Table of Contents

List of Figures

List of Tables

Chapter 1 Outline of the Study

1.1 Background

Initiating reforms in the Philippine power sector, Congress enacted into law the Electric Power Industry Restructuring Act (EPIRA) on June 8, 2001, which became effective on June 26 of the same year.

EPIRA paved the way for the restructuring of the Philippine electric power industry by dividing it into four distinct sectors: generation, transmission, distribution, and supply.

The law aimed to encourage competition and promote efficiency of service in the power sector by allowing the entry of new players in the generation and sales sectors. The law likewise mandates, among others:

- Breaking up and privatizing NPC;
- Strengthening market monitoring functions;
- Investment promotion; and
- Establishment of a wholesale electricity spot market (WESM).

The many changes that will take place under the restructured energy industry called for the strengthening of the institutions that will oversee these reforms. Section 37 of EPIRA, in fact, outlines 17 distinct roles the DOE would play under this new regime. Since some of these roles are new to the DOE the department needed expertise and assistance to fulfill its expanded mandate.

In response to a DOE request, the Japanese International Cooperation Agency (JICA) conducted a baseline study in September 2001. In January 2002, JICA, in cooperation with the Japan Ministry of Energy and Trade Industry (METI) task force, confirmed the necessity of a study to improve the planning and organizational capability of the DOE.

The JICA study team specifically identified four areas where the DOE needed assistance, including:

1) Assistance in preparing the power development program (PDP), including coordination with related subordinate programs;

2) Assistance in preparing the Missionary Electrification Development Plan (MEDP);
3) Assistance in evaluating / approving the Transmission Development Plan (TDP) prepared by the National Transmission Corporation (TRANSCO); and
4) Support for establishing the Energy Investment Promotion Office (EIPO).

On April 1, 2002, the Philippine government submitted an official letter of request and terms of reference (TOR) to the Japanese government for the conduct of the study. JICA sent a preliminary study mission in May 2002 and discussed the policy, scope and methodology for implementing the project. This was followed by an exchange of the Implementation Agreement and the Minutes of May 30, 2002.

JICA at the outset planned to complete the project in two years, considering the difficulty in acquiring technical knowledge on the Philippine power sector and ensuring an effective technology transfer. The DOE's submission of the current year's PEP to Congress on or before September 15 of each year, however, is an urgent issue. This concern has prompted the DOE to request JICA to revise its timetable for the conduct of the study. Thus, the duration was shortened by one year.

1.2 Objectives

This study not only clarifies the enforcement policy and materialization method of the DOE's new roles and functions mandated by EPIRA. The study also seeks to strengthen the organizational ability of the DOE. It also aims to develop the capacity of the DOE staff in the formulation of the PDP and evaluation of its subordinate plans.

PDP forms an integral part of the PEP—the government's overall energy plan which covers areas such as exploration, development, utilization, distribution, and conservation of energy resources. Under the EPIRA, the PDP "shall consider and integrate the individual or joint development plans of the transmission, generation, and distribution sectors of the electric power industry."

Furthermore, the study seeks to find ways to assist the EIPO—a new office in the DOE—in promoting private sector investments in the energy sector. Finding ways to assist EIPO is an important objective of this study, considering the existing barriers in the entry of investments into the local power sector. For one, while EPIRA mandates the privatization of the government's generation and transmission assets effectively passing on to the private sector the responsibility of supply expansion, reforms made on the power sector have lessened incentives in the private sector's participation in power project. With lesser incentives on investments in the power sector, the rate of supply expansion is likely to slowdown.

For instance, government guarantees given to private investors such as independent power producers (IPPs) have been discontinued. The government guarantee was used to entice IPPs—which were instrumental in expanding generating capacity in the 90's—to pour in investments into the country to solve the power crisis during that period.

In addition, this study does not limit contributions only to the formulation of PDP, but also focuses on the institutional capability building of DOE. Transfer of skills to the DOE staff is also an integral part of the study.

1.3 Main Activities

1.3.1 Assistance in PDP Formulation

(1) Review of the condition of the Philippine electric power sector and preparing the master schedule for PDP formulation.

To assist the DOE in meeting the deadline for the submission of the 2004 PDP to Congress, the JICA study team, after discussions with its Philippine counterparts, prepared a master schedule for the drafting of the PDP—including its subordinate plans. Under the EPIRA, the PEP is submitted to the Congress not later than September 15 of each year.

<Items reviewed >

Framework of the Electric Power Industry:

- Details and implementation status of EPIRA
- Current electric power rates in the Philippines

Investment Promotion in Electric Power Sector:

- Investment promotion system in the Philippines
- Current status of the DOE's EIPO

Demand Forecasting:

- Past demand forecasting methodology
- Basic data for demand-forecasting

Power Development Program:

- Data gathering flow for PDP
- Current condition of power generation facilities

Transmission Development Plan:

- TDP 2003

- Issues in the Philippine electric power transmission system

Rural Electrification Plan (Distribution Development Plan or DDP; and Missionary Electrification Plan or MEDP):

- MEDP 2002 and MEDP 2003
- Role of organizations involved in rural electrification
- Status of rural electrification

<Milestone>

March 15:	DDP submission to DOE
Early April:	Dissemination of NEDA Preliminary GDP forecasting
End of May:	Finalization of the power demand forecasting, together with approval of the Secretary of DOE
June – July:	Formulation of PDP by DOE, and approval of the supply expansion plan by the Secretary Formulation of TDP by TRANSCO
End of July:	The completion of TDP evaluation by DOE
August :	PDP documentation
September 15:	Submission of PEP to Congress

(2) Integration Process of PDP Subordinate Plans

In its study, the JICA team examined the over-all plan for the energy sector—PEP. In particular, the study focused on the elements in the formulation of the PDP and its subordinate plans.

Subordinate plans which are integrated into the PDP are as follows:

TDP:

- Transmission line expansion plan in conjunction with the supply expansion plan
- Island inter-connection transmission plan

DDP:

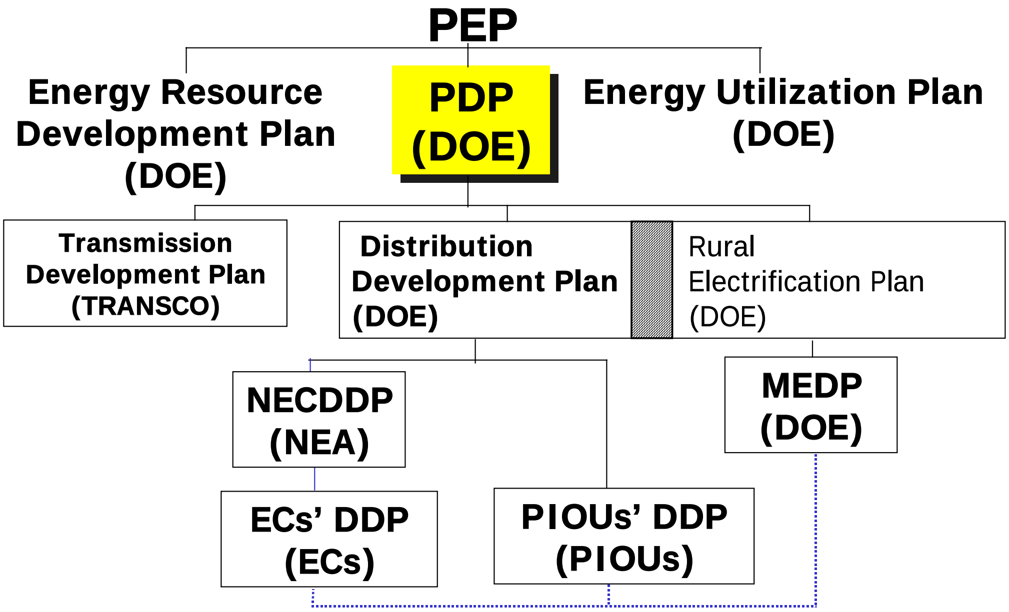
- Statistics of the total length of the distribution line and cumulative substation capacity

➢ Expansion plan of the distribution line and substations

MEDP:

➢ Historical results and targets of rural electrification

Fig. 1.1: Structure of Electric Power-related Plans



Note: The overlapping of DDP and the Rural Electrification Plan shows the electrification of unenergized areas through distribution line extension.

Note: Electrification by grid extension is being considered as a method of energizing unviable areas under DOE's new electrification programs.

Source: JICA Study team

<Rural Electrification>

In this study, the study team found the need to introduce a new concept for rural electrification. The group specifically proposed the adoption of a Rural Electrification Plan, which takes into consideration both the new rural electrification portions of the DDP and MEDP.

Rural electrification projects for unenergized areas in the Philippines are implemented utilizing either on-grid or off-grid modes. For areas considered viable, the grid extension (on-grid) method is adopted, while the installation of individual power systems is introduced in unviable areas. However, energizing unviable areas through grid extension is still strongly considered.

Several areas within the distribution utilities' (DUs) franchise areas are still without electricity given the economics involved in lighting up these barangays. These should be made part of the DDP. But EPIRA provided for the entry of a qualified third party (QTP) to undertake the energization of areas within the DUs franchise declared as remote and unviable. The energization of these areas are covered by the MEDP.

Given this, both the rural electrification portions of the DDP and MEDP must be taken into consideration when future Rural Electrification Plans are formulated.

The following table illustrates this scheme:

	Viable	Unviable
On-grid	DDP (Rehabilitation etc)	DDP
Off-grid		MEDP

Rural Electrification Plan

(3) Establishment of a data collection flow and a demand-forecasting scheme in view of the deregulation of the electric power sector

In its study, the JICA team saw the need to clarify the relationship between the actual electric power flow among the players, and the new sales transactions that will take place upon the liberalization of the industry. The group underscored the need to establish a mechanism which will allow for an efficient data collection flow, in particular the acquisition of data generated by DUs. Under a deregulated environment, data collected by DUs are necessary for demand forecasting since they are nearest to the end user in the structure of the Philippine power industry.

To establish a demand-forecasting scheme in the Philippine power sector, the study team created a multiple regression model tailored to each demand-forecasting area, taking into consideration the regional population growth rates, Gross Domestic Product (GDP), and GDP per capita rates as external parameters.

In its study, the JICA team analyzed the individual historical consumption data of the residential customer segment and other sectors.

In analyzing past demand patterns, the study team forecasted the electricity demand for the Philippines' three major island grids (Luzon, Visayas, and Mindanao); and the sub-grids within the Visayas region (Leyte-Samar, Cebu, Negros, Panay, and Bohol).

(4) Supply Expansion Plan prepared with WASP-IV and GT-MAX

In the conduct of the study, the JICA team prepared the supply expansion plan using the least cost planning method using the WASP simulation software, a widely-accepted software among many international organizations.

The JICA study team drafted a supply expansion plan for the entire Philippines, including individual supply expansion plans for the three major island grids as well as the four sub-grids within the Visayas region, taking into account the economical merit of an inter-island connection transmission line. For this analysis, the team employed the use of the GT-Max, which can chronologically analyze the optimal operation of power plants and calculate the power flow.

To examine policy issues, a sensitivity analysis of fuel prices—particularly of natural gas—was conducted to validate its impact of fuel prices on the supply expansion plan.

1.3.2 Assistance in TDP Evaluation and Approval

(1) Technical examination and evaluation on the previous TDP (TDP 2003)

With the use of the power flow analysis program Power Systems Simulator Engineering (PSS/E), the JICA study team carried out a technical examination of the TDP 2003 and identified the issues contained in the Plan that need further consideration, given the time constraints for TRANSCO's formulation of the TDP and for DOE's independent examination of the Plan.

Results of this technical evaluation—which the JICA team presented to TRANSCO in advance for the DOE's comments—were instrumental in increasing the efficiency of TDP 2004.

(2) Creating a framework of collaborative work between the DOE and TRANSCO.

Given the need for the DOE and TRANSCO to collaboratively decide whether they should construct a power plant on an island or expand inter-island transmission lines, the JICA study team examined the framework for collaborative work between the two agencies.

Likewise, the JICA team evaluated the extent of the need to expand inter-island transmission lines.

1.3.3 Assistance for MEDP Preparation

In the course of its study, the JICA team discussed the method of assistance for MEDP preparation. As a result, a conclusion was reached to conduct the assessment of MEDP and to build a database for MEDP preparation and project management.

(1) Framework for the Rural Electrification Plan and clarification of the MEDP workflow

The JICA team revised DOE's workflow of the electrification plan for unenergized areas to center on MEDP. This is to reflect the progress of the past rural electrification activities and the roles of the organizations involved in rural electrification.

Moreover, the study team identified the items necessary for planning, such as the establishment of databases. The study group likewise formulated an optimal electrification method with the end view of helping achieve the Philippine government's target of 100% rural electrification by 2006.

(2) Proposal of the database concept for planning and project management

The JICA study team suggested the establishment of a database in which social data, such as population; rate of electrification; route of distribution lines; and the number of houses, are stored. The establishment of such a database is envisioned to aid in monitoring the progress of the implementation of the electrification plan at the barangay level.

The study team even went to the extent of constructing a sample electronic map to further illustrate the details that need to be stored in the suggested database.

(3) Data collection format for the DDP

A data collection format was formulated to allow collection and retrieval of data from DUs. The format covers, among others, data required in demand forecasting, which are vital in understanding the current condition of the DUs.

1.3.4 Assistance to Launch the Investment Promotion Office

(1) Functions of the DOE investment promotion office

The JICA Study team studied ways on how the DOE can further boost its performance to fully carry out its functions, particularly in assisting prospective investors—a task which will be primarily carried out by the EIPO, a newly-created unit in the DOE.

Suggestions on how to improve efficiency and performance of this new function were made by the JICA team after a thorough appraisal of the EIPO's mandate.

(2) Clarification of the investment process

The JICA Study team likewise examined how the DOE could improve the investment process, from discovery of the project to its actual implementation. Currently, all power projects go through a tedious and bureaucratic process which entails numerous approvals from various government agencies. The study team suggested ways on how to rationalize this process with the end view of formulating an "investor-friendly" process.

(3) Proposed improvements in the Philippine investment promotion system based on the existing investment promotion systems in other Southeast Asian countries

The JICA Study team conducted a comparative study of the existing investment promotion system in the Philippines and those in other Southeast Asian countries. Issues on current investment promotion measures articulated by private investors in the Philippines were likewise tackled by the JICA study team during the discussions.

(4) Construction of an investment promotion office information-sharing system

JICA likewise assisted in setting up an information system on the DOE website (www.doe.gov.ph) to increase the efficiency of project data collection and management using the latest IT technology. Such system would allow the DOE to improve coordination with investors as this would allow communication with investors on a real-time basis.

1.3.5 Capability Building for DOE

This study not only aims to provide guidelines for the effective formulation of the PDP, but also to establish the institutional capability building of the DOE. Thus, attention was given to the following items in the course of the study:

(1) To establish a permanent unit which is primarily tasked to transfer and set technical knowledge;
(2) To respect the enthusiasm and autonomy of counterpart personnel;
(3) To use the workshops, technical seminars and training in Japan effectively; and
(4) To compile manuals considering sustainability after completion of the study.

1.4 Issues and Suggestions for each Study Area

1.4.1 Common Issues and Suggestions in Formulating PDP

(1) Preparation schedule

A PDP preparation schedule with identified target dates must be set, given that the schedule for the completion of the PDP is material in the accomplishment of the PEP.

Considering that the DUs are given until March 15 of each year to submit to the DOE their respective DDPs, the DOE has only six months—between March and September—to integrate these DDPs in the PDP to meet the September 15 submission deadline to Congress. In the Japanese milieu, such schedule is considered quite short.

This situation is compounded by problems in the preparation of the demand-forecasting scenario—which is a fundamental requirement in determining the TDP and the PDP. The demand-forecasting scenario hinges on the GDP growth rate forecast released by the National Economic Development Authority (NEDA), which is usually disseminated in mid-April.

Other delays in the preparation of the PDP should also be considered. In the preparation of the PDP 2004, for instance, further delays were encountered in the finalization of the demand-forecasting scenario after it was revised twice, at the instance of the Secretary of Energy. Thus, this deferred the completion of demand-forecasting until the beginning of September. Revisions on the demand forecasting consequently delayed the formulation of the PEP which was submitted to Congress by the end of September 2003.

The political environment prevailing at a particular time should also be considered in the preparation of the Plan. Therefore, there is a need to allocate ample time for the conduct of a political environment assessment.

Thus, to meet the statutory deadline for the submission of the PEP to Congress, it is essential for the DOE to make a final decision on the demand-forecast by the end of May.

(2) Staffing Assignments of DOE Personnel

Two years have passed since organizational reform in DOE was initiated as mandated by the EPIRA. EPIRA specifically mandated the restructuring of energy-related agencies, such as the DOE. As part of this, the Electric Power Industry Management Bureau (EPIMB), which is primarily tasked to formulate the PDP, was created.

While the implementation of the organizational reform in the DOE is continuing, the present number of specialists remains overwhelmingly insufficient. In particular, staff assignment for the EPIMB remains largely unfilled. The JICA team assessed that only half of the plantilla positions were filled. Such that the current EPIMB staff is overwhelmed with the volume of work that needs to be performed by the bureau.

Taking this study in particular, it bears noting that only one local counterpart was assigned for each study category, despite the JICA study team request for DOE to assign two or three people for each study category. Moreover, in the course of the study, two counterparts were transferred to other organizations with their posts in DOE declared vacant for some time.

Educating two or more persons designated in each field, placing them in charge of the same job for some years to accumulate knowledge and expertise through actual work are pre-requisites in the facilitation of skills transfer.

There is, therefore, a need to fast-track the implementation of organizational reforms not only to allow the DOE to efficiently discharge its mandate, but also to develop expertise of its various bureaus/units in their respective areas of concern.

(3) DOE as a policy-making organization

Under the current set-up, EPIMB itself conducts the demand forecasting and formulates the supply expansion plans which are the foundations of the PDP. The formulation of the PDP used to be a function of the NPC but was transferred to the DOE under EPIRA.

The EPIMB staff is overwhelmed by a huge volume of work because in addition to their main functions such as policymaking and implementation of laws, they have to conduct data analyses for demand forecasting. This is not the case in other countries. Abroad, it is rare that a policy-making organization directly performs analytical work, such as demand forecasting. Such work is usually entrusted to a specialized external organization or a consultant.

If the DOE decides to adopt such arrangement, it should oversee the external organization that will accumulate the data and expertise for the work, keep the data rotating, and continuously modify the analytical scheme.

But the JICA study team also noted that separating the analytical function is worth considering to raise the quality of DOE's work.

1.4.2 Issues and Suggestions for Power Demand Forecasting

(1) Data collection for demand forecasting

Prior to the effectivity of the law, all data required for demand forecasting could easily be collected from NPC since it monopolized the generation, transmission, and sale of electricity to DUs.

In light of EPIRA's mandate to restructure the power industry, the number of players ballooned from only one to a host of many players interacting and exchanging transactions with one another. These include, for instance, several players in the generation sub-sector (privatized NPC plants and IPPs); a transmission company (TRANSCO), DUs and large industrial users.

The increased number of players in the power sector has led to difficulties in collecting data from the various transactions involved in the sector.

Considering that the process of electric power transactions have become complex under a restructured environment, the JICA Study team formulated a process that would facilitate DOE's collection of data required for demand forecasting from ECs, DUs, and other players.

However, this process does not cover future electric power transactions which will come hand-in-hand with the introduction of the WESM. The prototype market management system will commence only in June 2004.

Thus, the DOE still needs to update the data collection process to reflect transactions in the WESM, which will be a major consideration in the formulation of the PDP 2005.

(2) Demand-forecasting model

The JICA Study team employed a multiple regression analysis model for residential demand forecasting, using population and GDP per capita data as external parameters; and single regression model for non-residential demand forecasting, using GDP data as external parameter. Due to the limited data available in the DOE and ERC, only the ten-year data of DUs' supply and demand figures were considered. A longer regression analysis period is needed for accurate forecasting in the future.

In addition, the fact that large industry users have resorted to self-generation, and that bulk sales from NPC to large-scale customers hardly increased are among the causes in keeping the load factor unchanged. PDP should take into account the impact of self-generation among large industry users and the flat growth in the bulk sales in its demand forecasting.

In its previous formulation of the PDP, the NPC used data on population and GDP per capita as external parameters, which showed a high correlation with electricity demand. In contrast, some developed nations adopt price elasticity to demand forecasting. However, there are some experts expressing doubt on the accuracy of this particular model. Analysis of the California electricity spot market proved the low elasticity of electricity as a commodity. For example, although power costs sparked the California electricity crisis due to shortage of supply capacity, electricity demand hardly decreased.

On the other hand, other developed nations use complex forecasting models between the econometric model and the end-use model, which calculate demand by multiplying number of commodities and their unit prices.

In this regard, an end-use forecasting model must be developed to facilitate the introduction of the Demand Side Management (DSM). Unfortunately, the Philippines is way behind in terms of statistical management which is necessary for the employment of the end-use model necessary for DSM promotion. The Philippines in particular should start by clarifying the saturation levels of major electronics appliances.

To calculate the peak demand, the JICA Study team divided the peak energy consumption by the assumed load factor. And since the load factor in each grid has hardly changed in the past ten years (based on the analysis of the data obtained from TRANSCO), the load factor for every grid was assumed constant.

Beginning 2004, DOE itself will collect the necessary data for demand forecasting and calculate demand forecasting; therefore, it must explain the results to both local and foreign stakeholders. If DOE corrects the demand-forecasting model completed by the JICA Study team, it is necessary to consider the sophistication of the forecasting model.

The factors to consider would include:

- Period of the data used for regression analysis;
- Precise analysis of the market structure and introduction of an end-use model; and
- Establishment of a demand forecasting model, reflecting actual market conditions and reflecting price elasticity.

1.4.3 Issues and Suggestions on the PDP

(1) Fuel for newly developed power plants

Consistent with the Philippine national energy policy of developing indigenous energy sources, the JICA team calculated the supply expansion plan with WASP.

In particular, the team conducted a price sensitivity analysis on the use of natural gas as fuel source since natural gas is seen as an emerging indigenous energy source for the Philippines. The Philippines began producing indigenous natural gas in large quantities in 2001 from the Malampaya gas field off Palawan island, providing fuel for the Ilijan, San Lorenzo, and Santa Rita power plants, all located in Batangas.

However, the huge initial cost of gas field development has resulted in higher Malampaya gas price compared with international-standard prices.

As a result of the simulation conducted by the JICA team, about 80% of the supply expansion required in the future will be supplied by coal-fired power plants, since the development of even one natural gas combined-cycle plants is not economically feasible under existing gas prices. But due to a high awareness on environmental preservation, the construction of a coal-fired power plant in the Philippines may be very difficult; though not impossible.

However, if the price of indigenous natural gas were to be lowered by 80% of the current price, calculation using WASP indicates that the development of natural gas combined-cycle power plants is economically feasible and could account for 90% of the supply expansion required. Therefore, dependence on coal-fired power plants will be reduced.

The JICA study team's calculations reveal that a reduction in the price of indigenous natural gas is necessary if the government intends to increase the country's energy self-sufficiency rate through the use of indigenous energy sources and improve the quality of environment.

However, assuming a lower natural gas price is seen to be a delicate problem.

(2) Allocation of indicative plants

To encourage private investors to infuse capital into the country's power sector, the DOE needs to disclose the country's power development scenario and publish information required for determining plant locations. (DOE can show the amount of supply expansion required for each region by combining the results of both WASP-IV and GT-Max.)

