

DISTRIBUTION NETWORKS

1. Introduction to distribution

Electric power distribution is the portion of the power delivery infrastructure that takes the electricity from the highly meshed, high-voltage transmission circuits and delivers it to customers. At a distribution substation, a substation transformer takes the incoming transmission-level voltage (35 to 230 kV) and steps it down to several distribution primary circuits, which fan out from the substation. Close to each end user, a distribution transformer takes the primary-distribution voltage and steps it down to a low-voltage secondary circuit (commonly 230/400 V; other utilization voltages are used as well). From the distribution transformer, the secondary distribution circuits connect to the end user where the connection is made at the service entrance. Functionally, distribution circuits are those that feed customers. Distribution circuits are found along most secondary roads and streets. Urban construction is mainly underground; rural construction is mainly overhead. Suburban structures are a mix, with a good deal of new construction going underground.

Low cost, simplification, and standardization are all important design characteristics of distribution systems. Distribution planning is the study of future power delivery needs. Planning goals are to provide service at low cost and high reliability. Planning requires a mix of geographic, engineering, and economic analysis skills. New circuits (or other solutions) must be integrated into the existing distribution system within a variety of economic, political, environmental, electrical, and geographic constraints. The planner needs estimates of load growth, knowledge of when and where development is occurring, and local development regulations and procedures.

2. Primary Distribution

Primary distribution distributes energy from distribution substations to distribution transformers, where the voltage is stepped down to customer utilization levels. Power distribution is normally done on the medium-voltage level, in the range of 6.6–33 kV. The primary distribution is universally carried out by 3-phase 3-wire system and handle large blocks of power.

Primary distribution systems include three basic types:

1. Radial systems, including duplicate and throw over systems
2. Loop systems, including both open and closed loops
3. Primary network systems

2.1. Radial Systems

The radial-type system is the simplest and the one most commonly used. It comprises separate feeders or circuits “radiating” out of the substation or source, each feeder usually serving a given area. The feeder may be considered as consisting of a main or trunk portion from which there are radiate spurs or laterals to which distribution transformers are connected, as illustrated in Fig. 4.1.

Radial circuits have many advantages over networked circuits including: Easier fault current protection; Lower fault currents over most of the circuit; Easier voltage control; Easier prediction and control of power flows; Lower cost.

Supply to hospitals, military establishments, and other sensitive consumers may not be capable of tolerating any long interruption. In such cases, a second feeder (or additional feeders) may be provided, sometimes located along a separate route, to provide another, separate alternative source of supply. Switching from the normal to the alternative feeder may be accomplished by a throw over switching arrangement (which may be a circuit breaker) that may be operated manually or automatically (Fig. 4.2).

