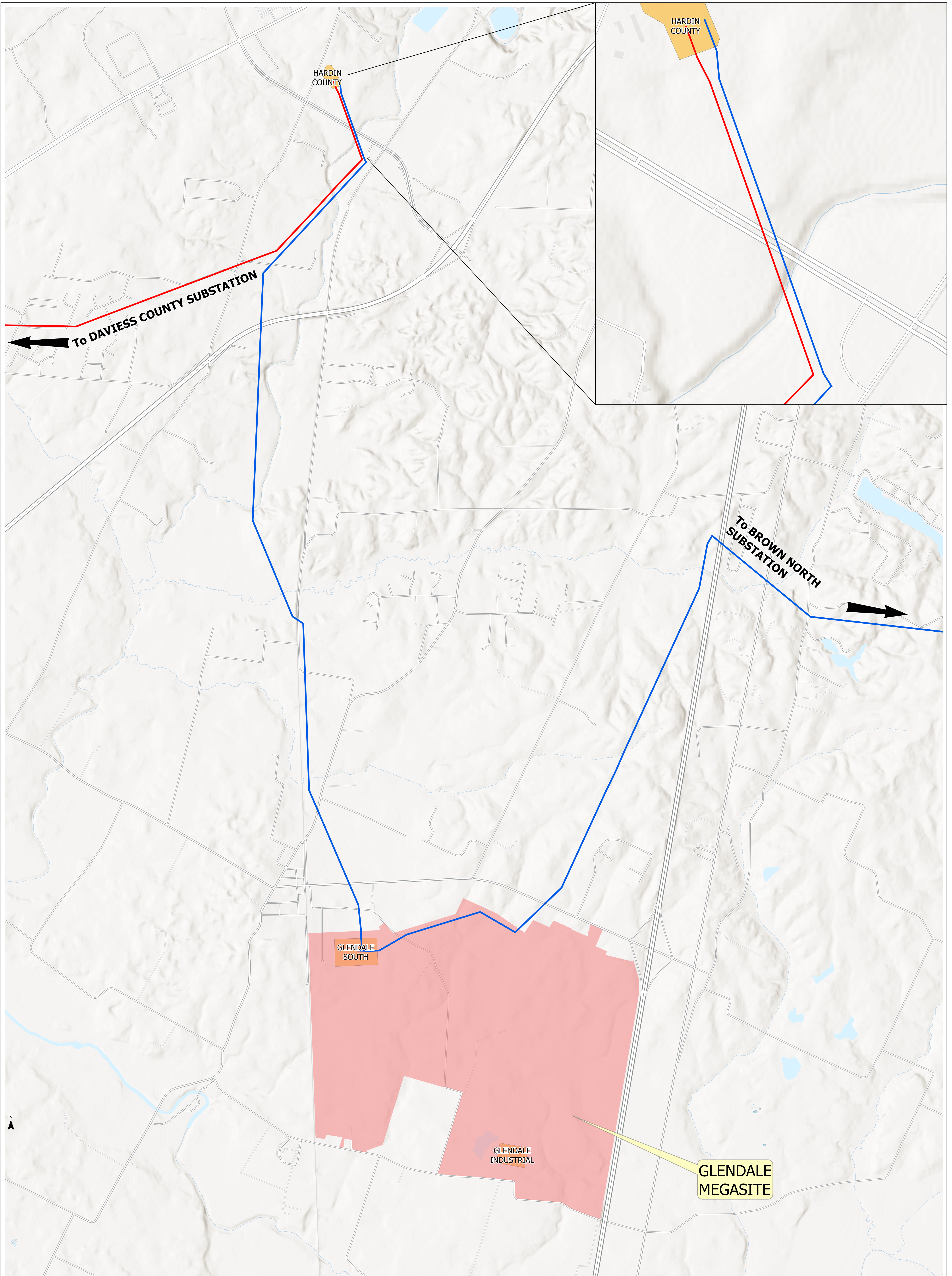
Unless otherwise indicated, all locations are taken from office records and must be verified in the field prior to any construction where there is a possibility of interference with existing KU/LG&E facilities.



0 0.13 0.25 0.5 Miles

6/9/2022

- Legend**
- Transmission Circuit
 - 345 kV
 - Glendale Megaste
 - Electric Substation Boundary



Proposed KU 345kV Circuit Configuration



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0 0.13 0.25 0.5 Miles

6/9/2022

- Legend**
- Transmission Circuits
 - Brown North - Hardin County
 - Daviess County - Hardin County
 - Glendale Megasite
 - Electric Substation Boundary

IEEE Std C37.113-2015
IEEE Guide for Protective Relay Applications to Transmission Lines

opposite directions in the protected line and the situation appears at both terminals to be an internal fault. The root cause is that different directional polarizing methods are used at the line terminals in this case.

This undesired tripping of a line would not occur if line and system negative- and zero-sequence impedances were identical. Normally, these impedances are not identical and, therefore, ground faults in small sections of the remote system parallel to the line appear as internal faults.

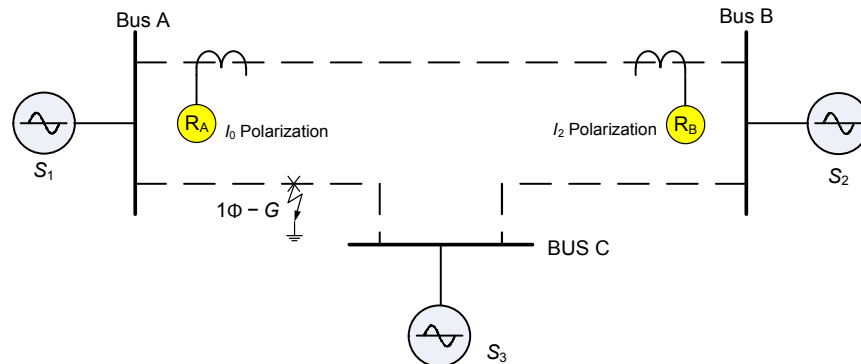


Figure 59—A single-phase-to-ground fault and ground fault relays on an adjacent line

6.6 Problems associated with multi-terminal lines

6.6.1 General

There are two challenges in applying protection for multi-terminal lines as discussed in a PSRC report, “Protection aspects of multi-terminal lines” [B44]:

Trip all terminals simultaneously for an internal fault at any location on the line with any expected distribution of current.

Do not trip any terminal for an external fault at any location on the system with any expected distribution of current.

These challenges are further complicated by the very large number of line configurations with varying numbers of terminals, lengths of lines, and capacities of energy sources and levels of loads. However, the protective systems that are used for two-terminal lines may be adapted for use on multi-terminal lines by choosing appropriate settings or by using additional hardware or software.

6.6.2 Current outfeed

Multi-terminal lines create the possibility of a current outfeed condition. Current outfeed occurs when, due to system source, load, and impedance conditions, current flows out at one or more terminals of a line during an internal fault. This outfeed condition may cause delay in operation or may result in sequential operation of protection systems at different terminals for some types of relays and the communication systems used with them. It is possible that some relays and pilots may not operate at all when current outfeed occurs.

Figure 60 shows an example of an outfeed condition. Distance and directional relays may be affected by the outfeed current at bus B. Consider that the phase angles of all the impedances are identical and the phase angles of all currents shown in this figure are identical as well, so that the calculations remain simple and straightforward.

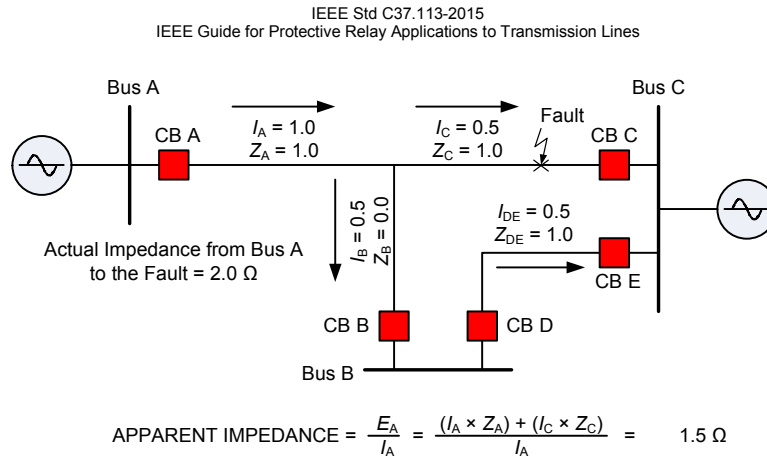


Figure 60—Current outfeed

The apparent impedance seen by the relay at bus A is 1.5 Ω due to the outfeed current at bus B. This measured value is less than the actual impedance to the fault, which is 2.0 Ω. A reverse-looking or blocking, distance, or directional relay at bus B would “see” an internal fault as an external fault and may prevent the pilot protection from operating for this internal fault.

6.6.3 Current infeed

Multi-terminal lines create the likelihood of a current infeed condition. This infeed condition may cause a distance relay not to see a fault beyond the location where the infeed of current occurs until the fault is isolated from the bus closest to the fault.

Figure 61 shows a condition in which there is a current infeed from bus B when there is a fault on the line near bus C. Consider that the phase angles of all the impedances are identical and the phase angles of all currents shown in this figure are identical as well, so that the calculations remain simple and straightforward.

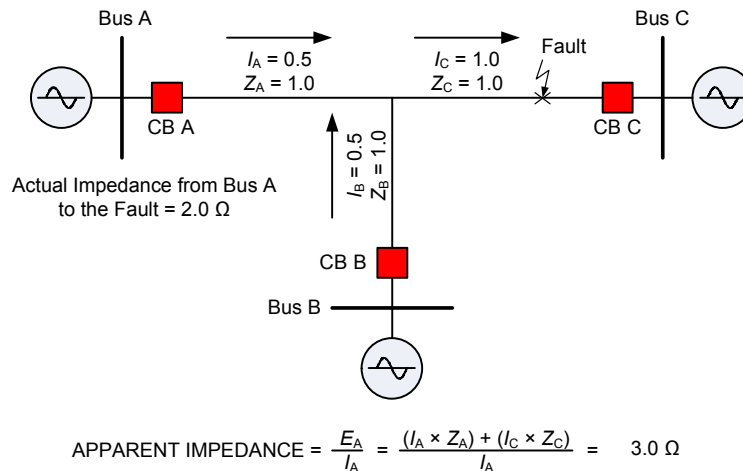


Figure 61—Current infeed

IEEE Std C37.113-2015
IEEE Guide for Protective Relay Applications to Transmission Lines

A distance relay at the bus A terminal of the line would see an apparent impedance of 3.0Ω ; this is greater than the actual impedance to the fault. Current infeed has the effect of causing a distance relay to underreach for all faults beyond the location where the infeed of current occurs. The distance relay could interpret an internal fault as a fault beyond the remote bus, which is bus C in this case.

6.6.4 Relay applications on multi-terminal lines

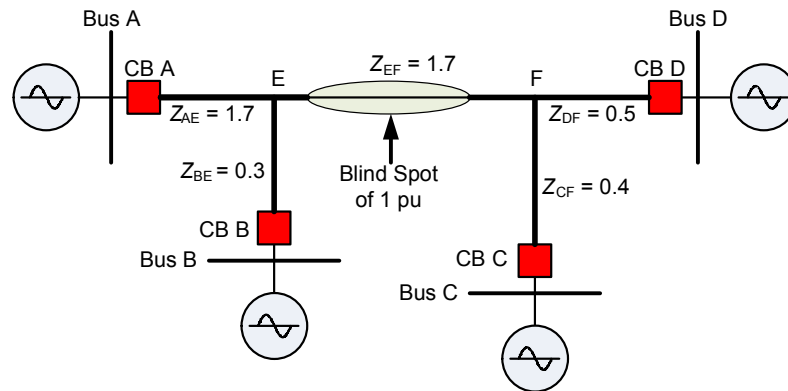
6.6.4.1 General

This subclause covers the issues that concern relay applications on multi-terminal lines and briefly discusses several communication-based relay schemes to protect such lines.

6.6.4.2 Distance relay setting considerations

Multi-terminal lines cause complications in the setting of both underreaching and overreaching distance relays. Zone 1, or underreaching elements, should be set so as not to reach the nearest terminal without considering the effects of current infeed from other terminals. This limitation may cause the application of some of the zone 1 elements to be ineffective on multi-terminal lines that have two of their terminals close together.

It might also result in a section of the line not covered under zone 1 of any relay, as discussed in a PSRC report, "Protection aspects of multi-terminal lines" [B44]. One such case is shown in Figure 62. The thick lines show the parts of the system covered by zone 1 elements. Clearly, the highlighted section of the line becomes a "blind spot"; the zone 1 relays provided at the two terminals of the line are not able to detect faults in this spot. Underreaching schemes cannot be employed for such cases.



All Impedances are in per unit values

Figure 62—A case of unsuitability of underreaching distance scheme

It can become a difficult problem to protect a multi-terminal line that has more than three terminals. Zone 2 elements are normally set to cover those portions of the protected line that are not covered by zone 1. For multi-terminal lines, this setting requires that the effects of infeed and fault resistance be considered. The settings required to cover the entire protected line with some margin could be large because the infeed current can be quite significant. However, if the infeed is not present or is removed by the tripping of a circuit breaker, this large setting may cause the zone 2 to reach beyond the zone 1 relays protecting the lines emanating from the remote bus. If this happens, it may be necessary to coordinate the zone 2 timer of

effect.” Fault current from other lines will cause relays at 1 to underreach. This effect can be seen by considering a solid three-phase fault at F. With $V_F = 0$, the relays at 1 receive current I_{GH} , but the bus G voltage is the drop $Z_{GH}I_{GH} + nZ_{HS}(I_{GH} + I_{HR})$. Thus, the relays at 1 “see” an apparent impedance of

$$\begin{aligned} Z_{\text{apparent}} &= \frac{Z_{GH}I_{GH} + nZ_{HS}(I_{GH} + I_{HR})}{I_{GH}} \\ &= Z_{GH} + nZ_{HS} + \frac{I_{HR}}{I_{GH}}(nZ_{HS}). \end{aligned} \quad (12.2)$$

This is a larger value by the third term, $I_{HR}/I_{GH}(nZ_{HS})$, than the actual impedance, which is

$$Z_{GH} + nZ_{HS}. \quad (12.3)$$

As a result, relay 1, when set to a value of the actual impedance of Equation 12.3, would not see fault F; in other words, relay 1 “underreaches” as a result of the fault contributions from other lines connected to bus H. Setting of the relays for the apparent impedance value has the danger of overreaching and miscoordination when the infeeds are removed or changed by system operation.

The infeed term can be quite large and also variable when a large part of the current fault is supplied by other circuits. The relay underreach will approach the remote bus, but not quite reach it, so primary protection is not inhibited. This is true for a two-terminal line without infeed taps, such as that shown in [Figure 12.12](#).

Undesired operation of zone 3 distance relays, applied for remote backup protection during major system disturbances, has caused the magnitude of the scope of such disturbances to be expanded. Large ohmic settings had been typically applied to the zone 3 relaying, in order to obtain the desired backup protection. Power swings and low voltage conditions that often exist during system disturbances resulted in the impedance seen by the zone 3 relay to be within its operating characteristic for a sufficient length of time for it to initiate a trip command. Such experiences have resulted in utilities restricting the use or reach applied to zone 3 relaying.

12.13 DISTANCE RELAY APPLICATIONS FOR TAPPED AND MULTITERMINAL LINES

Examples of single-tapped lines are shown in [Figure 12.13](#) and [Figure 12.14](#). Some lines have multiple taps (3 or 4). Although these may be economically, or physically, necessary they are always more difficult to protect. To provide

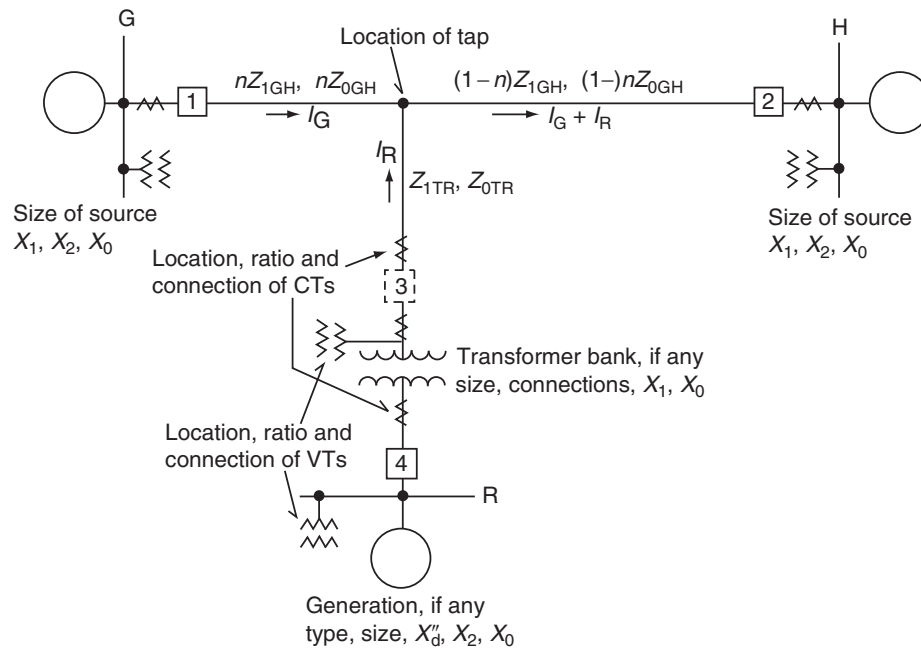


FIGURE 12.13 Typical tapped line and information required for a protection study. Currents are for a fault at bus H.

protection, considerable information is required, such as the type of tap(s) (see Figure 12.13 or Figure 12.14). If the taps are of the Figure 12.13 type, then beyond the normal information for the two-terminal lines, the information outlined on the figure should be supplied or obtained. If a wye–delta transformer bank is included as part of the tap, information that shows how the bank is grounded is required. Amazingly, this information is very frequently omitted from station one-line diagrams.

Consider the line of Figure 12.13; the tap T may be a transformer at or near the line, so that Z_{TR} would be the sum of the impedance from the tap and the transformer bank impedance. Sometimes, the tap ties through Z_{TR} to a bus, as shown in the figure. The tap may serve a load, so that negligible fault

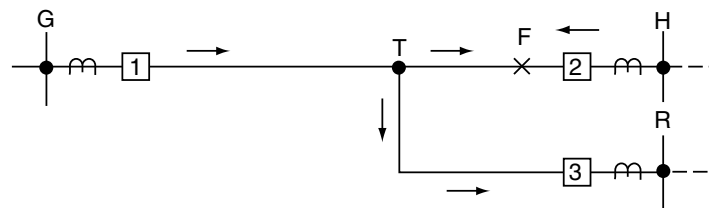


FIGURE 12.14 Multiterminal line where fault current can flow out at one terminal for internal faults.

current is supplied through it to line faults, or it may tie into a fault source at R, as shown by the broken line. Another variation is illustrated in Figure 12.14.

The fundamentals for setting distance relays on these types of lines for primary phase-fault protection are as follows:

1. Set zone 1 for k times the lowest actual impedance to any remote terminal for Figure 12. 13-type circuits, or for k times the lowest apparent impedance to any remote terminal for the special case of Figure 12.14, k is less than 1, normal 0.9.
2. Set zone 2 for a value greater than the largest impedance, actual or apparent, to the remote terminals.
3. The zone 2 time (T_2) must be set such that it does not cause misoperation when any terminal is out of service and, thereby, causes the distance unit to overreach.

For example, assume the high-side breaker 3 exists at the tap; therefore, distance relays would be applied using the high-side CTs and VTs at the tap. For a fault at bus H, the actual impedance from the high side of the tap to bus H is

$$Z_{R \text{ actual}} = Z_{1R} + (1-n)Z_{1GH}, \quad (12.4)$$

but with current from station G to the fault at H. The tap relays sees

$$Z_{R \text{ apparent}} = \frac{Z_{1R} + (1-n)Z_{1GH} + I_{1G}}{I_{1R}(1-n)Z_{1GH}} \quad (12.5)$$

when I_{1G}/I_{1R} is large, which would be with a small tap source where I_{1R} is very small relative to I_{1G} , $Z_{R \text{ apparent}}$ can be quite large requiring long Z_2, Z_3 settings. When breaker G is out of service or breaker 1 at G opens Z_2, Z_3 can overreach considerably. This can result in zone 2 and zone 3 backup being impracticable or requiring extended times.

For some arrangements of circuits, these requirements can make primary protection quite difficult or limited. In Figure 12.13, consider that tap T is very near bus G, so nZ_{GH} is small and $(1-n)Z_{GH}$ is large with Z_{TR} very small. Then zone 1 at breaker 1, bus G must be set at 90% of $(nZ_{GH} + Z_{TR})$, which is a very small value compared with $(1-n)Z_{GH}$. Thus, high-speed coverage of the line is almost negligible.

On the other hand, if the tap is a load transformer where Z_{TR} is high relative to Z_{GH} , zone 1 at breakers 1 and 2 can be set for 90% of the line to provide good high-speed line protection.

If R is a load tap in Figure 12.13, with negligible current to line faults, distance relays (and overcurrent) are not applicable at breaker 3, and basically

are not necessary, for opening breakers 1 and 2 terminates the line fault. The worst case is a small generator or source connected to R , large enough to maintain a fault on the line, but not large enough to support fault-detecting relays. In other words, the impedance to a line fault from bus R is very large and approaches infinity.

For the example in Figure 12.14, current can flow out of the R terminal for an internal line fault near the H bus. Thus, distance or directional relays at breaker 3 see the internal fault as an external one for no operation until after breaker 2 has opened.

Consequently, protection of tapped and multiterminal lines is more complex and requires specific data on the line impedances, location and type of tap or terminal, and fault data, with current distributions for the various system and operating conditions. Most often, except for small transformer load taps, these types of lines are protected best by pilot relaying.

12.14 VOLTAGE SOURCES FOR DISTANCE RELAYS

Three-phase voltage is required and provides reference quantities with which the currents are compared. For phase distance relays, either open-delta, or wye-wye voltage transformers (VTs), or coupling capacitor voltage devices (CCVTs) can be used and connected either to the used line or to the line that is protected. Both are widely used, and the decision is economic as well as involving use of line-side CCVTs for radio-frequency coupling for pilot or transfer trip relaying.

These voltage sources involve fuses—primary and secondary for VTs and secondary for CCVTs. These fuses should be generously sized, carefully installed, and well maintained, as a loss of one or more phase voltages may result in an undesired, unwanted relay operation. Where this is of great concern, overcurrent fault detectors can be added to supervise the trip circuit of the distance relays. For loss of voltage in the absence of an actual fault, overcurrent units would not operate. The disadvantages are the need for additional equipment and the loss of the feature of distance relays operating for fault levels less than maximum load.

Recently, detectors measuring V_0 , but not I_0 , have been used to supervise the relays. This requires wye-grounded-wye-grounded voltage sources.

12.15 DISTANCE RELAY APPLICATIONS IN SYSTEMS PROTECTED BY INVERSE-TIME-OVERCURRENT RELAYS

Zone 1 distance relays can be applied to provide increased instantaneous protection over that obtainable by instantaneous overcurrent relays. This is especially helpful when there is a large variation in fault level because of

Application Considerations for Protecting Three-Terminal Transmission Lines

Robert Jimerson

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Alex Hulen, Ritwik Chowdhury, Neeraj Karnik, and Bernard Matta

Schweitzer Engineering Laboratories, Inc.

Presented at the

74th Annual Georgia Tech Protective Relaying Conference

Virtual Format

April 28–30, 2021

Originally presented at the

74th Annual Conference for Protective Relay Engineers, March 2021

Application Considerations for Protecting Three-Terminal Transmission Lines

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Abstract—Three-terminal transmission lines pose protection challenges not encountered with more familiar two-terminal lines. Criteria for selecting protection element reach and pickup values require consideration of infeed and outfeed. Permissive overreaching transfer trip schemes can have dependability issues; whereas, directional comparison blocking schemes face both security and dependability challenges. A three-terminal line in Oncor Electric Delivery’s power system is considered in this paper. Different topologies and contingencies affect infeed and outfeed levels, requiring careful selection of protection element settings and directional element polarizing quantities. Lessons learned are generalized so they may be applied to optimize security and dependability in any three-terminal line application.

