CHAPTER 5

TRANSMISSION, SUBSTATION AND DISTRIBUTION FACILITIES ON LEYTE AND SAMAR ISLANDS

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5.1 Present Status

5.1.1 Existing Power System and Transmission Line Facilities

Figure 5.1.1-1 and Figure 5.1.1-2 in Appendix present diagrams for the transmission system and single-line connection, respectively, on Leyte and Samar. Appendix Figure 5.1.1-1 presents transmission line data.

The transmission system on Leyte and Samar islands consists of a 230 kV interconnection tie between Leyte and Cebu islands (placed into service in November 1997), trunk 138 kV transmission lines, and the 69 kV subtransmission lines. All of these lines are owned by the NPC. The distribution system consists of 132 kV, 7.62 kV, and 240 V lines, all of which are owned by the ECs.

At present, the 138 kV transmission system on Leyte and Samar consists of the following: 1) a single-circuit line using the Tongonan geothermal power station (GPS) as a power source and running to the Wright S/S on Samar through the Babatngon S/S in eastern Leyte, and 2) a double-circuit line running to a fertilizer factory and a copper smelting factory, which are bulk consumers located in the industrial park at Ormoc in western Leyte.

All 69 kV T/L on Leyte are single-circuit, and form a loop system using the Tongonan GPS and Babatngon S/S as power sources. However, the system is not operated as a loop; the NPC opens the transmission line by ABS at Maasin and also the breakers on the Tunga feeder side of the Tongonan GPS.

In other words, on Leyte island, the Tongonan GPS is responsible for supply to the western part, and the Babatngon S/S, for the supply to the eastern part.

On Samar as well, all 69 kV T/L are of the single-circuit type. They use the Wright S/S as a power source for supply to the eastern and northern areas.

The 138 kV T/L were built in the early 1980s, and the supporting structures are almost all wooden poles, with the exception of a few lattice steel ones.

Among the 69 kV T/L, the first to be constructed was the Tongonan-Ormoc line in 1977. Other sections were constructed from the late 1980s to the early 1990s. All of the supporting structures are wooden poles. Although wooden poles are generally regarded as having a service life of about 15 years, they ordinarily can remain fully serviceable for about 20 years. However, the Leyte-Samar area is located on one of the most severe typhoon belts in the Philippines, and facilities there are subject to intense damage from typhoons. The survey of only part of the 69 kV

T/L during the field study revealed the presence of supporting structures that were listing, in need of structural reinforcement, or in need of replacement. In addition, at an interview with one EC, it was stated that poles with a substandard strength were in use for 69 kV T/L, and that some toppled over spontaneously. There is consequently some doubt about strict observance of the NPC technical standards.

There are also problems with maintenance of these lines; they are not properly maintained when installed in mountainous locations or other places where it is difficult to transport supplies. Maintenance work is also lagging in eastern Samar, where some communist guerrillas are still active.

The NPC is cutting foliage to preserve ROWs for the 69 kV T/L sections of Wright-Calbayog, Calbayog-Catarman, and Wright-Taft.

There are no particular voltage drop problems in the 138 kV system. In the 69 kV system on Leyte, however, the lines were used for long-distance transmission from the Tongonan GPS to the eastern and southeastern districts before the Babatngon S/S was placed into operation. As a result, voltage at the receiving terminal dropped to as low as 57 kV in the eastern part of the Soleco area and at Leyeco I, and 58 kV at Leyeco II. The problem was resolved by the establishment of the 138 kV Babatngon S/S.

To judge from the findings of interviews, there have been no voltage problems in the 68 kV system on Samar island.

The main issues are as follows.

- The 15 meters standard for NPC ROW is not being maintained due to opposition from landowners.
- Transmission lines in mountainous areas or far from roads are not being properly maintained due to access difficulties.
- Wooden poles supporting 69 kV T/L are being damaged by the frequent passage of typhoons in the Leyte-Samar area.
- The use of substandard wooden poles for 69 kV T/L in some EC areas leads to spontaneous toppling.

5.1.2 Existing Substation Facilities

Figure 5.1.2-1 in Appendix outlines 138/69 kV S/S. Appendix Figure 5.1.2-1 presents a diagram of the secondary-side single-line connection for the 138/69 kV Isabel S/S.

The 138/69 kV S/S on Leyte have a total of four transformers (two at Tongonan, one at the

Isabel S/S, and one at the Babatgnon S/S) with a combined capacity of 100 MVA; on Samar, there is only one such transformer (at the Wright S/S), and it has a capacity of 30 MVA. In 1996, the peak-time transformer utility factors came to 66 percent and 62 percent on Leyte and Samar, respectively. The capacity therefore has considerable margin for the peak demand. However, there was less margin at the Tunga feeder of the Tongonan S/S, where the corresponding factor was 89 percent.

With the start of the operation of the Babatgnon S/S at 50 MVA in December 1997, the Tunga feeder load was switched over to the Babatngon S/S, and this resolved the capacity tightness at that feeder.

The transmission line protection system on the secondary side of the 138/69 kV S/Ss consists solely of an overcurrent relay and overcurrent ground relay.

Table 5.1.2-1 Outline of 138/69 kV substations

S/S Name	Nos. of Unit	Capacity(MVA)	Voltage(kV)	Commission
Isabel S/S	1	40	138/69/13.8	1982
Wright S/S	1	30	138/69/13.8	1988
Tongonan S/S (Ormoc Feeder)	1	30	138/69/13.8	1983
Tongonan S/S (Tunga Feeder)	1	30	138/69/13.8	1992
Babatngon S/S	1	50	138/69/13.8	1997
Ormoc Center S/S *	2	50	230/138	1996
Tabango S/S *	1	10	230/69/13.8	1996

Note *: This S/S will be used for supply to Cebu until the start of operation of an AC-DC converter. The Leyte-Cebu interconnection tie was placed into operation in November 1997.

Appendix Table 5.1.2-1 outlines the 69/13.2 kV S/S, and Appendix Figure 5.1.2-2 presents the single-circuit interconnection diagram for the Dorelco S/S as an example of the same.

The 69/13.2 kV S/S are not installed with circuit breakers on the primary or secondary side. In general, a power fuse and ABS are installed on the primary side, and a power fuse and recloser at each feeder on the secondary side. On-load tap changers are installed for transformers only at a few S/S (e.g., Dorelco, Tunga, and Hilongos); at other S/S, voltage regulators are added for this purpose. None of the 69/13.2 kV S/S has a protective relay.

The impact of outage due to trouble is magnified by the use of a single-circuit T-type branch for connection between 69 kV T/L and 69/13.2 kV S/S. For example, the following prospective difficulties must be considered.

- In the event of trouble on the 69 kV T/L

  A break to contain the trouble would be made by the breaker of the 69 kV T/L feeder on the secondary side of the substation, and this would make the power source unavailable until the complete restoration of service at the point of outbreak. As such, all 69/13.2 kV S/S connected to the 69 kV T/L feeder would be shut down.

- In the event of trouble in the 69/13.2 kV S/S

  A break to contain the trouble would be made by the power fuse on the primary side of the 69/13.2 kV S/S. However, if this power fuse does not operate, the trouble would spread to the 69 kV T/L and also could shut down nearby 69/13.2 kV S/S.

Some 69/13.2 kV S/S buildings have wooden structures. In addition, some make use of transformers acquired from other substation, a practice which is cause for concern about reliability. Furthermore, the space on substation grounds tends to be cramped and therefore to pose a higher risk of danger to personnel during work. In short, the 69/13.2 kV S/S facilities are somewhat lacking as regards full capability for supply of power both safely and with stability.

In the 69 kV system on Samar, there are some areas where power is not available in spite of completion of the T/L, because a 69/13.2 kV S/S has not yet been placed into operation.

The major issues are as follows.

- Because the 69/13.2 kV S/S are connected to the 69 kV T/L by a single-circuit T-type branch, there is a risk of magnification of impact in the event of trouble on the 69 kV T/L, since the trouble can shut down all substation connected to the transmission line.
- Protective relays are installed only at the NPC substation, and ECs therefore rely on removal by the breakers on the NPC 138/69 kV S/S in the event of trouble on 69 kV T/L.

5.1.3 Existing Distribution Facilities

Appendix Table 5.1.3-1 shows the current status of 13.2 kV D/L of each EC.

As shown in the table, there are three kinds of 13.2 kV D/L: three-phase, V-phase, and single-phase. The 240 V D/L are divided in terms of the number of circuits, i.e., open secondary and underbuilt.

Three-phase distribution line are installed as the main feeder for supply of power from 69 kV S/S, and in areas with a comparatively dense load. The V-phase distribution line and single-phase distribution line are installed mainly for supply in areas with a scattered load. This configuration is particularly evident in the case of Leyeco IV. At this EC, the residential demand accounts for 60 percent of the total, and the load is scattered in a north-south orientation. For this reason, a three-phase distribution line runs the length of the service area in this orientation, and single-phase lines branch off it for supply to houses.

The 240 V D/L consist of open secondary lines on wooden poles of their own and underbuilt lines sharing poles with 13.2 kV lines. The ECs are thought to prefer the underbuilt type, but each type accounts for about half of the 240 V D/L installation because 13.2 kV D/L are not installed in the service areas in sufficient amounts. However, at Leyeco V, whose service area contains the city of Ormoc, the installed length of the underbuilt type is about six times as great as that of the open secondary type.

The major issues are as follows.

- At peak time, the voltage of 13.2 kV D/L drops by 200 V at Leyeco I, 220 V at Leyeco IV and V, 210 V at Samelco I, and 165 V at Esamelco. The cause is supply through distribution line over distances in excess of 100 km. For the time being, the drop can be countered by installation of capacity banks, for example. At Leyeco I, the problem will be resolved with the inauguration of the new 138/69 kV S/S at Babatngon.

5.1.4 Property Boundary between the NPC and ECs

All 69/13.2 kV S/S are owned by the ECs, and the boundary between NPC property and EC property is the ABS on the primary side of these substation (see Appendix Figure 5-1-2-2). At almost all substation, this ABS is EC property.

The NPC provides only power purchasing meters to the ECs for the purpose of metering purchased power. This meter is supposed to be installed on the primary side of the transformer, but in some cases it is installed on the secondary side.

5.1.5 EC Distribution Line Interconnection

EC distribution line interconnection is separated by opening jumpers at distribution line poles, and there is consequently no power interchange among ECs.

However, before the installation of the 69 kV T/L, 13.2 kV D/L were used for supply of power. In other words, the EC distribution line were interconnected.

Even at present, when one EC wants to receive power through interchange from another nearby during repair of distribution line in its own area or to avoid long-distance distribution, it is difficult to do so due to the high interchange rates, in spite of the plans for interchange in the 13.2 kV distribution system. Some ECs have switched to single-phase lines in districts on the service area border due to the toppling of three-phase lines by typhoons. Use of these single-phase lines for interconnection would pose problems, e.g., the smaller transmission capacity would rule out full power interchange.

The major issues are as follows.

- Although efforts are being made to reinforce the transmission system (138 kV and 69 kV T/L on Leyte and Samar often become unavailable due to the toppling of facilities, since the islands are on a typhoon belt. There is also a need for reduction of distribution system loss due to long-distance distribution. This end as well requires the construction of a system enabling receipt of interchange power through 13.2 kV D/L in demand zones in border areas.

5.2 Network Coordination System

5.2.1 Existing Central Control System

The organization for operation and control of the power system in the NPC is topped by the System Operation Division. It divides the country into the three regions of Luzon, Visayas, and Mindanao, and under SOD are three regional control centers (RCC), one for each region. Facility operation is performed by the Area Control System (ACS), an organization subordinate to the RCC.

The system on Leyte and Samar is actually operated and controlled by the RCC on Cebu, which issues commands to the ACS for frequency adjustment, operation of generators, operation of ABS, etc. Similarly, the RCC obtains data on system voltage, kW, kVar, and the ABS status from the ACS on Leyte and Samar. It uses a large-scale computer for centralized management of the entire area.

5.2.2 Existing Communications System

Appendix Figure 5.2.2-1 shows the communications system of the NPC.

The NPC communications system on Leyte and Samar is connected with the Visayas Regional Center (VRC) on Cebu and with the Manila Control Center on Luzon by microwave circuits via the unmanned repeated station on Palompon. In addition, power line carriers and VHF circuits are used for communications between substation. In some cases, data communications are executed through the public telephone circuits of the Eastern Visayas Telephone Company (EVTELCO).

Communications between ECs are mainly through wireless VHF links. The EVTELCO circuits are also often used. Each EC has a wireless communications ground station and exchanges information through mobile communications circuits.

Wireless circuits and the public telephone circuits are the main means of communications between the NPC and ECs.

5.2.3 Power Flow

Appendix Figure 5.2.3-1 presents a diagram for power flow in 1996. Table 5.2.3 shows the transmission line utility factors, i.e., on-peak current as percentage of the T/L capacity.

Power from the Tongonan GPS is first sent to Leyte and Samar by 138 kV T/L and then is supplied to the ECs by 69 kV T/L.

The figure shows that voltage falls in eastern Leyte, dropping to 66.7 kV at Bontoc, at the system terminus. Since this figure is based on analytical data instead of actual data, voltage may not actually decline to 57 kV at the maximum as related above. Nevertheless, the analysis suggests that voltage decline is a problem in eastern Leyte.

As shown in Table 5.2.3, the utility factors for the 69 kV T/L range from a maximum of 50 percent at the Leyte Tunga feeder to a minimum of only a few percentage points on Samar. When evaluated in terms of thermal capacity, there are thought to be no problems with the current transmission line use.

Table 5.2.3 On-peak transmission line utility factors

From	To	Rating(MVA)	Percent Loaded(%)
138 kV single circuit(Wooden pole)			
Tongonan	Wright	126	12
Tongonan	Isabel	126	25
Tongonan	Isabel	126	25
Isabel	Philpos	126	11
Isabel	Philpos	126	11
138 kV double circuit(Steel tower)			
Isabel	Pasar	215	10
Isabel	Pasar	215	10
69 kV single circuit(Wooden pole)			
Tongonan	Tunga feeder	63	50
Tongonan	Ormoc feeder	63	20
Wright	Calbayog	63	18
Wright	Taft	63	6
Taft	Oras	63	2
Taft	Borongan	63	2

5.2.4 System Analysis

At present, the NPC is apparently using a power system simulator for engineering (PSS/E) for analysis of 138 kV and 69 kV systems on Leyte and Samar. Through this field study, the team obtained system analysis data for power flow and short circuit/ground fault capacity from NPC CORPLAN. ECs have not carried out system analysis independently; in the past, it has on occasion been carried out for them by outside consultants hired by the NEA.

According to the findings of the NPC power system analysis for 2005, the maximum power flow in the 69 kV system will be 44 MW through the feeder from the Babatgnon S/S to eastern Leyte. This would not pose a problem because the thermal capacity of 69 kV T/L is 63 MVA. There is a voltage drop to 65 kV at Catarman, and a drop on this order would not present a great problem as far as the transmission system is concerned. Nevertheless, the distribution system of the ECs is weak, and the assessment must take account of the distribution voltage on the EC level.

The findings of the analysis of short circuit and ground fault calculation indicate that short circuit current would reach a maximum of 17 kA at the Maasin-Cut point of interconnection between 138 kV and 69 kV T/L. This would not be a serious problem because the short circuit current rating of the 69 kV system breakers is 20 kA.

The NPC system analysis suggests that there would be no particular problems with the 69 kV system on Leyte and Samar.

The PSS/E used for power system analysis by the NPC may be profiled as follows.

Developed by the U.S. company Power Technologies, Inc., in 1976, the PSS/E is a simulation program for use in power system analysis. It can be operated by personal computer, and is now in use at some 300 firms in the United States and other countries around the world.

Centering around optimum power flow calculation, the assortment of functions consists of various options offered in a single package. More specifically, the following options are available.

- Optimum power flow
- Balanced and unbalanced fault analysis
- Relay coordination
- Dynamic simulation
- Eigenvalues analysis
- Extended term simulation
- Transfer analysis

The major issues are as follows.

- The ECs have neither the tools nor the know-how for performance of system analysis, these elements would have to be transferred to them after transfer of the 69 kV T/L. Until this transfer is completed, system analysis would have to be performed by the NPC.

5.3 System Loss

Appendix Table 5.3-1 shows the system loss at each EC.

The NEA has recommended reduction of the rate of distribution system loss to no more than 12 percent. In reality, however, the rate for the first three quarters of 1996 reached a maximum of 23.95 percent at Leyeco I, and was above 15 percent at as many as eight ECs. System loss is therefore generally on a high level.

At ECs where the rate of system loss is in excess of 20 percent, most of loss is thought to be non-technical. At Leyeco II, data show that technical loss accounts for 40 percent of the total, with the remainder being occupied by non-technical loss.

According to the data in Appendix Table 5.3-1, the rates of system loss at Leyeco I and Samelco II peaked at 33 percent in 1989 and 30 percent in 1988, respectively, and subsequently declined to 22 and 16 percent in 1996, but at the other ECs, they have stayed on roughly the same level over the last ten years.

