Electric Cooperatives Distribution Utility Planning Manual

ELECTRIC COOPERATIVE'S DISTRIBUTION UTILITY PLANNING MANUAL

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General Guide:

In utilizing and interpreting the provisions of this Manual, the same should be considered as general rules of what and how things should be done without prescribing any preference/s. The EC is given the discretion to justify the most appropriate manner of addressing its CAPEX concern.

1. DISTRIBUTION PLANNING PERSPECTIVES

Distribution services must be available continuously with adequate capacity considering the lead time for construction. The future demand must be accurately predicted so that facilities are prepared to meet the growing and dynamic need of consumers. The changing demand for electricity because of technological innovation, economic situation and even political interventions must be anticipated and quantified by planners. Unlike other commodities, electricity must be supplied to end-users at the exact amount and time of need.

System losses are burdens that are also shared by consumers. These must be controlled to a level that the costs of unrecovered energy and the costs of reducing the losses are just and reasonable to be passed-on to consumers through a prudently planned projects and activities.

Consumers suffer inconvenience and loss of productivity when the electricity service is unreliable and of poor quality. In addition to dissatisfied customers, power interruptions also affect the electric utility in terms of lost revenue and costly operations. The unreliability of electricity service ultimately leads to losses in national income and loss of investors' confidence that worsen unemployment in the country. Planners, therefore, must ensure that both quantity and quality needs of customers are met through timely expansion and rehabilitation of distribution facilities.

The Electric Power Industry Reform Act (EPIRA) of 2001 mandated the National Electrification Administration (NEA) to prepare the Electric Cooperatives (ECs) to operate as "viable distribution utility" (R.A. 9136, Sec. 58) which has an obligation to provide services and connections to customers consistent with the Distribution Code and supply electricity in the least cost manner (R.A. No. 9136, Section 23; IRR Rule 7, Sec. 5). ECs, therefore, must meet the same performance standards in service quality, reliability and efficiency that are imposed to all distribution utilities. On the other hand, EPIRA also provides that the distribution utility can impose and collect distribution wheeling charges and connection fees, retail rates and other charges as approved by the ERC based on a rate-setting methodology that will ensure reasonable price of electricity and allow the recovery of just and a reasonable costs to enable the utility to operate viably. Thus, the technical feasibility and financial sustainability of Electric Cooperatives depend on the efficiency of utility operation based on its implementation of a credible Distribution Plan.

1.1. Distribution Planning Objectives

The Distribution Plan of the ECs must have the following attributes:

a) Future demand and requirements for distribution service of customers are accurately predicted;

b) Problems and deficiencies of the distribution facilities to provide adequate capacity, to conform with safety requirements and to meet the performance standards are analytically identified and quantified;

c) The proposed projects to solve the problems and deficiencies of the distribution system have predicted performance that exhibits technical feasibility;

d) The proposed projects to comply with the said obligations and standards are the least-cost option which were selected among technically-feasible alternatives;

e) The proposed projects to improve system performance such as reliability and to reduce system losses have positive net benefits from the point of view of the customers;

f) The documentation of the proposed projects must show the compliance with regulatory requirements as well as the fact of having met the feasibility requirements of financing institutions; and

g) The financing plan identifies the funding sources, amount and repayment terms that could provide information on the impact of the Distribution Plan on the existing rates or the impact of the existing rates on the Distribution Plan.

The objective of Distribution Planning is to determine the orderly and economic expansion and rehabilitation of distribution facilities and the acquisition of assets necessary to attend to the needs of electricity customers that will meet safety and performance standards. Distribution System planners of the EC must determine the feasible and optimal solutions to the following planning problems:

a) Electrification of unenergized areas;

b) Locations, sizes and timing of distribution substations;

c) Types, sizes and routing of subtransmission lines;

d) Types, sizes and routing of distribution lines;

e) Locations and sizes of power conditioning, sectionalizing and switching equipment;

f) Locations and sizes of distribution transformers;

g) Service connection requirements of future customers; and

h) Other non-network assets to efficiently operate the distribution facilities and to attend to the needs of customers.

1.2. Distribution Planning Criteria and Goals

A distribution development plan must meet a number of criteria both under normal and abnormal operation. These criteria must be met but need not be exceeded.

First and foremost, the Electric Cooperative must meet its obligations to serve its customers. Hence, the distribution facilities of the EC must have sufficient capacity to meet the growing demand of the customers. Substations, lines and distribution transformers must not be overloaded. Substations must also provide reserve capacity margin for outage contingency. Additional capacity will be triggered on the year the substation will be loaded 70% of the maximum rated capacity.

The distribution services of the ECs must meet the criteria specified in the following codes and standards:

a) Performance standards set by the Philippine Distribution Code (PDC); and

b) Safety standards set by the Philippine Electrical Code (PEC).

The PDC specifies the performance standards in power quality, reliability and efficiency (system loss) that the distribution system must meet during normal operation. These are the criteria or the limits of operation that will be allowed as they directly impact the customers' use of appliances and the costs that they pay for the services they receive from the distribution utility.

Power Quality standards pertain essentially to the quality of voltage measured at the connection point of customers that must be met by the distribution system. The following are the power quality standards or criteria that planners must take into account in preparing the Distribution Development Plan which will be part of the Distribution Plan:

a) Long Duration Voltage Variations: 0.9 to 1.1 of the nominal voltage;

b) Short Duration Voltage Variations: Distribution System should have sufficient capacity so that the voltage sags, when starting large induction motors, will not adversely affect any user system and the voltage ratings of distribution equipment shall be selected based on maximum estimated voltage swell;

c) Harmonics: Maximum 5% Total Harmonic Distortion;

d) Voltage Unbalance: Maximum 2.5% (net of the unbalance caused by the transmission system); and

e) Flicker Severity: Maximum 1.0 unit for short term flicker and 0.8 unit for long term.

It should be noted that the flicker standards is usually translated in distribution planning guidelines to be maximum of three percent (3%) voltage spread at the connection point of customers during large motor starting.

The performance standard in distribution system reliability and segregated distribution system loss are still under study. For purposes of preparing the Distribution Plan of the ECs, the following criteria shall be considered by the Planners in the interim:

a) System Average Interruption Frequency Index (SAIFI): Maximum 20 customer-interruptions per customer-year; and

b) System Average Interruption Duration Index (SAIDI): Maximum 45 hours per customer-year.

The PEC requires that the electrical system is designed, installed, operated and maintained in a safe manner. In preparing the Distribution Plan, the following criteria must be met:

a) Short Circuit Duty of Protective Devices: At least 10% of the maximum fault; and

b) Location of Protective Devices: Minimum fault at the farthest end of feeders must be sensed by protective devices.