I. INTRODUCTION

Three-terminal line protection presents unique and complex challenges that are not encountered in applications with two-terminal lines. Three-terminal lines, unlike tapped lines, are characterized by the presence of sources or loads and line protection at all line terminals. The IEEE guide for transmission line protection [1] points to the consideration of current infeed and outfeed effects when protecting multi-terminal lines.

Current infeed is a condition where the current contribution from a line terminal can cause a distance relay to underreach [1] [2] [3]. The example system of Fig. 1 shows how current infeed from a relatively strong Terminal B can result in the apparent impedance measured at Terminal A to be 3.0Ω for a fault that is 2.0Ω away, as represented by (1). A higher calculated apparent impedance results in a distance relay underreach at Terminal A (and Terminal B). Section III of this paper provides application considerations when applying distance relays in three-terminal lines.

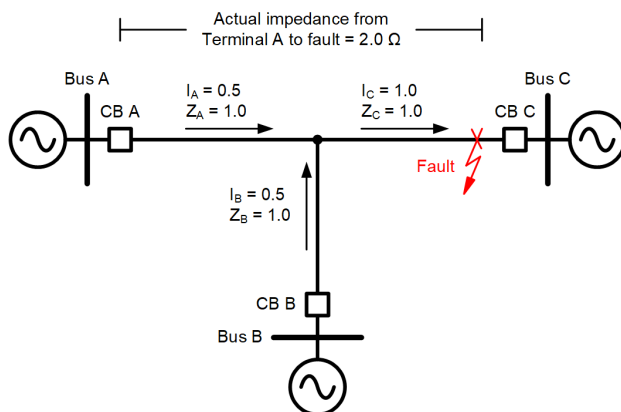


Fig. 1. Current infeed example at line Terminal A

$$\begin{aligned} \text{Apparent impedance} &= \frac{E_A}{I_A} \\ &= \frac{(I_A \cdot Z_A) + (I_C \cdot Z_C)}{I_A} \quad (1) \\ &= 3.0 \Omega \end{aligned}$$

Current outfeed is a condition where, for an internal or external fault, current flows out of one or more line terminals from the protected line because of the impedances in the network and the load flow [1] [2] [3]. Current outfeed can result in both security and dependability issues, depending on the protection scheme and settings applied. This is explained in the following:

- A security issue may result from an external fault at Bus C (shown in Fig. 2) when using a directional comparison blocking (DCB) scheme that is configured based on commonly applied practices for a two-terminal line application where the overcurrent thresholds of the reverse directional elements at Terminal B and Terminal C fail to engage. Section IV provides an overview of these pilot schemes and Section V provides general setting adjustments that ensure secure protective relay behavior.
- A dependability issue may result where the Terminal B relay declares reverse for an internal fault near Bus C, shown in Fig. 3, resulting in a delayed or sequential trip. A sequential trip is a scenario where a relay cannot detect and trip for a line fault until at least one other terminal of the line has opened. Sequential tripping is described in more detail in Section III and Section VI. Section VI also discusses the dependability challenges faced by both permissive overreaching transfer trip (POTT) and DCB schemes. A further dependability concern arises for a breaker-failure scenario where a sequential trip may be further delayed [2]. Section VII discusses the issues and details of the impact on fault-clearing times due to a breaker-failure scenario.

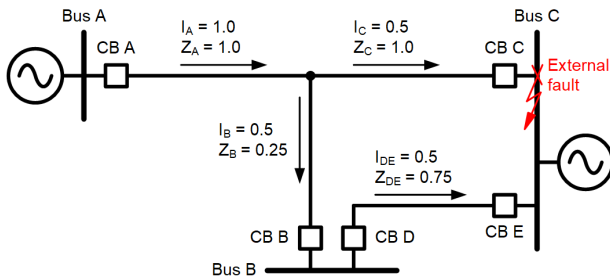


Fig. 2. Current outfeed at weak-terminal Bus B for an external fault

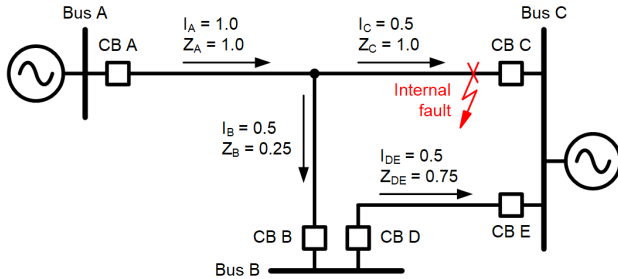


Fig. 3. Current outfeed at weak-terminal Bus B for an internal fault

Several factors influence the decision to configure a transmission line with three terminals, such as economics, constrained lead time, regulatory approvals, right-of-way availability, line overloads, and system performance requirements [2]. With the rapid penetration of inverter-based resources (IBRs), multi-terminal lines are increasing in popularity [4]. A line terminal supplied by an IBR often provides a strong zero-sequence path due to the transformer configuration but may behave as a weak positive-sequence and negative-sequence source, requiring application considerations [5] [6] [7] [8]. Section VIII shows how the choice of the directional element polarizing quantity may alleviate some protection challenges in a three-terminal line application.

This paper is based on a three-terminal line application in the Oncor system described in Section II. It discusses the unique challenges of three-terminal line protection and uses the Oncor system to identify some of the solutions applied. We then generalize the solutions so they may be applied to other systems to increase reliability in any three-terminal line application.

II. ONCOR THREE-TERMINAL LINE SYSTEM

Oncor Electric Delivery is a regulated electric distribution and transmission business that provides power to customers equaling about one-third the state of Texas' population via more than 139,000 miles of distribution and transmission lines. The Oncor service territory contains a sprawling combination of north central, east, and west Texas that includes high-growth areas in the Dallas-Fort Worth Metroplex as well as west Texas oil and gas commercial loads.

The Oncor transmission lines include a 345 kV bulk electric system backbone with a 138 kV load serving system, as well as some 69 kV lines. The 138 kV transmission lines are mainly composed of two-terminal lines, but there is also a subset of three-terminal lines. The three-terminal lines are mainly

employed due to the limitations of substation breaker positions, land, and right-of-way, among other considerations.

Transmission lines in the Oncor system use redundant microprocessor-based relays to protect the line. The 138 kV and 345 kV lines have communications-assisted pilot protection mainly via DCB schemes, with a lesser proportion of POTT schemes and line current differential relaying. A combination of power line carrier (PLC) and direct fiber optics is used as pilot-scheme communications media in the Oncor system.

The 138 kV three-terminal line studied here is in a landlocked area of the Dallas-Fort Worth Metroplex Area with a unique configuration where several three-terminal lines exist to serve loads. This line uses a DCB scheme for pilot protection. As shown in Fig. 4, this line is connected between Bus A, Bus B, and Bus C (referred to as Line ABC hereafter). The impedance Z_{BC} represents the transfer impedance from Bus B to Bus C, comprises two parallel lines of varying lengths, and varies depending on the network state. Bus A comprises two 138 kV buses and is attached to a combustion unit generation station, typically only energized during peak loading. The two 138 kV buses at Bus A are normally connected via an autotransformer, but there is an operating constraint to separate the buses when more than one of the three combustion generation units are in service. Therefore, both configurations of Bus A must be considered when calculating relay settings for Line ABC.

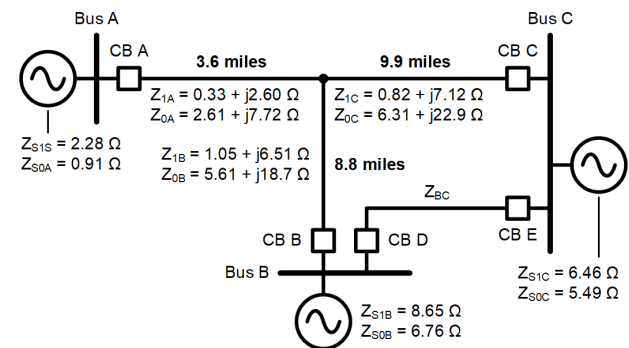


Fig. 4. Oncor three-terminal line impedances

Bus B borders the downtown city of Fort Worth distribution network system. The distribution network is connected to the 138 kV system via wye-delta-wye transformers where the low sides are tied together. This configuration produces a significant zero-sequence fault current contribution from all lines connected at Bus B. Lastly, Bus A, Bus B, and Bus C have other two- and three-terminal lines connected between them, which are not shown. This configuration produces a high amount of mutual coupling among all lines in this area. Fig. 4 shows the source impedances behind each terminal of the 138 kV Line ABC, with each source impedance based on a remote bus fault at the closer remote terminal bus with the other remote terminal breaker open to eliminate infeed/outfeed. It is evident that Bus A is a stronger source of fault currents in comparison to Bus B and Bus C. Additionally, it is located closer to the tap point of Line ABC. This paper will discuss challenges in setting protective relays for Line ABC.

III. DISTANCE ZONES IN THREE-TERMINAL LINES

Transmission lines are protected by distance elements in relays installed at all line terminals based on line-impedance data. Distance relay schemes may employ mho characteristics and separate zones, such as those shown on the R-X diagram in Fig. 5. Phase distance zones and ground distance zones are used in relay schemes for protection of the various fault types.

A. Traditional Two-Terminal Line Distance Element Considerations

The distance relays use an underreaching Zone 1 phase that is typically set to approximately 80 percent of the line impedance of a two-terminal line. Zone 1 ground is generally set at 80 percent of the smallest apparent impedance of the line under system contingencies, accounting for the effect of mutual coupling, which must be considered for ground faults. Zone 1 has instantaneous timing to trip the breakers for fast clearing of line faults. The underreaching nature of this zone is necessary due to possible inaccuracies in current transformers, relays, the short-circuit model, and to account for system transient effects.

Distance relays also use an overreaching Zone 2 to cover protection of the remaining portion of a two-terminal transmission line. The overreaching phase distance Zone 2 is typically set to 125 percent or more of the line impedance with a time delay of 20 to 30 cycles to coordinate with any distance zones exiting the remote-end terminal, as well as breaker-failure schemes of the remote bus. Ground distance Zone 2 is similarly set to 125 percent of the apparent impedance of the line with a similar time delay, considering the effect of mutual coupling. Zone 2 may also be used in pilot schemes, such as DCB and POTT, to obtain high-speed protection. Additional overreaching zones with larger reaches are sometimes employed for functions such as remote breaker-failure backup.

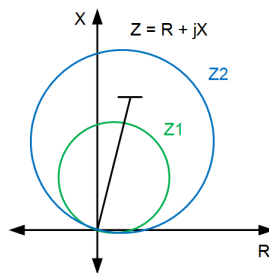


Fig. 5. R-X distance relay diagram

B. Three-Terminal Line Overreaching Distance Element Considerations

The distance zone principles for two-terminal lines can be applied to protect an entire three-terminal line. The addition of the third terminal introduces some challenges for setting the zones of protection. The three line sections connected to each terminal rarely have the same distance to the line tap point, so there is usually a short end and a long end of varying distance from the respective terminal being set. The overreaching Zone 2 on all three terminals must be set equal to or greater than 125 percent of its longest end line apparent impedance to maintain a fully dependable distance relaying scheme for a

three-terminal line. Additionally, the effect of current infeed must be considered when setting the overreaching Zone 2.

As mentioned in Section I, the relative source strength of a terminal will introduce current infeed into the three-terminal line, thus adding to the apparent impedance detected by the other two terminals for line faults. When setting the distance relay at Terminal A (in Fig. 1), the relay setting engineer must consider both the line impedance from Terminal A to Terminal C and the apparent impedance resulting from current infeed from Terminal B for faults near Terminal C. The relay setting engineer should perform fault simulations of a line-end fault and a close-in fault at Terminal C with the terminal closed to obtain the maximum apparent impedance as detected by Terminal A for all internal faults. The line impedance from Terminal A to Terminal B must also be considered, as does the apparent impedance for faults near Terminal B from additional fault simulations. Simulations should be performed under various system contingencies and operation scenarios to determine the worst-case resulting apparent impedance. Terminals that experience outfeed may detect some internal faults near the remote terminals in the reverse direction, so the fault simulation contingencies should include separate remote terminal-open scenarios. This simulates a case where the remote Zone 1 instantaneous element trips the breaker, redistributing the fault current and allowing the local Zone 2 element to now detect the fault as forward. The overreaching Zone 2 of Terminal A may then be set above 125 percent of the greatest of these apparent impedances to fully protect the three-terminal line and address any underreaching concerns.

The effect of infeed in setting the Terminal C overreaching Zone 2 reach for Oncor Line ABC is shown in Fig. 6. C Zone 2_1 is shown in green, with a zone reach of 17.2 primary Ω based on a 125 percent multiple of the greater of the line impedances from Terminal C to Terminal A and from Terminal C to Terminal B, without considering the effect of infeed. Separate three-phase line-end faults are simulated in front of Terminal A and Terminal B, both with infeed from the other terminal and with the other terminal opened to eliminate infeed, for a total of four faults. Faults F1 and F2 are bolted line-end faults at Terminal A, with the Terminal B breaker open and closed, respectively. Faults F3 and F4 are the faults at Terminal B, with the Terminal A breaker open and closed, respectively. The effect of infeed on the apparent impedance at Terminal C is evident in the increase in impedance from F1 to F2, and especially from F3 to F4. The proposed C Zone 2_1 reach is sufficient to cover the faults F1, F2, and F3, but fault F4, an internal fault with infeed, is well outside the zone reach. C Zone 2_2, shown in blue, was created with a zone reach of 37.4 primary Ω based on 125 percent of the worst-case simulated apparent impedance for a line-end fault under an additional single contingency (not pictured) and has sufficient margin to cover faults F1 to F4. Line-end faults are considered because these result in the largest apparent impedances.

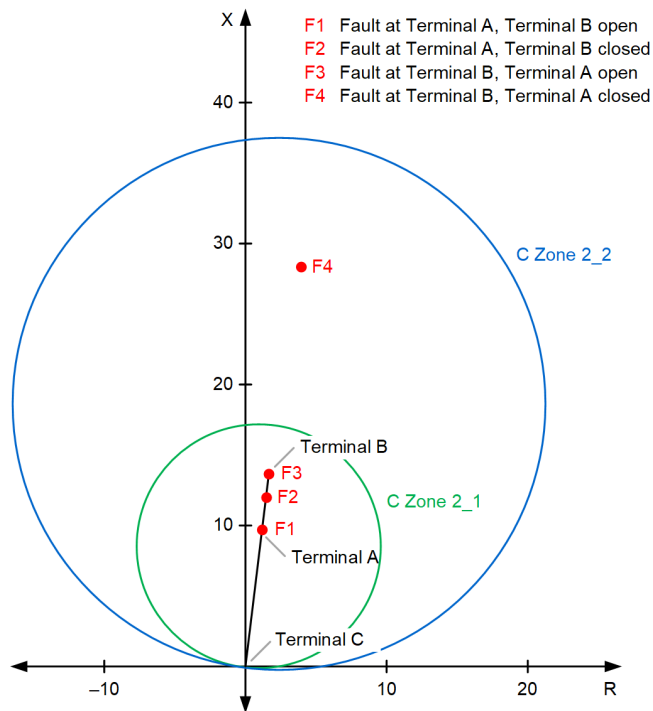


Fig. 6. Terminal C phase Zone 2 reach for line-end faults with and without infeed

The resulting overreaching Zone 2, considering the impedance of the longest end section and the apparent impedance from current infeed, can become quite large. The reach of Zone 2 must carefully be checked for coordination with all terminals exiting both remote terminal buses. The relay setting engineer should especially check relay coordination with relaying located at the closer terminal of the three-terminal line, although all coordination must be verified. Coordination issues were not exhibited in Oncor Line ABC, but the system shown in Fig. 7 provides an example. The Terminal C Zone 2 will overreach the Zone 1 of the remote relaying at Bus B, as the line section from Terminal C to Terminal B is the shorter of the two. In this case, the time delay of Terminal C Zone 2 must be set slower by an acceptable margin than that of the overlapping Zone 2 elements of the remote Bus B relaying to coordinate and obtain a selective system. Lastly, the relay setting engineer must verify that the fault current supplied during simulation will be enough to pick up the fault detectors for the distance Zone 2 to assert.

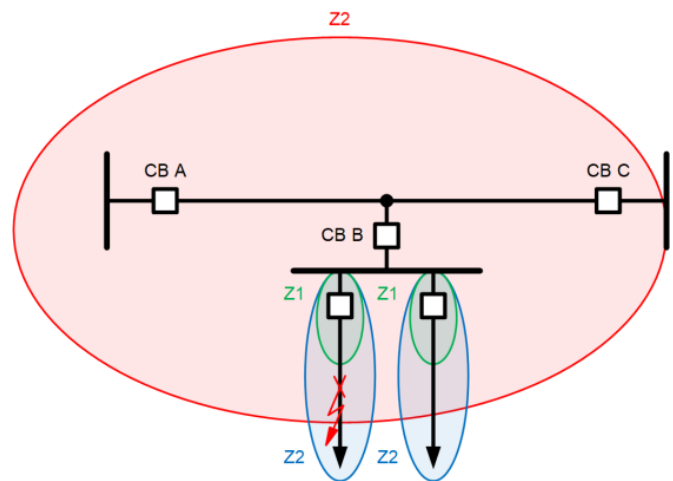


Fig. 7. Three-terminal line Zone 2 coordination

The potentially large reach of the overreaching Zone 2 in a three-terminal line system should prompt the relay setting engineer to check whether there are any line loadability concerns. According to the NERC PRC-023 standard [9], the phase protective relay element should not limit the loading capability of the transmission line. All phase distance zone elements must be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees to compare with the facility rating of the transmission line, as outlined by [10]:

Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

$$Z_{\text{RELAY } 30} = \frac{0.85 \cdot V_{LL}}{\sqrt{3} \cdot 1.5 \cdot I_{\text{RATING}}} \quad (2)$$

where:

$Z_{\text{RELAY } 30}$ is the relay reach in primary Ω at a power factor angle of 30 degrees.

V_{LL} is the rated line-to-line voltage.

I_{RATING} is the facility rating.

The larger the mho distance zone reach, the less the loading of the line tolerated by the relay system, so this is an important check for overreaching zones in a three-terminal line. The use of the load encroachment feature available in many relays can help mitigate these loadability concerns. Load-encroachment settings define an impedance region for which it will block the phase distance zone element from operating. Reliance on load encroachment does have limitations. As explained in [11], the probability of the mho distance element tripping on volt-ampere reactive (VAR) flow during system disturbances increases as the mho distance element reach increases, even when load encroachment is applied. Maintaining adequate loadability as the reach of the mho element is increased beyond the value given in (2) requires judgment by engineers. Reach settings beyond 150 percent of the value of (2) should be scrutinized.

C. Three-Terminal Line Underreaching Distance Element Considerations

Underreaching Zone 1 elements applied to three-terminal lines must not overreach either remote end under any operating condition. Setting Zone 1 for 80 percent of the impedance to the closer remote terminal, with the third terminal open to remove outfeed, may be sufficient for some three-terminal lines that will not experience outfeed [2]. However, in cases of lines with relatively weak sources at one or more terminals and strong system interconnections between terminals, the presence of current outfeed can cause relay distance elements to overreach. For the external fault at Bus C shown in Fig. 2, Zone 1 at Terminal A calculates an apparent impedance that includes the impedance to the tap point, plus the parallel impedances from the tap point through both remote terminals to the fault. This apparent impedance must be considered in selecting a secure reach for Zone 1 because the apparent impedance may be smaller than the line impedance to the closest terminal.

Consider Oncor’s Line ABC shown in Fig. 4. When determining the Zone 1 phase distance reach for Terminal A, taking 80 percent of the lower of the impedances from Bus A to Bus B and from Bus A to Bus C, without considering outfeed, gives a reach of 7.37 primary Ω . Fig. 8 shows the Terminal A relay set with this 7.37 primary Ω reach as “Zone 1 Initial,” in green, on an R-X diagram.

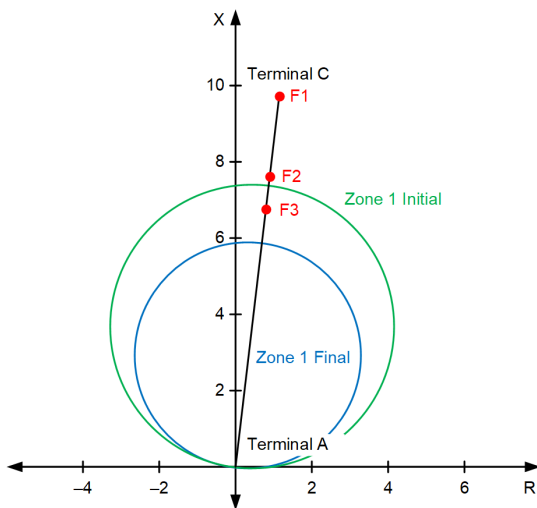


Fig. 8. Terminal A phase Zone 1 reach for remote bus faults

Three separate external faults are placed at Bus C under different conditions, plotted in Fig. 8, for which the Zone 1 element operation is not desirable. Fault F1 is a three-phase fault at Bus C, with the Terminal B breaker open, eliminating any outfeed. F1 plots at an apparent impedance of 9.79 primary Ω , well outside the zone reach. Fault F2 is a three-phase fault at Bus C under normal operating conditions with the breaker for Terminal B closed, with an apparent impedance of 7.64 primary Ω , just outside the zone reach, with an effective margin of 96 percent. For a fault F2 scenario, the relatively weak source at Bus B and the other system interconnections between Bus B and Bus C cause significant current outfeed at

Terminal B, resulting in this reduced apparent impedance. As this simulated apparent impedance with outfeed is determined with less confidence than the line impedance, additional margin may be considered when the reach is set based on the apparent impedance, which makes this 96 percent margin insufficient. Fault F3 is a three-phase fault at Bus C, with the breaker at Terminal B closed, and a line outage at Bus B. This outage causes the already weak source at Bus B to weaken further, leading to greater current outfeed at Terminal B. The F3 apparent impedance maps at 6.85 primary Ω , which is within the initial 7.37 primary Ω Zone 1 reach. The “Zone 1 Final” reach of 6.00 primary Ω , 81 percent of the lowest apparent impedance, shown in blue in Fig. 8, was selected as the Zone 1 phase distance reach at Terminal A to address the simulated overreach in the presence of outfeed.

In addition to outfeed, mutual coupling with the line must be considered in setting ground distance elements. Differences in the sequence networks and mutual coupling can result in substantially different current distributions; thus, outfeed may occur under different conditions between phase and ground faults. A thorough study is necessary to account for these differences, and different reaches between phase and ground distance elements may result. For example, the Zone 1 ground distance element at Terminal A was set with a reach of 4.74 primary Ω , which is shorter than the 6.00 primary Ω reach used for the phase element.

Since underreaching zones must account for the impedance to the closer terminal, and may be further reduced for outfeed considerations, the resulting short zone reaches in certain line configurations could lead to a portion of the protected line that is not covered by any Zone 1 element. While this was not a concern on the Oncor Line ABC, the example line shown in Fig. 9 has a Zone 1 “blind spot,” highlighted in yellow, due to the relatively long leg to Bus C. Pilot schemes employing overreaching elements, such as DCB and POTT schemes or current differential schemes, can be used to facilitate fast tripping for this portion of the line, but direct underreaching transfer trip (DUTT) and permissive underreaching transfer trip (PUTT) schemes should not be used because they employ underreaching zones, as discussed in Section VI.

