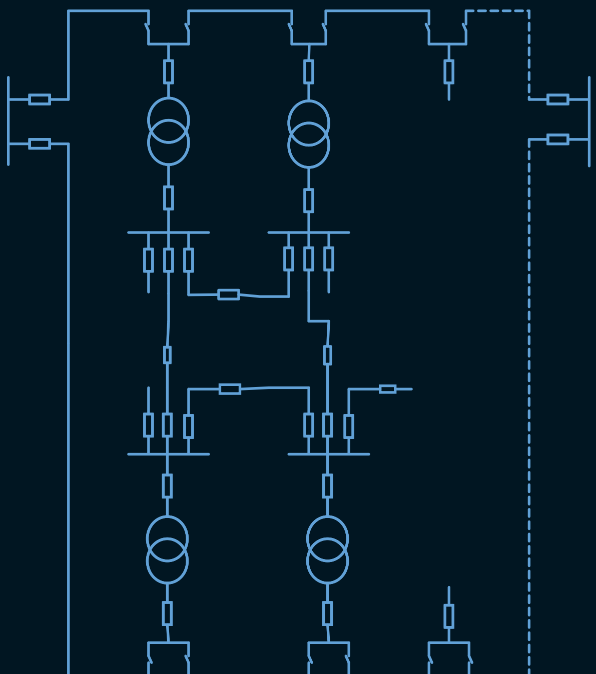
Electric Distribution Systems

Second Edition



Abdelhay A. Sallam

Om P. Malik

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WILEY

ELECTRIC DISTRIBUTION SYSTEMS

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PART II *PROTECTION AND SWITCHGEAR*

PART III *POWER QUALITY*

PART IV *MANAGEMENT AND AUTOMATION*

PREFACE

THANKS TO THE VERY GOOD response received by the first edition of this book, the authors were encouraged to revise and prepare a second edition. In taking advantage of this opportunity, the first edition has been thoroughly revised from the perspectives of

- having a critical look at the organization and structure of the first edition, and
- the inclusion of new developments that have taken place since the first edition was prepared.

Although the basic objective of the book remains the same as described in the preface to the first edition and the material is still grouped in five parts, the original edition had 14 chapters, whereas the new edition has 20 chapters. Some of the new chapters are the result of re-arrangement of the material in the original book, while the rest contain new material. A brief description of the five parts highlighting the changes is given in what follows.

PART I: FUNDAMENTAL CONCEPTS

The background and power system structure, in addition to the layout of the distribution system for both small and large distribution systems, is presented as an introduction in Chapter 1. The fundamental concepts of distribution systems are now the subject of Chapters 2 and 3. The duties of distribution engineers including the factors affecting the planning process are introduced here. It is aimed at identifying the key steps in planning. Examples of structures used in distribution systems at medium and low voltages are presented.

Definitions of load forecast terms and different methods of estimating the demand forecast with application examples are now explained in Chapter 4.

PART II: PROTECTION AND SWITCHGEAR

Earthing, protection schemes and distribution switchgear are included in this part. Various methods of earthing, as the protection system is based on it, are explained in Chapter 5. Computation of short-circuit current, on which the design of protection is based, is presented in Chapter 6. General description of the types of protection schemes in distribution systems is now split and is presented in Chapters 7 and 8.

Details about switchgear devices and switchgear installation, including the major factors affecting the design of switchboards, have also been reorganized in Chapters 9 and 10, respectively.

PART III: POWER QUALITY

The key elements of quality of power supply (voltage quality, power factor and harmonics) and means of their improvement are now explained in Chapters 11 through 15 with relatively minor revisions to the material in the original edition.

PART IV: MANAGEMENT AND AUTOMATION

Reliability, economics, investment aspects and methodologies applied to improve the performance of the distribution systems are explained in Chapter 16 by applying demand-side management and energy-efficiency policies.

The difference between system automation and monitoring, using supervisory control and data acquisition (SCADA) systems, and the conditions of using various architectures are given in Chapter 17. In addition, the role of SCADA to modernize the distribution system to become a smart grid is illustrated.

PART V: DISTRIBUTED ENERGY RESOURCES AND MICROGRIDS

Various types of distributed energy sources and the corresponding effect of integrating these sources with the distribution system are described in Chapter 18.

Energy storage systems are required to meet the intermittency of the power source when using solar or wind sources and to provide added benefits such as improved control, power quality, dynamic and transient stability, reliability and satisfactory operation. Various types of energy storage systems that can be used for this purpose are discussed in Chapter 19.

The integration of distributed generation, energy storage systems and consumption into one system, commonly referred to as a microgrid, in addition to the recent trend to modernize it to become a smart grid, is illustrated in Chapter 20.

Electric power distribution systems cover a broad spectrum of topics. To keep the overall length of the book within a reasonable limit, many of these topics are, per force, not covered in depth. However, all material is supported by an extensive list of references from which the interested reader can get more details for an in-depth study.

ABDELHAY A. SALLAM
OM P. MALIK

ACKNOWLEDGMENTS

NO WORK OF ANY significance can be accomplished without the help received from many sources. In that respect, this book is no exception. The authors are grateful for the invaluable help received from many sources and wish to express their gratitude to the following, in particular, without whose help it would not have been possible to put this book together:

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- Square-D North America for permission to include the AccuSine® product photos.
- Technical and Sales staff members of ABB-Egypt for making available manuals describing the company practices and a number of illustrations included in the book with permission.
- Dr. Azza Eldesoky for the information on load forecasting that is included in the book and Dr. Ahmed Daoud for editing some of the illustrations.
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In addition, help has been received from a number of other sources to which the authors are indebted and wish to acknowledge and express their sincere thanks.

All this work requires the moral support of the families, and we wish to recognize that with our sincere appreciation. We dedicate this book:

To our wives,
Hanzada Sallam and Margareta Malik

A. A. S.
O. P. M.

PART I

FUNDAMENTAL CONCEPTS

CHAPTER 1

INTRODUCTION

1.1 INTRODUCTION AND BACKGROUND

A distribution system is the interface between the electricity generator and the electricity consumer. To achieve a good understanding of the electric distribution system, a very broad description of the electric power system structure is given first. It is followed by a general description of the main concepts and components of electric distribution systems so that the reader can get acquainted with the appropriate background and obtain an appreciation of where the distribution system fits in the context of the overall structure of the power system. Detailed description of the various aspects, structure and components of the distribution systems is given in the subsequent chapters. Some of the more recent developments in the evolution of the distribution systems are also included in the last part of the book.

1.2 POWER SYSTEM STRUCTURE

A power system contains all electric equipment necessary for supplying the consumers with electric energy. This equipment includes generators, transformers (step-up and step-down), transmission lines, subtransmission lines, cables, switchgear [1]. As shown in Figure 1.1, the power system is divided into three main parts. *The first part* is the *generation* system in which the electricity is produced in power plants owned by an electric utility or an independent supplier. The generated power is at the generation voltage level. The voltage is increased by using step-up power transformers to transmit the power over long distances under the most economical condition. *The second part* is the *transmission* system that is responsible for the delivery of power to load centers through cables or overhead transmission lines. The transmitted power is at extra-high voltage (EHV) (transmission network) or high voltage (HV) (subtransmission network). *The third part* is the *distribution* system, where the voltage is stepped down at the substations to the medium voltage (MV) level. The power is transmitted through the distribution lines (or cables) to the local substations (distribution transformers) at which the voltage is reduced to the consumer level and the power lines of the local utility or distribution company carry electricity to homes or commercial establishments.

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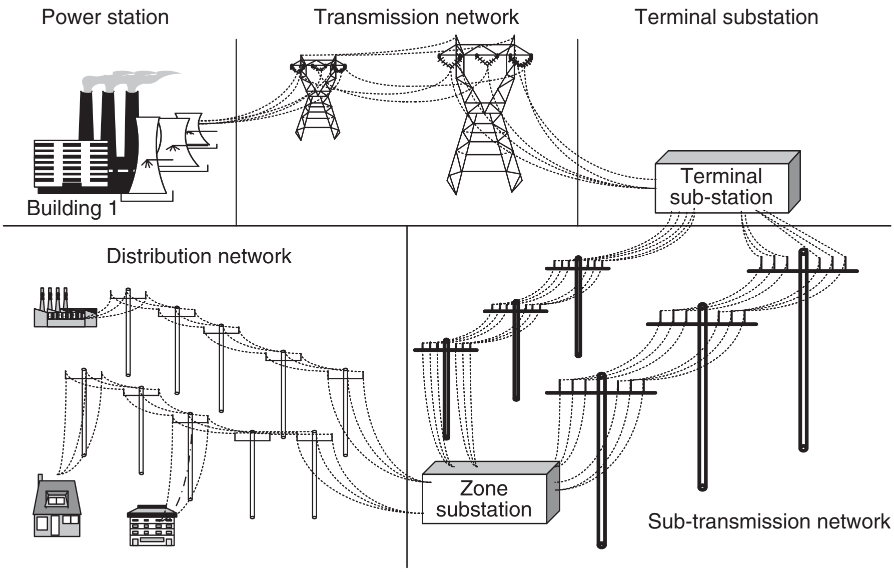

Figure 1.1 Electricity supply system [2].

The physical representation given in Figure 1.1 needs to be expressed by a schematic diagram adequate for analyzing the system. This is done by drawing a single-line-diagram (SLD) as shown in Figure 1.2. This figure illustrates two power systems connected together by using tie-links as they exist in real practice to increase system reliability and decrease the probability of load loss. The voltage values shown in this figure are in accordance with the standards of North American power systems.

Each system contains *generators* delivering power at generation voltage level, say 13.8 kV. By using step-up-transformers, the voltage is stepped up to 345 kV and the power is transmitted through the *transmission* system. The transmission lines

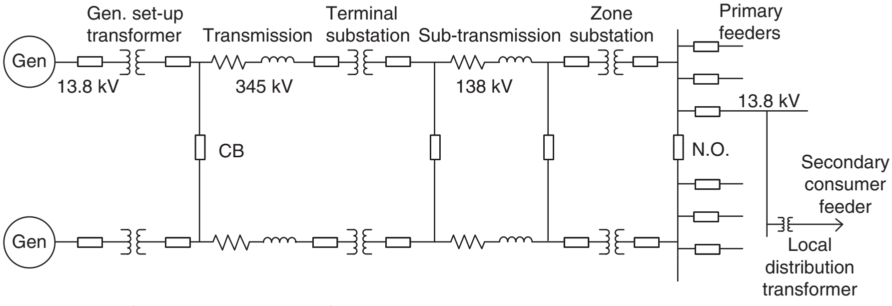

Figure 1.2 A typical electric supply system single-line diagram. CB = circuit breaker; N.O. = normal open.

are followed by 138 kV subtransmission lines through terminal substations. The subtransmission lines end at the zone substations, where the voltage is stepped down to 13.8 kV to supply the MV distribution network at different distribution points (DPs) as primary feeders. Then the electricity is delivered to the consumers by secondary feeders through local distribution transformers at low voltage (LV) [3, 4].

1.3 DISTRIBUTION LEVEL

To get a better understanding of the physical arrangement of the distribution level in a power system, consider how electricity is supplied to a big city. The first part of the arrangement, the power stations, is often located far away from the city zones and sometimes near the city border. According to how big the city is, the second part of the arrangement (transmission and subtransmission systems) is determined. Overhead transmission lines and cables can be used for both systems. They are spanned along the boundary of the city, where the terminal and zone substations are located as well. This allows the planner to avoid the risk of going through the city by lines that operate at HV or EHV. For the third part, the distribution system, the total area of the city is

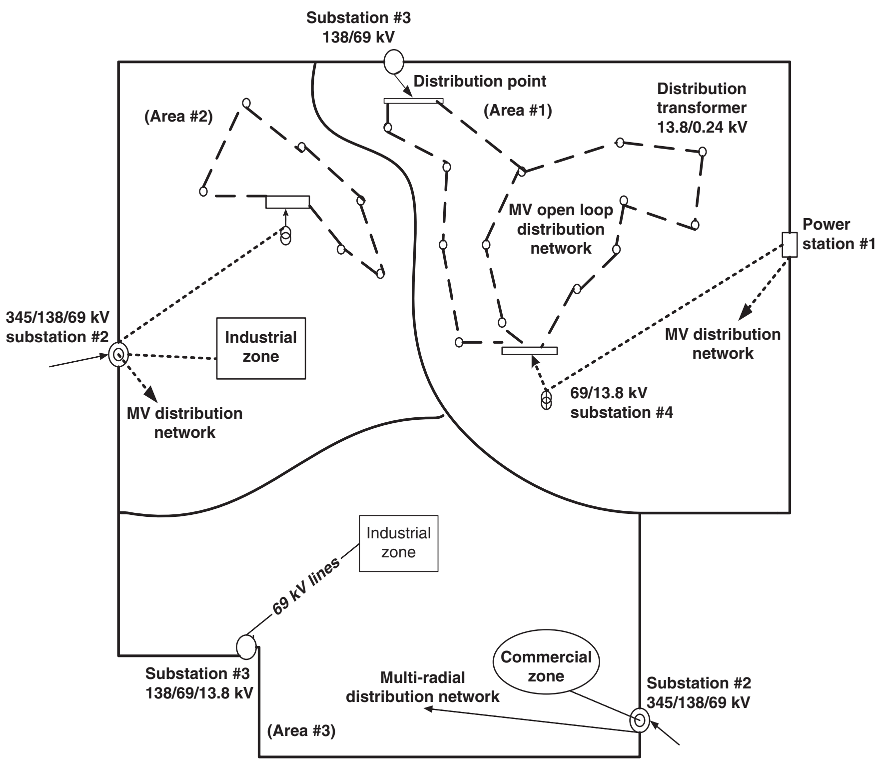

Figure 1.3 Electric supply system to a big city.