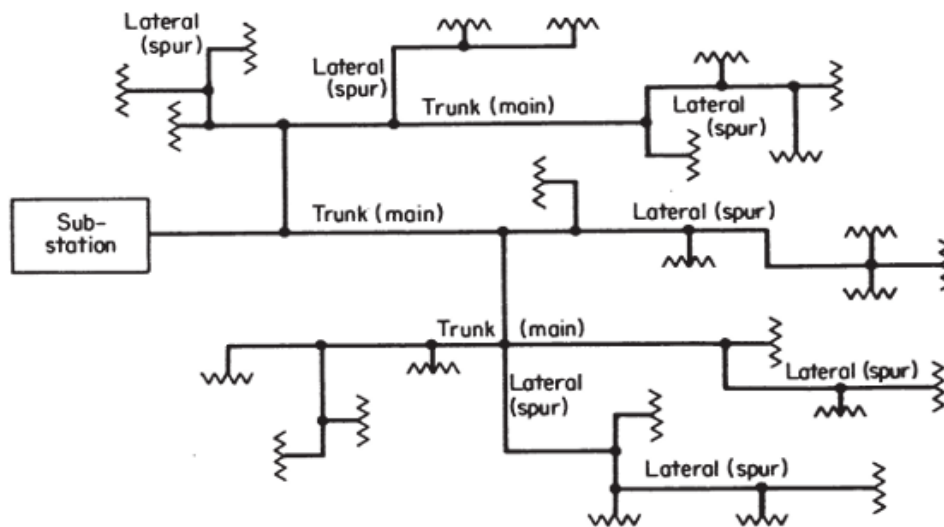


Fig. 4.1: Primary feeder schematic diagram

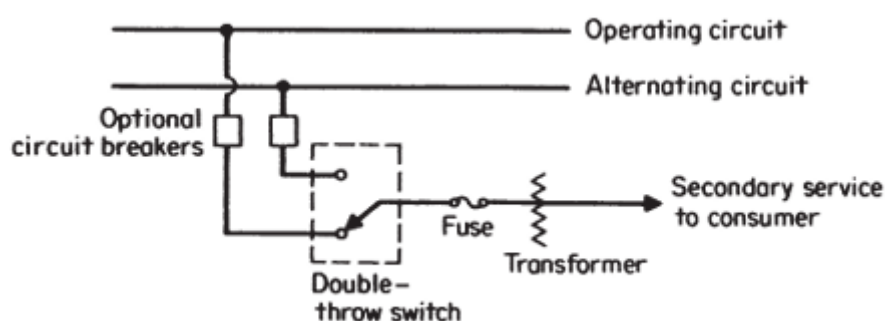


Fig. 4.2: Schematic diagram of alternate feed-throw over arrangement for critical consumers

2.2. Loop Systems

Another means of restricting the duration of interruption employs feeders designed as loops, which essentially provide a two-way primary feed for critical consumers (Fig. 4.3). Here, should the supply from one direction fail, the entire load of the feeder may be carried from the other end, but sufficient

spare capacity must be provided in the feeder. This type of system may be operated with the loop normally open or with the loop normally closed.

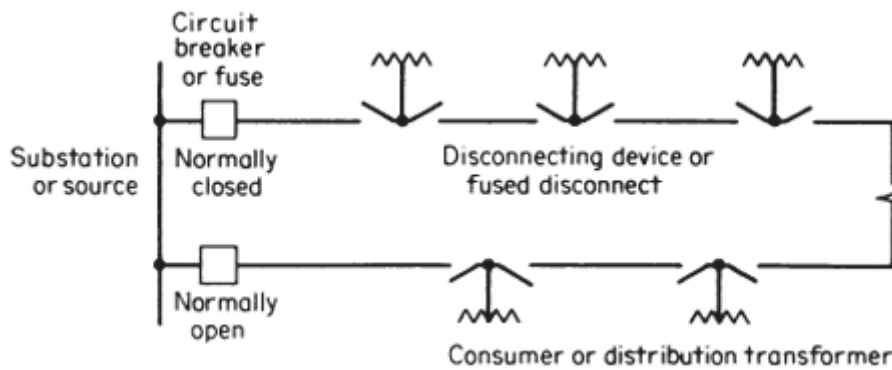


Fig. 4.3: Open-loop circuit schematic diagram

2.3. Primary Network Systems

This system is formed by tying together primary mains ordinarily found in radial systems to form a mesh or grid. The grid is supplied by a number of power transformers supplied in turn from sub-transmission and transmission lines at higher voltages (Fig. 4.4).