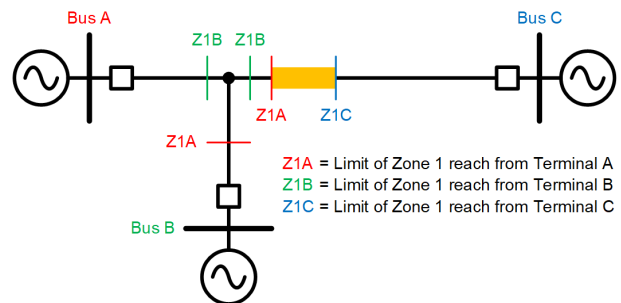


Fig. 9. Zone 1 blind spot (highlighted yellow) in a three-terminal line

Zone 1 elements play an important role in the protection of three-terminal lines with outfeed. During an outfeed scenario, one of the line terminals may detect an internal fault as reverse. Thus, to clear the fault in a timely manner, the Zone 1 element at one of the other terminals may have to trip to start the

sequential tripping of the internal fault. When the breaker opens, fault currents redistribute, allowing the terminal that previously detected the fault as reverse to detect it as forward and trip with its overreaching distance element. As described in Section VI.A, Zone 1 elements are also critical in the sequential tripping of internal faults via a pilot scheme. If there is a possibility of outfeed for a fault in the Zone 1 blind spot, the engineer should investigate whether the outfeed can be mitigated by choosing different polarizing quantities (see Section VIII.C) or consider applying current differential protection for the line.

D. Summary

Distance elements are liable to both underreach and overreach on three-terminal lines due to the presence of current infeed and outfeed, respectively. Therefore, overreaching elements must be set quite large, which can lead to remote coordination and loadability concerns. On the other hand, underreaching elements may have to be set relatively short, leading to potential Zone 1 blind spots. Comprehensive short-circuit model analysis of the protected line is essential to setting reliable distance zone reaches.

IV. PILOT SCHEME OVERVIEW

Many DCB and POTT schemes use phase distance elements and either ground distance or directional ground overcurrent elements, or both, to provide high-speed protection for the entire line [1] [12] [13]. An overview of these schemes and their application to three-terminal lines is provided in the following.

A. DCB Scheme in Two-Terminal Lines

A brief overview of the DCB scheme for a two-terminal line is provided in Fig. 10 and Fig. 11. The pilot-tripping element at each terminal employs an overreaching forward distance zone or forward directional ground overcurrent element set to detect internal line faults with fault resistance. The pilot-blocking element is a reverse distance zone or a reverse directional ground overcurrent element that keys a block signal that is communicated to the remote end for external faults. The pilot-blocking elements are set to have a larger reach or lower pickup in primary A than the remote-end pilot-tripping elements. In some applications, an additional nondirectional element is used to provide a relatively fast key of the block signal. Note that the nondirectional elements are not discussed in this paper.

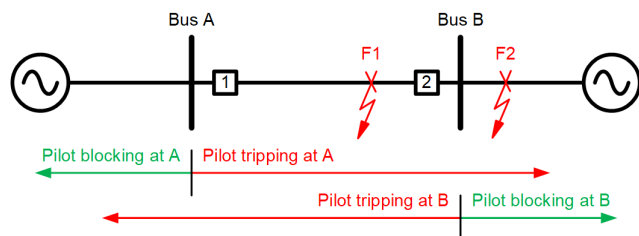


Fig. 10. Pilot-tripping and pilot-blocking zones in two-terminal lines

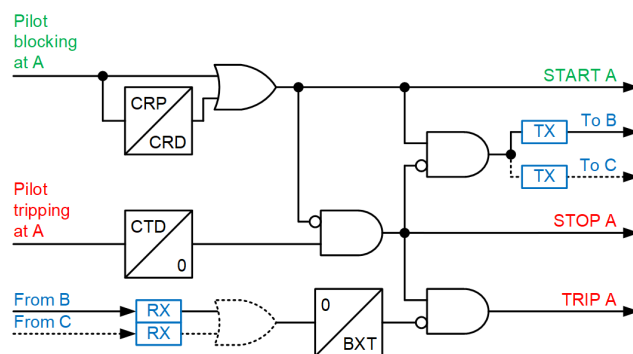


Fig. 11. Two- and three-terminal DCB scheme for a relay at Terminal A (relays at Terminal B and Terminal C are logically similar)

For a DCB implementation over a PLC channel, the START signal is provided to an on/off carrier transceiver to initiate a block signal transmission to the remote terminal. The STOP output to the carrier transceiver stops the block signal transmission and takes precedence over the START transceiver input. For DCB schemes over digital communications media, the TX logic in Fig. 11 is used to send a block signal. The TX logic has stop precedence.

Referring to Fig. 10 and Fig. 11, focusing on Terminal A, the DCB scheme behaves as follows. For fault F1 internal to the transmission line, the pilot-tripping element at Terminal A picks up, and after a short coordination time delay (CTD), trips after not receiving a block signal from the remote end. For a fault external to the line, such as F2, the reverse pilot-blocking element at Terminal B picks up and issues a block signal to Terminal A relaying. The pilot-tripping element at Terminal A may pick up, but the block signal is received before CTD times out, and the relay refrains from tripping. A block extension timer (BXT) is used to maintain the blocking for momentary gaps in the received signal due to communications channel issues like carrier holes.

The DCB scheme is considered very dependable [1] because it operates when no block signal is received, whether that is due to no block signal being issued or due to a communication failure.

DCB schemes typically include current reversal logic to accommodate sequential clearing operations on parallel transmission paths. For a fault near one terminal of a parallel line, the underreaching instantaneous elements at the near terminal may trip faster than the remote terminal relay elements. The resulting current reversal on the healthy protected line caused by this sequential clearing on the parallel line can result in a dropout of local reverse pilot-blocking elements prior to the dropout of remote pilot-tripping elements [1]. The current reversal dropout (CRD) delay timer shown in Fig. 11 is included to prevent undesired trips under this scenario by continuing the block signal for a period of time after the pilot-blocking element deasserts. The current reversal timer has a short current reversal pickup (CRP) timer that is typically one cycle to ensure an external fault has occurred before the CRD time is executed.

B. DCB Scheme in Three-Terminal Lines

The DCB scheme may be applied to a three-terminal line, as shown in Fig. 11, with the inclusion of the dotted portions. Pilot-tripping elements will be similarly employed in each line terminal relaying, though pilot-tripping distance elements must overreach both remote terminals and account for current infeed at the tap point, as discussed in Section III. The pilot-blocking elements must be set more sensitively than in the two-terminal application if outfeed is possible to achieve the desired security for external faults, which is expanded in Section V.

The DCB scheme tripping and blocking logic for a three-terminal line is very similar to that for a two-terminal line. Terminal A, Terminal B, and Terminal C trip for internal fault F3 in Fig. 12 after a delay of CTD and having not received a block signal. For external fault F4, Terminal A and Terminal B refrain from tripping after receiving a block signal from Terminal C. Note that a block signal from one terminal is sufficient to inhibit pilot tripping.

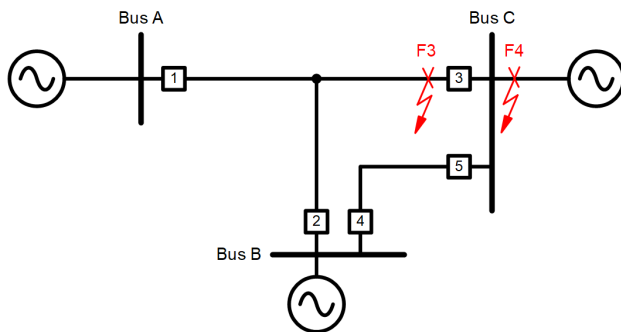


Fig. 12. Fault locations on a three-terminal line

C. POTT Scheme in Two-Terminal Lines

The two-terminal line POTT scheme employs pilot-tripping elements in the form of forward overreaching distance or directional overcurrent elements to send a permissive signal to the remote terminal and to trip the local breaker if a permissive signal is correspondingly received from the remote terminal. Reverse-looking distance or directional overcurrent elements are also included in the scheme as pilot-blocking elements used in current reversal logic [1] [12] [13]. Reference [13] discusses the use of these pilot-blocking elements in hybrid POTT scheme implementations for echo keying logic. The pilot-tripping and pilot-blocking zones are illustrated in Fig. 10.

The POTT scheme is illustrated in Fig. 13. The fault locations indicated in Fig. 10 show that for an internal fault F1 on the transmission line, the pilot-tripping element at Terminal A detects a forward fault and sends a permissive signal to Terminal B. The pilot-tripping element at Terminal B also detects the forward fault and sends a permissive signal to Terminal A. At both Terminal A and Terminal B, the pilot-tripping elements are picked up and a permissive signal is received; thus, both relays trip their respective breakers.

Now, a nearby external fault behind Terminal B, F2 in Fig. 10 is considered. The pilot-tripping element at Terminal A detects the fault in the forward direction and sends a permissive signal to Terminal B. At Terminal B, the fault appears in the

reverse direction. Although the Terminal B relay receives the permissive signal from Terminal A, because the pilot-tripping elements do not assert, the relay will not trip for this external fault and no permissive signal is sent to Terminal A. At Terminal A, since no permissive signal was received from the remote end, the relay refrains from tripping under the POTT scheme logic.

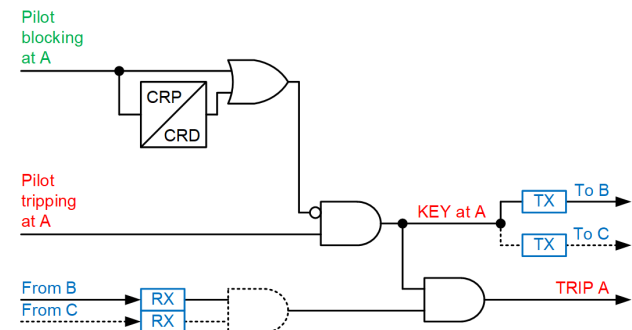


Fig. 13. Two- and three-terminal POTT scheme for a relay at Terminal A (relays at Terminal B and Terminal C are logically similar)

Current reversal logic, which is similar to the logic in DCB schemes, is employed to prevent a misoperation for a current reversal scenario. The pilot-blocking elements have a dropout timer to prevent tripping and keying the remote end following a reverse fault detection. The CRP and CRD delays are typically the same in POTT and DCB schemes. A POTT scheme is considered secure [1] because the scheme does not issue a trip when no permissive signal is received, whether that is due to no permissive signal being issued or due to a communications failure.

D. POTT Scheme in Three-Terminal Lines

The three-terminal POTT scheme application is an extension of the two-terminal scheme, as shown in Fig. 13, including the dotted portions. The differences are as follows:

- The forward distance or directional overcurrent pilot-tripping elements for a three-terminal line are set to overreach both remote terminals while accounting for current infeed at the tap point, as discussed in Section III.
- For the three-terminal POTT scheme, permissive signals are required from both remote terminals for the local terminal to issue a pilot trip.

The POTT scheme tripping logic for a three-terminal line is similar to that of a two-terminal line. The fault locations indicated in Fig. 12 show that Terminal A, Terminal B, and Terminal C trip for an internal fault F3 after receiving permissive signals from both of their respective remote terminals. For an external fault F4, Terminal A and Terminal B receive a permissive signal from each other, but refrain from tripping because no permissive signal is received from Terminal C. At Terminal C, though permissive signals are received from both remote terminals, no trip occurs because the fault is not detected by the pilot-tripping elements.

V. PILOT SCHEME SECURITY

DCB schemes may encounter security issues when applied to three-terminal lines if current outfeed is not accounted for. The security of directional ground overcurrent schemes and distance schemes are discussed in the following subsections. While the discussion in this section focuses on the DCB scheme, hybrid POTT schemes that employ reverse-looking pilot-blocking elements [13] face similar security concerns.

A. Security Challenges to Ground Overcurrent Element-Based Pilot Schemes Due to Outfeed

Pilot-tripping ground overcurrent pickups are set to detect internal faults under contingencies, with margin, for dependable operation. It is essential that a pilot-blocking element at a terminal detects all external faults that are within the reach or sensitivity of the pilot-tripping elements at the other terminals. Fig. 14 shows the zero-sequence impedance network for a two-terminal line, neglecting zero-sequence charging capacitance. Both relays measure the same zero-sequence current for an external fault; therefore, setting the Terminal B blocking element pickup below the Terminal A tripping element pickup ensures the blocking element picks up for all external faults that are within the sensitivity of the tripping element. The setting criterion in (3) is applicable, where $32F50_A$ is the forward pilot-tripping ground overcurrent pickup at Terminal A, $32R50_B$ is the reverse pilot-blocking ground overcurrent pickup at Terminal B, and k_1 provides a margin typically chosen between 1.25 to 2.0. Values are calculated in primary A to account for any difference in current transformer ratios at the terminals. The pilot-tripping element pickups may be set differently at the two terminals, so (3) is applied separately to determine the respective pilot-blocking element pickup for each terminal.

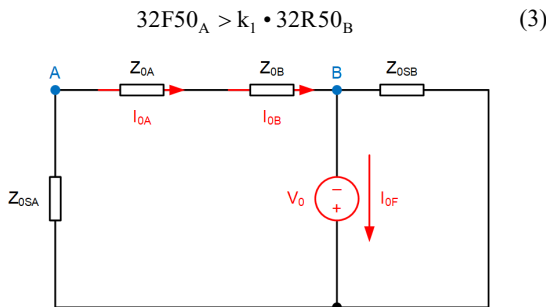


Fig. 14. Two-terminal zero-sequence impedance network for an external ground fault

The zero-sequence impedance network for a three-terminal line with no connections between the terminals, except for the line, is shown in Fig. 15. The setting criterion of (3) is effective for the system configuration because, for an external fault, the blocking element measures the additional contribution from the third terminal, making the blocking element even more sensitive relative to the tripping elements.

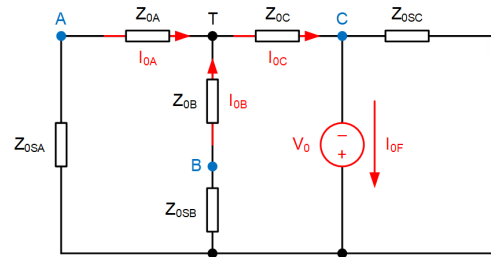


Fig. 15. Three-terminal zero-sequence impedance network for an external ground fault with infeed

Using (3) may lead to a loss of security when there is an outfeed condition due to an additional path between terminals, such as the path depicted by impedance Z_{BC} between Terminal B and Terminal C in Fig. 16. If the source at Terminal B is weak relative to the interconnection impedance between Bus B and Bus C, the currents detected by Terminal B and Terminal C may both flow out of the protected line. The current I_{0A} splits at the tap point T, flowing to the fault point at C via both paths Z_{0C} and $Z_{0B} + Z_{0BC}$, as I_{0C} and I_{0B} , respectively.

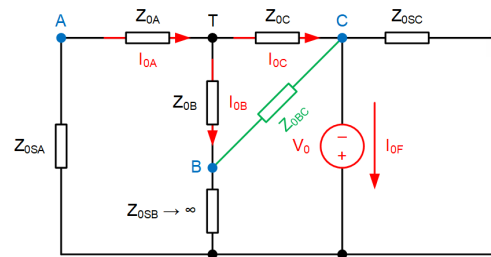


Fig. 16. Three-terminal zero-sequence impedance network for an external ground fault with outfeed

Consider the scenario of the three-terminal line of Fig. 16, where $Z_{0C} = Z_{0B} + Z_{0BC}$ and Z_{0SB} is an open circuit. In this case, $I_{0A} = I_{0B} + I_{0C}$ and $I_{0B} = I_{0C} = 0.5 \cdot I_{0A}$. If k_1 in (3) is less than 2, then an undesired pilot trip may be issued by the DCB scheme at Terminal A for this external fault case. Equation (3), which is used for two-terminal lines, is inadequate for secure operation in a three-terminal line application. A better setting criterion is given in (4), which accounts for the relative decrease in the current available for the pilot-blocking elements at Terminal B and Terminal C compared to that which is available for the pilot-tripping element at Terminal A.

$$32F50_A > 2 \cdot k_1 \cdot 32R50_{B,C} \quad (4)$$

Differing pilot-tripping thresholds may lead to different pilot-blocking thresholds at the terminals. When this applies, the worst-case scenario occurs when the ratio of the I_{0B} and I_{0C} magnitudes is equal to the ratio of pilot-blocking thresholds of the two terminals, $32R50_B : 32R50_C$. This leads to the application of (5), a more general form of (4), where the two remote pilot-blocking thresholds, $32R50_{R1}$ and $32R50_{R2}$, may differ, and where $32F50_L$ is the local pilot-tripping threshold. It is important to ensure that (5) is satisfied for all three terminals.

$$32F50_L > k_1 \cdot (32R50_{R1} + 32R50_{R2}) \quad (5)$$

The application of these additional three-terminal line specific margins is demonstrated in the Oncor Line ABC. For a single line-to-ground fault nearby on an outgoing line from Bus C, the fault currents detected by each terminal relaying are listed in Table I, as well as each relaying directional element assertion.

TABLE I
CURRENTS FOR A SIMULATED FAULT BEHIND BUS C

Terminal	310 Current (Primary A)	Directional Assertion
A	758.8 \angle 0.0°*	F
B	418.3 \angle 179.7°	R
C	340.2 \angle -179.7°	R

* Terminal A 310 relay current is taken as the angle reference.

Terminal A has a ground overcurrent pilot-tripping pickup of 752 primary A. Using the two-terminal typical approach to set the pilot-blocking pickup settings at Terminal B and Terminal C with (3) and a k_1 value of 1.5, a setting of 500 primary A would meet that criterion. According to Table I, there is sufficient current at Terminal A to assert the pilot-tripping element, but due to the current outfeed distribution, neither Terminal B nor Terminal C has sufficient fault current to assert their respective pilot-blocking elements, despite a reverse directional assertion. These pilot-blocking settings would not be secure for this outfeed scenario. The application of (4) with the same k_1 value of 1.5 results in a pilot-blocking pickup of 250 primary A at Terminal B and Terminal C. According to Table I, there is more than 250 A of fault current available at Terminal B and Terminal C, which is sufficient, with margin, for each terminal pilot-blocking element to assert and issue a block to the remote terminals. The (4), and thus (5), setting criteria are sufficient for secure operation for this simulated external fault scenario with outfeed.

B. Security Challenges to Distance Element-Based Pilot Schemes Due to Outfeed

Pilot-tripping distance elements are set to overreach both remote terminals when considering infeed. The reach of these distance zones can become quite large, well above two times the line impedance to the farther terminal in some cases. It is imperative that the pilot-blocking distance element reach at each terminal is set appropriately to account for large overreaches of the tripping elements.

The approach used by Oncor to set the local reverse pilot-blocking distance element reach in the two-terminal line application is to set the reach above a multiple of the remote pilot-tripping distance element reach, minus the line impedance, such as in (6), which ensures sufficient margin for the remote pilot-tripping distance element overreach of the line. Another commonly used approach is to set Z_{R_L} equal to or greater than Z_{F_R} , where at least Z_{LINE} is the coordination margin.

$$Z_{R_L} > k_2 \cdot Z_{F_R} - Z_{LINE} \quad (6)$$

where:

Z_{R_L} is the reach of the local blocking element.

k_2 is typically a value 1.5 or greater.

Z_{F_R} is the reach of the remote tripping element.

Z_{LINE} is the line impedance.

A straight application of the approach used by Oncor to a three-terminal line presents some problems, the first of which is the ambiguity of the “line impedance.” Additionally, the margin provided by the multiple k_2 in (6) is reduced when there is outfeed. Consider the three-terminal line in Fig. 17, where there is a strong connection between Terminal B and Terminal C. For an external fault at Bus C, Terminal B experiences outfeed, and the apparent impedance at Terminal A is given by (7). Given $I_C < I_A$ for an outfeed scenario, the calculated apparent impedance is less than the actual impedance, $Z_A + Z_C$, causing an overreach as the relay perceives the fault as closer than it really is.

$$Z_{APPARENT} = Z_A + \frac{I_C}{I_A} \cdot Z_C \quad (7)$$

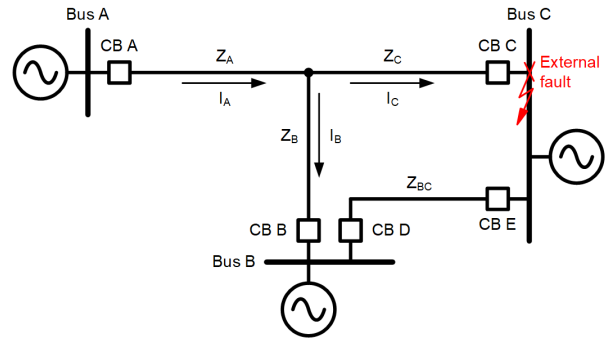


Fig. 17. Three-terminal external fault with outfeed

The worst-case element overreach for an outfeed scenario occurs when the apparent impedance is minimized for an external fault, which will occur in the theoretical case where Z_{BC} goes to zero. In this case, a fault at Bus C electrically becomes a fault at Bus B, and the apparent impedance to the fault can be simplified to the sum of Z_A and the impedances Z_B and Z_C in parallel, given in (8).

$$Z_{APPARENT} = Z_A + \frac{Z_B \cdot Z_C}{Z_B + Z_C} \quad (8)$$

This minimum apparent impedance can be used as a substitute for the line impedance in applying the typical two-terminal approach to setting the pilot-blocking distance element reach (6) for a three-terminal line application. Substituting, the pilot-blocking reach at Terminal A would be set to satisfy (9), with the terms calculated in (10) and (11).

$$Z_{R_A} \geq \max(Z_{R_{AB}}, Z_{R_{AC}}) \quad (9)$$

$$Z_{R_{AB}} = k_2 \cdot Z_{F_B} - \left(Z_B + \frac{Z_A \cdot Z_C}{Z_A + Z_C} \right) \quad (10)$$

$$ZR_{AC} = k_2 \cdot ZF_C - \left(Z_C + \frac{Z_A \cdot Z_B}{Z_A + Z_B} \right) \quad (11)$$

If the reverse blocking element also provides backup protection (as is the case for Oncor), or if loadability is a concern when using (9), lesser reaches that still provide proper coverage of the tripping elements overreaches can be found by taking into account the actual impedance, Z_{BC} , or by using short-circuit study programs.

For the Oncor Line ABC, the outfeed phenomenon was observed for a three-phase fault occurring nearby on one of the lines connecting Bus C. Fig. 18 shows the phase pilot-tripping zone at Terminal A (in green), lesser reaches that still provide proper coverage of the tripping elements overreaches can be found by taking into account the actual impedance, Z_{BC} , or by using short-circuit study programs.

For the Oncor Line ABC, the outfeed phenomenon was observed for a three-phase fault occurring nearby on one of the lines connecting Bus C. Fig. 18 shows the phase pilot-tripping zone at Terminal A (in green) and two potential phase pilot-blocking zones at Terminal C. The C Pilot Block 1 zone (in blue) is generated by (6) using the impedance from Bus C to the tap point to Bus A as Z_{LINE} , while the C Pilot Block 2 zone (in black) is generated by (9), regardless of the Terminal B pilot-tripping reach for demonstration purposes, both using a k_2 multiple of 1.5. The simulated fault with the open breaker (no outfeed) at Terminal B is plotted on the R-X diagram in Fig. 18 as points F1A and F1C, and the fault for normal operation (with outfeed) at Terminal B is plotted as points F2A and F2C, where F_{nA} faults are mapped apparent impedances as detected by the Terminal A relay and F_{nC} faults are the apparent impedances as detected by the Terminal C relay.