In particular, the DOE should be able to identify the desired scale, fuel type and project developer—if the project is an extension project—to aid potential investors in pinpointing projects where they could participate. Since such information greatly influences a project, information on project development must be carefully aligned between the DOE and TRANSCO.

Considering the supply expansion required, the JICA Study team presented to TRANSCO some prospective projects, though not committed, as indicative plants. The team asked TRANSCO to prepare the TDP. However, for TRANSCO to formulate TDP, the location of indicative plants and substations to which the plant will be connected must be identified to some extent.

Due to the need to build new generating capacity in the coming years to meet the increasing power demand, investors will be keeping an eye on the Philippine electric power sector as an investment opportunity. Investors would particularly be closely monitoring the power sector reforms being implemented by the government.

(3) Power Development Plan for individual areas

The Power Development Program contains plans for the country's three major regions, namely: Luzon; Visayas; and Mindanao.

In the middle of the JICA study, the government—through a Presidential Order—created a task force led by DOE. The task force is mandated to resolve issues of a looming power shortage in the Panay island (in the Visayas).

However, considering previous data, the imminent power shortage in Panay island should have been predicted several years before. Since NPC was restructured by EPIRA, a critical situation was left unsolved. As far as this issue is concerned, DOE was late in preparing countermeasures.

More than the rapid change in the demand growth, the cause of electric power shortage in Panay can be traced to the delay in construction of a new power plant. The proposed plant was envisioned to compensate for the decline in power generation capacity resulting from the decommissioning of an outdated diesel power plant. Although NPC has tried to prolong the remaining life of the diesel plant, the retirement of the plant was inevitable.

To counterbalance the shortage, NPC tried to source electricity from the neighboring Negros Island via an interconnection cable, but capacity restrictions of the interconnection line did not allow complete compensation. The increasing power demand in Negros only exacerbates the situation. Forecasted demand growth in Negros indicates a power crisis in the island in a few years, if the situation remains unaddressed. Therefore, its capacity to export power in quantities that would be enough to compensate the shortage in Panay is a cause for concern.

To prevent this electricity crunch on individual islands, it is necessary that the DOE formulate a supply expansion plan for the entire Visayas region and observe the balance of supply and demand on each island grid.

DOE needs to draw up a supply expansion plan for the Visayas region, performing an economical comparison of when electric power is supplied from adjacent areas through the interconnection line against when a power plant is built for each island.

Such a comparison will aid the DOE in determining its policy towards addressing the current as well as future power imbalances particularly in the Visayas. This data would prove useful in the determination whether the DOE should adopt a policy that is geared towards the improvement of interconnection lines, or a policy that is geared towards building more generation facilities for each island.

1.4.4 Issues and Suggestions for the Transmission Development Plan

(1) Necessity for an island interconnection line

In the Philippines, two or more island interconnection lines are planned as a transmission line expansion project. Currently, three interconnection lines, with financial support of the Japan Bank for International Cooperation (JBIC), are already in the implementation stage. Some projects, such as the Leyte-Mindanao line, are planned in accordance with the increase in electricity demand.

The JICA Study team reviewed TDP2003 prepared by TRANSCO, checking the validity of the system planning. Corollary to this, the JICA study team found it necessary to review the TRANSCO draft. In its review of the TRANSCO draft, the JICA team found an insufficient examination of the construction schedule and lack of contents.

For this reason, it was suggested that when the DOE examines the necessity for an interconnection line, the following items should be considered:

- Economical efficiency as a measure of demand increase (comparison with power plant construction);
- Improvement in electric supply reliability;
- Impact on transmission tariffs; and
- Political commitment.

The DOE, in close coordination with TRANSCO, likewise needs to examine the necessity for an interconnection line from a technical, economical, and political viewpoint for the above-mentioned items.

(2) Organization and schedule for TDP evaluation

TRANSCO cannot start TDP preparation unless DOE finalizes demand forecasting. Furthermore, unless DOE provides TRANSCO with the supply expansion plan—the downstream procedure of demand forecasting—TRANSCO cannot determine where transmission expansion is needed.

Given that NEDA's announcement of preliminary GDP growth forecasting in April is the starting point, even when the submission of PDP is met, TRANSCO is only left with three weeks to formulate the TDP. TRANSCO will be unable to correspondingly modify the draft TDP in such a short period, especially if there is drastic change in the demand forecast.

Even if a tight schedule is fixed and TRANSCO and DOE are working sequentially, the September 15 deadline for the submission of the PEP to Congress cannot be met.

Therefore, DOE should inform TRANSCO at an early stage of both the policy of DOE and the highlights of the supply expansion plan. DOE should also undertake its best effort to finalize the demand forecasting and supply expansion plan quickly to eliminate the process of sending the draft back and forth as much as possible.

However, it is important that TRANSCO, which is in charge of planning, and DOE, which is the examiner, remain independent of each other. They share the idea of seeking a stable, inexpensive electricity supply, and this collaboration should bring good results.

1.4.5 Issues and Suggestions for the Rural Electrification Plan

(1) Building an appropriate database

The current electrification target is 100% electrification, to be achieved at the barangay level by 2006, and 90% electrification at end-user level to be achieved by 2017.

It is recommended that electrification planning should have long-term vision and clear targets on each step, considering that after electrification in the barangay level is completed, electrification proceeds from the barangay level to the *sitio* level and further down to the end-user level.

Likewise, the MEDP needs to follow a long-term vision. Thus, a practical action plan should be included in the Plan. As it is, the MEDP—which is revised on a yearly basis—merely outlines a five-year plan.

Building an appropriate database is essential for target-setting and planning of which areas should urgently be prioritized. Without an appropriate database, planning and project management cannot be performed efficiently.

The study team prepared a Geographic International System (GIS) map for rural electrification project management and will relinquish the same to the DOE. A selection procedure of the electrification method was likewise formulated by the JICA team, which will also be transferred to the DOE. For this purpose, the JICA team formulated a simple comparison method.

The study team proposes that DOE establish the necessary database that would cover the following items:

- Relation between electrification through grid extension and introduction of individual system;
- Social baseline data such as number of sitios, etc.;
- Economical efficiency comparison in the SPUG areas between connecting to the TRANSCO system and keeping the current grid isolated; and
- Current situation of the installed renewable energy system, etc.

(2) Establish core organizations for rural electrification promotion

To facilitate concrete rural electrification planning and implementation, core organizations headed by national government needs to take the initiative to solicit the cooperation of institutions such as local governments and the barangay.

This is so since local government units are more familiar with the local community, and support from these institutions is useful in establishing a management scheme, including tariff setting and facility maintenance for the electrification of each village.

The cooperation of these organizations is likewise necessary in the maintenance of the power generation equipment introduced.

With the cooperation of the local government units and the barangays, the DOE would likewise be able to carry out an efficient monitoring of the rate of electrification both on the barangay and household levels.

To achieve this, a reporting system from the bottom, like barangays and DUs, to the top, like DOE and NEA, should be built so that DOE can reflect the status of DOE's long-term rural electrification plans.

(3) Promote technology development

Renewable energy development and utilization is the thrust of the Philippine energy policy. However, the initial cost of renewable energy development is relatively high due to the high cost of equipment. And since renewable energy systems depend highly on factors such as weather conditions, these systems are considered less reliable compared to other generating systems. Thus, it is very important for DOE to join actual system management in collecting a variety of data on system operation, and to seek cost reduction methods with the private sector.

In addition, technical education is essential in developing skills and for technology transfer. In this respect, establishing technical training centers should be made part of the DOE's human resource development program.

Also, proper maintenance of renewable energy systems to keep long-term sustainability is required.

1.4.6 Issues and Suggestions for Investment Promotion

(1) The Role of DOE's EIPO

Since the Board of Investments (BOI) plays the lead role in promoting investments in the Philippines, the role of the DOE investment promotion office is limited to the following:

- Providing an information service to both investors and project developers, and promoting project formation between these parties; and
- Being the primary contact point of an investor and to guide the investor through the investment procedure.

Considering the fact that EIPO does not have enough influence over other government agencies, and it does not have the required staff to perform the unit's envisioned role, the realization of the vision for the EIPO to serve as a one-stop shop service center in investment in the energy sector seems quite difficult.

How to concretize DOE's ideal vision is an issue for EIPO.

Therefore, the DOE needs to advertise the role of EIPO as a coordinator for investment promotion to related agencies (BOI and NEDA, among others), and have them recognize EIPO.

To create its own niche, EIPO should concentrate on providing information required by prospective investors, such as investor trends, status of project development, and the seriousness of power shortage in a specific area, among others.

To be able to do this, EIPO needs to have an information distribution system, which is essential in project formation. The JICA study team formulated an information distribution system for EIPO, which was officially launched by the DOE in November 2003. Chapter 7 outlines this system.

Without an effective information distribution system, information on investors and potential projects cannot function as a database and, thus, will serve very limited use as an investor's guide.

(2) The investment promotion system of the Philippines

The following problems were pointed out as a result of conducting a survey of 30 potential investors about the investment climate in the Philippines.

- Absence of government guarantees offered for electricity off-take, thus, exposing the private investor to higher risks;
- Unavailability of data required for investment evaluation;
- Intricate investment procedure;
- Lack of an institutionalized clear-cut and systematic approval process on the local government level; and
- Inadequate tax incentives.

Moreover, when compared with the many systems for investment promotion in countries in Southeast Asia (Thailand, Indonesia, Vietnam), the Philippines lags behind Vietnam in terms of the duty-free period of corporate income tax and the corporate income tax rate.

It, however, bears noting that the Philippines is more advanced than Indonesia on such terms.

Investors' proposals are summarized as tax cuts and an efficient investment procedure. Since the Department of Finance (DOF) is averse to reducing its tax take, the DOE should propose the revision of the local governments' unpredictable, complicated, and long approval processes for permits.

Chapter 2 Policy Framework for the Electric Power Sector

2.1 Electric Power Price in the Philippines

As of 2001, the retail price of electricity in the Philippines is one of the highest among Asian countries, second only to Japan.

The retail sales prices (2001 fiscal year) of Asian countries are shown in Table 2.1.

Table 2.1: Comparison of electricity retail sales price (2001 fiscal year) US cent/kWh

	Philippines	Japan	Indonesia	Vietnam	Thailand	Malaysia	China	South Korea
Electric power price	10.9	13.3	3.2	4.81	5.88	6.05	4.77	5.69
Electric power company	MERALCO	average of whole utilities	PLN	EVN	MEA	TNB	National Electric Power Corp.	KEPCO

Source: Japan Electric Power Information Center

This was not the case until the late 80s. Prior to 1990, the retail sales price of electricity in the Philippines was relatively low.

However, the years from the late 1980s to 1993 when the country was faced with severe power supply crisis saw a sharp increase in power rates. This increase stemmed from measures undertaken by the government to solve the power crisis during this period.

Due to the urgency of the need to add generation capacity at that time, peak-load generating facilities, which are mostly diesel-fired plants, were constructed. These plants—which are more costly for having a shorter construction period compared to base-load plants' construction period of three to four years—were the immediate solution to arrest the shortage in supply.

Other perks such as tax relief and government guarantee on the purchased power agreement were offered along with other non-fiscal incentives to entice IPPs to participate in the resuscitation of the country's power sector.

While these measures effectively solved the power crisis, these backed a sharp increase in the country's power rates given the high cost of electricity produced by the IPPs.

Table 2.2: Transition of average wholesale electric power price of NPC (Peso/kWh)

Area	1990	1995	1999	2000	2001
Luzon	1.20	1.85	2.84	3.34	3.01
Visayas	1.24	1.93	2.58	3.23	3.08
Mindanao	0.70	1.28	1.67	1.93	2.02
National average	1.13	1.77	3.65	3.12	2.90

Source: 2001 NPC Annual Report

It, however, bears noting that the retail sales price of electricity for commercial and industrial consumers in the Philippines are at parity with the electricity sales price for residential customers, as shown in Table 2.2. In the Luzon area, owing to the Special Program to Expand Electricity Demand, or SPEED, which aims to reduce the tariff for power-intensive customers, the electricity sales price for bulk users were reduced by P0.80.

Table 2.3: Average Retail Price of MERALCO and TEPCO (P/kWh)

	Residential	Commercial	Industrial
MERALCO	4.87	4.88	4.33
Tokyo Electric Power Co.	9.62	6.43	5.56

Notes: Computation period January - December 2001 and 1 peso = 2.3 yen 1 US$ = 52.83 peso

Adapted 'high voltage electric power A' for the commerce sector and 'high voltage electric power B' for industry

Source: MERALCO Annual Report, "International comparison of electricity bills " June 2002, Institute of Energy Economics, Japan

2.2 The Status of the Implementation of the EPIRA

The Philippine Congress enacted EPIRA in June 2001. EPIRA sought, among others, the reduction of the electricity retail price; the reduction of NPC's huge debt, which swelled to approximately P800 million, broken down into 300 million peso long-term debts and 500 million lease obligations for BOT contracts in 2001; the unbundling of the vertically integrated functions of NPC; the establishment of a electric power wholesale market; and the sale of NPC's assets.

The policy objectives of the EPIRA, among others, are 1) to ensure transparent and reasonable prices of electricity in a regime of free and fair competitive market; and 2) the transparent and orderly privatization of assets and liabilities of NPC. Thus, the generation, transmission and distribution functions of NPC were unbundled.

More than two years since EPIRA took effect, some of the implementation of certain reforms mandated by the law have been delayed and are still in the planning stages.

For instance, the privatization of TRANSCO, the establishment of WESM and the sale of at least 70% of NPC's generating assets in Luzon and Visayas—all of which are pre-conditions for the initial implementation of the open-access in the retail market—are behind schedule. Given this track record, it will take time to realize the objectives of EPIRA.

2.2.1 Progress of NPC privatization

Alongside the transfer of NPC's assets and liabilities to Power Sector Assets and Liabilities and Management Corporation (PSALM), EPIRA likewise mandated the privatization of the government's generation and transmission facilities which are presently being managed by NPC and TRANSCO, respectively.

In line with the privatization of NPC, President Gloria Macapagal-Arroyo approved on October 4, 2002 the privatization plan for the generation and transmission assets of NPC prepared by PSALM.

The President's move came in the wake of the approval of the NPC privatization plan by the Joint Congressional Power Commission (JCPC), with its Resolution No. 2002-1 (March 13, 2002) and JCPC Resolution No. 2002-2 (August 29, 2002).

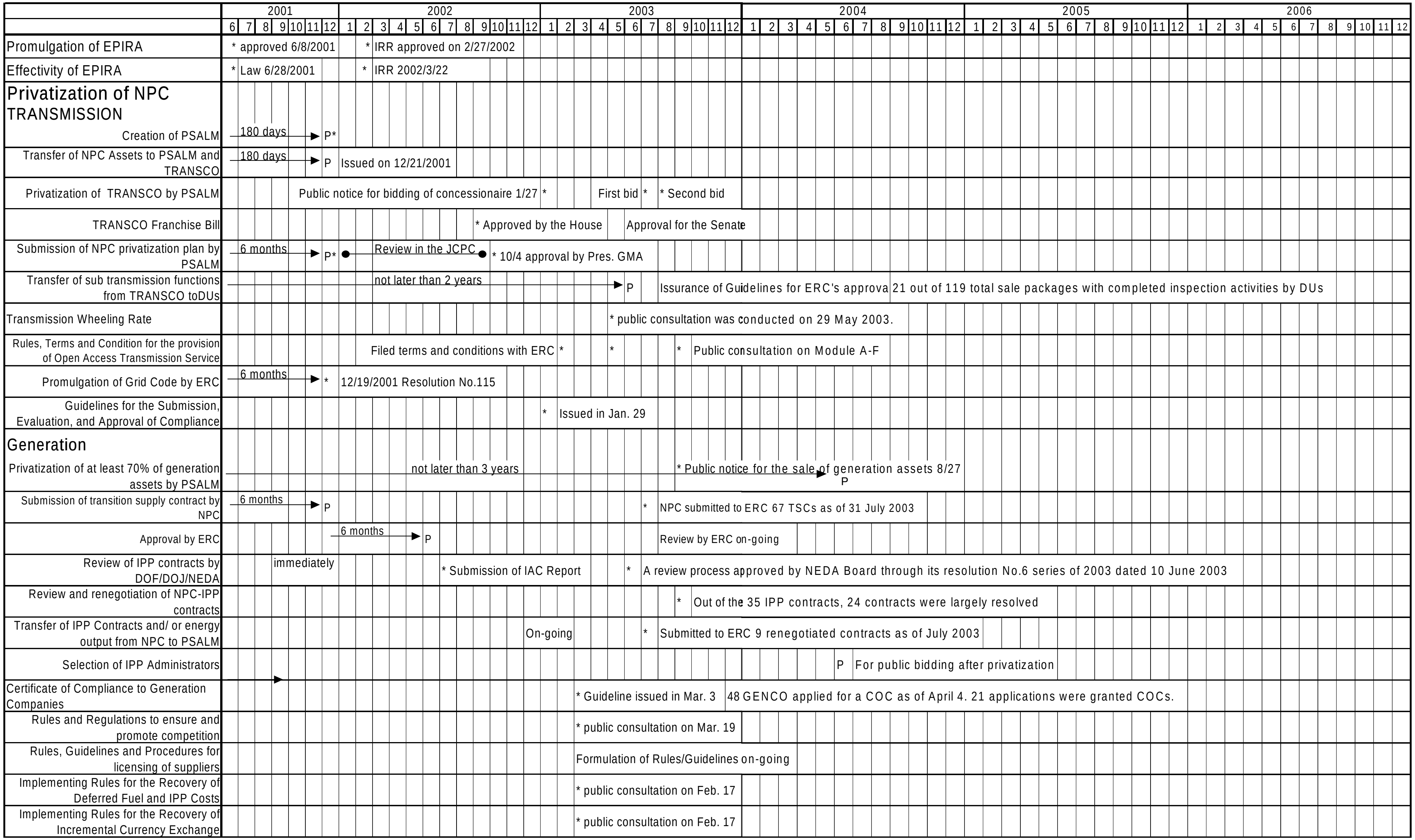
Originally, the NPC privatization plan was supposed to follow three steps: (1) Congress' approval on the TRANSCO franchise bill; (2) transfer operational responsibility of TRANSCO to the concessionaire; and (3) sale of power generation assets.

The first invitation for bidding is expected to commence in December for the sale of Navotas Power Plant.

On the other hand, President Arroyo certified the necessity for the passage of the TRANSCO franchise bill by Congress to facilitate the privatization of transmission facilities. However, since the prospect of the law's passage through Senate was unclear to date, PSALM launched the plan that facilitates the initial process of TRANSCO privatization pending the franchise bill's passage. PSALM officially opened TRANSCO's sale when it published notices in local and international newspapers on January 27th, 2003.

However, as of July 2003, the bidding for TRANSCO was declared a failure. Likewise, the second bidding in August 2003 was declared a failure, further pushing back the implementation of TRANSCO's privatization. The planned schedule and track record are shown in the following pages.

Fig. 2.1: Progress situation of Electric Power Industry Reform Act

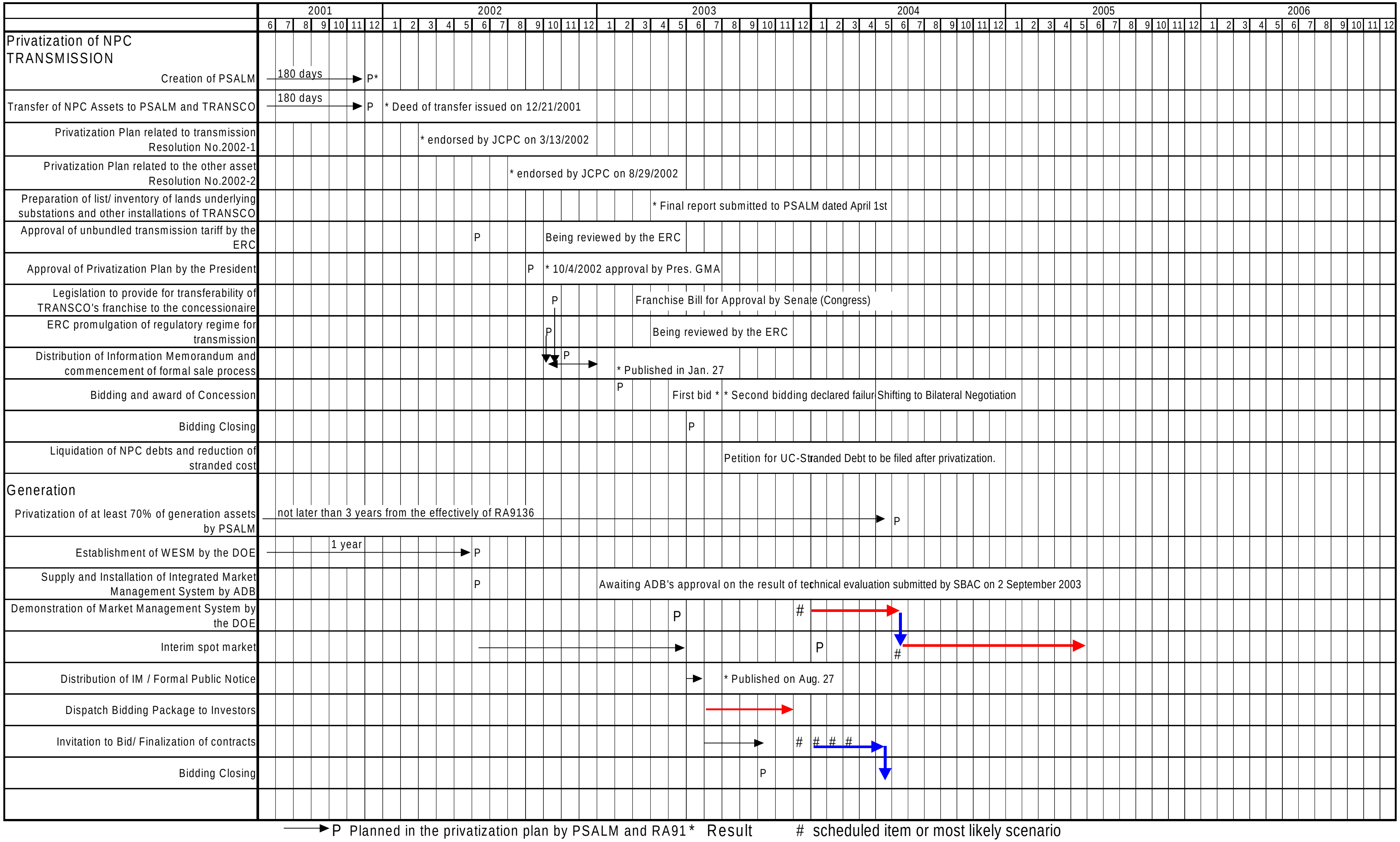


Activity	Timeline
WESM	
Establishment of WESM by the DOE	1 year → P; Demonstration of WESM P; P Trial Commercial Operation
Supply and Installation of Integrated Market Management System by ADB	P; * Loan approved on 12/19/2002
Procurement and Installation of the Market Management System (MMS)	Approval of bid document *; P Award of contract to the winning bidder
Finalization of the Market Fees structure	P Filing of market fees with the ERC
Constitution of the AGMO, or Philippine Electric Market Operator (PEMC) by the	1 year → P On-going activity; * 9/4/2003 TWG approved the Articles of Incorporation
Formation of the Independent Market Operator (IMO)	1 year → P * Selected site of MO; → P
AGMO's function transfer to the IMO	1 year → P
Promulgation of WESM Rules by the DOE	1 year → P* issuance on 6/28/2002
Promulgation of Competition Rule by ERC	1 year → P Formulation of Rules on-going
Promulgation/ Approval of Competition Rules, Competition Guildlines and Complaint Procedures Rules	1 year → P; The ERC's position paper was endorsed to DOJ on 18 August 2003.
Creation of technical sub groups to assist the WESM TWG	*; * DOE Department Circular issued on 22 July 2002
Submission of the Price Determination Methodology (PDM) to ERC	* 6/26/2003 PDM endorsed by WESM-TWG for submission to ERC
Retail Competition and Open Access	
Open access	not later than 3 years → P
Ed-users with $\geq$1MW allowed by ERC	1 year →
End-users with $\geq$750kW allowed by ERC	2years (until 2007) →
Open access in EC	not earlier than 5 years → P

Activity	Schedule / Result
Distribution	
Filing by DU's of the recovery of stranded contract cost with ERC	1 year → P
ERC's determination on recovery of stranded cost	3 months → P
Promulgation of Distribution Code by ERC	6 months → * 12/19/2002 Resolution No.115
Guidelines for the Submission, Evaluation, and Approval of Compliance	* Issued in Jan. 29
Selling the common share of stocks (not less than 15%)	not later than 5 years → P
Universal Charge	
Filing of petition	P on or before March,15; P on or before March,15; P on or before March,15
Determination by ERC	1 year → P
Calculation of the amount of Stranded Debts and Stranded Contracts Costs	Petition to ERC deferred at the request of ERC; Petition for UC-SD will be filed after the privatization.
Missionary Electrification component	Petition on 12/20 *; * Provisional approval 1/2/2003; * Final approval on UC-ME
Environmental charge	* ERC made decision on the petition for 20; * NPC filed its petition on 2 April. First hearing conducted by ERC on 29 September 2003.
Initial implementation of the cross subsidy removal scheme	→
Removal of cross subsidy	not exceeding 3 years → P
Unbundling of Rate and Function	
Filing of unbundling rate by Dus and NPC	6 months → * NPC; * as of 9/22/02 all DUs filed with ERC
Approval of Unbundled Rate Application of DUs by ERC	6 months →; * 4 DUs; * 36 Applications out of 138 DUs approved
Approval of Unbundled Rate Application of NPC/NPC-SPUG by ERC	* NPC; * NPC; * NPC-SPUG; * Provisional approval issued on 29 September 2003
Implementing Guidelines on the unbundled rates	6 months → * TRANSCO Billing manual for approval by management committee
Approval of unbundled Transmission and Distribution Wheeling Charge byERC	1 year → P
Restructuring Program for ECs	
Issuance of restructuring program for ECs	* 8/28 issuance of Executive order No.119
Assumption of EC's debt by PSALM	1 year → P
Condonation of ECs Debts	3 years → P
Reorganization Plan for NEA	thin 30 Calendar days from effectively of E.O.119 → * 10/14/2002
NEA Action Plan for the assumption of rural electrification loan	ithin 30 Calendar days from effectivity of E.O.119 → * 10/14/2002
Guidelines for the implementation of reduction in rate of the ECs due to the condonation of debts	* Issued on Oct. 21; 113 ECs were issued provisional approval for loan condonation
Guidelines for the submission of EC Performance Improvement Program (PIP)	* Issued on Oct. 8; NEA recieved 116 PIPs.