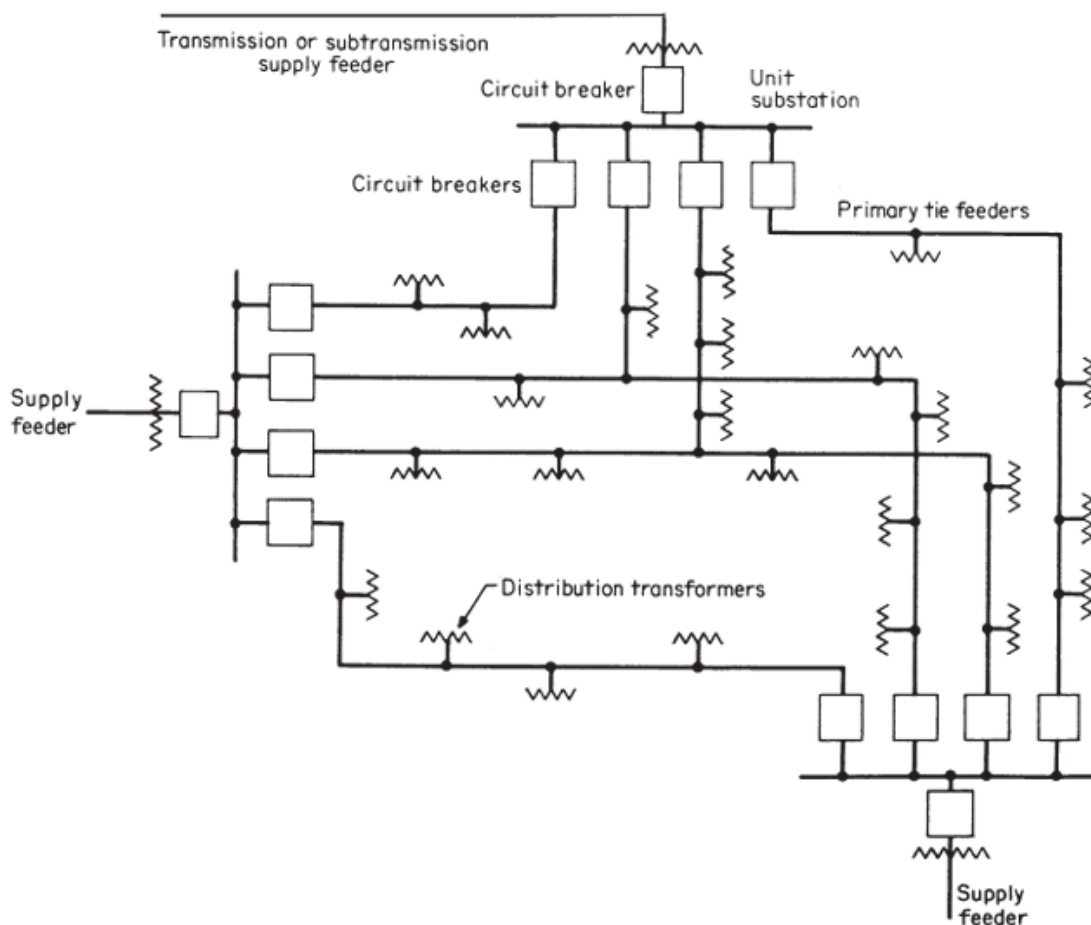


Fig. 4.4: Primary network

3. Secondary Distribution

Secondary distribution distributes energy at customer utilization voltages to meters at customers' premises. Secondary distribution systems operate at relatively low utilization voltages and, like primary systems, involve considerations of service reliability and voltage regulation.

3.1. Individual Transformer—Single Service

Individual-transformer service is applicable to certain loads that are more or less isolated, such as in rural areas where consumers are far apart and long secondary mains are impractical, or where a particular consumer has an extraordinarily large or unusual load even though situated among a number of ordinary consumers. In this type of system, the cost of the several transformers and the sum of power losses in the units may be greater (for comparative purposes) than those for one transformer supplying a group of consumers from its associated secondary main. The diversity among consumers' loads and demands permits a transformer of smaller capacity than the capacity of the sum of the individual transformers to be installed. On the other hand, the cost and losses in the secondary main are obviated, as is also the voltage drop in the main. Where low voltage may be undesirable for a particular consumer, it may be well to apply this type of service to the one consumer (Fig. 4.5).

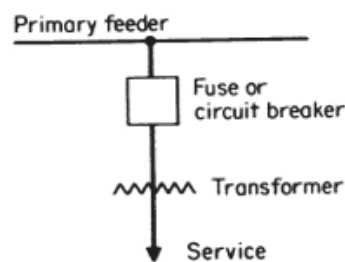


Fig. 4.5: Single-service secondary supply

3.2. Common Secondary Main

Perhaps the most common type of secondary system in use employs a common secondary main. It takes advantage of diversity between consumers' loads and demands, as indicated above. Moreover, the larger transformer can accommodate starting currents of motors with less resulting voltage dip than would be the case with small individual transformers (Fig. 4.6). In many instances, the secondary mains installed are more or less continuous, but cut into sections insulated from each other as conditions require. As loads change or increase, the position of these division points may be readily changed, sometimes holding off the need to install additional transformer capacity. Also, additional separate sections can be created and a new transformer installed to serve as load or voltage conditions require.

3.3. Secondary Networks

Secondary networks at present provide the highest degree of service reliability and serve areas of high load density, where revenues justify their cost and where this kind of reliability is imperative. In some instances, a single consumer may be supplied from this type of system by what are known as spot networks.