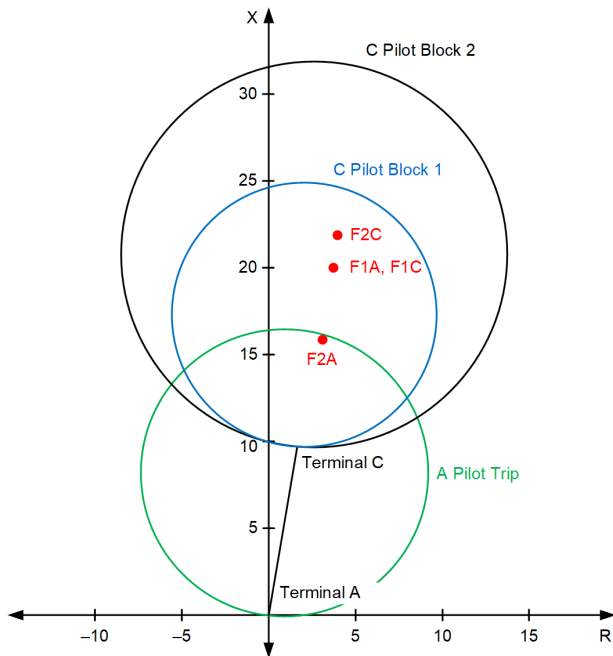


Fig. 18. Terminal A pilot-tripping and Terminal C pilot-blocking coordination for external Bus C three-phase faults

F1C is within both pilot-blocking zones and F1A is well outside the Terminal A pilot-tripping zone for the no-outfeed scenario. However, for a fault at this same location, but with outfeed at Terminal B, F2A plots within the pilot-tripping zone at Terminal A. While F2C does plot within both pilot-blocking zones at Terminal C, the fault is somewhat close to the C Pilot Block 1 zone boundary, coming in at 12.25 primary Ω of the

C Pilot Block 1 reach of 14.96 primary Ω , a margin of 122 percent. It is worth reiterating that these distance element reaches are based on the less accurate simulated apparent impedances rather than known line impedances; thus, this 122 percent margin is insufficient. However, the C Pilot Block 2 reach of 22.10 primary Ω provides adequate margin at 180 percent of the F2C fault apparent impedance and was selected for the pilot-blocking distance element reach.

C. Summary

Traditional methods of setting pilot-scheme blocking elements for two-terminal lines could fail to provide adequate security for three-terminal line applications. With the presence of outfeed, one terminal may detect significantly more current flowing into the line than the other two terminals detect flowing out of the line, requiring greater pickup margins between pilot-tripping and blocking overcurrent elements. Distance pilot-tripping elements overreach more in the presence of outfeed, necessitating greater margin to be built into the reverse pilot-blocking distance element reach. The approaches discussed in this section to set the pilot-blocking elements at each terminal of a three-terminal line provide sufficient margin for secure scheme operation.

VI. PILOT SCHEME DEPENDABILITY

A reasonable follow-up to the security problem explained in the previous section is to ask, “What happens when a fault with outfeed is moved internal to the line?” The answer is that the presence of current outfeed during an internal fault presents a dependability challenge for both DCB and POTT schemes, whereby an internal fault is interpreted as an external fault by one of the line terminals.

A. Dependability Challenges to Pilot Schemes Due to Outfeed

The presence of outfeed at any terminal of a three-terminal line may impact the dependability for internal faults for both DCB and POTT schemes.

A three-phase fault at location F3 in Fig. 12 on the Oncor Line ABC demonstrates the impact of outfeed on the dependability of line protection. Terminal B exhibits outfeed for a fault at this location. Focusing on the DCB scheme for the three-terminal line, it is evident that pilot-tripping elements at Terminal A and Terminal C assert for the internal fault, as shown in Fig. 19. The phase pilot-tripping elements are shown for each relay, with the Terminal A element plotted at the origin and the Terminal B and Terminal C elements reversed and offset by their respective line impedance from Terminal A. The apparent impedance each relay calculates for the fault F3 is shown with the appropriate terminal letter appended. However, relays at Terminal B make a reverse directional decision, as well as a pilot-blocking element assertion. As Terminal A and Terminal C receive a block signal from Terminal B, DCB scheme operation is inhibited, and the dependability is adversely impacted for an internal fault.

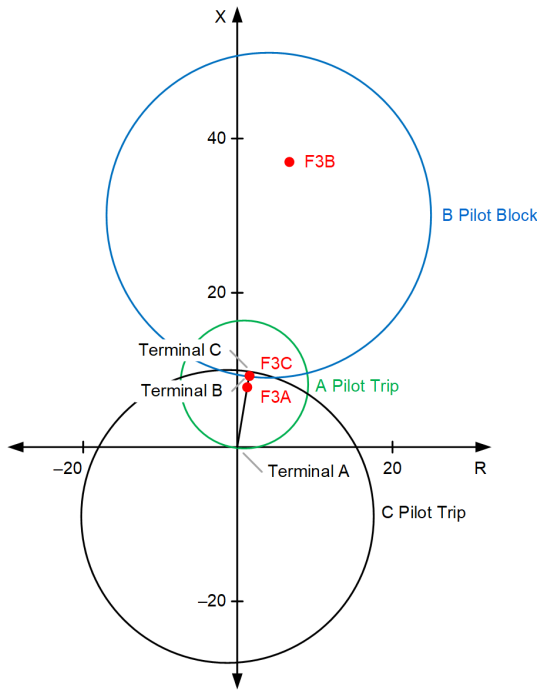


Fig. 19. Relay apparent impedances for 3LG Fault F3 on Oncor Line ABC

Dependability would also be challenged if the line were to employ the security-biased POTT scheme instead of the dependability-biased DCB scheme. In the POTT case, Terminal A and Terminal C assert their respective pilot-tripping elements and receive permissive trip signals from each other. However, because a permissive signal is not received from Terminal B, the POTT scheme does not operate.

It is evident that the presence of outfeed for an internal fault on Line ABC prevents fast fault clearing via a DCB or a POTT scheme. Instead, sequential tripping of the line terminals must be relied on. The sequence of operations for fault F3 is initiated by the tripping of Terminal C, which is closest to the fault, via the underreaching Zone 1 element. Circuit breakers at Terminal C require time (typically 2 to 3 cycles) to open after the Zone 1 element issues a trip. After Terminal C opens, current at Terminal B reverses, the relaying detects a forward fault, and its pilot-tripping elements assert. If a DCB scheme is used, Terminal B does not immediately stop issuing a block signal to Terminal A, but it instead maintains the block signal until the CRD in Fig. 11 expires. Further, the BXT at Terminal A must expire after the block signal from Terminal B stops. In PLC applications, Terminal B may receive its own block signal and be delayed by BXT as well. After these timers expire, the DCB scheme trips Terminal A and Terminal B because neither of the two currently receive a block signal.

Likewise, a POTT scheme also trips because Terminal A and Terminal B provide permissive trip signals to their respective remote terminals after the CRD timer at Terminal B expires. Note that the breaker at Terminal C has already opened. Therefore, echo logic is required for a POTT scheme so that Terminal C can echo the received permissive trip signal back to Terminal A and Terminal B [12] [13]. One option is the

simplified open-breaker logic shown in Fig. 20, which can be built into the POTT scheme. A key point for a three-terminal line application is that a permissive signal from both of the other line terminals (Terminal A and Terminal B) must be received for the echo to be sent back. An alternative option is echo keying supervised by the relay not detecting a reverse fault with its pilot-blocking element, as shown in Fig. 21. This echo scheme typically employs the previously discussed current reversal logic for the pilot-blocking elements and an echo blocking delay (EBD) following the assertion of pilot-tripping elements [13].

Either echo logic employed at Terminal C increases the total fault clearing time. According to the open breaker echo logic in Fig. 20, after Terminal C opens and permissive signals from Terminal A and Terminal B are received, the echo time-delay pickup timer (ETDPU) must expire. Only after this timer expires does Terminal C echo the received permissive signals to both remote terminals. Regarding the pilot-blocking element supervised echo logic in Fig. 21, after the pilot-tripping elements stop asserting at Terminal C, the EBD timer must run out before the ETDPU timer starts timing with the receipt of permissive signals from both remote terminals. Because the breaker at Terminal C is open, the pilot-blocking element is not asserted after ETDPU expires, allowing Terminal C to echo-key to the remote terminals.

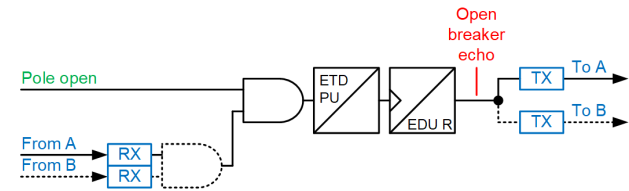


Fig. 20. Simplified open-breaker echo logic for a POTT scheme (Relay C)

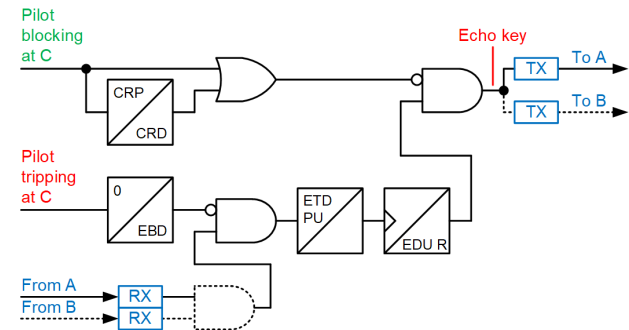


Fig. 21. Pilot-blocking element supervised echo logic for a POTT scheme (Relay C)

Reference [1] points out that a modification to the echo logic may be required during reclosing because when there is a permanent fault, both terminals must echo on receipt of only one signal. A simpler alternative is to rely on an instantaneous overreaching zone in the switch-on-to-fault logic to trip for a permanent fault instead of the pilot scheme.

Note that regardless of the pilot scheme employed, the underreaching Zone 1 element at the terminal closest to the fault initiates the sequential tripping. This highlights the significance

of Zone 1 in a three-terminal line with outfeed, without which, fault clearing would not be achieved via the pilot scheme and time-delayed tripping via backup Zone 2 or time-overcurrent elements would have to be relied upon. If there is a possibility of outfeed for a fault in the Zone 1 blind spot, alternatives such as choosing different polarizing quantities (see Section VIII.C) or using current differential protection should be considered.

To summarize, although the line-protection system eventually isolates the internal fault, presence of outfeed results in sequential tripping and a delay in fault clearing. This delay results from the limitation of the pilot scheme only clearing all terminals after Terminal C has opened so that current flow is redistributed, thereby eliminating outfeed. Fault clearing is further delayed if contingencies such as circuit-breaker failure occur at any line terminal (discussed in Section VII).

B. Solutions to Dependability Challenges Due to Outfeed

There are a few solutions to mitigate the dependability challenges for DCB and POTT schemes due to outfeed.

1) DUTT Scheme

A DUTT scheme presents a viable option to improve dependability. It is evident that the underreaching distance element (Zone 1) at Terminal C asserts for a fault at location F3 in Fig. 12. A DUTT scheme uses the Zone 1 assertion at Terminal C to key a transfer trip signal for Terminal A and Terminal B. These terminals are set to trip upon receipt of the transfer trip signal from Terminal C. As the DUTT scheme uses the underreaching zone of Terminal C to securely detect an internal fault, there is no supervision of the received transfer trip signal at Terminal A and Terminal B. Thus, the relay at Terminal B trips without additional delay, even though it identifies the fault in the reverse direction.

Three-terminal applications benefit from overlapping underreaching zones so that no portion of the line is left without coverage from at least one terminal, allowing the DUTT scheme to clear the fault from all line terminals. On the other hand, it is critical to ensure that underreaching zones do not overreach any remote terminal for all credible operating conditions and contingencies. These two objectives may not be met simultaneously on certain three-terminal lines, which makes the DUTT scheme ineffective for fast total line clearing for all faults in such cases.

It is important to emphasize that reliability of the communications channel is critical to ensuring dependable operation of the DUTT scheme. The DUTT scheme is similar to a traditional POTT scheme in this aspect. The transfer-trip signal may not reach remote terminals if the faulted line is used as a communications channel. Consequently, PLC channels may not be suitable for implementing a DUTT scheme.

2) PUTT Scheme

A PUTT scheme seeks to achieve a compromise between security and dependability. Like the DUTT scheme, the underreaching zones provide a permissive signal to the remote terminals. However, for added security, each remote terminal uses a forward overreaching zone to supervise the received permissive signal from either terminal. For example, in Fig. 12, a forward overreaching zone at Terminal A also asserts for a

fault at location F3. Assertion of this overreaching zone, along with the permissive signal from Terminal C, is necessary for Terminal A to trip via the PUTT scheme. Note that receipt of a permissive signal from Terminal C alone is sufficient for tripping Terminal A via the PUTT scheme. This is possible because a PUTT scheme uses underreaching zones (which do not pick up for an external fault) to provide a permissive signal. This enhances dependability over a POTT scheme where receipt of permissive signals from both remote terminals (Terminal B and Terminal C) is required for tripping. Lastly, when a PUTT scheme is employed, Terminal B will not trip instantaneously because its overreaching zone does not assert when the fault is identified as reverse. It eventually trips via overreaching time-delayed elements after Terminal A and Terminal C have opened.

A PUTT scheme, therefore, provides improved performance over a DCB or a POTT scheme by achieving fast fault clearing at two terminals (Terminal A and Terminal C). In comparison, if a DCB or a POTT scheme is implemented, only Terminal C provides fast clearing via its underreaching Zone 1 elements. However, a PUTT scheme is unable to provide fast clearing at all three terminals (as with a DUTT scheme) due to local supervision of the received permissive signal. A PUTT scheme can be used to strike a balance between security and dependability requirements.

C. Weak-Terminal Tripping Considerations

A variation to an outfeed condition is the case where Terminal B does not exhibit outfeed for the fault close to Terminal C but is a weak source with insignificant fault current contribution so that its pilot-tripping elements do not assert. If a DCB scheme is employed for such a scenario, Terminal A and Terminal C trip as expected, but not Terminal B. In most cases, after Terminal A and Terminal C open, current redistribution occurs and Terminal B can trip via the pilot scheme. However, if Terminal B has no sources behind it, the terminal will not trip. A POTT scheme with weak infeed logic [12] [13] may provide better dependability for such cases. In the case of this scheme, Terminal B echoes the received permissive signals to Terminal A and Terminal C, as shown in Fig. 20 and Fig. 21, which allows them to trip via the POTT scheme. Additionally, Terminal B converts the echo signal to trip via the weak infeed logic. This logic typically employs supervision via phase-to-phase undervoltage and residual overvoltage elements. These elements assert at Terminal B during a fault condition, thereby permitting echo-to-trip conversion, which, in turn, opens Terminal B. It is noteworthy that a DUTT scheme may also provide dependable operation during a weak infeed condition.

D. Summary

The outfeed effect and presence of weak terminals have a significant impact on the dependability of pilot protection schemes on three-terminal lines. Schemes that are traditionally deemed dependable for two-terminal lines, such as DCB schemes, may not always retain the same characteristics in three-terminal applications. Careful analysis of network topologies, credible operating conditions, and verification using short-circuit programs are necessary to ensure that three-

terminal lines are dependably protected. Less-commonly applied schemes such as DUTT or PUTT schemes may need to be evaluated based on the application. As discussed in Section VIII, other options may include using different operating principles to mitigate an outfeed or weak-terminal issue.

VII. BREAKER FAILURE CONSIDERATIONS

The delay in clearing internal faults until outfeed is removed is worsened if a breaker fails to interrupt current. The longer fault-clearing time results because the current reversal logic maintains a pilot-blocking signal or prevents permissive keying until the outfeed is removed and the logic timers dropout. The delay in clearing a fault on a three-terminal line with outfeed and a breaker-failure condition can be very long (in the range of step-distance Zone 2 backup clearing times), and the impact on system transient stability may need to be evaluated.

The commonly used DCB and POTT scheme logic shown in Fig. 11 and Fig. 13 is assumed for the following analysis. The current reversal logic and control of the block or permissive signal may vary among line relays and impact the analysis.

A. Local Fault-Clearing Time at Terminal C

The longest clearing of a close-in fault at a terminal occurs if the breaker at that terminal fails, or if the breaker at the other terminal not experiencing outfeed fails, assuming all terminals have the same breaker-failure timer pickup setting. For a close-in fault F3, shown in Fig. 12, and a breaker failure at Terminal C, the total clearing time (in cycles) from fault inception to clearing the Terminal C source is shown in (12).

$$\text{Terminal C Clearing} \approx \text{RTC} + 62\text{BF} + 86 + \text{BKR} \quad (12)$$

where:

RTC is the relay trip time at Terminal C.

62BF is the breaker-failure timer pickup setting.

86 is the lockout relay time.

BKR is the interrupting time of the breakers adjacent to the failed breaker.

Using typical values for RTC (1 cycle), 62BF (10 cycles), 86 (1 cycle), and BKR (2 cycles), the total breaker-failure clearing time at Terminal C is approximately 14 cycles. This also corresponds to the total clearing time of a breaker-failure condition for a two-terminal line because the breakers at the other terminal would have already tripped.

B. Fault-Clearing Time at Remote Terminals

For the three-terminal line with outfeed at Terminal B, unlike in a two-terminal line, the relays at the other line terminals wait for the fault to be cleared from Terminal C. The current reverses after Terminal C clears, and the additional time to clear Terminal A and Terminal B depends on the delays from the current reversal logic and other delays specific to the pilot scheme used.

1) Terminal B Clearing Time

In a DCB scheme, when Terminal C clears, the blocking elements at Terminal B drop out and the current reversal timer runs. When the timer expires, a STOP command is given to the carrier transceiver, the block signal is removed when the transceivers reset, and Terminal B clears the fault with a clearing time calculated in (13).

Terminal B Clearing \approx

$$\text{Terminal C Clearing} + \text{RD} + \text{CRD} + \text{BXT} + \text{BKR} \quad (13)$$

where:

RD is the blocking element reset time.

CRD is the current reversal dropout delay.

BXT is the blocking extension time included because the transceiver at Terminal B could receive its own block signal. BXT can be set to zero delay when fiber optics are used for the pilot communications medium.

Using typical values for RD (1 cycle), CRD (5 cycles), BXT (1 cycle), and BKR (2 cycles), Terminal B takes an additional 9 cycles to clear after Terminal C is cleared. Consequently, the total clearing time at Terminal B via the DCB scheme is about 23 cycles. This is comparable to a typical overreaching step-distance Zone 2 time delay. Note that because of the outfeed condition, Zone 2 at Terminal B must also wait for Terminal C to clear the fault and be delayed by approximately 14 cycles based on (12).

A POTT scheme also has the current reversal logic and gets delayed in a similar manner because of the outfeed condition. The scheme remains dependable, provided that the permissive signals from Terminal C are received by the other two terminals following breaker-failure clearing at Terminal C. If an echo keying scheme is relied upon at Terminal C to supply its permissive signals, then the clearing at Terminal B depends on the scheme employed and may be delayed further.

2) Terminal A Clearing Time

The total clearing time at Terminal A is approximately the same as the clearing time at Terminal B, unless the step-distance Zone 2 elements at Terminal A trip first, which results in (14). Unlike at Terminal B, the Zone 2 distance elements at Terminal A should pick up within one cycle of fault inception and start the Zone 2 timer. The total clearing time at Terminal A will be the lesser of either the time it takes the pilot scheme to trip or the Zone 2 timer to time out. The Zone 2 timer may be set longer than usual if the Zone 2 elements must coordinate with other Zone 2 elements of adjacent lines, as shown in Fig. 7.

$$\text{Terminal A Clearing} \leq \text{Terminal B Clearing} \quad (14)$$

C. Breaker-Failure Application Considerations

To prevent breaker-failure clearing times from becoming too long, a breaker-failure initiation at Terminal C benefits from fast underreaching elements. For phase fault protection, this may be the Zone 1 phase element; and for ground fault protection, it may be the Zone 1 ground or a high-set instantaneous overcurrent element that picks up for the faults that result in outfeed. If an inverse-time ground overcurrent

element initiates the breaker-failure scheme, overall clearing times could become exceptionally long.

For the Oncor application to Line ABC, primary protection includes Zone 1 phase and ground distance elements, as well as phase distance and directional ground overcurrent pilot protection in DCB schemes over a PLC channel. Backup protection comprises phase and ground distance and inverse-time ground overcurrent elements. Oncor determined that the additional time to clear a breaker-failure condition on their three-terminal line would not result in system instability. Thus, Oncor did not modify their standard protection and relay settings.

If faster breaker-failure clearing on three-terminal lines is needed, an option is to apply direct transfer tripping for a breaker-failure condition using channels other than the power line. The use of DUTT or PUTT schemes with fiber-optic channels would reduce the overall clearing times during breaker-failure conditions. Other options are reducing the delay settings associated with breaker failure, current reversal, or blocking extension timers. Reducing delays reduces scheme security, therefore, the impact must be carefully evaluated.

VIII. DIRECTIONAL ELEMENT POLARIZING CONSIDERATIONS

Many relays provide the user flexibility in choosing the polarizing quantity for directional elements for ground fault protection. Two popular choices are the negative-sequence (Q) and zero-sequence (V) voltage-polarized elements. Users have the flexibility to use one or both in a preferential order that suits the application [14].

A. Polarizing Similarities in Two- and Three-Terminal Lines

There are some general similarities in application guidelines for choosing the directional element polarizing quantity for both two- and three-terminal transmission lines. First, it is preferable to use negative-sequence (Q) voltage-polarized directional elements when there is a possibility of zero-sequence mutual coupling with parallel transmission lines [15] [16]. There can be conditions under which the zero-sequence networks of the faulted and unfaulted portions of the system are electrically isolated but mutually coupled [15]. These conditions typically result in the most significant impact of mutual coupling on the zero-sequence (V) voltage-polarized elements causing them to make incorrect directional decisions. Fault studies that use short-circuit analysis programs, assessment of system topology, and knowledge of operating conditions should be used to decide whether the Q polarized element is better suited under conditions with mutual coupling [15] [16]. Second, the use of zero-sequence (V) voltage-polarized directional elements is preferable when there may be insufficient or poor negative-sequence currents at the relay location [7].

This situation is becoming increasingly prevalent with the interconnection of IBRs to the power system. When radially feeding a fault, IBRs may inject negative-sequence currents that are not coherent with the negative-sequence voltages due to control system response, so their pickup settings should be desensitized to prevent a misoperation [8]. However, IBRs are

typically connected to the transmission system via a transformer that has its high-voltage winding in a grounded-wye configuration, with one other winding that is delta-connected [7] [17]. This configuration provides a strong zero-sequence path for transmission system ground faults. Also, unlike the negative-sequence voltages and currents that may be incoherent in the presence of IBRs, the zero-sequence quantities follow the traditional phase-angle relationships. Consequently, the zero-sequence (V) polarized directional element may provide better ground-fault protection when protecting transmission lines that are fed by IBRs. Short-circuit programs provide the capability of fault studies with zero-sequence mutual coupling and, more recently, systems with IBRs [17] although they may not accurately capture the transient IBR control response and require application specific guidance for systems with IBRs [8].

B. Polarizing Differences in Two- and Three-Terminal Lines Due to Disagreement Between Sequence Networks

To understand some of the differences between two- and three-terminal lines, we first explain the criteria for a very commonly applied directional element preference order of QV [14]:

- Negative-sequence current magnitude should be higher than user-settable forward or reverse current thresholds.
- Negative-sequence current magnitude should be higher than 10 percent of the positive-sequence current magnitude and 20 percent of the zero-sequence current magnitude.

If both the magnitude and percentage checks for the negative-sequence directional element are not satisfied, the relay resorts to the zero-sequence voltage-polarized directional element using similar criteria [14]:

- Zero-sequence current magnitude should be higher than user-settable forward or reverse thresholds.
- Zero-sequence current magnitude should be higher than 10 percent of the positive-sequence current magnitude.

In two-terminal lines, the preference order QV works very well for an external fault because the current entering one terminal must exit the other terminal, and the magnitude and percentage checks are satisfied identically at both terminals.