The major categories of causes of system loss are technical loss and non-technical loss. The major cause of technical loss is thought to lie in the composition of the distribution system.

In the first place, power is supplied by distribution lines over long distances because the load is scattered.

In the second place, phase currents become unbalanced due to the use of single-phase D/L for supply to the final customers, and this results in loss due to the flow of current through neutral lines.

The main causes of non-technical loss include pilferage and non-payment.

Reduction of system loss is required also for improvement of corporate profit, and the ECs are making plans for reduction. The major elements of these plans are as follows.

Plans for reduction of technical loss

- Boosting of conductor size (enlargement of undersized distribution line)
- Switch from single-phase to three-phase distribution line
- Transformer load management (preparation of an overloaded transformer data base, increase in transformer capacity, and installation of new 13.2/0.4 kV S/S)
- Balancing of load
- Improvement of the load factor (installation of capacitor bank)
- Replacement of defective insulators
- Preservation of ROW clearance

- ➢ Program for cutting back foliage

Plans for reduction of non-technical loss

- ➢ Increase in the precision of kWh meters and replacement of defective kWh meters
- ➢ Promotion of anti-pilferage campaigns through the media
- ➢ Relocation of kWh meters and installation of meter boxes to prevent pilferage
- ➢ Imposition of heavy penalties for violations
- ➢ Establishment of special surveillance and inspection team
- ➢ Development of rewards and incentives for discovery of pilferage
- ➢ Installation of mother meters under transformers and checking of the same
- ➢ Comprehensive training of meter readers
- ➢ Rotation of meter reader areas
- ➢ Installation of meters for street lights

The main issues are as follows.

- Reduction of loss due to long-distance distribution requires contraction of distribution line length through establishment of 69/13.2 kV S/S and countermeasures for a drop in voltage through installation of power condensers.
- Extra funds must be allocated for the implementation of measures to reduce loss.

The following point must be borne in mind in this connection.

- At substation in which the meter for purchased power is installed on the secondary side of the transformer, the transformer loss is attributed to the NPC.

5.4 Natural Conditions and Frequency of Outage

Appendix Tables 5.4-1 and 5.4-2 show the cumulative duration and frequency of outage at each EC over the last ten years with a breakdown by ascription of cause (i.e., NPC facilities or EC facilities).

The cumulative duration of outages per enterprise caused by NPC facilities averaged 362 hours, and that of outages caused by EC facilities, 469 hours. The corresponding figures for outage frequency were 106 and 160 times. Naturally, an outage at NPC facilities leads to outage at the ECs below them. As such, the cumulative duration of EC outages averages nearly 34 days a year.

The area is on the typhoon belt and, in years when there are many typhoons, it may be struck by over ten. There is consequently great damage to facilities from typhoons. In addition, even if foliage is cleared to preserve transmission line ROWs, palm tree branches and other foliage rapidly grow back in the subtropical climate, and there are many ground faults caused by contact with trees.

Because wooden poles are used to support both the NPC transmission line and EC distribution line, there does not appear to be large gap between the two in point of strength of supporting structures. However, NPC outages have a greater impact because they affect several ECs. While the outage data indicate that outage causes are mostly on the EC side, there is a need for improvement as regards the NPC outage frequency and duration in view of this larger impact.

5.5 Profile of the Tongonan GPS

The Tongonan GPS is profiled in Table 5.5-1. It contains three units with a combined capacity of 112.5 MW. It transmits through two 138 kV lines to the Isabel S/S and one 138 kV line to the Wright S/S. It also uses a 138/69 kV transformer on the premises to reduce voltage to 69 kV for transmission through one line to the Maasin S/S and one line to the Tunga S/S.

In addition, the NPC purchases geothermal steam power for use as an energy source from the adjacent Philippine National Oil Corporation (PNOC).

Plans are currently being made for construction of a GPS with a capacity of 600 MW in the Tongonan area through a BOO project.

Another project now under development is Leyte A (for a combined capacity of 119.6 MW). This power is to be used for interconnection with the systems of Luzon, Mindanao, and Cebu. Development is also planned at San Juan in southern Leyte.

Table 5.5-1 Profile of the Tongonan GPS

Unit #	Date of commercial operation	Installed capacity	Gross generation in 1966
Unit #1	July 2, 1983	37.5 MW	223,656.31 MWh
Unit #2	April 28, 1983	37.5 MW	176,982.55 MWh
Unit #3	March 11, 1983	37.5 MW	210,150.21 MWh

5.6 Future Interconnection Plans

5.6.1 Plan for interconnection among islands

Appendix Figure 5.6.1-1 presents a diagram of the planned interconnection among islands, and Table 5.6.1-1, an outline of the same.

It is the aim of the interconnection to make effective use of the large-scale energy supply from the Tongonan GPS. On 15 November 1997, Leyte and Cebu islands were connected by 230 kV T/L. The interconnection between Leyte and Samar has resolved the power shortage on Samar and stabilized the supply-demand balance on both islands.

The plans include the prospect of using energy from the Tongonan GPS to supply power to islands other than Leyte and Samar as well. To this end, they envision interconnection in a north-south orientation from Luzon to Mindanao via Leyte through plus/minus 350 kV DC T/L, and in an east-west orientation between Leyte and Bohol through 138 kV T/L. All interconnections are to be completed in 2000. The new 230/138/69 kV S/S at Ormoc, which was placed into operation in July 1997, is to serve as a base of interconnection. There are plans to install an AC-DC converter in this S/S for interconnection with Luzon and Mindanao. As of 10 October 1997, the construction for the Leyte-Luzon interconnection was 99 percent complete.

The following paragraph concerns the plans for Leyte-Bohol interconnection, which will have a great influence on the subject of this study.

The Leyte-Bohol interconnection plan is to proceed in two stages. The first stage facilities are to commence operation in March 1999 through a 138 kV submarine cable operated at 69 kV. At this stage, the existing 69 kV T/L between Ormoc S/S and Maasin S/S is to be used for interconnection between the islands. The second stage facilities are to commence operation in 2000. At this stage, a new 138 kV T/L is to be constructed between Ormoc S/S and Maasin S/S, and the voltage on the line between the islands is to be raised to 138 kV.

Table 5.6.1-1 Outline of interconnection line among islands

Project	Voltage	Capacity	Commission. Year	Description
Leyte – Luzon	±350 kV 2ckt-DC	440MW	1997	OHL-432km, SMCable-23km
Leyte - Mindanao	±350 kV 1ckt-DC	400MW	2000	OHL-384km, SMCable-29km
Leyte - Cebu (I)	230 kV 2ckt-AC	200MW	1997	OHL-145km, SMCable-32km
Leyte - Cebu (II)	230 kV 1ckt-AC	200MW	2000	SMCable-32km
Leyte - Bohol	138 kV 2ckt-AC	100MW	2000	OHL-180km, SMCable-17km

Note : SMCable denotes submarine cable.

The main issues are as follows.

- In the NPC plans, the 138 kV T/L (Ormoc-Maasin) is to be completed in 2000, and 69 kV T/L that are included in the transfer are to be used for interconnection until the voltage on the Leyte-Bohol line is raised to 138 kV. In this case, it would be difficult to transfer these 69 kV T/L before 2001.

5.6.2 Plans for the System within Leyte and Samar

Tables 5.6.2-1 and 5.6.2-2 show the system plans for transmission line and substation, respectively, on Leyte and Samar. The NPC development concerns mainly trunk (138 kV) lines, and has not made sufficient provisions for 69 kV T/L.

To reinforce the 138 kV system, the NPC is planning to construct a new route in addition to the existing Ormoc-Wright route.

For reinforcement of the 69 kV system, the only project now under construction or planned is that for the Mcarthur-Guiunan route.

Prospects at the stage of feasibility study include the looping of the 69 kV system on Samar and the construction of a 138 kV line between Wright and Calbayog.

Table 5.6.2-1 Outline of plans for transmission line development on Leyte and Samar

Project	Voltage	Structure	Commission. Year	Description
Ormoc - Babatngon	138 kV 1ckt-AC	Steel	1998	OHL-81km
Babatngon - Wright	138kV 1ckt-AC	Steel	1998	OHL-60km
Tongonan - Isabel	138kV 2ckt-AC	Steel	1998	OHL-35.5km
Mcarthur - Guiuan	69kV 1ckt-AC	Wooden	1995	OHL-32km

Table 5.6.2-2 Outline of plans for substation expansion on Leyte and Samar

Project	Voltage	Capacity	Commission. Year
Tongonan S/S	138/69/13.8kV	1 x 50MVA	2000
Wright S/S	138/69/13.8kV	1 x 50MVA	2000
Ormoc S/S	230/138/13.8kV	2 x 50MVA	2004

5.7 Technical Standard

According to the findings of interviews with the 11 ECs on Leyte and Samar and the NEA, the ECs do not have their own technical standards and receive their technology from the NEA. The provision of technology by the NEA takes the form of the NEA engineering bulletins, which were prepared in August 1993 with funding from USAID. The Bulletins are reports prepared by foreign consultants and presenting technical know-how needed by the ECs. To date, they have served as the technical standards for the ECs.

The contents of the bulletins center around application, facility planning, design drawings, construction, and O&M technology for distribution lines and distribution transformers. They also cover a wide range of other subjects, including specifications of feeders to the home and meters as well as outlooks on power loss, service reliability, and the substance of requisite technical analyses. Some treat the specifications and design of 69 kV transmission lines. Together, they constitute an extensive and comprehensive body of technical knowledge.

The study team was able to obtain NPC standards for construction technology, design of 69 kV poles, and procedures for system operation, but it was not able to obtain any other information related to technical standards from the NPC.

However, according to the O&M checklist obtained from the NPC, it is thought that checks are made in accordance with standards.

The following sections concern the facility planning standard, construction standard, and O&M standard presented in the NEA engineering bulletins, and the system operation procedure of the NPC.

5.7.1 Facility Planning Standards

The planning standard DX1000 was prepared for the drafting of plans for the distribution system. However, it covers the method of drafting long-term plans, the level of demand estimation, the need for system analysis, and planning with an emphasis on economic merit. It is therefore thought to be fully applicable for planning for the transmission system as well.

At the same time, it should be noted that, whereas the distribution system distributes electricity in the required amounts to a vast pool of individual households, the transmission system supplies electricity in large amounts. This difference would naturally be reflected in others in respect of the requisite reliability and specifications of the facilities. The following section outlines the DX1000 standard and discusses points that should be borne in mind in application to transmission system planning.

Related standard

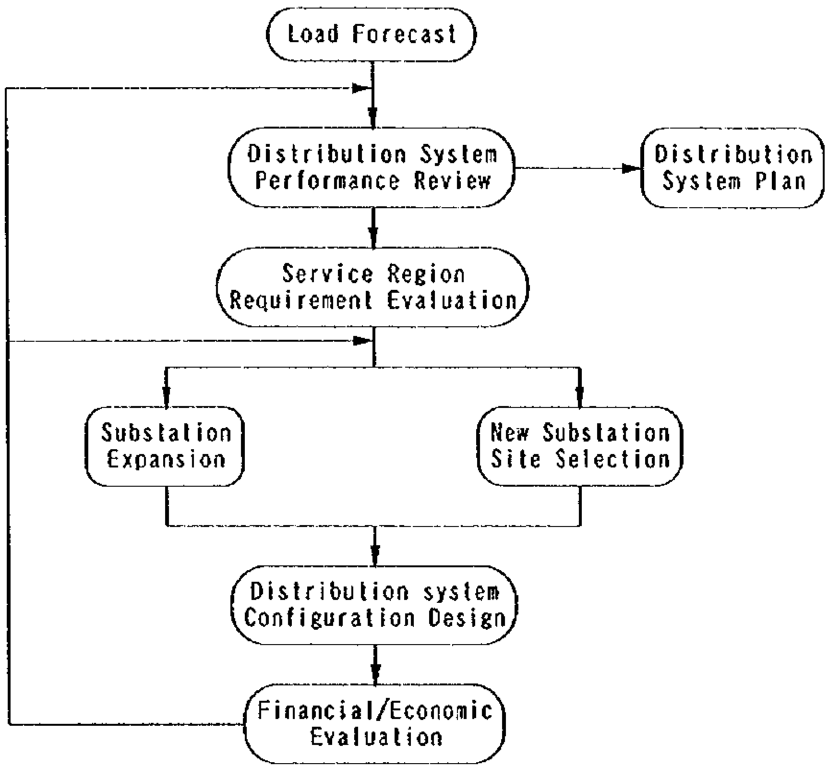
- NEA Engineering Bulletin DX1000: System Planning Guide, Electric Distribution Systems

Outline

* The DX1000 standard underscores the necessity of long-term plans and sets forth the promotion of facility planning in steps upon execution of accurate demand forecasts. To this end, it describes the need for technical analysis of the power system, pursuit of economic merit, and improvement of system reliability.

* The standard proposes division of facility planning work into five stages: 1) collection of basic

data and demand forecasting, 2) review of what should be reflected in plans, based on the actual status of the power system, 3) field study for preparation of long-term plans, 4) stage of detailed planning (identification of the optimal plan incorporating the results of system analysis and of assessments of economic merit), and 5) preparation of plans for construction work. The following chart shows the flow of the planning process for distribution substations.



* Tasks at the stage of detailed planning include division of the service area into blocks and analysis of the demand growth pattern in each, determination of the current load and forecast of the future load, study of the voltage level and current balance, investigation of reliability, estimate of power loss, and estimate of requisite O&M expenditures.

Issues

* Although the DX1000 encourages the implementation of system analyses (covering stability, power flow, voltage drop, etc.) in facility planning, the ECs have apparently not carried out such analyses and do not have the requisite know-how. This results in the aforementioned current unbalance between distribution line phases and the lack of numerical data on the level of voltage drop at distribution line ends. Upon acquisition of ownership of the transmission system, inability to resolve these technical problems could affect the entire system.

* The existing 69 kV transmission lines are built away from roads even in flat areas, and it is difficult to gain access to poles for maintenance and repair. Although the NPC design standards stipulate acquisition of access roads and establishment of routes along roads, the existing 69 kV transmission lines are generally routed not along roads but along the line of shortest distance

between substations.

5.7.2 Design Standard

The design standard is a guideline for construction work based on the design drawings. It stipulates construction in accordance with the standard design specifications and the types of changes in specifications and other items that must be undertaken with the support of technicians.

According to NEA design standard TX1300, 69 kV transmission line poles are standardized, the types including single poles and multiple (two or three) poles. There are standardized drawings for each type of pole, and standards have been established for all items, from material quality and measurements to clearance distance. There are also some drawings of steel poles.

This standard is a guideline for construction work based on design drawings.

Related standard

- NEA Engineering Bulletin TX1300: Specifications and Drawings for 69 kV Transmission Line Construction

Outline

* The standard presents supporting entries for everything from minimum measurements for underground portions in each category of pole length to position of structures, method of making apertures, backfill, bolts, nuts, guy wires, anchors, insulators, and stringing cable.

* It also contains specifications for clearing the ROW.

* It stipulates a setting depth of 7.5 feet for a 55-foot pole.

* The standard requires approval of technicians at each stage of construction, and takes account of quality control.

* There are separate standard drawings for single, double, and triple poles.

Issues

* There is no substantial difference between the NPC and EC design standards, and the NEA design standard could fully discharge the same role. In addition, the ECs have experience and know-how in erection of distribution poles. However, there is a major difference between transmission poles and distribution poles in that the method of erection and type of insulator vary depending on the pole length (i.e., distribution poles use pin insulators, and transmission poles, strain or suspension insulators). This is reflected in other differences in aspects such as the way of stringing the cable and measures based on the load on the cable and the pole (attachment of bolts and load design for poles and ground). These differences are anticipated to cause problems in execution.

* The work of erecting poles depends heavily on manpower. In other words, human labor is used to haul materials and equipment to the site, and poles are erected by means of towers. This is because transmission poles are generally located in forested areas, paddies, or mountainous districts without road access.

* Designs of standard rigging for each category of pole exist on drawings, but load design is not carried out separately for each.

5.7.3 O&M and Inspection Standard

The NEA has an O&M and inspection standard for distribution lines in the form of Engineering Bulletin OM8200, but it does not have one for transmission lines. Nevertheless, the 69 kV transmission lines that are the subject of this study are strung on wooden poles, as are the distribution lines. As such, the performance of O&M and inspection for these transmission lines could follow the standard for distribution lines.

Related standards

* NEA Engineering Bulletin OM8200: Distribution Line Inspection and Maintenance
* NEA Engineering Bulletin OM8300: Inspection and Retreatment of Standing Wooden Poles
* NEA Engineering Bulletin DX4100: Line Inspection and Retreatment Record
* NEA Engineering Bulletin DX4214: Pole Inspection and Maintenance

Outline

* Operators are obligated to inspect transmission lines visually and submit the findings in written reports to the responsible party. All distribution lines are routinely inspected once every five years (i.e., in a five-year cycle). In addition, other inspections are made of locations that are the cause of outages, as necessary in response to events such as typhoons and lightning strikes.