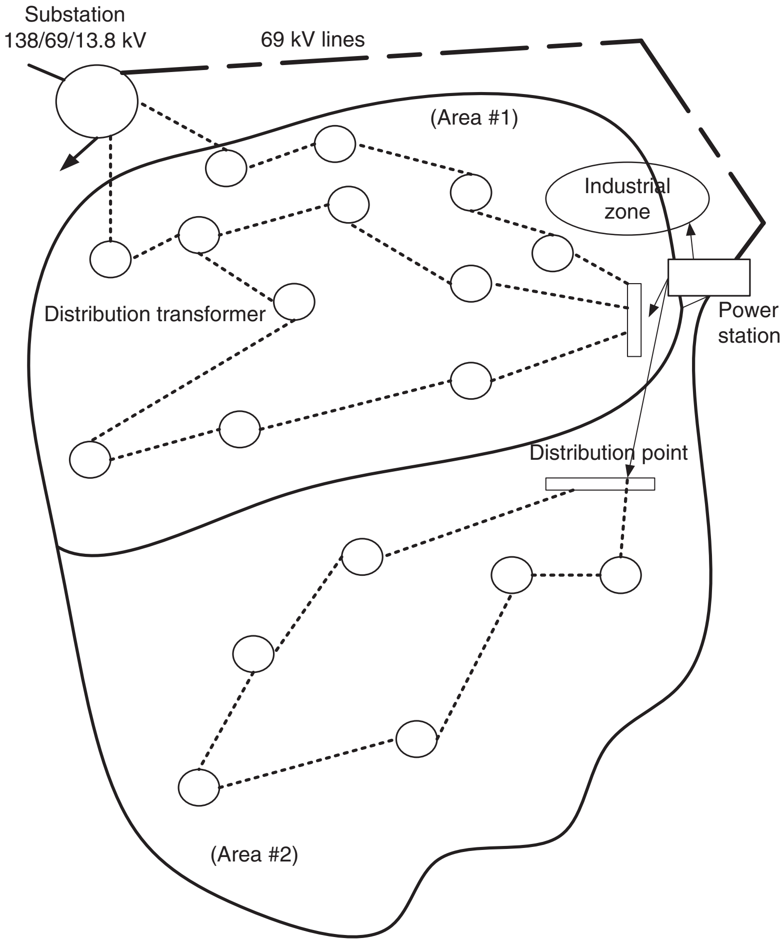

Figure 1.4 Electric supply system to a small city.

divided into a number of subareas depending on the geographical situation and the load (amount and nature) within each subarea. The distribution is fed from the zone substation and designed for each subarea to provide the consumers with electricity at LV by using local transformers.

As an illustrative example, consider the total area of a big city is divided into three residential areas and two industrial areas as shown in Figure 1.3. Power station #1, terminal substations #2 (345/138/69 kV) and the zone substations #3 (138/69/13.8 kV) are located at the boundary of the city. The transmission system operates at 138 kV & 69 kV. Effort is made for these systems to go around the city rather than through the city subareas. Of course, the most economical voltage for the transmission and subtransmission systems is determined in terms of the transmitted power and the distance to the point of consumption. Also, the supply network to the industrial zones operates at 69 kV because of the high power demand and to avoid the voltage-drop violation at the MV level [5].

Substation #4 (69/13.8 kV) is located at a certain distance inside the city boundary, where the distribution system starts to feed the loads through distribution points. The outgoing feeders from DPs are connected to local distribution transformers to step down the MV to LV values.

For small cities, the main sources on the boundary are either power stations or substations 138/13.8 kV or 69/13.8 kV to supply the distribution system including various DPs in different zones of the city. The outline of this arrangement is shown in Figure 1.4.

1.4 GENERAL

Electrical energy, being a very convenient form of energy, has become fully pervasive in the modern world. As the distribution system is the link through which an individual consumer draws electrical energy from the power system, proper design of the distribution system becomes very important for reliability and maintenance of continuity of electric supply. Detailed description of all aspects of design, construction and operation of a distribution system involves a number of steps that include planning, layout, load forecast and design, equipment, protection schemes, power quality, distribution system management and more recently distributed energy resources (DERs) at the local level. More details of all these aspects are given in the subsequent chapters.

CHAPTER 2

DISTRIBUTION SYSTEM STRUCTURE

2.1 DISTRIBUTION VOLTAGE LEVELS

North American and European practices are the two systems of distribution voltage levels in most use around the world. The primary and secondary voltages (MV and LV, respectively) are given in Table 2.1 for both systems. The voltage choice depends on the type of load (residential, commercial, industrial), load size and the distance at which the load is located. This is illustrated by a typical block diagram shown in Figure 2.1.

It is seen that the distribution voltage in the European system is higher than that in the North American system. It has both advantages and disadvantages as listed in what follows.

- *Advantages:* The system can carry more power for a given ampacity and has less voltage drop and less line losses for a given power flow. Consequently, the system can cover a much wider area. Because of the longer reach, the system needs fewer substations.
- *Disadvantages:* more customer interruptions because the circuits are longer, that is, lower level of reliability. Therefore, a major concern is to keep reliability at the desired level depending on the load category (more details are given in Section 2.2.2). From the cost point of view, the system equipment (transformers, cables, insulators etc.) is more expensive.

2.2 DISTRIBUTION SYSTEM CONFIGURATION

Configuration of the distribution networks follows one or a combination of the following standard systems:

- radial system where the load is supplied through one radial feeder;
- open-ring system where the load is supplied through one of two available feeders, that is, one side of the ring;

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TABLE 2.1 Distribution Voltages for North American and European Systems

Type of voltage	North American system	European system
Primary distribution voltage (line-to-line)	From 4 to 35 kV	From 6.6 to 33 kV
Three-phase secondary voltage (line-to-line)	208, 480 or 600 V	380, 400 or 416 V
Single-phase secondary voltage (line-to-neutral)	120/240, 277 or 347 V	220, 230 or 240 V

- closed-ring system where the load is supplied through the two sides of the ring simultaneously;
- dual-ring system in which the load is connected with two rings at the same time, that is, it has four incoming feeders; and
- multiradial system, which means supplying the load by more than one radial feeder.

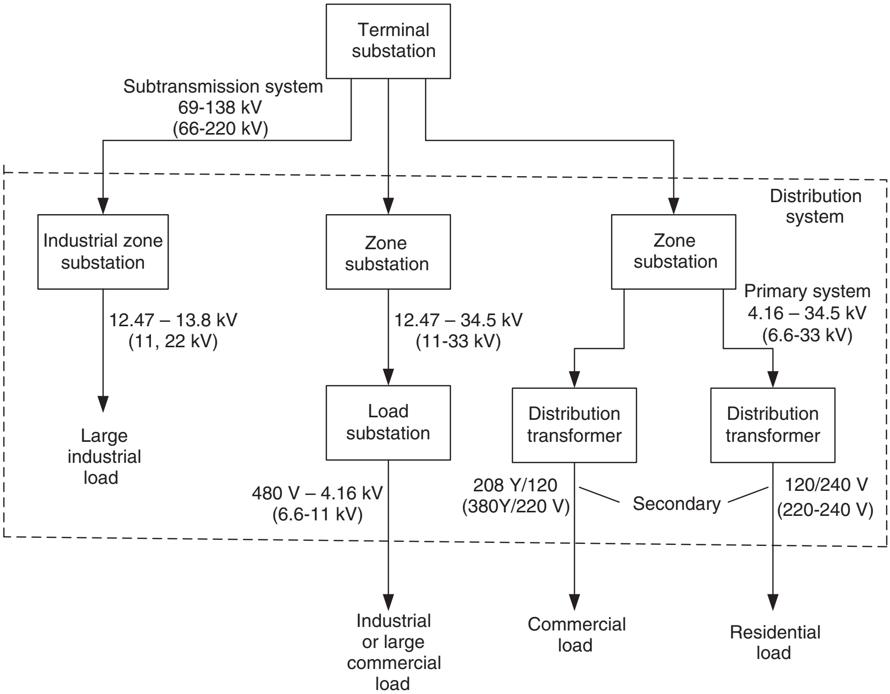

Figure 2.1 Distribution voltages for different loads (values written between parentheses describe the European practice; otherwise the values describe the North American practice).

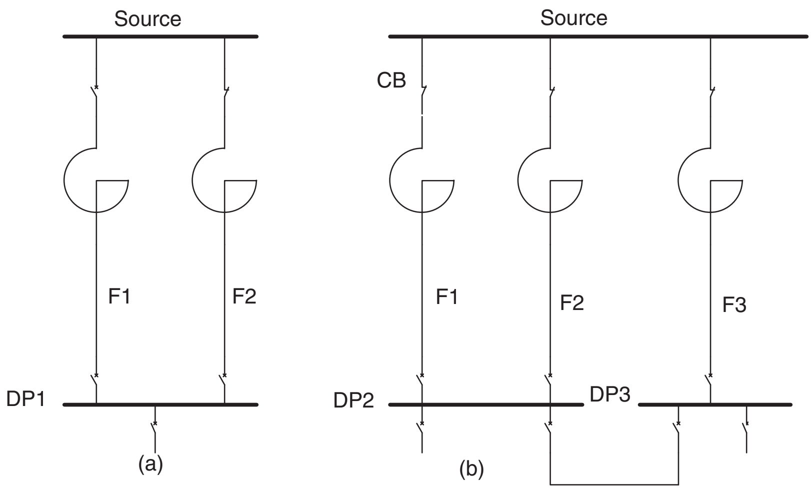

Figure 2.2 MV supply network to DP with parallel feeders (CB = circuit breaker with overcurrent protection; F = feeder, DP = distribution point).

These systems can be applied to establish the distribution network at either the MV or the LV level.

2.2.1 MV Distribution Networks

The MV distribution networks are the intermediate networks between the sources and the DPs in different zones of the load area.

The DP can be connected to the source through two in-service parallel feeders. At the same time, one feeder can operate at full load if a fault occurs in the second feeder, as shown in Figure 2.2a. For more reliability, two DPs can be connected to each other as shown in Figure 2.2b. In this case, DP2 is connected to the source through two parallel feeders while DP3 is connected to the same source through one feeder.

Of course, it is better and more reliable to use different sources feeding the DPs. In Figure 2.3a, DP1 has two incoming feeders; the first is connected to source #1 while the second is connected to source #2. In this case, one feeder only is in service. The other feeder is a standby and feeds DP1 through automatic reserve switching (ARS). Another way is to divide the bus bar of DP2, Figure 2.3b, into two sections connected to each other by a bus-coupler circuit breaker that is normally open. Each section has an incoming feeder connected to an independent source, as shown in Figure 2.3b. Different configurations can be applied such as given in Figures 2.4a and 2.4b, respectively. A ring bus scheme, shown in Figure 2.5, can also be applied (popular in the United States). In this scheme, a fault anywhere in the ring results in two circuit breakers opening to isolate the fault. For example, when a fault occurs in source #1 circuit breakers CB1 and CB4 would operate to isolate the fault, while source #2 would

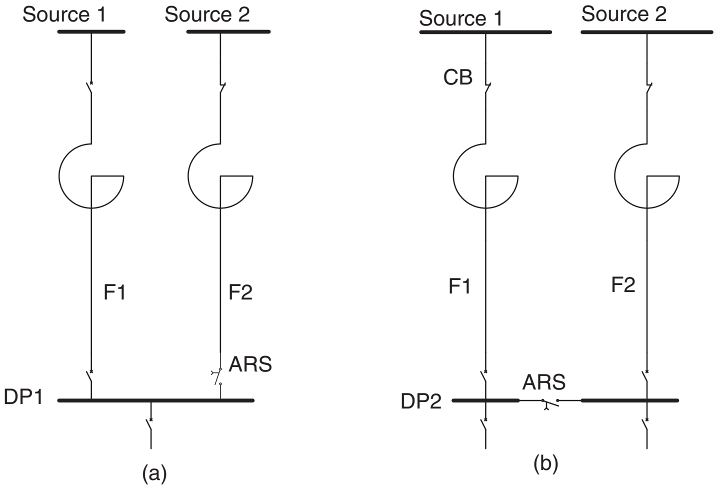

Figure 2.3 MV supply network to DP with independent feeders (ARS = automatic reserve switching, F = feeder, CB = circuit breaker, DP = distribution point).

feed the loads. Circuit breakers are installed with two manual isolating switches on both sides to perform maintenance safely and without service interruption. Alternatively, radial and multiradial configurations can be used as shown in Figures 2.6 and 2.7, respectively. Two additional configurations, an integrated open-ring and a radial distribution network, are shown in Figures 2.8 and 2.9, respectively.