→ P Planned in the privatization plan by PSALM and RA9136 * Result

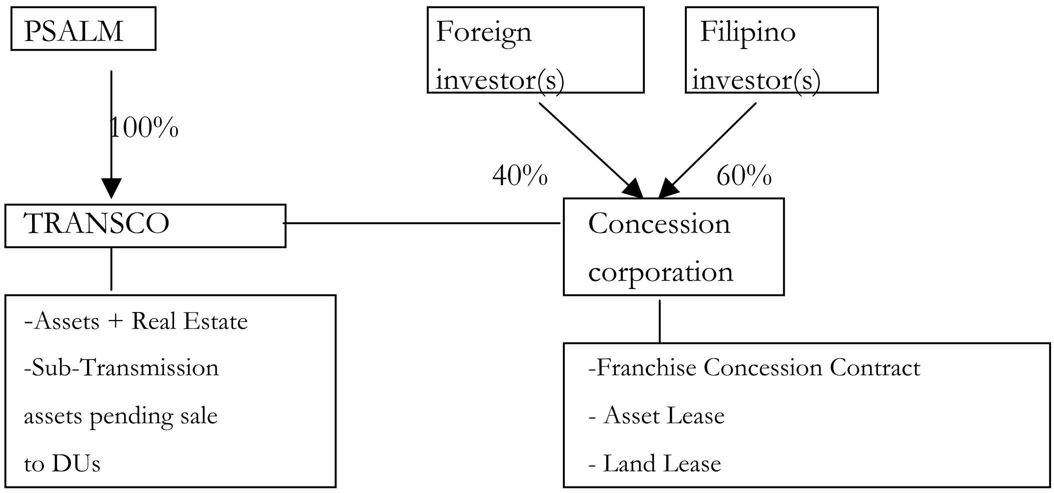
Fig. 2.2: Progress situation of NPC privatization



Since only one company expressed interest to bid for TRANSCO in the two biddings scheduled in July and August 2003, the biddings were declared a failure.

The terms of reference called for the Concession Contract to be an exclusive contract between TRANSCO and the bidder. In addition, the concessionaire will rent the assets of TRANSCO and pay a rental fee to the government. The investment scheme for TRANSCO is shown in Figure 2.3.

Fig. 2.3: TRANSCO privatization scheme



Sources: Privatization Plan by PSALM

Following the failure of TRANSCO bidding, in early September 2003, PSALM went ahead with its plan to distribute the preliminary Information Memorandum (IM) to the companies and investors that have submitted their expression of interest, changing the original process to sell generation assets only after the selection of the TRANSCO concessionaire.

As of November 2003, 37 parties submitted expression of interest and 34 acquired the preliminary IM.

Judging from the track record of the TRANSCO bidding process, completing the first bidding for generation assets would take about six months.

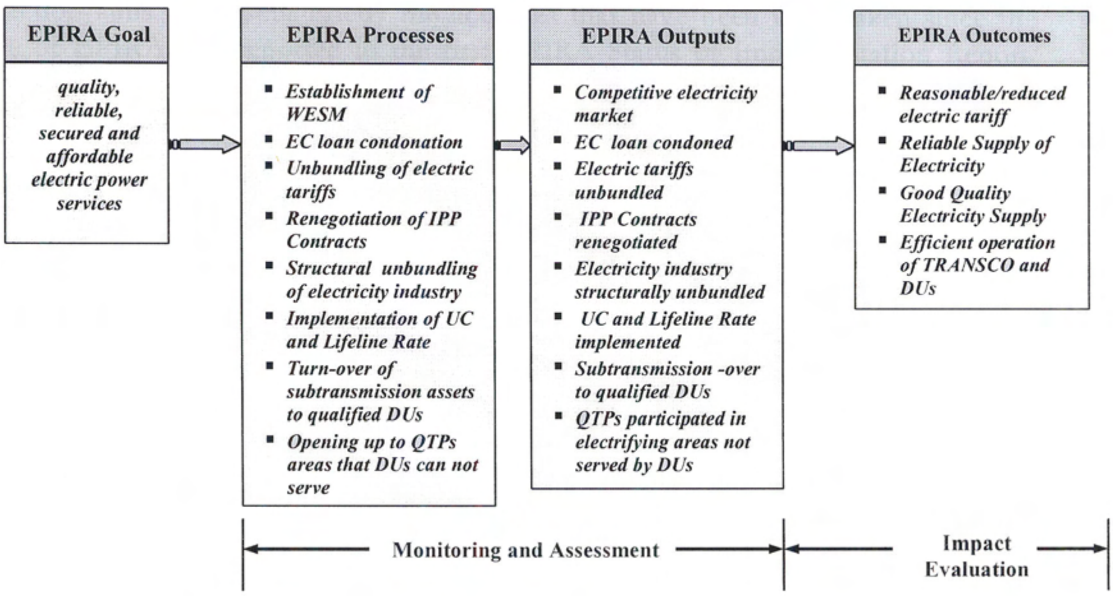
2.2.2 Objectives of EPIRA

Eleven policy objectives are described in EPIRA. They can be summarized as follows:

1) Stable supply of reasonably-priced electricity;
2) Ensure and accelerate total electrification in the country;
3) Introduction of market mechanism by establishing WESM;
4) Privatization and debt transfer of NPC; and
5) Establishment of an independent regulatory body.

The means and outputs of these objectives are illustrated, as follows:

Fig. 2.4: Conceptual picture of EPIRA Implementation



Source: DOE

However, the connection between means and output cannot materialize until certain assumptions are met. Considering the effect of tariff reduction on the industry's stakeholders—the single most important target in EPIRA—a great deal of work needs to be undertaken to realize the objectives of EPIRA.

Table 2.4: Measures to maintain assumptions under which EPIRA becomes effective

Effect	Means	Assumption	Phenomenon that breaks down the assumption	Measures to maintain the assumption
Reduction in electricity tariff	Introduction of WESM	Pricing mechanism of microeconomics works.	- Market participants manipulate the price. -Congestion of power lines	-Develop a concrete market-monitoring method -Public sector participation in transmission line construction.
		Bilateral contract fees decrease, linking to WESM.	-The price in WESM does not fall. -DUs prefer a long-term contract.	-Operate WESM as designed. -Strengthen the tariff review of bilateral contracts.
		Benefits of tariff reduction through WESM trickles down to consumers.	-Tariff reduction is absorbed by DUs. -Dealing in WESM is too small to have an impact on electricity rates.	-Strengthen the review of petitions for rate unbundling. -Identify the optimal balance between WESM and bilateral contract.
		Power Purchase Adjustment does not go up.	- The currency exchange rate and fuel cost change. (weak Peso, high fuel cost)	-The Power Plant Operator should absorb the risk.
	Condonation of EC debt	EC maintains the income-and-outgoing balance without any interest burden.	-ECs continue to incur losses despite debt condonation. -DUs unable to raise electricity tariff.	-Reduce the operating expense of EC.
	Phase-out of cross subsidy in DUs	Fairness for customers is maintained and benefits redound to ordinary consumers.	-The upheaval relief measure by UC does not function. - Tariffs in residential sectors will rise. -Large customers drop out from DUs.	-Lessen the impact on electric power price in the residential sector. -Prevent large customers from dropping out.

2.2.3 Wholesale Electricity Spot Market (WESM)

(1) Schedule of WESM establishment

Under EPIRA, DOE must to establish WESM within one year after the law's effectivity. As earlier contemplated, commercial operation would be followed by a one-year trial operation.

However, the cancellation of a US $ 7 million loan from the World Bank consequently resulted in the cancellation of the establishment of an interim WESM, thus, delaying WESM's introduction.

Releases of the US $ 600 million Power Sector Loan from the ADB and JBIC as well as the third tranche amounting to US $ 200 million—which were hinged on the success of the interim WESM introduction—were delayed.

Thus, delays in the establishment of the interim WESM not only delayed the commencement of the actual WESM operations, but likewise postponed the release of funds needed to finance other power sector reform projects.

DOE has scheduled the commencement of a demonstration market for December 2003 and a trial operation of the market prototype system for June 2004.

In sum, WESM establishment is expected to be delayed by more than two years from the original schedule.

(2) Challenges facing WESM

WESM in the Philippines is modeled after the US and UK experience, where vertically integrated utilities are dominant. It bears noting that these two countries are the leading lights in deregulating the electric power sector. DOE, therefore, has to consider how to reflect the preceding experience in the US and UK in WESM.

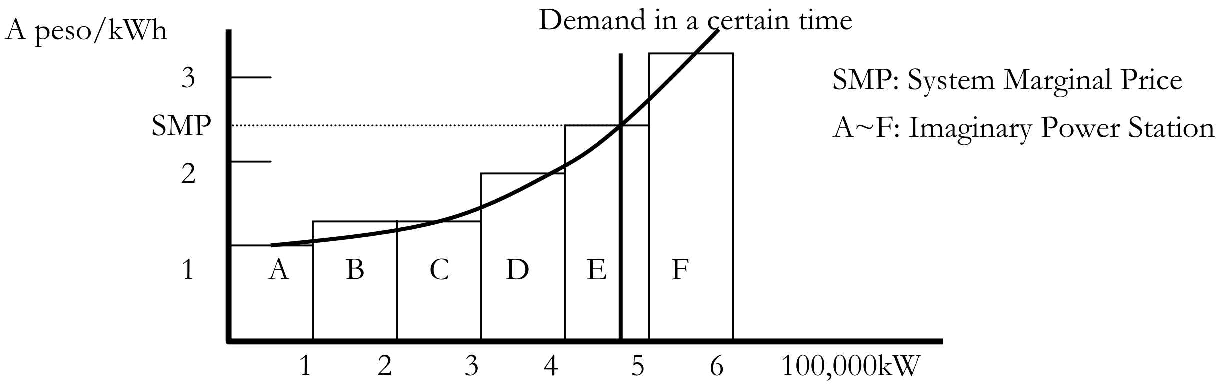


Fig. 2.5: Image of electric power

The price determination method of WESM in the Philippines is shown in the simplified drawing above, Fig. 2.5. The management method of the market is as follows:

1) A market operator collects the assumed electricity demand of the target time range from buyers (power distribution companies, etc.);
2) All power generation plants offer bids on how much electricity they sell in the time range;
3) A market operator opens the tender documents of sellers and buyers and puts the seller's tender documents in order from the lowest price one; and
4) The electricity price and the amount of supply in the time range are decided at the point where the total amount of power generation (kW) corresponds with the aggregated electricity demand. The price calculated based on SMP (System Marginal Price) is paid to the seller.

The electricity to be pooled in WESM will be more than 10% of the total amount of DUs' purchased energy. Considering that the maximum demand in Luzon grid is 6,000 MW, the market scale may be less than 1,000 MW initially. In this case, although Fig. 2.5 indicates that six companies offered a bid, one or two generation companies can supply the amount so that they can decide a market price. Moreover, there might be only a few electricity generation companies in the Philippines. Correspondingly, the market price remains high because the generation companies analyze the tendency of the contract price.

Regarding the bilateral contract that occupies the great portion of the electric power trading volume, DUs will not enter into long-term supply contracts, like the current PPA contracts, with generation companies. DUs will prefer single or short-term contracts and reflect the market price at WESM to issue bilateral contracts for the following year. Given that the market price of WESM is high, the electricity price in the bilateral contract will rise, and as a result, the retail power sales price will increase.

Although WESM in the Philippines has adopted a bilateral contract system, the settlement system of the electric power price is similar to the models of UK and California in the US, which were used in the 90's.

For WESM to function as planned, the following three preconditions are necessary:

(1) A sufficient number of generators (seller side bidders);
(2) Surplus in transmission line capacity; and
(3) Independent relationship among market players.

If the current condition of the Philippines is examined, none of the three preconditions will be met. Hence, DOE needs to carefully observe whether the electric power price would decline as expected with the introduction of the WESM.

2.2.4 Issues in Supply Responsibility

Before the enforcement of EPIRA, NPC took charge of the PDP, and was responsible in maintaining stable power supply. Moreover, it was responsible for ensuring the expansion of the power transmission system vis-à-vis power development. With the enactment of the EPIRA, the supply expansion will be left to the market. Thus, the issue of who will be responsible for securing the supply expansion is also a concern.

Responsibility for ensuring reliable supply was not major concern in the US and European countries because these countries had surplus generation capacity as well as a relatively slow increase in demand level.

Although the GDP growth rate in the Philippines is lower than GDP growth rates in other Southeast Asian countries, it is still around 4% per year. Electricity demand has constantly increased by 6% (300 MW) every year.

Despite a robust demand growth, however, the Philippine energy sector is encountering problems of how to encourage prospective investors to construct new power plants and to expand the necessary transmission lines.

This situation, thus, brings forth concerns over the security of power supply in the country, much less concerns on who will be responsible for meeting the supply expansion with the introduction of the WESM.

Uncertainties in the investment climate forces prospective investors to postpone their plans until the environment has improved. With government's policy not to issue any form of guarantee to these types of investments, investments in either power plants or in transmission lines are unwarranted because of uncertain recovery on investment.

For the investing company, political considerations such as subsidy to compensate for the unrecoverable cost are needed to allow them to recover investments and earn reasonable returns.

2.3 Role and Organization of the DOE

2.3.1 DOE organizational chart and staff allocation

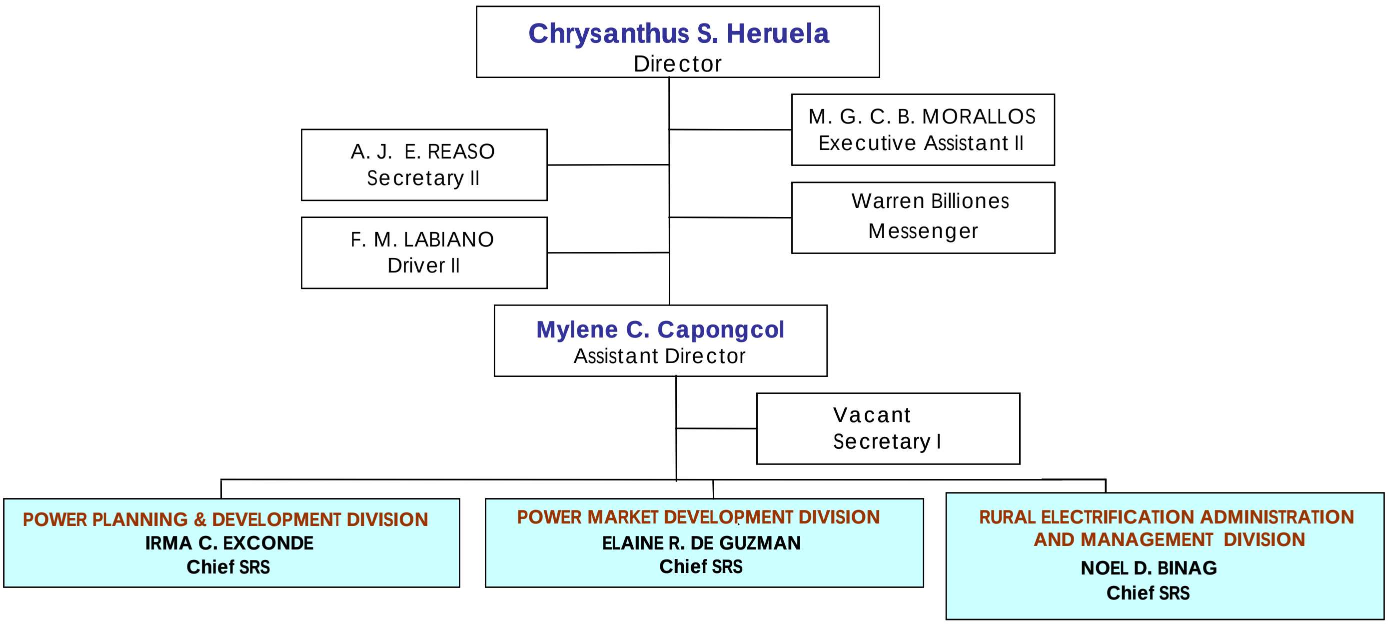
Along with the EPIRA enforcement, the DOE is advancing organizational reform to respond to the changes in its roles and promote efficient operations.

DOE submitted its organizational reformation proposal to the Department of Budget Management (DBM). DBM has since reviewed and approved the necessary budget to establish the new organization.

This gave way for the creation of the EPIMB in 2003. The bureau was primarily tasked to push electric power reform as well as to manage the electric power industry.

DOE's organizational chart relevant to electric power industry is shown in Figure 2.6.

Fig. 2.6: DOE Electric Power Industry Management Bureau Organizational chart



The planning division is in charge of planning PDP, MEDP, DDP, and examination of TDP. (The role of each division in EPIMB is shown in Table 2.5.)

However, more than two years have passed since EPIRA's enactment, only half of the full staff complement has been filled, as shown in Table 2.6.

Table 2.5: Functions and Composition of the EPIMB

Power Planning and Development Division	Power Market Development Division	Rural Electrification Administration and Management Division
➢ Supply Expansion Plan ➢ Transmission Development Plan ➢ Distribution Development Plan ➢ Missionary Electrification Development Plan	➢ Electricity market research and development ➢ Monitoring and evaluation of EPIRA implementation	➢ Rural Electrification Promotion and Management ➢ Rural Electrification Project Administration ➢ Non-electrification Project and Management Administration Section

Source: DOE

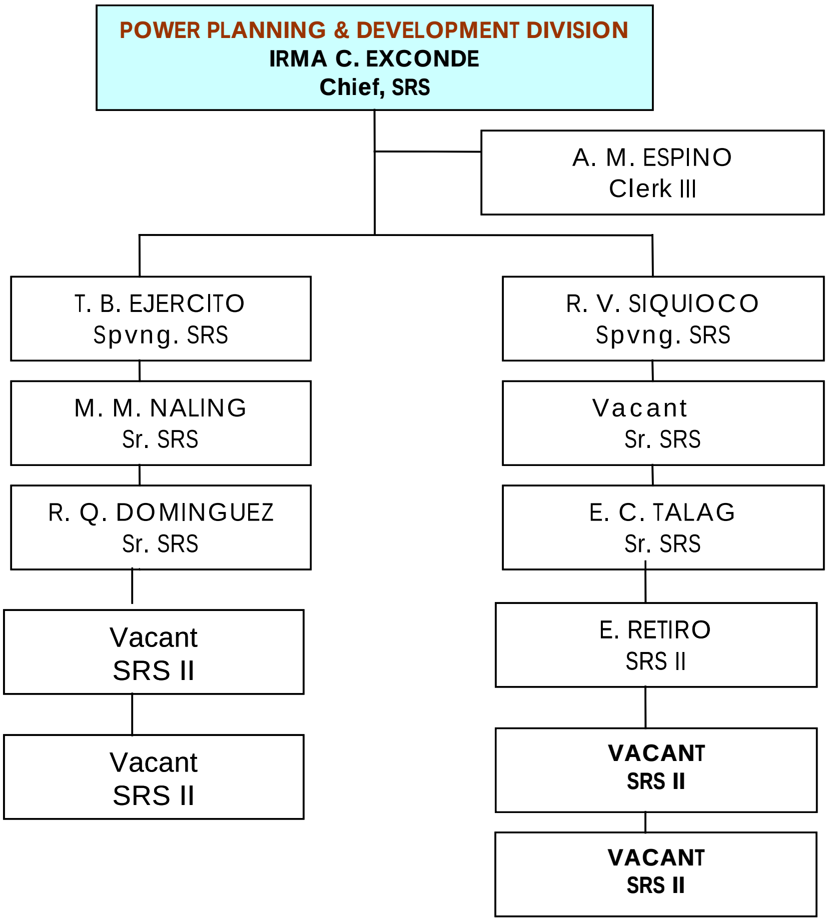
Table 2.6: Comparison of actual staff members and personnel plan

	Planning Division	Market Division	Rural Division	Total
Full Complement	13	12	28	53
Positions Filled	8	N.A.	N.A.	About 25 persons

Source: DOE

The organizational chart and staff allocation of the planning division to which most of the counterparts of the JICA study belong are shown in Fig. 2.7. There are enough senior members, but the complement for lower-level staff are insufficient in number.

