With the possibility of current for line faults supplied from both the distributed generator (DG) and the utility, the radial line tends to become a loop type for which directional relays might be needed. For Figure 12.4, if a DG is connected to the feeder circuit as shown, a problem may exist for a fault on an adjacent feeder. The DG supplies current to the fault through the feeder, and its nondirectional overcurrent relays on the adjacent feeder. The possibility exists that both the unfaulted DG feeder and the faulted feeder may trip.

However, practically, the DG contribution is often quite small when compared with that from the utility. The large utility contribution requires a high setting, and with very inverse-time–current relay characteristics generally used, the operating time for the low DG contribution through its feeder is very long. Hence, directional-type relays may not be required. However, with increased proliferation of DGs on distribution circuits, this can evolve into a concern over time. Ground current contribution from DGs can also decrease the sensitivity of relaying on the line breaker for detecting ground faults. Protection engineers need to be alert to these concerns.

It is mandatory, as emphasized in Chapter 8 and as repeated in this chapter, that all distributive power sources be promptly disconnected from the utility, whenever there is an interruption between the utility and the nonutility sources. This can be accomplished by undervoltage (27), overvoltage (59), and under-and-overfrequency (81/U, 81/O) relays at the DG units. Instantaneous tripping on overvoltages should be provided, where high voltages can occur because of ferroresonance in an isolated island that includes a generation source. A setting high enough to prevent nuisance tripping is required.

If the utility and its ground source can be separated from an ungrounded DG, the DG and the connected system can operate in an ungrounded mode. A 59N relay connected across the wye-grounded–broken delta should be used for protection.

When a DG can become islanded with part of the utility system, for which it could supply the load, some method of remote tripping of the DG is required. One reason, among many cited in Chapter 8, is that the utility cannot restore its service without potential damage to the DG and connected customers.

Instantaneous, automatic reclosing cannot be used on circuits with DG sources. Reclosing should be done at the utility terminal only on the assurance that the DG is not connected or that synchronization is not required. As is appropriate, the DG unit must be connected or resynchronized to the utility only after assurance that the utility line has been permanently restored.

Specific application for all DG connections must be coordinated with the utility, for each has its own requirements.

12.8 EXAMPLE: COORDINATION FOR A LOOP SYSTEM

Coordination for a loop system is much more complex and difficult. For each fault, the current-operating relays that overreach other relays will be different from those of the current that operates the overreached relays. This is in addition to the variation in current levels by system operation. Thus, the current overlay technique is very difficult or impossible to use. A coordination chart will be used in the example. Because fault current can flow in either direction through the line, directional-type time–overcurrent relays are required. They may not be required for instantaneous overcurrent units, but they are often used for uniformity and possible future system charges that might make them necessary. The "trip direction" of the directional relays normally is into the line that is protected.

A typical loop system is shown in Figure 12.6, the key faults that are documented for the several breakers at the three buses of the loop for three