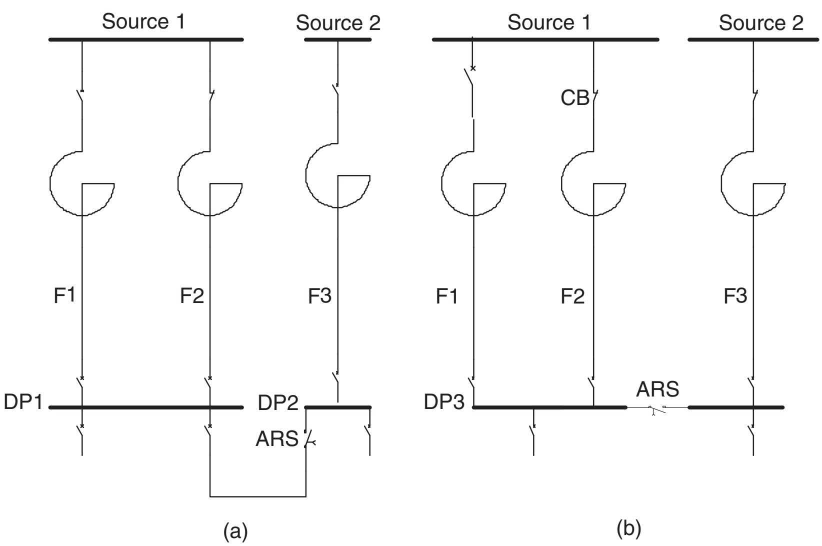

Figure 2.4 Combined MV supply network to DP.

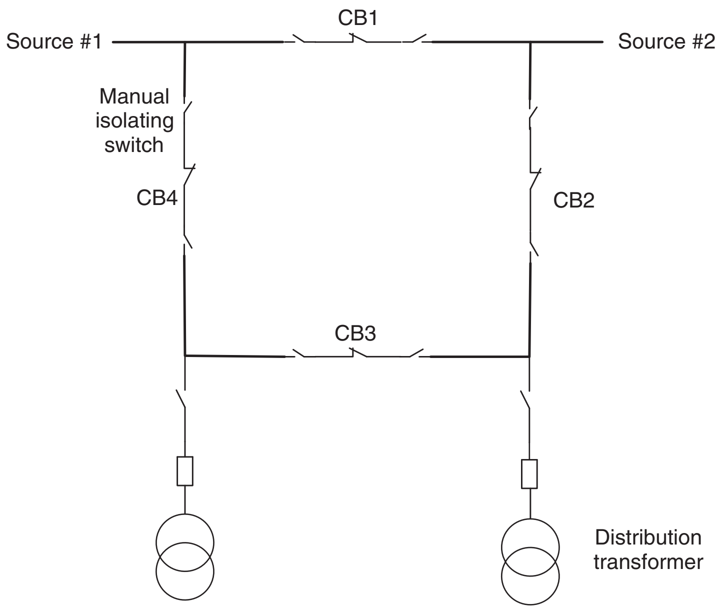

Figure 2.5 Ring bus scheme.

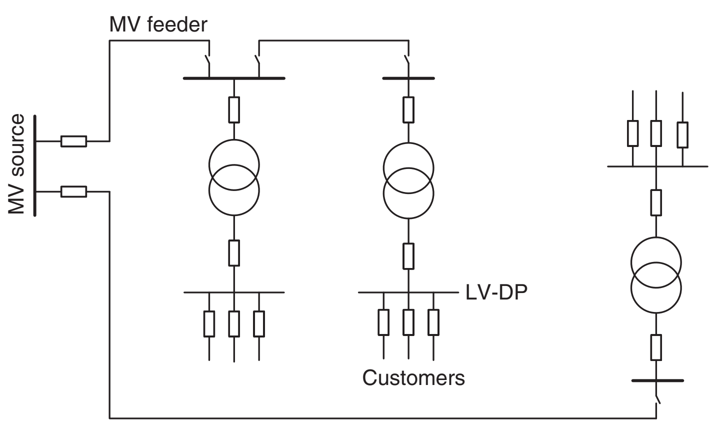

Figure 2.6 Radial nonreserved distribution network.

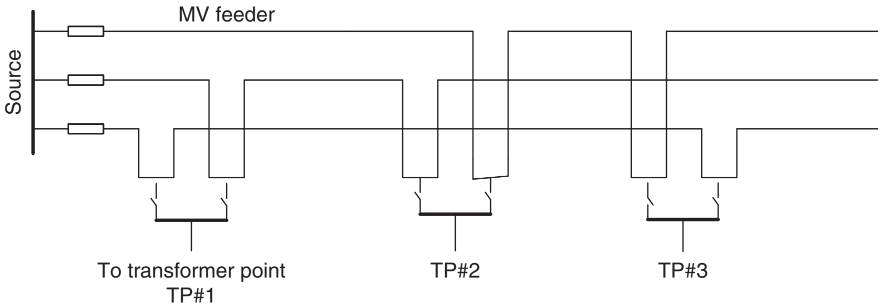

Figure 2.7 Multiradial distribution network with automatic reserve switching on MV side.

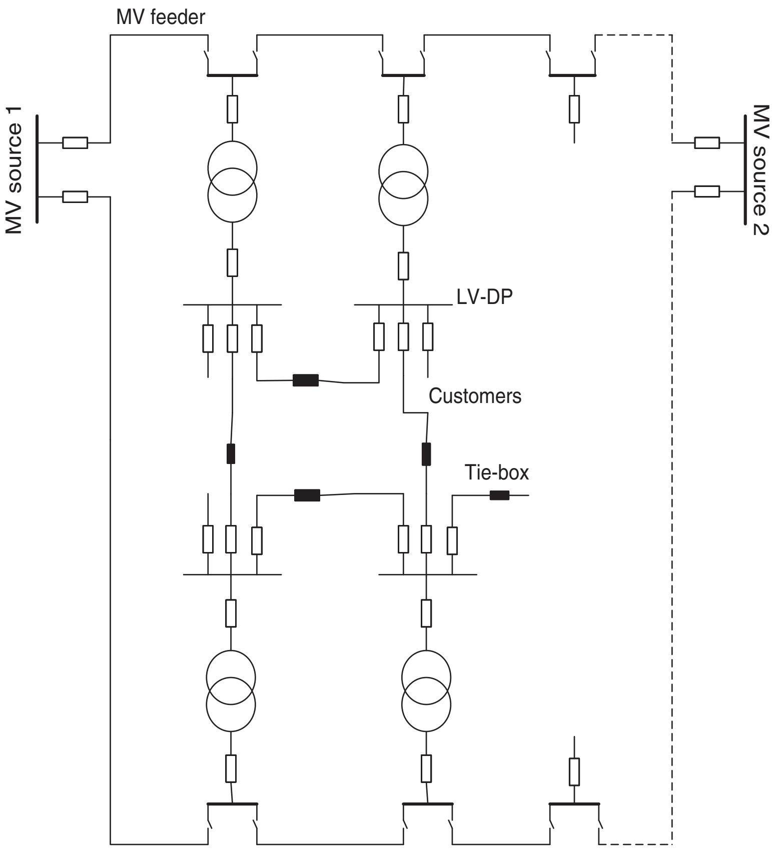

Figure 2.8 Open-loop distribution network.

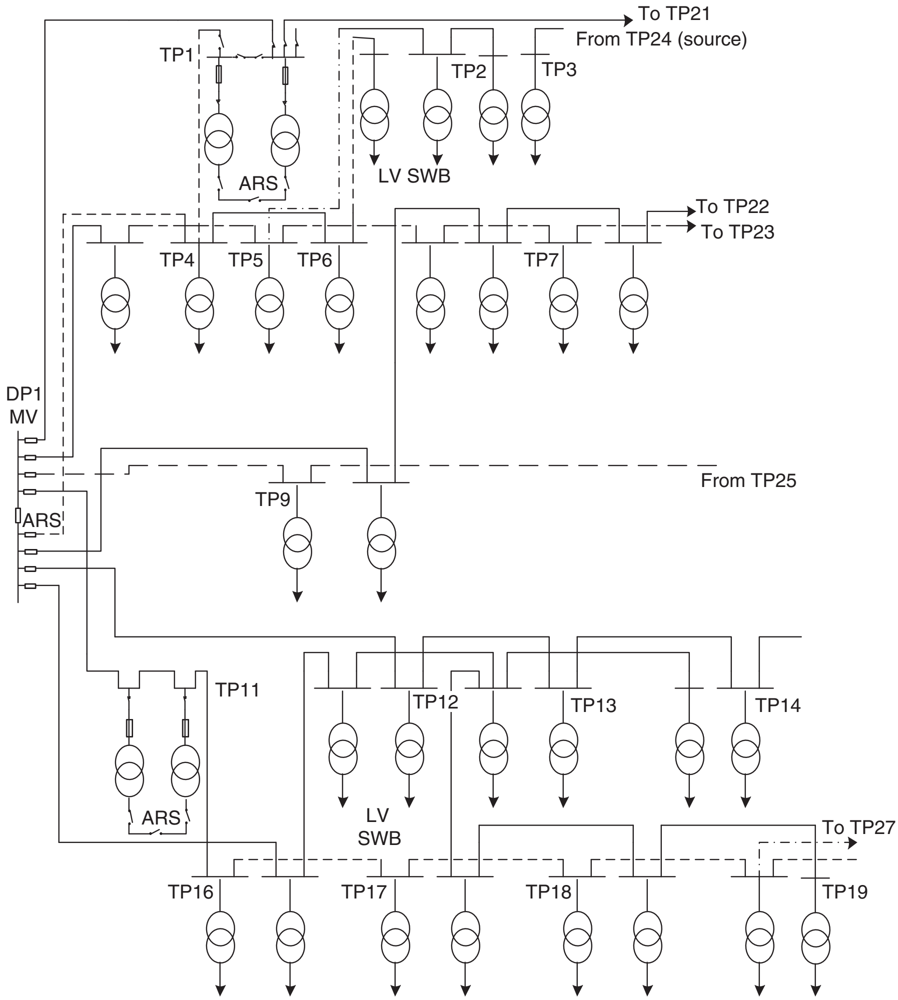

Figure 2.9 Radial MV network with DP (ARS on LV bus-bar of TP). TP = transformer; DP = distribution point; ARS = automatic reserve switching; SWB = switchboard.

2.2.2 LV Distribution Networks

2.2.2.1 North American System

Radial structure is the most commonly used in North America. The secondary feeders transmit power to the loads through distribution transformers (MV/LV). Single-phase power at voltage level 120/240 V is usually supplied to residences, farms, small offices and small commercial buildings (Fig. 2.10a). Three-phase power is usually supplied to large farms, as well as commercial and industrial customers. Typical voltage levels for three-phase power are 208Y/120 V, 480Y/277 V or 600Y/347 V (Fig. 2.10b).

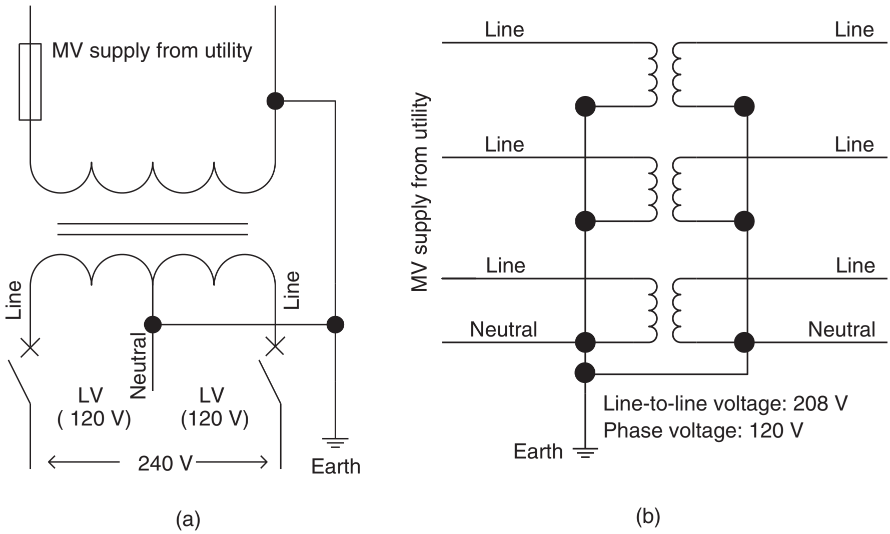

Figure 2.10 North American MV/LV distribution transformers. (a) 120/240 V single-phase service, (b) Typical 208 V, 3-phase Y-connected service.

To increase the reliability, in particular, for LV applications with a very high load density, two or more circuits operate in parallel to transmit power into a secondary (LV) bus at which the load is connected. Each circuit includes a separate primary (MV) feeder, distribution transformer, and secondary feeder that is connected to a secondary bus through a network protector. This scheme is known as a "secondary spot network" (Fig. 2.11). If a fault occurs on a primary feeder or distribution transformer of one of the circuits, its network protector receives a reverse power from the other circuits. This reverse power causes the network protector to open and disconnect the faulty circuit from the secondary bus. The load is only interrupted in case of simultaneous failure of all primary feeders or at fault occurrence on the secondary bus. Of course, this scheme is more expensive because of the extra cost of network protectors and duplication of transformer capacity. In addition, it requires a special construction of the secondary bus to reduce the potential of arcing fault escalation as well as a probable increase of secondary equipment rating since the short-circuit current capacity increases in case of transformer parallel operation.