Fig. 2.7: Responsibilities of the DOE EPIMB Planning Division



2.3.2 Powers and Functions of DOE under EPIRA

Section 37 of EPIRA clearly outlines the powers and functions of DOE. Among these functions, DOE is tasked to encourage the efficient use of energy as well as to assure the stable supply of affordable electricity. The DOE is supposed to meet and outline the plans to attain these objectives and, in addition, promote supply expansion and rural electrification in coordination with the private sector.

Aside from the establishment of the WESM, the law specifically mandated DOE to formulate and update the PEP and PDP every year.

Also, the DOE is required to formulate a five-year rural electrification plan—the MEDP—to which NPC-SPUG refers to when filing petitions for changes in the universal charge.

The law likewise requires DUs to submit to the DOE their respective distribution development plans. The rule implies yet another function of the DOE which is to consolidate these distribution development plans and monitor their implementation.

These aforecited duties will be assumed by EPIMB. Responsibilities and the divisions in charge are summarized below.

Table 2.7: Role of the DOE Power Bureau

Responsibility	Legal Basis	Division	Remarks
Preparation of PEP/PDP	Section 37, EPIRA Section 3, IRR	Power Planning and Development Division	Submission due on September 15th
Establishment of WESM	Section 30, EPIRA	Power Market Development Division	Within 1 year after EPIRA enactment
EPIRA Monitoring and Evaluation	Section 61, EPIRA	Power Market Development Division	Every April and October of each year
Preparation of DDP	Rule 7, IRR	Power Planning and Development Division	End May
Preparation of MEDP	Rule 13, IRR	Power Planning and Development Division	Prior to filing petition for use of UC

2.2.3 Issues in the Electric Power Industry Management Bureau (EPIMB)

(1) Establishment of new organization

With the completion of the organization of EPIMB, only the supervising senior research specialist (SRS) class staff was determined as of August 2003 and only about half of the full staff complement of EPIMB were filled. Thus, there is not enough qualified staff to carry out important tasks mandated to EPIMB.

Moreover, it is necessary to consider the introduction of monetary incentives to prevent talented people from leaving.

(2) Enhancement of DOE staff's capabilities

The DOE should carefully examine following items in the discharge of its duties:

- Consistency in Policy Implementation

  DOE needs to practice consistency in the supply expansion plan policy, energy mix, and environmental protection.

  Investors are likely to judge that the risk of participating in the market is high if energy policy changes are frequently made.

- Knowledge and skills on simulations

  DOE needs a clear understanding of the fundamentals of simulation models to be able to effectively modify the simulation models by itself and make the necessary adjustments.

  Since PDP is akin to an Information Memorandum that gives investors a view of the Philippine electric power sector, the DOE has to formulate plans considering basic data—such as assumptions; fluctuations in fuel price and exchange rate; and the impact of WESM—for demand forecasting and the supply expansion plan.

  DOE likewise needs to analyze the predicted wholesale price in the Philippines, the possibility of fluctuations and so forth, and to indicate the data analyzed when considering investment promotion, thereby reflecting the thinking of investors from advanced nations. It should be emphasized that the electricity wholesale price is an important criterion for investment.

  Since the simulations use various economic indicators, if these values change, the assumptions in a simulation may collapse. For example, it may become less appropriate to use population and GDP as external variables for power demand forecasting, and the ten-year period for regression analysis may not be accurate. Although the current simulation assumes that each parameter does not have a correlation, correlation may appear gradually from now on.

While the electricity price—the second highest in Asia—may have restricted the amount of consumption in the Philippines, the extent of the impact of price elasticity on electricity consumption cannot currently be calculated because of insufficient data. Thus, the DOE needs to analyze price elasticity.

- Good Governance

  Because DOE is at the forefront of energy-related organizations, it should strongly lead and support these organizations to implement its various mandates.

  The electric power industry is at a transition stage and many activities are underway to establish appropriate governance. These include formulation of guidelines and framework, among others, consistent with EPIRA. For instance, while the DOE needs to formulate a long-term plan at the national level, the sustainability of individual electrification projects needs to be considered in the planning for electrification plans for specific areas.

(3) Role of the ERC and DOE

In the electric power sector, DOE supervises the implementation of the restructuring of the power industry and formulates policies, while the ERC promotes competition, encourage market development, ensure customer choice and penalize abuse of market power. The DOE is mandated to formulate the MEDP and to evaluate the TDP because the public sector should take the initiative in areas such as transmission and rural electrification. However, evaluation and approval by the ERC are required when an individual project is carried out.

Furthermore, although DOE would like to encourage private investors to construct new power plants, disseminating PDP, a supply contract between generators and distribution utilities, has to be reviewed by ERC.

Although the DOE can draw a future image of an electric power sector, the range of its authority is limited because implementation of a project is subject to the judgment of ERC. For example, even if DOE publicizes the necessity for transmission line reinforcement project in the future, the concessionaire should decide whether to carry out the plan, while

ERC will be the final authority to approve the project. Thus, the timely completion of the projects planned in the TDP and MEDP would largely depend on the ERC.

(4) Establishment of a database

Establishing a data collection flow should be a priority because most data necessary for the PDP are collected from outside the DOE. Therefore, DOE needs to reinforce the proposed data flow established in the JICA study so that it can be used in drafting future plans.

Since PDP requires the consideration of a wide range of data, DOE should manage valuable data systematically and utilize it effectively to prevent data loss and maintain data credibility—which are seen as possible problems that may arise in the future.

Currently, the data and information are saved in paper format. As a result, some data were lost in the process while project information are kept by different divisions. A systematic inventory of data is not also being observed.

Due to these problems, not only planning new projects is difficult, it has also resulted in the duplication of projects.

To address this problem, DOE at the outset should collect the remaining data of the rural electrification projects and should manage historical data appropriately using an electronic data format.

2.4 Donor Activity

(1) The situation of each country's ODA

The status of the ODA loan awarded to the Philippines as of December 2002, as classified by sector is shown in Table 2.8. The number of loans in the energy sector and the amount of the loans are comparatively small, at 6.8% and 7.4% of the total ODA loans, respectively.

Table 2.8: ODA loans to the Philippines (as of end December 2002)

Sector/Sub-sector	No. of Loans	Commitments	
		$ Million	% Share
Agriculture, Agrarian Reform and Natural Resources	51	2,229	20.7
Agriculture and Agrarian Reform	38	1,652	15.3
Environment and Natural Resources	12	560	5.2
Integrated Area Development	1	17	0.2
Industry and Services	5	476	4.4
Infrastructure	116	7,229	67.0
Communications	4	81	0.7
Energy, Power and Electrification	14	793	7.4
Social Infrastructure	10	253	2.3
Transportation	57	4,923	45.6
Water Resources	31	1,177	10.9
Social Reform and Development	26	857	7.9
Education and Manpower Development	9	374	3.5
Health, Population and Nutrition	7	95	0.9
Social Welfare and Community Development	8	188	1.7
General Social	2	200	1.9
Project Total	198	10,791	91.0
Grain Sector Development	1	100	9.4
Pasig River Environment Management and Rehabilitation	1	100	9.4
Metro Manila Air Quality Improvement (ADB, JBIC)	2	490	46.0
Non-Bank Fnancial Governance	1	75	7.0
Power Sector Restructuring	1	300	28.2
Program Loans	6	1,065	9.0
Grand Total	204	11,856	100.0

Source : NEDA, US $ 1 = ¥ 125

The grant-in-aid situation classified by donor as of December 2002 in the Philippines is shown below.

Japan is the second greatest contributing donor in terms of the grant amount, dominating 16% of the total grant-in-aid to the Philippines. The comparison of the average expense per project highlights how little international donor agencies, such as WB, ADB, and UNDP, have donated.

Table 2.9: Each donor's grant aid in the Philippines

Funding Source	No. of Projects	Average Project Cost (in US$M)	Grant Amount (in US$M)	Percent Share (%)
ADB	42	0.67	28.29	3.00%
Australia	11	8.33	91.66	9.73%
Belgium	1	18.00	18.00	1.91%
Canada	10	5.45	54.48	5.78%
Czech Republic	1	0.00		0.00%
EU	11	13.66	150.27	15.95%
France	1	0.43	0.43	0.05%
Germany (GTZ)	10	4.24	42.43	4.50%
Germany (KfW)	3	7.51	22.54	2.39%
Japan	**30**	5.10	**153.11**	**16.25%**
Netherlands	3	5.31	15.94	1.69%
Spain	3	2.61	7.83	0.83%
UNDP	17	0.88	14.91	1.58%
UNFPA	3	1.25	3.76	0.40%
UNICEF	1	46.50	46.50	4.93%
United States	31	7.90	245.03	26.00%
WB	33	1.43	47.24	5.01%
Grand Total	**211**		**942.41**	**100.00%**

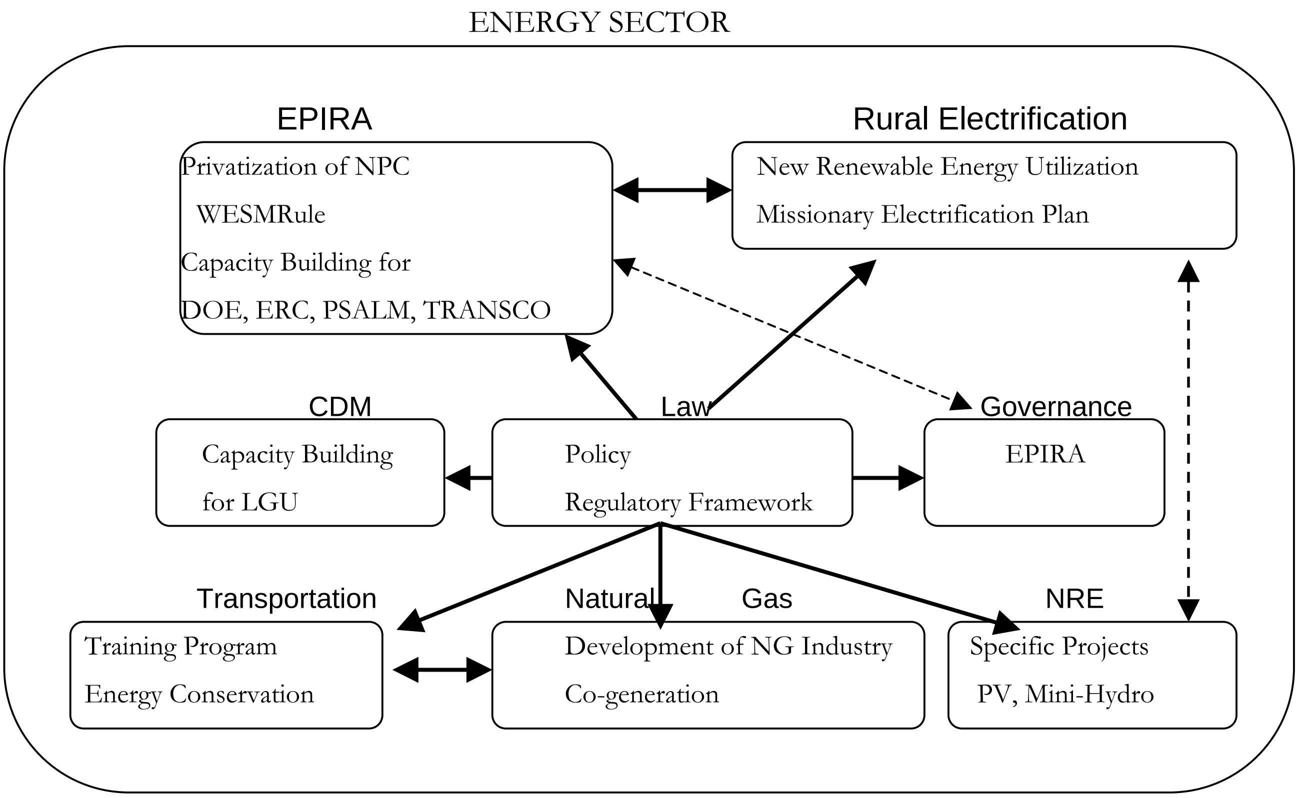
According to the NEDA, as of December 2002, 17 countries including donor agencies have offered technical assistance to the Philippine government. A total of 211 grant projects are ongoing as of December 2002. Of this number, 16 projects are connected to the DOE. Seven of these organizations have contributed significantly in improving the Philippine power sector through technical and financial assistance, namely:

- Asian Development Bank (ADB)
- World Bank (WB)
- Japan Bank for International Cooperation (JBIC)
- United Agency for International Development (USAID)
- Australian Agency for International Development (AusAID)

- United Nations Development Program (UNDP)
- Japan International Cooperation Agency (JICA)

The range of the technical cooperation to the energy sector is extensive, as shown in Figure 2.8.

Fig. 2.8: Donor's activity situation



Source：Made by JICA Study team based on the field survey

Most of the technical assistance related to the DOE, which supports the EPIRA implementation, has been terminated. It should also be noted that only form of assistance related to the PDP formulation is this study. Most of the current technical assistance for DOE is for the promotion of rural electrification and the increased utilization of renewable energy.

2.5 Proposal for Electric Power Policy

2.5.1 NPC Privatization

(1) Necessity TRANSCO franchise bill passage

The TRANSCO franchise bill under consideration by the Senate includes the provision that allows TRANSCO to hand over to the concessionaire its franchise without congressional approval. Since the Senate insists that even if the concessionaire wins the competitive bidding, congressional approval is required for the franchise's transfer; therefore, the passage of the law has been hindered.

Since the passage of the TRANSCO bill is supposed to precede TRANSCO's privatization, the sale of TRANSCO has consequently been delayed due to the issues raised on the proposed transferability of TRANSCO's franchise.

EPIRA mandates the concessionaire to operate the transmission system; build new transmission lines; maintain the existing infrastructure; file petitions for transmission tariffs; and operate TRANSCO infrastructure. However, it is not clear whether EPIRA—which is silent on the issue franchise transferability—automatically grants the would-be concessionaire a franchise to operate the transmission system.

Evidenced by the American Chamber of Commerce in the Philippines' urging the Philippine government for the immediate enactment of the law, investor confidence in the country's power sector remains low. The situation was highlighted by the fact that only one company applied in the first and second biddings offered in July and August 2003, respectively.

To address the concerns of potential bidders for TRANSCO while at the same time continuing the current sales process, PSALM should clarify the conditions of congressional approval on franchise transfer to the concessionaire on one hand, and the obligations of the concessionaire, on the other.

(2) Sale of power generation assets

PSALM originally planned to complete TRANSCO's privatization before it proceeds with the sale of NPC's generation assets. However, before actually investing in the power sector, private investors are likely to observe the implementation of the WESM.

But even before TRANSCO privatization is completed, PSALM had to begin the procedures for the sale of power generation assets since EPIRA requires the sale of 70% of NPC property within three years after the law took effect. At the outset, power generation assets were grouped for selling, but will now be sold individually.

Since the government does not provide any for of guarantee, selling some of the plants may be difficult except for competitive base load plants. If asset sales are assumed to be the first priority, the government should partially guarantee and an investment recovery scheme should be formulated for plants that are less attractive to investors.

For instance, the sale of twenty- and thirty-year-old plants may require rehabilitation to further prolong its economic life. Construction of new fuel infrastructure may also be needed. In this case, the government can construct the fuel infrastructure and recover the expenses by collecting lease fees over a long period. This scheme will reduce the initial investment by the investor and mitigate the risk in cost recovery.

2.5.2 Investment Promotion for the Electric Power Sector

(1) Information service for investors

The main role of the EIPO is to serve as an information service for investors and project developers. Therefore, JICA assisted EIPO in building an information distribution system on the DOE web page.

The functions of the information system are as follows:

- To identify potential projects and recruit investors to these projects;
- To initiate a sharing of project proposals among project developers, and conduct information disclosure;
- To process project development proposals from potential investors; and
- To serve as link to relevant organizations' homepages.

The promotion of investment cannot be attained only by web page construction. Hence, DOE needs to constantly update the data of the information distribution system and upload the data requested by registered users.

(2) Clarification of investment-related procedure

To invest in the Philippines, it is necessary to obtain the approval of a host of agencies, such as NEDA, DENR, BOI, and the local government. However, no flow charts or checklists, which comprehensively show investment procedure, are available.

Since each investment-related organization is seldom aware of cooperation with other organizations, completing the procedure may take at least one year.

EIPO, as a primary contact point in investment, should clarify the investment procedure tailored to investment types and function as a guide for investors.

Moreover, DOE should propose to concerned agencies the revision of the systems or procedures that impede investment.

(3) Implementation with continuity

From the government's viewpoint, reducing the electricity tariff necessitates a review and eventual reduction of the IPPs' wholesale electricity prices.

However, from the point of view of investors, the EPIRA's mandated compulsory reduction of the once-contracted wholesale price might eliminate investments in the Philippine energy sector.

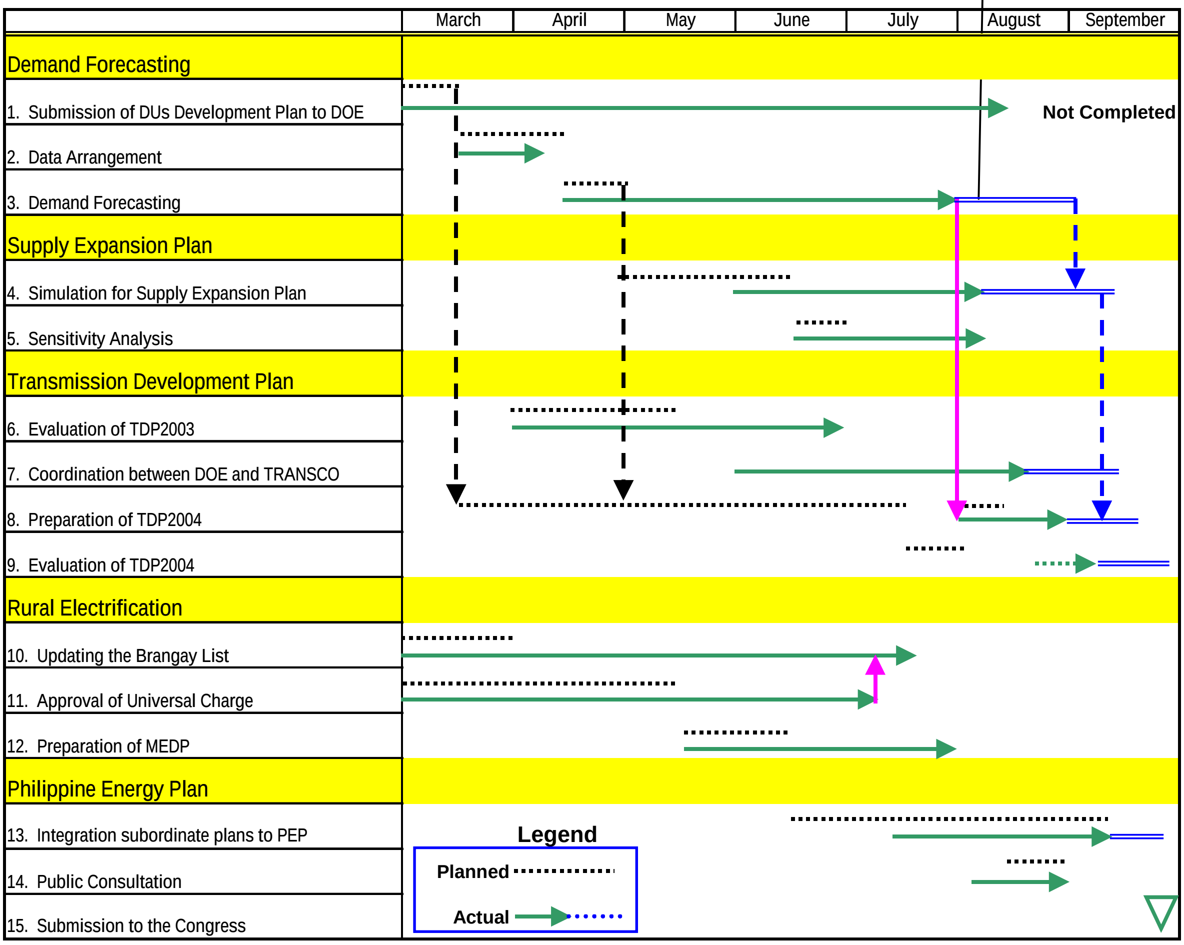
Thus, DOE needs to eliminate the idea that political risk in the Philippines is high by releasing the contract reexamination information of IPPs whose contracts were negotiated. Such release of information, however, should be contingent on honoring confidentiality.

2.5.3 Validity of the PDP Formulation Process

(1) Comparison of the track record with the master schedule

The master schedule and the track record of PDP formulation are shown in Table 2.10. Difficulty in completing PDP by September 15 and submitting it to the Philippines Congress is assumed from the track record below.

Table 2.10: PDP formulating master schedule and track record



The JICA Study team started demand forecasting in April 2003, based on the preliminary GDP growth scenario released by NEDA, and finished the calculation by the end of May 2003. However, obtaining approval from DOE senior management on the demand-forecasting results took time, and, as a result, the formulation of the supply expansion plan and the transmission development plan, which use approved demand forecasting results, were more than two months behind the target schedule.

If the DOE complies with the mandated PDP submission to Congress by September 15, it needs to finalize the demand forecasting by the end of May. If the DOE finds difficulty in meeting this statutory target, the submission schedule should be revised.

(2) DOE as a policy-maker

In the Philippines, DOE is mandated to perform demand forecasting and formulate the supply expansion plan mandated in EPIRA.

The DOE is supposed to formulate policy, analyze statistics, and conduct simulations in parallel. But because it remains understaffed, its analytical functions tend to be neglected. The DOE should entrust most of the PDP preparation work to a specialized agency that will be created and instead specialize in its policy making and administrative work.

Judging from the examples of foreign countries, it is uncommon that the organization in charge of energy policy carries out direct demand forecasting.

The comparison of practices for demand forecasting, forecasting in developed nations, in which the deregulation of power industry has progressed, is summarized below.

Table 2.11: Role of government organization in demand forecasting

(As of September 2003)

Country	Philippines	Japan	United States	Britain	Norway	Sweden	Germany
Demand-forecasting organization	Government organization	Utilities union	Government organization	Power system operator	Government organization	Government organization	Consultant
Name	DOE	Japanese electric power investigation committee	DOE (EIA)	NGC	Statistics Norway	Energy Administration	Prognos AG
Use	Supply Expansion Transmission Development	Transmission Development	Policy making	Transmission Development	Transmission Development Policy making	Policy making CO2 emissions	Policy making
Calculation frequency	Every year	Every year	Every year	Every year	Every year	Irregular	Every Three year
Data source	DU	Electric power company	EIA FERC	DU Large scale user	N.A.	Central Statistical Office	Central Statistical Office
Approach	Macro	Combination of Micro and Macro	Combination of Micro and Macro	Combination of Micro and Macro	Combination of Micro and Macro	Industry: Micro Other sectors: Macro	Combination of Micro and Macro
Degree of retail liberalization	0%	30%	0 - 100% depending on the state	100%	100%	100%	100%

Source: a Japanese electric power investigation committee, "example of electricity demand forecasting in European countries and America," and the Energy Economics Institute, Japan, "present situation of electric power reform in overseas countries"

In nations under an advanced deregulated regime, demand forecasting results are used for energy policy making or expansion of transmission lines, which is public infrastructure. Since supply expansion in Western countries is the responsibility of individual companies, there are no countries that have formulated a power development program in a nation-wide scale. For example, in Japan, each electric power company expands its power supply capacity based on its original electric supply plan.