In three-terminal lines, however, the current at one terminal is the sum of the currents at the other two terminals. While the magnitude check is addressed in Section V using well-coordinated forward and reverse thresholds, the percentage check may not be satisfied if the negative-sequence current is much smaller than the zero-sequence current and the negative-sequence network is non-homogenous. A strong zero-sequence network with a weak negative-sequence network could exist in weak systems (i.e., lines that have a breaker open on the low-voltage delta side of a delta-wye transformer) during system contingencies, or in systems with IBRs.

Fig. 22 illustrates the scenario where relays at all three terminals declare a forward fault even though the fault is external and the sequence currents entering and exiting the line

are equal. At Terminal C, the negative-sequence current magnitude is less than 20 percent of the zero-sequence current magnitude, so the relay uses the zero-sequence directional element to declare a forward fault direction. At Terminal A and Terminal B, since the percentage check is satisfied, the negative-sequence directional element is used to declare a forward fault direction.

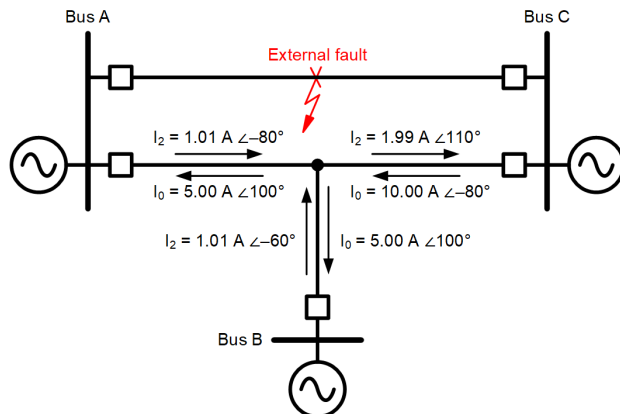


Fig. 22. Negative- and zero-sequence currents for an external fault

To overcome this scenario, an option is to use only one polarizing quantity (i.e., V only for the example in Fig. 22) at all line terminals. The polarizing option may be selected based on the guidance in Section VIII.A, while considering the relative strengths of the negative- or zero-sequence networks to mitigate outfeed effects and/or improve protection sensitivity. For the Oncor Line ABC, this was not an issue, but it may be a consideration for other three-terminal lines or tapped lines.

C. Polarizing Differences in Two- and Three-Terminal Lines Due to Outfeed Effect

The choice of polarizing quantity (Q or V) also impacts the infeed versus outfeed scenario for internal and external faults near Terminal C shown in Fig. 12. The requirement for an outfeed condition at Terminal B is the presence of a relative weak source behind Terminal B but a strong interconnection from Bus B to Bus C, such as the example in Fig. 2. However, a terminal that is weak in the negative-sequence network may provide a strong zero-sequence path due to the presence of grounding transformers, as explained in Section VIII.A. The Oncor system in Fig. 4 is an example where all three sources have a lower zero-sequence impedance than the positive- and negative-sequence impedance, especially behind Terminal A where the generator step-up transformers of the combustion unit generating station presents a low-impedance zero-sequence path.

Based on short-circuit studies on the Oncor system in Fig. 4, for faults near Bus B, there was outfeed at Terminal C when considering the negative-sequence network but not on the zero-sequence network. On the other hand, for faults near Bus C, Terminal B experienced outfeed in both the negative- and zero-sequence networks. However, the outfeed in the zero-sequence network was more severe than in the negative-sequence network and was observed for faults further internal to the line.

Use of either polarizing quantity (Q or V) led to outfeed for differing fault locations, and thus resulted in the security and dependability issues described in Section V and Section VI. Ultimately, due to the relative severity of observed outfeed behavior for simulated faults and the presence of mutual coupling with adjacent lines, the negative-sequence polarizing quantity was used for the directional element (Q only) at the three terminals of Line ABC.

To summarize, comprehensive short-circuit studies should be performed to evaluate the choice of ground directional element polarization and evaluate the desired directional element behavior under varying system configurations.

IX. CONCLUSION

The following summarizes the differences encountered when protecting three-terminal lines relative to two-terminal lines:

- Overreaching distance zones may require larger reach settings due to infeed, whereas underreaching zones may require shorter reach settings due to outfeed.
- Outfeed effect and the presence of weak terminals necessitates greater coordination margins between forward and reverse directional element overcurrent thresholds and distance element reaches to achieve adequate pilot scheme security.
- Outfeed effect and the presence of weak terminals may also reduce pilot scheme dependability. To address this, consideration may be given to less-commonly applied DUTT and PUTT schemes.
- Current reversal logic in two-terminal lines addresses sequential clearing of an external fault on an adjacent line. For three-terminal lines, this logic may engage for an internal fault due to an outfeed scenario. If current reversal logic engages, fault-clearing times may incur an additional delay of about 8 or 9 cycles. If there is an additional breaker failure scenario, fault-clearing times could have a similar delay as step-distance Zone 2 backup.
- It is preferable to use only one polarizing quantity for the ground directional element. A consideration includes the strength of the negative-sequence network relative to the zero-sequence network to mitigate issues related to directionality disagreement between the sequence networks and outfeed effect.

Many of the above considerations require comprehensive short-circuit studies.

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XI. BIOGRAPHIES

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Bernard Matta received his BS degree in electrical engineering from Pennsylvania State University. He joined Virginia Power (presently Dominion Energy) in 1986 and worked in the System Protection department calculating relay settings, performing system studies, testing protection systems, and writing standard procedures. He was on a team that evaluated and implemented microprocessor-based relays to replace electromechanical equipment. Bernard joined Schweitzer Engineering Laboratories, Inc. in 2000. He has served many electric utilities and customers throughout the U.S. by providing relay settings to protect transmission, distribution, and generation equipment. Bernard is an IEEE member.

The Complexity of Protecting Three-Terminal Transmission Lines

North American Electric Reliability Council



A Technical Document

Prepared by the

System Protection and Control Task Force

of the

NERC Planning Committee

September 13, 2006

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Three-Terminal Line Protection

CONCLUSION AND SUMMARY

Three-terminal lines are relatively common throughout North America, and many good reasons exist for using this configuration for transmission facilities. However, protection of three-terminal lines presents serious challenges and requires very careful design and application to maintain overall system reliability

The protection challenges presented by three-terminal lines include the following:

- Transmission line relay loadability
- Sequential clearing for transmission line faults
- Compromises in the ability of the protection to detect faults
- Compromises in relay coordination between the three-terminal line protection and the protection on adjacent facilities
- Increased complexity of associated communications system
- Increased susceptibility to false tripping for heavy transient loading conditions and stable power swings.

The discussions and related examples presented in this technical report convey general protection considerations and philosophies for three-terminal line protections. The protection scheme examples are listed for illustration and indicate possible methods of applying and/or setting relay zones of protection. The actual protection scheme used and the associated settings for a three-terminal line will be application dependent. The protection scheme must take into consideration the specific topology of the three-terminal line, and the protection scheme and associated settings used must be adequate to meet the necessary clearing times and the reliability and security needs of the power system.

The intent of this paper is to describe the most common types of three-terminal protection complexities found in the industry. These complexities should be considered when evaluating high-voltage transmission plans that include multi-terminal lines. Analyses of past cascading outages have indicated that because of the relay settings necessary to protect three-terminal lines, they were susceptible to protection system operations.

Three-terminal and other multi-terminal line construction projects are generally a trade-off of planning economics and protection complexities, and can, sometimes, lead to compromises in reliability.

Three-terminal line configurations require an increase in complexity of the line protection systems. This is due to the fault current flow from a third terminal affecting the voltage and current present at the other two terminals. In the case of distance based line protection, this current causes the relays to underreach line faults beyond the third terminal tap point.

The underreach is overcome by extending the relay reach. This reach extension limits the load carrying capability and increases the likelihood for operation on stable power swings. The paper also discusses several other possible three-terminal protection complexities such as overreaching for “outfeed” conditions, Zone 1 reach limitations, and the use of sequential tripping and its impact on reliability and security.

The current differential principle is considered to be suited to protect three-terminal lines and it does not need to contend with problems associated with voltage, loading, and swings. However, a three-terminal line may affect line current differential protection schemes if outfeed conditions occur during internal line faults. The protection system should be set to operate in the presence of the outfeed condition. Also, if used, it should be noted that the line differential backup protection schemes are subject to the same type of complexities.

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INTRODUCTION

The North American power system consists of thousands of high voltage transmission lines transmitting electrical power between generators and load centers. They represent the foundation of the power system. The majority of transmission line construction is of overhead type and therefore, is easily susceptible to various transient and permanent faults. These faults can lead to damage of the line itself and can cause power system instability. It is of the utmost importance that protective relay systems are capable of clearing all faults within the designed operating time, and have a high degree of dependability and security.

Typically, there are three types of line configurations used within the industry. These line configurations include (a) radial (one-terminal), (b) two-terminal, and (c) multi-terminal of which three-terminal is possibly the most prominent multi-terminal type. It should be noted that "terminals" in this context, refers to source terminals and not-tapped transformer terminals or stations. The reader unfamiliar with these configuration types should refer to Appendix A. The two-terminal line configuration is the most dominant type followed by radial, and the three-terminal lines are the exceptions.

Three-terminal and other multi-terminal line construction projects are generally a trade-off of planning economics and protection complexities, and can lead to compromises in reliability. Two-terminal lines with long tap(s) supplying remote load from the main line may display many of the same protection and loadability issues as three-terminal lines. These types of configurations and those with multiple tapped transformer stations (low voltage tie breaker closed) are beyond the scope of this discussion. However, it should be noted that some of the same types of complexities may be experienced with these types of configurations as three-terminal lines.

The complexity of protecting these line configurations increases from the relatively simple radial, to the more difficult two-terminal, and to the still more difficult three-terminal. Relaying three-terminal lines has been and continues to be a challenge for protection engineers.

Appendix A provides a brief description of some of the common types of line protection schemes used in the industry. It is intended to provide a basis for readers unfamiliar with such protection schemes to better understand the discussion for suitability of such schemes for three-terminal line protection. For a more detailed discussion on line protection schemes, the reader is referred to the IEEE Standard C37.113-1999, *Guide for Protective Relay Applications to Transmission Lines* [see reference 4 noted in Appendix D].

This paper addresses Recommendation TR-19 from the *Transmission and Generation Performance Report Blackout of August 14, 2003 – Detailed Power System Forensic Analyses and Modeling*¹, and describes three-terminal lines and highlights the associated protection complexities from a phase loadability perspective. These complexities should be considered when evaluating transmission plans that include multi-terminal lines.

¹ TR-19 — NERC should review and report on the advantages and disadvantages of the use of multi-terminal line configurations on the EHV system, and any associated complex protection and control (sequential) schemes. Particular attention should be paid to the performance of such configurations and its protection during emergency operation conditions, including expected system swings.

Three-Terminal Line Protection

1.0 Three-Terminal Lines

Three-terminal and other multi-terminal line construction projects are generally a trade-off of planning economics and protection complexities, and sometimes may lead to compromises in reliability.

1.1 Justifications for Three-Terminal Lines

There are a number of factors that influence the decision to configure a transmission line with three terminals, such as economics, constrained lead time, regulatory approvals, right-of-way availability, line overloads, and system performance requirements.

- There is an economic benefit in the construction of three terminals because it avoids the expense of all or a portion of a substation and typically reduces the transmission line miles.
- Use of three-terminal lines may be more expeditious in addressing system needs.
- Right-of-way may be limited or not obtainable for new lines and stations.
- Regulatory approvals may be problematic. There may be opposition to the construction of new facilities and the construction of a three-terminal line may reduce the overall project impact.
- Three-terminal line configuration may mitigate the possibility of transmission line overloads due to single contingency events. However, this is very dependent on system topology.

1.2 Effect of Infeed at the Tee Point – Apparent Impedance

For a fault on a transmission line, a distance relay will measure impedance equal to the line positive sequence impedance, provided there are no sources of fault current between the line terminal at which the relay is located and the fault. The distance relay measures impedance by comparing the voltage drop between its location and the fault with the current at the relay.

Referring to Figure 1 on the next page, the actual line impedance from the relay terminal (Terminal A) to the fault is not always the impedance measured by the relay. This is because the third line terminal (Terminal C) tapped (Tee point) to a line is an additional source of current for a line fault. Current will be supplied to a fault that occurs on the line section beyond the tap of Terminal C through both Terminal A and Terminal C. The voltage drop resulting from the input of fault current from each of these sources into the common section of the line will be measured by the distance relay at the Terminal A. Since the current input from Terminal C is not applied to the relay at Terminal A, the impedance measured by this relay is higher than the actual impedance from the Terminal A to the fault. The relay will underreach; that is, for a given relay setting the relay does not cover the same length of line it would if the additional current source were not present.

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Consider a typical apparent impedance effect as follows in Figure 1 below.

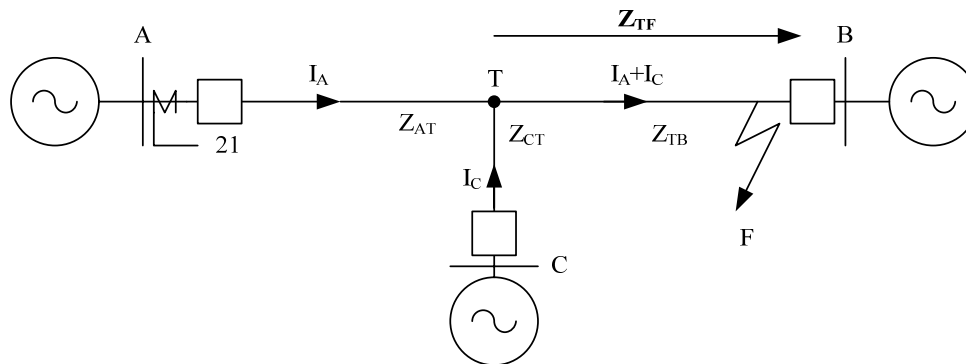


Figure 1 — Infeed Effect

Voltage at Terminal A with **zero infeed** from Terminal C:

$$V_A = V_{AT} + V_{TF} = I_A Z_{AT} + I_A Z_{TF} = I_A (Z_{AT} + Z_{TF}) = I_A Z_{AF}$$

Impedance as measured from Terminal A:

$$Z_{AF} = \frac{V_A}{I_A} \quad \text{This equals the true impedance.}$$

Voltage and impedance measured at Terminal A (relay location) for fault F, with Terminal C **closed (infeed)** is:

Voltage:

$$V'_A = V_{AT} + V_{TF} = I_A Z_{AT} + (I_A + I_C) Z_{TF}$$

Impedance as measured at Terminal A:

$$Z_{app} = Z_{AF} + \frac{I_C Z_{TF}}{I_A}$$

Z_{app} = The impedance that appears at the distance relay terminal which is referred to as apparent impedance

$\frac{I_C}{I_A}$ = The infeed factor, for Terminal A; the ratio of tapped infeed current to relay location current.

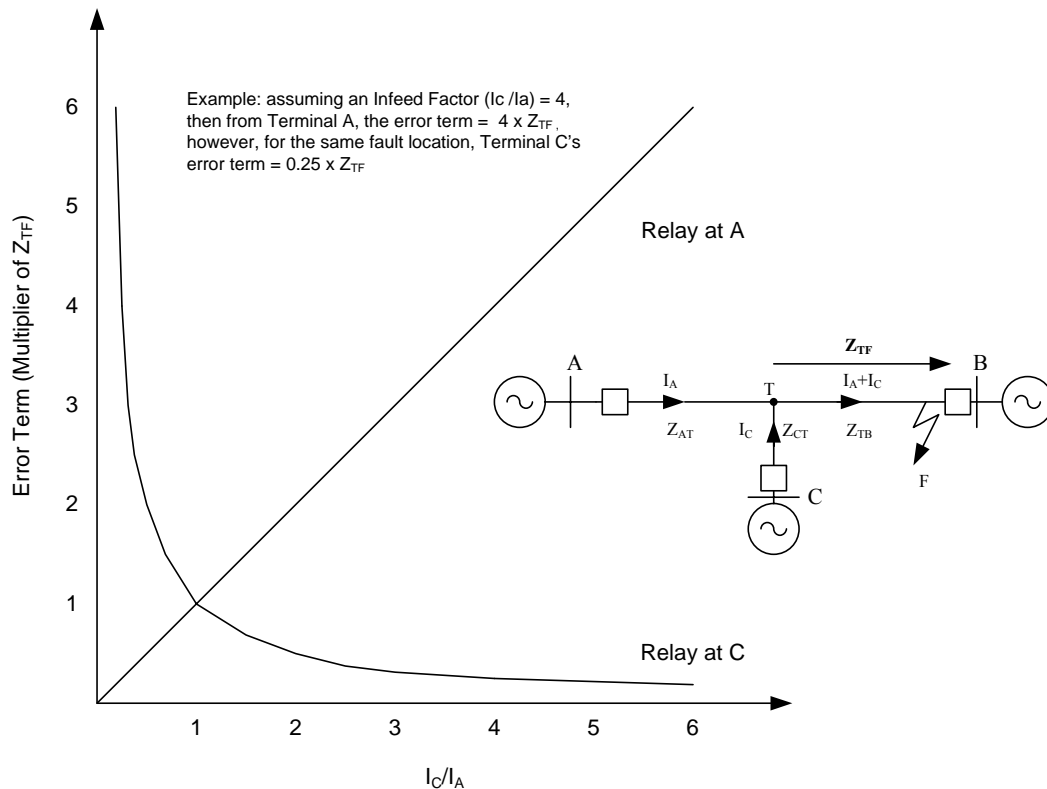
$$\frac{I_C Z_{TF}}{I_A} = \text{error term}$$

The effect of the fault infeed I_C from Terminal C is to increase the apparent impedance viewed from Terminal A and, therefore, reduce the reach of the relay for a given setting. The underreaching tendency

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is a function of the ratio $\frac{I_C}{I_A}$. This relationship is depicted in Figure 2, where the error term $Z_{TF} \times \frac{I_C}{I_A}$ is plotted as a function of the ratio $\frac{I_C}{I_A}$, from Terminal A and Terminal C's perspective.

For the same fault location, the impedance viewed from Terminal C is:



$$Z_C = Z_{CT} + Z_{TF} + Z_{TF} \left(\frac{I_A}{I_C} \right)$$

Figure 2 — Infeed Error Term Measured From Terminals A and C

From Figure 2, the two curves intersect at $I_C / I_A = 1$, resulting in the conclusion that if the error term is greater than Z_{TF} , as viewed from one terminal, it will be less than Z_{TF} when viewed from the other. The importance of this relationship is discussed in the report section on sequential tripping (section 1.12).

As an example:

The actual impedance from Station A to the fault at Station B, with the line terminal at Station C open is:

$$Z_{A-B} = 1 \Omega + 1 \Omega = 2 \Omega$$

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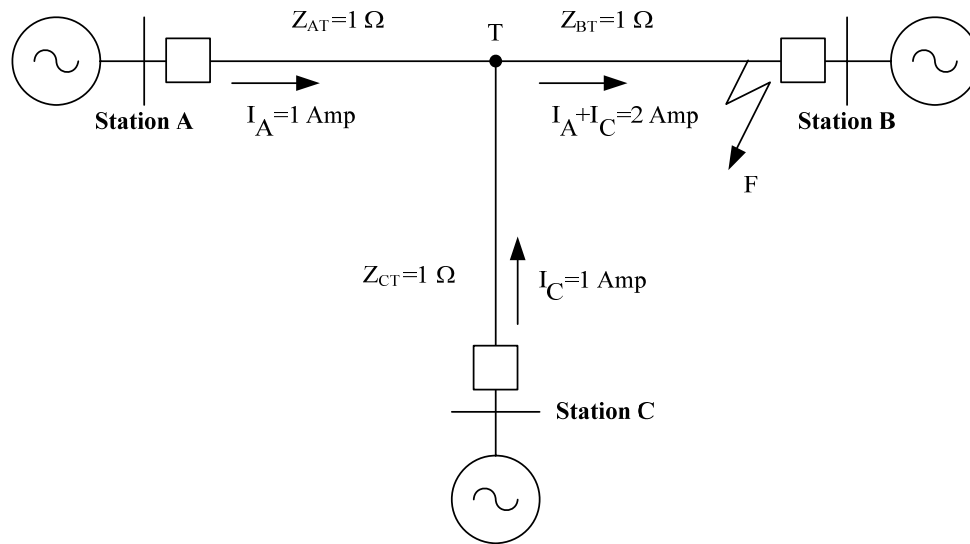


Figure 3 — Apparent Infeed Example

The apparent impedance from Station A to the same fault, with the line terminal at Station C closed is:

$$Z_{app_{A-B}} = \frac{V'_A}{I_A} = \frac{(1 \times 1) + (1 \times 2)}{1} = 3 \Omega$$

To overcome this effect, the relay setting has to be calculated in terms of the widely varying apparent impedance measured by the distance relay located at the line terminal. The setting required providing complete coverage of the line can be much larger than the setting necessary without the three-terminal configuration. The measured impedance is typically referred to as apparent impedance.

It should be noted that these apparent impedance effects limit the ability to provide remote backup functions for adjacent circuits.

Relay schemes must be set considering the effects of varying system conditions in deriving the maximum credible apparent impedance. Reasonable contingencies that weaken the source at the relay terminal should be considered in determining a relay setting. This magnifies the degree to which the relay setting must be raised due to apparent impedance effects. Typically, fault calculations are conducted to determine the maximum apparent impedance as measured from each of the three terminals. By evaluating potential contingencies, source impedances are maximized or minimized to generate the maximum infeed affect. The longest Tee length determines the fault location. As an example, for Terminal A, with a fault at Terminal C, assuming Z_{TC} is larger than Z_{TB} , the source impedance at Terminal A should be maximum (minimum system), and at Terminal B, the source impedance should be minimum (maximum system). This will result in the largest infeed factor.

A similar conclusion may be arrived at when considering a phase-to-ground fault provided the Z_{L0}/Z_{L1} ratio for each branch of the protected line is the same. The infeed effect for phase-to-ground faults is very much a function of the system grounding and needs to be determined by conducting system fault studies for the specific application.

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1.3 Outfeed

Section 1.2 above, describes the effect of providing a fault “infeed” at the “Tee” location for a three-terminal line which causes a distance relay to underreach. It is also possible, based on system configuration, to experience an outfeed at the “Tee” location for a fault internal to the protection section. For these cases, the same equations apply, but instead of an underreaching effect, the tendency is to overreach.

For Example:

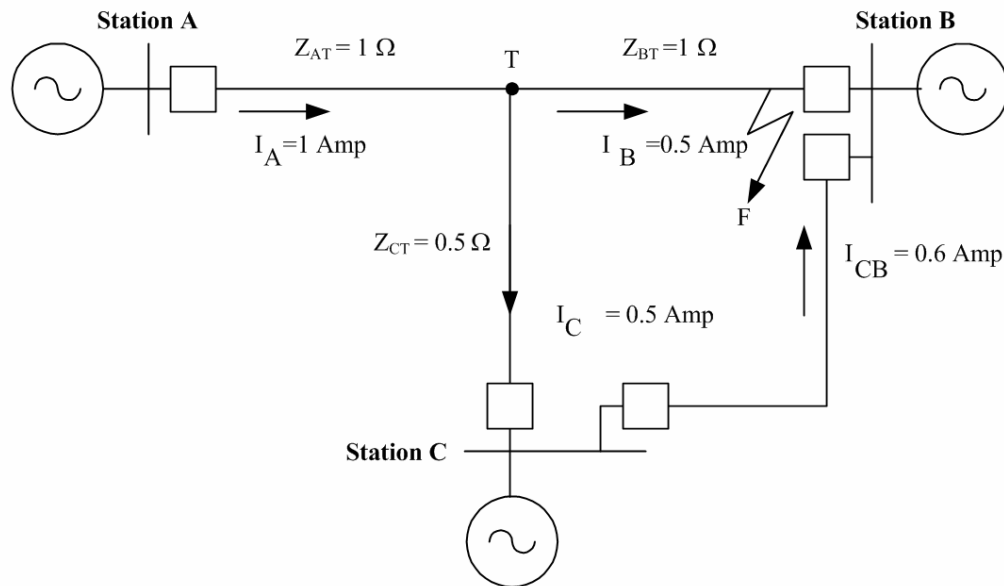


Figure 4 — Outfeed Example

For Terminal A relaying, the actual line impedance to the fault is 2.0 Ohms, however, the apparent impedance measured is:

$$Z_{app_{A-B}} = \frac{V'_A}{I_A} = \frac{(1 \times 1) + (0.5 \times 1)}{1} = 1.5 \Omega \quad \text{The relay overreaches.}$$

This particular phenomenon, although not too common, will influence the Zone 1 settings at each terminal, and may cause delayed or sequential tripping.