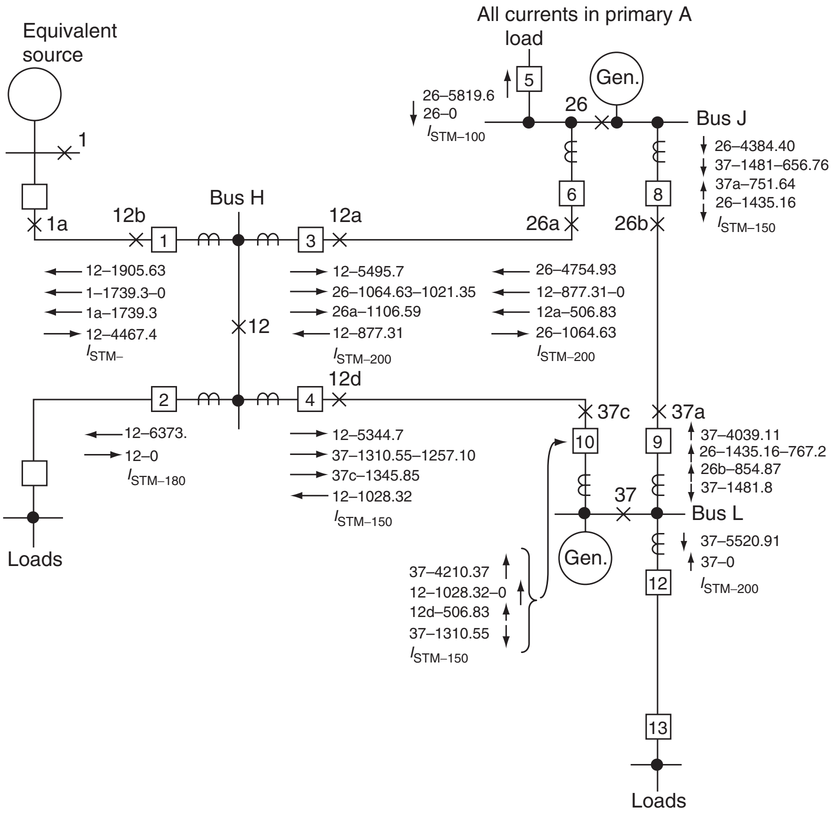

FIGURE 12.6 Typical loop system with multiple sources. Three-phase fault currents at 34.5 kV. First value is the maximum current, second value is the minimum current. The minimum-operating condition considered was the generators at buses J and L of service for light load. The generator–transformer units have fast differential protection.

phase faults. Typical settings will be made for the phase relays. The setting ground relays for the system is similar using phase-to-ground fault data and relay pickup values, as outlined earlier. In general, these taps will be one-half or less of the phase relays taps for most systems.

The directional time–overcurrent relays are applied at breakers 1, 3, 4, 6, 8, 9, and 10, with each directional unit "looking into the line" or operating when current is flowing into the line section.

Around the loop, clockwise:

- Relays at 3 must coordinate with relays at 5 and 8.
- Relays at 8 must coordinate with relays at 10 and 12.
- Relays at 10 must coordinate with relays at 1, 2, and 3.

Around the loop, counterclockwise:

- Relays at 4 must coordinate with relays at 9 and 12.
- Relays at 9 must coordinate with relays at 5 and 6.
- Relays at 6 must coordinate with relays at 1, 2, and 4.

Thus, it is seen that the loops are not completely independent. The settings in both are dependent on the settings of the relays on other circuits (and loops) from the several buses. In the example, these other circuits are the relays at breakers 1, 2, 5, and 12, and the generators at buses J and L. In setting relays around the loop, the first step is to determine the settings and operating times for these relays. To simplify the example, assume that the settings for these are the following:

- *Phase relays breaker 1*: Pilot relays with operating time not exceeding 0.06 sec are used on this short line.
- *Phase relays breaker 5*: Maximum-operating time for fault 26 on the line is 0.24 sec.
- *Phase relays breaker 12*: Maximum-operating time for fault 37 on the line is 0.18 sec.
- *Phase relays breaker 2*: Maximum-operating time for fault 12 on the line is 0.21 sec.

In setting relays around a loop, a good general rule is to attempt to set each relay to operate in less than 0.20 sec for the close-in fault and at least 0.20 sec and the CTI for the far-bus fault. Where the relays protective lines extending from the remote bus have operating times longer than 0.20 sec, the setting should be the sum of that maximum time and the CTI. For this example, a CTI of 0.30 sec will be used.

The relay coordination information for setting the relays around the loop in the clockwise direction, starting arbitrarily at breaker 3, is documented for convenience in Figure 12.7a. With the short-time maximum load of 200 A, 250:5 CTs can be used. The maximum load is then $200/50 = 4$ A secondary. Select relay tap 6, which is 1.5 times this maximum load and gives a primary fault current pickup of $6 \times 50 = 300$ A.