On behalf of US-DOE, EIA (Energy Information Administration), which is an external organization of US-DOE that manages information statistics, performs demand forecasting. The US-DOE itself does not perform demand forecasting but is dedicated to policy making. The same practice can be found in Norway and Sweden. In Germany, the government has outsourced demand forecasting to special consultants.

Chapter 3 Electric Power Demand Forecasting

3.1 Economic Growth and Power Demand Indicators in the Philippines

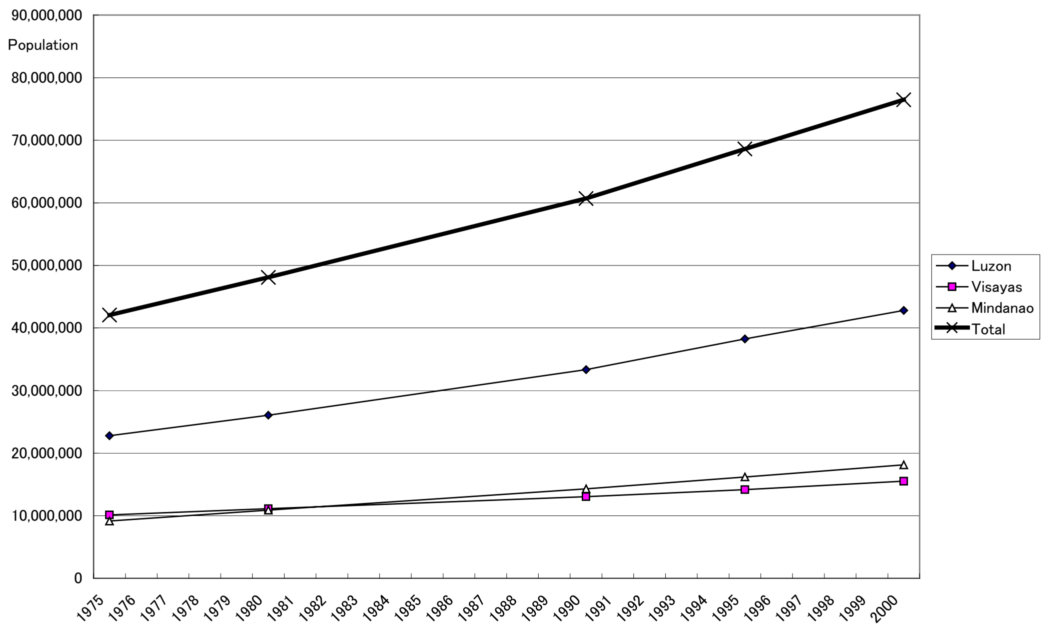
3.1.1 Historical Census Data in the Philippines

(1) Population

The Philippines has a total land area of 300,000 square kilometers and consists of about 7,000 islands of various sizes. National census results show that in 2000, the Philippine population has already reached a little over 75 million. (The Philippine population in the last 25 years is seen in the figure below.)

Population growth rate from 1975-2000 averaged almost 2%. The Philippine population will reach 100 million between 2015 and 2020 as indicated by studies conducted by the government statistics offices National Statistics Office (NSO) and National Statistical Coordinating Board (NSCB) as well as the United Nations.

Fig. 3.1 Historical population data of the entire Philippines and three major areas of the Philippines



(2) Growth of the Economy

In the early 90s, the Philippines experienced a low growth period. In the mid 90s, however, the Philippine GDP growth rate rose to approximately 5%. But in 1998, negative growth was recorded as a result of the effects of the Asian financial crisis. After recovering from the currency crisis, a growth rate of 3% to 4% has been maintained. Figure 3.2 shows historical GDP values in the Philippines from 1990 to 2001. The historical growth rate of GDP is also shown in Figure 3.3.

Fig. 3.2 Historical GDP values

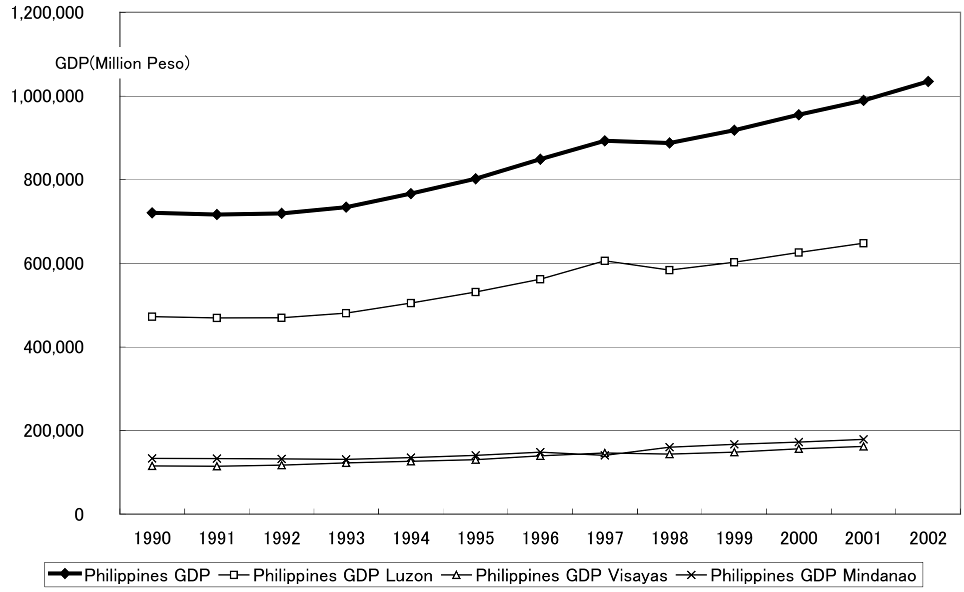


Fig. 3.3 Historical GDP Growth Rate

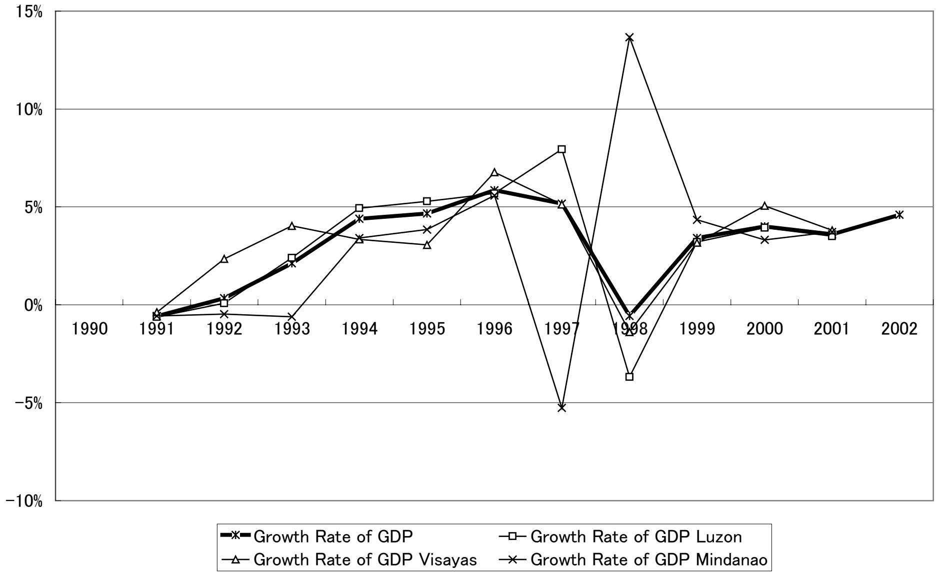
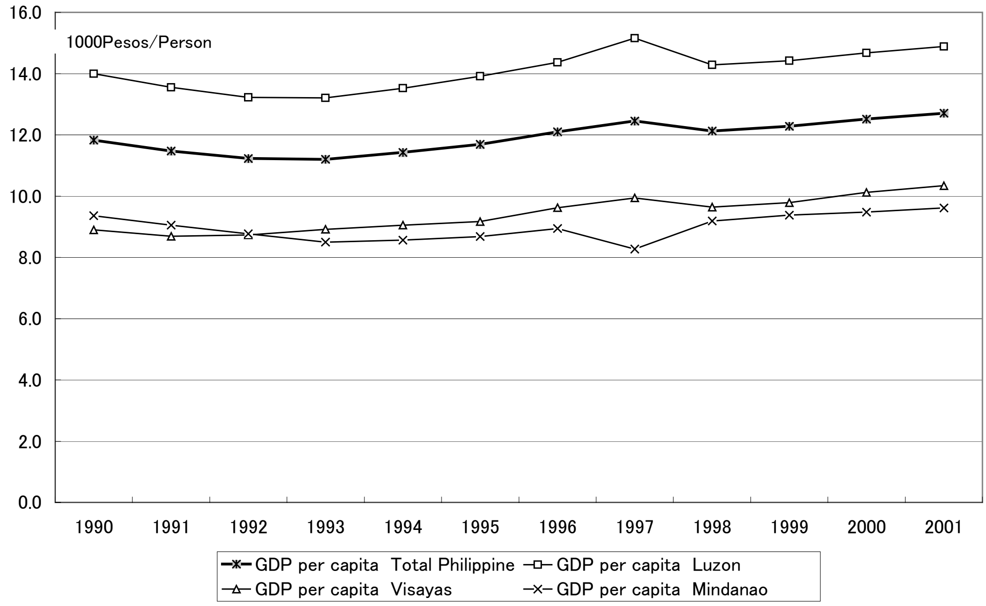


Fig. 3.4 Historical GDP per Capita in the Philippines



A look at the GDP per capita (GDP per person) indicates that the GDP per capita for the entire Philippines has not risen dramatically since 1990 until the late 1990s. A separate examination of the GDP per capita scenarios in the three major islands (Luzon, Visayas, and Mindanao) likewise show such trend. This was exacerbated by the Asian financial crisis, which triggered steep decline in the country's GDP per capita in 1998.

However, GDP per capita has shown signs of recovery starting 2000, driven by an increased consumer spending—which has proven to be the backbone of the country's economic recovery. At present, the Philippines' GDP growth is highly dependent on the agriculture and services sectors.

3.1.2 Historical Trends in Electricity Demand

Population growth and economic indicators are primary drivers of the electricity demand growth. After discussing historical census data and GDP patterns in previous sections, historical trends of pertinent electricity demand patterns are discussed in this section.

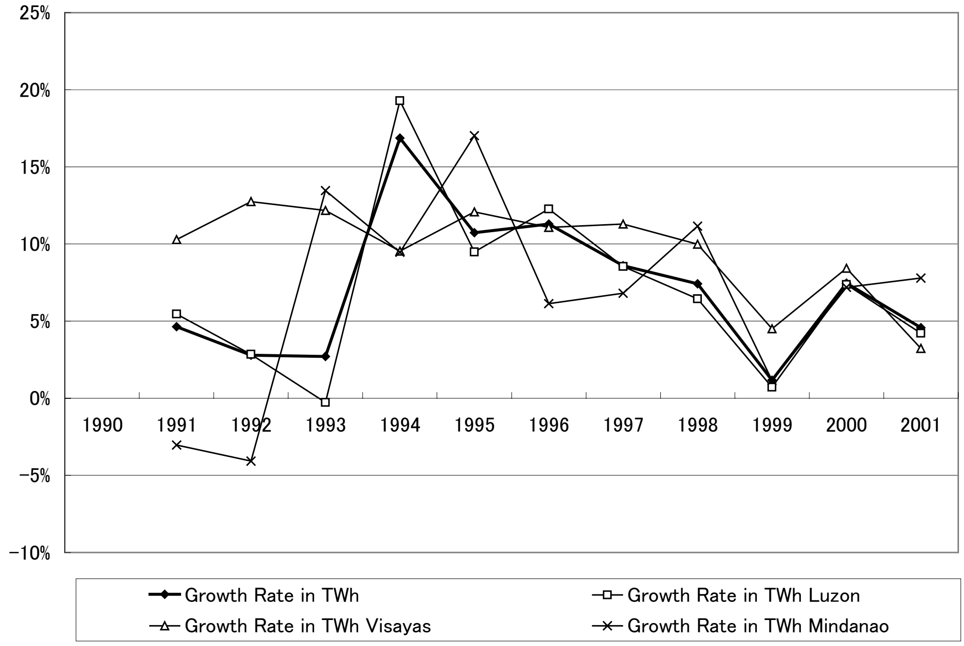
(1) Electricity Demand Growth

Electricity demand growth in the Philippines was limited from the early 1990 until 1993, when the country experienced an economic recession as a result of the power crisis. However, when the economy began to recover from 1994 to 1996, electricity demand growth increased sharply. During this period, a growth of over 10% in electricity demand was recorded.

This growth momentum, however, slowed down in 1997 when the Asian financial crisis dampened economic activities not only in the Philippines but in other countries in the region as well.

Figure 3.5 shows the rate of electricity demand growth from 1990 to 2001.

Fig. 3.5 Historical electricity demand growth

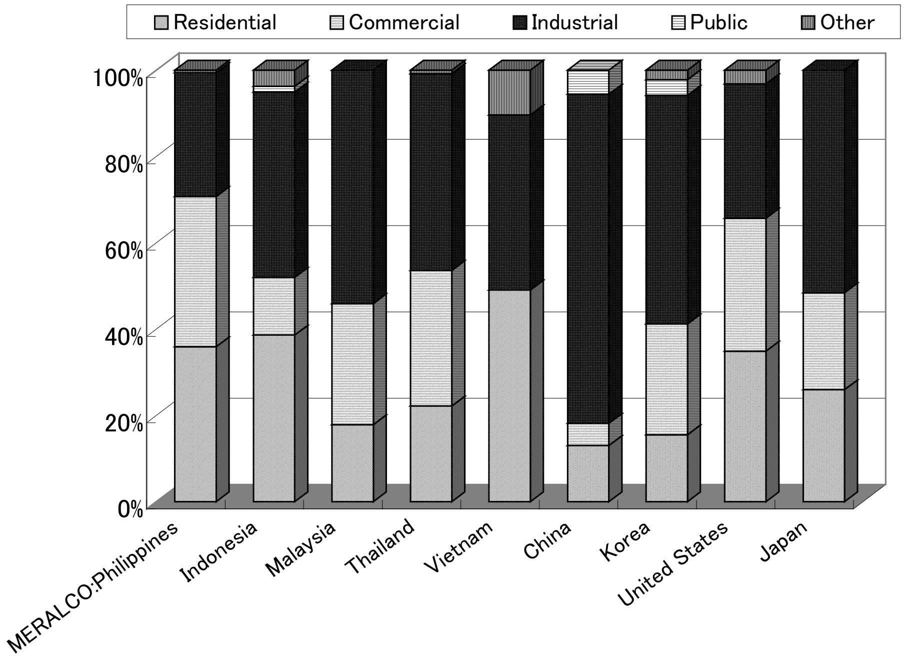


In the examination of electricity demand patterns in the Philippines, it bears noting that one of the significant characteristics of energy consumption in the Philippine electric power sector is that the share of the sales to industrial sector is relatively lower than other countries. Fig. 3.6 shown below is the comparison of the share of energy sales in electric power sector among the countries.

For the purpose of comparing the breakdown of the Philippines' electricity sales with those of other countries', the study team used sales data of the Manila Electric Co. (MERALCO) which accounts for 60% of the country's total electricity sales. MERALCO's energy sales to industrial customers account to only about 30% of its total sales, while in most developing and developed countries except the U.S., share of sales to industrial sector covers 50% or more of the total energy sales.

Therefore, it can be said that the Philippine electric power sector is strongly dependent on sales to non-industrial sectors, such as the residential and commercial sectors.

Fig. 3.6 Comparison of share of sales to each customer sectors



These historical factors in demand growth influenced the changes in the elasticity of demand growth rate against GDP growth rate. In the mid 90s, the value of elasticity was relatively high, because of high demand growth and the rebound of capacity shortage. The value of elasticity declined through the latter part of 90s due to the Asian financial crunch.

Also, reliability and quality of supply are important factors that influence growth rate. This is especially true in the Philippines, where the demand of large industrial customers has not increased for the past 15 years since most of the industrial customers opted to generate their own electricity for their factories.

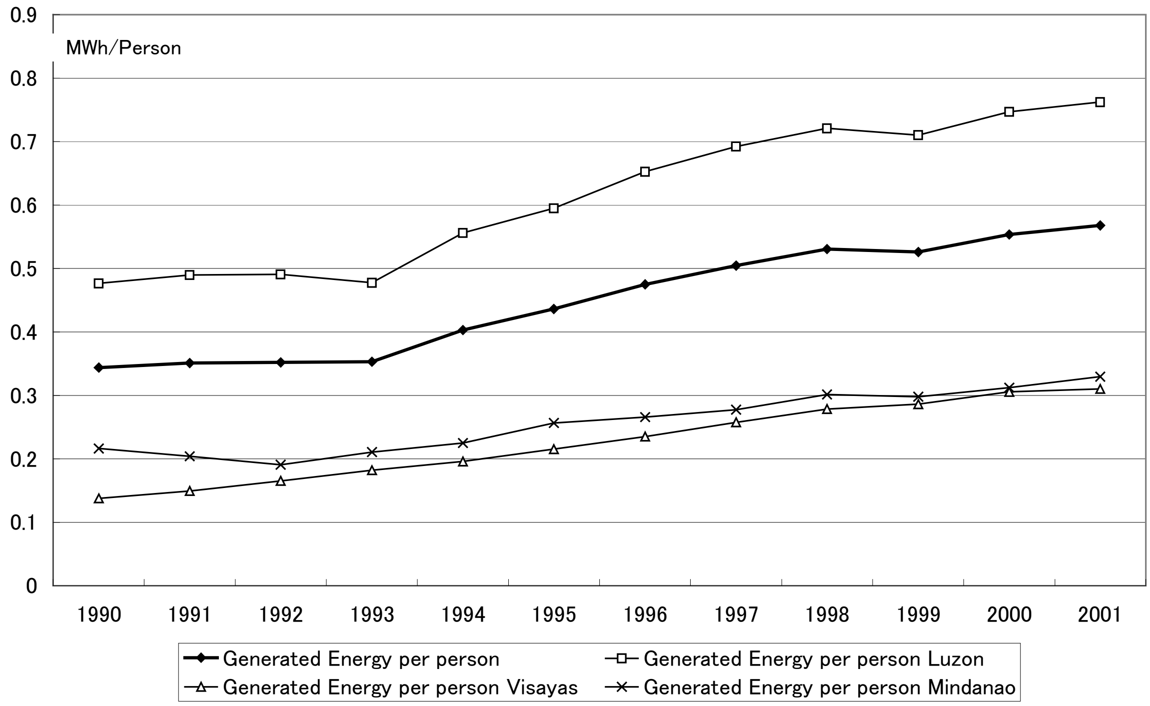
For instance, one of the more reputable Japanese electronics factories where PCs are assembled stressed in an interview that when the firm was still connected to the grid, it experienced voltage fluctuations up to almost 10,000 times per year. Given the situation, the company decided to invest in a 50-MW self-generation plant to protect itself from such problem also experienced by other customers connected to the grid.

Addressing these types of issues may thus give utilities business opportunities to provide the electric power needs of industrial customers.

(2) Electricity Consumption Per Head

Even though the GDP per capita value was relatively low through the 90s, electricity consumption per head grew after 1993, shown as Fig. 3.7. This means that population and the GDP value may be more effective metrics in predicting demand growth rather than the GDP per capita factor.

Fig. 3.7 Historical growth of electric demand per head



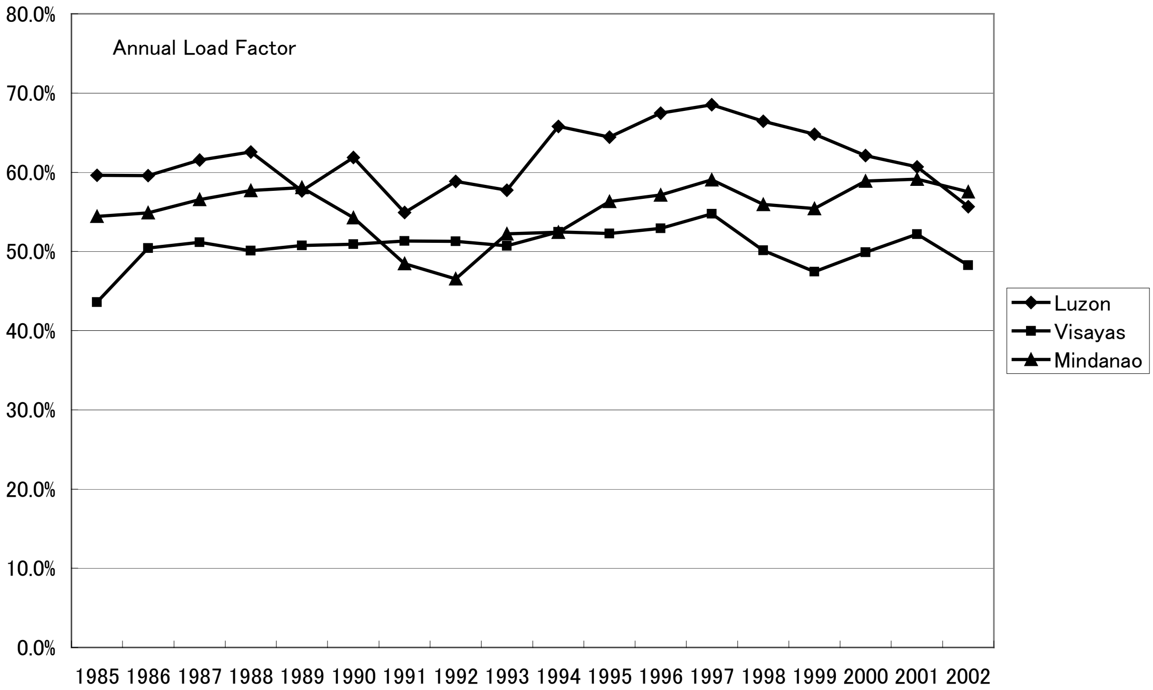
(3) Load factor

"Load factor"—(meaning "Demand for Energy"/("Peak demand" * 8760 hours))—is an important factor in the computation of electricity demand because it is an indicator of the system performance for a specific period of time and is, thus, an indicator of how efficient energy is utilized in a system.

In the current Philippine situation, there is no indication that the load factor is <u>decreasing</u>. This is likely to be the trend, since the country's industrial sector contributes minimally in the electricity demand growth rate as industrial firms are mostly self-generators, and demand coming from these firms is not included when considering the power sector's demand. Typically, these new industries operate 24 hours a day, and are not as effective in decreasing the load factor as the traditional manufacturers.

Historical data on load factor of the entire Philippines and each main grid in various areas are shown in Figure 3.8.

Fig. 3.8 Historical load factor



(4) Sales to Directly Connected Customers

In the Philippines, customers who are connected to the transmission system are mostly large industrial consumers, although there are a number of commercial customers availing direct connection as well.

NPC data indicate that the amount of direct sales did not increase in the 90's. The percentage even went down when compared against total NPC sales after DUs started sourcing power from IPPs other than NPC beginning 1998. From 2002, NPC-GENCO's sales were lower than the total sales of distribution companies.