The EC must also plan to meet the electrification target of the government under the policy and regulatory framework of EPIRA.

The Distribution Plan must meet “criteria” while maximizing attributes of system performance such as reliability and efficiency. The solutions to problems and deficiencies in safety, capacity and power quality must be fully addressed before considering system and service performance improvements. The EC may pursue projects to improve the reliability of its service to the customers above the criteria or to reduce the system losses below the caps only if the benefits (i.e., cost of interruptions) exceed the cost of system improvement program.

The Electric Cooperatives were created to be the government’s agent for rural electrification under the supervision of the National Electrification Administration (NEA). Since EPIRA mandates that the ECs must operate as “viable distribution utility”, their plan to energize the remaining barangays and sitios pursuant to their mandate under PD 269 should be conscientiously prepared by setting practical goals subject to the available financial resources. It is important to ensure that the “missionary” component of the rural electrification plan is not funded by the consumers in the coverage area of the EC. Since rural electrification is a social program of the government primarily to improve the quality of life of the people in island and remote rural communities, the subsidy needed to pursue the social objectives must come from the following sources: (a) national government; (b) local government; (c) voluntary contributions; and (d) universal charge (UC). Considering the subsidies that can be accessed by the ECs, planners must set practical and reasonable goals for the Distribution Plan.

Therefore, at the start of the planning or after the assessment of the performance of the EC relative to its mandates as a distribution utility and as agent of rural electrification, the planners must set the goals and prioritize the problems that will be addressed in the Distribution Plan.

1.3. Distribution Planning Process

The general procedure in preparing the Distribution Plan is illustrated in Figure 1. The process starts with the updating of distribution network, customer and equipment costs database as well as gathering of relevant information from other organizations.

After data gathering, the future demand per substation and per customer class is forecasted. The forecasting models that the EC will use must pass the validity and accuracy tests.

A comprehensive assessment of performance for historical (base year) and forecasted demand will then be conducted to identify and quantify the problems and deficiencies of the existing distribution facilities and utility operation in the following attributes:

a) Capacity (substations and lines);

b) Safety (short circuits and ground faults);

c) Power Quality (undervoltage, overvoltage, and unbalance voltage);

d) Reliability (frequency and duration of interruptions, loss of load and energy not supplied);

e) System Loss (segregated technical and non-technical losses);

f) Customer Service; and

g) Electrification.

Based on the comprehensive lists of problems and deficiencies, the utility's goals for the planning period is set based on the mandates and priorities of the Electric Cooperative. As distribution utility, the EC's facilities must be adequate to meet its obligations to customers. As rural electrification agent, the EC must commit to electrify un-energized areas based on available resources. Based on the set goals and available resources, the EC may set the priority problems to be addressed by the Distribution Plan. Problems in meeting safety and performance standards are deemed "mandatory" while system improvements above the standards are deemed "desirable".

After setting the goals and prioritization of problems, projects (i.e., alternatives and options) will be formulated to solve the identified and quantified problems. The project ideas must be validated whether they are physically feasible and practical to implement.

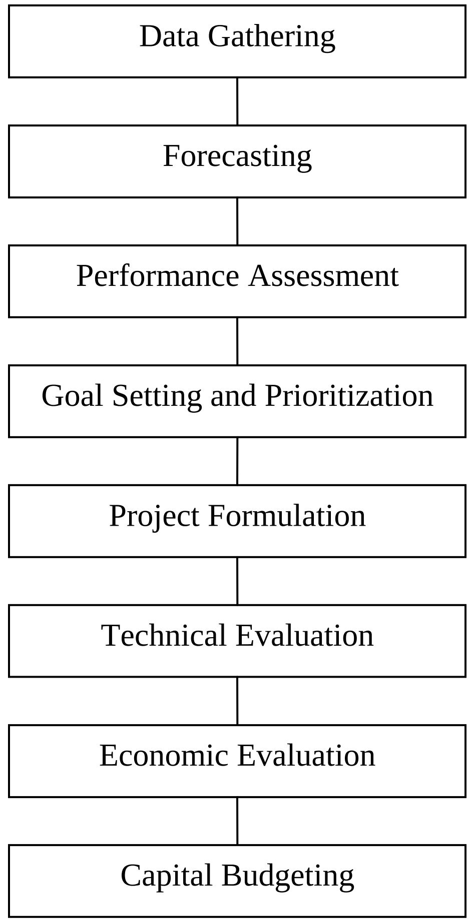

Figure 1 – General Procedure of Distribution Planning

Each formulated project will then be evaluated for technical feasibility. This will entail some modifications in the analytical models used in the performance assessment to capture the proposed solutions and predicting the results to determine whether planning criteria are met. The project ideas that are not technically-feasible will be screened out of the list while feasible ones will be ranked according to technical effectiveness.

The technically-feasible solutions to the problems will then be evaluated for economic or financial feasibility. The least cost among the alternatives or options that can solve the problem shall be selected for problems that are deemed "mandatory" to meet the obligations of the EC to its customers according to standards. For "desirable" projects which are optional (e.g., reliability improvement and system loss reduction above the standards), the net present value of benefits and costs must be positive or the benefit/cost ratio must be greater than one. The EC may also conduct incremental benefit-cost analysis for the combined mandatory and optional projects to optimize the Distribution Plan based on allowed costs or given capital budget. For electrification projects, the required subsidy to implement the project must be calculated.

If certain problems may only have one solution, necessary justification of its necessity and/or benefit should be provided.

Other requirements of the network to meet the forecasted demand of additional customers such as distribution transformers, secondary distribution lines, service drops and metering equipment are estimated. Non-network projects required to provide efficient service are also estimated.

The Project Documentation will then be prepared for each project or group of projects to systematically record and report the details of the project including priority ranking, title, description, justification, technical analysis, economic analysis and all relevant information.

The last step in Distribution Planning is the Capital Budgeting where the sources and scheme of funding for each project are identified. The cash flow of the EC with the Distribution Plan is simulated.