Typical time–overcurrent relay curves are illustrated in Figure 12.8 for determining the time dial setting for coordination. In Figure 12.7a, relay 3 operating times for fault 26 at the far bus must be at least $0.24 + 0.30 = 0.54$ sec, assuming that relays at breaker 8 can eventually be set to operate for close-in fault 26 at not more than 0.24 sec. For this maximum fault (26), relay

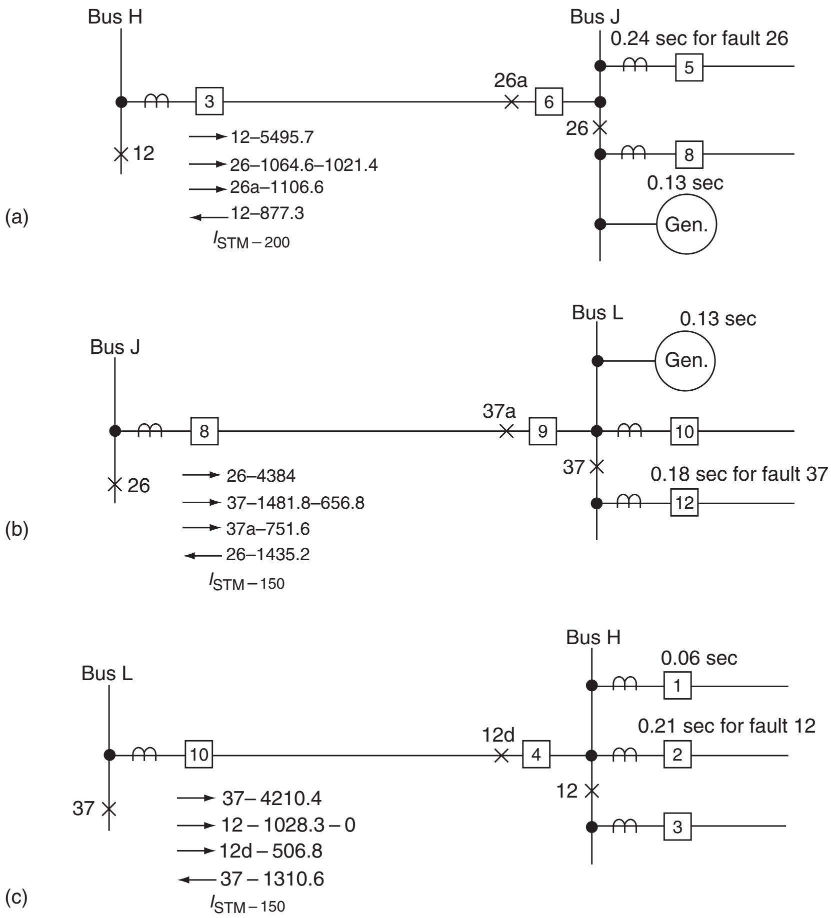

FIGURE 12.7 Information for setting relays for phase-fault protection, clockwise around the loop of Figure 12.6: (a) data for setting breaker three–phase relays; (b) data for setting breaker eight phase relays; (c) data for setting breaker ten phase relays.