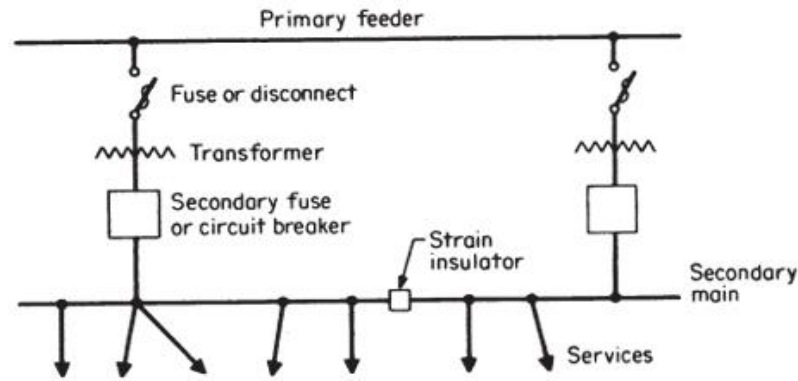


Fig. 4.6: Common-secondary-main supply

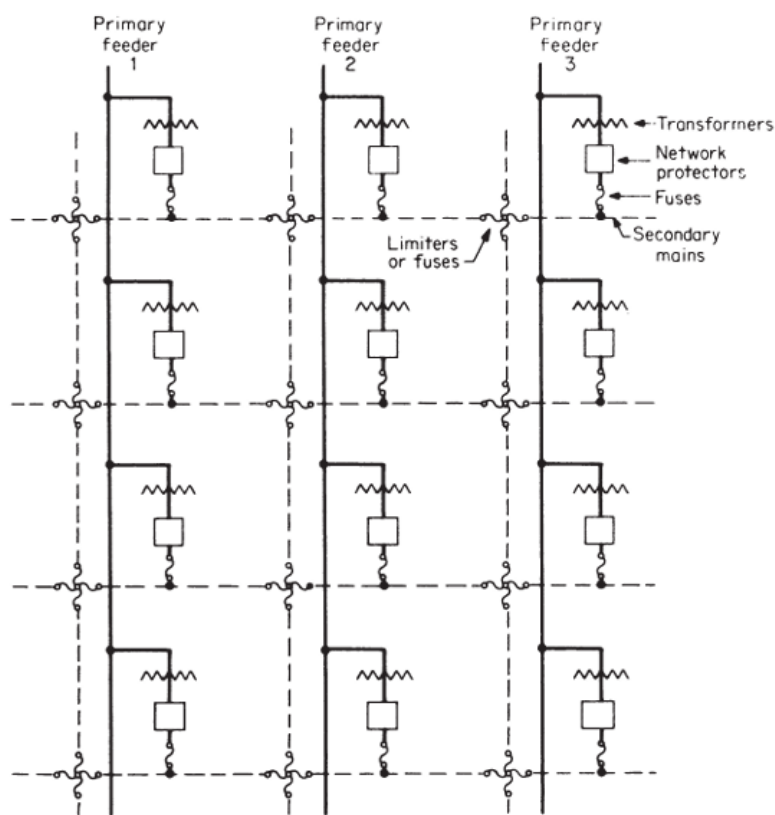


Fig. 4.7: Low-voltage secondary network

In general, the secondary network is created by connecting together the secondary mains fed from transformers supplied by two or more primary feeders. Automatically operated circuit breakers in the secondary connection between the transformer and the secondary mains, known as network protectors, serve to disconnect the transformer from the network when its primary feeder is de-energized; this prevents a back feed from the secondary into the primary feeder. This is especially important for safety when the primary feeder is de-energized from fault or other cause. The circuit breaker or protector is backed up by a fuse so that, should the protector fail to operate, the fuse will blow and disconnect the transformer from the secondary mains (Fig. 4.7). The number of primary

feeders supplying a network is very important. With only two feeders, only one feeder may be out of service at a time, and there must be sufficient spare transformer capacity available so as not to overload the units remaining in service; therefore, this type of network is sometimes referred to as a single-contingency network.

4. Transformers in distribution systems

Distribution substations come in many sizes and configurations. A small rural substation may have a nominal rating of 5 MVA while an urban station may be over 200 MVA.

As much as possible, many utilities have standardized substation layouts, transformer sizes, relaying systems, and automation and SCADA (supervisory control and data acquisition) facilities. Most distribution substation bus configurations are simple with limited redundancy. Transformers smaller than 10 MVA are normally protected with fuses, but fuses are also used for transformers to 20 or 30 MVA. Fuses are inexpensive and simple; they don't need control power and take up little space. Fuses are not particularly sensitive, especially for evolving internal faults. Larger transformers normally have relay protection that operates a circuit switcher or a circuit breaker. Relays often include differential protection, sudden pressure relays, and overcurrent relays. Both the differential protection and the sudden-pressure relays are sensitive enough to detect internal failures and clear the circuit to limit additional damage to the transformer.

Transformers in distribution systems include distribution substation transformers and distribution transformers.

4.1. Distribution substation transformers

Distribution substation transformers come in a wide variety of ratings. They usually contain mineral oil for insulating and cooling purposes. In some units, an inert gas such as nitrogen fills the space above the oil, in order to keep moisture and air out of the oil, and the transformer tank is sealed. Some sealed transformers have a pressure relief diaphragm that is designed to rupture when the internal pressure exceeds a specified value, indicating possible deterioration of the insulation. Sealed transformers may also have a sudden pressure relay to either provide an alarm or de-energize the transformer when the internal pressure suddenly increases above a specified threshold.

Many distribution substation transformers have load tap changers (LTCs) that automatically regulate voltage levels based on loading conditions. Fig. 4.8 shows a distribution substation transformer that has an internal LTC on the low-voltage side. Some distribution substations have distribution substation transformers with fixed taps and separate voltage regulators. A voltage regulator is basically an autotransformer with taps that automatically raise or lower voltage, operating in a similar way as LTCs on distribution substation transformers. In addition to voltage regulators for distribution substations, there are also pole-mount voltage regulators that can be placed on feeders.