* The inspections are conducted in accordance with a Line Inspection Checklist. The results provide the basis for repairs and replacements in accordance with the Pole Line Inspection and Maintenance Log Sheet.

* Upon receipt of the report of the inspection results, the responsible party must report these results and the repair situation to the general manager and board of directors each month.

Issues

* The standard stipulates a five-year cycle of routine visual inspection. In some cases, however, wooden poles are rotting inside, and visual inspection of the outside would not be sufficient.

5.7.4 Written Procedure for System Operation

From the NPC, the study team obtained a document entitled Draft Standard Operation Procedure for CNPLS (Cebu, Negros, Panay, Leyte, and Samar) Power Grid Operations. System operation is being carried out in accordance with this document.

The Procedure sets forth the method of control in system operation and the system operation procedure in emergencies. The following is an outline of the related NPC guidelines and regulations, and the procedure for 69 kV transmission lines.

Outline

* The NPC guidelines and regulations for system operation stipulate that fluctuation in the frequency and voltage of supplied power must be held within the range of plus or minus 0.20 Hz (the standard frequency being 60 Hz) and 66 kV (peak time) - 72 kV (off-peak time), respectively. It also stipulates that the duration and frequency of outages must be held to reasonable levels.

* The guidelines and regulations stipulate proper maintenance and use of transmission lines for supply of power to customers, and preparation of yearly maintenance programs to this end.

* The role of the NPC in load dispatch and control during routine operation is defined as follows.

1) RCC/ACC collect data for substation and feeder load.

2) RCC makes load forecasts for the next day.

3) RCC/ACC control switching equipment, i.e., control the opening and closing of ABS and breakers.

* The role of the NPC in load dispatch and control in times of emergency is defined as follows.

1) After removal of the accident situation, the NPC resumes service in accordance with load priorities. In other words, load recovery is made in accordance with the load shedding scheme prepared by the area office.

2) All the leaders of transmission line work crews present reports to the RCC/ACC before and after performance of maintenance or repair.

* In the procedure at time of load-end transmission line failure, it is stipulated that the customers (i.e., ECs) are to confirm the status of switches at the time of failure, the location of failure, and the status of the system at time of recovery, as well as follow instructions for supply.

Issues

* If the facilities to be transferred to the ECs are 69 kV transmission lines only, the supply-side breakers for the same would be left under the operational jurisdiction of the NPC while the ABS located along the lines would be transferred to the ECs. This arrangement would create a need for coordination of the operation of breakers and ABS. For example, in resuming service after

removal of the causes of accident, there would have to be a procedure and communication scheme for closing the ABS and putting in the breaker, for example.

* System operation at the NPC rests on the obligation for stable supply of power. Tasks such as assurance of power quality, maintenance of the supply-demand balance, and stable operation of generators are performed for the whole of the system. The 69 kV transmission lines are treated as parts of this system. For example, tardiness in resolution of failure on 69 kV transmission lines would exert an adverse influence on the generation unit at the nearby Tongonan geothermal plant, and delay in resumption of service would have an effect on the supply-demand balance in the entire Visayas region.

  With the transfer of the 69 kV transmission lines, however, responsibility for their operation would belong to their owners, meaning the ECs, which do not have the operational know-how to fulfill this responsibility for the aforementioned problems.

* The ECs also do not have a written procedure for system operation; their operation of the ABS is based on instructions relayed from the NPC by wireless radio.

5.8 Level of ECs Technology

The preceding sections of this chapter have taken up the current status and problems of distribution facilities and transmission and transformation facilities on Leyte and Samar as well as issues related to EC technical standards. This section summarizes problems involving the level of EC technology based on the findings of interviews and collected data.

Technical level of system analysis

* The ECs have not determined the current status of power flow and voltage drop in distribution lines. In other words, they have not implemented flow calculations. And because they have not ascertained the current status of the system through analysis, they are not able to incorporate appropriate facility measures into facility plans for the future.

* It is not clear whether or not the EC engineers are accumulating know-how for, and understand the need for, system analysis.

  In the distribution system, it is possible to connect load (customers) to an extent allowed by the current capacity of the lines. In other words, there is not much need for analysis to extend distribution lines. However, there are cases in which distribution loss has arisen due to current imbalance among phases on distribution lines. This phenomenon is one of the reasons that distribution line loss has not declined.

* Given the present level of capabilities of system analysis at ECs, it would be difficult for the ECs to carry out calculations for power flow and short- and ground-circuit capacity on 69 kV

transmission lines upon transfer of the same. There would consequently be apprehensions about decline in power quality and in supply reliability for reasons related to the level of technical capabilities for system analysis as well as for other reasons.

Issues in system operation

* The term "system operation" refers to stable operation and maintenance of the system through performance of technical analyses to determine the current status and to forecast the future power flow and voltage. In light of the present level of technical analysis noted above, it would probably be difficult for ECs to perform system operation by themselves in a manner that would satisfy these objectives.

* It should also be noted that the ECs do not have their own communications system, which constitutes the nerves of system operation. In times of emergency, this could result in inability to secure communications circuits or failure to make accurate relay of operation instructions.

* In reality, it is the NPC which is in possession of system operation know-how; the ECs do not perform system operation independently. For this reason, they also do not have the required know-how or facilities.

* The NPC also performs system operation for the upper system consisting of transmission lines with a voltage of 138 kV or higher as well as the related substations and generation units. It is desirable for the scheme of instructions for system operation to be unified in the interest of unified operation of the power system. If the ECs were to have their own scheme of instruction, it could disunite system operation.

Issues in technical standards

* The ECs use the bulletins prepared by USAID at the request of the NEA as technical standards. As technical standards, the bulletins represent comprehensive coverage of all areas, and are in good order. However, USAID personnel stated in an interview that the bulletins were a kind of bible to the ECs and were not being put to actual use. Similarly, interviews with the ECs did not yield clear responses as to how the bulletins were actually used.

* While the ECs collect data on items such as facility checks, power loss, outage record, and facility status, and make reports of the same to the NEA, it is doubtful whether this information is being put to effective use. For example, frequent power outages would presumably point to a need for priority countermeasures or efforts to reduce power loss. It is also doubtful whether the NEA, upon receipt of reports on the actual status of facilities, is extending ad-hoc financial or technical aid for the requisite countermeasures. At the same time, however, excessive financial aid could have the effect of weakening the financial disposition of the ECs and increasing their dependence on the NEA, and excessive technical aid could dampen EC inclinations for intention of technical improvement. For this reason, it is advisable for the ECs to make their own efforts to improve

their planning capabilities.

5.9 Points for Improvement in the Current Technology of ECs

The Region VIII ECs are thought to be in possession of know-how for construction and maintenance of wooden poles based on their experience with distribution work. However, the transfer of the 69 kV transmission lines will create a need for higher levels of technology for operation and maintenance of high-voltage facilities.

This chapter consequently presents recommendations for improvement of outfitting, facility planning, and systematic operation, as well as of technological capabilities from a long-term perspective. Formulated by the study team, these recommendations take account of the current level of EC technology, the state of facilities, and the surrounding environment and circumstances.

5.9.1 Improvement of Facilities

(1) Improvement of construction technology for 69 kV transmission lines

A major problem with the 69 kV transmission lines at present is their poor condition. Besides poor maintenance, the major causes of poor condition include the use of wooden poles and the natural environment in the area. Wooden poles ordinarily have a service life of more than 30 years. Nevertheless, the area in question is often hit by typhoons, and there is extensive deterioration to wooden poles due to toppling and rotting. A prospective solution here is a switch in construction to concrete poles or steel towers, which are stronger.

The current level of construction technology for 69 kV transmission lines, however, compels reliance on manpower because heavy machinery cannot reach installation locations due to the lack of access roads. This situation could rule out a switch from wooden poles to concrete poles or steel towers, since assembly of heavy structures like the latter cannot be done manually.

According to information received from the Cebu RCC of the NPC operating the 69 kV transmission facilities in Region VIII, which the team visited in February, the unit price of concrete poles is about 29,000 pesos. This is almost double that of wooden poles at 15,000 pesos, and the switch could therefore also be ruled out by financial considerations.

The study team therefore recommends continued construction and maintenance of wooden poles for 69 kV transmission lines on Leyte and Samar for the time being.

The following are perspectives on measures for improvement of construction technology for wooden poles in such aspects as increasing strength for withstanding loads and preventing deterioration.

Field studies of 105 transmission line poles revealed that wooden poles are in many cases installed in marshland or paddies. Many of these poles were consequently rotting at the bottom. There were also cases in which poles were rotting because of infiltration of rainwater into cracks from the top.

The following are prospective countermeasures for deterioration due to water.

1) Reinstallation of poles in dry locations

2) Sealing of the base in concrete for avoidance of contact with water

3) Installation of a water-repelling cap on the top

Leyte and Samar are in the typhoon belt, and poles are installed in ground with a fragile foundation. Pole listing is therefore a problem. The following are prospective measures to increase pole strength to withstand load.

1) Installation of the double-pole type even on flat land to increase resistance to wind pressure in typhoons

2) Extensive use of struts

3) Use of longer poles and deeper installation of the same in wet locations

4) Supporting structure fundamentals for wooden poles in Japan

* Burial of at least one-sixth of the length (i.e., height) of poles with a length of no more than 15 meters

* Burial of at least 2.5 meters of the length of poles with a length of more than 15 meters

* Firm bracing for poles installed in locations with a fragile foundation

To resolve right-of-way (ROW) problems at the time of construction, it is also necessary to use poles with a long length to keep lines above steadily growing foliage.

1) Installation of high poles to preserve the ROW

(2) Improvement of maintenance technology for 69 kV transmission lines

Maintenance and operation of 69 kV transmission lines in a sound condition over the long term are essential for the stable supply of electricity through them and will help to induce a favorable business result because of the linkage to firm sales of electricity.

As such, it is desirable to detect trouble promptly and to perform the appropriate maintenance by the appropriate method and at low cost.

In Region VIII, there are currently many poles that are listing or rotting at the base. There is also a need for preparation of plans for cutting back foliage in accordance with locations of contact identified by patrols and thereby to preserve the ROW.

The specific additional items of maintenance are as follows.

1) Attachment of braces when re-erecting poles that have fallen

2) Implementation of pole splicing and base reinforcing (Refer to Appendix 5.9-1)

3) Preparation and execution of systematic stoppage programs in coordination with the NPC

4) Early detection of trouble and preservation of the ROW through implementation of routine checks

Item 1) is to be implemented to prevent toppling of poles installed in weak ground. Item 2) is to be implemented for reinforcement in the event of rotting.

The point of Item 3) is the fact that work on 69 kV transmission lines, which are single lines, would entail long outages due to the need for stoppage of live-wire operations. To reduce the duration of outage, it is necessary to prepare monthly work programs that are implemented at the same time as the live-wire stoppage work of the NPC. The routine inspections described in next section are of importance for this reason as well.

(3) Revision of technical standards

In the past, 69 kV transmission lines were owned by ECs such as Dorelco, Soleco, and Samelco II, but the concerned technicians moved to the NPC along with the transfer of the lines in 1987, and the ECs no longer have the related technical know-how.

However, there is thought to be somewhat of a store of know-how for operations such as clearing, since certain ECs are performing clearing work for ROWs on commission from the NPC.

What the ECs must do at present is perform regular inspections and maintenance. While the Bulletins of the NEA also stipulate performance of regular and emergency checks, this section presents additional comments on the detailed categories and contents of checks.

The means of inspection of transmission line routes are defined as observations, checks, and patrols. The objective is to make careful inspections and thereby to detect defects early and to prevent occurrence of injury to people and damage to facilities.

The definitions and subject facilities of observations, checks, and patrols are presented below. Observations are made for transmission lines installed in places with relatively good visibility. Checks are made for lines whose condition cannot be verified visually due to foliage and lines on poles at risk of deterioration because of installation in wetlands. It is advisable to carry out priority inspection, through patrols, of poles in danger of rotting or toppling. Patrols should be stepped up in the event of occurrence of typhoons or other natural disasters.

1) Observations

Visual observation of all facilities from the outside for maintenance of the performance of the same. Observations should be made about once every two years.

a. Regular observation: observation at regular intervals

b. Occasional observation: observation in response to special circumstances, etc.

2) Checks

Investigation, using tools and meters, of items for which degree of facility deterioration and performance cannot be verified by visual observation and of facilities that cannot be visually observed from the outside.

In the case of degree of pole deterioration, checks should be made sometime between the fifth and seventh year after construction initially and every two or three years thereafter. If the previous check revealed no deterioration, the next could be made at intervals of five- seven years. It should be noted, however, that the interval should be set with consideration of the circumstances in the area in question.

a) Regular checks: checks at regular intervals

b) Occasional checks: checks of performance implemented as necessary in response to local conditions (lightning strikes, etc.), and the facility status (number of years of service, incidence of trouble, etc.).

3) Patrols

Patrols for visual inspection of routes from the outside, implemented as necessary apart from observations and checks.

a. Regular patrols: patrols implemented regularly in areas subject to great changes in environmental circumstances

b. Occasional patrols: patrols implemented in response to emergencies and trouble in reclosing success

Table 5.9-1 shows the categories of inspection. Appendix 5.9-2 shows the items of patrol.

Table 5.9-1 The categories of inspection in transmission line

Facility	Maintenance and control in consideration of Facility characteristics	Method		
		Observations	Patrols	Internal checks
Poles	Management of facility condition (e.g., external damage) by visual observation of appearance	O	O	
	Management of deterioration through determination of the status of rotting			O
Lines	Management of condition as regards structures, distance from foliage, height, and other such items by visual observation of appearance	O	O	
Insulators, crossarms, and other attachments	Management of condition as regards rotting, rusting, damage, and other such items by visual observation of appearance	O		

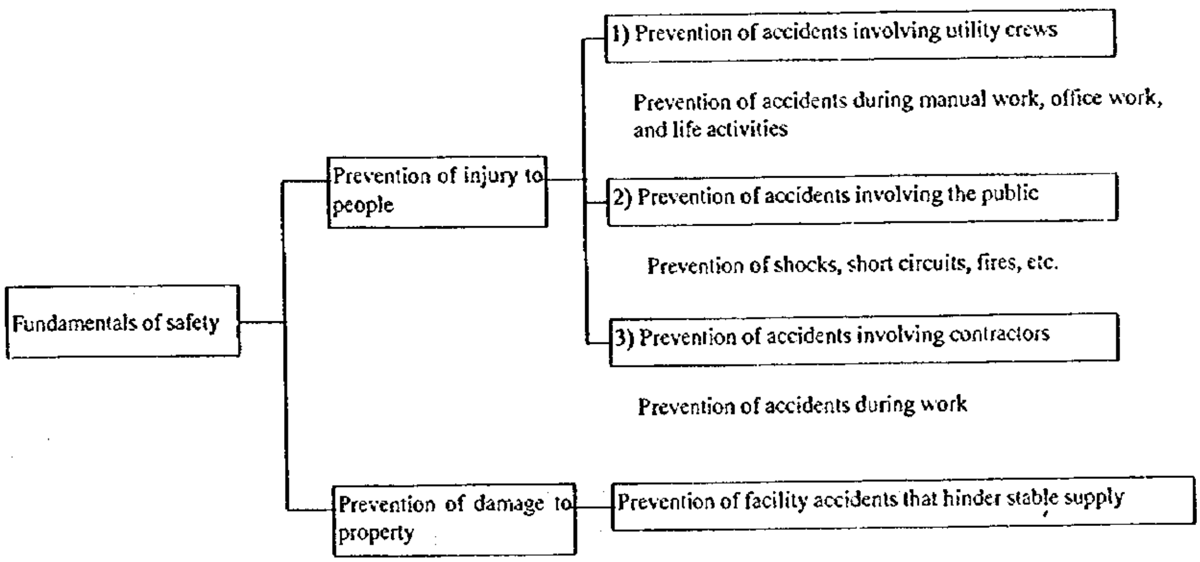
(4) Safety measures in 69 kV transmission work

As the basic perspective, assurance of the safety of all parties, not only technicians but also the crews of contractors undertaking the actual construction and other work and, of course, local residents must be at the very cornerstone of management.

To discharge the responsibility for supply of power with safe and sure operation and maintenance of existing facilities and construction of additional ones, efforts must be made to anticipate and prevent at least any damage or inconvenience to customers as a result of incidents with causes attributable to the facilities of the electric power enterprise.

Table 5.9-2 presents this basic perspective on the issue of safety.

Table 5.9-2 Basic perspective on the issue of safety



For prevention of injury, the following comments can be made about safety in work by utility crew and contractors.

Although they have a variety of causes, including improper acts, misidentification of charged parts or the subject of the work, inadequate knowledge, and improper work sequences, accidents involving transmission lines or other power transportation facilities and causing injury or death generally occur because of slight inattention or failure to follow rules for work behavior. As such, it is imperative to implant an awareness of individual responsibility for safety in the minds of each and every worker in all work sites, to lay down rules and regulations to be obeyed by workers, and to ensure strict enforcement of the same in actual work.