Fig. 3.9 Relation between NPC sales and total sales by distribution companies

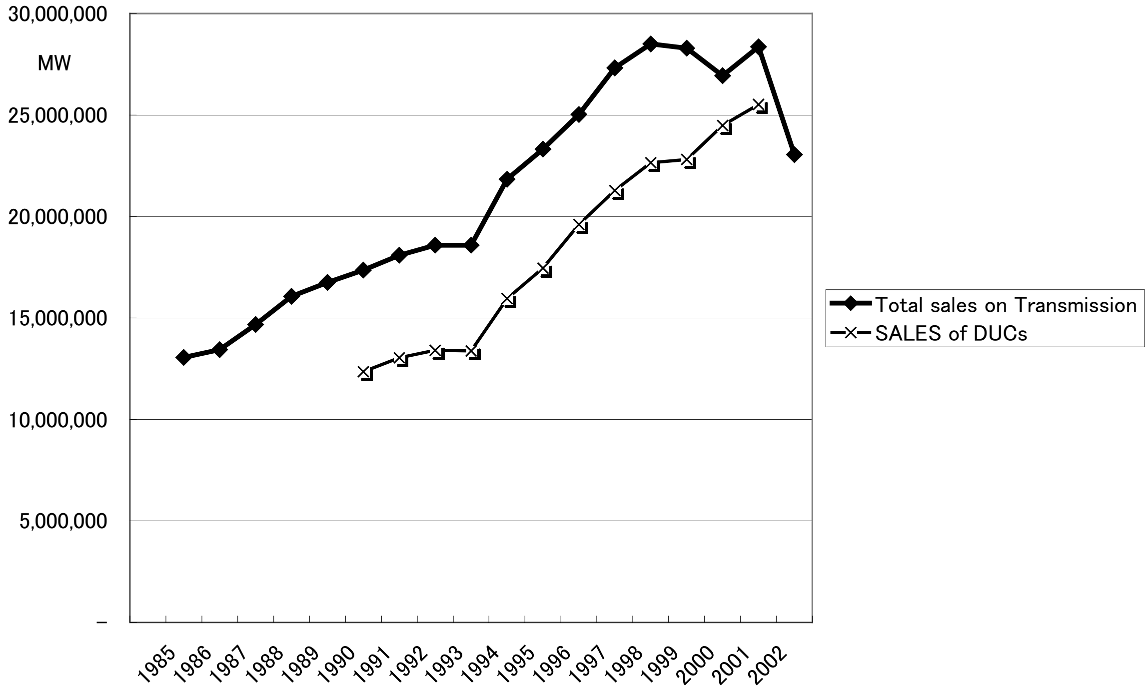
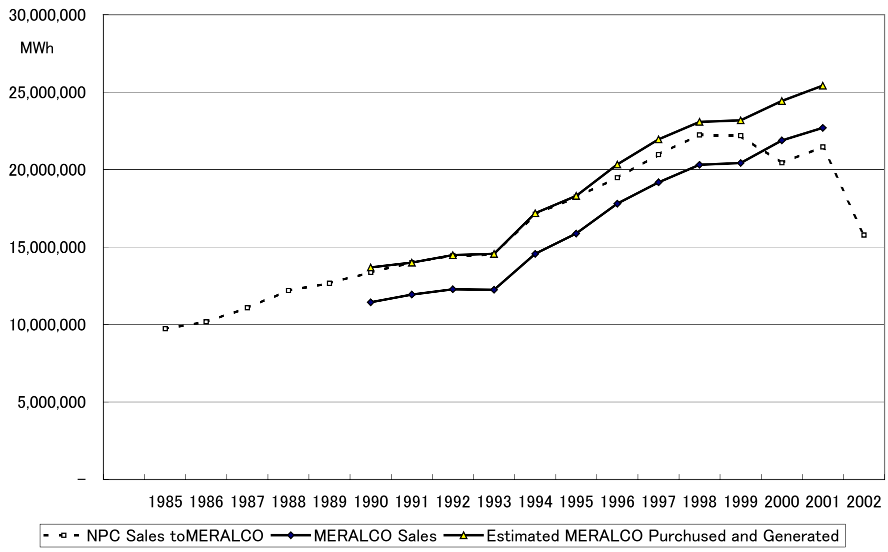


Fig. 3.10 Relation between the sales data of MERALCO, and NPC sales to MERALCO



3.1.3 Economic perspectives in the Philippines

(1) Short-term economic growth in the Philippines

Short-term economic (GDP) growth in the Philippines is usually disclosed by government agencies such as NEDA, international organizations such as the WB, ADB and IMF, and several private banks and think-tanks.

In a report by the Ministry of Foreign Affairs of Japan, ADB expected 2.7%, IMF expected 2.9% and WB expected 2.5% growth for the Philippines in early 2001. The actual GDP growth in the Philippines was 3.2% in 2001, indicating more than 20% margin of error even in economic forecasting for the current year.

NEDA's GDP forecasts for 2003 and 2004 (released in early 2003) are as follows:

- year 2003:4.2% - 5.2%
- year 2004: 4.9% - 5.8%

The other GDP growth forecasts in the Philippines according to foreign public and private organizations are as follows. It bears noting that these data are at the same level as the average forecasted ASEAN growth rate of 4.0%.

Agency	2003	2004
IMF	4.0%	4.0%
ADB	4.0%	4.5%
UFJ Bank (Japan)	3.9%	4.3%
Mizuho Bank (Japan)	4.3%	4.5%
Nomura Research Institute (Japan)	3.8%	4.1%
Mitsubishi Research Institute (Japan)	4.2%	3.9%

Compared with both sets of disclosed results, the lower NEDA forecast is almost the same as the forecast by other organizations.

In addition, the higher NEDA forecast is 1.0 point higher than other forecasts for 2003. Forecasts for 2004 by NEDA are 0.5 point higher than other organizations in the lower their forecast, and 1.5 points higher in the higher tier forecast.

(2) Long-term economic growth in the Philippines

Generally, long-term economic growth forecasting is more difficult than short-term forecasting. There are two main approaches for long-term economic growth forecast, namely: (1) the qualitative approach considering the economical situation, and (2) the quantitative approach using long-term econometric models.

Long-term economic growth forecasting results using the quantitative approach was used in the formulation of the PDP. The most recent forecasted results, disclosed in May 2003, under two scenarios—the NEDA High GDP scenario and the NEDA Low GDP scenario—as shown in Table 3.1.

Table 3.1 Forecast GDP disclosed by NEDA and modified by DOE

In %

	NEDA High GDP	NEDA Low GDP	Modified Low GDP
2002	4.6	4.6	4.6
2003	5.2	4.2	4.2
2004	5.8	4.9	4.9
2005	6.3	5.3	5.3
2006	6.7	5.8	5.8
2007	6.3	5.3	5.3
2008	6.8	5.8	5.1
2009	7.0	6.0	5.1
2010	7.0	6.0	5.1
2011	7.0	6.0	5.1
2012	7.0	6.0	5.1
2013	7.0	6.0	5.1
AAGR(%)	6.6	5.6	5.1

NEDA is responsible for creating and running econometric models for long-term forecasting. The output of these models are thereafter used as the basis for the country's economic targets.

For its demand forecasting, the DOE relies heavily on NEDA's economic projections and treats the bullish scenario as the national target. The DOE further revises the low growth scenario into a lower modified scenario by applying the average of an early five-year growth rate to a later five years.

In the mid-90s, the Institute of Developing Economies in Japan disclosed a long-term economic forecast for the Philippines. The results were obtained by running the institute's own econometric model. Looking at these results, the later 6% growth rate in the late 90s, and a growth rate above 7% were expected. These results were as bullish as NEDA's forecasting. (Long-term forecasting is very difficult, as shown through these examples.)

Qualitatively, the economy of the Philippines has already escaped from being "the Sick Man of Asia" in the mid 90s. In fact, recently, it is widely accepted that the economy of the Philippines has a potential 4-5% growth rate. In addition, if the investment by electronics industries that started in the late 90s continues, the average growth rate of ASEAN countries can be maintained.

Economic experts at the Mitsubishi Research Institute expects that a 4.5%- 5.5% growth rate can be maintained by the ASEAN countries, including the Philippines, until 2010, which is an important assumption in the Japanese economic forecast report.

These figures on the government's long-term GDP forecasting for the Philippines, especially in the 10-year forecast, indicate that government forecast for the country may be 1.5 – 2.0 points higher than the results of independent forecasting made by other organizations.

3.2 Demand forecasting models

3.2.1 Model used in Past PDP

(1) Structure of the Philippine Power Sector under a Vertically-Integrated Structure

The structure of the Philippine power sector in the past, as shown in the physical power flow in Fig. 3.11., was that NPC was the organization which was solely responsible for sales to wholesale customers, while private distribution companies and cooperatives were responsible for sales to retail customers.

From the late 90s, NPC-IPPs and IPPs, that contracted supply agreements with DUs, constructed new power facilities in addition to NPC-owned generation plants.

However, NPC can recognize wholesale and retail sale data as the double round point shown in the figure through the relationship between the seller and the buyer in the past.

As shown in Fig . 3.12, the relation between the transaction contracts is not very different from the physical power flow shown in Fig. 3.10. Thus, it was not difficult to collect actual sales data. Now, NPC is divided into TRANSCO, GENCO and other organizations. In addition, it is in a transient situation in which IPPs increase direct sales to customers. These structures are changing.

Fig. 3.11 Structure of the Philippine power sector

under a Vertically-Integrated Structure

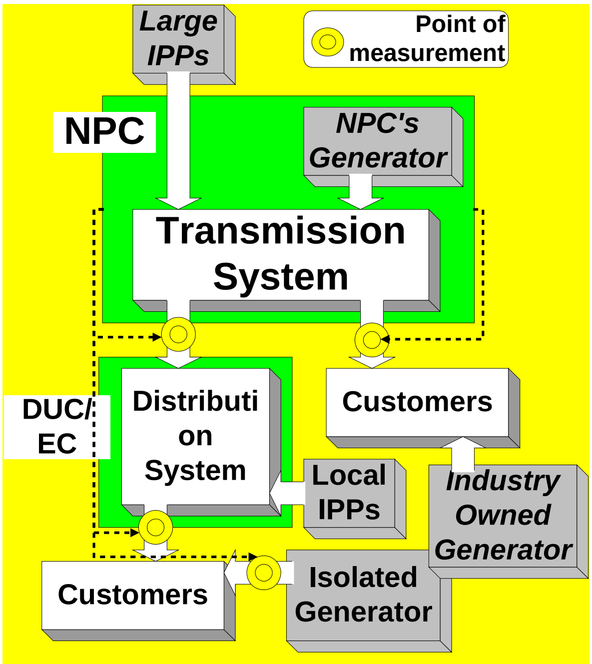
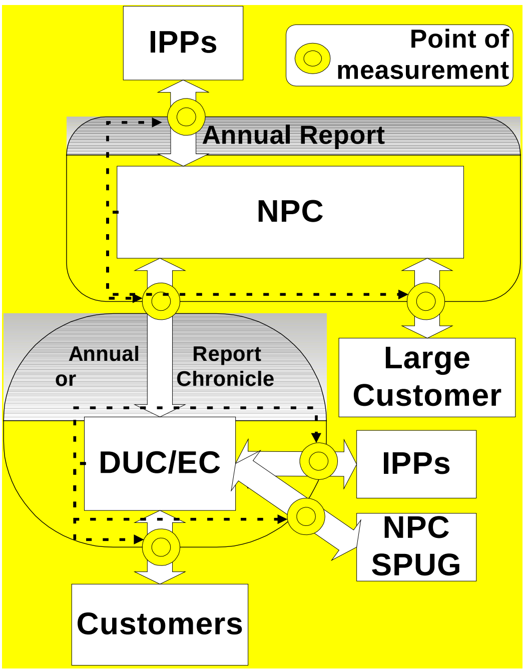


Fig. 3.12 Transactions Flow in the Philippine power sector

under a Vertically-Integrated Structure



(2) Forecasting method in the PDP 2002-2011 and PDP 2003-2012

The NPC used the following assumptions in its demand forecasting for the PDP covering the periods 2002-2011 and 2003-2012.

- Demand forecasting for the main grid was conducted for three major areas, namely: Luzon, the Visayas and Mindanao.
- The forecasting model for Luzon was separated into MERALCO and other companies.
- The following forecasting formulation was adopted for the MERALCO franchise area.

Residential Demand = EXP (a + b *(LN (GRDP in Luzon)) + c *(LN (Number of residential customers))

Commercial Demand = EXP (a + b * (LN(Service sector's GRDP in Luzon))

Industrial Demand = EXP (a + b *(LN (Industrial GDRP in Luzon))) + c * (LN (Number of industrial customers))

On the other hand, the following regression formulation was adopted for Mindanao:

Residential Demand = EXP (a + b * LN(GDP in Mindanao))

Commercial Demand = EXP (a + b * LN (GDP in Mindanao))

Industrial Demand = EXP (a + b * LN (Industrial GDP in Mindanao))

Forecasting by sector was not applied for the Visayas, but rather a single formulation was applied to total demand in the Visayas.

In all cases, these regression models adopted a logarithm of external variables and target variables for the regression model. In addition, NPC directly forecasted sales in transmission levels including direct sales to large customers by NPC.

(3) Comment on past demand forecasting results

Very few organizations forecasted or disclosed forecasted future demand in the Philippines. An exceptional example is the forecast of Mitsui Global Strategic Studies Institute. This organization compared its own forecasted results with PDP 2002-2011.

This organization estimated future demand assuming a 3.2% average GDP growth and an elasticity of 1.7%. The results were 30% lower than PDP 2002-2011 at year 2011.

In PDP 2002-2011, even though DOE adopted a modified GDP scenario based on NEDA's low GDP scenario and replaced the later five-year growth rate with an average of the early five-year growth rate, the result was still an average elasticity of as high as 1.5 - 2.0. The results were often criticized as over-estimations.

In the work of the Taskforce Project held by METI in Japan in 2001, the Japanese government suggested that the Philippine DOE should forecast a more realistic demand and not be too bullish, because investors have, in the past, doubted too bullish forecasts released by the DOE.

However, in PDP 2003-2012, forecasted demands were greatly adjusted downward. For example, demand in 2011 in Luzon is 20% lower than the PDP 2002-2011 results.

In addition, demand in 2011 in the Visayas and Mindanao is 30% lower than the PDP 2002-2011 results.

This means that the growth rate was adjusted to 1.2 point lower from 9.5% to 7.3% in Luzon, and the growth rate was lowered from 10 or 12% to nearly 7% in the Visayas and Mindanao.

These results can be obtained by estimating a lower future elasticity than in PDP 2002-2011. The results of PDP 2003-2012 are close to the new forecasted results obtained through work of PDP 2004-2013.

Fig. 3.13 Difference between PDP 2002-2011 and PDP 2003-2012 in Luzon

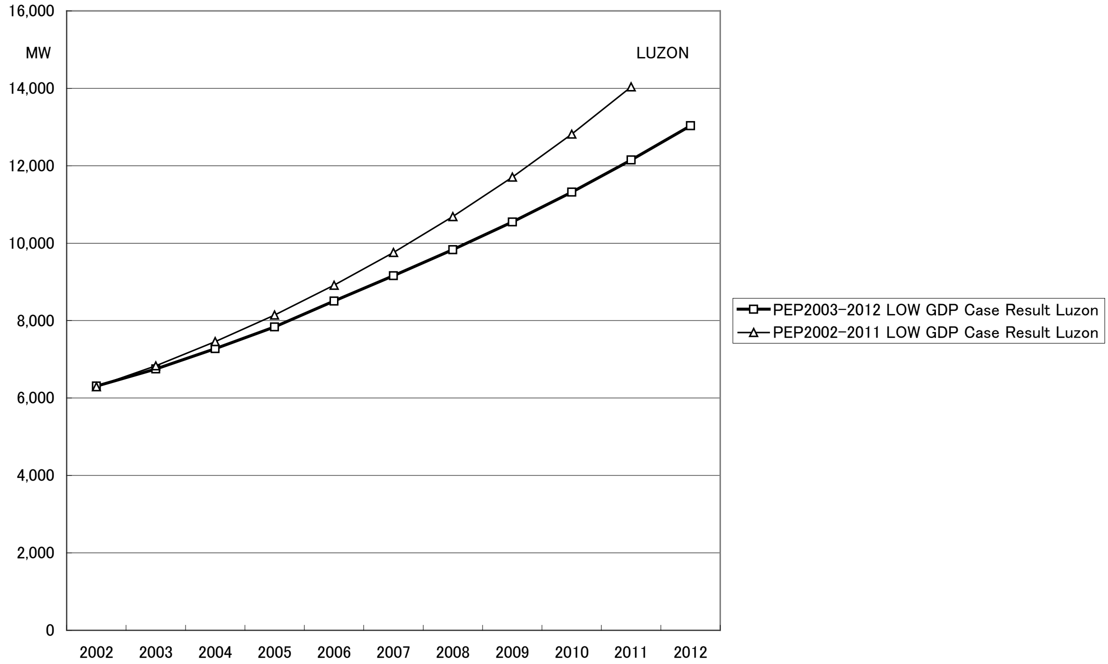
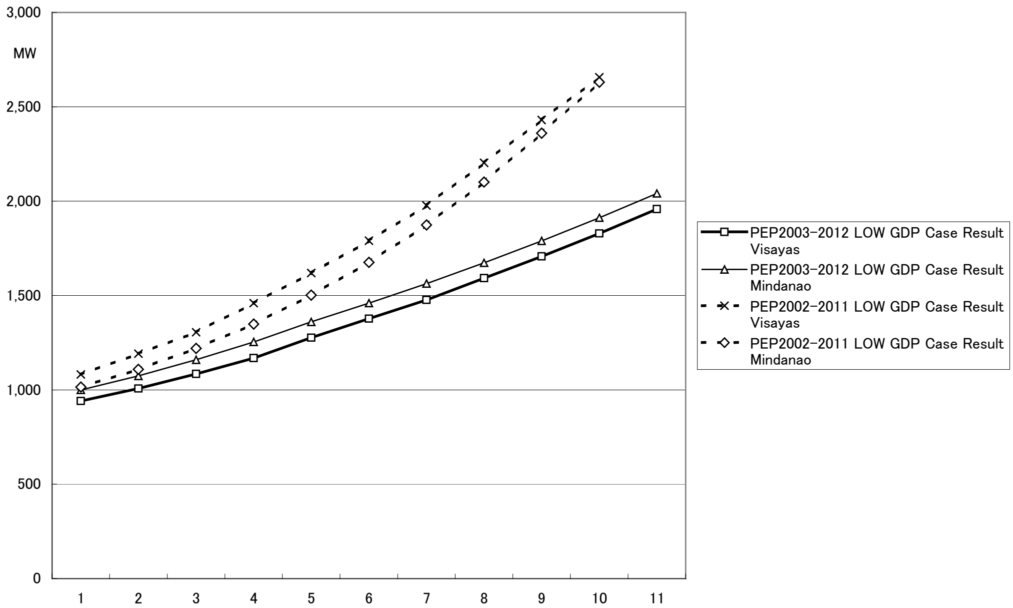


Fig. 3.14 Difference between PDP 2002-2011 and PDP 2003-2012 in the Visayas and Mindanao



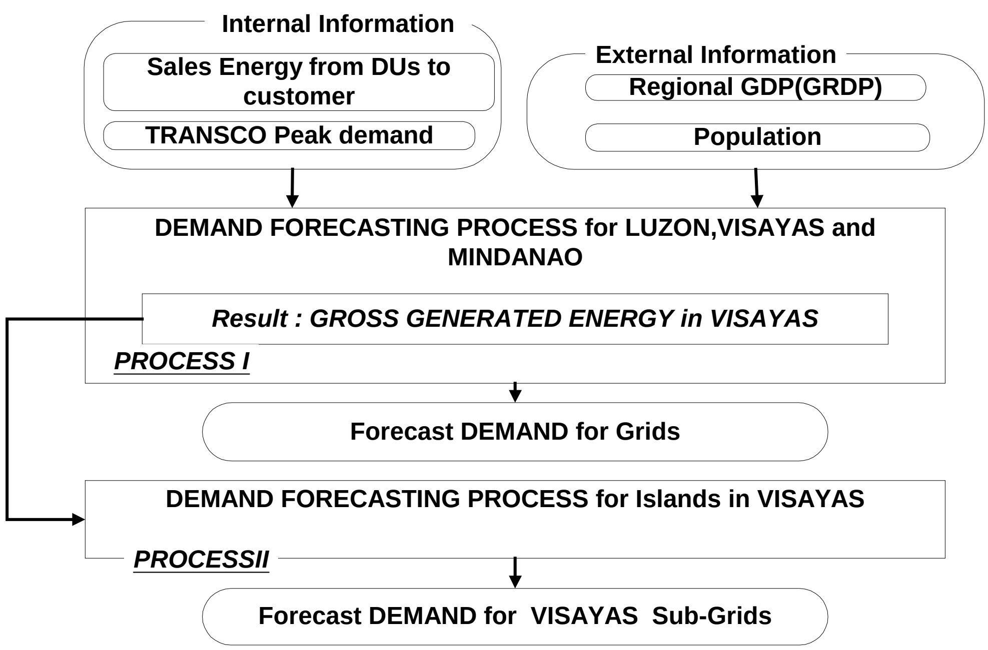
3.2.2 Forecasting model in PDP 2004-2013

(1) Overview of the Forecasting Model

Because it is difficult for NPC to forecast future demand using the past forecasting scheme, a new forecasting scheme—which is based on sales data in the distribution system—has been adopted in this project. Under this new scheme, sales forecast is performed by regression using the variables of population and GDP-related data with segmentation by region.

Looking at historical sales data, bulk sales were sometimes categorized as "industrial," and sometimes categorized as "bulk sales." Thus, for the purpose of this study, sales were identified as two categories, i.e., "residential" and "non-residential" to avoid confusion.

Fig. 3.15 Overview of the demand forecasting process



In demand forecasting, sales in distribution and the TRANSCO peak demand were used as the estimated variable, and regional GDP and population were used as external explanatory variables. The main flow of demand forecasting process is shown in Fig. 3.15.

This demand forecasting was performed for the main grids of Luzon, the Visayas and Mindanao (Process I in Fig. 3.15), and was also performed for large islands in the Visayas (Process II in Fig. 3.15).

In addition, an adjustment process has been adopted to avoid variance between estimated gross generated energy in the Visayas according to PROCESS I, and total gross generation of large islands obtained according to PROCESS II. This new model is a type of econometric model similar to the model previously used in PDP 2003-2012 or PDP 2002-2011.

Comparing the scheme used in past demand forecasting and the new forecasting scheme, there is a difference on the scope of forecasting between the two models. The new forecasting model relatively depends on regional forecasting rather than forecasting by utility (especially in the Manila area). Also, it depends on sales data of end-user rather than transmitted energy on the transmission system.

The next table illustrates the difference between the forecasting methods used in the past PDP (PDP 2004-2013) and ideal and well-developed forecasting model in a deregulated situation. In the future competitive market, forecasting models also must evaluate market conditions using end-use forecasting models and price elasticity in volatile markets, among others.