Another concern regarding outfeed, for DCB schemes, is that directional comparison would be blocked from tripping. DCB relays at Station C would send a block to Stations A and B for the internal line fault at F. The pilot scheme may be momentarily blocked for an internal fault until one terminal clears, when an outfeed occurs and current at one terminal looks to be in the external direction. This also affects POTT schemes.

The planner needs to be aware of such conditions when completing stability studies as the overall line clearing time may be increased by the time it takes Terminal B or C to clear, until the outfeed condition ceases. In addition, the protection engineer should ensure that there is adequate coordination margin for relays looking through the terminal that may be delayed in tripping due to the outfeed condition.

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1.4 Decrease in Line Loadability

The settings typically required to provide protection coverage of a three-terminal line, where fault infeed is experienced, will be much larger than the setting necessary without the third terminal. This setting can reach many multiples of the actual impedance of the protected line, resulting in a decrease of the line loadability unless some form of load blinder or encroachment logic is applied.

To illustrate, consider the following 230 kV example in Figure 5:

It should be noted that the impedances defined below represent the values based on system fault calculations to obtain the maximum credible apparent impedance for reasonable system conditions.

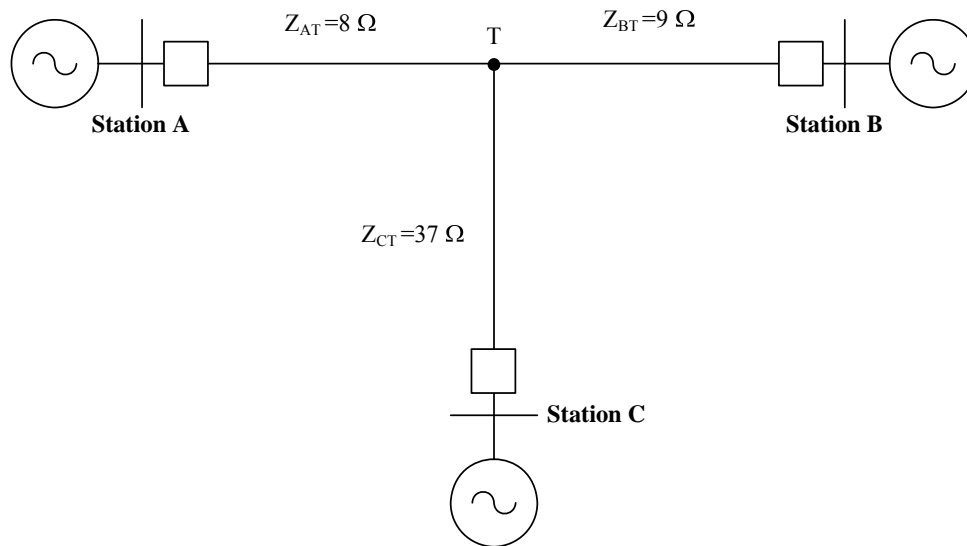


Figure 5 — Three-Terminal Line Loadability Example

Table 1 — System Data for the Example Used in Figure 5

DATA	TERMINAL A	TERMINAL B	TERMINAL C
Z_i to Closest Terminal	17 Ohm @ 82 degrees Pri.	17 Ohm @ 82 degrees Pri.	45 Ohm @ 82 degrees Pri.
Z_i , Apparent Impedance	79 Ohm @ 82 degrees Pri. (Fault @ C, Brk. Open) Apparent = 465% of Z Line	95 Ohm @ 84 degrees Pri. (Fault @ C, Brk. Open) Apparent = 559% of Z Line	96 Ohm @ 82 degrees Pri. (Fault @ B, Brk. Open) Apparent = 213% of Z Line

Assume that the line originally was configured as a two-terminal line between Terminals A and B – Terminal C is open. The distance Zone 1 and Zone 2 settings, at Terminal A, will typically be set as follows:

$$\text{Zone 1} = 80\% \text{ of } Z_{\text{line}} = 0.8 \times 17 = 13.6 \text{ Ohms Primary}$$

$$\text{Zone 2} = 125\% \text{ of } Z_{\text{line}} = 1.25 \times 17 = 21.3 \text{ Ohms Primary}$$

Three-Terminal Line Protection

The Zone 2 represents the largest reach setting; therefore, in this case, it represents the limiting protection element for loadability. Refer to Figure 6.

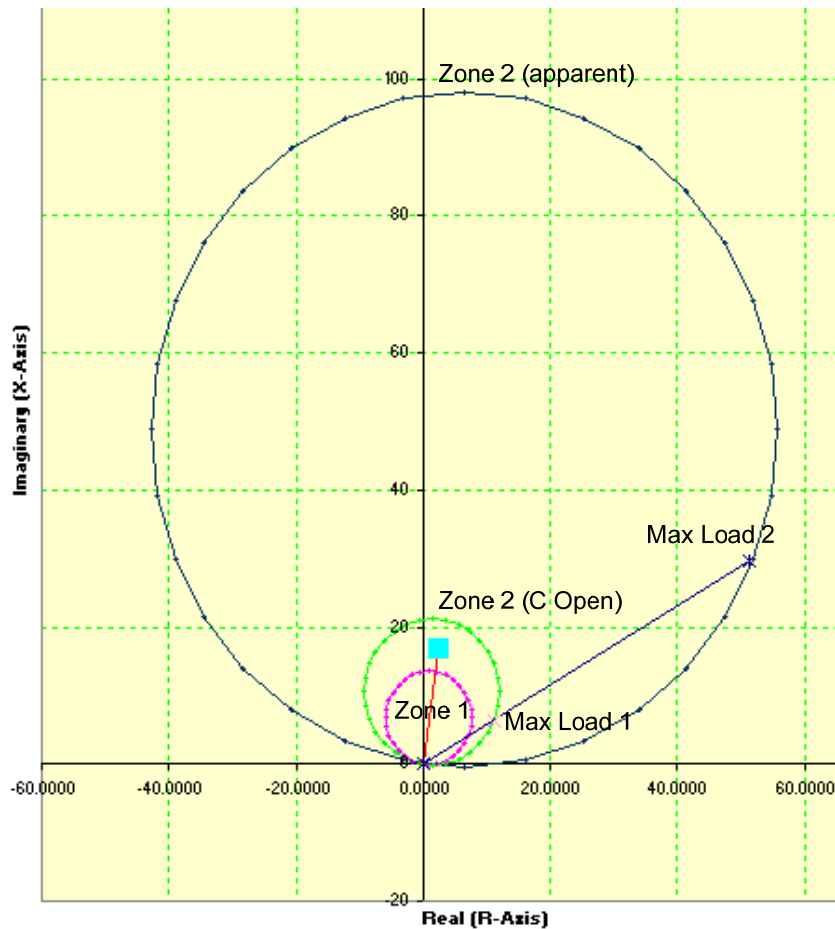


Figure 6 — RX Plot Illustrating Line Loading for the Example of Figure 5

Figure 6 represents an impedance plot of the operating characteristics of the Zone 1 and Zone 2 Terminal A, phase mho distance elements.

If Terminal C is closed, the line becomes a three-terminal line. From Table 1.0, above, the maximum three-phase apparent impedance at Terminal A is 79 ohms primary. Therefore, the new Zone 2 settings will have to be increased to $1.25 \times 79 = 98.75$ ohms primary.

Figure 6 depicts Zone 2 settings, as a two-terminal line (Zone 2 with C Open) and the Zone 2 requirement as a three-terminal line (Zone 2 apparent). It should be noticed that the infeed effect necessitates a Zone 2 setting of 4.6 times the settings as a two-terminal line, and therefore, represents a much larger operating characteristic.

The larger operating characteristic reduces the line loadability, as the line protection must not trip according to the following loadability requirement [1]:

1.5 times the maximum current line rating, at 85% nominal voltage, and at a load angle of 30 degrees.

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Referring to Figure 6 above, a load line is drawn from the origin at an angle of 30 degrees. The Zone 2 element loadability constraints can be calculated as:

Zone 2 as a Two-Terminal Line (Maximum Load 1)

$$21.25 \times \cos(83^\circ - 30^\circ) = 12.75 \text{ Primary Ohms}$$

$$12.75 \text{ Ohms} = (0.85 \times 230) / (1.732 \times I)$$

$$I = (0.85 \times 230) / (12.75 \times 1.732) = 8.85 \text{ kA}$$

Zone 2 as a Three-Terminal Line (Maximum Load 2)

$$98.5 \times \cos(83^\circ - 30^\circ) = 59 \text{ Primary Ohms}$$

$$59 \text{ Ohms} = (0.85 \times 230) / (1.732 \times I)$$

$$I = (0.85 \times 230) / (59 \times 1.732) = 1.9 \text{ kA}$$

Which represents a 78% (from 8.85 kA to 1.9 kA) reduction in loadability.

It should be noted that three-terminal lines must meet the NERC requirements as per reference [1]. A technical exception 8 is provided for lines that can not meet this requirement — it has been included, as a reference in this paper as Appendix C. In addition, the NERC, SPCTF technical paper *Methods to Increase Line Relay Loadability* [reference 3 in Appendix D], provides methods and recommendations to increase loadability of protective relaying functions by augmenting, repositioning, and reshaping, who element impedance relays without decreasing protection coverage.

1.5 Protection System Security is More Reliant on Communication Reliability

On multi-terminal lines, the Zone 2 protection zone reaches are generally set farther and over-current settings are made more sensitive to cover infeed considerations. This results in reaches much farther beyond remote line terminals than Zone 2 relays set on two-terminal lines. Thus, these relays will see more external faults and are more prone to false tripping for communication failures when using a DCB scheme (i.e., failure to receive a block on a DCB scheme).

1.6 Susceptibility to Trip for Stable Power Swings

Due to the need for extended Zone 2 coverage to accommodate the apparent impedance effect, it is possible that stable power swings may encroach into the relay phase characteristics. While susceptibility to tripping during power swings is typically thought of as a concern for Zone 1 protection where tripping occurs without intentional time delay, tripping during power swings has been observed for Zone 2 and Zone 3 relays providing nonconditional time delayed tripping as well as Zone 2 relays operating in communication-assisted protection schemes.

1.6.1 Nonconditional Time-Delayed Overreaching Relays

The exposure to operation of relays providing nonconditional time delayed tripping is significantly increased when relay reaches are extended to account for infeed effects on three-terminal lines or infeed effects associated with providing remote backup protection. The increased size of the relay operating characteristic increases the amount of time that an apparent impedance swing will remain inside the relay characteristic. Figure 7 illustrates the impact of increasing the apparent impedance characteristic to accommodate a three-terminal line. Note the reach of the Zone 2 and Zone 3 relay characteristics relative to the Zone 1 reach. In the following figures the triangular markers on the apparent impedance trajectory

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represent a time interval of 250 ms between each marker and the apparent impedance after the line trips is recorded as $0+j0$, resulting in a straight line from the apparent impedance just prior to the trip to the origin on the R-X plane. The apparent impedance in this example remains inside the Zone 3 relay characteristic for longer than the Zone 3 timer setting of 650 ms, resulting in a trip of the line terminal. The apparent impedance trajectory is just changing direction at the time the line terminal trips as depicted on the green (solid) trace in Figure 7. The blue (dashed) trace depicts the apparent impedance trajectory with tripping of the line terminal blocked, indicating a stable swing.

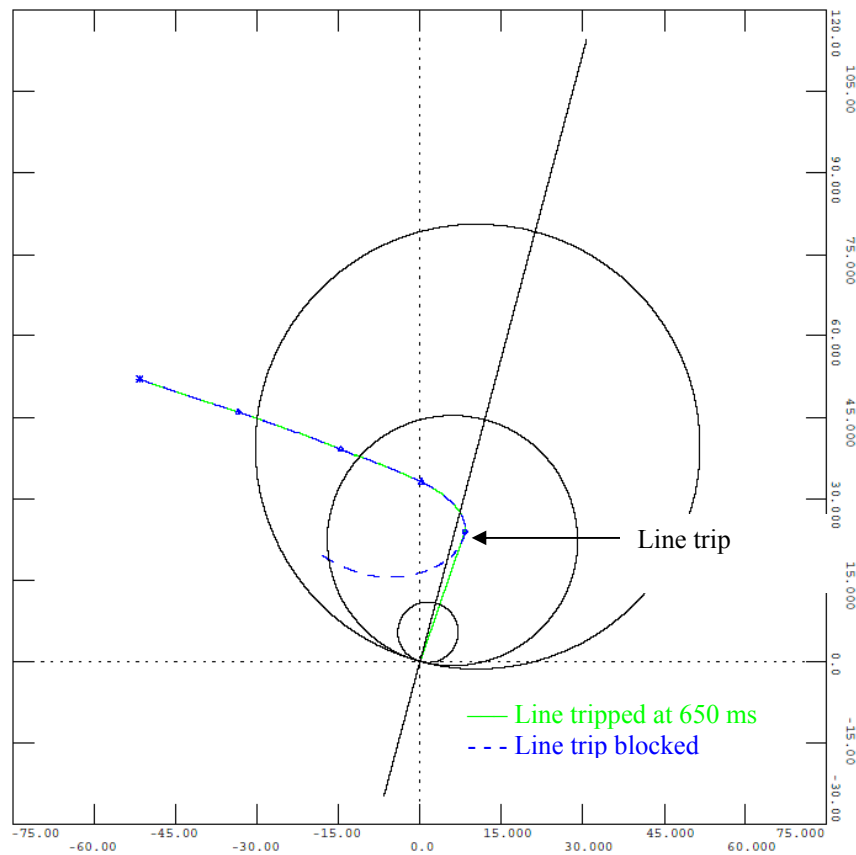


Figure 7 — Apparent Impedance Trajectory Through a Zone 3 Relay Characteristic

1.6.2 Communication Assisted Protection Schemes

Communication assisted protection schemes are also more susceptible to operation during system swings when relay reaches are increased to account for infeed effects. During typical system loading conditions the security of communication assisted protection schemes is improved relative to unconditional tripping relays because all line-terminals must see the fault within the protected zone in order to initiate tripping. During system swings however, it is possible for the apparent impedance to appear within the protected zone at all terminals resulting in a protection operation. As relay reaches are increased the likelihood that the apparent impedance is within the relay characteristic also is increased.

Direct Underreaching Transfer Trip (DUTT) schemes have limited susceptibility since the tripping relays do not overreach the end of the line and the Zone 1 relay reaches are not increased to account for infeed effects. Permissive Overreaching Transfer Trip (POTT) and Directional Comparison Blocking (DCB)

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schemes do have increased susceptibility on multi-terminal lines since the tripping relay reach must be increased to account for infeed effects. The susceptibility for operation of POTT schemes is limited to swings for which the apparent impedance is inside the protected zone at all relay terminals. The susceptibility for operation is greatest for DCB schemes since the apparent impedance could be seen as outside the reach of the carrier trip relay at one or more relay terminals, but also outside the reach of the carrier blocking relays at all terminals. Figures 8 and 9 illustrate this phenomenon for a two-terminal line.

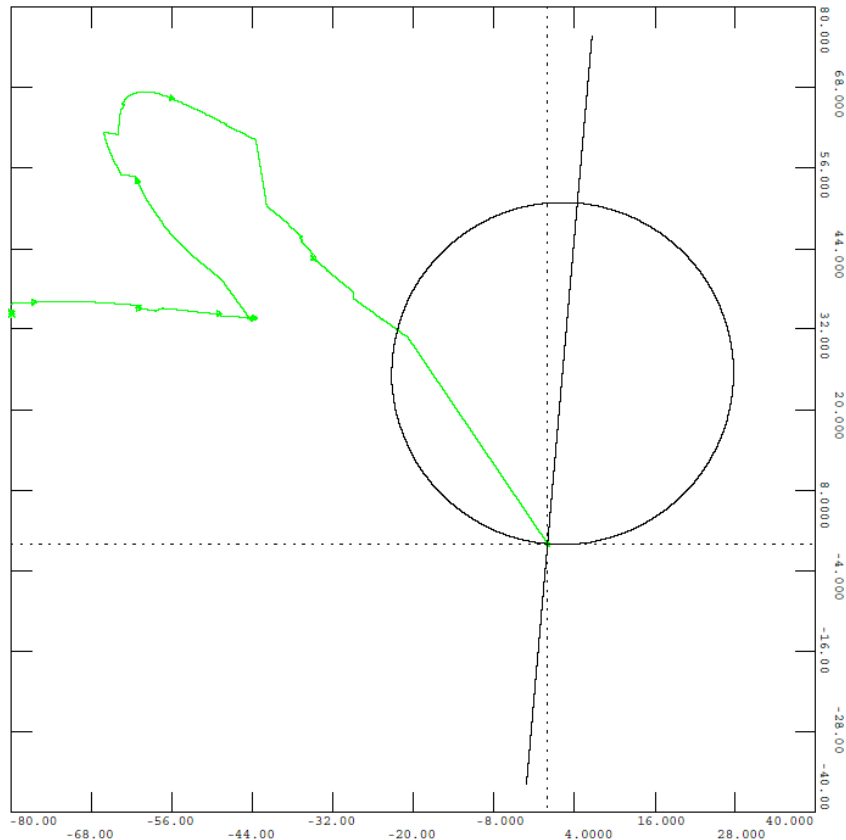


Figure 8 — Receiving Terminal Apparent Impedance Trajectory Entering Trip Relay Characteristic

Note that the apparent impedance trajectory at neither line terminal is in the third quadrant where the reverse Zone 3 carrier blocking relay characteristic would be located. In this case, the apparent impedance at the receiving terminal entered the Zone 2 carrier trip relay characteristic resulting in a line trip (see Figure 8). At the same time the sending end apparent impedance is approaching the Zone 2 carrier trip relay characteristic from the fourth quadrant, such that a blocking signal is not sent to the receiving terminal (see Figure 9). This phenomenon can easily be extended to the case of a three-terminal line.

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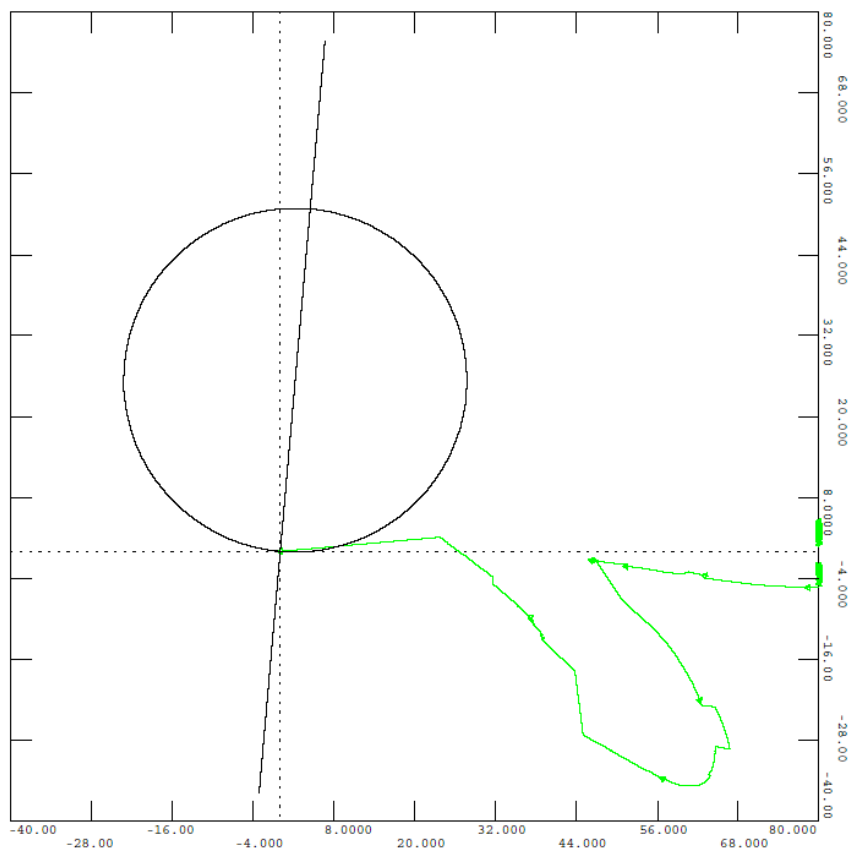


Figure 9 — Sending Terminal Apparent Impedance Trajectory Outside Trip and Blocking Relay Characteristic

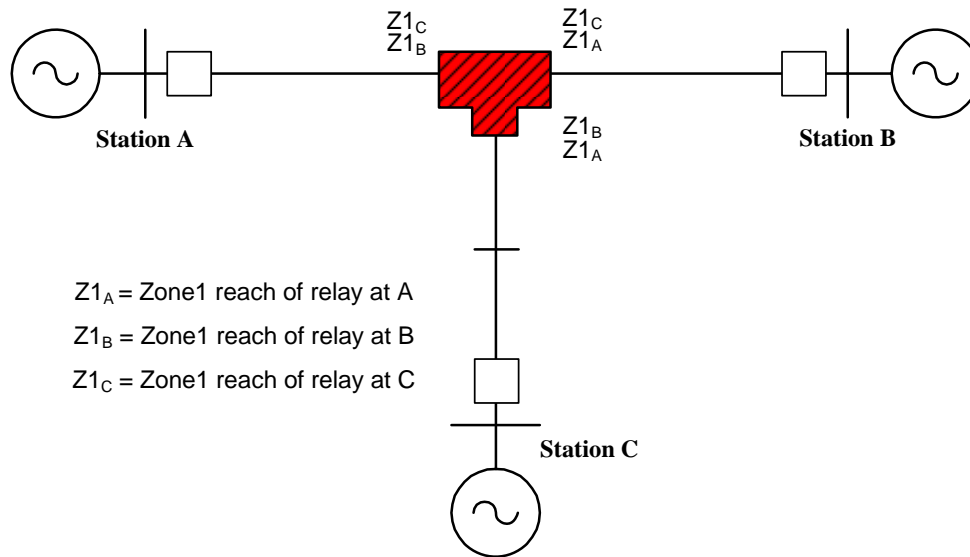
1.7 Zone 1 Reach Limitations

The location of the “Tee” point and the length of the three “legs” of a three-terminal line can vary based on transmission line configuration. The Zone 1 reach settings, from each terminal, must not operate for a fault external to the protected section (selectivity). They must also not operate under conditions with zero infeed at the Tee point, or possibly with the outfeeding condition.

If high-speed clearing is required from all terminal for faults in the vicinity of the Tee, and if the Zone 1 reach cannot cover faults up to the Tee point, then a communication assisted design such as direct underreaching transfer tripping scheme is required. At least one Zone 1 relay must see the fault for the scheme to work. For trip dependability, Zone 2 shall be used in either a POTT or DCB scheme. It should be noted that the Zone 1 settings are based on zero infeed at the Tee point for security reasons. However, with normal operation and a Tee infeed, the actual Zone 1 apparent impedances measured will be much higher and will underreach. For some three-terminal applications, the Zone 1 protection scheme coverage may be greatly limited.