1.4. Planning Data

The Distribution Planning will require the gathering and updating of the following relevant data:

a) Historical Customer, Demand and Sales Data [At least 7 years]

1. No. of customers per customer class;
2. Monthly and annual peak and energy demand (kWh) per substation (preferably per feeder);
3. Monthly and annual energy sales (kWh) per customer class; and
4. Monthly and annual demand of special and/or large customers (kW and kWh);

b) Historical Distribution System Performance and Statistical Data [At least 7 years]

1. System Loss, Load Factor and Power Factor;
2. Distribution System Reliability (SAIFI, SAIDI and MAIFI);
3. Total installed Substation and distribution transformer capacity (MVA); and
4. Total Lengths of Lines per voltage category classified into urban/rural installations.

c) Historical and forecasted/targeted economic, demographic and development plan data [At least 7 years]

1. Gross Regional Domestic Product (GRDP) per industry sector;
2. Population within the Coverage Area of the EC (per Barangay, City/ Municipal & Provincial);
3. Municipal, City and Provincial Development Plans; and
4. Plans of industrial, large commercial, institutional and special load customers.

d) Distribution System Maps and Diagrams [Latest and Updated]

1. Subtransmission System Maps or Line Diagrams;
2. Substation Line Diagrams;
3. Primary Distribution System Maps or Power Line Diagrams; and
4. Secondary Distribution System Maps or Power Line Diagrams.

e) Distribution Network and Customer Data (ERC DSL Segregation Data) [Latest and Updated]

1. Subtransmission Lines;
2. Primary Distribution Lines;
3. Primary Customer Service Drops;
4. Distribution Transformers classified into “Sole-User” or “Communal”;
5. Automatic Voltage Regulators and Capacitors;
6. Secondary Distribution Lines;
7. Customer Service Drops; and
8. Customer Consumption

f) Fault Data at connection points to the Grid [Current Year]

1. Three-phase fault magnitude and X/R Ratio or equivalent Thevenin positive sequence impedance; and
2. Single-line-to-ground fault magnitude and X/R Ratio or equivalent Thevenin positive, negative and zero sequence impedance

g) Interruption Data [Average of at least Five Years]

1. Three-phase and single-line-to-ground fault data at connection points to the Grid;
2. Subtransmission and distribution circuit interruptions (number interruption per kilometer-year and cumulative duration per year of circuits owned by the transmission company and the EC);
3. Substation scheduled outages per year; and
4. Restoration time of sustained interruptions.

h) Committed Expansion, Rehabilitation and Electrification Projects

1. Subtransmission acquisition, refurbishment and expansion;
2. Substation and Associated Subtransmission Projects;
3. User Development Projects (Large prospective customers) requiring extension of primary lines or dedicated circuits;
4. Primary Distribution Line Extension within Energized Areas;
5. Primary Distribution Line Extension Outside Energized Areas (Rural Electrification Project); and
6. Line Rehabilitation and System Improvement Projects.

The above comprehensive list of data must be gathered by the ECs as much as possible. However, if the EC could not immediately gather all data needed, the planner must use proxy information and alternative approaches in preparing the Distribution Plan.

2. FORECASTING

The ability of the electric cooperative to accurately forecast future energy and demand requirement of the distribution system is a critical component for effective and correct identification of CAPEX projects. Inaccurate forecast may result to wrong prescription of projects by the system managers or planners, either by overbuilding or underbuilding capacity. In any case, this would result in significant cost to the consumers.

2.1. General Procedure of Forecasting

The flow of activities and procedures for forecasting are outlined below:

1. Examine and analyze accuracy of the data for possible erroneous values or outliers. Historical data requirements depend on the forecast horizon and the methodology or approach in forecasting;

2. Develop Forecasting Models based on useful data that are available;

3. Test the Validity of the Models. Reject models that did not pass the tests. Improve or formulate more Forecasting Models until all variables passed the tests;

4. Test the valid models for accuracy;

5. Select the best Load Forecasting Model;

6. Forecast the future (demand, sales and customers);

7. Determine Annual Growth Rates; and

8. Document the Forecasting Data, Methodology, Models (include selected and rejected models) and the forecasts.

2.2. Forecasting Approaches and Methodology

The most appropriate forecasting methodology for distribution utilities is *Small Area* forecasting to capture both magnitude and spatial characteristics of the load within the franchise or coverage area of the utility company. However, the current state of database and analytical models of the Electric Cooperatives are not sufficient yet to apply this approach or methodology. There are two forecasting methodology that can be used by the ECs. These are the *Econometric Analysis* which uses economic and demographic information to forecast the load and *Trend Analysis* which requires only historical load data. It is advisable for the ECs to gather sufficient and reliable historical load, economic and demographic data so that the two methodologies can be used in forecasting. The econometric analysis can be used with high level of accuracy for medium-term (5-10 years) and long-term (greater than 10 years) forecasting. However, the economic data that may be gathered by the ECs could be on regional basis which may not give good correlation for the limited coverage area of the ECs. On the other hand, trend analysis which requires only historical demand may not give high level of accuracy for forecasts beyond five years. Given that the ECs will commit the 5-Year Statement of the Distribution Development Plan and the CAPEX Plan required by regulators are also about five years, the forecasting models developed using trend analysis may be sufficient for the ECs in preparing their Distribution Utility Plan.

There are also two (2) approaches in forecasting the Peak Demand. The first approach is to forecast the peak demand directly. The second approach is to forecast energy first then compute the peak demand from an assumed load factor. The Distribution Planner must assess which approach is best for the data available.

Likewise, the Total Demand can be forecasted using two (2) approaches. It can be forecasted directly or by load component. In the first approach, the Total Demand of a substation or of the entire distribution system is forecasted directly from the historical data. The second approach requires individual forecasting of each load component usually per customer classification (e.g., residential, commercial, industrial, etc.) then the forecasts are added. The Distribution Planner must also assess the best approach to forecast the Total Demand of the substations and the Total System.

2.3. Developing Forecasting Models

The EC shall formulate models to forecast the following:

a) Annual peak demand and energy for each substation;
b) Annual peak demand and energy for the Total System;
c) Annual Sales or Customer Consumption per customer class;
d) Annual Number of customers per customer class; and
e) Monthly peak demand and energy for each feeder.

2.3.1 Econometric Models

Regression models based on ordinary least square method can be used to develop the forecast models with population, GRDP, price and other independent variables as predictors.

2.3.2 Trend Models

A polynomial trend and its variants (e.g., log and power) can be used to develop the forecasting models using historical demand to forecast annual peak and energy demand.

To capture seasonality for monthly peak and energy forecast, time series technique such as Holt-Winter's method and optimized trend with seasonal factors using regression analysis may be used. An alternative approach to capture seasonality is to develop a load variation curve in per unit and used the per unit values to predict the monthly demand from the annual forecast.

The Growth Rate method in NEA's ICPM shall be treated as one of the forecasting models formulated under the trend analysis approach.

2.4. Testing and Improving the Forecasting Models

The forecasting models formulated must be tested for validity. The R^2 and Adjusted R^2 statistics are good measure of fit of the model to the historical data. These statistics must be used to assess whether the addition of independent variable are valid or not. For econometric models, the Adjusted R^2 statistic should be at least 80% while for trend models, it should be at least 99% for the model to be valid.