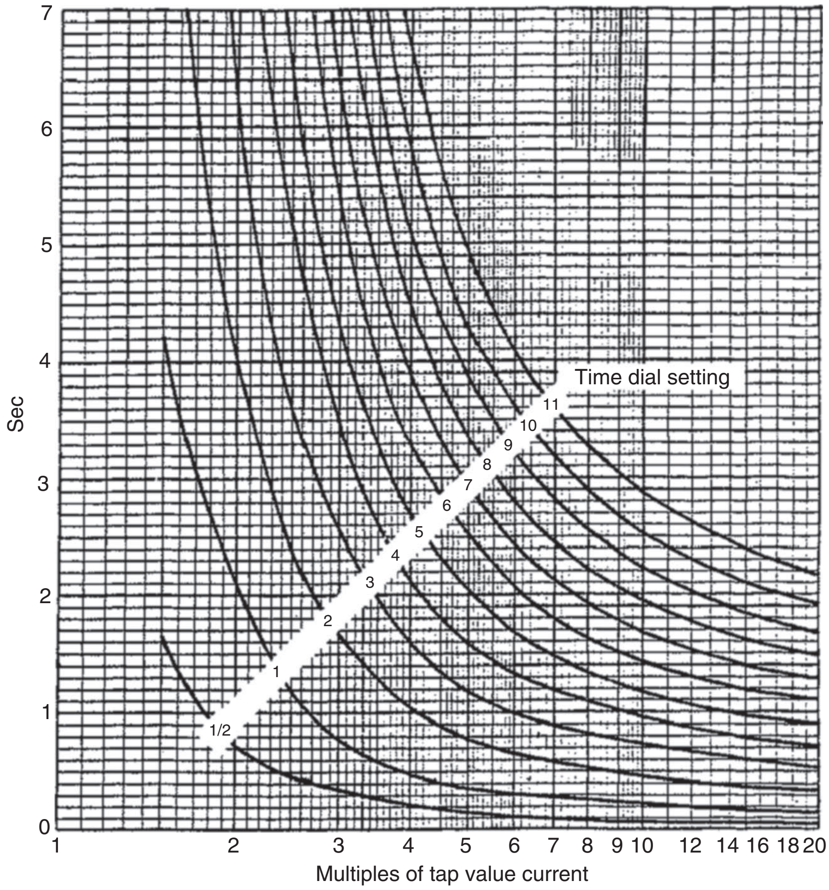

FIGURE 12.8 Typical inverse-time–overcurrent relay curves. (Courtesy of Westinghouse Electric Corporation.)

3 receives 1064.6 A or $1064.6/300 = 3.55$ multiple of its pickup current. From Figure 12.8, a time dial of 1 provides an operating time of 0.58 sec at this multiple, and thus coordination. Relay 3 operating times are for minimum fault 26, 0.61 sec ($1021.4/300 = 3.4$ multiple), maximum close-in fault 12, 0.18 sec ($5495.7/300 = 18.32$ multiple), and minimum line-end fault 26 A, 0.54 sec ($1106.6/300 = 3.69$ multiple). This line-end fault is not a coordination concern, because for it, breaker 6 is open. With directional relays at 3, bus fault 12 is not involved.

At this point move to bus J to set relays at breaker 8. The data are shown in Figure 12.7b. With a 150 A load, 200:5 ratio CTs are suggested. With these, secondary load is $150/40 = 3.75$ A. Tap 5 provides a margin of 1.33 times maximum load and a primary fault current pickup of $5 \times 40 = 200$ A. At this instance, with relay 3 operating at 0.61 sec minimum for fault 26, from the foregoing, relay 8 should not operate more than 0.61–0.3 = 0.31 sec for fault 26. The time of relays at 10 are unknown, but for the rest at bus L, relay 8 for faults 37 must be at least 0.18 + 0.3 = 0.48 sec. Maximum close-in fault 26 is 4384 A, to provide a multiple of 4384/200 = 21.9. For the far-bus fault 37, the multiple is 1481.8/200 = 7.41. From the time curves (see Figure 12.8), time dial 2 provides 0.35 sec for the close-in fault and 0.56 sec for the far-bus maximum fault. This does not coordinate. Going back to relay 3 and increasing its time dial to 1.5, changes the operating times to 0.25 sec for the close-in fault and 0.85 sec for the far-bus maximum fault. This is 0.5 sec longer than relay 8.

Continuing around the loop to relays at breaker 10, the 150 A load suggests 20:5 CTs, giving a secondary load current of 150/40 = 3.75 A. Tap 5 provides a margin of 1.33 more than the maximum load, and a primary current pickup of $5 \times 40 = 200$ A. For the close-in fault 37, the relay multiple is 4210.4/200 = 21. For the maximum far-bus fault 12, the multiple is 1028.3/200 = 5.14. The limits for relay 10 are shorter than 0.26 sec (0.56−0.30) for the close-in fault and longer than 0.55 sec (0.25 + 0.30) for the far-bus fault. Time dial 1.5 just meets this, thereby providing coordination.