2.2.2.2 European System

For European distribution systems, the choice of any of the standard structures (Section 2.2) to establish the LV distribution networks depends on the type of the majority of loads and the reliability level required supplying these loads.

For reliability level 3, the distribution transformers are supplied by two incoming feeders (one is a standby to the other) on the medium voltage side. The outgoing feeders at the low voltage side are radial feeders (cables or overhead lines) as shown

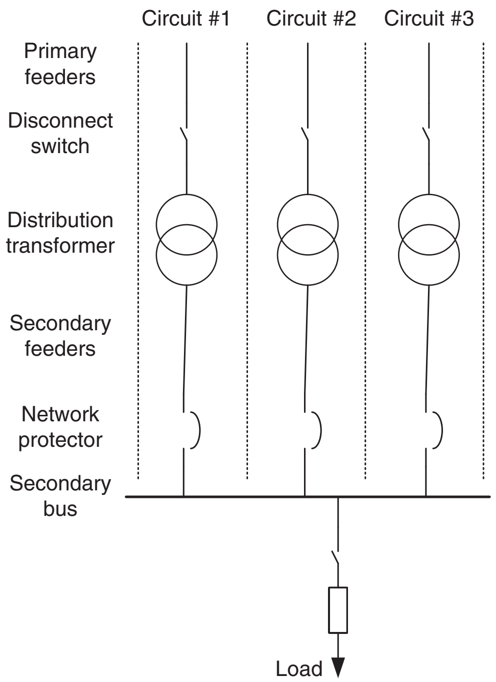

Figure 2.11 Secondary spot network.

in Figure 2.12. If a fault occurs on one of these outgoing feeders, the concerned load is disconnected until the fault is repaired.

For reliability level 2, the medium-voltage side of the distribution transformer is connected to the source through two feeders (one in-service and the other is a standby). The outgoing feeders on the low voltage side are structured by one of the following:

- open-ring network (Fig. 2.13),
- combined open/double radial network (Fig. 2.14),
- double radial/double transformer cabinet network as in Figure 2.15, and
- double radial network where each radial feeder is connected to a single transformer cabinet (Fig. 2.16).

These structures can reduce the interruption periods significantly.

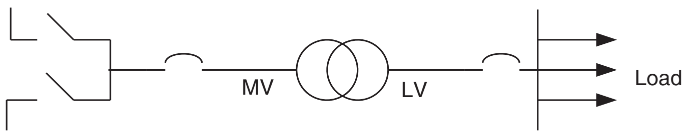

Figure 2.12 Supply system to a third-category customer.

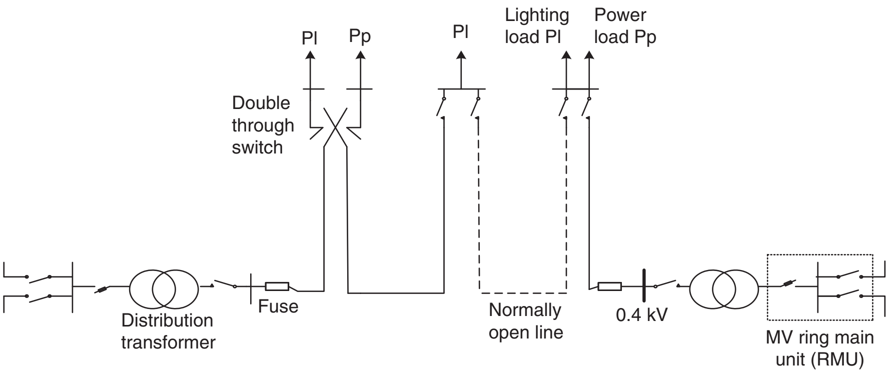

Figure 2.13 Open-loop 0.4 kV network.

For reliability level 1, the same structures as for level 2 are used but equipped with fast automation techniques. In addition, a local generator with rating sufficient for the very critical parts of the load is located at the load location.

Also, the closed-ring or semiclosed-ring systems can be used. They need more complex protection and control systems.

2.2.3 Comparison of North American and European Systems

Two typical examples of both North American and European design aimed to highlight the difference of configurations and structures of distribution networks, MV and LV, are shown in Figure 2.17 and Figure 2.18, respectively.

It is seen that the North American configuration is based on [6]:

- maximizing network primaries by reducing the length of secondaries in order to reduce losses;
- regular earthing of MV neutral distribution (three-phase, four-wire multi-earthed primary);

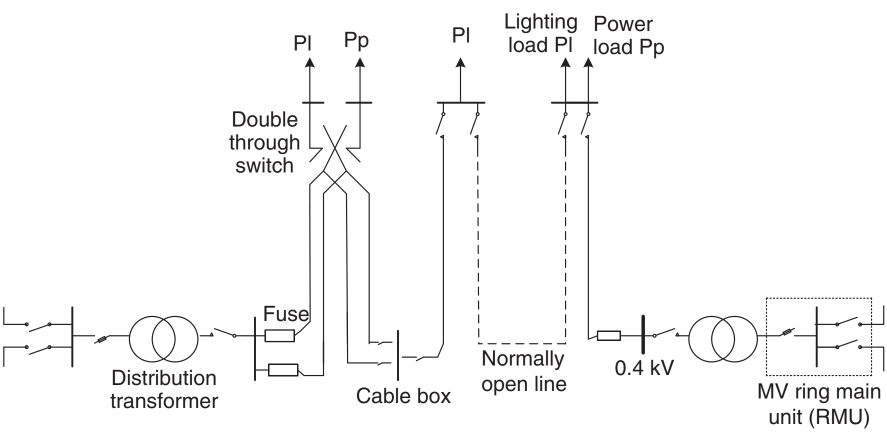

Figure 2.14 Combined open-/double-radial LV network.

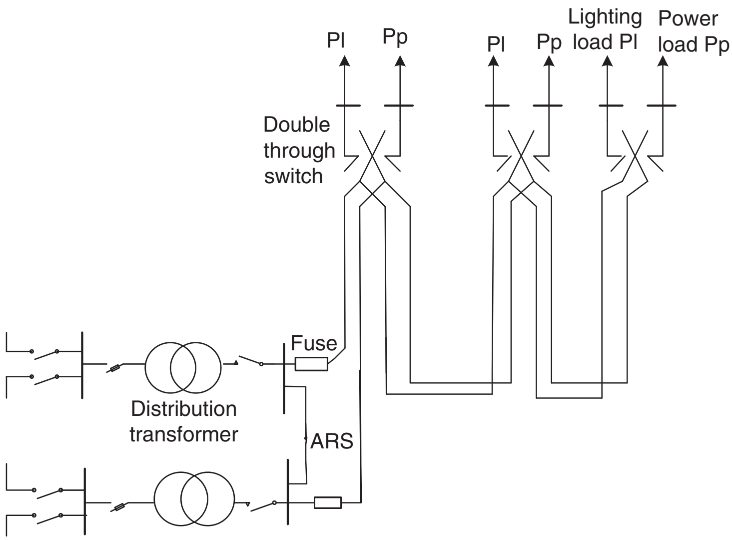

Figure 2.15 Double-radial LV network. ARS = automatic reserve switching.

- using three phase main primary with three-phase, two-phase or single-phase shunting for branches (MV/LV connections); and
- radial structure.

On the other hand, the European configuration applies the following principles:

- At the zone substation (HV/MV substation), neutral earthing is either solid earthing or earthing via an impedance limiting the phase-to-earth short-circuit current.
- Three-phase primaries without distributed neutral are used.
- Radial structure.

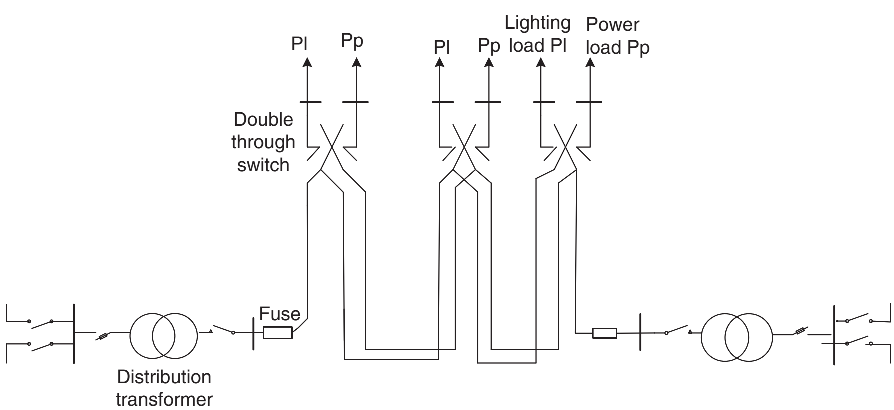

Figure 2.16 Double-radial LV network. Each radial is connected to a single distribution transformer point.

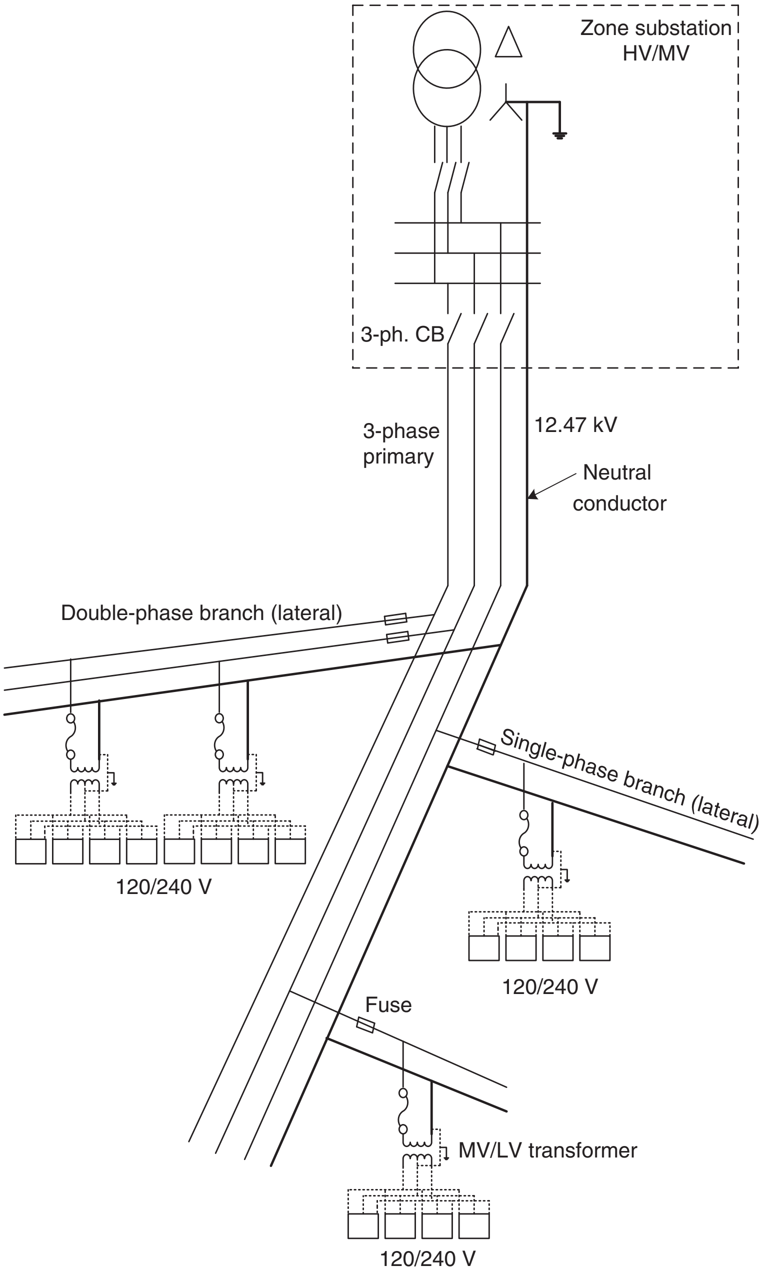

Figure 2.17 North American distribution layouts.