Some outdoor distribution substation transformers are equipped with a tank on the top of the transformer called a conservator, in which expansion and contraction of the oil takes place.

Distribution substation transformers have MVA ratings that indicate the continuous load that the transformers carry without exceeding a specified temperature rise of either 55°C (for older transformers) or 65°C (for newer transformers) above a specified ambient (typically 40°C). Also, distribution substation transformers are typically equipped with external radiators with fans and/or oil circulating pumps, in order to dissipate heat generated by copper and core losses.

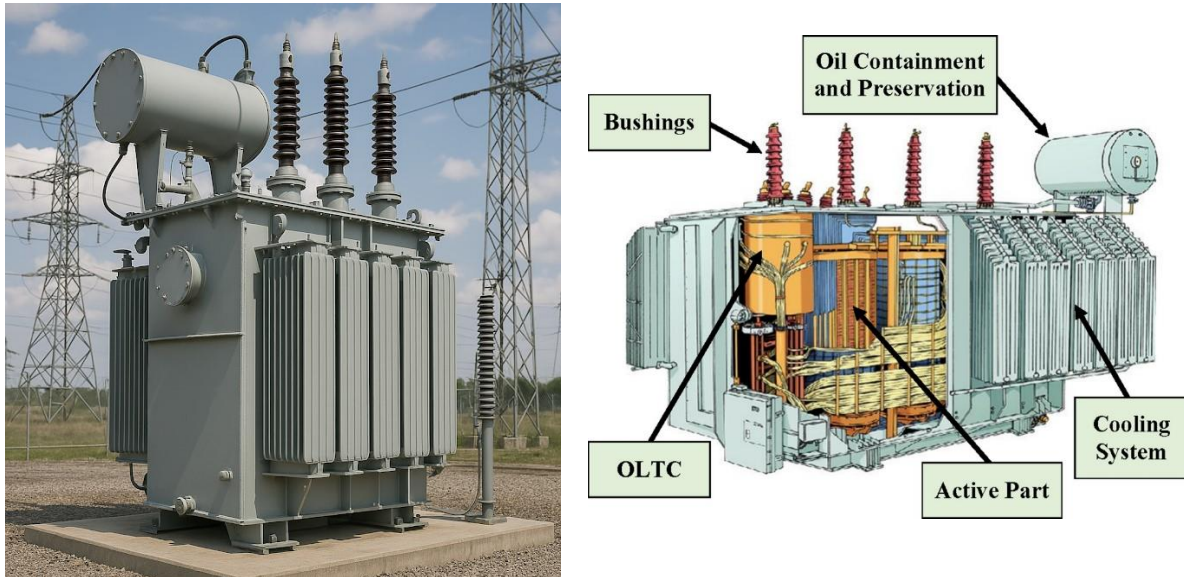


Fig. 4.8: Distribution substation transformer

On-load tap changers

On-load tap changers (Fig. 4.9) are very necessary to maintain a constant voltage on the LV terminals of the transformer for varying load conditions where the voltage had to be maintained constant without interrupting the power supply. This is achieved by providing taps as shown below on the HV winding. The diverter switch is controlled by a motor which ensures that the switch is stepped up or down from one tap to the next taps until the desired secondary voltage is obtained. The ranges are normally chosen depending upon the input supply conditions also. A typical range of taps could be +15% to -5% giving an overall range of 20%.

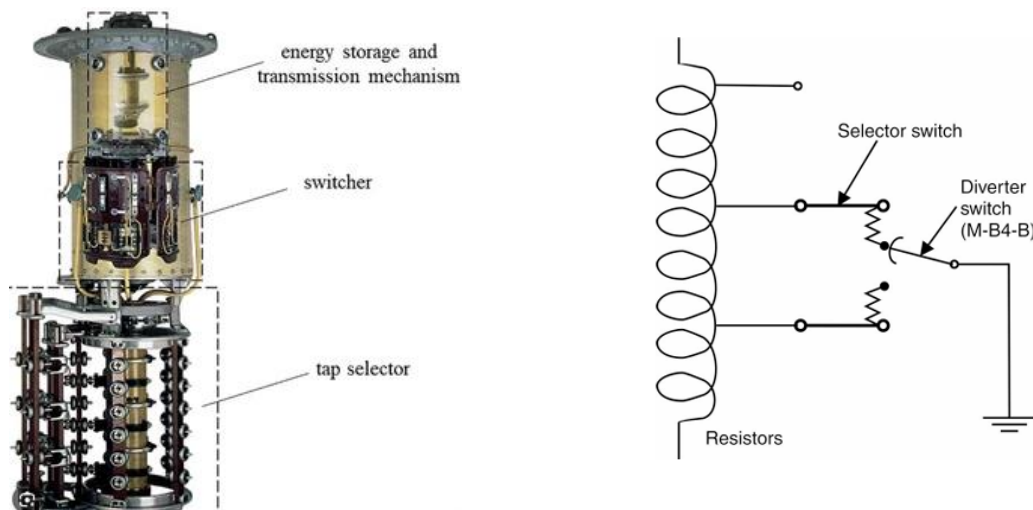


Fig. 4.9: On-load tap changer (LTC)