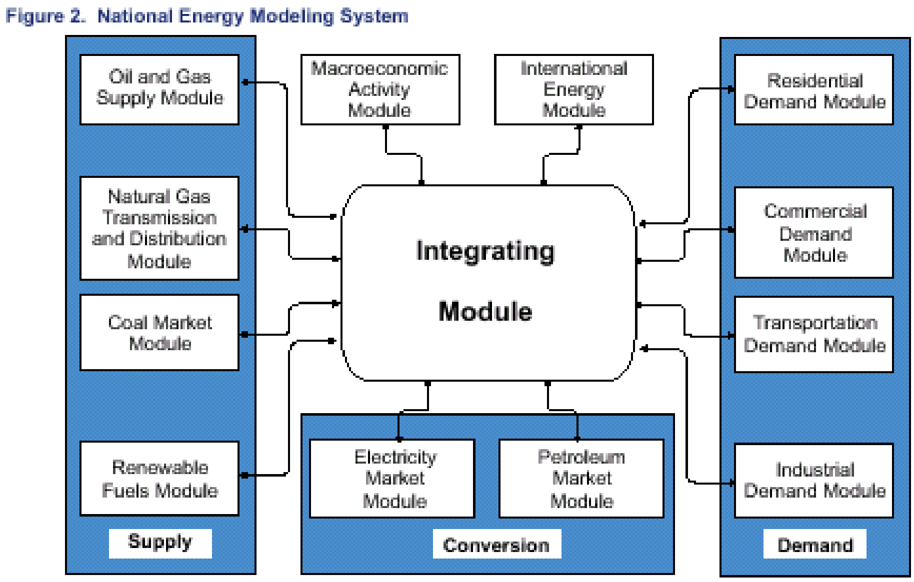
Table 3.2 Comparison of demand forecasting models

Model	Past PDP	PDP 2004-2013	Ideal and well developed forecasting model
Implementing agencies	Utilities (NPC)	Government (DOE)	Outsourcing to special organization
Forecasting models	Econometric	Econometric	Hybrid (Combination of Econometric and end-use model)
Data collection regarding	GDP related indicator, Sales at whole sales and Number of customer	GDP related indicator, Sales at retail and social data such as population	More detail economic indicators, Sale at end-use level, penetration of end-use equipment, data such as number of household or flower space.
Competition model	Not considered	Not considered	Including penetration model and price elasticity model.

In developed countries, these forecasting models become more complicated. As a norm, forecasting models in these countries include not only macro (econometric) models but also include micro (end-use) models, or a combination of such models.

For example, the National Energy Modeling System (NEMS)—which was developed by the U.S. DOE—is the most complicated demand forecasting model, as illustrated in Figure 3.16.

Fig. 3.16 Structure of NEMS system



The most significant feature of this tool, which includes the market model (Table 3.6), is that it requires market prices of indigenous energy. It can also evaluate the impact of conservation and renewable energy on future electricity demand. Such models are very important for the government to formulate policies and strategies affecting the energy sector.

In the case of the U.S., some parts of end-use model included in NEMS have derivate models such as "Reeps" and "Commend". These models are used for business entity by EPRI. Still those models are typical in the electric power business in the U.S.

Typically, likewise, end-use forecasting for each sector in NEMS requires data shown below.

Table 3.3 The Residential Demand Module of NEMS

RDM Outputs	Inputs from NEMS	Exogenous Inputs
Energy product demand	Energy product prices	Current housing stocks and retirement rates
Changes in housing and appliance stocks	Housing starts	Current appliance stocks and life expectancy
Appliance stock efficiency	Population	New appliance types, efficiencies, and costs
		Housing shell retrofit indices
		Unit energy consumption
		Square footage

Table 3.4 The Commercial Demand Module of NEMS

CDM Outputs	Inputs from NEMS	Exogenous Inputs
Energy product demands	Energy product prices	Existing commercial floor space
Changes in floor space and appliance stocks	Interest rates	Floor space survival rates
	Floor space growth	Appliance stocks and survival rates
		New appliance types, efficiencies and costs
		Energy-use intensities

Table 3.5 The Industrial Demand Module of NEMS

IDM Outputs	Inputs from NEMS	Exogenous Inputs
Energy product demand	Energy product prices	Production stages in energy-intensive industries
Electricity sales to grid	Economic output by industry	Technology possibility curves
Cogeneration output and fuel consumption	Refinery fuel consumption	Unit energy consumption
	Lease and plant fuel consumption	Stock retirement rates
	Cogeneration from refineries and oil and gas production	

Table 3.6 The Electricity Market Module of NEMS

EMM Outputs	Inputs from NEMS	Exogenous Inputs
Electricity prices and price components	Electricity prices	Financial data
Fuel demands	Fuel prices	Tax assumptions
Capacity additions	Cogeneration supply and fuel consumption	Capital costs
Capital requirements	Electricity sales to the grid	Operation and maintenance costs
Emissions	Renewable technology characteristics, allowable capacity, and costs	Operating parameters
Renewable capacity	Renewable capacity factors	Emission rates
Avoided costs	Gross domestic product	New technologies
	Interest rates	Existing facilities
		Transmission constraints
		Hydropower capacity and capacity factors

(2) Data collection

To aid the DOE in the management of data which are necessary for demand forecasting, the JICA team proposed the collection of these data, as described below.

Population: Both actual and forecasted data were collected from NSO and NSCB. Because a national census is held every five years, interpolating is necessary to fill in the data between census years.

GDP: Historical regional and by sector GDP data can be obtained from NSO statistics each year. Forecasted GDP can be obtained from NEDA. A five-year forecast is officially disclosed to the public, but DOE can obtain a ten-year forecast. However, the DOE must prepare regional forecasted GDP data using trend analysis.

Actual sales in distribution companies: Historical sales data of PIOUs based on the filing data in the ERC. Some data are missing in these databases, and annual reports stored in the ERC were also referred to. Even as a result of these inquiries, data was still missing, and interpolation has been adopted to estimate the missing data.

Historical sales data of electric utilities can be obtained from chronicles published by NEA. These sales data were prepared between 1990 and 2001.

Peak demand: Historical peak demand, such as the "TRANSCO Peak" (meaning the actual transmission system level peak) and the "System Peak" (meaning the peak including the embedded demand supplied generator connecting onto distribution level), are obtained from TRANSCO. In addition, more than 10 years of historical gross generated energy by NPC and direct sales on the transmission system by NPC have been obtained. However, the ratio between sales in distribution and gross generation are determined by referring to data from 1999 to 2001.

(3) Specifics of the demand forecasting method

The JICA team formulated a step by step process for the determination of the demand forecast, both for the entire Philippines and the grids within the Visayas region.

The process used by the JICA team to forecast electricity demand for the entire country is shown in Fig 3.19, while the forecasting process for the Visayas grids is shown in Fig 3.20.

The steps followed in these processes are described below.

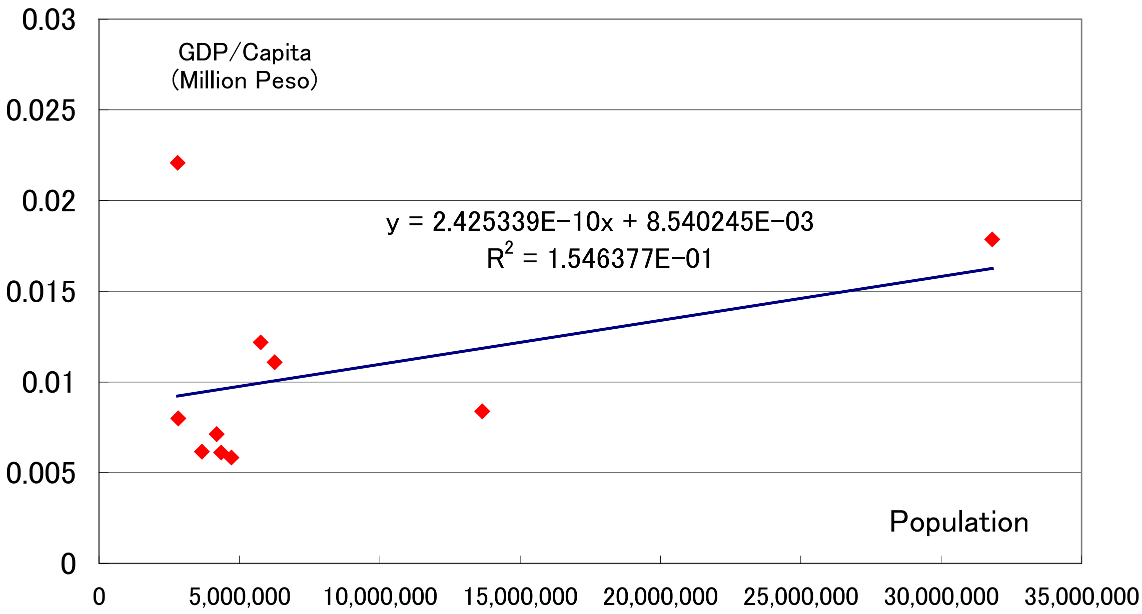
a) Sales data forecasting at the distribution level

Regression formulas by region are created based on the past sales data of distribution companies. The coefficients of these formulas are derived using a single and a multiple regression process employing statistical tools. These analyses are performed for residential and non-residential sectors. The structures of these regression formulas are as follows:

Residential Sector sales = a *population + b* GDP/Capita + c
Non- Residential Sector sales = a* regional GDP

In the first formula, it is assumed that the population and the GDP per capita are independent of each other. The population and the GDP per capita, which indicates the affluence of an area, are not related. For example, the relation between both variables in each region in the Philippines is shown in the next figure, and there is little correlation.

Fig. 3.17 Relation between GDP per Capita and population



b) Conversion to sales in the main grid

In the next step, energy sales on small islands, which are not connected to the main grid, are separated.

c) Conversion to gross generation

The total sales in distribution systems in each main grid are calculated. These values are then converged to Gross Generated Energy, using the Adjustment Factor (AF). This explains the past three year' average ratio between Gross Generated Energy and Sales in the distribution system. Gross Generated Energy is calculated from Sales data.

Gross Generated Energy = (1+AF) * Sales in distribution

d) Conversion to MW values

The "Peak Demand" is derived by interpolating "Load Factor" and "Gross Generated Energy" data. In PDP 2004-2013, the same load factors as used in the past PDP are used (shown in Table 3.2).

Table 3.7 Load Factor

Grid	Load Factor (%)
Phils	**59.0**
Luzon	**71.2**
Visayas	**70.0**
Leyte-Samar	66.0
Cebu	64.0
Negros	52.0
Panay	59.0
Mindanao	**70.0**

e) Adjustment of the starting point of peak demand growth

At this stage, a growth curve for peak demand is created for each GDP scenario. In addition, other adjusted elasticity curves can be created. However, the starting point for the curve for 2002 is not fitted to actual peak demand in 2002, so the next treatment is conducted to fit the starting point to the actual 2002 peak value and to adjust the growth curve after 2002.

Fig. 3.18 The method for adjusting the starting point for peak demand

	NEDA LOW GDP CASE			
	Phils	Luzon	Visayas	Mindanao
2002	7,753	5,850	910	993
2003	8,276	6,251	978	1,047
2004	8,885	6,720	1,055	1,110
2005	9,558	7,239	1,140	1,179
2006	10,314	7,823	1,234	1,256
2007	11,045	8,391	1,326	1,328
2008	11,869	9,031	1,429	1,409
2009	12,756	9,722	1,539	1,495
2010	13,686	10,448	1,655	1,583
2011	14,662	11,213	1,777	1,673
2012	15,687	12,017	1,905	1,765
2013	16,763	12,864	2,040	1,860
2014	17,894	13,756	2,182	1,956
2015	19,082	14,695	2,331	2,055

NEDA LOW GDP CASE			
Total Ph.	Luzon	Visayas	Mindanao
7,970	6,039	936	995
8,508	6,454	1,006	1,049
9,134	6,937	1,085	1,112
9,827	7,473	1,172	1,181
10,604	8,076	1,269	1,259
11,357	8,662	1,363	1,331
12,204	9,323	1,469	1,412
13,117	10,036	1,582	1,498
14,074	10,786	1,702	1,586
15,079	11,575	1,827	1,676
16,133	12,406	1,959	1,769
17,241	13,280	2,097	1,864
18,404	14,201	2,243	1,960
19,627	15,171	2,397	2,060

1. Adjust 2002 data to actual

2. Calculate demand from 2003 using same elasticity as in the original forecasting results

f) Demand forecasting for sub-grids

The method for demand forecasting for the smaller grids in the Visayas is almost the same as the method used for the main grids. However, the first step is the distribution of Gross Generated Energy in the Visayas to each area that requires energy on the islands of the Visayas.

In this process, the historical share of total sales of the distribution companies on each island is calculated, and trends in future shares are analyzed using trend analysis. Using these island shares, Gross Generated Energy is distributed and translated into peak island demand.

g) Preparing the energy requirement for the Generation and Transmission Plan

Using forecasted peak demand in MW, Gross Generated Energy was re-calculated. This process is necessary for Generation and Transmission planning. This process is basically accomplished using the load factor of each island. However, the total Gross Generated Energy obtained by calculating each island's value will be slightly different from the Gross Generated Energy obtained by forecasting for the main grid of the Visayas. Therefore, there needs to be some adjustment to the load factor to match both values.

Fig. 3.19 Demand forecasting flow for the main grids

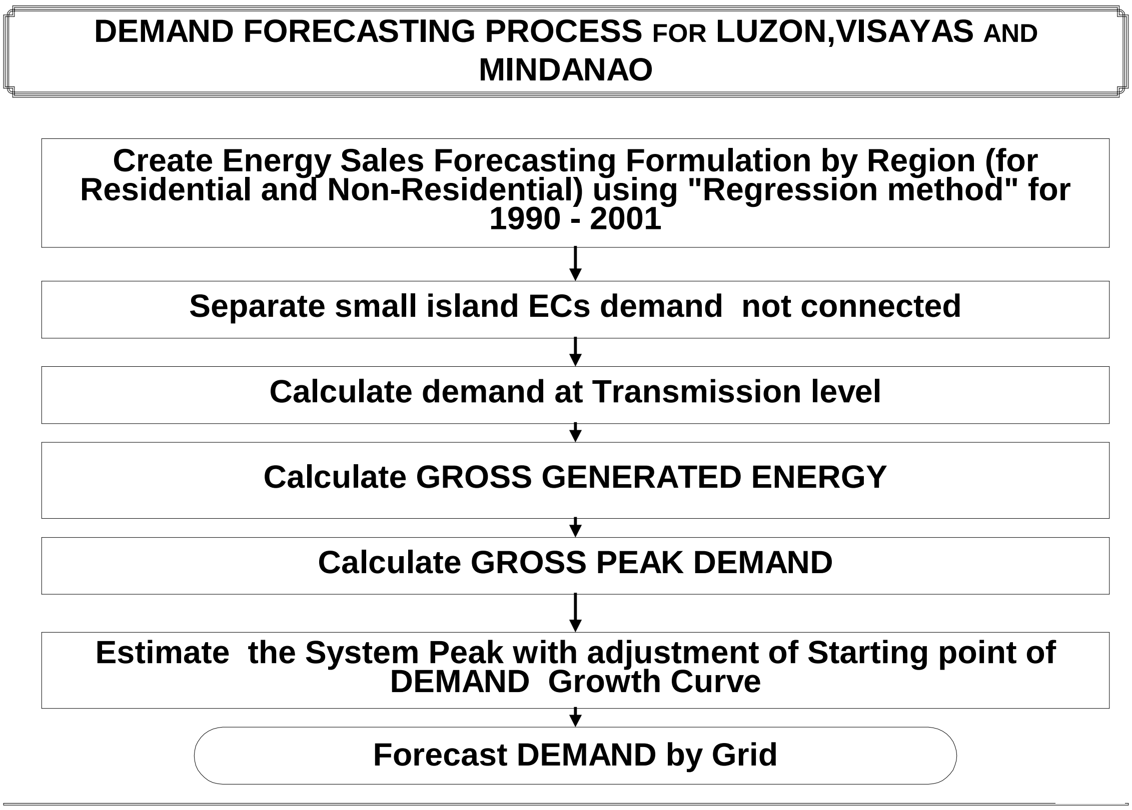
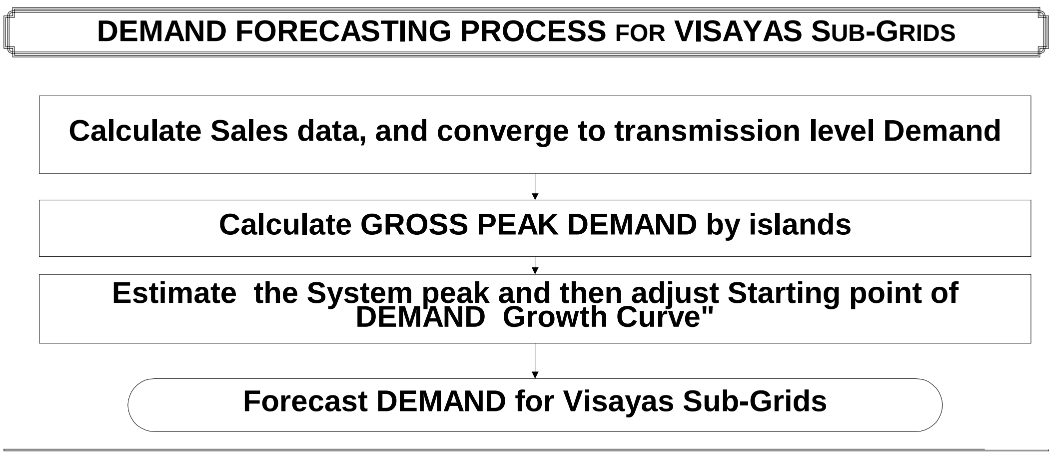


Fig. 3.20 Demand forecasting flow for grids within the Visayas region



3.3 Forecast Results and Considerations

3.3.1 Forecast results

Demand forecast in PDP 2004-2013 is performed assuming the three GDP scenarios shown below.

- High GDP growth scenario from NEDA
- Low GDP growth scenario from NEDA
- Modified scenario by DOE from a low GDP scenario, by replacing a later five-year growth rate with an average early five-year growth rate

Originally, the results for PDP 2004-2013 show a declining trend in GDP elasticity. Thus, other results tallied with the original results, assuming elasticity will be maintained at the same level as the 2003 level. Finally, six different demand-forecasting results were calculated for each of the major island grids as well as the sub-grids within the Visayas region.

These results calculated for the Luzon, Visayas and Mindanao grids are as follows:

Luzon grid:

Assuming a declining elasticity, three result curves are close to the PDP 2003-2012 results. Only the case of high GDP becomes higher than the curve in PDP 2003-2012 (Fig. 3.21). If there is constant elasticity, there are three results between the curve in PDP 2002-2011 and in PDP 2003-2012 (Fig. 3.24).

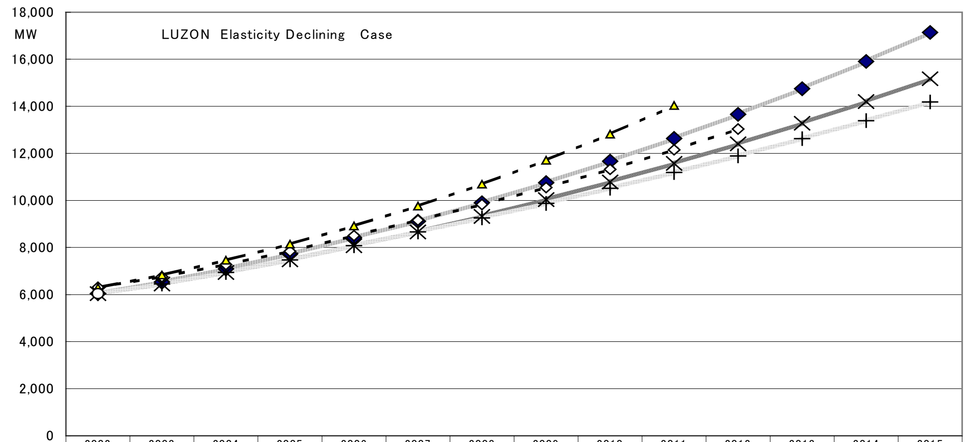
Visayas grid:

When there is a declining elasticity, the growth curve is very similar to the results of PDP 2003-2012 (Fig .3.22). On the other hand, if elasticity remains constant, all three curves are between the curve in PDP 2002-2011 and PDP 2003-2012 (Fig. 3.25). It seems that the results in PDP 2002-2011 are overestimated, but the results in PDP 2003-2012 are only a little higher, and are reasonable when compared with the results in PDP 2004-2013.

Mindanao grid:

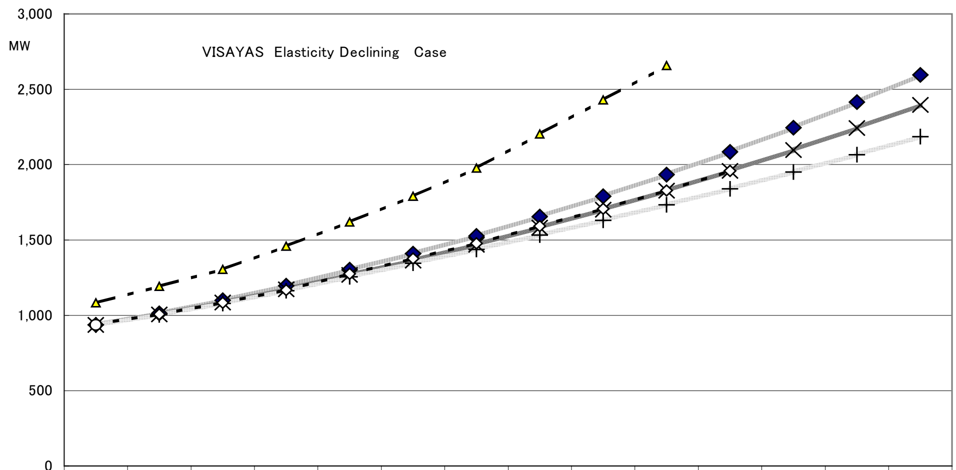
Forecast results for Mindanao indicate that the curves are below the PDP 2003-2012 when the elasticity is on the decline (as shown in Figure 3.23). In the case of a constant elasticity, low GDP has almost the same curve as the PDP 2003-2012 results (Fig. 3.26). Therefore, the results in PDP 2003-2012, which were modified to be lower than the PDP 2002-2011 results, are still higher.