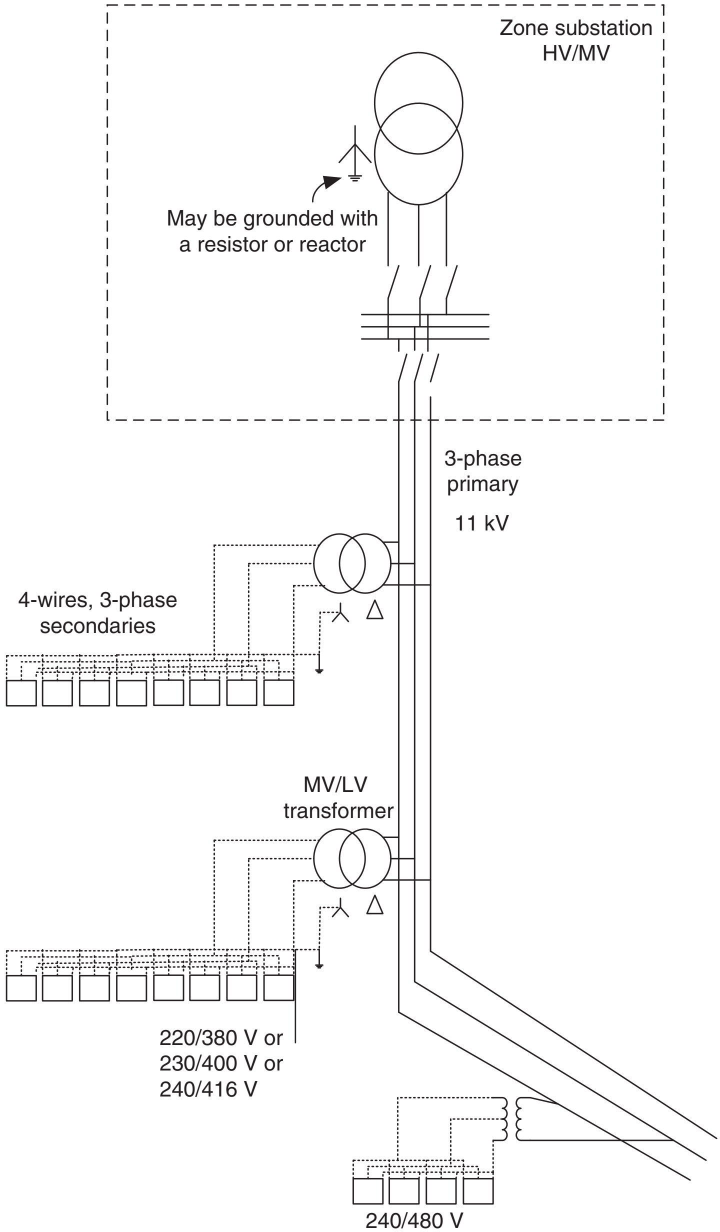

Figure 2.18 European distribution layouts.

2.3 GENERAL COMMENTS

An electric utility normally serves power to all types of consumers. The needs of security and reliability of service for each type of consumer—for example, residential, commercial, industrial—is slightly different. That to a certain extent influences the layout of the distribution network. As described, it can be radial, loop or some combination of these. The layout used affects both the reliability and economy. Depending on the actual circumstances, at times it may become necessary to compromise between the two.

In rural and less congested areas, it is quite common to use radial overhead distribution, which is less expensive than the underground distribution. However, in more congested areas, such as business districts and downtown, it may be necessary to use a network of interconnected lines with well-protected multiple-service points for reliability and underground distribution for both safety and esthetic considerations despite the extra cost involved.

CHAPTER 3

DISTRIBUTION SYSTEM PLANNING

3.1 DUTIES OF DISTRIBUTION SYSTEM PLANNERS

The planners must study, plan and design the distribution system 3 to 5 years and sometimes 10 or more years ahead. The plan is based on how the system can meet the predicted demand for electricity supplied through its subtransmission lines and zone substations and on improving the reliability of supply to the customers.

This necessitates gathering the following information:

- The history, demand forecasts and capacity of each zone substation.
- Evaluation of probable loss of load for each subtransmission line and zone substation. This requires an accurate reliability analysis including the expected economic and technical impact of the load loss.
- Determination of standards applied to the planning of the distribution system.
- Studying the available solutions to meet forecast demand including demand management and the interaction between power system components and embedded generation, if any.
- The choice and description of the best solution to meet forecast demand including estimated costs and evaluation of reliability-improvement programs undertaken in the preceding year. The benefits of improving the system reliability and the cost of applying the best solution to enhance the system performance must be compiled; that is, a costwise study must be done.

The main steps of electric distribution system planning can be depicted by the flow chart shown in Figure 3.1. The flow chart starts with identifying the system capacity to enable the planner to model the network loading and performance and identify system inadequacies and constraints. This is done as a second step with the aid of information about demand forecasts, standards, asset management system and condition monitoring (CM). As a third step, all feasible network solutions are identified, and the cost of each in addition to the lead time of implementation is estimated. Consequently, it leads to the preparation of a capital plan and investment in major works for specific years ahead as a fourth step. The next procedure is concerned

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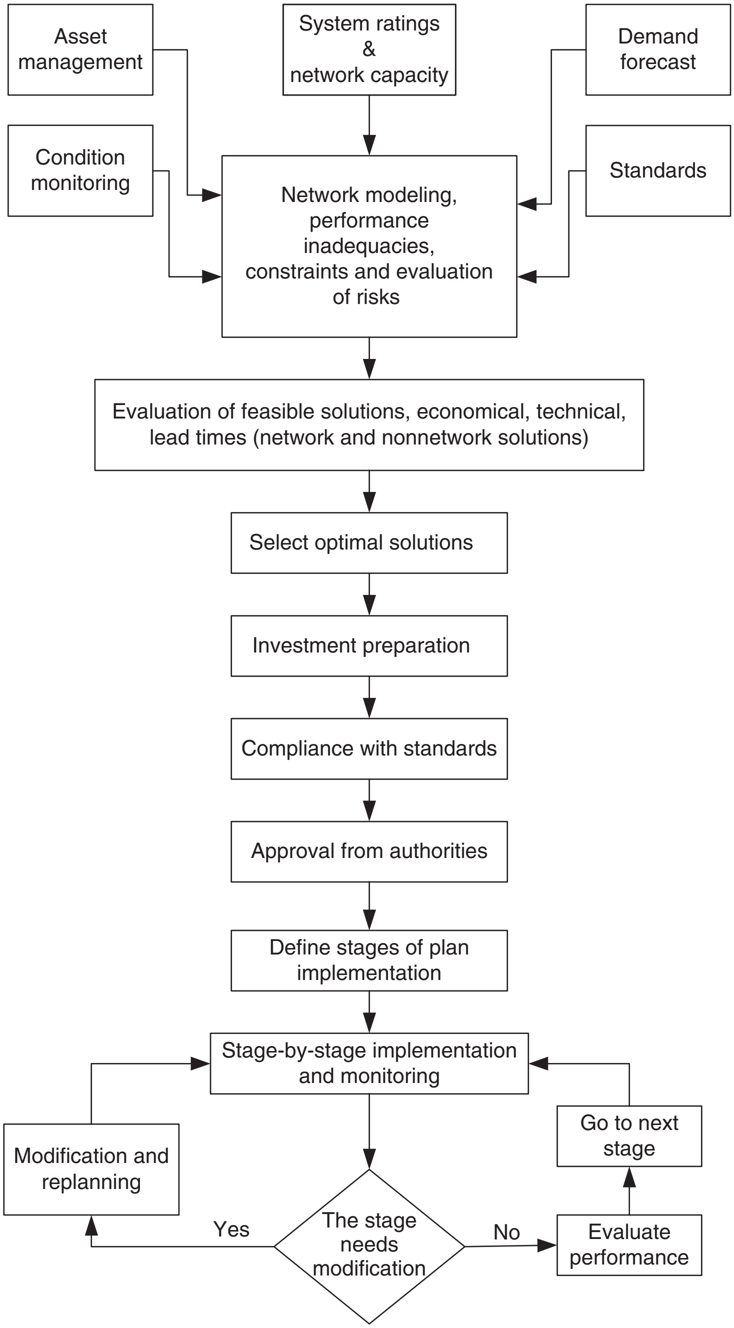

Figure 3.1 Flowchart of distribution system planning process.

with detailed economic and technical evaluation of feasible solutions. It is obvious to expect the next step to be the selection of the preferred solution. This is followed by a review of its compliance with standards requirements and obtaining the approval of relevant bodies to approve and authorize the implementation of the plan as the last step of the flow chart. The planner will normally monitor the plan during implementation. Usually, the implementation will be in multiple stages. At each stage, it is probable to receive feed-back that may necessitate some modification and replanning.

3.2 FACTORS AFFECTING THE PLANNING PROCESS

As described in Section 3.1, the planning process depends mainly on the factors mentioned in what follows.

3.2.1 Demand Forecasts

For distribution systems, the study of demand forecast is concerned primarily with the estimation of expected peak load in the short term. The peak load is affected by several factors such as social behavior, customer activity, customer installations connected to the network and weather conditions.

In general, there is no doubt that the study of load forecasting is very important, as it provides the distribution planners with a wide knowledge domain. This domain encompasses not only the expected peak load but also the nature and type of loads, for example, commercial, industrial and residential. This knowledge domain helps the planners identify to what extent the distribution system is adequate. It also helps when proposing a plan to meet the load growth and choosing the optimal solution, which may be network augmentation or no network augmentation. The network-augmentation solutions mean that additional equipment will be added to the system to increase its capacity, while no network-augmentation solutions mean maximizing the performance of the existing system components.

3.2.2 Planning Policy

The suggested distribution system plan must be evaluated as an investment process. Its fixed and running costs are estimated as accurately as possible. The plan may include replacement of some parts of the network and/or adding new assets in addition to increasing the lifetime of the present system components in accordance with an asset-management model. Thus, asset management plays a prominent role in the planning process. It aims to manage all distribution plant assets through their life cycle to meet customer reliability, safety and service needs. The asset-management model consists of an asset manager who is functionally separated within the company from the service providers. Based on the assessment of asset needs, the asset manager decides what should be done and when and then retains service providers to perform those tasks. Consequently, the asset manager develops distribution plant

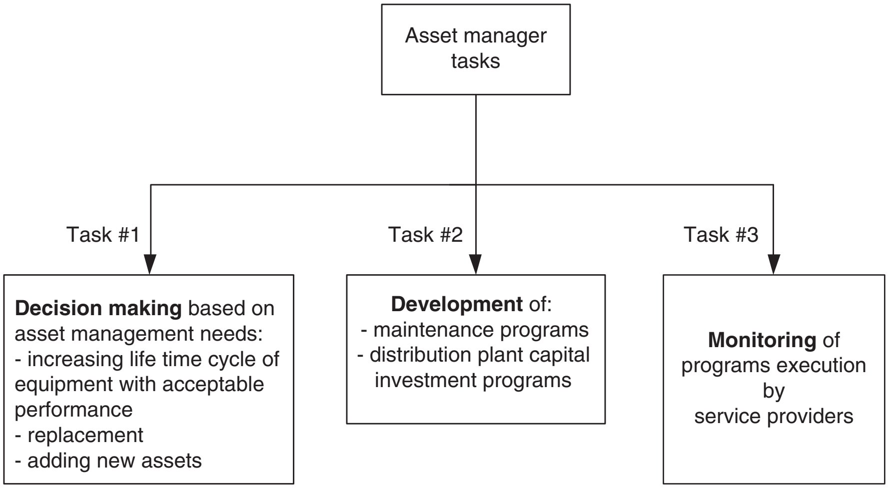

Figure 3.2 Tasks of asset manager.

capital investment programs, develops all distribution plant maintenance programs and ensures execution of programs by service providers (Fig. 3.2).

There is no doubt that utilities have to find ways to reduce maintenance cost, avoid sudden breakdown, minimize downtime and extend the lifetime of assets. This can be achieved by CM with the capability to provide useful information for utilizing distribution components in an optimal fashion (more explanation is given in the next section). It can be concluded as both the investment and management of planning process must be integrated to achieve maximum revenue and efficiency for the customers and utilities as well.

3.2.3 CM

CM is a system of regularly scheduled measurements of distribution plant health. It uses various tools to quantify plant health so that a change in condition can be measured and compared. CM can also be an effective part of both a plant maintenance program, including condition-based maintenance (CBM), and performance optimization programs.

Time-based maintenance (TBM) has been the most commonly used maintenance strategy for a long time. TBM, to examine and repair the assets offline either according to a time schedule or running hours, may prevent many failures. However, it may also cause many unnecessary shutdowns, and unexpected accidents will still occur in between maintenance intervals. Manpower, time and money are wasted because the maintenance activity is blind, with little information on the current condition of the assets. In contrast, CBM lets operators know more about the state of the assets and indicates clearly when and what maintenance is needed so that it can reduce manpower deployment as well as guarantee that the operation will not halt

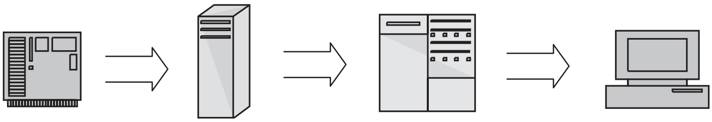

Figure 3.3 Main parts of a CM system.

accidentally. CBM can be an optimal maintenance service with the help of a CM system to provide correct and useful information on the asset condition [7, 8].

CM should be capable of performance monitoring, comparing the actual measured performance to some design or expected level. When conditions slowly degrade over time, simple trend analysis can be used to raise alerts to operators that attention is required. For instance, in distribution systems, temperatures, pressures and flows can be monitored and the thermal performance computed from these measurements. This can be compared to design conditions, and if negative trends develop over time, they can be indicative of abnormal or other performance-related problems [9].

The more difficult challenge is to identify when imminent equipment or component failure will cause an unplanned outage or will otherwise produce a change in plant performance. In some cases, simply trending the right parameter may be effective in avoiding this scenario, but usually degradation is due to a combination of several factors that cannot be predicted a priori or detected from a casual review of the trend data.