The following items can be cited as concrete steps for assurance of personnel safety in work on 69 kV lines. Specific measures are presented in Appendix 5.9-3.

1) Measures for prevention of electric danger

2) Division of work into blocks

3) Prevention of danger of falling

4) Reinforcement of preventive (anticipatory) safety measures

5.9.2 Improvement of Facility Plans

(1) Power system plans

The following four items deserve special attention in preparation of power system plans.

1) Achievement of service

2) Improvement of reliability

3) Pursuit of economic merit

4) Planning in accordance with the long-term vision

The point of the first item is that care must be taken to maintain the supply quality, i.e., a proper level of service in such aspects as voltage and frequency on the demand end, frequency of outage, and duration of outage. Besides improvement of facility dependability, this calls for a proper level of capacity margin in consideration of occurrence of failure.

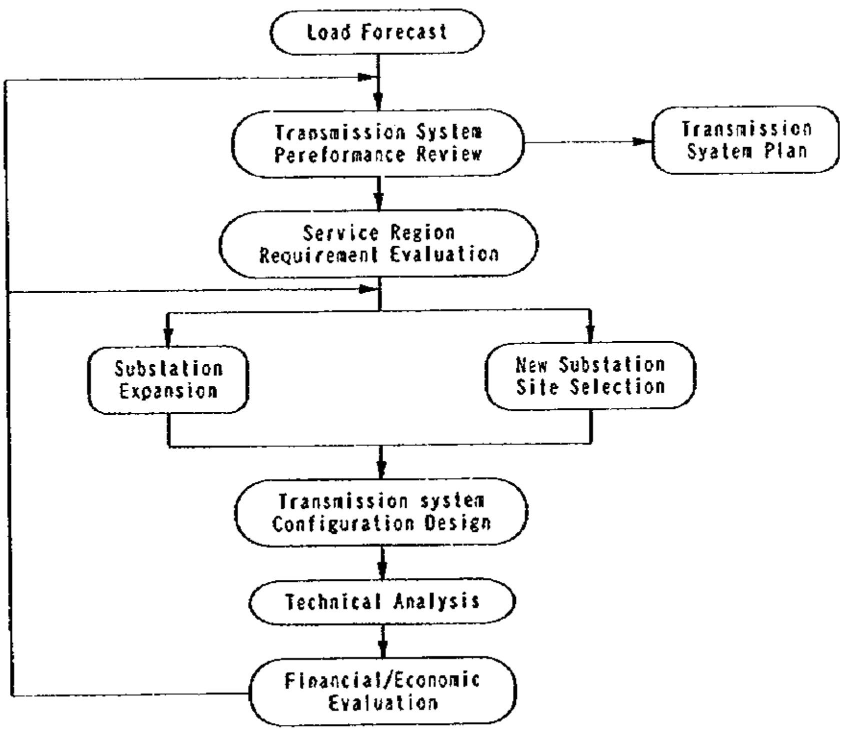
Regarding the second item, it can be noted that accidents causing outages over a wide area have a great impact on customers and must be prevented from happening. The system must be constructed with a view to precluding occurrence and to enabling limitation of the scope and swift resumption in the event of occurrence.The point of the third item is that the system must have a high economic merit. In the case of amortization of the cost of transmission and transformation facility construction in terms of the number of years in service, economic merit rises along with the difference (B-C) between the rate revenue recovered through those facilities (B) and the cost of loss arising in the facilities and of yearly depreciation (C).

As for the fourth item, because the service life of power facilities extends for many years, plans for the same must be prepared with a view to power supply that is both economical and stable over the long term. It is consequently necessary to prepare and execute power system plans on the basis of the future demand trend.

The items of plans for 69 kV transmission line facilities may be exemplified by installation of condenser banks to counter voltage drops, construction of new substations, switch to loop systems for contraction of the duration of outage, and accurate forecasts for long-term demand (up to about ten years into the future).

Figure 5.9-3 shows the procedural flow for preparation of the 69 kV power system plans. The flow is the same as that for the distribution system presented in Section 5.7.1. In other words, the procedure for distribution is the same as that for transmission. Technical analysis is a critical step in the planning procedure for the transmission system. The methods shown in Figure 4.9-4 should be employed for the analysis in the flow.

Figure 5.9-3 Flow of planning procedure for 69 kV transmission system



(2) Substance of system analysis technology

The major items of technical investigation are system stability, short- and ground-circuit capacity, power flow, and voltage drop.

Figure 5.9-4 shows the methods of technical investigation required for preparation of transmission and transformation plans.

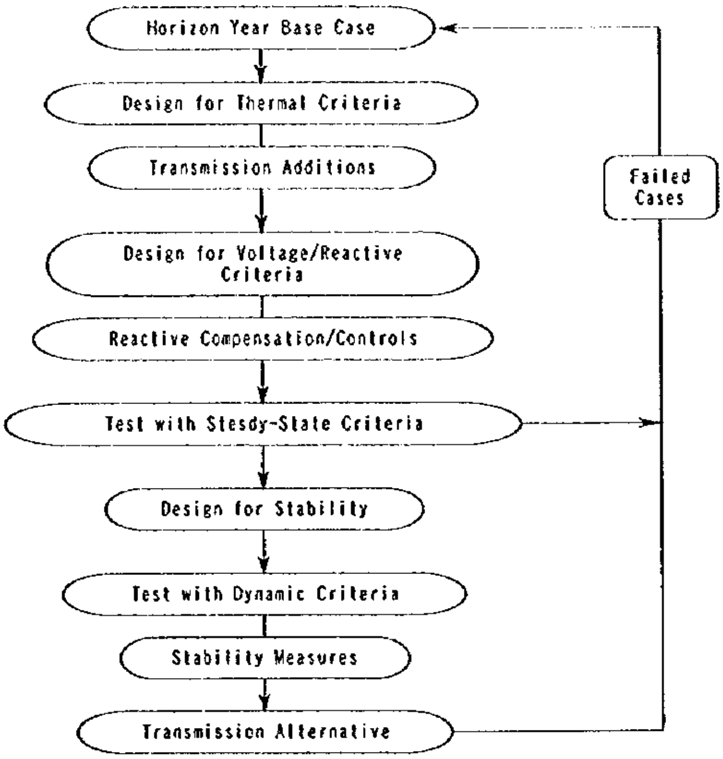
The study of system stability should be made on the responsibility of the NPC, which owns large-scale power sources. A power barge and small diesel generator are operated non-simultaneously with the Tongonan geothermal generator, under conditions ruling out use of 69 kV transmission lines in certain cases. Because of this operation on an independent basis, accidents would result in the shutdown of only this power barge or small diesel generator, without any influence on other generators. For this reason, there is thought to be no need for study of system stability by ECs.

However, such a need would arise in the event of connection of large generators to the 69 kV grid and operation of the same simultaneously with the Tongonan geothermal generator.

Similarly, ECs would presumably not have to study short- and ground-circuit capacity for the foreseeable future because no problems are anticipated at least until 2005. However, a need to make arrangements for regular study of such capacity could arise along with the change in the power system over the years.

Study of power flow is required for checking current capacity and voltage drop on transmission lines. The ECs as well must acquire the know-how needed for carrying out such study independently. At their current technological level, it would be difficult for the ECs to analyze the power system. For the future, however, they should purchase analytical tools (e.g., PSS/E) and carry out technical analyses of the system.

Figure 5.9-4 Items of technical investigation required for transmission and transformation planning



(3) Selection of transmission line routes

The selection of transmission line routes in transmission and transformation plans has a great bearing on investment requirements. It is consequently necessary to select the route offering the highest cost-effectiveness based on the results of technical investigation. Under this thinking, the optimal choice is installation of T feeders from the nearest substation or the nearest transmission line if there are no particular technical problems. It is also necessary to secure access roads for proper maintenance and rehabilitation of wooden poles after construction to ensure that they remain in use for a long time.

In reality, however, circumstances such as the difficulty of acquiring straight routes because of mountainous terrain, private property, and rivers, and inability to win the understanding of landowners may compel construction of circuitous routes.

The present transmission system on Leyte and Samar exhibits many cases of selection of routes with straight-line connection of substations. For this reason, there are some instances of construction of transmission lines far away from roads at fairly inaccessible locations and in paddies, marshland, and mountainous locations. This situation presumably lies behind the inability to carry out full maintenance and rehabilitation on a regular basis.

In light of the above, installation of new poles or relocation of existing ones should be done at places close to access roads, as far as possible and with full consideration of the economic aspect, to facilitate construction, inspection, and maintenance.

However, it may be impossible to do so if landowners do not permit installation or terrain or other unavoidable circumstances rule it out.

(4) Improvement of dependability

Unplanned outages in the transmission system have a greater impact on customers than those in the distribution system. On Leyte and Samar, which are the subject of this study, the supply of electricity depends on independent transmission through single transmission lines, and it would be difficult to supply power through other routes in times of failure. Although there is backup by power barges, diesel engines, and small hydropower units, transmission line failure would cause total outages at one or two ECs for a long time and have a great impact on customers. In other words, an improvement of the dependability of the transmission system would be linked to a rise in the reliability of the entire power system. Such improvement must be incorporated right from the planning stage.

The conceivable measures of improvement to be taken by the ECs after the transfer are as follows: 1) acquisition of transmission line routes next to roads to facilitate checking and maintenance, 2) performance of regular checks and maintenance, 3) use of the loop system on Leyte for load switchover in the event of failure, 4) formation of a looped system on Samar, and 5) installation of breakers for prompt removal of failed sections.

The first and second measures could be readily taken by the ECs even at present. The third, fourth, and fifth must be taken from a long-term perspective, as described in Section 10.3.4.

(5) Addition of voltage adjustment guidelines

The major aim of voltage adjustment in the distribution system is supply of the proper voltage to customers. Maintenance of the proper voltage to reduce power loss is another objective. The requisite guidelines for voltage adjustment in the transmission system should include the objectives of proper operation of power equipment (e.g., transformers and voltage adjusters) and assurance of stable operation of the power system. (Drops in system voltage and increases in the transmission current reduce the degree of system stability. Similarly, frequent system failures physically damage power source units. Fluctuation of the system frequency or voltage also has an adverse influence on protection and control equipment. Stable operation of the power system means operation free of such problems.)

Because of the close connection with the superior voltage system, i.e., the NPC transmission system, stable operation of the power system demands coordination with the NPC.

The final target should be a supply to end users at a voltage in the range of 216 - 252 volts (for a customer-use voltage on the 240 V basis). Upon the transfer, the voltage could be improved by means of capacitor banks and shunt reactor after receipt of the wholesale supply from the NPC with a voltage in the range of 66 - 72 kV.

5.9.3 Improvement of System Operation

(1) Need for cooperation in the operation of the 69 and 138 kV transmission systems

In the aspect of system operation, the 69 kV transmission system could be operated in a radial manner with the superior system to which it is directly connected.

In this case, the loop on Leyte would be opened at a certain point, and the form of operation would be the same as that between the NPC and the ECs at present.

With this type of operation, the load balance among the ECs would exert an impact on the superior system; for example, an increase in the load capacity of the 69 kV transmission lines would create a need for an increase in the bank capacity at 138 kV substations. As such, it would be necessary to the bank capacity in accordance with EC demand forecasts or to switch over to the 69 kV system.

In the routine operation, the system must be operated with preparations for scheduled or unscheduled stoppages of the 138 kV bank. Scheduled stoppages are made for the purpose of repair of the bank or related equipment, and require a switchover to another system for the load of capacity made unavailable by the stoppage. At present, for example, power is supplied through the power barge moored in Tacloban Bay in the event of stoppage of the Babatngon substation. Such operation must be maintained after the transfer.

The ECs must also be prepared for unscheduled stoppages due to failure of the bank or transmission lines. In a radial single-circuit system, failure of the bank or the upstream 69 kV transmission line would lead to outage over the whole transmission line. There is consequently a need for arrangements for response to unscheduled stoppage. Failure of the 138 kV bank could be countered by installation of a reserve bank, and transmission line failure, by installation of breakers for swift system switchover and remote control. Installation of a reserve bank would naturally be the responsibility of the NPC as the supplier to the ECs, but the ECs would have to assume the cost for installation of breakers as the owners of the 69 kV transmission lines.

In 1997, a DC transmission line linking the Ormoc substation to Luzon is scheduled to be completed. The following can be cited as prospective problems in the aspect of system operation upon the completion of this line.

1) Given its characteristics, the DC-AC converter would have a massive consumption of leading reactive power. This would result, in turn, in a worsening of the balance of leading reactive power (due to the shortage of the same), a decline in the system voltage, and finally a voltage drop in the supply to customers.

2) The DC-AC converter would convert AC power to DC power by the pulses of a thyristor valve. The high-order harmonics induced by this pulse conversion would adversely affect the AC system.

Countermeasures for these problems would, of course, be the responsibility of the NPC as the owner of the AC-DC converter, their cause. The prospective countermeasures include installation of a leading condenser or a harmonic filter. In the operational aspect, these problems would require checks of the routine system voltage with an automatic harmonic recorder and reflection of the results in installation of a condenser bank for the 69 kV system.

As described above, cooperation with the 138 kV system would raise problems related to switchover of the 69 kV transmission system, proper allocation of the 138 kV bank capacity, drop in system voltage, and harmonics. Response to these problems would call for a fairly high degree of experience and knowledge. As such, it would be advisable for the NPC to continue in charge of system operation.

At the same time, resolution would require the cooperation of the ECs. Therefore, a consultative institution should be established for smooth system operation. For example, the ECs must consider system operation at the stage of facility planning and technical studies.

1) For system switchover and other elements of operation, the ECs must install breakers and engage in protective cooperation (manual switchover in the case of ABS).

2) The ECs must implement adequate checks and maintenance to increase system reliability.

3) EC demand forecasts must be accurate for proper allocation of bank capacity.

4) The ECs should acquire system analysis technology enabling them to cope with technical problems involving system voltage and harmonics, also in order to improve their technical capabilities and cooperate with the NPC.

(2) Operating instructions for system operation

Special-purpose microwave communications circuits have been installed to link the Cebu SOD and Izabel RCC for relay of instructions for equipment manipulation and for exchange of information, but there are no such arrangements with the ECs. Independent communications circuits for the ECs have not been needed because the ECs have not participated in system operation, and because installation of microwave circuits would entail a great cost.

However, a loop operation realized through the installation of breakers as described later would make ECs part of system operation, and require the establishment of special-purpose communications circuits and operating instructions.

5.9.4 Technical Improvement from a Long-Term Perspective

On Leyte, there exists a loop system joining two mutually different voltages (69 and 138 kV transmission lines). However, a loop operation is not being conducted there at present.

On Samar, there are plans for looping through construction of new transmission lines by the NPC, but these plans have not been realized. After transfer, financial considerations would probably rule out looping by the ECs. Over the long term, however, it is advisable to implement loop operation on Leyte and to form a looped system on Samar in order to make the transmission system on both islands more dependable.

Furthermore, the following tasks must be performed for looped system operation.

1) Determination of loop flow and short- and ground-circuit current

2) Determination of need for system operation (operating instructions for switches and installation of relays)

As for the first task, it must be determined whether or not the loop flow to the transmission line is overloaded. It would also be necessary to ascertain in advance the extent of short- and ground-circuit current in the event of failure. The tasks can be accomplished by analyzing the power system and determining the power flow and short- and ground-circuit capacity in advance.

In the event of failure, there would also be a need for prompt removal of the sections in question. ABS requires considerable time for system switchover and would not offer a contraction of outage duration. For this reason, it would be necessary to switch from ABS to breakers and to install relay devices, as noted in the second task. There would also be a need for cooperation with the 138 kV system in operation. Breakers would have to be closed by remote control or relay of system instructions. Here as well, there would be a need for technical analysis for advance checking as to whether or not the change in the power flow after removal would result in transmission overload.

Similarly, advance technical analyses should be made of the impact of system change induced by input of breakers on generators (i.e., the Tongonan generator) and AC-DC conversion facilities. Since the ECs lack the requisite know-how, this study should be made by the NPC, which is in charge of overall system operation.

In sum, looping and reinforcement of system operation could be expected to lead to a contraction of system outage (i.e., improvement of reliability) and increase in EC profit.

CHAPTER 6

REGULATORY ISSUES

Chapter 6: REGULATORY ISSUES

There is a concern about the transfer of the 69kV transmission system from a regulatory viewpoint. After the passage of the Omnibus Electric Power Industry Bill currently discussed in the national assembly, not only the National Power Corporation (NPC) but also the governmental organizations and their authorities, including the National Electrification Administration (NEA), are expected to be reformed through the liberalization of the power industry. Moreover, rationalization of the electric cooperative (EC) sector through merger, acquisition, and consolidation are also expected to start.

In this chapter, in addition to analyzing the current status of the Omnibus Bill, we contemplated how the ongoing structural reform discussed in the government and the national assembly would affect the future of the NEA and ECs and what kind of appropriate measures they could take.