Consider the following three-terminal line (see Figure 10), with approximately equal branch lengths:

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**Figure 10 — Zone 1 Coverage for a Three-Terminal Line Having Equal Branches
(Shaded Area Represents the Region of Overlapping Zone 1s)**

High-speed tripping is achieved at all terminals without the need for communications only for the shaded section in Figure 10. Provided that the reach settings at each of the three terminals permit operations beyond the Tee point (overlap), Zone 1 tripping is obtained for faults anywhere on the protected line, using a DUTT scheme. Three-terminal configurations can limit Zone 1 reaches at multiple terminals and thus limit or severely limit the ability of Zone 1 relays to detect faults with resistance.

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Consider the following three-terminal line (see Figure 11), with unequal branch lengths:

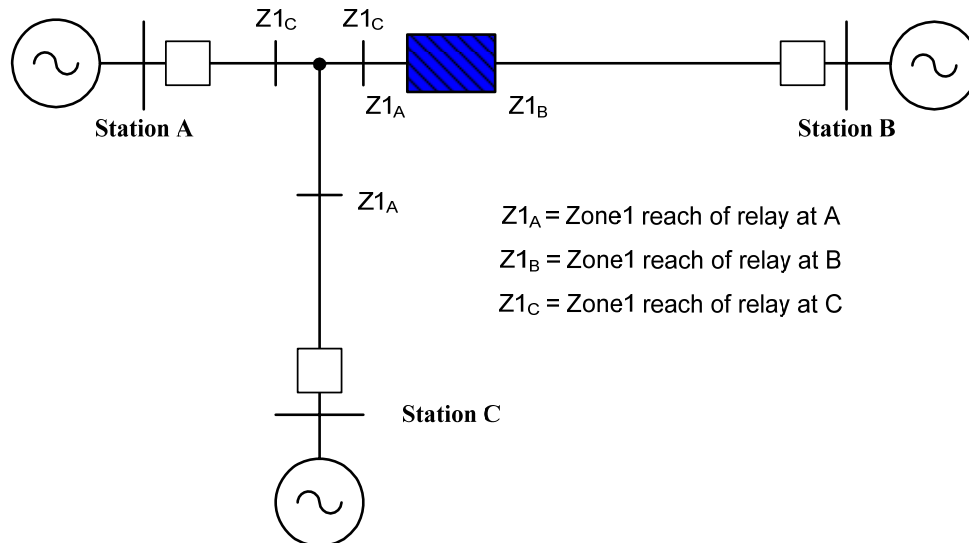


Figure 11 — Zone 1 Coverage for a Three-Terminal Line Having Unequal Branches (Shaded Area Represents the Region Where the Fault is Undetectable by any Zone 1 Relay)

With unequal branch lengths, problems may be apparent when choosing a reach setting for the relay on the longest branch. For the above configuration, the section defined by $Z1_A - Z1_B$ is not covered for faults from any of the terminal Zone 1 relays. If this is unacceptable, then high-speed clearing must be achieved by using an appropriate pilot scheme, such as POTT or DCB.

1.8 Stepped Distance Schemes

Stepped distance relay schemes applications are complicated by the following factors.

1. Zone 1 reach limitations.
2. Zone 2 and Zone 3 setting requirements will, generally, be very large due to infeed effects.
3. The larger Zone 2 and Zone 3 settings may not meet the line loadability requirements.
4. The larger Zone 2 and Zone 3 settings may not coordinate with adjacent lines due to their extended reach, or if they can coordinate, it may result in unacceptable clearance times.
5. The Zone 2 and Zone 3 settings may reach through tapped step-down transformers and must coordinate for low voltage faults.
6. The longer clearing times may not be acceptable from a system stability perspective.

Therefore, three-terminal line protection systems generally require the use of communication assisted schemes.

1.9 Direct Underreaching Transfer Tripping

A Zone 1-based direct underreaching transfer-tripping scheme is a suitable scheme for three-terminal line protection. For this type of scheme, a fault within the protected line must be detected by at least one Zone 1 relay terminal for operation.

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As discussed in Section 1.7 above, for trip dependability, Zone 2 should be used in either a POTT or DCB scheme. It should be noted that the Zone 1 settings are based on zero infeed at the Tee point for security reasons. However, with normal operation with a Tee infeed, the actual apparent impedances measured will be much higher and Zone 1 protection scheme coverage may be greatly reduced.

1.10 Permissive Overreaching Schemes

A permissive overreaching scheme is very secure; requiring all three terminals to detect the fault before tripping can be initiated at any given terminal. Tripping requires the local overreaching Zone 2 distance element operation and receipt of a permissive trip signal from the two remote terminals. For this scheme to operate successfully, the reach of the permissive Zone 2 elements must be set to detect all line faults for all infeed conditions. The Zone 2 permissive setting is generally set for 125% of the maximum apparent impedance as measured from each terminal.

A modified (standard in most modern relays) POTT scheme that is commonly applied is one where if the breaker is open, the relays echo back permission to high-speed trip to the other terminals. In addition, if the terminal is very weak and does not detect a fault when a permissive signal is received, the relay can be programmed to echo back permission to trip to the stronger terminals that see the fault. Both of these schemes allow high-speed tripping of all terminals on the line.

For some three-terminal applications, where the infeed factor is several multiples of the actual line impedance, it may not be possible to set the Zone 2 permissive elements.

Typically, that is due to the following reasons:

1. The required Zone 2 reach may not meet the line loadability requirements, and may impose more restrictive line loading limits.
2. The larger Zone 2 settings may not coordinate with adjacent lines due to their extended reach, unless the Zone 2 tripping times are increased to provide the coordination.
3. The Zone 2 unconditional timed tripping elements, if used, may reach through tapped step-down transformers and must coordinate for low voltage faults.
4. The Zone 2 relays could trip for stable power swings.

For such cases, an alternate scheme will be required.

1.11 Directional Blocking Schemes

A directional blocking scheme is more trip dependable than a permissive scheme, however it is less secure. This type of scheme requires the use of forward and reverse fault detecting protection elements at each terminal. Tripping is initiated if a local Zone 2 overreaching distance element or a ground overcurrent element operates, and a remote-blocking signal is not received within channel coordination time (a short time varying by equipment manufacturer and type of channel, usually ranging up to 50 ms). If a remote blocking signal is received from any of the remote terminals, then tripping will be prevented. Reverse directional distance elements and ground current elements are used to initiate the sending of the blocking signals.

Similar to the permissive scheme, high-speed tripping is achieved at all terminals if the Zone 2 overreaching protection elements are set to detect all line faults for all infeed conditions. It is subject to the same protection issues as the permissive scheme discussed above. However, directional blocking has an advantage over a permissive scheme when system changes over time alter the infeed error ratio, preventing one of the terminals from seeing a fault. Under such conditions a permissive scheme would

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not be able to high-speed trip at any terminal, but the directional blocking scheme will trip, albeit sequentially (discussed below), making it less dependent on the source impedances.

1.12 Directional Blocking with Sequential Tripping²

Directional blocking with sequential tripping schemes accept that at least one terminal must open before the relays at the remaining terminals can detect the fault, and that no blocking elements operate. Moreover, once the first terminal is open (removing the infeed effect); the other two terminals must be able to detect the fault.

The rationale for operation of such a scheme, namely apparent impedance impacts, is described in section 1.2 of this paper. The following example illustrates the relationships between the apparent impedance at different terminals, as described previously in Figure 2.

Consider the following three-terminal line where the line fault is at Station B, resulting in $Z_{TF} = Z_B$:

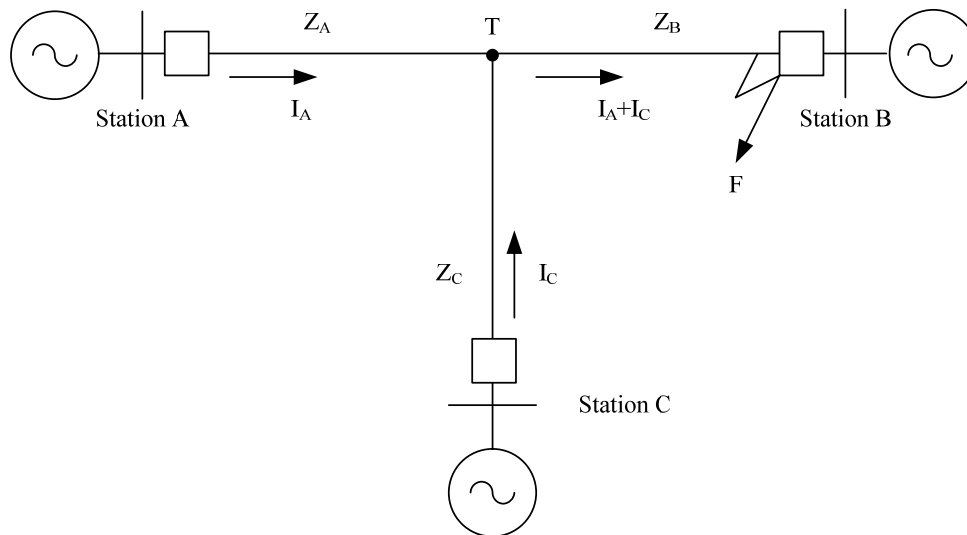


Figure 12 — DCB with Sequential Tripping

The apparent impedances at Terminals A and C are shown below, assuming the infeed factor term is $I_C/I_A = 4$.

At Terminal A:

$$Z_{A \text{ relay}} = Z_A + Z_B + Z_B (I_C/I_A)$$

$$\text{Actual } Z_{\text{line}} = Z_A + Z_B$$

$$\text{Then } Z_{A \text{ relay}} = Z_{\text{line}} + 4 Z_B$$

However, for reasons outlined in section 1.11, the relay at Terminal A can only be set for $Z_{A \text{ relay}} = Z_{\text{line}} + 2 Z_B$. Therefore, the relay at A would not operate for that fault location.

² IEEE Standard 100-2000 (*The Authoritative Dictionary of IEEE Standards Terms*), defines sequential tripping as: “A situation where one or more relay terminals of a line cannot detect an internal line fault, typically because of infeed, until one or more terminals has already opened and removed the infeed.”

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At Terminal C:

$$Z_{C \text{ relay}} = Z_C + Z_B + Z_B (I_A/I_C)$$

$$\text{Actual } Z_{\text{line}} = Z_C + Z_B$$

$$\text{Then } Z_{C \text{ relay}} = Z_{\text{line}} + 0.25 Z_B$$

Assuming the relay at Terminal C is set to detect this fault, the sequential tripping scheme relies on relay C to trip first. In doing so, the relay at Terminal A would now measure $Z_A + Z_B$ only, and would trip subsequent to Terminal C.

This scheme relies upon the operation of one of the three-terminal relays for fault clearance. For this reason, this type of scheme should be used with backup protection either local or remote. If local backup protection is used, then redundancy of relay input sources and devices are necessary, as a failure of one input source or relay will prevent one or more remote terminals from detecting the faults.

Issues with Applications of Sequential Clearing

For some three-terminal lines, one relay terminal may not be able to detect a fault at the remote end of the line due to the infeed effect of the third line terminal. In these situations, one terminal of the line must open before the other terminal(s) can detect the fault.

The interdependency of the two terminals causes fault clearing times to double. Some of the issues associated with longer fault clearing times include, but are not limited to the following:

- Increased fault clearing times decrease or eliminate critical clearing stability margins resulting in dynamic instability.
- Remote backup clearing times may be extended or clearing time margins reduced.
- Breaker failure clearing times will increase at the sequential terminals.
- Voltage recovery post fault can take longer due to the longer clearing times.
- Damage at the point of fault will increase.
- Transformers supplying fault current may exceed their mechanical through-fault duration curve limits.
- The longer tripping times may have a negative impact on loads.

Some schemes use high-speed communications (transfer trip) to send a trip command from the one terminal that can detect the fault to the other terminals that cannot detect the fault. In such schemes, the possibility of a communications failure must be considered.

Application of high-speed communication, preferably redundant communications, may avoid the impact of longer clearing times on the interconnected system. For those systems that use sequential clearing as an acceptable practice, it is essential to the reliability of the interconnected system that stability studies be performed to verify the stability of the system. Such studies must include time delayed clearing (breaker failure clearing) to meet NERC reliability standards.

1.13 Line Differential

The current differential principle was initially used, and continues to be used, in the form of pilot-wire protection. Modern microprocessor-based protection relays and digital communications make line differential schemes more versatile. The scheme performs a differential comparison on a per-phase basis and communicates using one of several types of communication media.

The current differential principle is suited to protect three-terminal lines and it does not need to contend with problems associated with voltage, loading, and swings. Moreover, with current differential relays at

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each terminal, there is no infeed error. Phase-comparison relay schemes share many of the advantages of line current differential, but are not discussed further in this document.

A typical differential scheme is depicted below in Figure 13.

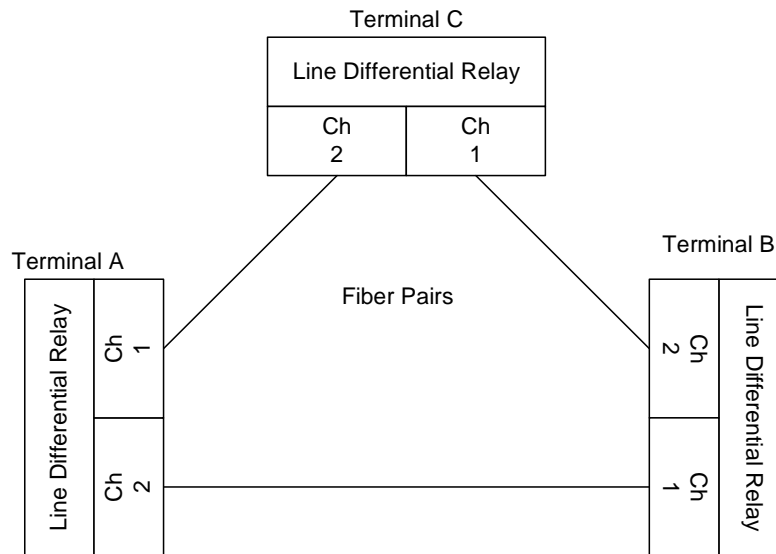


Figure 13 — Three-Terminal Line Differential Scheme

In this implementation of a three-terminal line protection scheme, each of the line differential relays connects to its two remote units using two channels — Channel 1 and Channel 2. Channel 1 of any given relay connects to Channel 2 of the next relay, forming a ring between all three units. Under normal operation, with all communications channels in service, each relay receives two remote current waveform samples and makes its local tripping decision based on a comparison with its locally acquired samples. A local trip decision also causes transfer trip to be sent to the two remote terminals. If one of the three bidirectional communications paths is interrupted, two of the three remaining relays will still be able to receive remote samples from the other two and is still capable of making a local tripping decision and sending transfer trip.

Current differential protection systems are very dependant on a functioning communication channel at all terminals of the line, and the loss of this channel may prevent high-speed clearing of faults. If high-speed clearing of faults is needed for stability, the application of protection system redundancy should be considered. The current differential system should be backed up by a pilot system or a second communication channel.

An example of one implementation of a line differential protection system for a three-terminal line, using redundant and diverse communication paths over a SONET network, is illustrated in Appendix B.

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APPENDICES

Three-Terminal Line Protection

APPENDIX A — LINE CONFIGURATIONS AND PROTECTION SCHEMES

1.0 Line Configurations

1.1 Radial Lines

Radial lines are lines that supply loads from a single power source — Terminal A. Nondirectional overcurrent or distance relays are normally used to protect these types of lines. Communication assisted tripping is not generally necessary.

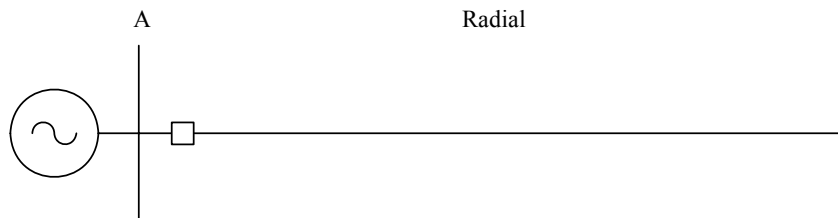


Figure A-1a — Radial Configuration

1.2 Two-Terminal Lines

Two-terminal lines are used for bulk power transfer and to supply loads from two power sources — Terminals A and B. To obtain proper selectivity and coordination, the industry normally uses directional distance relays for phase and ground fault detection. Directional ground overcurrent relaying is sometimes applied in addition to, or in place of, directional ground distance relay functions.

One or two communications-based protection groups are normally utilized with two-terminal line applications at transmission voltages greater than 200 kV.

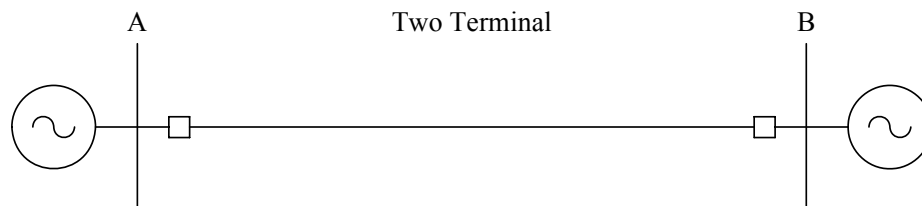


Figure A-1b — Two-Terminal Line Configuration

1.3 Three-Terminal Lines

Three-terminal lines are used for bulk power transfer and to supply loads from three power sources — Terminals A, B, and C. Protection systems are similar to that of two-ended lines except with more sophisticated techniques. In many cases, an existing two-terminal line is converted to a three-terminal

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line as part of a program to reinforce the power system. At least one (or in the general case, two) communications-based protection groups are normally utilized with three-terminal line applications.

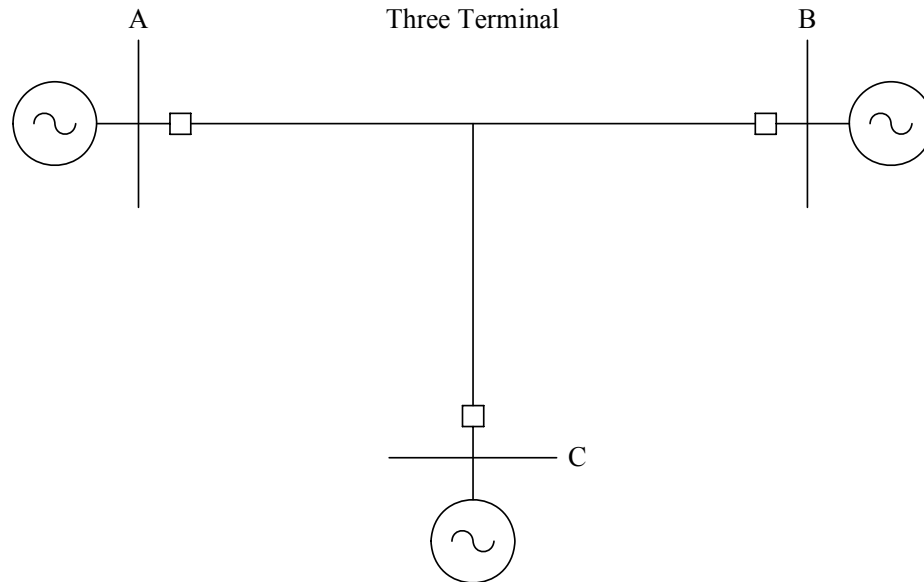


Figure A-1c — Three-Terminal Line Configuration

2.0 Two-Terminal Line Protection Systems

This section briefly describes some of the most common types of line protection schemes used in the industry. It is provided as a reference for readers unfamiliar with such schemes. For a more detailed discussion on line protection schemes, the reader is referred to the IEEE Standard C37.113-199, *Guide for Protective Relay Applications to Transmission Lines* [reference 4].

Just as transmission lines vary widely in their characteristics and configurations, so too do their protection schemes. Several fundamental factors influence the choice of protection schemes applied to a given line.

- Type of line: overhead, cable, line length, single line, parallel line, radial, two-ended, three-ended, etc.
- Line function and importance effect on service continuity and timing requirement for isolation from the system.
- Coordination and compatibility with associated lines and systems.

2.1 Nonpilot Schemes

Most high-voltage transmission lines are protected by distance relays. Compared to overcurrent relays, distance relays are inherently directional, less susceptible to source impedance variations, and have higher loadability limits.

Step distance protection is generally used for nonpilot applications of distance relaying. An example of such a scheme is illustrated in Figure A-2 (next page).

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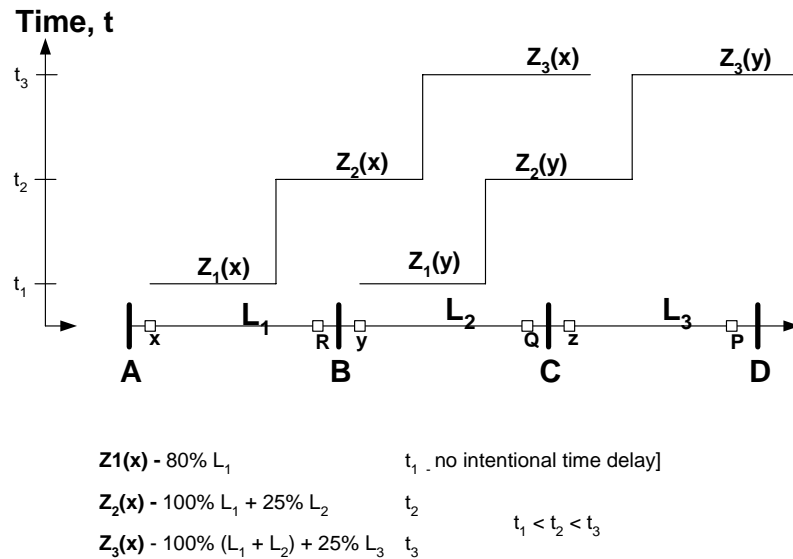


Figure A-2 — An Example of a Stepped Distance Scheme for Terminal A

In this stepped distance scheme example, three protection zones are used for Terminal A:

Zone 1: Set with no intentional time delay and covers 80% of the line so not to overreach Terminal B (selectivity).

Zone 2: Set to cover 100% of L_1 plus at least 25% of L_2 , covering faults for the section between 80–100% of L_1 , with a time delay selected to coordinate with Terminal B protection systems.

Zone 3: This zone is typically applied as a backup protection for single protection failures at Terminal B (breaker failure, battery, etc.). It is set to cover 100% ($L_1 + L_2$) plus at least 25% of L_3 , and is time coordinated with protection systems at Terminals B and C.

2.2 Pilot (Communication-Assisted) Schemes

The three most commonly used communication assisted distance protection schemes in the industry are Direct Underreaching Transfer Trip (DUTT), Permissive Overreaching Transfer Trip (POTT), and Directional Comparison Blocking (DCB). The DUTT scheme is used with the Zone 1 elements and the DCB and POTT schemes use Zone 2 overreaching elements.

DUTT has the advantages of minimal susceptibility to power system swings. DUTT has the disadvantage of dependency on communication channels for faults external to overlapping coverage regions.

The POTT scheme has the advantage of being more secure, as it requires permission from the remote relays to trip, and it can provide higher-speed tripping. It has the disadvantage of being dependent upon the communication channel time for all line faults.

The DCB is the most trip dependable, because its operation is not dependent on the communication channel or operation of the remote relays. It is the least secure in that a loss of communication can result in line trips for faults not on the line. The DCB scheme requires a forward reaching element (Zone 2), and a reverse directional element.

Generally, a complimentary use of high-speed schemes is used for the protection of most 200 kV and above transmission lines.

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2.3 Direct Underreaching Transfer Trip

Attributes of a direct underreaching transfer trip scheme include the following:

- The direct underreaching transfer trip scheme uses the Zone 1 distance elements typically set at 70% to 90% of the line.
- The Zone 1 elements trip locally and will transfer trip via communication channel to the remote end. Receipt of a transfer trip signal (from the remote end) will also initiate a local trip (see Figure A-3 below).
- This scheme requires only one Zone 1 operation to trip both ends of the protected line, but to do so; it is dependent upon having reliable communication channels. This scheme will not detect faults beyond the Zone 1 reach upon total loss of communication channels, or if the remote breaker is open.
- This scheme is generally implemented with dual communications channels, and it is augmented with either a POTT or DCB scheme for breaker open operations (refer to sections 2.4 and 2.5), and/or a time backup protection.