CM contains four parts, as shown in Figure 3.3. The first is to monitor and measure the asset physical parameters (usually by using sensors) if their detectable changes can reveal incipient faults long before catastrophic failures occur. It converts the physical quantities into electrical signals. The second is a data-acquisition unit that is built for amplification and pre-processing of the output signals from monitors, for example, conversion from analogue to digital. The third part is to analyze the collected data for fault detection by comparing the results of measurements with design conditions. Based on detected abnormal signals and existing expert systems, the fourth part presents to the operator full prescriptions, for example, fault location, fault type, status of asset and advice for maintenance.

3.2.4 Reliability Planning Standards

The various assets of a power system (generation, transmission and distribution) must follow the standards that ensure the continuity of supply in the event of system component outages. Components outage may be either a maintenance outage or a contingency outage such as external disturbances, internal faults, component failures and lightning strikes.

Reliability standards provide a criterion for decision making toward the continuity and availability of power supply at any time and at different operating conditions. The decision may include an increase of operation automation and monitoring and/or adding some of the following equipment:

- Automatic circuit reclosers (ACRs) that result in a significant reduction of customer interruptions and customer minutes-off supply. In addition, the fast fault clearance provided by ACRs reduces the probability of secondary damage to assets, thereby increasing the chances of successful recloser attempts for transient faults. As a result, customers experience fewer sustained outages.
- Fault locators to provide system control and network operators with the approximate location of faults, enabling operators to locate the faults faster, thereby reducing supply-restoration times.
- Ultrasound leakage detectors to detect leakage current on assets, enabling corrective action to be carried out before pole fires develop.
- Thermovisions to detect hot spots on assets to enable corrective actions to be carried out before they develop into faults due to thermal breakdown of components.

The planner must establish an acceptable compromise between the economic and technical points of view with the goal of supplying electricity to customers at a price as low as possible and at accepted category of reliability level. Categorization of customer reliability levels in regard to distribution systems is explained next.

3.2.4.1 Categories of Customer Reliability Level

A distribution system is reliable when the interruption periods are as small as possible, that is, less loss of load (LOL). Therefore, the distribution system structure must be designed in such a way that the continuity of supply at a desired level of quality is satisfied. Different structures are explained in Chapter 2.

As a standard, it is common to classify the customers into three levels of reliability:

- *Level 1:* for high-priority loads such as hospitals, industries, water pump plants, emergency lighting and essential commercial loads, the system reliability must be as high as possible. This can be achieved by feeding the load through two independent sources (one in service and another as a standby). The interruption time is very short. It is just the time for transferring from one source to another and isolating the faulty part in the network automatically.
- *Level 2:* for moderate-priority loads such as domestic loads, the interruption time is sufficient for manually changing the source feeding the loads.
- *Level 3:* for other loads having low priority, the interruption time is longer than the former two levels. This time is sufficient for repairing or replacing the faulty equipment in the distribution system.

3.2.4.2 Reliability Indices

System planners and operators use the reliability indices as a tool to improve the level of service to customers. Accordingly, the requirements for generation, transmission and distribution-capacity additions can be determined by the planners. Operators use these indices to emphasize the system robustness and withstanding possible failures without catastrophic consequences.

Generation reliability is measured by the index "loss-of-load probability" (LOLP). It is defined by the probability that generation will be insufficient to meet demand at some point over a specific period of time (hourly or daily, typically 1 day in 10 years). LOLP is actually an expected value, and its calculation is based upon a probabilistic analysis of generation resources and the peak loads.

Transmission reliability is measured by its availability (AVAIL), which refers to the number of hours the transmission is available to provide service divided by the total hours in the year.

$$\text{AVAIL} = \frac{\text{available hours of equipment to be in service}}{\text{total hours in year}}$$

Distribution reliability is measured by indices based on customer outage data. These data describe how often electrical service was interrupted, how many customers were involved with each outage, how long the outages lasted and how much load went unserved. The used indices, as reported in IEEE Std. 1366$^{\text{TM}}$-2003, are classified in what follows.

Sustained Interruption Indices:

System Average Interruption Frequency Index (SAIFI): It is the average frequency of sustained interruptions per customer over a predefined area:

$$\text{SAIFI} = \frac{\text{total number of customers interrupted}}{\text{total number of customers served}}$$

System Average Interruption Duration Index (SAIDI): It measures the total duration of interruptions. It is cited in units of hours or minutes per year:

$$\text{SAIDI} = \frac{\text{sum of all customer interruption durations}}{\text{total number of customers served}}$$

Customer Average Interruption Duration Index (CAIDI): It is the average time needed to restore service to the average customer per sustained interruption:

$$\text{CAIDI} = \frac{\text{SAIDI}}{\text{SAIFI}} = \frac{\text{sum of all customer interruption durations}}{\text{total number of customers interrupted}}$$

Customer Total Average Interruption Duration Index (CTAIDI): It represents the total average time in the reporting period that customers who actually experienced an interruption were without power. This index is a hybrid of CAIDI and is similarly calculated except that those customers with multiple interruptions are counted only once:

$$\text{CTAIDI} = \frac{\text{sum of customer interruption durations}}{\text{total number of customers interrupted}}$$

Customer Average Interruption Frequency Index (CAIFI): It gives the average frequency of sustained interruptions for those customers experiencing sustained interruptions. The customer is counted once regardless of the number of times interrupted for this calculation:

$$CAIFI = \frac{\Sigma N_i}{N_c}$$

where

N_i = number of interrupted customers for each sustained interruption event during the reporting period and
N_c = total number of customers who have experienced a sustained interruption during the reporting period.

Average System Availability Index (ASAI): It represents the fraction of time (often in percentage) that a customer has received power during the defined reporting period:

$$\text{ASAI} = \frac{\text{customer hours service availability}}{\text{customer hours service demand}}$$

Customers Experiencing Multiple Interruptions ($\mathbf{CEMI_n}$): It indicates the ratio of individual customers experiencing more than n sustained interruptions to the total number of customers served:

$$\text{CEMI}_\text{n} = \frac{N_n}{\text{total number of customers served}}$$

where N_n = total number of customers that experience more than n sustained interruptions.

Momentary Indices:

Momentary Average Interruption Frequency Index (MAIFI): It indicates the average frequency of momentary interruptions:

$$MAIFI = \frac{\Sigma\ total\ number\ of\ customer\ momentary\ interruptions}{total\ number\ of\ customers\ served}$$

Momentary Average Interruption Event Frequency Index ($\mathbf{MAIFI_E}$): It has the same definition as MAIFI, but it does not include the events immediately preceding a lockout.

$$\text{MAIFI}_\text{E} = \frac{\Sigma\ \text{total number of customer momentary interruptions events}}{\text{total number of customers served}}$$

Load-Based Indices:

Average System Interruption Frequency Index (ASIFI): It includes the magnitude of the load unserved during an outage:

$$\text{ASIFI} = \frac{\sum kVA_{sustained}}{kVA_{served}}$$

Average System Interruption Duration Frequency Index (ASIDI): It includes the magnitude of the load unserved during an outage.

$$\text{ASIDI} = \frac{\sum kVA_{sustained} D_{sustained}}{N_{served}}$$

It is difficult to compare these indices from one location to another or from one utility to another because of differences in how they are calculated. Some utilities exclude outages due to major events or normalize their results for adverse weather. For SAIDI calculation, some utilities consider an outage over when the substation is returned to service, and others consider it over when the customer is returned to service. Some utilities use automatic data collection and analysis, while others rely on manual data entry and spreadsheet analysis.

Another common reliability index is referred to as "nines." This index is based upon the expected minutes of power availability during the year. For example, if the expected outage is 50 min per year, the power is available 99.99% of the time, or four nines. However, if this index is calculated using the LOLP, it would not reflect outages in the T&D systems. If the nines are calculated based on SAIDI, the nines index will give some indication of the average system availability but not the availability for any particular customer.

3.3 PLANNING OBJECTIVES

The distribution system planning objectives are summarized as follows:

- meeting the load growth at desired quality,
- providing efficient and reliable supply,
- maximizing the performance of system components,
- satisfying the most cost-effective means of distribution system development and
- Minimizing the price of electricity to customers by:
  – Choosing the most cost-effective solution and
  – Minimizing total life cycle costs.

Therefore, distribution system planning is based on the following key aspects:

- load forecasting,
- power quality,
- compliance with standards,
- investment with highest revenue,
- power loss and
- amount of LOL.

3.3.1 Load Forecasting

Load forecast study is one of the most important aspects in planning because the loads represent the final target of the power system. Generation and transmission systems planning depends on long-term load forecast, while the distribution system planning depends on the short-term load forecast. The function of the power system is to feed the loads. So load forecasting is the main base for estimating the investment.

The difficulty in load forecasting results from its dependence on uncertain parameters. For instance, the load growth varies from time to time and from one location to another. Various techniques of demand forecast estimation are given in Chapter 4.

3.3.2 Power Quality

Meeting the demand forecasts by distribution system planning is a necessary but not a sufficient condition to achieve a good plan. The power quality is a complementary part. It must be at a desired level to be able to supply the customers with electricity. The power quality is determined by the electrical parameters: voltage, power factor, harmonic content in the network and supply frequency. More details are explained in the forthcoming chapters (Part III).

3.3.3 Compliance with Standards

The distribution system planner takes into account the rules and standards that must be applied to system design. The system infrastructure such as lines, cables, circuit breakers, transformers and so on, system performance and system reliability, must all be in compliance with the international codes. Supervisory control and data acquisition (SCADA) systems have been employed for distribution-automation (DA) and distribution-management systems (DMS) in order to achieve high operational reliability, reduce maintenance costs and improve quality of service in distribution systems. Moreover, once reliable and secure data communication for the SCADA system is available, the next step is to add intelligent application operation at remote sites as well as at the DA/DMS control centers. Use of intelligent application software increases the operating intelligence, supports smarter grid initiatives and achieves a greater return on investment. More details are given in Chapter 17 (Part IV).

3.3.4 Investments

Investments required to establish the system infrastructure must be estimated before implementing the plan. It is associated with financial analysis. As mentioned in [1], financial analysis, including life cycle costs, should be performed for the solutions that satisfy the required technical and performance criteria. Individual components within the network may have a life span, in some cases, in excess of 60 years, and life-cycle costs can be a significant issue.

Investments of distribution systems should be guided by the principles of efficient reliability, power quality and least cost [10]. They can be divided into new investments and replacement investments.

In *new investments*, the existing network is expanded, a new network is constructed or the present network that may need to add some components is reconstructed.

In *replacement investments*, an existing component is replaced by a new identical component. This is usually done for maintenance purposes due to aging or malfunction of the old component.

The major target of the investment strategy is the minimization of the total cost within technical boundaries during the whole lifetime of the distribution network. The total cost for a network lifetime is considered to be comprised of three components; capital cost, operational cost including losses and interruption cost [11].

$$C_{total} = \int_0^T (C_{cap} + C_{oper} + C_{intp})\, dt \tag{3.1}$$

where

C_{total} = total cost
C_{oper} = operational cost
T = network lifetime
C_{cap} = capital cost
C_{intp} = interruption cost

An ideal example of the determination of supply reliability (one of the technical requirements) at which the total cost is minimum is depicted in Figure 3.4. It is seen that as the supply reliability increases, the interruption cost decreases, while the sum of the other two components, $C_{cap} + C_{oper}$, increases. Thus, the total cost has a minimum value providing the optimum level of supply quality.

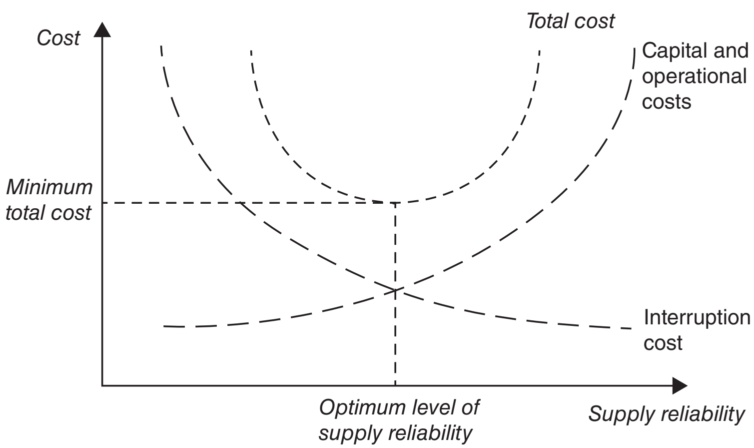

Figure 3.4 Balancing of the direct cost of service and the indirect cost of interruption [2].

In general, the problem is not as simple as illustrated in the example. Detailed and efficient planning is necessary to supply the demand growth, to accomplish reliability and power quality requirements and, at the same time, to optimize the use of the financial resources. In addition, the planning depends on many aspects such as consumers' and regulatory agencies' requirements, environmental issues and technological evolution as well as budget constraints. Therefore, it is a rather complex optimization problem because of its dependence on an enormous number of variables and constraints.

Different available expansion and improvement projects as solutions to such problems can be applied. They must be analyzed and prioritized to optimize the plan, considering their costs and benefits. Therefore, the project prioritization problem is aimed at a search for the formulation of a network strategic plan, for a specific period ahead, that best accomplishes the technical requirements and best improves the system performance subjected to budget constraints.