6.1 1997 Omnibus Electric Power Industry Bill

The future structure of the power industry will fully depend on the passage of the Omnibus Bill. Both the House and Senate committees have consolidated their versions into individual bills, and the Joint Committee of the House and Senate will consolidate these bills into a final one by fixing differences between the House and Senate versions. This consolidation by the Joint Committee and the passage of the bill by both the House and Senate is expected by the end of February 1998 because the presidential election is to be held in May 1998. If the Omnibus Bill is not passed by this presidential election, it will be abandoned. In other words, the national assembly must start their discussion of bill for power sector reform beginning with the start of the next session.

The Senate Committee on Energy headed by Senator Freddie Webb finalized its version—Senate Bill No. 2016 (SB2016)[1]. On the other hand, the House Committee on Energy headed by Congressman Dante Tinga has completed public hearings and also finalized its version—House Bill No. 9991[2].

These versions of the bill are called 1997 Omnibus Electric Power Industry Bill and aimed at restructuring the power industry and privatizing the National Power Corporation (NPC).

[1] SB2016 was replaced with the Senate Energy Committee Report—Committee Report No. 868—on January 12, 1998. This committee report will be the final version of the Senate bill, (i.e., SB2448).
[2] According to information from the DOE, both the House and Senate floors are expected to pass their final versions of the bill individually by the end of January 1998.

So far, there are several differences between the House and Senate bills, but they are being consolidated into one bill. Major differences between the two versions are as follows:

6.1.1 NPC Privatization

The only difference between the House and Senate versions is their timetables for implementing the NPC privatization. While the Senate gives the Department of Energy (DOE) six months after the effectuation of the Omnibus Act to prepare the restructuring and privatization plan, the House gives three months. The plan is subject to the approval of President and accordant with the following guidelines:

- Privatization value to the government shall be optimized;
- Significant participation by Filipino citizens and corporations in the ownership of NPC privatized units shall be promoted;
- Capability of NPC privatized units to attract investors and substantial equity infusion and to absorb market risks;
- Continued expansion of power supply to the small islands and remote areas as a missionary responsibility of the government;
- Wide base of ownership of privatized units or assets to be fostered;
- Interest of employees of all affected agencies to be protected; and
- Submission of a plan by the NPC to the DOE for the disposal of its allied undertaking and non-strategic assets.

The procedures of the privatization of the NPC in the Senate and House versions are similar, and these are:

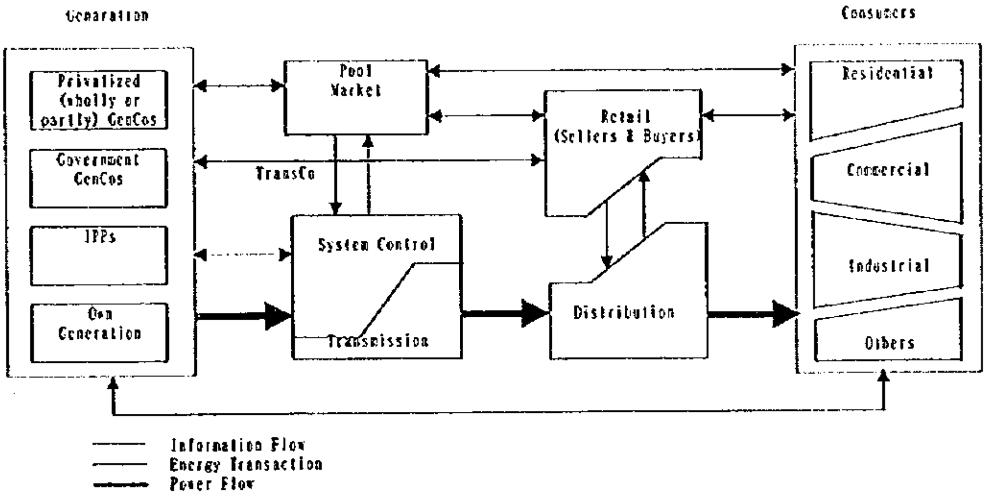
- Sale of assets;
- Strategic allocation of assets to NPC spin-off corporations and sale of its stock to institutional or individual investors in the domestic or, if warranted, international financial markets;
- Sale to a strategic partner;
- Employee stock option plan; and
- Such other mode as may be determined, in accordance with law.

6.1.2 Structure of the Power Market

One of the important objectives of the bill is to improve the industry's efficiency and productivity. Both chambers of Congress support disbundling the generation and transmission subsectors and aim to open the generation subsector up to competition while the transmission subsector remains a regulated but non-discriminatory monopoly.

To establish a competitive circumstance in the generation subsector, a wholesale pool market will be established and power transaction will be liberalized. Moreover, to ensure market competition, open access to the transmission system is to be allowed. Distributors can have a direct contractual relationship with suppliers. Single consumers can also have a direct contractual relationship with independent power producers (IPPs). The distribution subsector will be reformed to uncouple the management of the physical assets from the power sales transaction. The desired structure of the deregulated power industry is shown in Figure 6.1-1

Figure 6.1-1: Structure of the Deregulated Power Industry



Source: Viray 1997.

One concern about the deregulated industry is how to treat the existing power purchase agreements (PPAs) between IPPs and NPC. Since it is not possible for the NPC to breach these PPAs, the NPC or spin-off subsidiaries are expected to retain the position of the offtaker

In implementing the sector reform, retail competition will be in progress. Direct connection is being considered to promote competition in the power market.

In the House bill, direct connection is allowed only in cases approved by the regulatory body after due notice and hearing where the utility cannot provide at reasonable cost the power requirements needed by an end-user within the technical, safety and reliability standards established by the authority. In case direct connection is allowed, the distribution utilities cannot refuse distribution service for such an end-user but are entitled to impose and collect the proper wheeling tariffs from the end-user.

The Senate version, conversely, has a stronger provision that direct connection within the franchise area of a distribution facility may be allowed in cases approved by the regulatory body with the customer paying the cost of connection. Upon the commencement of the wholesale market regime, competition in retailing to industries is allowed for customers with a contract maximum demand of at least 2MW. Accordingly, electric utilities shall provide non-discriminatory access to their distribution systems subject to wheeling tariffs and standard conditions.

Both the House and the Senate explicitly do not allow direct connection or retail competition. Competition is limited to the generation subsector and allows the distributors to benefit through it, i.e., is wholesale competition. The only, minor, difference between the bills here is that the Senate bill employs a positive expression for direct connection, and the House bill, negative.

Through the deregulation of the power industry, the desired structural relationship creates a pool market which establishes the dispatch system and the pricing mechanism. The transmission company dispatches from the pool market in accordance with duly set rules and regulations. These rules of electricity sales will be agreed upon by the generators and distributors, and allow wholesale and retail competition to reflect the true cost of electricity eventually.

In both the House and Senate versions, all generation and distribution utilities, including bulk buyers and sellers, other than those not connected to the grid are required to participate in the wholesale market.

6.1.3 Transmission Company

Both versions of the bill call for the NPC to incorporate the National Transmission Company (NTC). However, there are some difference in their provisions, as follows:

(1) Timetable: The House bill requires it to be done within three months from the effectuation of the act, and the Senate Bill, within one year.

(2) NTC organization: The House Bill describes the NTC as a regulated common carrier, while the Senate Bill says that the NPC will control the NTC initially as the sole owner and later through its preferential retained equity.

(3) Independence of the NTC: Both versions speak of an independent NTC. The House says

that generation companies and distribution utilities shall not own shares in any transmission company, and vice versa. A stockholder with beneficial interest of 10% or more in a transmission company cannot have a beneficial interest of more than 2% equity in any generation company or distribution utility, and vice versa. The Senate says that, except with respect to the government, generation companies, distribution utilities, and their stock holders cannot own shares in the NTC and vice versa.

(4) Sale of NPC shares: Both versions prescribe the sale of 30-40% of NPC shares to the strategic partner and another 20% for the initial public offering (IPO). But they differ in the sales schedule. The House version says that the sales to the strategic partner by tender is within six months after incorporation and the IPO follows within six months after the strategic sales; conversely, the Senate version gives up to one year to do the same. The IPO comes after the strategic sales. With regard to the remaining stocks, the House version provides that all or virtually all are to be sold under a plan to be drawn up by the DOE in consultation with the Oversight Committees and approved by President.

(5) Rights of way (ROW): The House version grants the NTC the power of eminent domain. In the Senate version, this power is to be exercised by the NPC for the benefit of the NTC, but in case the NPC is dissolved, it is transferred to the NTC. The NTC is going to be a nationwide monopoly and can execute the grid of eminent domain in taking up the ROW issue.

6.1.4 Sub-transmission

Both the House and Senate versions state that the NPC shall relinquish its sub-transmission system to the electric utilities to the extent practical; those not acquired will remain with the NPC until a utility gets them.

Both versions also agree that distributors and generators may develop and own or operate dedicated point-to-point limited transmission facilities that are consistent with the national expansion plan, for the purpose of connection to the grid and use solely by the user concerned. The Senate version adds that, in the event such assets are required for competitive purposes, the ownership will be transferred to the NTC at a fair market price

6.1.5 Regulatory Environment and Energy Regulatory Board (ERB)

Both the House and Senate bills contemplate establishing a single regulatory agency. The House names it the Energy Regulatory Commission (ERC); the Senate calls it the Energy Regulatory Authority (ERA). Both of them emanate from the present ERB.

The Senate ERA has exclusive power to grant franchises to industry participants, revoking the analogous power of the NEA, Philippine Economic Zone Authority (PEZA), and Philippine Veterans Investment Development Company (PHIVIDEC). The House's ERC takes over the NEA's power to grant franchise, but there is no mention if there is a similar take-over from the PEZA and PHIVIDEC.

On the matter of breach of rules, the House empowers the ERC to suspend or revoke a franchise or authority, such as a license or permit of any party to operate. In the Senate version, a license or permit is implied.

The power of the House's ERC include the issuance of permits authorizing any person to undertake or engage in the construction of gas transportation and distribution facilities; the provision of gas sales, transportation and distribution services; and the importation of gas into the country.

6.1.6 National Electrification Administration (NEA)

Both the Senate and House versions prescribe that the NEA is responsible for the management training and financial support to cooperatives and small distribution utilities. The NEA also acts as the channel for government loans or loans granted by the government equity and grant funds for power infrastructure investments in generation, sub-transmission or distribution to pursue nationwide electrification.

In the House version, the NEA may as a last resort act as a guarantor for power purchases by electric cooperatives and small distribution utilities to support their credit standing in exchange for adequate security and a guarantee fee.

6.1.7 Distribution Utilities and Electric Cooperatives

The Senate would like to see the NEA and the regulatory body jointly develop a plan for joint action, collaboration, consolidation or merger of small distribution utilities and electric cooperatives with stronger ones, or with one another to achieve optimal sizes and load mixes within one year from the effectuation of the Act.

On the other hand, the House requires that economies of scale in utility operation be pursued through structural and operational reforms, such as the consolidation or merger of existing distribution utilities, to achieve efficiency under the performance standards to be established by the ERC.

As part of the social obligations of distribution utilities, both the House and Senate versions provide that they shall serve unviable areas within a franchise territory which are contiguous with viable areas of a distribution utility shall be served by the utility as part of its social obligations in a manner that sustains the economic viability of the utility and conforms with the Act, existing laws, and the implementing rules and regulations of the Act.

6.1.8 Missionary Electrification, Strategic Power Utilities Group (SPUG), and Countrywide Electrification Service Company (CESCO)

Both the House and Senate versions state that the SPUG will spin off from the NPC as a government-owned and -controlled corporation (GOCC) and attached to the DOE. The SPUG will carry out its missionary function of power generation and sub-transmission services in areas that are commercially unviable and not connected to the grid. However, there is a difference between the House and Senate bills in the structure of SPUG operation.

In the House version, a public corporation—Countrywide Electrification Service Company (GESCO) is to be created. Within six months from the effectuation of the act, NPC shall transfer all its assets used by the SPUG to the GESCO. In other words, the SPUG is to be integrated into one corporation. The GESCO will undertake and be responsible for providing power delivery systems and generation in areas that are not connected to the grid, where no private sector entity is willing to invest. The GESCO will exist for 50 years from the date of effectuation of the act and privatize its facilities and operation, where commercially viable, on an area-by-area and system-by-system basis.

The authorized capital stock of the GESCO is eight billion pesos divided into one million shares with a par value of one thousand pesos per share. The GESCO will be funded from the special fee for missionary electrification, net proceeds from the sales of NPC assets and shares of stocks, and 10% of the electricity franchise tax receipts every year is to be appropriated for it.

In the Senate bill, on the other hand, the spin-off SPUG is to be responsible for missionary electrification and perform the task of assessing the requirements and prospects for bringing each island system to commercial viability, and if feasible, to privatization.

As regards private-sector participation in the SPUG operation, the Senate version states that the SPUG may enter into a power generation, sub-transmission and distribution agreement with a private company allowing the latter to perform the missionary function under satisfactory terms and conditions.

There is no description about the funding scheme for SPUG in the Senate version.

6.1.9 Universal Levy

The House states that there shall be no subsidy or cross-subsidy in transmission and distribution wheeling tariffs as well as in retail electricity tariffs.

The Senate's standpoint is a consumer benefit charge. This is assessed from every user of the transmission and/or distribution system, determined and monitored by the regulatory body, and administered by the NPC, to defray the net costs of missionary electrification, development of indigenous energy, stranded assets, ancillary and system services, and cost of operating the wholesale market. The Senate also says that the government, when owning shares in companies across sub-sectors, cannot effect cross-subsidies through its holdings.

6.1.10 Anti-Trust

Both the House and Senate have explicit provisions on market domination and anti-competitive behavior. Both also provide that the regulator (ERC or ERA) shall limit the beneficial ownership of control of a significant market share in any sub-sector of the industry, and likewise the common ownership of significant assets in two or more sub-sectors.

Both the House and Senate versions have similar provisions. A distribution utility may deliver a portion of its total power requirement not exceeding 20%, from a generation company in which it has more than 20% direct or indirect interest, equity or control, except for an isolated system not connected to the grid. However, in the House bill, this 20% limitation of power supply is applied for the first eight years from the date of the effectuation of the act.

6.1.11 Indigenous Resources

The Senate version provides that the government shall have a preferential retained equity, to be held by the residual NPC, in strategic assets such as transmission, multi-purpose hydro, geothermal, indigenous natural gas projects and the like to ensure protection of public interest.

6.1.12 Other Provisions

The House and Senate versions address various other concerns, such as employee benefits which pertain to NPC employees in the House version and to NPC, NEA, and ERB employees in the Senate version.

The Senate also contemplates the creation of the Agency for Non-Conventional Energy Systems Technology Application (ANESTA) as an adjunct to the DOE to pursue the integration of non-conventional energy systems into the power industry as means of providing electricity in commercially unviable areas that are not connected to the grid. This is not contained in the House version.

The House version, conversely, has the following provisions:

(1) Oversight Committees, to be created in each chamber of Congress to monitor the implementation of the Omnibus Act and to provide assistance to the DOE in connection with studies and plans to be made.

(2) Tax Exemption: (a) direct and indirect taxes, in connection with the transfer of NPC assets to any subsidiary or GENCO; and (b) value-added tax (VAT) and import duties on fuel for power generation, VAT, production of sales taxes on electricity generation, transmission or distribution, and similar indirect taxes; all these with respect to all power generation intended for distribution or sales to final consumers as well as for transmission and distribution activities.

(3) Franchise Tax, to replace the tax exemption on distribution utilities.

(4) Environmental Protection compliance required by all industry sector participants with environmental rules, regulations and standards issued by the Department of Environment and Natural Resources (DENR).

6.2 Status of Electric Cooperatives

There is a big argument in the government on the status of electric cooperatives (ECs). Pursuant to Presidential Decree 269 (PD269), existing ECs have been defined as non-stock and non-profit organizations registered with the NEA, while all cooperatives were required to register with the Cooperative Development Authority (CDA) as stock cooperatives due to the passage of Republic Act No. 6938 and Republic Act No. 6939 (RA6938 and RA6939). The CDA gave a deadline of May 4, 1997 for all non-stock cooperatives to register[3].

However, this argument on the status of ECs between the NEA and CDA has continued, and both agencies have not reached a common conclusion. Because Article 127 on RA6939 provides that nothing in this Code (RA6938) shall be interpreted to mean the amendment or repeal of any provision of PD269, the NEA claims that the existing ECs can hold the current status of non-profit and non-governmental organizations and remain under the NEA's governance.

But the conclusion for this dispute seems to rest on the CDA's opinion. This is because:

[3] Major differences between a stock-cooperative and a non-stock cooperative are as follows:

- The membership fee for a non-stock cooperative, which is used for a part of capital, is 5 pesos. The major part of capital is raised by government low-interest funds and grant.
- Share price of a stock-cooperative is 100 pesos. Equity is raised by selling shares; 25% of authorized capital must be subscribed, and 25% of subscribed capital must be paid-up. Moreover, paid-up capital must be more than 2000 pesos.