Numbers are confusing, so the coordination around the loop is summarized in Figure 12.9. The relays at bus H are repeated to show coordination. The times in parentheses are the operating times for the far-bus minimum fault and the line-end fault. With the generators out of service at both buses J and L for the minimum condition, no current flows through breakers 10 and 6 for far-bus faults. This changes after the far-bus relay 4 or 3 opens, which provides fault current per 12d and 12a, respectively, the line-end faults. It is important to ensure that the relays can respond to these line-end faults; otherwise, they cannot be cleared.

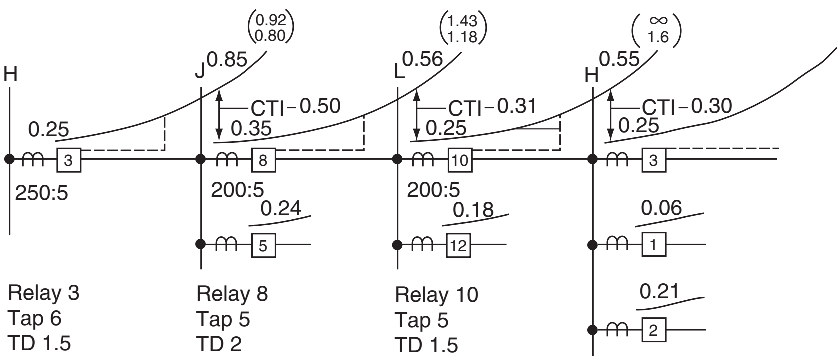

FIGURE 12.9 Summary of the phase relay settings around the clockwise loop of the Figure 12.6 system. The dashed horizontal lines represent instantaneous overcurrent protection.

The loop for this minimum-operating condition becomes a single-source loop. Although most distribution systems are radial, some are of this single-source loop type. It is also used in industrial plant complexes where there are several separate load areas. The advantage is that any one-line circuit can be removed with service available to all the loads. In this type of system, where the source is at bus H only (see Figure 12.6), the relays at breaker 6 do not need to coordinate with the relays at 1, 2, and 4, because they do not have current for fault 12. Similarly, relays at 10 do not need to coordinate with relays at 1, 2, and 3. Faults on the lines, such as at 12a and 12d, can be detected only after breakers 3 or 4, respectively, have opened when the fault current of the line-end fault exists. Thus, these faults are "sequentially cleared." Load current into these lines would also be zero, unless there are other line taps. As a result, direction instantaneous relays can be applied at breakers 6 and 10 and set very sensitively and below the values for line-end faults. This provides "high-speed sequential operation" for these terminals. The next phase in the coordination process for the loop example is to set relays 4, 9, and 6 counterclockwise around the loop. This will not be continued, as the basic principles have been covered.

In most actual systems, attention must be given to the possibilities of various lines out of service and other operating conditions that may occur. It would be desirable to set all the relays to provide complete backup protection over all the adjacent remote lines. In the example, this would be to have the relays at breaker 3 provide protection for faults to bus L and out on load line 5 to any sectionalizing point. This may or may not be possible. The "infeed" of fault current by the source at bus J tends to reduce the fault current through 3 for faults on line JL and at bus L.

The computers that provide fault data for many variables and operating conditions also provide an excellent tool for setting and coordinating relays. Several such programs exist with varying degrees of capability and sophistication, and others are developed. These can be of great value in reducing the time and the drudgery of hand coordination, and often consider more alternatives and conditions than would otherwise be convenient.

12.9 INSTANTANEOUS TRIP APPLICATION FOR A LOOP SYSTEM

When a reasonable difference in the fault current exists between the close-in and far-bus faults, instantaneous units can be used to provide fast protection for faults out on the line. The fundamentals were outlined in Section 12.4.3. For the example of Figure 12.6 and using Figure 12.7, instantaneous unit at relays 3 must be set at k times the maximum far-bus fault current of 1064.6. Using $k = 1.2$, the setting would be 1277.5 A or 1278 A. This gives good coverage for the line compared with the close-in fault of 5495.7 A. The