New tools, smart search methods, such as genetic algorithms and pareto optimality, have been used in the distribution system planning problem to generate and to test some alternatives for the network expansion. They can solve complex and discrete objective function problems, with large search space, that cannot be solved by other optimization techniques [12–14].

Introduction of deregulation and power markets has brought new challenges for the optimal investment strategies where the significance of the total cost components varies depending on the regulation model. For example, the importance of the power quality and thereby incentives for investments that improve power quality are strongly dependent on the regulation model and how power quality is included in the regulation. For instance, the interruptions as a measure of power quality can be identified by their number (number of interruptions) and/or duration (interruption time). The investments are focused on developing the distribution network to decrease the number of interruptions if it has more weight than the interruption time. On the contrary, where decrease in the interruption time has greater importance, the investments are directed to increase the distribution automation. Therefore, it can be said that the prioritization of the investments depends on the parameters of regulation.

Investments can also gain economic benefits not only by reduced total cost but also by increased allowed return on investment. Allowed return in many cases is dependent on the current value of the distribution network assets, which can be increased by investments and based on the regulation method used (e.g., rate-of-return, price cap, revenue cap and yardstick regulations) [11].

In addition, the distribution network investment decisions aim to minimize the cost to customers. Such alternatives include but are not necessarily limited to demand-side management and embedded generation.

3.3.5 Distribution Losses

Distribution losses are inevitable consequences of distributing energy between the zone substations and consumers. Losses do not provide revenues for the utilities and are often one of the controlling factors when evaluating alternative planning and operating strategies. The distribution utilities concern themselves with reducing the losses in the distribution systems according to the standard level. The level of losses will be influenced by a number of factors, technical and operational, such as network configuration, load characteristics, substations in service and power quality required. It is important to manage these factors by appropriate incentives and thus optimize the level of losses.

Losses in distribution networks can be broken down into technical losses and non-technical losses.

Technical losses comprise variable losses and fixed losses.

Variable losses (load losses) are proportional to the square of the current, that is, depend on the power distributed across the network. They often are referred to as copper losses that occur mainly in lines, cables and copper parts of transformers. Variable losses can be reduced by

- increasing the cross-sectional area of lines and cables for a given load;
- reconfiguring the network, for example, by providing more direct and/or shorter lines to where demand is situated;
- managing the demand to reduce the peaks on the distribution network;
- balancing the loads on three-phase networks;
- encouraging the customers to improve their power factors; and
- Locating the embedded generating units as close as possible to demand.

Fixed losses (no-load losses) occur mainly in the transformer cores and take the form of heat and noise as long as the transformer is energized. These losses do not vary with the power transmitted through the transformer and can be reduced by using high-quality raw material in the core (e.g., special steel or amorphous iron cores incur lower losses). Another way to reduce fixed losses is to switch off transformers operating at low demand. Of course, this depends on the network configuration that enables the operator to switch some loads to other sources in the distribution network.

Nontechnical losses (commercial losses) comprise units that are delivered and consumed but for some reason are not recorded as sales. They are attributed to metering errors, incorrect meter installation, billing errors, illegal abstraction of electricity and unread meters. Use of electronic meters will help reduce those losses since the accuracy is high. Also, incentives and obligation on participants should be as correct as possible to reduce the illegal abstraction of electricity. The chart shown in Figure 3.5 depicts a summary of types of distribution losses and the factors affecting them.

Reducing losses may have an added value to the cost of capital expenditure. It, on the other hand, will help reduce the amount of electricity production required to meet demand, and this will have wider benefits. Therefore, it yields the necessity of direct trade-off between the cost of capital expenditure and the benefits gained from loss reduction. To do that, the losses should be estimated as accurately as possible. More explanation of loss estimation in distribution systems is given in Chapter 12.

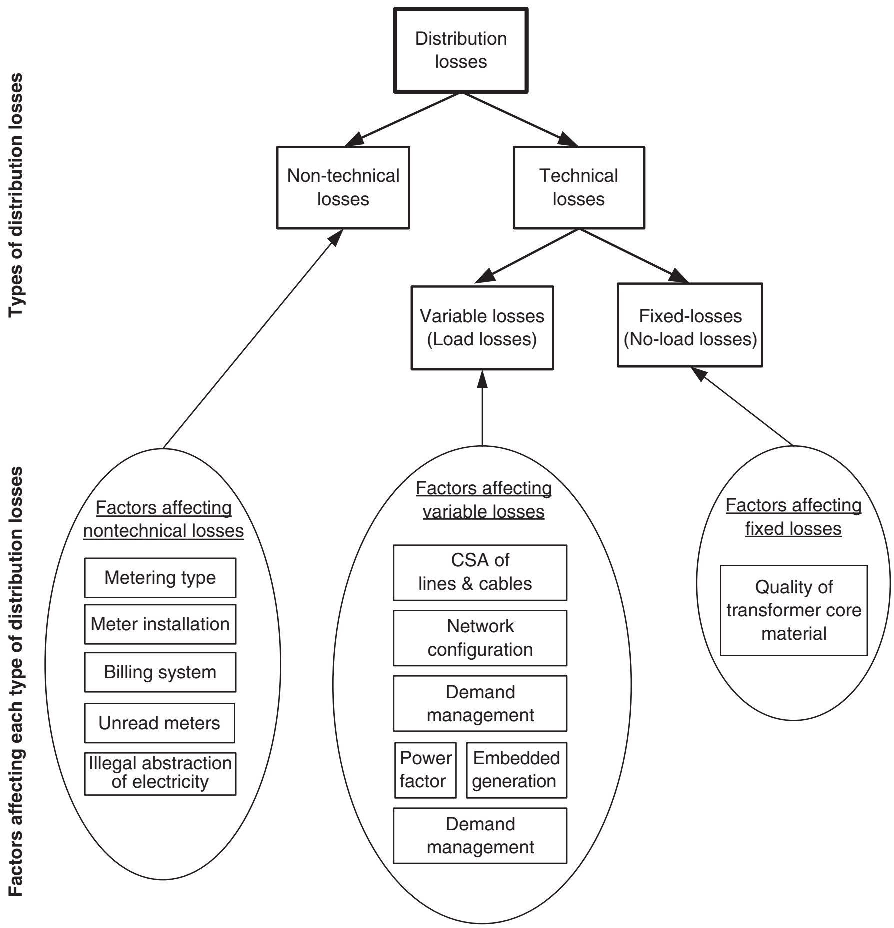

Figure 3.5 Types and factors affecting distribution losses.

3.3.6 Amount of LOL

The distribution system components are exposed to unexpected failure and thus being out of service. If the failed component is a major component in the system, a shortage of capacity will occur, and the system will not be able to provide some customers with electricity. The power demand of those customers is expressed as the amount of loss of load.

For example, a zone substation includes N transformers at normal conditions. Assuming one transformer is out of service under contingency conditions, the total rating of the substation is decreased as shown in Figure 3.6. According to the line representing the demand forecast, the shaded area is the expected energy loss for a specific period.

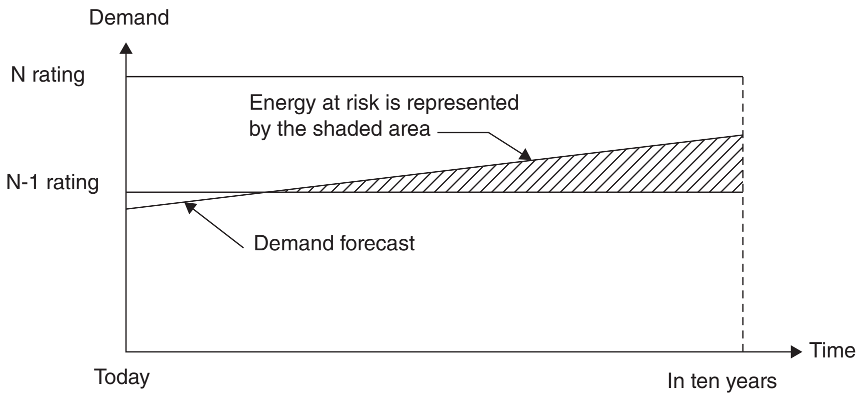

Figure 3.6 Relationship between *N* rating and *N*-1 rating and energy at risk [2].

3.4 SOLUTIONS FOR MEETING LOAD FORECASTS

The planners should think about the available solutions that can be applied to modify the distribution network installations to meet the load growth in the next 3 to 5 years.

The solutions can be classified into two types; network solutions and nonnetwork solutions. Network solutions are the solutions that need adding and/or augmenting some network assets, while nonnetwork solutions are concerned with optimizing the performance of existing network assets.

3.4.1 Network Solutions

According to the power system arrangement shown in Figure 1.1, Chapter 1, the network solutions start from the load points to determine the adequacy of the size of the feeder. If it is not the standard size for the expected loads, the feeders must be resized. This is as a first solution, but if it is not sufficient, the planner must look at the distribution point switchboard design, because it may be necessary to add a panel with circuit breaker for a new feeder or rearrange the present load loops.

Then the testing of adequacy goes towards the infrastructure at higher voltage level to decide the best solution that may be adopted or a combination of the following solutions:

- adding new subtransmission lines,
- adding new transformer to zone substation and
- adding new zone substation.

In addition to the former solutions related to the system structure, the planner may need to add capacitors to improve the power factor or regulators to enhance the voltage profile as alternative solutions.

3.4.2 Nonnetwork Solutions

These types of solutions have a priority of application, particularly, if they are feasible, because these solutions are mostly more economical. The following are different possible alternative solutions:

(a) *Embedded Generation*: The embedded generation would be connected to the distribution networks. Possible embedded generation could include the following types:
- gas turbine power stations,
- cogeneration from industrial processes and
- generation using renewable energy.
  More details are described in Chapter 18 (Part V).

(b) *Demand Management and Demand Response*: *Demand management* schemes have the potential to substantially reduce energy use for a given energy service, thereby reducing long-term energy and capacity needs, and so defer augmentation projects. This can be achieved by shifting customers' usage to off-peak and/or by using high-efficiency, low-energy appliances and reducing energy wastage. Demand-management schemes could include
- peak clipping,
- valley filling,
- load shifting,
- strategic conservation,
- load building and
- flexible load shape.

If such schemes were established, their effectiveness would depend on the extent of customer uptake.

Demand can also be reduced through encouragement for the use of high-efficiency appliances and energy-efficient-designed homes and buildings (insulation, natural lighting etc.). The subject of demand-side management is dealt with in more detail in Chapter 16 (Part IV).

Demand response, which means "actions voluntarily taken by a consumer to adjust the amount or timing of his energy consumption," results in short-term reductions in peak energy demand. Actions are generally in response to an economic signal and comprise three possible types [15, 16]:

- price response, which refers to situations where consumers voluntarily reduce energy demand due to high prices during times of peak demand;
- demand bidding, where large consumers could "sell" their reductions in demand to the utility in times of peak demand; and

- voluntary load shedding, which refers to situations where consumers voluntarily reduce energy demand during times of high demand and/or constrained supply.

Therefore, demand management is focused on achieving sustained energy use reductions and is often driven by incentives, whereas demand response is market driven and results in temporary reductions or temporal shifts in energy use.

Nonnetwork solutions of distribution system planning may enable the deferment or avoidance of major distribution system augmentation projects. Part of the avoided costs of the augmentation projects may be passed on to the owner of the embedded generation (or other means of demand reduction) as annual network support payment.

CHAPTER 4

LOAD FORECASTING

4.1 INTRODUCTION

Customer load in electric distribution systems is subject to change because human activities follow daily, weekly and monthly cycles. The load is generally higher during the daytime and early evening when industrial loads are high, lights are on and so forth and lower from late evening to early morning when most of the population is asleep. Estimating the distribution system load expected at some time in the future is an important task in order to meet exactly any network load at whatever time it occurs [17].

On the other hand, distribution system planning is a multistep process as described by the flow chart (Fig. 3.1) in Chapter 3. The most important key element, on which all steps are based, is load forecast. This defines the distribution system capabilities that need to be achieved by the future system. If it is done inappropriately, all subsequent steps will be directed at planning for future loads different from the load that will develop, and the entire planning process is at risk.

Therefore, load forecast plays a crucial role in all aspects of planning, operation and control of an electric power system. It is an essential function for operating a power network reliably and economically [18]. So the need and relevance of forecasting demand for an electric utility has become a much-discussed issue in the recent past. It is not only important for distribution or power system planning but also for evaluating the cost-effectiveness of investing in the new technology and the strategy for its propagation.

According to the time horizon, load forecast can be classified as short term, midterm and long term [19]. Short-term load forecasting (STLF) over an interval ranging from an hour to a week is important for various operating functions such as unit commitment, economic dispatch, energy transfer scheduling and real-time control. The midterm load forecast (MTLF), ranging from 1 month to 5 years and sometimes 10 or more years, is used by the utilities to purchase enough fuel and for the calculation of various electricity tariffs. Long-term load forecast (LTLF) covering from 5 to 20 years or more is used by planning engineers and economists to plan for the future expansion of the system, for example, type and size of generating plants and transmission lines, that minimize both fixed and variable costs.