4.2. Distribution transformers

Distribution transformers connect the primary system to the secondary system. Distribution transformers may be installed outdoors on overhead poles (pole-mount), outdoors at ground level on pads (padmount transformers), indoors within buildings, or underground in manholes and vaults.

Pole-mount transformers for overhead distribution are liquid-filled transformers that can be either single-phase or three-phase, depending on the load requirements and the primary supply configuration. Pole-mount distribution transformers may be manufactured as conventional transformers with no integral surge protection, overload protection, or short circuit-protection, or alternatively as completely self-protected (CSP) transformers.

For conventional pole-mount transformers, the protective devices are mounted external to the transformer. Typically, a fuse cut-out, which is a combination of a fuse and a switch, is installed adjacent to the conventional distribution transformer to disconnect it from the primary under overload conditions or an internal transformer failure. Similarly, a surge arrester is installed adjacent to the conventional transformer primary to protect it against transient overvoltages due to switching and lightning surges. Fig. 4.10 shows a conventional three-phase pole-mount distribution transformer.

Padmount transformers for underground distribution are liquid-filled or dry-type transformers that can be either single-phase or three-phase, outdoors or indoors. Dry type padmount distribution transformers, whose insulation is solid (for example glass, silica, epoxy, or polyester resins) are primarily used where safety is a major concern, in close proximity to people such as at schools, hospitals, commercial buildings, and industrial plants, both indoors and outdoors.



Fig. 4.10: conventional pole mount transformers



Fig. 4.11: Padmount indoor transformer for underground distribution

5. Reactive energy compensation in distribution networks

Shunt capacitors in distribution systems

Loads in electric power systems consume real power (MW) and reactive power (Mvar). At power plants, many of which are located at long distances from load centers, real power is generated and reactive power may either be generated, such as during heavy load periods, or absorbed as during light load periods. Unlike real power (MW), the generation of reactive power (Mvar) at power plants and transmission of the reactive power over long distances to loads is not economically feasible. Shunt capacitors, however, are widely used in primary distribution to supply reactive power to loads. They draw leading currents that compensate the lagging component of currents in inductive loads. Shunt capacitors provide an economical supply of reactive power to meet reactive power requirements of loads as well as transmission and distribution lines operating at lagging power factor. They can also reduce line losses and improve voltage regulation.

Example

Figure 4.12 shows a single-line diagram of a 13.8-kV primary feeder supplying power to a load at the end of the feeder. A shunt capacitor bank is located at the load bus. Assume that the voltage at the sending end of the feeder is 5% above rated and that the load is Y-connected with $R_{load} = 20\Omega/phase$ in parallel with load $jX_{load} = j40\Omega/phase$.

(a) With the shunt capacitor bank out of service, calculate the following: (1) line current; (2) voltage drop across the line; (3) load voltage; (4) real and reactive power delivered to the load; (5) load power factor; (6) real and reactive line losses; and (7) real power, reactive power, and apparent power delivered by the distribution substation.

(b) The capacitor bank is Y connected with a reactance $X_C = 40\Omega/phase$. With the shunt capacitor bank in service, redo the calculations. Also calculate the reactive power supplied by the capacitor bank.

(c) Compare the results of (a) and (b).