Predictors or independent variables must also be tested for their validity using at least the *p-value* and *t-statistic.* For the variable to be valid, the p-value should be lower than 0.1 while the t-statistic should be greater than 2 or less than -2.

For all the valid forecasting models formulated, the Mean Absolute Percentage Error (MAPE) must be computed. The MAPE of the final forecasting model should not exceed 5%.

In case, the forecasting models formulated failed either or both in terms of validity and accuracy, the Distribution Planner must improve the model by using additional data or through some variants of the model.

Summarize the Forecasting Models formulated and evaluated in the following table:

Model No.	Forecasting Model	Model Description	Validity Tests	Accuracy Tests	Remarks

2.5. Demand and Customer Forecasts

The EC must forecast the following:

a) Annual peak demand and energy for each substation for at least 15 years;
b) Annual peak demand and energy for the Total System for at least 15 years;
c) Annual Sales or Customer Consumption per customer class for at least 5 years;
d) Annual Number of customers per customer class for at least 5 years; and
e) Monthly peak demand and energy for each feeder for at least 5 years.

The feeder demand forecast must be allocated to feeder load points (i.e., distribution transformers and MV customers).

The number of customers and sales in MWH must be forecasted for the following customer class:

a) Residential;
b) Sale for Resale;
c) Other Residential;
d) BAPA;
e) Small Commercial;
f) Large Commercial (LV);
g) Industrial (LV);
h) Public Buildings;
i) Irrigation;
j) Street Lights;
k) Special Lightings;
l) Communal Water System;
m) Large Commercial (MV);
n) Large Industrial (MV);
o) Large Industrial (HV); and
p) Others.

3. PERFORMANCE ASSESSMENT

This Chapter outlines the tasks necessary to identify and quantify the problems of the distribution system for the latest historical year load (base year) and forecasted loads (at least 5 years in the future).

3.1. Development of Analytical Models

Using available computational and/or simulation tools, the electric cooperative must develop analytical models of its distribution system to assess the system performance based on the latest historical year and forecasted loads (at least 5 years in the future. Below is the general procedure:

1. Model the distribution system for the base-case year using appropriate simulation tools. It is important to capture the unbalanced characteristics of the distribution system in developing the network and load models;

2. Input the ratings and parameters of each of the elements in the distribution system such as power transformers, subtransmission lines, distribution lines, loads in each feeder, capacitor bank, etc.;

3. Convert real values to their corresponding per unit values, when necessary to suit the requirements of the simulation software that will be used;

4. Provide the power factors of the loads especially for bulk loads; and

5. Perform the necessary analysis to test the validity of the developed model.

3.2. Loading Analysis

Analyze the capacity requirement of substations, lines and distribution transformers and determine the year that the loading criteria of equipment are violated. The following tasks shall be undertaken:

1. Perform loading analysis of substations for the base year and each of the forecasted years (at least 15 years). For each forecasted year, compare the transformer loading to its maximum rated capacity. A substation is considered fully loaded if the loading of the transformers exceeds 70% of the maximum rated capacity. It should be noted that

the maximum rated capacity of the substation is the sum of all the highest capacity listed in the equipment nameplate. For example, if a substation has only one transformer with 5/6.25 MVA OA/FA rated capacity on the nameplate, the maximum capacity of the substation is 6.25 MVA. If the substation has two (2) 5/6.25 MVA transformers, the maximum capacity of the substation is 12.5 MVA. Consider planning for augmentation of substation capacity if it will be 70% loaded in reference to a 10 year planning horizon; and

2. Perform load flow analysis. Determine distribution line and distribution transformer loading for each of the forecasted year. If the loading exceeds the thermal capacity of conductor or the transformer, the loading problem is considered as priority problem to be solved. On the other hand, if the loading exceeds the economic loading range of conductors, the distribution line segment or transformer shall be noted for system loss reduction.

3.3. Future Requirements of Large Customers

Demand and Location of new and future customers must also be anticipated, especially for bulk loads. These information are usually available through inquiries of customers, from the city/municipal/provincial development plans, or business permits applications. The EC must also ask its existing large customer if they have plans to increase or reduce its demand at least in the next five years.

3.4. Safety Analysis

Calculate and analyze the available short circuit currents in the distribution system. Assess the short circuit duties of the protective devices against maximum faults and their adequacy to sense minimum faults. The following must be considered in conducting short circuit analysis:

1. Quantify the range of currents that will flow in the network under faulted conditions. Faulted conditions mean conditions that include on or more short circuits somewhere in the network. Calculate at least the three-phase and single line to ground fault currents;

2. The *short circuit duty* of all protective devices must be at least *110%* of maximum; and

3. The *minimum faults* which usually happen at the far end of the feeder must be sensed and isolated by protective devices. For purposes of calculating minimum fault currents, a fault resistance of 30 ohms in MV feeder can be used.

The EC must also include the line and equipment that need to be rehabilitated because of violations in safety criteria specified by the PEC such as clearances and insulations.

3.5. Voltage Analysis

Calculate the voltages at the load points of the MV Feeder for the base year and forecasted years and analyze the power quality of distribution system. For purposes of Distribution Planning, power quality assessment shall include the under/overvoltage and unbalance voltage in the primary distribution feeders. Where there is very large induction motor that may cause flickers, a motor starting analysis must also be conducted. The service areas of the MV feeders where there are power quality problems shall be identified.

1. Perform load flow to assess the voltage profile of feeders for the base year and forecasted years based on the annual peak demand;

2. Identify feeders with voltage violations. Use the criteria: *0.9 - 1.1 per unit (p.u.) voltage and 2.5% max unbalance voltage;*

3. Quantify the impact of voltage violations in terms of percentage of service area and number of customers affected; and

4. Note the voltage violations (if any) and identify the possible reasons that cause the voltage violations.

3.6. Reliability Assessment

In the interim the reliability criterion for the subtransmission system is single outage contingency or (N-1) redundancy and for the distribution system, the maximum SAIFI and SAIDI are set at maximum 20 customer-interruptions per customer-year and 45 hours per customer-year, respectively.

In calculating the reliability of the subtransmission and distribution system, the EC must establish the average failure rates (failure or faults per year) and repair times (hours). Using the existing network configuration and the forecasted customers and loads, calculate the following reliability indices:

1. The System Average Interruption Frequency Index (SAIFI). SAIFI is the average number of interruptions that a customer would experience, and is calculated as:

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

SAIFI is measured in units of interruptions per customer.