- The Senate version of the Omnibus Bill has a provision for amendment of PD269 and change of the EC's status from a non-profit cooperative to a stock cooperative in order to make EC management sound[4], and registration of the new ECs as stock cooperatives with the CDA (although the House version dose not have such provision); and
- Through discussion of the Omnibus Bill in the national assemblies, the role of the NEA becomes to clarify, and both the Senate and House intend to remove the NEA's regulatory power.

If the provision of the Omnibus Bill is finalized in accordance with the Senate version, ECs must change their status to stock cooperatives and streamline their organization by pursuing better economics of scale through consolidation.

6.3 Technical Code and Standards

In line with the discussion of the bill in the national assembly, the NPC has drafted the Grid Code. The Code is apparently circulating within several governmental organizations, and the contents have not been disclosed yet. The Code will be made public after the passage of the bill.

6.4 Environmental Regulation

As regards the existing 69kV transmission facilities, we do not see any problems in environmental regulations. But if ECs construct new transmission facilities or expand the existing ones, environmental assessment shall be required for such plans.

6.5 Land Property

The NPC received right of ways for the land on which transmission facilities were constructed and has been using it free of charge, we estimate. From the interview regarding the evaluation of the asset value of the transmission facilities, it was learned that the land used for the transmission facilities of the Tacloban-Palo and Wright-Calbayog lines is lent free of charge, while the NPC pays compensation for clearing trees and foliage which can be obstacles to the construction of facilities[5].

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[4] S2016, Sec. 23.
[5] Asian Appraisal Co., Inc. 1997.

6.6 Discussion of Issues Relating to the Transfer of the Transmission Lines

With regard to the 69kV transmission lines which are the focus of this study, we suggest that potential problems relating to regulations and laws exist. Basically, the transfer of the transmission lines is to be implemented as part of the ongoing sector reform stipulated in the Omnibus Bill. This affects not only the physical transfer of the assets but also the changes in the future roles of the NPC, NEA, and ECs.

Issues arising from the transfer are as follows:

- Transmission assets to be transferred
- Rationalization of EC structure through consolidation
- The NEA's administrative power and future roles

In this section, we discuss what is expected to happen in the future and related prospective measures.

6.6.1 Properties of the Transmission Assets

The Omnibus Bill stipulates that, in principle, transmission facilities shall be transferred to the newly established NTC. An important viewpoint in this discussion is whether the 69kV transmission lines are defined as trunklines or sub-transmission lines. In the Senate version, there is a provision that sub-transmission lines are to be transferred to distribution utilities. Our scheme for the transfer of the transmission lines to ECs in Leyte and Samar is in accordance with the Senate provision. However, clear definitions of trunklines and sublines do not exist, and we therefore cannot clarify the legal status of the 69kV lines in Leyte and Samar.

The final conclusion is expected to be reached by the PLN based on its plans for future expansion of transmission facilities and its management decision-making[6]. For example, during our first mission to the Philippines in January-February 1997, the NPC denied the plan for selling its 69kV lines. But on our second mission in July-August 1997, the NPC showed a positive attitude for the plan.

6.6.2 Rationalization of EC Structure through Consolidation

We cannot evade the issue of rationalization of EC structure. As shown clearly in the Senate and House versions, one of the most important aims of the Omnibus Bill is to make

[6] We were informed that on January 26, 1998, the NPC director board approved its policy for the transfer of sub-transmission lines. Transmission lines below 69 kV in Leyte and Samar, 230 kV in Luzon, and 138 kV in Mindanao are to be defined as sub-transmission lines, but we could not receive other conditions in detail.

distribution utilities of the optimal size through merger, acquisition, and consolidation of small utilities and ECs. In the future, the market mechanism will be introduced in rural electrification and the structure of subsidy and cross subsidy will be corrected.

For the aforesaid reason, the 11 ECs in Leyte and Samar are required to streamline their management for pursuit of higher economies of scale through consolidation. Although we see possible political difficulties in implementing rationalization, we cannot avoid such discussion.

As part of the rationalization of ECs, discussion on the organizational structure of the ECs is in progress. As noted about the current status of the Omnibus Bill in the previous section, the Senate version intends to enforce the change of EC status as cooperative, and current non-profit ECs must become stock cooperatives. The NEA will face a similar issue relating to its role. Both the Senate and House versions limit NEA's future role, and regulatory power relating to EC management will be transferred to another agency.

Rationalization of EC structure is necessary according to market-economy principles, but we see several problems arising in the process. Firstly, it is not easy to change EC status from non-profit cooperative to stock cooperative.

Pursuant to the Cooperative Laws (i.e., RA6938 and RA6939), the membership fee must increase from 5 pesos to 100 pesos. A more substantial financial burden for the members is the allocation of shares; 25% of authorized capital must be subscribed and 25% of subscribed capital must be paid-up to establish a new EC. If shares are allocated equally among members, there is a great uncertainty whether all members could afford their share capitals, especially in small and financially weak ECs. If an EC fails to issue and pay-up its shares, it cannot register with the CDA as a stock cooperative. Furthermore, if the EC loses its status as a cooperative, it will also lose the privileges of a cooperative, including preferential tax treatment, and is expected to experience difficulties in its operation.

Given these conditions, it is necessary to merge financially weak and small cooperatives with strong and bigger ones and to streamline their operation. This is the requirement of the era of the market economy. In this context, now is the time for the 11 ECs to prepare for future consolidation.

6.6.3 NEA Power and Role in the Future

The role of the NEA is becoming clear. As seen in the Omnibus Bill, NEA responsibility is to be limited to the following two functions: Management training for small utilities and ECs, and channeling grants from bi- and multilateral organizations to investment in the power infrastructure in order to facilitate electrification throughout the country.

The NEA's other regulatory powers, including power tariffs and registration of ECs, will be transferred to the ERA (or ERC) and CDA.

The aim of the Omnibus Bill is to apply the market mechanism to rural electrification as far as possible in order to strengthen the basis for business operation, and finally to make electricity supply on commercial basis possible. To attain this target, the NEA is strongly expected to show its leadership in implementing rationalization of the EC management structure, making the EC financial position sound by correcting the present subsidy system, and making clear the responsibility for EC management.

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Senate Bill No. 2016, "An Act to Ordain Reforms in the Electric Power Industry, Pursuing the Goal of Total Electrification with the Optimal Use of Indigenous New and Renewable Energy Resources, Promoting the Active Participation of the Private Sector in Power Generation, Transmission and Distribution, Defining the Powers and Responsibilities of Appropriate Government Agencies, Amending Pertinent Provisions of Related Laws, and for Other Purposes"

Senate Bill No. 2448, "An Act to Help Resolve the Power Shortage by Encouraging the Construction of and Use of Solar Power to Generate Electricity"

Viray, F. L. (1997), "Update of Restructuring the Power industry and Privatizing the National Power Corporation," *The Philippine National Information Forum, Shangri-la EDSA, May 22, 1997*, Manila

CHAPTER 7

PREMISES OF THE STUDY

Chapter 7: PREMISES OF THE STUDY

7.1 Scope of Facilities to be Transferred

The subject of this study is 69 kV transmission facilities in Leyte and Samar. This section clarifies the scope of these facilities.

The 69 kV transmission facilities consist of the lines (including the wooden poles, pole fittings, and conductors), breaker and ABS switching equipment, metering equipment, protective control equipment, communications facilities, load dispatching facilities, and the associated buildings and supporting structures with foundation.

In consideration of their nature, the scope does not include 69 kV transformation equipment within 138 kV substations, i.e., breakers, metering equipment, and protective control equipment. The breakers are installed to prevent influx of external disturbance into the transformation equipment as well as to remove the transmission line accidents. The metering equipment and protective control equipment function as eyes for the operation of the breakers. Furthermore, the NPC must operate breakers when switchover are made of the bus bar configuration in the substation. For these reasons, it would be more natural for the NPC to own the breakers both for operation of its 138 kV substations and for protection of the transformation equipment from external disturbance and naturally the associated buildings and supportive structures with foundation would not be included in this study.

The scope of transfer would not include communications facilities, since the NPC and ECs are currently linked by telephone circuits and wireless circuits.

The load dispatching facilities are not included because it is preferable for system operation to be centralized in the NPC, as noted in Section 5.2 and 5.8.

As such, the scope of transfer would include only the 69 kV transmission line facilities, i.e., the lines extending from the 69 kV transmission line outlet of the 138 kV substations of the NPC, and the associated poles, pole fittings, conductors, and ABS and breakers on the lines. The specific points of division of responsibilities between the NPC and the ECs are to be decided upon negotiation between the NPC and the ECs receiving the transfer.

In light of the connection with NPC facilities, the following additional points can be made about the scope of transfer as regards inclusion of certain 69 kV transmission lines on Leyte and Samar.

1) The transfer should not include the 12.1 km section of 69 kV transmission lines between the Isabel substation and the power barge. This is a power source transmission line sending power from a power barge owned by the NPC to a 138 kV substation owned by the NPC.

Its transfer to the ECs would not be in the interest of effective system operation.

2) The transmission line leading to the capacitor bank station on the outskirts of Palo should be included in the transfer, because there are plans to convert this station into a 69/13.2 kV substation in the future.

3) The transfer should also include additional transmission lines built by the NPC for supply of power to the ECs by the time of completion of the transfer.

7.2 Demand Forecast and Review

Table 7.2-1 presents a forecast of the electric power demand on Leyte and Samar derived from the projected rates of increase in the gross domestic product (GDP) and gross regional domestic product (GRDP), and from the related power elasticity. This forecast is based on the trend of consumption of power nationwide and in the subject region over the 11-year period 1985 - 1996 as well as the rate of increase in the GDP and GRDP, and the power elasticity. Figure 7.2-1 compares this forecast with that of the NEA. As related in Section 3.10.2, the EC and NEA forecast figures are close to those of the study team in the high estimation case (optimistic), but the low estimation case (pessimistic) forecast figures constituting harsher conditions for EC management were applied in the financial analysis. In addition, there is a need to review the power demand, which fluctuates with the economic and social situation, to ascertain the level of the 69 kV T/L delivery charge after the NPC's privatization, and to adjust the transfer plans accordingly, by the time of the establishment of the new cooperative for the transfer, as described in Section 8.3.

Table 7.2 - 1 Review of Power Demand Forecast in Region VIII

Sold Energy in 1996

	Philippines	32,891.0 GWh
	Region VIII	216.6 GWh

Year	1998-2003	2003-2008	2008-2013	2013-2018
Average growth rate of Gross Domestic Product(AGRGDP)				
High case (%)	7.2	7	6.8	6.6
Low case (%)	5.2	5	4.8	4.6
Average growth rate of Gross Regional Domestic Product(AGRGRDP)				
High case (%)	7	6.8	6.6	6.4
Low case (%)	5	4.8	4.6	4.4
Elasiticity(ELS)				
Nation base	2.2	1.8	1.7	1.6
Region base	2	1.8	1.7	1.6

Year	1997	1998	1999	2000	2001	2002	2003	2004
Philippines								
High case GWh	38,100.9	44,136.1	51,127.3	59,225.8	68,607.2	79,474.6	92,063.4	103,663.4
Low case GWh	36,653.7	40,846.9	45,519.8	50,727.3	56,530.5	62,997.6	70,204.5	76,522.9
Region VIII								
High case GWh	246.9	281.5	320.9	365.8	417.0	475.4	542.0	608.3
Low case GWh	238.3	262.1	288.3	317.1	348.8	383.7	422.1	458.6

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013
Philippines									
High case GWh	116,725.0	131,432.3	147,992.8	166,639.9	185,903.4	207,393.9	231,368.6	258,114.8	287,952.9
Low case GWh	83,409.9	90,916.8	99,099.3	108,018.3	116,832.6	126,366.1	136,677.6	147,830.5	159,893.5
Region VIII									
High case GWh	682.8	766.4	860.2	965.5	1,073.8	1,194.3	1,328.2	1,477.3	1,643.0
Low case GWh	498.2	541.2	588.0	638.8	688.7	742.6	800.7	863.3	930.8

*** Input Data ***

Year	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
Category											
Sold energy of PHILIPPINES GWh	17645.0	19605.0	20593.0	22243.0	22012.0	23598.9	23959.0	24608.0	28446.0	31029.0	32891.0
Sold energy of REGION VIII GWh	131.4	144.6	116.6	96.3	116.0	120.9	131.3	143.9	159.0	176.1	216.6
G D P $\times 10^6$ Peso	591423.0	616926.0	658583.0	699449.0	720691.0	716523.0	718942.0	734156.0	766451.0	803450.0	842016.0
G R D P $\times 10^6$ Peso	16057.0	16175.0	17297.0	17373.0	17322.0	17396.0	17088.0	17851.0	18387.0	19374.0	20420.0

*** Growth rate & Elasticity ***

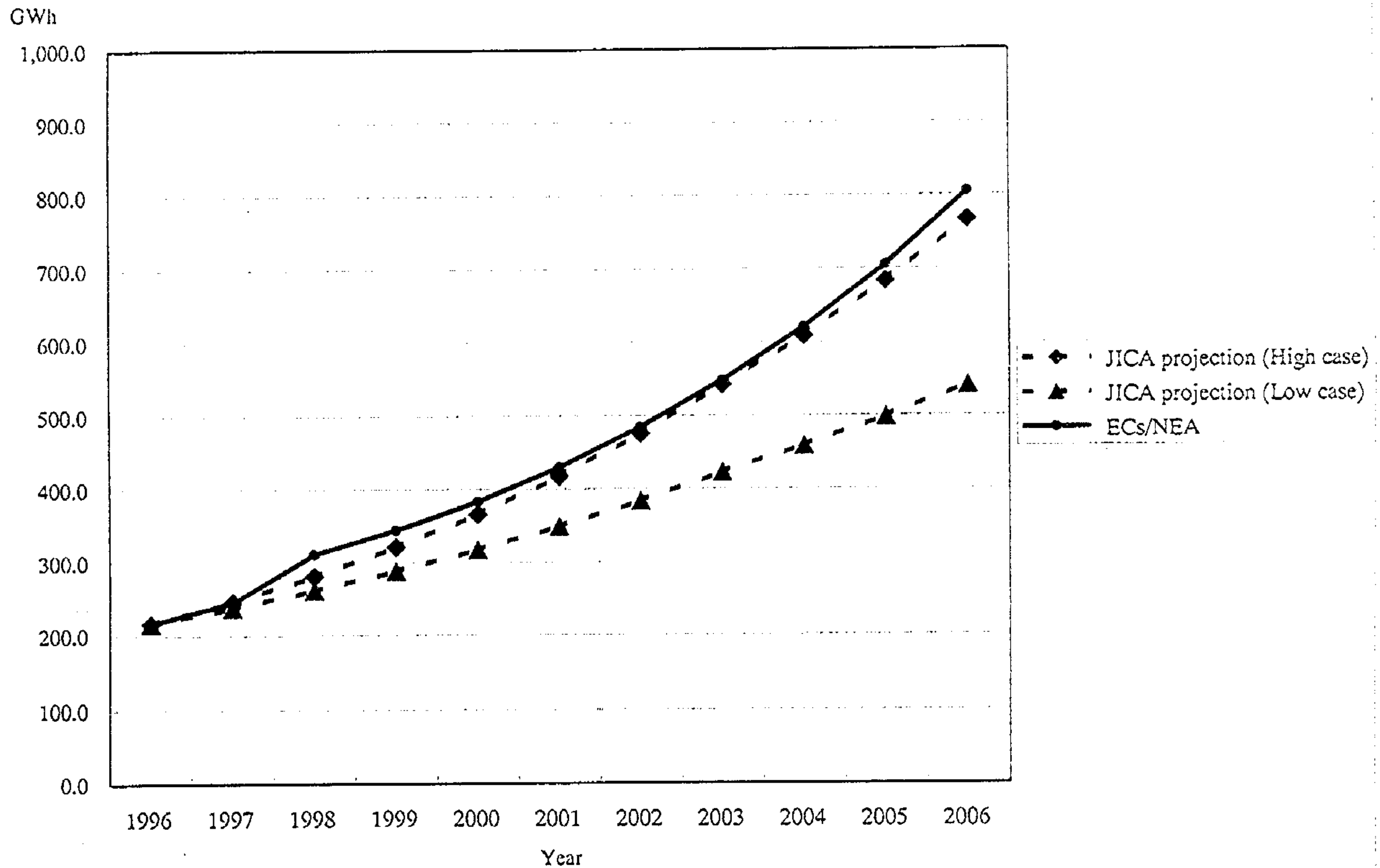
** Macro Method - 1 **

GDP Growth	1998 - 2003	2003 - 2008	2008 - 2013	2013 - 2018
Low (%)	5.20	5.00	4.80	4.60
Medium (%)	6.20	6.00	5.80	5.60
High (%)	7.20	7.00	6.80	6.60
Elasticity	2.20	1.80	1.70	1.60

** Macro Method - 2 **

GRDP Growth	1998 - 2003	2003 - 2008	2008 - 2013	2013 - 2018
Low (%)	5.00	4.80	4.60	4.40
Medium (%)	6.00	5.80	5.60	5.40
High (%)	7.00	6.80	6.60	6.40
Elasticity	2.00	1.80	1.70	1.60

Fig. 7.2 - 1 Power Demand Forecast Comparison between ECs/NEA and JICA team



7.3 Application of the Unbundled Power Tariff System

7.3.1 Course of Introduction

In the process of privatization for introduction of the market mechanism and more efficient management, the NPC intends not only to detach the electric power generation division and transform it into an independent enterprise but also to transfer the subtransmission lines to distribution enterprises.