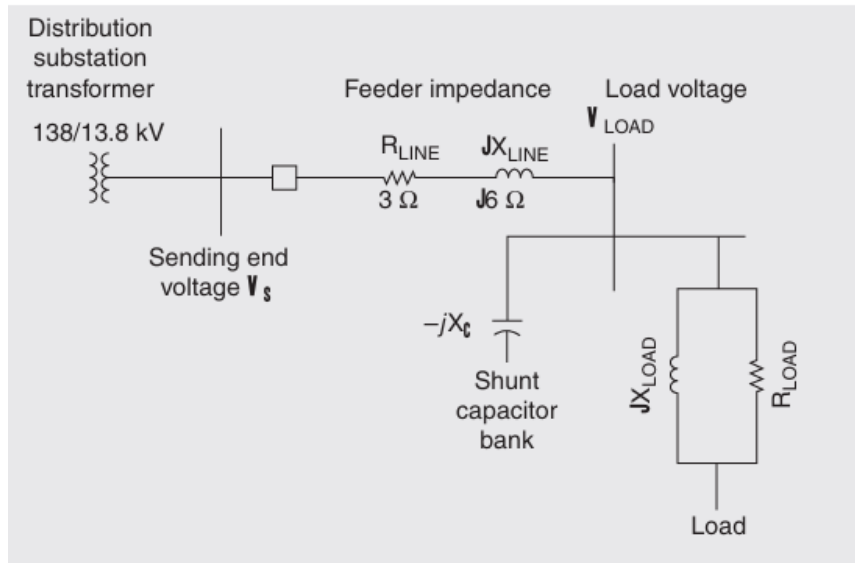


Fig. 4.12: Single-line diagram of a primary feeder for Example

Solution

a. Without the capacitor bank, the total impedance seen by the source is:

$$Z_{total} = R_{line} + jX_{line} + \frac{1}{\frac{1}{R_{load}} + \frac{1}{jX_{load}}} = 3 + j6 + \frac{1}{\frac{1}{20} + \frac{1}{j40}} = 19 + j14 = 23.6 \angle 36.38^\circ \Omega/\text{phase}$$

1. The line current is:

$$I_{line} = \frac{V_s}{Z_{total}} = \frac{1.05(13.8/\sqrt{3}) \angle 0^\circ}{23.6 \angle 36.38^\circ} = 0.3545 \angle -36.38^\circ \text{ kA}$$

2. The voltage drop across the line is:

$$\Delta V = Z_{line} I_{line} = (3 + j6)(0.3545 \angle -36.38^\circ) = 2.378 \angle 27.05^\circ \text{ kV}$$

3. The load voltage is:

$$V_{load} = V_s - Z_{line} I_{line} = 1.05(13.8/\sqrt{3}) \angle 0^\circ - 2.378 \angle 27.05^\circ = 6.342 \angle -9.814^\circ \text{ kV}$$

$$U_{load} = 6.342 \sqrt{3} = 10.98 \text{ kV}$$

4. The real and reactive power delivered to the three-phase load is:

$$P_{load} = 3 \frac{(V_{load})^2}{R_{load}} = \frac{3(6.342)^2}{20} = 6.033 \text{ MW}$$

$$Q_{load} = 3 \frac{(V_{load})^2}{X_{load}} = \frac{3(6.342)^2}{40} = 3.017 \text{ Mvar}$$

5. The load power factor is:

$$pf = \cos \varphi = \cos[\tan^{-1}(Q/P)] = \cos[\tan^{-1}(3.017/6.033)] = 0.89 \text{ lagging}$$

6. The real and reactive line losses are:

$$P_{line} = 3I_{line}^2 R_{line} = 3(0.3545)^2(3) = 1.131 \text{ MW}$$

$$Q_{line} = 3I_{line}^2 X_{line} = 3(0.3545)^2(6) = 2.262 \text{ Mvar}$$

7. The real power, reactive power, and apparent power delivered by the distribution substation are:

$$P_s = P_{load} + P_{line} = 6.033 + 1.131 = 7.164 \text{ MW}$$

$$Q_s = Q_{load} + Q_{line} = 3.017 + 2.262 = 5.279 \text{ Mvar}$$

$$S_s = \sqrt{7.164^2 + 5.279^2} = 8.899 \text{ MVA}$$

b. With the capacitor bank in service, the total impedance seen by the source is:

$$Z_{total} = R_{line} + jX_{line} + \frac{1}{\frac{1}{R_{load}} + \frac{1}{jX_{load}} - \frac{1}{jX_C}} = 3 + j6 + \frac{1}{\frac{1}{20} + \frac{1}{j40} - \frac{1}{j40}}$$

$$= 23 + j6 = 23.77 \angle 14.62^\circ \Omega/\text{phase}$$

1. The line current is:

$$I_{line} = \frac{V_S}{Z_{total}} = \frac{1.05(13.8/\sqrt{3}) \angle 0^\circ}{23.77 \angle 14.62^\circ \Omega} = 0.3520 \angle -14.62^\circ \text{ kA}$$

2. The voltage drop across the line is:

$$\Delta V = Z_{line} I_{line} = (3 + j6)(0.3520 \angle -14.62^\circ) = 2.361 \angle 48.81^\circ \text{ kV}$$