2. System Average Interruption Duration Index (SAIDI). SAIDI is the average outage duration for each customer served, and is calculated as:

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

3. The Momentary Average Interruption Frequency Index (MAIFI). MAIFI is the average number of momentary interruptions that a customer would experience during a given period (typically a year). MAIFI is calculated as:

$$\text{MAIFI} = \frac{\text{total number of customer interruptions less than the defined time}}{\text{total number of customers served}}$$

   MAIFI has tended to be less reported than other reliability indicators, such as SAIDI, SAIFI, and CAIDI. However, MAIFI is useful for tracking momentary power outages, or "blinks," that can be hidden or misrepresented by an overall outage duration index like SAIDI or SAIFI. Momentary power outages are often caused by transient faults, such as lightning strikes or vegetation contacting a power line, and many utilities use reclosers to automatically restore power quickly after a transient fault has cleared;

4. Loss of Load Expectation (LOLE). LOLE is the expected number of times per year that the system will have to shed load due to the outage of substation; and

5. Expected Energy Not Served (EENS). EENS is the expected megawatt-hours that a system will not be able to supply due to the outage of distribution facilities.

Determine if each substation, feeder and the total system will meet the interim reliability criteria.

3.7. System Loss Segregation

Calculate and analyze the segregated system losses of the distribution system for the base year and 5-forecasted years. Develop system loss reduction CAPEX as needed considering cost and benefit.

3.8. Rural Electrification

Analyze the electrification performance of the EC against the target set in the past. Determine the problems (if any) why the target were not met.

List the electrification projects that are being proposed or requested to be implemented by the EC for the next five years.

3.8 Summary of Performance Assessment of the Distribution System

The problems that are identified and quantified shall be summarized in the following table:

No.	Problem Description	Problem Type

The problem must be described with identified and quantified performance indices and impacts. Classify the problem into the following types:

a) Capacity;

b) Customer Requirements;

c) Safety;

d) Power Quality;

e) Reliability;

f) System Loss;

g) Rural Electrification; and

h) Others.

It should be noted that some problems in capacity, safety and power quality may also appear to be problems in reliability and system loss. These problems should not be classified under the reliability or system loss type.

4. GOAL SETTING AND PRIORITIZATION

4.1. Priority Problems

The performance assessment identifies and quantifies the problems and deficiencies that must be addressed by the planners in preparing the Distribution Plan of the EC. The Electric Cooperative must prioritize the following problems to meet the established criteria:

a) Safety deficiencies;

b) Capacity inadequacies; and

c) Power Quality violations.

The safe installations and operation of the distribution system cannot be compromised. Compliance with the safety requirements of the Philippine Electrical Code must be the first priority of the Electric Cooperative that must be addressed in Distribution Planning.

Since the EC operates as a monopoly utility company in its coverage area, the distribution facilities must have adequate capacity to meet its obligation to serve its captive customers. Hence, the capacity problems take second priority after the safety problems. This shall include the identified future requirements of customers.

The third priority of the EC is to correct the voltage violations in the distribution system. If there are voltage problems in many feeders, the planner may plan to correct the voltage violations in phases within the 5 year planning horizon. If all the voltage problems cannot be addressed within five years without resulting in price shocks (i.e., abrupt increase in rates), the planner must prioritize the primary feeders and secondary distribution lines that has highest impact to customers and performance of the EC. The other power quality problems may be included in the future.

4.2. Goals and Priorities in System Improvements and Rural Electrification

Priorities regarding improvements in service reliability, reduction of system losses and rural electrification must be set by the EC considering its access to financial resources. The EC's Board of Directors (BOD) must set the policy on prioritization and must commit resources that can be used to pursue the projects.

While most power quality and substation projects will reduce system loss and improve reliability, these projects must not be classified as system loss or reliability projects. If the levels of reliability or system loss in a specific service area of the distribution system are deemed to be problems of the EC that must solved or needs improvement, these problems shall be classified either as “reliability” or “system loss”.

The planner must list the priority problems and the goals to be pursued in planning using the following table:

Problem Description	Problem Type	Priority	Goal

The problem must be described and classified according Section 3 of this Manual. Safety, capacity, and power quality should take priority 1 to 3, respectively. The goal of the planner is ***full compliance***. However, in the case of power quality problem when it is not practicable to implement within the five-year period the solution to the problem, goal should be either ***partial compliance*** or ***compliance deferred.***

The planner must indicate the target reliability (i.e., ***level of SAIFI and SAIDI***) or the ***level of system loss*** in the planning goal.

In the case of rural electrification, the management and BOD must commit to solicit subsidies in order to fund the projects. The un-energized areas (Barangays or Sitios) must be listed in the Problem Description. The planner must indicate the goal for each electrification problem if it is for ***full implementation*** or ***differed implementation***.

5. PROJECT FORMULATION

5.1. Project Ideas

For each problem identified and quantified in performance assessment, the planner must generate project ideas (i.e., solutions to the problems). These project ideas must be verified if physically feasible and practical to implement. The project ideas must be classified as a *stand-alone* (i.e., mutually exclusive), *sequential* or *complementary*. The problem and project ideas must be summarized in the following table:

Problem Description		
Project Ideas (Solutions)		**Classification**
Alternative 1		
Alternative 2		
Alternative 3		
:		
:		
Alternative n		

5.2. Solutions to Problems

This section outlines the general solutions to the problems and deficiencies of the distribution system. The list of solutions is not exhaustive. Hence, planners may generate other solutions that have been tried in the past or in other installations. The planner must also formulate the specific solution. For example, the solution to capacity deficiency is to build new substation, the specific solution should indicate the capacity and location of the substation. This solution has several alternatives from the combination of the following decision variables:

a) Capacity of substation (5 MVA, 10 MVA, 20 MVA, etc.);

b) Number of transformers in substation (1, 2, etc.);

c) Timing of installation of transformer units if more than 1 transformer in a substation; and

d) Location of substation (there may be several alternative sites).

5.2.1. Safety (Short Circuit) Compliance Projects

Safety problems may be solved by the following projects:

- Replacement of protective devices with inadequate short circuit duty;
- Reconfiguration of subtransmission system to reduce available fault currents; and
- Installation of protective devices midstream of the primary distribution feeder to sense minimum fault currents.

5.2.2. Capacity Augmentation Projects

Problems in substation capacity deficiencies may be solved by the following projects:

- Uprating of existing substation capacity; and
- Construction of new substation.

In the case of subtransmission and distribution lines, the following projects may be considered:

- Uprating of existing conductors;
- Construction of new lines; and
- Voltage conversion.

5.2.3. Expansion Projects

To meet the connection requirements and demand of new customers within the energized area, the following alternatives may be considered:

- Extension of primary feeders (single phase or three phase); and
- Construction of new substation.