Electric Distribution Systems, Second Edition. Abdelhay A. Sallam and Om P. Malik

STLF involves the prediction of the electric load demand on an hourly, daily and weekly basis. It is an area of significant economic value to the utilities. It is also a problem that has to be tackled on a daily basis. Reliable forecasting tools would enable the power companies to plan ahead of time for peak demands and better allocate their resources to avoid any disruptions to their customers. It also helps the system operator efficiently schedule spinning reserve allocation and provides information that enables the possible energy interchange with other utilities. In addition to these economic reasons, it plays an important role in the real-time control and the security function of an energy-management system. The amount of savings in the operating costs and the reliability of the power supply depend on the degree of accuracy of the load prediction.

There is an essential need for accuracy in the demand forecast [20, 21]. This is because the underestimated demand forecast could lead to undercapacity, resulting in poor quality of service where blackouts may occur. On the other hand, overestimation could lead to overcapacity, that is, excess capacity not needed for several years ahead. Consequently, the utility has to cover the cost of such overcapacity without revenues, and this is not favorable. In addition to ensuring the accuracy of forecast, the rationalization of pricing structures and design of demand-side management programs must be emphasized as well. Demand-side management is implemented using different methods explained in Chapter 16. These methods are based on an hour-by-hour load forecast and the end-use components with a goal of changing the system load shape.

Most forecasting methods use statistical techniques or artificial intelligence algorithms such as regression, neural networks, fuzzy logic (FL) and expert systems. Two methods, the so-called end-use and econometric approaches, are broadly used for medium- and long-term forecasting. A variety of other methods, which include the so-called similar day approach, various regression models, time series, neural networks, FL and expert systems, have been developed for short-term load forecasting [22].

There is no single forecasting method that could be considered effective for all situations. The selection of a method of load forecast depends on the nature of the data available and the desired nature and level of detail of the forecasts. Sometimes it may even be appropriate to apply more than one method and then compare the forecasts to decide the most plausible one. Hence, every utility must find the most suitable technique for its application.

4.2 IMPORTANT FACTORS FOR FORECASTS

Several factors should be considered for STLF, such as time factors, weather data and possible customer classes. The medium- and long-term forecasts take into account the historical load and weather data, the number of customers in different categories, the appliances in the area and their characteristics including age, the economic and demographic data and their forecasts, appliance sales data and other factors.

Three principal time factors affect the load pattern. These are seasonal effects, weekly/daily cycle and holidays, which play an important role in load patterns.

The seasonal fluctuations rely on the climatic influences (temperature, length of the day etc.) and varying human activities (holidays, seasonal work etc.). There are seasonal events that produce an important structural modification in the electricity consumption patterns such as the shifts to and from daylight saving time, start of the school day, and significant reductions in activities during holidays. Weekly fluctuations, that is, type of day, are due to the presence of working days and weekends. The existence of holidays and weekends has the general effect of significantly lowering the load values to levels well below normal. Daily fluctuations, the day shape during the day, depend on human activities such as work, school and entertainment [23].

Most utilities have large components of weather-sensitive loads such as those due to air conditioning. Thus, weather factors such as temperature, wind speed and humidity have a significant effect on the variation in the load patterns. In many systems, temperature and humidity are the most important weather variables for their effect on the load.

Most electric utilities serve customers of different types such as residential, commercial and industrial. The electric usage pattern is different for customers that belong to different classes but is somewhat alike for customers within each class. Therefore, most utilities distinguish load behavior on a class-by-class basis.

4.3 FORECASTING METHODOLOGY

It is evident that forecasting must be a systematic process dependent on the time period for which it is going to be used. Forecasting methodologies can be classified on the method used. In a more definitive way, they can be categorized as deterministic or probabilistic. A third approach is a hybrid combination of both deterministic and probabilistic methods. Accordingly, the categories are mathematically based on extrapolation, correlation or a combination of both.

Over the last few decades, a number of forecasting methods have been developed and applied to the problem of load forecast. Two of the methods, the so-called end-use and econometric approaches, are broadly used for medium- and long-term forecasting. A variety of methods used for short-term forecasting fall in the realm of statistical techniques such as time series and regression method, or artificial intelligence algorithms such as expert systems, FL and neural networks.

4.3.1 Extrapolation Technique

This is simply a "fitting a trend" approach that depends on an extrapolation technique. The mode of load variation can be obtained from the pattern of historical data, and hence the curve-fitting function is chosen. Selected well-known functions for the curve fitting are as follows:

- Straight line: $Y = a + bx$
- Parabola: $Y = a + bx + cx^2$

- S curve $Y = a + bx + cx^2 + dx^3$
- Exponential $Y = c\,e^{dx}$
- Double exponential curve: $Y = \ln^{-1}(a + c\,e^{dx})$

The exponential form has a special application, and that is when the abscissa is obtained from a logarithmic scale as ln Y. To explain, it is assumed that a simple straight line fits. Then,

$$\ln Y = a + dx$$

From which

$$Y = e^{a+dx} = e^{a}\ e^{dx}$$

Thus, $Y = c\,e^{dx}$ is the exponential form, where $c = e^{a}$.

Clearly, this does not exclude the use of exponential form with linear abscissa if the data fits the assumption.

The most common curve-fitting technique to evaluate the coefficients a and d is the well-known "least squares method."

4.3.2 Correlation Technique

This technique is based on the calculation of correlation coefficient, which necessitates the calculation of what is known as variance and covariance as below.

Assume two random independent variables x and y, that is, the events $x = x_i$ and $y = y_i$, are independent events. The product of two random independent variables, xy, is a random variable $x_i y_i$, that is, the expectation of a product is the product of the expectations (only for independent type). That is,

$$E(xy) = E(x)E(y)$$

where E represents the "expectation of."

Assume $E(x) = \mu_x$ and $E(y) = \mu_y$ where μ is defined as the number of events/number of possible outcomes.

Therefore,

$$E(xy) = \mu_x \mu_y$$

To measure the deviation from its expected value μ, the quantity σ, defined as standard deviation, is introduced:

$$\sigma = \sqrt{E(x - \mu)^2}$$

The variance is defined as

$$\sigma^2 = E(x - \mu)^2 \tag{4.1}$$

The covariance of two independent variables is given by

$$\sigma_{xy}^2 = E(x - \mu_x)\,(y - \mu_y) \tag{4.2}$$

It should be noted that when $y = x$, the covariance proves to be the generalized form of variance.

Expanding the above relationship:

$$\begin{aligned}\sigma_{xy}^2 &= E(xy - y\,\mu_x - x\,\mu_y + \mu_x\mu_y) \\ &= E(xy) - E(y)\mu_x - E(x)\mu_y + \mu_x\mu_y \\ &= E(xy) - E(x)E(y)\end{aligned}$$

where

$$\begin{aligned}E(x)\,E(y) &= 0 \text{ if } x \text{ and } y \text{ are independent variables} \\ &\neq 0 \text{ if } x \text{ and } y \text{ are dependent variables}\end{aligned}$$

The quantitative measure of the strength of dependability is called the correlation coefficient Γ.

Thus,

$$\Gamma = \frac{\sigma_{xy}^2}{\sigma_x\,\sigma_y} \tag{4.3}$$

Sample Variance:

If $x_1, x_2, x_3, \ldots, x_n$ are n independent observations of a variable x, the sample variance is defined by

$$S_{sv}^2 = (\mathrm{i/n}) \sum (\mathrm{x_i} - \bar{x})^2,$$

where $\bar{x}$ is the arithmetic mean of the variables, that is,

$$\begin{aligned}\bar{x} &= (x_1 + x_2 + x_3 + \ldots + x_n)/n \\ &= (1/n)\sum x_i \quad \text{for } i = 1, 2, 3, \ldots, n\end{aligned} \tag{4.4}$$

It should be noted that unlike the theoretical σ^2, the sample variance is computed from the observed samples, and hence it is actually available. Methods based on correlation technique relate the load to its dependent factors such as weather conditions (humidity, temperature etc.) and economic and general demographic factors. This could clearly include population data, building permits and so on.

4.3.3 Method of Least Squares

A number of functions, to be used as curve fitting for load curves, are introduced in Section 4.3.1. To generalize, a curve fit in a polynomial form is represented as below:

$$Y = a_0 + a_1\,x + a_2\,x^2 + \ldots + a_m\,x^m.$$

Start with "simple regression" to fit the straight-line $Y = a_1 + a_2\,x$ to rectangular points shown in Figure 4.1.

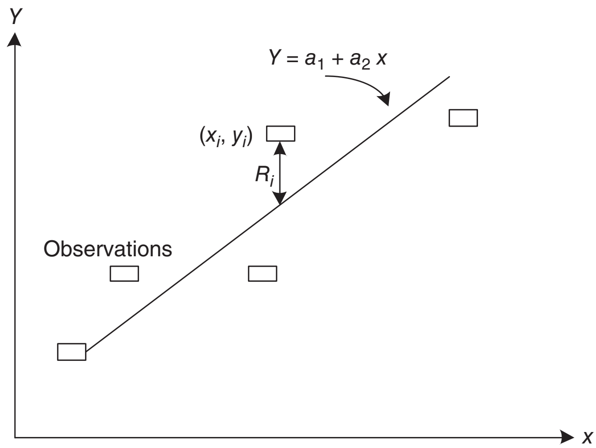

Figure 4.1 Straight line fit to observations.

The deviation of observation points from the assumed straight line should be minimized. Assuming a set of data (x_i, y_i), $i = 1, 2, 3, \ldots, n$ is represented by some relationship $Y = f(x)$, containing r unknowns $a_1, a_2, a_3, \ldots, a_r$, the deviations, sometimes called residuals R_i, are formed by

$$R_i = f(x_i) - y_i.$$

The sum of squares of residuals is

$$S = \sum R_i^2 = \sum [f(x_i) - y_i]^2.$$

The unknown polynomial coefficients, a's, can be determined so that S is minimum by applying the relations

$$\frac{\partial S_i}{\partial a_i} = 0, \quad i = 1, 2, \ldots, r \tag{4.5}$$

This particular form of Equation 4.5 is known as the "normal equations," and the technique is called the "principle of least squares."

The residuals in this case (straight line curve fit) are

$$R_i = (a_1 + a_2 x_i) - y_i,$$

so that

$$S = \sum R_i^2 = \text{minimum}, \; i = 1, 2, 3, \ldots, n.$$

Thus,

$$S = [(a_1 + a_2 x_1) - y_1]^2 + [(a_1 + a_2 x_2) - y_2]^2 + \ldots + [(a_1 + a_2 x_n) - y_n]^2.$$

Differentiating S partially with respect to a_1 and a_2, the two relations below are deduced:

$$\frac{\partial S}{\partial a_1} = 0 = 2[(a_1 + a_2x_1) - y_1] + 2[(a_1 + a_2x_2) - y_2] + \dots + 2[(a_1 + a_2x_n) - y_n]$$

$$\frac{\partial S}{\partial a_2} = 0 = 2x_1[(a_1 + a_2x_1) - y_1] + 2x_2[(a_1 + a_2x_2) - y_2] + \dots + 2x_n[(a_1 + a_2x_n) - y_n]$$

Rearrange the two relations to be written in the form

$$na_1 + \left(\sum x_i\right) a_2 = \sum y_i$$

$$\left(\sum x_i\right) a_1 + \left(\sum x_i^2\right) a_2 = \sum x_i y_i \quad i = 1, 2, 3, \dots, n$$

and in a matrix form

$$\begin{bmatrix} K_{11} & K_{12} \\ K_{21} & K_{22} \end{bmatrix} \begin{bmatrix} a_1 \\ a_2 \end{bmatrix} = \begin{bmatrix} C_1 \\ C_2 \end{bmatrix}$$

where $K_{11} = n$, $K_{12} = \sum x_i$, $K_{12} = K_{21}$, $K_{22} = \sum x_i^2$, $C_1 = \sum y_i$, $C_2 = \sum x_i\, y_i$ and $i = 1, 2, 3. \dots, n.$

By matrix inversion,

$$\begin{bmatrix} a_1 \\ a_2 \end{bmatrix} = \frac{1}{D} \begin{bmatrix} K_{22} & -K_{12} \\ -K_{21} & K_{11} \end{bmatrix} \begin{bmatrix} C_1 \\ C_2 \end{bmatrix},$$

where the determinant of matrix, $D = K_{11}\, K_{22} - K_{12}\, K_{21}$.

The same procedure can be applied when the curve fit is a polynomial of the mth order, where $(m + 1)$ linear equations are obtained to be solved for $(m + 1)$ unknowns.

Example 4.1 Hourly data for the load on a cable feeding an industrial system and the corresponding atmospheric temperature for a 24-hour period are given in Table 4.1. It is required to develop an equation to fit this data to be used for forecasting.

Apply the above technique for the two correlated events, load and temperature, to fit a straight line with the equation:

$$Y_i = a_1 + a_2x_i + \varepsilon_i, \quad i = 1, 2, 3, \dots, 25$$

where ε_i is the deviation from the true line.

The sum of squares of deviations from the true line is

$$S = \sum_{i=1}^{25} \varepsilon_i^2 = \sum_{i=1}^{25} (Y_i - a_1 - a_2\, x_i)^2.$$