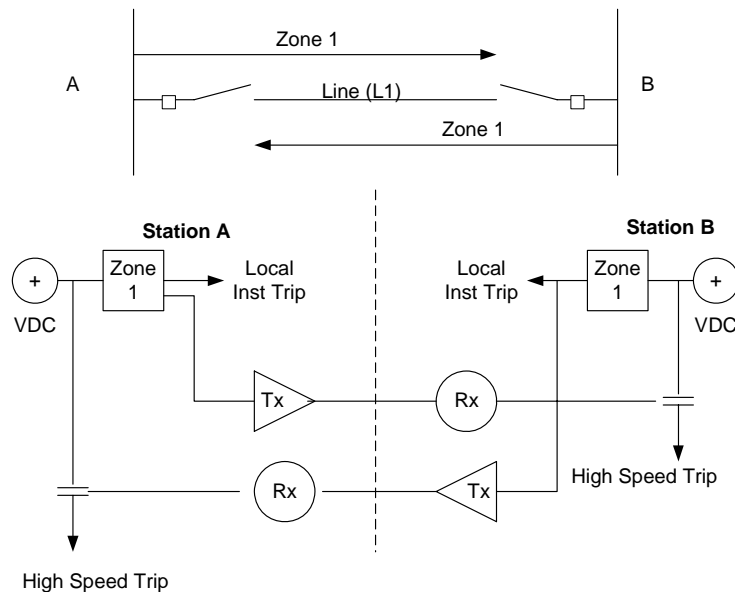


Figure A-3 — Direct Underreaching Transfer Trip

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2.4 Permissive Overreaching Scheme

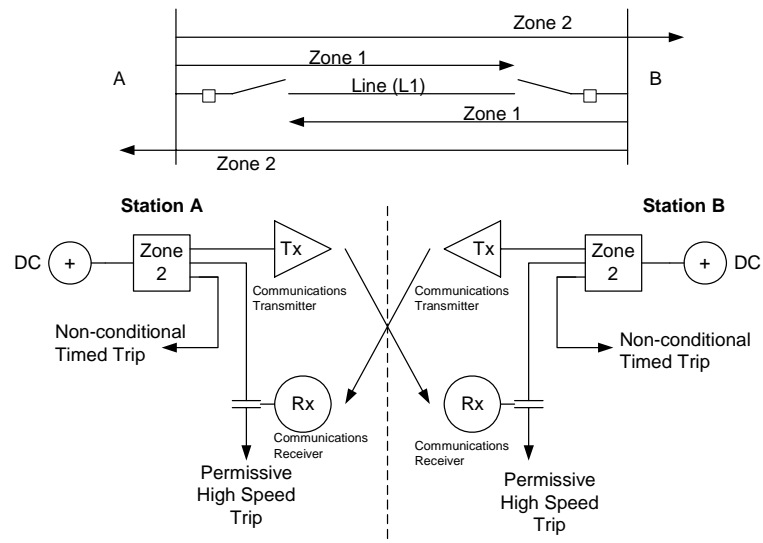


Figure A-4 — A Permissive Overreaching Scheme

Attributes of a permissive overreaching scheme include the following:

- The Zone 2 overreaching elements key permissive signals to the remote end.
- Upon receipt of a permissive signal from the remote end, the Zone 2 elements are permitted to trip locally without any time delay.
- If the remote end line is open, either due to the remote line disconnect switch being open or the remote breakers being open, the permissive signal is echoed back to the local end ("Permissive Echo"). With the receipt of the permissive echo signal, the Zone 2 overreaching elements generally initiate similar protection schemes as mentioned above.

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2.5 Directional Comparison Blocking

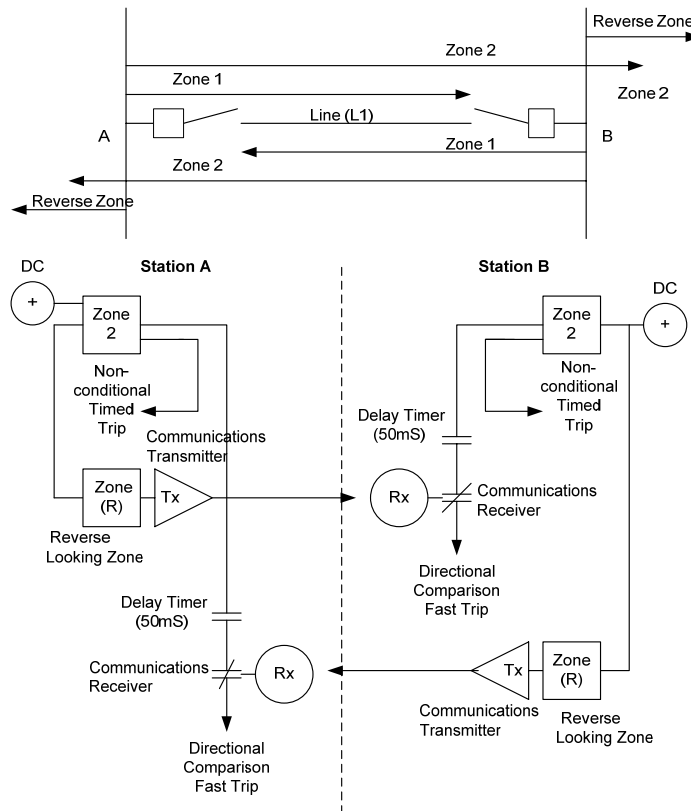


Figure A-5 — A Typical Directional Comparison Blocking Scheme

Attributes of a directional comparison blocking scheme include the following:

- Operation of the Zone 2 elements initiates a timer (channel coordination time, usually ranging up to 50 ms). If a blocking signal is received, within channel coordination time, the Zone 2 elements will not trip locally. If a blocking signal is not received within the channel coordination time, the Zone 2 elements will trip locally.
- The reverse directional Zone 3 elements initiate a blocking signal to the remote terminal, and must be set to cover more line impedance, with margin, than that measured by the forward looking Zone 2 relays at the remote end.

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APPENDIX B — EXAMPLE OF USING REDUNDANT AND DIVERSE PATHS OVER A SONET SYSTEM

The following is one implementation of a line differential protection system for a three-terminal line. The protection system uses redundant local protection systems, consisting of an “A” group line differential relay, and a “B” group line differential, one at each of the three-terminal — six measuring relays.

An example of protection system using redundant and diverse paths over a SONEt system is depicted below.

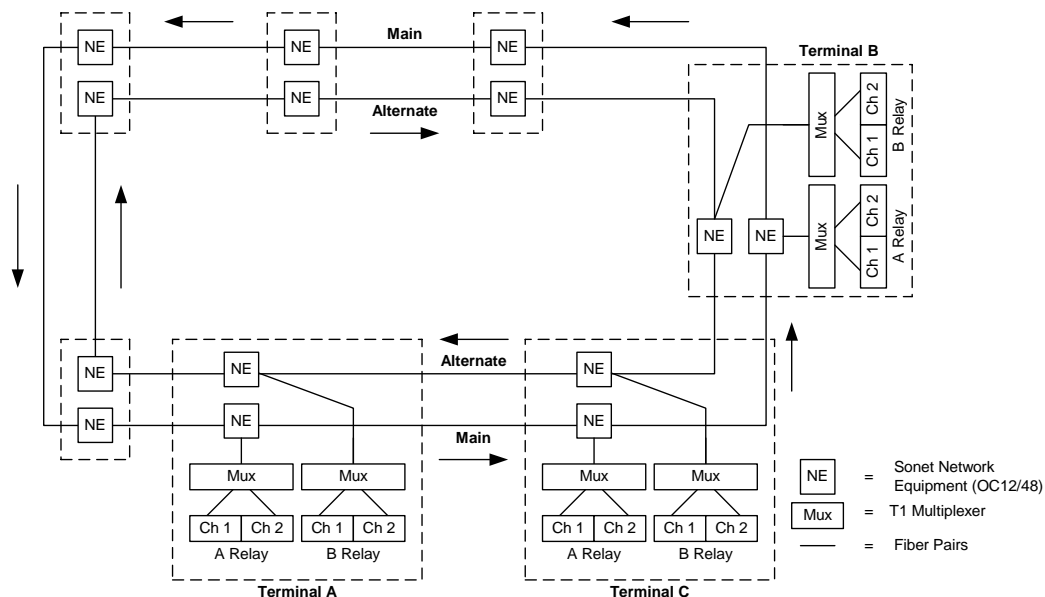


Figure B-1 — An Example of a Three-Terminal Line Differential Scheme Used With Redundant Local Protection Systems

With this implementation, redundant line differential relays with redundant and diverse communication media paths, the backup distance protection systems are only asserted upon total loss of communication failure, and they are designed to trip unconditionally after a time delay (i.e., 400 ms).

Three-terminal lines can be further complicated by the presence of tapped load stations not equipped with a current differential relays. In a line differential application, these tapped load stations represent an error current that may cause a false operation due to load or inrush currents.

Similarly, faults on the low-voltage side of the tapped load stations can cause the line differential system to trip for an out-of-zone fault. For such fault contingencies, the local tapped load protection systems should operate to isolate the fault and not disrupt the line.

Three-Terminal Line Protection

To overcome this complexity, the following techniques may be used:

1. Line differential relays have minimum current sensitivity settings. This setting can be set at a threshold that is above any error current caused by the current outflows. The line differential current setting must ensure fault coverage for all line faults under all expected operating conditions.
2. The line differential operating element (87) can be supervised with a phase distance element. The distance element should be set "short" of the low-voltage tapped station — it should not detect a low-voltage bus fault. However, it must be set to operate for all line faults under all expected operating conditions.
3. If the maximum infeed error is such that, the required distance element setting will result in operation for a low-voltage fault, sequential tripping can be considered. Again, it should be noted that the trip dependability for this scheme relies upon the operation of one of the three-terminal relays for fault clearance. For this reason, this type of scheme should be used with local redundant protection systems, using a design that mitigates common mode of failures.
4. Alternatively, the tapped stations can send blocking signals to the three-terminal stations to block line tripping for low-voltage faults.

Three-Terminal Line Protection

APPENDIX C — TECHNICAL EXCEPTION 8³

Exception 8 — Three (or more) Terminal Lines and Lines with One or More Radial Taps

Three (or more) terminal lines present protective relaying challenges from a loadability standpoint due to the apparent impedance as measured by the different terminals. This includes lines with radial taps. For this exception, the loadability of the line may be different for each terminal of the line so the loadability must be done on a per-terminal basis:

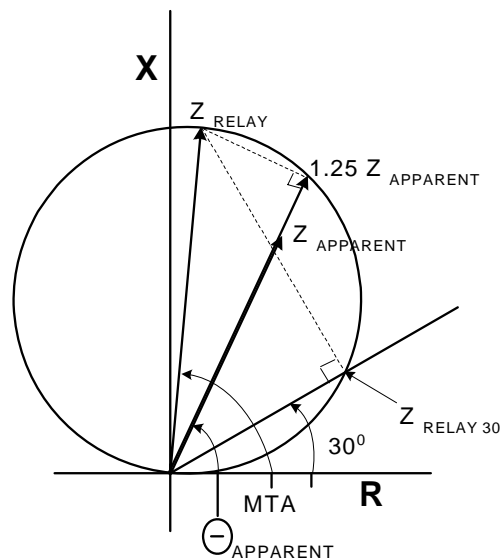


Figure 8 – Three (or More) Terminal Lines and Lines With One or More Radial Taps

The basis for the emergency current loading is as follows:

V_{relay} = Phase-to-phase line voltage at the relay location

$Z_{apparent}$ = Apparent line impedance as measured from the line terminal. This apparent impedance is the impedance calculated (using infeed where applicable) by the TPSO for a fault at the most electrically distant line terminal for system conditions normally used in their protective relaying setting practices.

$\Theta_{apparent}$ = Apparent line impedance angle as measured from the line terminal

Z_{relay} = Relay setting at the maximum torque angle

MTA = Maximum torque angle, the angle of maximum relay reach

$Z_{relay30}$ = Relay trip point at a 30 degree phase angle between the voltage and current

I_{trip} = Trip current at 30 degrees with normal voltage

³ An excerpt from *Relay Loadability Exceptions — Determination and Application of Practical Relaying Loadability Ratings*, Version 1.2, dated August 8, 2005.

Three-Terminal Line Protection

$I_{emergency}$ = Emergency current (including a 15% margin) that the circuit can carry at 0.85 voltage at a 30 degree phase angle between the voltage and current before reaching the trip point

For applying a mho relay at any maximum torque angle to any apparent impedance angle:

$$Z_{relay} = \frac{1.25 \times Z_{apparent}}{\cos(MTA - \Theta_{apparent})}$$

The relay reach at the load power factor angle of 30° is determined from:

$$Z_{relay30} = \left[\frac{1.25 \times Z_{apparent}}{\cos(MTA - \Theta_{apparent})} \right] \times \cos(MTA - 30^\circ)$$

The relay operating current at the load power factor angle of 30° is:

$$I_{trip} = \frac{V_{relay}}{\sqrt{3} \times Z_{relay30}}$$

$$I_{trip} = \frac{V_{relay} \times \cos(MTA - \Theta_{apparent})}{\sqrt{3} \times 1.25 \times Z_{apparent} \times \cos(MTA - 30^\circ)}$$

The emergency load current with a 15% margin factor and the 0.85 per unit voltage requirement is calculated by:

$$I_{emergency} = \frac{0.85 \times I_{trip}}{1.15}$$

$$I_{emergency} = \frac{0.85 \times V_{relay} \times \cos(MTA - \Theta_{apparent})}{1.15 \times \sqrt{3} \times 1.25 \times Z_{apparent} \times \cos(MTA - 30^\circ)}$$

$$I_{emergency} = \left(\frac{0.341 \times V_{relay}}{Z_{apparent}} \right) \times \left(\frac{\cos(MTA - \Theta_{apparent})}{\cos(MTA - 30^\circ)} \right)$$

APPENDIX D — REFERENCES

1. *Relay Loadability Exceptions — Determination and Application of Practical Relaying Loadability Ratings, Version 1.2*, August 8, 2005, NERC System Protection and Controls Task Force
2. *Protection System Review Program, Beyond Zone 3*, August 2005, NERC System Protection and Controls Task Force
3. *Methods to Increase Line Relay Loadability*, June 7, 2006, NERC System Protection and Controls Task Force
4. IEEE Standard C37.113-1999, *Guide for Protective Relay Applications to Transmission Lines*

Three-Terminal Line Protection

APPENDIX E — SYSTEM PROTECTION AND CONTROL TASK FORCE

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KENTUCKY UTILITIES COMPANY

**Response to Commission Staff's Post-Hearing Request for Information
Dated June 3, 2022**

Case No. 2022-00066

Question No. 5

Responding Witness: Elizabeth J. McFarland

Q-5. Provide the number of additional megawatts of load available, without sacrificing reliability, for the following:

- a. Daviess–Hardin County line;
- b. Brown North–Hardin County line;
- c. The proposed Western 345 kV route;
- d. The proposed Eastern 345 kV route;
- e. The two proposed substations; and
- f. The proposed project in total.

A-5.

- a. The currently available capacity on the Daviess County–Hardin County line is 657.9 MVA in the Summer and 647.8 MVA in the Winter.

The planned available capacity on the Daviess County—Hardin County line after the addition of the Ford load is 540.2 MVA in the Summer and 575.4 MVA in the Winter.

- b. The currently available capacity on the Brown North–Hardin County line is 931.6 MVA in the Summer and 851.3 MVA in the Winter.

This line will be split into the Hardin County—Glendale South and Glendale South—Brown North lines during this project, so the Brown North—Hardin County line will not exist as such.

- c. The planned available capacity on the Hardin County–Glendale South 345kV (including the West Route) after the addition of the Ford load will be 785.8 MVA in the Summer and 769.9 MVA in the Winter.

- d. The planned available capacity on the Brown North–Glendale South 345kV (including the East Route) after the addition of the Ford load will be 1,022.3 MVA in the Summer and 1,088.5 MVA in the Winter.
- e. The ratings of the equipment at the proposed substations are inherently included in the rated available and planned capacities in responses (a) – (d).
- f. The planned available capacity of the Glendale South substation before network upgrades would be required depends on the power factor of that additional load. Also, the limiting constraint of the Glendale South substation capacity is a lack of voltage support when the transmission system is under contingency, not the expected available capacity on the 345kV lines.

At 99% power factor, the total available capacity is estimated to be approximately 400 MW, 320 MW of which is Ford. At 98% power factor, the total available capacity is estimated to be approximately 385 MW, 320 MW of which is Ford. At 95% power factor, the total available capacity is estimated to be approximately 380 MW, 320 MW of which is Ford.

KENTUCKY UTILITIES COMPANY

**Response to Commission Staff's Post-Hearing Request for Information
Dated June 3, 2022**

Case No. 2022-00066

Question No. 6

Responding Witness: Elizabeth J. McFarland

- Q-6. Reconcile the testimony regarding proposed Western Route D, specifically the following statements:
- a. Western Route D would have required the purchase of two residences according to Ms. McFarland.
 - b. Team Spatial report lists in estimated expenses \$0 for cost of residences for the Western Route D.
- A-6.
- a. During the Alternate Route Evaluation phase, Team Spatial did not identify any residences within the projected right-of-way. The two residences in question are just over 200 feet apart and Team Spatial believed an alignment could be situated to avoid residences within the right-of-way. In the Expert Judgement phase of the siting study, the team evaluated the location of the two residences along the proposed Western D route. In this particular case, due to the close proximity of the line to these two residences, it was judged that these residences would likely be purchased based on the type of line being constructed and proximity to the houses.
 - b. Team Spatial did not apply costs of the residences in the alternate route evaluation model because they did not identify any residences within the projected right-of-way. From a practical standpoint, the reality is that these structures are so close to the right-of-way, that a full purchase of the property would likely be required. This is an example of the experience and practicalities being applied in the Expert Judgment Model to reach the best overall and implementable result.

KENTUCKY UTILITIES COMPANY

**Response to Commission Staff's Post-Hearing Request for Information
Dated June 3, 2022**

Case No. 2022-00066

Question No. 7

Responding Witness: Elizabeth J. McFarland

- Q-7. For the proposed Western Route D, provide parcel numbers, distance from the centerline, and the reason requiring the utility to purchase the residences along the proposed Western Route D.
- A-7. The parcel numbers for the two potentially impacted residential homes are 205-00-01-049 and 205-00-01-056. The distance from the centerline to the homes on parcels 205-00-01-049 and 205-00-01-056 is approximately 100 ft. Constructing a new transmission line in close proximity to a residential home is not an engineering best practice and would have required additional structures and short span construction to complete the necessary alignment shifts to avoid an encroachment in the proposed ROW. The 200' right of way's impact to these two properties and adjacent parcels without residences would have likely required KU to purchase these properties. See the response to Question No. 6 of these requests and the response to Question No. 1 of the Wade Post-Hearing Data requests for a map depicting the subject situation.

KENTUCKY UTILITIES COMPANY

**Response to Commission Staff’s Post-Hearing Request for Information
Dated June 3, 2022**

Case No. 2022-00066

Question No. 8

Responding Witness: Elizabeth J. McFarland

Q-8. Provide a breakdown of all anticipated costs of constructing each of the alternative eastern proposed routes and each of the alternative western proposed routes for the 345 kV transmission lines.

A-8. For the 345 kV West Route refer to Team Spatial page 53 “Engineering” section or the attached table for a cost breakdown of 345 kV proposed routes.

	Route A	Route B	Route C	Route D
Total Project Costs	\$19,469,092	\$20,134,072	\$17,808,900	\$17,688,287
Construction Cost (\$2.9M/mile)	\$14,261,916	\$13,633,698	\$12,710,277	\$11,923,924
Land Acquisition Cost	\$131,296	\$475,362	\$236,623	\$218,363
Angles	\$3,640,000	\$4,750,000	\$4,070,000	\$4,730,000
0-3° Angle (\$90K)	\$90,000	\$450,000	\$270,000	\$180,000
3-26° Angle (\$500K)	\$2,000,000	\$2,000,000	\$1,500,000	\$1,500,000
26-60° Angle (\$750K)	\$750,000	\$1,500,000	\$1,500,000	\$2,250,000
26-80° Angle - Ford Property Only (\$400K)	\$800,000	\$800,000	\$800,000	\$800,000
Clearing Cost (\$40K/Acre)	\$835,880	\$675,013	\$792,000	\$816,000
Transmission Line Crossing (\$600k/crossing)	\$ 600,000	\$ 600,000	\$ -	\$ -
Cost of Residence (100k/resident)	\$ -	\$ -	\$ -	\$ -

For the 345 kV East Route refer to Team Spatial page 69 “Engineering” section or the attached table for a cost breakdown of 345 kV proposed routes.

	Route A	Route B	Route C
Total Project Costs	\$15,846,287	\$14,822,945	\$16,363,257
Construction Cost (\$2.9M/mile)	\$10,333,442	\$10,838,863	\$11,136,632
Land Acquisition Cost	\$535,535	\$185,793	\$186,476
Angles	\$4,790,000	\$3,550,000	\$4,550,000
0-3° Angle (\$90K)	\$90,000	\$0	\$0
3-26° Angle (\$500K)	\$3,500,000	\$2,000,000	\$1,500,000
26-60° Angle (\$750K)	\$0	\$750,000	\$2,250,000
26-80° Angle - Ford Property Only (\$400K)	\$1,200,000	\$800,000	\$800,000
Clearing Cost (\$20K/Acre)	\$187,309	\$248,289	\$490,148
Transmission Line Crossing (\$600k/crossing)	\$ -	\$ -	\$ -
Cost of Residence (100k/resident)	\$ -	\$ -	\$ -

Updated estimates were provided for the preferred (East & West) routes in response to PSC 4-7. The updated estimates for the preferred routes were established through engineering design utilizing historical material costs. Completing engineering design for the alternate routes will require 3-4 weeks and KU expects the alternate route cost estimates to remain relative to the costs provided for the preferred routes. Additionally, for all the reasons set forth in the Team Spatial Siting Study, the identified preferred routes would remain the preferred routes.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Post-Hearing Request for Information Dated June 3, 2022

Case No. 2022-00066

Question No. 9

Responding Witness: Elizabeth J. McFarland

- Q-9. Provide a detailed description, including documentation and criteria, for the expert judgment portion of the funnel model documented in the Team Spatial Report, including a list of any qualitative and/or quantitative characteristics, categories, or features taken into consideration along with the corresponding weight in the valuation resulting in the figure on page 61 of the Team Spatial Report.
- A-9. All of the data collected by Team Spatial, specifically the data shown on pages 53-58 (West Route) and pages 69-74 (East Route) of the Team Spatial Siting Study, was used to guide the Expert Judgment Model and evaluation.

The weighting of each criterion was established using expert judgement based on relative importance to the project. The *qualitative* evaluation of each criterion, guided by the statistics presented in the siting study, was performed by the expert team to score each route based on the following: community issues, schedule delay risk, reliability, natural environment considerations, and construction/maintenance accessibility. Expert judgement was used to score each route according to their perceived impact and each of those considerations was assigned a 1 or 2 as shown on page 61 of the Team Spatial Siting Study for the West Route. Because these are qualitative criterion, the scoring is binary – either a 1 or 2 is assigned as the score when judging between two alternatives.

The *cost* criterion is the only *quantitative* criteria represented in the expert judgement model and is scored *relative* to the total project cost, presented in Figure 45 (West Route, page 53) and Figure 59 (East Route, page 69). For example, for the West Route, see page 61 of the Siting Study showing a 1.1 value for Route A and a 1.0 value for Route D with the statement above Figure 51 that “score was based on relative cost compared to the lowest cost route.” This is not a binary “1 or 2” scoring that is used for qualitative criteria. The preferred route was scored and selected using the expertise of utility professionals with experienced gained from past projects.