5.2.4. Electrification Projects

Electrification may consider the following options:

- Extension of primary feeders (single phase or three phase);
- Construction of new substation;
- Construction of mini-grid to be supplied by micro-hydro power or small diesel generator;
- Stand-alone solar home system; and
- Community battery charging station.

5.2.5. Power Quality Correction Projects

The following solutions may be considered to improve the voltage performance of the distribution system:

- Capacitor placement;
- Installation of Automatic Voltage Regulator (AVR);
- Conductor uprating;
- Reconfiguration of primary distribution system; and
- Advance construction of new substation.

5.2.6. Reliability Improvement Projects

Reliability can be improved through the following projects:

- Looping of subtransmission system to meet single outage contingency criterion;
- Installation of sectionalizing devices to improve SAIFI and MAIFI; and
    a. Reclosers midstream and at strategic laterals of the primary distribution feeders; and
    b. Fuses at lateral lines.
- Installation of switching devices to improve SAIDI;
    a. Switches midstream (Break and Transfer); and
    b. Switch at end of trunk (Tie Switch to adjacent feeder).

5.2.7. System Loss Reduction Projects

Technical losses can be reduced by:

- Power factor improvement;
- Conductor uprating;
- Reconfiguration of feeder System;
- Rationalization of distribution transformer capacity; and
- Development of subtransmission system and substations.

6. TECHNICAL EVALUATION

6.1. Technical Analysis

The power system model or electric circuits used to assess performance of the distribution system should be modified to reflect the proposed projects or solutions.

Conduct the appropriate technical analysis (i.e., loading, short circuit, load flow or voltage drop, reliability and system loss analysis) to predict the performance of the distribution system with the proposed project. Summarize the results of technical analysis using the table below.

Problem Description			
Project Alternative	**Project Description**	**System Performance**	
		Without Project	**With Project**
Alternative 1			
Alternative 2			
Alternative 3			
:			
:			
Alternative n			

6.2. Screening and Ranking of Technically-Feasible Projects

Projects that are deemed technically feasible (i.e., those that can solve the identified and quantified problems) shall be separated from those that did not pass the criteria.

If all the project alternatives in any of the problems are not feasible, the planner must formulate more alternatives. In some cases, the combination of several projects which are individually not feasible can solve the problem.

The technically feasible projects for each problem must be ranked in terms of technical effectiveness.

7. ECONOMIC/FINANCIAL EVALUATION OF TECHNICALLY FEASIBLE PROJECTS

Projects that are considered technically-feasible shall be subjected to economic or financial evaluation, that is, the project from among the identified alternative projects that provide least total cost shall be selected. While there is clear distinction between economic and financial evaluations, the figures considered in this chapter are in terms of financial costs and benefits.

7.1. Incremental Costs, Life-Cycle Costs, and Benefits

Economic and financial analysis should start with financial costs and benefits, i.e., the Electric Cooperative's expenses and revenues. In certain projects, for example: construction of a new substation, the project is an independent with a clear measurable output. In some other projects, for example: expansion of distribution feeders, the project adds a component to the existing facility. The primary attempt must be aimed at assessing the incremental costs and benefits, i.e., those that are associated with the project. However, when this is not possible the analysis shall be based on total facilities. Costs shall be based on the life-cycle cost of the project, i.e., the sum of all relevant costs over a given study period or economic life, adjusted for the time value of money.

In order to calculate the life-cycle cost of the project, it is necessary to determine the following information of the project:

- Investment Costs;
- Renewal Costs;
- O&M Costs; and
- Technical Loss Costs (when applicable).

Project alternatives shall be compared using the present worth or present value of the life cycle costs.

For purpose of economic evaluation the Asset Lives used in the PBR of Private DUs shall also be used for the CAPEX Planning of ECs.

7.2. Projects that “Must Meet Criteria”

Projects that must meet criteria (i.e., compliance with safety, capacity and power quality standards) shall be selected based on **least cost** criteria. Since these problems concern the obligation of a monopoly utility company affecting public interest, the problems must be solved regardless of the net present value or internal rate of return of the project. The quantification of the benefits of these projects to the social objectives and national economy is beyond the tasks of Distribution Planners.

The economic evaluation of the alternative projects must be summarized using the following table:

Problem Description		
Project Alternative	**Project Description**	**Present Worth**
Alternative 1		
Alternative 2		
Alternative 3		
:		
:		
Alternative n		

7.3. Projects that “Optimize Attributes”

In the case of projects that optimize attributes such as system reliability and system loss, the key measures used to assess the financial viability of the project are the Net Present Value (NPV), the Internal Rate of Return (IRR) and Benefit-Cost ratio (B/C). The value of discount rate to be used for the selection of optimal project shall be based on the cost of debt of the ***Electric Cooperative***. If the Net Present Value or NPV or the project is positive, the project is economically viable. The Benefit-Cost Ratio of the project with positive NPV will be greater than one (1) while the IRR will exceed the discount rate.

The economic/financial evaluation of projects that seeks to improve system performance and not classified as “compliance” project shall be summarized in the following table:

Problem Description				
Project Alternative	**Project Description**	**NPV**	**B/C**	**IRR**
Alternative 1				
Alternative 2				
Alternative 3				
:				
:				
Alternative n				

7.4. Projects for "Rural Electrification"

The Rural Electrification projects shall also be evaluated using *Least Cost* criteria. The projects shall also be technically feasible (i.e., they comply with standards and do not create performance problems).

The Planner must calculate the amount of subsidy needed to pursue the least cost rural electrification project. In order to calculate this, the expected revenue from the project must be calculated based on the ERC-Approved rates for CAPEX.

The Rural Electrification Project shall be summarized using the following table:

Area to be Energized		
Project Alternative	**Project Description**	**Present Worth**
Alternative 1		
Alternative 2		
Alternative 3		
:		
:		
Alternative n		
Investment	**Funds from Rates**	**Subsidy Requirements**

7.5. Project Selection and Prioritization

The table below shows the methods for evaluating and ranking technically-feasible alternative projects.

Prioritization of Project	Type of Project	Method of Evaluation and Procedure	Ranking and Selection of Project
First Priority	Safety, Capacity (including customer requirements), Power Quality	Calculate the Present Worth of the life-cycle costs of the alternative projects based on the economic life of the longest-lived investment option	Select and implement the least-cost project (i.e., lowest Present Worth of life-cycle cost) The project may be implemented even if the NPV<0 and/or IRR< the discount rate
Second Priority	Rural electrification and other projects with funding subsidy	Calculate the Present Worth of the life-cycle costs	Implement the project when NPV is at least equal to zero with the condition that funding subsidy or capital fund put in by sponsors is available
Third Priority	Reliability Improvements and System Loss Reduction above performance standards	Calculate the Present Worth or Value, Net Present Value (NPV) and/or Internal Rate of Return (IRR) of the life-cycle costs of the projects based on the economic life of the longest-lived investment option (should be consistent with the PBR provisions for DUs	Select and implement the project that provides higher NPV and/or IRR; provided NPV > 0 and/or IRR is higher than the chosen discount rate

The EC may also conduct incremental benefit-cost analysis in project prioritization if the allowed CAPEX budget to be used for the projects is already known.