In this way, the NPC is planning a switch to a system of unbundled power tariffs to give any party free access to its transmission lines. It has already applied for this revision to the Energy Regulatory Board (ERB).

The new system will be effected upon approval by the ERB. The NPC wants to move to it early in 1998.

7.3.2 Main Differences from the Existing Tariff System

1) The existing system

- The NPC collects two charges: a demand charge for recovery of fixed costs and an energy charge for recovery of variable costs.
- Under the existing system, the ECs receive a primary voltage discount (PVD) amounting to about 5 centavos per kWh on the wholesale price from the NPC (for supply at 69 kV, there was a discount of 2.5 percent on the 1996 tariff of 2 pesos per kWh wholesale, and this works out to about 5 centavos).

2) New system

- The tariffs will be mainly for generation costs and transmission costs.
- For generation costs, the NPC will apply time-of-use rates (peak and off-peak) with different unit prices in the interest of load-leveling.
- For transmission costs, it has decided to set different unit prices for trunk transmission lines and subtransmission lines.
- Transmission lines will be freely available for use, in keeping with the idea of open access. This will make it possible for customers who want to use transmission lines to do so freely upon payment of the wheeling charge.
- The PVD will be abolished under the new system.
- If the new system is approved, the enterprises receiving the transfer of 69 kV transmission lines will no longer be using 69 kV lines owned by the NPC. As such, the

subject of discounting will be the tariff for transmission costs applied for 69 kV lines in wholesale from the NPC (this came to 11.31 centavos per kWh in 1996 in the Visayas Grid).

7.3.3 Unbundled Power Tariff Constituents

Tables 7.3-1 and 7.3-2 show the unit prices and significance, respectively, of the constituents of the unbundled power tariff system applied in Luzon, Visayas and Mindanao Grid in 1996.

7.3.4 Future Tariff Forecast

1) Future tariffs for use of NPC subtransmission lines

Figure 7.3-1 shows the unbundled power tariffs for which the NPC has applied to the ERB. However, this schedule is based on actual data for 1996, and therefore does not include items that would be involved upon privatization, such as profit, corporation tax, and dividends for shareholders. For this reason, the study team took account of the average annual rate of increase in NPC tariffs in the Visayas region and the nationwide inflation rate in its estimate of tariffs for use of subtransmission lines.

2) Future NPC power sales prices

Table 7.3-3 shows the forecast of rates applied in power sales from the NPC to the ECs in Leyte and Samar, with consideration of Table 7.3-1 and the past average annual rate of NPC tariff increase.

Besides the past rate of increase and inflation, the forecast also took account of profit as a private company, corporation tax, and dividends for shareholders.

3) Future EC power purchasing costs

The 11 ECs on Leyte and Samar purchase power from the NPC and sell it to customers through the 69/13.2 kV substations and 13.2 kV/400 V distribution lines.

Table 7.3-4 shows the forecast for the tariffs made with consideration of factors including the forecast demand (low estimation case), loss rates, and the cost of power purchased from the NPC as percentage of all EC revenue.

Table 7.2 - 1 Unbundled Power Tariff for Luzon, Visayas and Mindanao Grid

Unit: Peso/kWh(1996 Base)

Name of Grid / Item	LUZON	VISAYAS	MINDANAO
Unbundled Rate Component			
1. Off-Peak Charge (Average of Long & Short-term contracts)	1.2513	1.1682	0.9033
2. Peak Charge (Average of Long & Short-term contracts)	1.6752	1.6780	1.0103
Sub-Total Generation Charge (Average of LTC & STC)	*1.5577*	*1.5450*	*0.9750*
3. Transmission Power Delivery Charge	0.0869	0.1471	0.0747
4. Sub-Transmission Power Delivery Charge	0.0683	0.1131	0.3140
5. Interconnection Charges between Grids	-	0.0624	-
Sub-Total Power Delivery Charge	*0.1551*	*0.3226*	*0.3887*
6. Load Following & Frequency Regulation Charge	0.0109	0.0115	0.0109
7. Spinning Reserve Service	0.0406	0.0427	0.0404
8. Back-up Power Charge	0.0766	0.0805	0.0762
Sub-Total Ancillary Services (Generation-related)	*0.1281*	*0.1348*	*0.1275*
9. Customer Charge	-	-	-
Sub-Total without Levies	*1.8410*	*2.0024*	*1.4912*
10. Transition Charges	-	-	-
11. Development of Indigenous Resources Charge	0.1134	0.1134	0.1134
12. Subsidies to Small Island Grid (SIG)	0.0154	0.0154	0.0154
13. Environmental & Other Socio-political Obligations	0.0075	0.0075	0.0075
Sub-Total Non-Bypassable Levies	*0.1363*	*0.1363*	*0.1363*
Grand Total	*1.9773*	*2.1387*	*1.6275*

Source : NPC Tariff Division, Diliman Office

Table 7.2 - 2 Rationale of Unbundled Power Tariff

Type	Unbundled Rate Component	Rationale
GEN	1. Off-Peak Charge (Average of Long & Short-term contracts)	Set to recover generation-related marginal costs
GEN	2. Peak Charge (Average of Long & Short-term contracts)	
PWR DLVRY	3. Transmission Power Delivery Charge	Set to recover transmission costs and provide sufficient cash flow for expansion
PWR DLVRY	4. Sub-Transmission Power Delivery Charge	Set to recover sub-transmission costs and provide sufficient cash flow for expansion
PWR DLVRY	5. Interconnection Charges between Grids	To be treated as equivalent overhead line and charged to user - the rest become part of non-bypassable system benefit charges (SBC)
ANCLRY	6. Load Following & Frequency Regulation Charge	Generation-related ancillary service for power quality, security and reliability
ANCLRY	7. Spinning Reserve Service	Generation-related ancillary service for power quality, security and reliability
ANCLRY	8. Back-up Power Charge	Generation-related ancillary service for power quality, security and reliability
CUST	9. Customer Charge	To address specific requirements of particular customers (minimize cross subsidy)
SBC	10. Transition Charges	To recover investments in non-competitive resources made before restructuring
SBC	11. Development of Indigenous Resources Charge	For national security purpose
SBC	12. Subsidies to Small Island Grid (SIG)	Social responsibility
SBC	13. Environmental & Other Socio-political Obligations	Social responsibility

Source : NPC Tariff Division, Diliman Office

Table 7.2 - 3 Unbundled Tariff Forecast for Visayas Grid

Unit: Peso/kWh

Unbundled Rate Component / Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
1. Off-Peak Charge (Average of Long & Short-term contracts)	1.1682	1.2266	1.2879	1.3523	1.4200	1.4910	1.5655	1.6438	1.7260	1.8123	1.9029
2. Peak Charge (Average of Long & Short-term contracts)	1.6780	1.7619	1.8500	1.9425	2.0396	2.1416	2.2487	2.3611	2.4792	2.6031	2.7333
Sub-Total Generation Charge (Average of LTC & STC)	*1.5450*	*1.6223*	*1.7034*	*1.7885*	*1.8780*	*1.9719*	*2.0704*	*2.1740*	*2.2827*	*2.3968*	*2.5166*
3. Transmission Power Delivery Charge	0.1471	0.1545	0.1622	0.1703	0.1788	0.1877	0.1971	0.2070	0.2173	0.2282	0.2396
4. Sub-Transmission Power Delivery Charge	0.1131	0.1188	0.1247	0.1309	0.1375	0.1443	0.1516	0.1591	0.1671	0.1755	0.1842
5. Interconnection Charges between Grids	0.0624	0.0655	0.0688	0.0722	0.0758	0.0796	0.0836	0.0878	0.0922	0.0968	0.1016
Sub-Total Power Delivery Charge	*0.3226*	*0.3387*	*0.3557*	*0.3734*	*0.3921*	*0.4117*	*0.4323*	*0.4539*	*0.4766*	*0.5005*	*0.5255*
6. Load Following & Frequency Regulation Charge	0.0115	0.0121	0.0127	0.0133	0.0140	0.0147	0.0154	0.0162	0.0170	0.0178	0.0187
7. Spinning Reserve Service	0.0427	0.0448	0.0471	0.0494	0.0519	0.0545	0.0572	0.0601	0.0631	0.0662	0.0696
8. Back-up Power Charge	0.0805	0.0845	0.0888	0.0932	0.0978	0.1027	0.1079	0.1133	0.1189	0.1249	0.1311
Sub-Total Ancillary Services (Generation-related)	*0.1348*	*0.1415*	*0.1486*	*0.1560*	*0.1638*	*0.1720*	*0.1806*	*0.1896*	*0.1991*	*0.2091*	*0.2195*
9. Customer Charge	-	-	-	-	-	-	-	-	-	-	-
Sub-Total without Levies	*2.0024*	*2.1025*	*2.2076*	*2.3180*	*2.4339*	*2.5556*	*2.6834*	*2.8175*	*2.9584*	*3.1063*	*3.2616*
10. Transition Charges	-	-	-	-	-	-	-	-	-	-	-
11. Development of Indigenous Resources Charge	0.1134	0.1191	0.1250	0.1313	0.1378	0.1447	0.1520	0.1596	0.1675	0.1759	0.1847
12. Subsidies to Small Island Grid (SIG)	0.0154	0.0162	0.0170	0.0178	0.0187	0.0197	0.0206	0.0217	0.0228	0.0239	0.0251
13. Environmental & Other Socio-political Obligations	0.0075	0.0079	0.0083	0.0087	0.0091	0.0096	0.0101	0.0106	0.0111	0.0116	0.0122
Sub-Total Non-Bypassable Levies	*0.1363*	*0.1431*	*0.1503*	*0.1578*	*0.1657*	*0.1740*	*0.1827*	*0.1918*	*0.2014*	*0.2114*	*0.2220*
Grand Total	*2.1387*	*2.2456*	*2.3579*	*2.4758*	*2.5996*	*2.7296*	*2.8660*	*3.0093*	*3.1598*	*3.3178*	*3.4837*

Note: The forecast was made based upon the 1996 base prepared by NPC and the escalation with 5 % per year.

Table 7.3 - 4 Retail Rate Forecast for Region VIII (Eastern Visayas)

Not taking over 69 kV T/L
Low case power demand forecast base

Item / Year		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
		Actual	Forecast									
Sales energy to end user	MWh	216,565	238,260	262,086	288,295	317,124	348,837	383,720	422,092	458,561	498,181	541,223
Retail rate to end user	Ctv/kWh *1	398.4	400.2	509.3	486.2	486.2	486.2	486.2	486.2	492.2	498.4	504.6
Operating revenue	Mil. Peso	862.8	953.4	1,334.8	1,401.6	1,541.7	1,695.9	1,865.5	2,052.0	2,257.2	2,482.9	2,731.2
Operating revenue(Net)	Mil. Peso	799.8	879.8	1,231.7	1,293.3	1,422.7	1,564.9	1,721.4	1,893.6	2,082.9	2,291.2	2,520.3
Other Operating revenue	Mil. Peso	26.9	29.6	41.5	43.6	47.9	52.7	58.0	63.8	70.1	77.2	84.9
Reinvestment fund	Mil. Peso	36.0	44.0	61.6	64.7	71.1	78.2	86.1	94.7	104.1	114.6	126.0
Growth rate of sales energy	%	-	10.02	10.00	10.00	10.00	10.00	10.00	10.00	8.64	8.64	8.64
Growth rate of Operating revenue(Net)	%	-	10.00	40.00	5.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Growth rate of Operating revenue	%	-	10.50	40.00	5.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Power purchase energy from NPC *2	MWh	261,723	285,390	311,496	340,568	369,020	403,564	439,360	480,518	521,884	566,035	614,626
Power purchase rate from NPC	Ctv/kWh	211.6	-	-	-	-	-	-	-	-	-	-
Estimated power purchase rate from NPC	Ctv/kWh	-	218.8	280.6	269.5	273.6	275.2	278.1	279.7	283.2	287.3	291.0
Power cost	Mil. Peso	605.7	651.0	911.5	957.1	1,052.8	1,158.0	1,273.8	1,401.2	1,541.4	1,695.5	1,865.0
Power cost for sales power *3	Mil. Peso	553.8	624.3	874.2	917.9	1,009.6	1,110.6	1,221.7	1,343.8	1,478.2	1,626.0	1,788.7
O & M cost	Mil. Peso	52.0	26.7	37.3	39.2	43.1	47.4	52.2	57.4	63.1	69.4	76.4
Growth rate of power purchase energy	%	-	9.0	9.1	9.3	8.4	9.4	8.9	9.4	8.6	8.5	8.6
Power cost percentage	%	69.2	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0
Energy loss	MWh	45,158	47,130	49,410	52,273	51,896	54,727	55,640	58,426	63,323	67,855	73,402
Loss percentage	%	17.25	16.51	15.86	15.35	14.06	13.56	12.66	12.16	12.13	11.99	11.94

Note: *1; Cvt means centavos.
: *2 & *3; 1996's data are derived from financial statement of ECs in Leyte and Samar.

7.4 Assets Value of 69 kV Transmission Lines

1) NPC assets value for the existing 69 kV transmission lines

The NPC asks outside consultants to carry out a revaluation of its assets every four years and makes its own revaluation every year. Table 7.4-1 shows the assets value as calculated by the NPC for 69 kV transmission lines on Leyte and Samar as of the end of 1995 and 1996, and recently constructed lines is unclear because the NPC did not provide such data for them.

As shown in Table 7.4-1, there are two types of assets value for the facilities in question: the revalued price and sound value.

In terms of sound value, the assets value of the 69 kV transmission lines was put at 396.1 million pesos as of the end of 1996. In terms of the revalued price taking account of inflation, the corresponding figure was over twice as large at 848.5 million pesos. It is clear that the assets value applied in the transfer will have a great financial impact on the receiving company.

While there is a need for independent calculation of the assets value of 69 kV transmission lines, the study team was not able to do this because of inability to obtain related data from the NPC and limitations of time and expense in the performance of the field study.

Therefore, it was decided to implement a field study for a portion (about 10 kilometers) of the subject transmission lines and to compare the results with the assets value as calculated by the NPC. Chapter 9 relates the results of this comparison while also commenting on the influence of the revalued price and sound value.

In this way, the assets value of the subject T/L facilities used in this study is based on NPC calculations.

Table 7.4-1 The existing 69 kV transmission line in Leyte & Samar

Line strech	Voltage	Length /km	Comm. year	As of Dec. 1995		As of Dec. 1996	
				Revalued price(1000peso)	Sound value(1000peso)	Revalued price(1000peso)	Sound value(1000peso)
Leyte Sub Area							
Tongonan-Tunga	69	44.20	1991	43,834	28,452	44,683	23,837
Tunga-Palo	69	28.00	1979	32,819	16,295	33,455	17,847
Palo-Tacloban	69	14.00	1979	40,400	8,114	16,727	8,923
Lemon-Biliran	69	27.00	1988	44,869	27,420	45,739	24,400
Palo-Doreco	69	19.00	1979	22,270	11,057	22,701	12,110
Doreco-Mabuhay	69	61.00	1979	71,499	35,501	72,883	38,881
Mabuhay-Bontoc	69	25.00	1980	29,302	14,922	29,870	15,935
Bontoc-Himayagan *1	69	28.00	1996	-	-	-	
Himayagan-St. Bernard *1	69	15.00	1996	-	-	-	(40,340 *2)
Bontoc-Maasin	69	30.00	1980	35,163	17,907	35,844	19,122
Tongonan-Ormoc	69	19.60	1977	19,149	9,020	19,521	10,414
Ormoc-Bayabay	69	51.00	1985	84,777	48,567	86,442	46,098
Baybay-Maasin *1	69	75.00	1996	-	-	-	(63,680)
Sub-total		436.80		424,082	217,255	407,866	217,567
Samar Sub Area							
Wright-Calbayog	69	68.00	1989	72,348	31,172	74,541	30,144
Calbayog-Catarman	69	67.00	1989	71,284	30,713	73,445	29,701
Catarman-Catubia	69	92.00	1990	97,609	40,716	95,416	38,585
Wright-Taft	69	90.00	1989	90,526	39,004	93,270	37,718
Taft-Oras	69	33.20	1990	49,789	21,890	51,299	20,745
Taft-Borongan *3	69	33.00	1993	51,069	21,105	52,617	21,650
Borongan-MacAthur *1	69	72.00	1994	-	-	-	(58,050)
Sub-total		455.20		432,625	184,600	440,589	178,542
Total		892.00		856,707	401,855	848,454	396,109

(Note) *1: Source of construction cost is from Engineering Department in Visayas Regional Center.
*2: Total amount from Bontoc - (Himayagan) - St. Bernard
*3: The line was reconstructed in 1993
Since the Isabel-Pallugue line is from the power burge to Isabel, and the Sound value & Revalued price of the line for Bontoc-St. Bernardo, Baybay-Maasin and Borongan-MacAthur are not availabe, this table does not include these data.