3. The load voltage is:

$$V_{load} = V_S - Z_{line} I_{line} = 1.05(13.8/\sqrt{3}) \angle 0^\circ - 2.361 \angle 48.81^\circ = 7.038 \angle -14.62^\circ \text{ kV}$$

$$U_{load} = 7.038 \sqrt{3} = 12.19 \text{ kV}$$

4. The real and reactive power delivered to the three-phase load is:

$$P_{load} = 3 \frac{(V_{load})^2}{R_{load}} = \frac{3(7.038)^2}{20} = 7.430 \text{ MW}$$

$$Q_{load} = 3 \frac{(V_{load})^2}{X_{load}} = \frac{3(7.038)^2}{40} = 3.715 \text{ Mvar}$$

5. The load power factor is:

$$pf = \cos \phi = \cos[\tan^{-1}(Q/P)] = \cos[\tan^{-1}(3.715/7.430)] = 0.89 \text{ lagging}$$

6. The real and reactive line losses are:

$$P_{line} = 3I_{line}^2 R_{line} = 3(0.3520)^2(3) = 1.115 \text{ MW}$$

$$Q_{line} = 3I_{line}^2 X_{line} = 3(0.3520)^2(6) = 2.230 \text{ Mvar}$$

7. The reactive power delivered by the shunt capacitor bank is:

$$Q_C = 3 \frac{(V_{load})^2}{X_C} = \frac{3(7.038)^2}{40} = 3.715 \text{ Mvar}$$

8. The real power, reactive power, and apparent power delivered by the distribution substation are:

$$P_S = P_{load} + P_{line} = 7.430 + 1.115 = 8.545 \text{ MW}$$

$$Q_S = Q_{load} + Q_{line} - Q_C = 3.715 + 2.230 - 3.715 = 2.230 \text{ Mvar}$$

$$S_S = \sqrt{8.545^2 + 2.230^2} = 8.875 \text{ MVA}$$

c. Comparing the results of (a) and (b), with the shunt capacitor bank in service, the real power delivered to the load increases by 23% (from 6.033 to 7.430 MW) while at the same time:

- The line current decreases
- The real and reactive line losses decrease
- The voltage drop across the line decreases
- The reactive power delivered by the source decreases
- The load voltage increases

The above benefits are achieved by having the shunt capacitor bank (instead of the distribution substation) deliver reactive power to the load.

6. Distribution reliability

Reliability in engineering applications, as defined in the The Authoritative Dictionary of IEEE Standard Terms (IEEE 100), is the probability that a device will function without failure over a specified time period or amount of usage. In the case of electric power distribution, reliability concerns have come from customers who want uninterrupted continuous power supplied to their facilities at minimum cost.

A typical goal for an electric utility is to have an overall average of one interruption of no more than two hours' duration per customer year. Given 8760 hours in a non-leap year, this goal corresponds to an Average Service Availability Index (ASAI) greater than or equal to:

$$8758 \text{ service hours} / 8760 \text{ hours} = 0.999772 = 99.9772\%$$

IEEE Standard 1366–2003 entitled, IEEE Guide for Electric Power Distribution Reliability Indices, defines the following distribution reliability indices:

System Average Interruption Frequency Index (SAIFI):

$$SAIFI = \frac{\sum \text{Total Number of Customers Interrupted}}{\text{Toatal Number of Customers Served}}$$

System Average Interruption Duration Index (SAIDI):

$$SAIDI = \frac{\sum \text{Customer Interruption duration}}{\text{Toatal Number of Customers Served}}$$

Customer Average Interruption Duration Index (CAIDI):

$$CAIDI = \frac{\sum \text{Customer Interruption duration}}{\text{Toatal Number of Customers Interrupted}} = \frac{SAIDI}{SAIFI}$$

Average Service Availability Index (ASAI):

$$ASAI = \frac{\text{Customer Hours service Availability}}{\text{Customer Hours service Demands}}$$

In accordance with IEEE Std. 1366–2003, when calculating the above reliability indices, momentary interruption events are not included. A momentary interruption event has an interruption duration that is limited to the time required to restore service by an interrupting device (including multiple reclosures of reclosers or circuit breakers). Switching operations must be completed within five minutes for a momentary interruption event. As such, customer interruption durations less than five minutes are excluded when calculating the reliability indices. IEEE Std. 1366-2003 also includes a method, when calculating reliability indices, for excluding major events, such as severe storms, for which the daily SAIDI exceeds a specified threshold.

The above formulas for reliability indices use customers out-of-service and customer-minutes out-of-service data. Electric utilities with outage management systems including geographical information systems (GIS) and customer information systems (CIS) are able to very accurately keep track of this data.

Methods for improving distribution reliability include replacement of older distribution equipment, upgrades of problem circuits, crew staffing and training for fast responses to outages and rapid restoration of service, formal maintenance programs, and public awareness programs to reduce hazards in the vicinity of distribution equipment such as contract or dig-ins. Reliability evaluation has also become an important component of bid selections to procure new distribution equipment. Also, great strides in distribution reliability have come through distribution automation.