8. OTHER CAPEX REQUIREMENTS

8.1. Distribution Transformers

The Distribution Development Plan of the EC contains the projects in subtransmission, substation and primary distribution. The expansion of the primary distribution system has corresponding requirements to serve the new low voltage customers. The number and size of distribution transformers must be estimated.

Since the ECs has no small area load forecasts yet, the required distribution transformers in the future must be estimated using alternative approaches. One approach is to analyze the historical data on distribution installations. The following steps may be followed by the planner:

a) Determine the number of distribution transformers installed and the customers connected in the past 6 to 7 years;

b) Classify and determine the ratios of the installed distribution transformers by:

   1. Capacity installed in rural areas for (i) sole users and (ii) communal users; and
   2. Capacity installed in urban areas for (i) sole users and (ii) communal users.

c) Develop a regression model that will predict the number of distribution transformers with the number of customers as predictor;

d) Predict the number of distribution transformers for the forecasted number of customers;

e) Using the ratios of capacities, determine the total number of distribution transformers per capacity; and

f) Determine the cost of the required distribution transformers.

Summarize the CAPEX requirements for the distribution transformers in the following table:

DT Capacity (KVA)	Quantity	Cost
Total		

8.2. Low Voltage Distribution Lines

The low voltage distribution lines may also be estimated using alternative approaches in the absence of spatial forecast for secondary distribution system. Using typical low voltage networks for the rural and urban service areas, estimate the additional low voltage distribution lines associated to the new distribution transformers by following the following steps:

a) Determine the sizes and circuit-lengths of low voltage distribution lines for each typical distribution transformers for the past 6 to 7 years;

b) Classify the low voltage distribution lines according to capacity of distribution transformer installed in (i) rural and (ii) urban areas;

c) Classify the low voltage distribution lines into (i) underbuilt and (ii) open secondary;

d) Conduct clustering analysis for the low voltage distribution lines to determine the average circuit-length of secondary lines for each capacity and installation type of the distribution transformer; and

e) Predict the circuit-lengths of (i) under-built and (ii) open secondary distribution lines that will be associated with the new distribution transformers estimated in section 8.1.

The other approach to estimate the low voltage distribution lines is to conduct a regression analysis similar to that one described in section 8.1 where the total circuit lengths of underbuilt and open secondary lines in rural and urban service areas are predicted using the forecasted number of customers.

Summarize the CAPEX requirements for the low voltage distribution lines in the following table:

Line Type	**Circuit-Length (km)**	**Cost**
Total		

8.3. Customer Service Drops and Metering Equipment

Based on the forecasted number of customers per customer class, estimated the required service drops and metering equipment. Use average length of service drop and typical metering equipment per customer class.

Summarize the CAPEX requirements for the customer service drop and metering equipment using the following tables:

Service Drop Type	Length (km)	Cost
Total		

Metering Type	Quantity	Cost
Total		

8.4. Non-Network Assets

Determine the non-network assets needed by the EC to provide efficient services to its customers. This may include the following:

a) Distribution Automation System or SCADA;

b) Communication System;

c) Geographical Information System;

d) Meter reading, Billing and Collection System;

e) Management Information System;

f) Tools and Instruments;

g) Vehicles;

h) Computers; and

i) Buildings.

The non-network assets must be justified by quantifying (as much as possible) the benefits and costs to facilitate the prioritization and approval of the project.

9. CAPITAL BUDGETING

Investment decisions can be heavily conditioned by the project financing, even if the technical and financial viabilities of the project have been fully demonstrated. It is important to undertake an analysis of the impacts of the project on the financial condition of the Electric Cooperative and thus its effect on the consumers. The following activities may be undertaken by the planner: preparation of financing plan; projections of the financial performance of the EC which include the income statement, balance sheets and cash flows; and analysis on the impacts of projects on the rates.

9.1. Financing Plan for the 5-Year CAPEX

The five-year CAPEX financing plan involves the determination of available funds and sources needed to carry out the project, the financing conditions, including the debt-service modalities. The procedure in the preparation of the financing plan is outlined below:

- Determine the subsidy requirements for rural electrification projects or projects that will be funded from grants and donations;
- Rank and determine the projects that could be financed by the existing members' contribution fund (internally generated fund or reinvestment fund);
- Identify projects that require financing from NEA, banks, multi-lateral international agencies, and other lending institutions; and
- Prepare a schedule of debt servicing for the contemplated loans, indicating the interest rates, grace periods, repayment, etc.

9.2. Financial Performance Assessment

The usual financial statements necessary to assess the impacts of the projects on the performance of the electric cooperatives are the income statement, balance sheet, and cash flow. Financial indicators can be derived from these statements which are essential in evaluating the current and future financial performance of the electric cooperative.

The EC following financial statements shall be prepared to simulate the financial performance of the EC:

a) Forecast the income statements starting from the base year showing the projected 5-year expenses and revenue of the Electric Cooperative;

b) Prepare a 5-year balance sheets forecast of the Electric Cooperative; and

c) Prepare a 5-year forecast of the EC's cash flows of Revenue and Expenses.

9.3. Rate Impact Analysis

The projects that require external financing are identified in Section 9.1. Based on the financial statements mentioned in Section 9.2, determine if the existing ERC-approved rates are sufficient to cover the Distribution Plan. If not, determine the increase in member's contribution that is necessary to ensure the financial viability of the Electric Cooperative.

10.4 Sensitivity Analysis

Despite how intensive the analysis made in evaluating the projects, certainty is never one hundred percent. To deal with the uncertainty, the planner needs to conduct sensitivity analysis. Consider the following scenarios in conducting sensitivity analysis:

a) Sales is +10% of the forecast;

b) Sales is -10% of the forecast;

c) Interest Rates (above and below expected rates); and

d) Repayment Periods (above and below expected period).

10. DOCUMENTING AND INTEGRATING THE DISTRIBUTION PLAN

This section deals with the preparation and integration of Distribution Development Plan (DDP) specified by the Philippine Distribution Code, Electrification Plan, CAPEX Plan for Regulatory Compliance and other plans of the EC for global competitiveness, performance improvement, and institutional development.