(Remarks) 1. Replacement of wooden pole in Samar sub-area started from June 1997, though any replacement has not been taken.
2. 69 kV T/L (wooden poles/sc) as of Sep. 1995 June 1997,
Average cost of installation only P 120,000 - 150,000/km, 1993 - 1995
Average cost of line hardware $ 18,000/km,
Average cost of wood material(local one) P 190,000/km

2) Plans for rehabilitation of 69 kV transmission lines by the NPC

The NPC has drafted plans for rehabilitation of the 69 kV transmission lines on Leyte and Samar in 1997 and 1998. The objective is thought to be capital investment in anticipation of the transfer of 69 kV transmission lines (in the subtransmission category) to ECs and other electric companies, as has become necessary in the process of privatization.

Table 7.4-2 shows the rehabilitation plans of the NPC for 1997 and 1998. The total investment for Leyte and Samar comes to 53.1 million pesos. It goes without saying that studies of the transfer price must take account of this rehabilitation price.

It can be seen that, whereas the rehabilitation in Leyte is based on rerouting, that in Samar emphasizes improvement of the lines on the existing routes.

Table 7-4-2 NPC rehabilitation plans for 1997 and 1998

Unit: pesos

	Substance of rehabilitation	Amount
Leyte		
1997	Re-routing of the 69 kV Palo-Tacloban	1,200,000
	Sub-total	1,200,000
1998	Re-routing of the 69 kV Ormoc-Baybay	1,150,000
	Re-routing of the 69 kV Palo-Abucay	3,500,000
	Sub-total	4,650,000
	Total	5,850,000
Samar		
1997	Rehab. of the 69 kV Taft-Borongan	1,520,750
	Inst. Of PCB for Calbayog-catarman	600,000
	Row expan. clearing Wright-Calbayog	1,000,000
	Row expan. clearing Calbayog-Catalman	1,000,000
	Row expan. clearing Wright-Taft	1,000,000
	Rehab. of the 69 kV Wright-Calbayog	7,000,000
	Re-routing a portion of Wright-Taft	251,000
	Sub-total	12,371,750
1998	Rehab. of the 69 kV Catbalogan-Calbayog	18,690,000
	Rehab. of the 69 kV Taft-Borongan	16,150,000
	Sub-total	34,840,000
	Total	47,211,750

Source: Financial Department in Visayas Regional Center

3) Assets value of the 69 kV transmission lines at the time of transfer

The assets value of the subject facilities used in this study is the sum of the assets value prepared by the NPC and the price of the rehabilitation carried out in 1997 and 1998. Table 7.4-3 shows the figures as of the end of 1996 in terms of both the revalued price and the sound value.

As noted above, however, these figures do not include the value of certain transmission lines, and the actual transfer price would therefore probably be somewhat higher.

Table 7.4-3 Assets value of 69 kV transmission lines used in this study

Unit: Thousand pesos

	Revalued Price	Sound Value
A. Value of existing transmission lines as of the end of 1996	848,454	396,109
B. Cost of rehabilitation implemented in 1997 and 1998	53,062	53,062
Total	901,516	449,171

Source: The A figures are reported from Table 7.4-1, and the B figures, from Table 7.4-2.

7.5 Rehabilitation Plans of the 69 kV Transmission Lines

7.5.1 Calculation of the Cost Required for the 69 kV Transmission Lines

In the event of transfer of the 69 kV transmission lines to the ECs, which is the object of this investigation, the ECs would become responsible for O&M and rehabilitation of the lines.

As such, there is a need to make a rough calculation of the cost of these tasks in the interest of smooth management of the ECs.

The basic perspectives applied in calculation of the cost are as follows.

- O&M work is for the keeping good condition of the facilities and should be treated as routine work. For this reason, it is advisable for the ECs as well to perform it at least as efficiently as by the NPC in the past. In other words, it will be assumed for the purpose of the calculation that the performance of O&M by the NPC will be carried on by the ECs.

In addition, the Leyte and Samar areas, which are the subject areas of this investigation, are located in the typhoon belt, and maintenance costs vary significantly by the year depending on the extent of damage from typhoons (see Table 7.5-1). As such, average values for past O&M costs will be employed in the forecast for the future.

- The estimate of the requisite rehabilitation costs in the future will be based on the results of the 10-kilometer sampling survey implemented to assist valuation of 69 kV transmission line assets in the second field study.

1) Calculation of O&M costs to 2005

Table 7.5-1 shows actual figures for O&M costs over the last six years in the Leyte and Samar areas according to documentation obtained from the NPC. These figures are totals for 138 and 69 kV substations and transmission lines. The concern here, however, is the cost of implementation of O&M by ECs for 69 kV transmission lines only.

Table 7.5-1 Total O&M costs on Leyte and Samar over the last six years

Units: thousand pesos, km

	1991	1992	1993	1994	1995	1996
Leyte						
S/S and T/L O&M Cost	23,133	24,995	8,021	3,479	20,031	24,197
Samar						
S/S and T/L O&M Cost	7,784	-	13,364	13,203	14,203	18,080

Note: Figures for Leyte in 1992 include Samar O&M.
Source: Financial Department in Visayas Regional Center

The procedure for calculation of the O&M costs for 69 kV transmission lines in the event of implementation by the ECs is set forth below. The calculation results are shown in Table 7.5-2.

1) First, a separation was made between the O&M costs for substations and those for transmission lines. A proportional distribution was made based on the actual cost of O&M for substations and transmission lines in 1996. The O&M cost shares for substations and transmission lines on Leyte were 10 and 90 percent, respectively. The corresponding shares on Samar were 15 and 85 percent.

2) Next, the cost derived as described in 1) above was distributed between 138 and 69 kV transmission lines. The 138 kV transmission line distance over the last six years was put at 148.9 kilometers for Leyte and 58.5 kilometers for Samar. Finally, costs were distributed in proportion with the route length in the year in question.

Table 7.5-2 Results of calculation of O&M costs for 69 kV transmission lines on Leyte and Samar over the last six years

Unit: thousand pesos, km

	1991	1992	1993	1994	1995	1996
Leyte						
69kV T/L O&M Cost	16,106	8,675	5,026	2,180	12,522	16,429
69kV transmission line distance	318.8	318.8	318.8	318.8	318.8	451.2
69kV T/L O&M cost per km	50.52	27.21	15.77	6.84	39.28	36.41
Samar						
69kV T/L O&M Cost	5,643	8,559	9,868	9,750	10,843	13,802
69kV transmission line distance	290.2	290.2	323.2	395.2	438.0	438.0
69kV T/L O&M cost per km	19.45	29.49	30.53	24.67	24.76	31.51

Note 1: Figures for 1992 are proportional distributions based on the 138 and 69 kV transmission line distance.

Note 2: 69kV T/L O&M cost isn't included Isabel-power barge transmission line.

According to this calculation, the O&M cost per kilometer per year for 69 kV transmission lines over the last six years averaged 29,340 pesos on Leyte and 26,740 pesos on Samar. It was assumed that this cost level would be maintained after the transfer.

Personnel cost accounts for about 50 percent of the total O&M cost. In Table 7.5-2, the O&M cost isn't included the personnel cost.

Table 7.5-3 shows the post-transfer O&M cost on Leyte and Samar. The calculation assumed that there would be no change in the plans for additional installation of transmission lines (the installed distance as of the end of 1996 being 436.8 kilometers on Leyte and 455.2 kilometers on Samar).

Table 7.5-3 Forecast of O&M cost for 69 kV transmission lines on Leyte and Samar to 2005

Unit: thousand pesos

	1997	1998	1999	2000	2001	2002	2003	2004	2005
Leyte									
O&M Cost	6,619	6,619	6,619	6,619	6,619	6,619	6,619	6,619	6,619
Samar									
O&M Cost	5,856	5,856	5,856	5,856	5,856	5,856	5,856	5,856	5,856

Note: The O&M cost isn't included the personnel cost.
O&M cost on Leyte is calculated by 29.34 thousand pesos per km *451.2 km * 50 percent
O&M cost on Samar is calculated by 26.74 thousand pesos per km *438.0 km * 50 percent

2) Estimate of rehabilitation cost to 2005

Interviews with the NPC found that almost no rehabilitation work is performed for 69 kV transmission lines except in cases of toppling due to typhoons, etc. As a result, the current condition of transmission lines on Leyte and Samar is not very good. This was also revealed by the sampling survey of transmission line poles at 105 locations (as described in Chapter 9). Table 7.5-4 shows a classification of the number of poles by class of condition, based on the findings of this survey.

Table 7.5-4 Results of the sampling survey of Palo-Dorelco-Tacloban T/L and Wright-Calbayog T/L

Unit: number of poles

	Class A	Class B	Class C	Class D	Total	Number of locations
Palo-Dorelco-Tacloban						
Single pole	28	12	9	1	50	50
As percentage of the total	56%	24%	18%	2%	100%	
Wright-Calbayog						
Single pole	5	17	12	0	34	34
Double pole	2	12	3	1	18	9
Triple pole	5	21	8	2	36	12
Total	12	50	23	3	88	55
As percentage of the total	13.6%	56.8%	26.1%	3.4%	100%	

Note: The classification is based on the findings of this survey.

Class A contains poles in good condition, with a residual value of from 50 to 70 percent as high as when totally sound (at the time of installation). Class B contains poles in fair condition allowing use without repair. Class B poles have a residual value in the range of 30 - 45 percent. Class C contains poles in inferior condition. Such poles require repair and have a residual value in the range of 10 - 25 percent. Class D contains poles that are rotten or on point of toppling, and that cannot stand up to use. Class D poles have a residual value of 0 - 5 percent. The Class C and D poles require immediate rehabilitation.

Similarly, the Class A and B poles will require rehabilitation in the future along with the natural process of aging. Ordinarily, wooden poles have a service life of from 25 to 30 years. Deterioration therefore proceeds at a rate averaging 3.3 percent annually. If so, rehabilitation plans for the future should be prepared with an awareness of the need for rehabilitation of Class A poles beginning 12 - 18 years in the future and of Class B poles beginning 6 - 10 years in the future.

The procedure for preparation of rehabilitation plans is as follows.

1) Separation between Leyte and Samar

A separation is made because the condition of facilities on Samar is worse than on Leyte.

2) The NPC has rehabilitation plans for 1997 and 1998, and the transmission lines that are to be rehabilitated according to these plans are excluded from the preparation of plans to 2006 by this investigative group. Similarly, It is also assumed that the transfer would be made after completion of Stage II of the Ormoc-Bohol interconnection project, which is scheduled for 2001.

3) The transmission lines studied in the sampling survey (i.e., Palo-Dorelco-Tacloban and Wright-Calbayog) are thought to have been well maintained relative to other lines due to their proximity to 138 kV substations and to the comparatively level terrain. However, it would not be appropriate to judge the status of transmission lines throughout Leyte and Samar solely on the basis of this sampling survey. However, it was assumed that there was a need for rehabilitation on at least the same level as for these two lines throughout Leyte and Samar.

4) Rehabilitation will be carried out for Class D in 2001. For Class C, the rehabilitation will be distributed evenly over the years leading up to 2004, the year before it becomes necessary to commence rehabilitation of Class B poles eight years from now. For Class B, the rehabilitation will be distributed evenly over the years leading up to 2010, the year before it becomes necessary to commence rehabilitation of Class A poles 14 years from now.

Table 7.5-5 shows the yearly schedule for rehabilitation of transmission lines in each class on Leyte and Samar.

The calculation of the cost required for rehabilitation employed the unit cost of rehabilitation in the assets valuation method used in Chapter 9. It should be noted that the calculation was based on the unit cost per location, with distribution corresponding with the number of poles. This is because, whereas single poles are the rule on Leyte, there are double and triple poles on Samar. Besides the cost of poles, parts, conductors overhead ground wires, and other materials, this unit rehabilitation cost includes personnel expenses and other overhead expenses. The unit rehabilitation cost is shown in Table 7.5-6.

Table 7.5-5 Rehabilitation schedule for lines on Leyte and Samar by class

Unit: number of poles

	Total	2001	2002	2003	2004	2005	2006
Leyte							
Class B	656					94	94
Class C	492		164	164	164′		
Class D	54	54					
Samar							
Class B	1,693					212	212
Class C	778		259	259	259		
Class D	101	101					

Note: For Class B, the rehabilitation of 94 and 212 poles per year would continue up to and including 2010.

The number of pole in each class is assumed by Study Team.

Table 7.5-6 Unit rehabilitation cost in each class on Leyte and Samar

Unit: pesos

	Leyte	Samar
Standard unit cost	68,744	108,911
Class B	44,700	70,800
Class C	55,000	87,100
Class D	65,300	103,500

Note: Unit rehabilitation cost in each class is based on the findings of this survey.

As shown in Table 7.5-5, the rehabilitation would be implemented in a sequence, beginning with the lowest class. Using the unit cost as of 1997 shown in Table 7.5-6, the rehabilitation cost was calculated as shown in Table 7.5-7 for the years 2001 and following.

Table 7.5-7 Rehabilitation cost in 2001 and following years

Unit: thousand pesos

	2001	2002	2003	2004	2005	2006
Leyte	3,526	9,020	9,020	9,020	4,202	4,202
Samar	10,454	22,559	22,559	22,559	15,010	15,010

Note: Based on prices as of fiscal 1997.

7.5.2 Operating Cost in the Event of Transfer of 69 kV Transmission Lines to Leyeco V

1) Transmission lines to be transferred

There are plans for four new 69 kV substations at Leyeco V to be constructed after 1997. In light of these additions, it would be better for Leyeco V to receive all 69 kV transmission lines in its supply area at present if it is to be transferred such lines. This would have the advantage of offering a high degree of freedom in the plans for the new substations and enable full maintenance and rehabilitation of transmission lines.

Table 7.5-8 shows the distance, revaluation price, and sound value of the subject transmission lines. The 12.1 km section between Izabel and the power barge is not included here because it is a line from an NPC power source to an NPC substation.

Table 7.5-8 Transmission lines in the Leyeco V service area

Unit: kms, poles, and thousand pesos

Lines to be transferred	Distance	Number of poles	Revaluation price	Sound Value
Tongonan – Limon	14.7	112	14,557	7,766
Limon – Biliran	27.0	170	45,739	24,400
Tongonan – Ormoc	19.6	150	19,521	10,414
Border with Ormoc-Leyeco IV	30.0	255	50,848	27,116
Total	91.3	687	130,665	69,696

Note:Proportionate distribution was made of the 44.2-km Tongonan-Tunga section for Tongonan-Limon section and of the 51-km Ormoc-Baybay section for the border with Ormoc-Leyeco IV.

Source: These data is reported from data of Leyeco V in Figure 7.4-1.

2) O&M cost (not including personnel costs)

The O&M cost for 69 kV transmission lines on Leyte is estimated at 29,340 pesos per year per kilometer. This estimate includes personnel costs. Assuming that personnel costs account for 50 percent of this amount, the O&M cost excluding personnel costs would come to 14,670 pesos per year per kilometer.

Because the total distance of the lines to be transferred is 91 kilometers, the total O&M cost per year would be 1.335 million pesos.

3) Rehabilitation cost

Among the rehabilitation projects to be undertaken by the NPC in 1997 and 1998 is one related to the transmission lines to be transferred, i.e., the 1998 relocation of the Ormoc-Baybay route. Distribution in terms of the line length for the 30 km Ormoc-Leyeco IV section would yield a rehabilitation cost of 676,000 pesos.

Wooden poles have a service life of from 25 to 30 years, and deterioration can therefore be regarded as progressing at a rate of 3.3 percent per year. Assuming a definite need for rehabilitation when the remaining value is only 10 percent, rehabilitation would become necessary for Class A poles from 12 to 18 years in the future and for Class B poles from six to ten years in the future.

Table 7.5-9 Classification of rehabilitation plans in Leyeco V by pole class

Unit: number of poles

	Total	2001	2002	2003	2004	2005	2006
Class B	165					28	28
Class C	123		41	41	41		
Class D	14	14					

Note: Rehabilitation of Class B poles would extend to 2010.
The number of pole in each class is assumed by Study Team.

Table 7.5-10 shows the rehabilitation plans beginning in 2001 in Leyeco V based on the unit price figures in Table 7.5-6.

Table 7.5-10 Rehabilitation plans at Leyeco V beginning in 2001

Unit: thousand pesos

	2001	2002	2003	2004	2005	2006
Class B					1,252	1,252
Class C		2,255	2,255	2,255		
Class D	914					
Total	914	2,255	2,255	2,255	1,252	1,252

Note: Rehabilitation plans are assumed by the Study Team.

4) Number of personnel

The O&M work for 69 kV transmission lines could be performed by a crew of eight. The related administrative work could be handled by the current staff of Leyeco V.