10.1. PDC Distribution Development Plan

The Distribution Development Plan covers the expansion, rehabilitation, modernization projects that are related to the distribution network and the projects to meet User development. The DDP is classified as medium-term development plan as it covers at least 10 years period. The DDP must be prepared in accordance with procedures detailed in Sections 2 to 7 of this Manual.

The first five years of the DDP is a committed period. i.e., the BOD of the ECs has approved the projects and committed technical and financial resources to pursue the projects. This is termed in the Philippine Distribution Code as the ***Five-Year Statement of the DDP***. The Philippine Grid Code requires the Distributors to submit this Five-Year Statement of the DDP to the Grid Owner to be included as requirements in preparing the Transmission Development Plan.

The remaining years (i.e., after five years), of the DDP is patching period and contains projects that are considered to be indicative. The general information about the projects during this period is needed by the Department of Energy for the Philippine Energy Plan which outlines the medium-term to long-term master plan of the country for the development of the country's power industry.

Projects that are determined through the distribution development planning process and requirements specified in the Philippine Distribution Code shall be documented according to the following template:

Project Code	<Code>	**Project Type**	<Type>	**Priority Rank**	<Rank>
Project Category	<Category of Distribution Development Project>				
Project Title	<Abbreviated Title of the Project>				
Project Cost					
Project Duration	<Duration of project implementation and Year of project start up and year of project commissioning>				

Project Description	<Detailed description of the Project>
Project Justification	< Describe the problem being addressed by the project and consequences if the project is not pursued>
Technical Analysis	<Criteria and System Performance without and with the proposed project >
Economic Analysis	<Summary of technically feasible projects that are evaluated, the present value of life cycle costs of each project alternative, and the financial indices (NPV and B/C). Mandatory project must be marked as least-cost>
Annexes	< Data and assumptions used in technical and economic analysis, calculation sheets, simulation reports, and other relevant information such as diagrams, drawings and pictures>

The EC shall indicate the project code, project type (i,e, safety, capacity, power quality, reliability, system loss, or electrification) and priority ranking. NEA may develop a standardize coding which is coordinated with the ICPM.

The Distribution Development Projects shall be categorized according to the following:

a) Subtransmission Development;
- Acquisition (of TransCo Subtransmission Lines);
- Refurbishment (of acquired TransCo Subtransmission Lines); and
- Reinforcement (to meet capacity and reliability criteria).

b) Substation Project;
- Uprating (of capacity of existing substation); and
- New (substation in new location).

c) Primary Distribution Project;
- Network Expansion;
- Safety and Protection; and
- Power Quality Correction.

d) Secondary Distribution Project;
- Network Expansion; and
- Rehabilitation.

e) Reliability Improvement Projects; and

f) System Loss Reduction Projects.

10.2. NEA Electrification Plan

The electrification projects shall be documented using the following table:

Project Code	<Code>	**Project Type**	<Type>	**Priority Rank**	<Rank>
Project Title	<Abbreviated Title of the Project>				
Project Cost					
Project Duration	<Duration of project implementation and Year of project start up and year of project commissioning>				
Project Description	<Detailed description of the Project>				
Technical Analysis	<Criteria and System Performance of the proposed project >				
Economic Analysis	<Summary of alternatives for electrification that are evaluated, the present value of life cycle costs of each alternative, financial indices (NPV and B/C), and subsidy requirements. This project must be marked as least-cost>				
Annexes	< Data and assumptions used in technical and economic analysis, calculation sheets, simulation reports, and other relevant information such as diagrams, drawings and pictures>				

10.3. ERC CAPEX Plan

From regulatory point of view, the Five-Year Statement of the DDP shall be included in the CAPEX Plan of the EC for rate setting purposes. In addition to the DDP, the CAPEX Plan also includes Other CAPEX requirements detailed in Chapter 8 of this Manual. Thus, the CAPEX Plan includes all requirements of the EC for the next five years requiring capital funding and includes the following projects and requirements:

a) Network Related CAPEX Projects (Five Year Statement of the DDP);

b) Other Network Requirements (Distribution Transformers, Secondary Lines, Customer Service Drops and Metering Equipment); and

c) Non-Network Requirements (General Plant Assets, Vehicles, Tools, etc. needed for utility operation).

10.3.1. Network Assets

This part of the CAPEX Plan is to be taken from the DDP. The documentation is specified in Section 10.1

10.3.2. Other-Network Assets

For the other network assets that are estimated using alternative approaches because of insufficient data and access problems to analytical tools, the CAPEX requirements shall be documented according to the following table:

Network Asset	<Distribution transformers, secondary distribution lines, service drops or metering equipment>
Specifications	<General specifications of the network assets such as sizes and types of equipment>
Quantity	<Quantity of assets needed for each year>
Costs	<Costs of the assets to be procured for each year>
Estimation Model	<Description of estimation model and methodology such as the regression and clustering model developed>
Annexes	< Data and assumptions used in analysis, calculation sheets, and other relevant information>

10.3.3. Non-Network Assets

For the non-network assets, the required CAPEX shall be documented using the following table:

Non-Network Asset	<Name of Asset>
Description	<General description and specification of the asset to be procured>
Procurement Year	<Year the asset will be procured>
Costs	<Costs of the assets to be procured >
Justification	<Describe the benefits of procuring the asset>
Annexes	< Data and assumptions used in analysis, calculation sheets (if any), and other relevant information>

10.4. Global Competitiveness and Performance Improvement Plan

The EC shall prepare the Global Competitiveness and Performance Improvement Plan by summarizing the DDP Projects that are intended to improve the system and service performance of the EC. This shall include the projects that are classified as Reliability Improvement Project and System Loss Reduction Project.

In addition to the DDP system improvement projects, the Global Competitiveness and Performance Improvement Plan shall include the *Non-Technical Loss*

Reduction Projects and *Financial Performance Improvement Projects* such as meter reading, billing and collection efficiency activities.

The Customer Service Program of the EC prescribed by the Distribution Code shall also be included in the Global Competitiveness and Performance Improvement Plan.

10.5. Institutional Development Plan

The EC shall prepare plans for institutional development. This shall include the following projects:

a) Organizational Development;

b) Human Resource Development;

c) Corporate Image and Public Relations;

d) Institutional Support for GCP and PIP; and

e) Preparation for the Competitive Electricity Market.

10.6. Annual Work Plan

The projects under the DDP, CAPEX Plan, and Institutional Development Plan in the first year of the planning horizon shall be detailed in the Annual Work Plan of the EC. The Work Plan shall specify the performance indicators and targets on a quarterly basis and the funding sources for the projects and activities of the EC.

10.7. Integrating the Distribution Plan of the EC

The different plans prepared by the EC shall be integrated through the *Integrated Computerized Planning Model* (ICPM) of the National Electrification Administration.