Fig. 3.21 Demand growth curve in Luzon (declined elasticity)



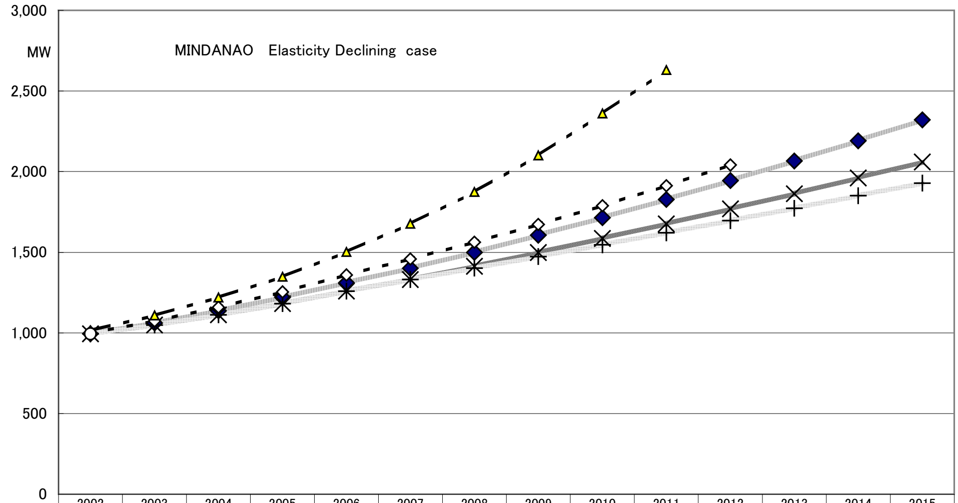
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
NEDA High GDP CASE Luzon	6,039	6,530	7,090	7,718	8,416	9,115	9,903	10,759	11,667	12,632	13,657	14,746	15,905	17,137
NEDA LOW GDP CASE Luzon	6,039	6,454	6,937	7,473	8,076	8,662	9,323	10,036	10,786	11,575	12,406	13,280	14,201	15,171
LOWER GDP Modified CASE Luzon	6,039	6,454	6,937	7,473	8,076	8,662	9,255	9,872	10,517	11,189	11,890	12,622	13,387	14,186
PEP2003-2012 LOW GDP Case Result Luzon	6,308	6,752	7,275	7,835	8,503	9,161	9,830	10,548	11,319	12,149	13,034			
PEP2002-2011 LOW GDP Case Result	6,293	6,830	7,458	8,143	8,915	9,762	10,689	11,705	12,816	14,038				
Luzon Actual	6,039													

Fig. 3.22 Demand growth curve in the Visayas (declined elasticity)



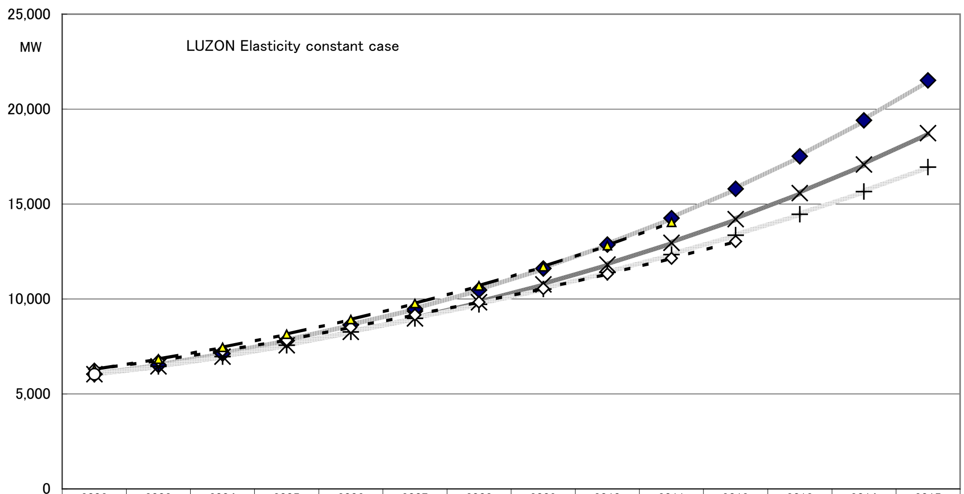
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
NEDA High GDP CASE Visayas	936	1,013	1,100	1,197	1,302	1,409	1,527	1,655	1,790	1,933	2,085	2,245	2,415	2,596
NEDA LOW GDP CASE Visayas	936	1,006	1,085	1,172	1,269	1,363	1,469	1,582	1,702	1,827	1,959	2,097	2,243	2,397
LOWER GDP Modified CASE Visayas	936	1,003	1,079	1,163	1,256	1,346	1,438	1,532	1,631	1,733	1,840	1,950	2,066	2,186
PEP2003-2012 LOW GDP Case Result Visayas	941	1,007	1,084	1,168	1,276	1,377	1,477	1,592	1,707	1,829	1,958			
PEP2002-2011 LOW GDP Case Result	1,082	1,192	1,305	1,459	1,619	1,790	1,977	2,203	2,430	2,657				
Visayas Actual	936													

Fig. 3.23 Demand growth curve in Mindanao (declining elasticity)



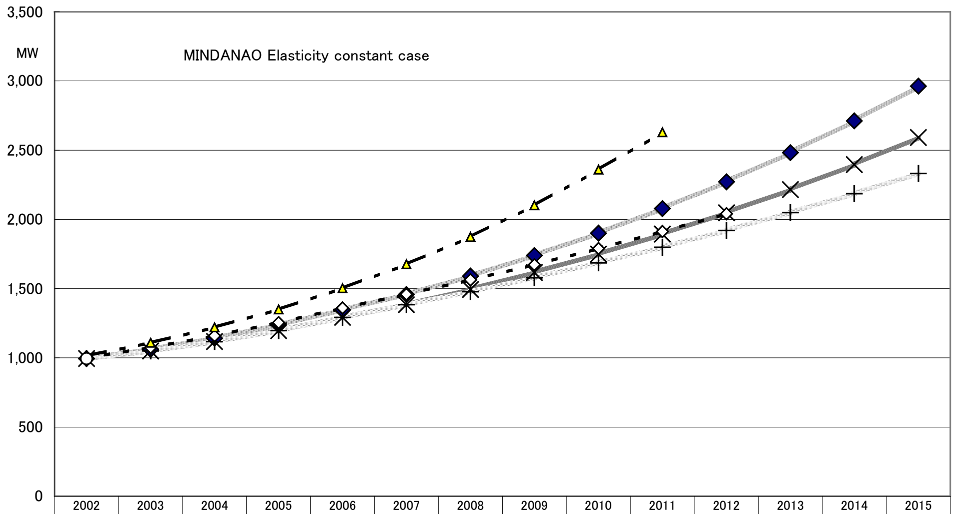
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
NEDA High GDP CASE Mindanao	995	1,061	1,136	1,220	1,312	1,401	1,500	1,605	1,715	1,828	1,945	2,066	2,192	2,321
NEDA LOW GDP CASE Mindanao	995	1,049	1,112	1,181	1,259	1,331	1,412	1,498	1,586	1,676	1,769	1,864	1,960	2,060
LOWER GDP Modified CASE Mindanao	995	1,049	1,112	1,181	1,259	1,331	1,402	1,474	1,547	1,621	1,696	1,773	1,850	1,929
PEP2003-2012 LOW GDP Case Result Mindanao	1,000	1,074	1,159	1,254	1,360	1,459	1,563	1,673	1,789	1,912	2,041			
PEP2002-2011 LOW GDP Case Result	1,015	1,109	1,220	1,349	1,502	1,676	1,874	2,101	2,360	2,630				
Mindanao Actual	995													

Fig. 3.24 Demand growth curve in Luzon (constant elasticity)



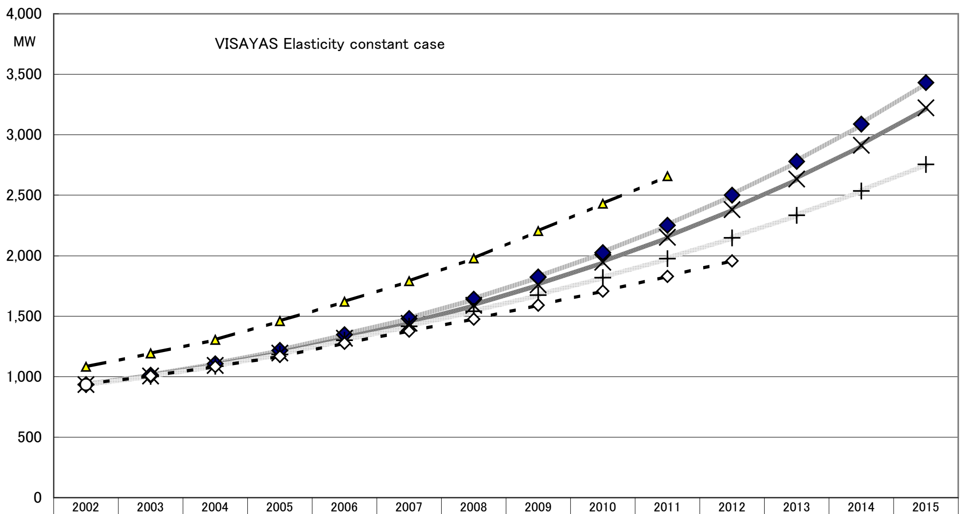
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
NEDA High GDP CASE Luzon	6,039	6,530	7,120	7,817	8,628	9,472	10,470	11,605	12,862	14,256	15,800	17,512	19,409	21,511
NEDA LOW GDP CASE Luzon	6,039	6,454	6,967	7,564	8,272	8,982	9,822	10,771	11,812	12,954	14,206	15,579	17,084	18,735
LOWER GDP Modified CASE Luzon	6,039	6,454	6,967	7,564	8,272	8,982	9,724	10,527	11,397	12,339	13,358	14,462	15,656	16,949
PEP2003-2012 LOW GDP Case Result Luzon	6,308	6,752	7,275	7,835	8,503	9,161	9,830	10,548	11,319	12,149	13,034			
PEP2002-2011 LOW GDP Case Result	6,293	6,830	7,458	8,143	8,915	9,762	10,689	11,705	12,816	14,038				
Luzon Actual	6,039													

Fig. 3.25 Demand growth curve in the Visayas (constant elasticity)



	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
NEDA High GDP CASE Mindanao	995	1,061	1,142	1,236	1,347	1,458	1,590	1,739	1,901	2,078	2,271	2,482	2,712	2,963
NEDA LOW GDP CASE Mindanao	995	1,049	1,117	1,197	1,292	1,384	1,494	1,617	1,750	1,893	2,048	2,216	2,396	2,591
LOWER GDP Modified CASE Mindanao	995	1,049	1,117	1,197	1,292	1,384	1,478	1,578	1,685	1,799	1,920	2,049	2,186	2,333
PEP2003-2012 LOW GDP Case Result Mindanao	1,000	1,074	1,159	1,254	1,360	1,459	1,563	1,673	1,789	1,912	2,041			
PEP2002-2011 LOW GDP Case Result	1,015	1,109	1,220	1,349	1,502	1,676	1,874	2,101	2,360	2,630				
Mindanao Actual	995													

Fig. 3.26 Demand growth curve in Mindanao (constant elasticity)



	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
NEDA High GDP CASE Visayas	936	1,013	1,107	1,218	1,347	1,482	1,642	1,824	2,026	2,251	2,501	2,779	3,087	3,430
NEDA LOW GDP CASE Visayas	936	1,006	1,093	1,196	1,319	1,442	1,591	1,759	1,946	2,153	2,381	2,634	2,914	3,223
LOWER GDP Modified CASE Visayas	936	1,003	1,086	1,184	1,301	1,418	1,541	1,674	1,819	1,976	2,148	2,334	2,536	2,755
PEP2003-2012 LOW GDP Case Result Visayas	941	1,007	1,084	1,168	1,276	1,377	1,477	1,592	1,707	1,829	1,958			
PEP2002-2011 LOW GDP Case Result	1,082	1,192	1,305	1,459	1,619	1,790	1,977	2,203	2,430	2,657				
Visayas Actual	936													

3.3.2 Considerations in the Demand Forecast

(1) Growth rate

Demand forecasting results show that declined elasticity and the Lower GDP Modified case has a similar growth rate to the past average growth rate.

Although the Lower GDP Modified case scenario is still 1.0 point higher than the GDP forecast by external organizations, declining elasticity balances have a greater influence on the higher GDP assumption. Therefore, this curve is the possible lowest growth curve in the forecast.

On the other hand, if the declining trend from the middle of the 90s soon ceases, and GDP growth continues as NEDA has estimated, constant elasticity and the NEDA low GDP case curve is a possible scenario. Therefore, this curve was recommended as the highest growth curve in the forecast. In this highest case, demand growth in 2013 comes before 1.5 to 2.5 year against declined elasticity and the Lower GDP Modified case.

In its forecasting, however, DOE utilized the declined elasticity and the NEDA Low GDP case, which has a curve near to these two recommended results, as the most likely scenario and the base of the capacity planning. This means that future demand growth will be 0.2 – 1.2 points higher than the growth experienced in the past 10 years.

The table below shows the results of demand forecasting in PDP 2004-2013 (see Table 3.6) including the average for the next 10 years' forecasted growth rates. The table likewise shows the past 10 years' actual average growth rate.

Table 3.8 Future 10-year-growth rate and the past 10-year-average growth rate

	Average Growth Rate of Forecasted Result for 2003–2013						Actual Average Growth Rate for 1992–2002
	Declining Elasticity Case			Constant Elasticity Case			
	NEDA High GDP CASE	NEDA LOW GDP CASE	LOWER GDP Modified CASE	NEDA High GDP CASE	NEDA LOW GDP CASE	LOWER GDP Modified CASE	
Luzon	8.5%	7.5%	6.9%	10.4%	9.2%	8.4%	6.3%
Vusayas	8.3%	7.6%	6.9%	10.6%	10.1%	8.8%	7.1%
Mindanao	6.9%	5.9%	5.4%	8.9%	7.8%	6.9%	5.7%

Results of the review of forecasts in PDP 2004-2013 are shown below.

Luzon grid:

The results of the growth rate are higher than in the past. In the next five years, an 8% –10% growth rate can be expected. However, if elasticity declines, the growth rate will be 2.0 points lower than in the previous five years. (Figure 3.27)

Visayas grid:

In the past, the growth rate fluctuated by 4 - 6 points at around 10%. In the next five years, an 8% –10% growth rate can also be expected. However, if elasticity declines, the growth rate will be 2.0 points lower than in the previous five years. (Figure 3.28)

Mindanao grid:

Because the growth rates have been low in the past five years, a 6%–7% growth rate is expected in the near future. In addition, if elasticity declines, the following 10 years' growth rate will be almost 5%, and it is possible that demand will be lower than in the Visayas by 2014. (Figure 3.29)

Fig. 3.27 Actual and forecasted growth rate in Luzon

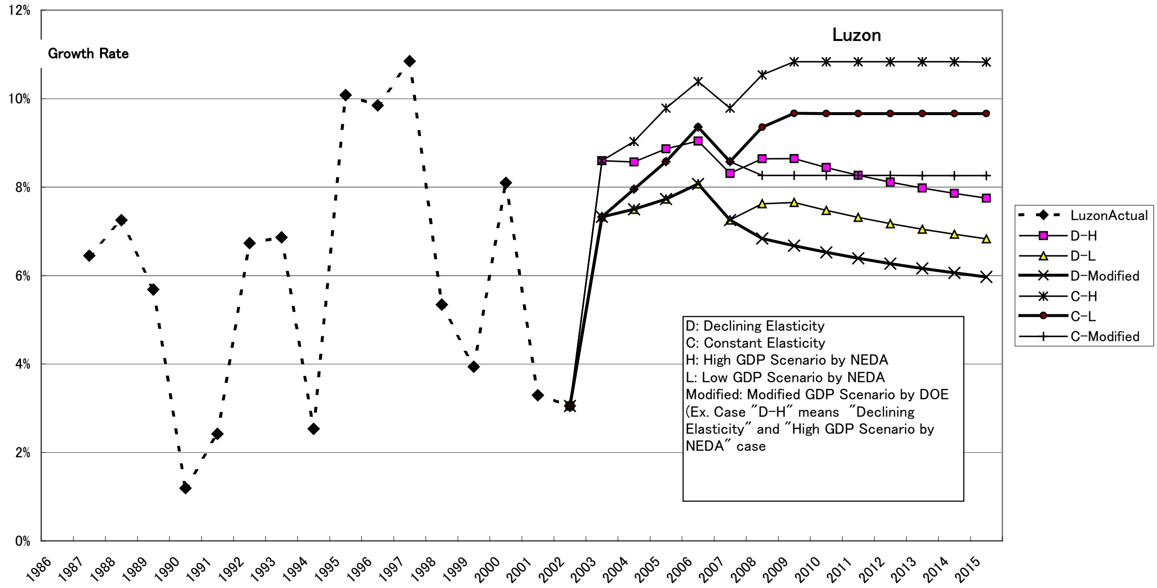


Fig. 3.28 Actual and forecasted growth rate in the Visayas

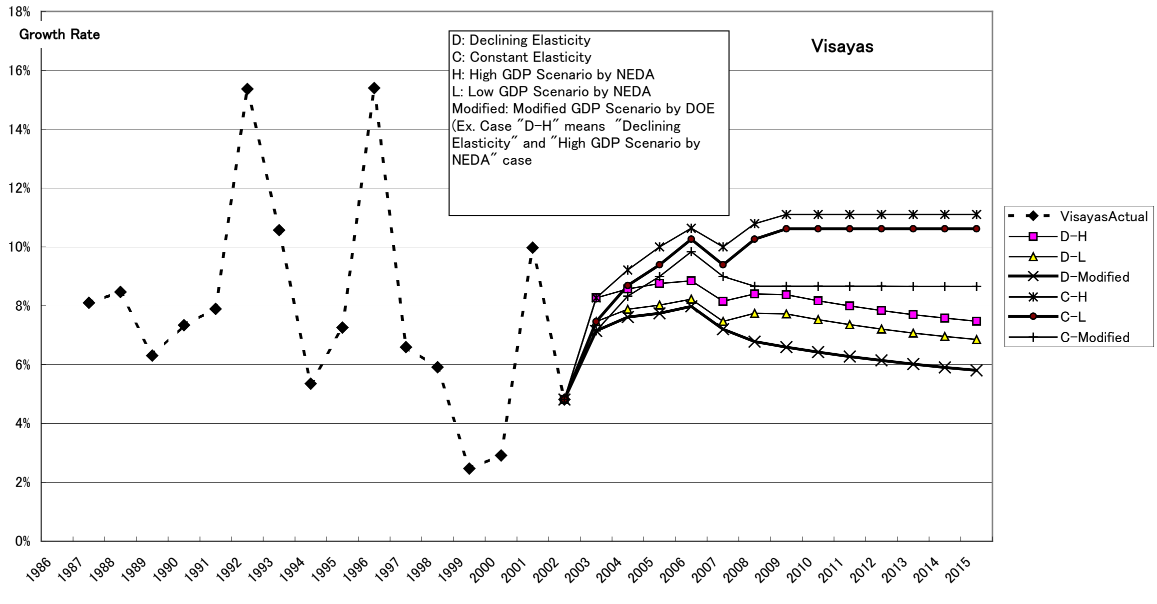
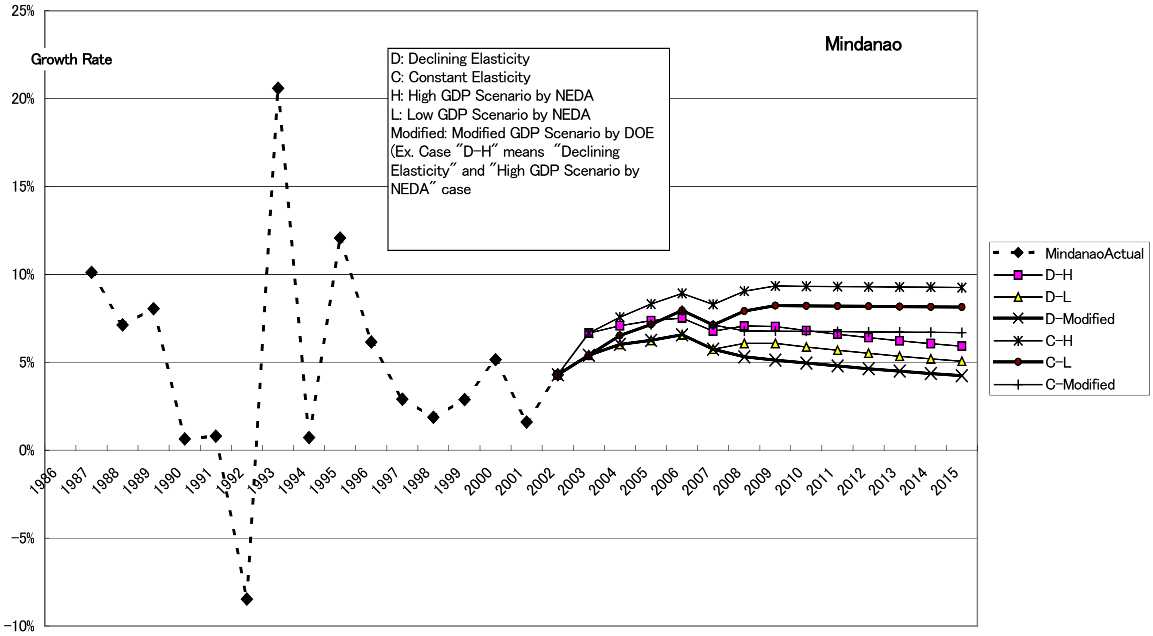


Fig. 3.29 Actual and forecasted growth rate in Mindanao



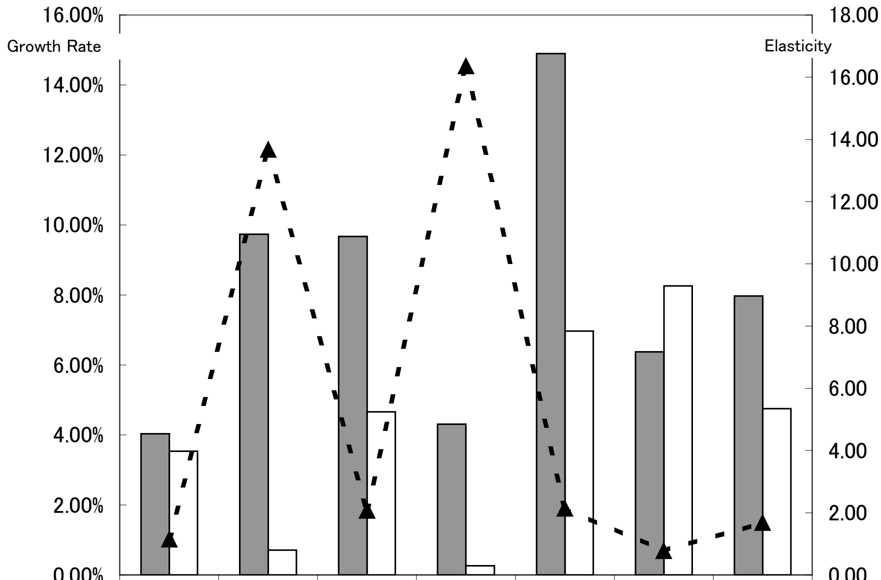
(2) Elasticity

Philippine GDP elasticity—which is equal to the ratio of the demand growth rate against GDP growth rate—is relatively lower than in other Southeast Asian countries as shown in Figure 3.30.

Most of the other Southeast Asian countries, which usually experience low GDP growth rate, experienced relatively high elasticity.

However, low GDP elasticity is experienced in the Philippines because the share of industrial sector in computing GDP is relatively lower than other countries (as shown in Figure 3.5). These industries usually consume more electricity to achieve the same amount of production (price base). Therefore, evaluating elasticity or consumption of electricity measured by each production is also important to understand the domestic economy and energy market structure.

Fig. 3.30 Comparison of GDP elasticity



	NPC+IPP:Philippines	Indonesia	Malaysia	Thailand	Vietnam	China	Korea
Average Demand growth rate 1996-2000	4.04%	9.74%	9.67%	4.30%	14.90%	6.38%	7.97%
Average GDP growth rate 1996-2000	3.54%	0.71%	4.66%	0.26%	6.97%	8.26%	4.75%
Elasticity	1.14	13.67	2.07	16.36	2.14	0.77	1.68

A study on the four-year moving trend of GDP elasticity in the Philippines showed large fluctuations in the trend.

Taking Mindanao as an example, negative elasticity has sometimes been experienced in the region, suggesting possible problems in the reliability of social and economic data or a delay in data collection.

Elasticity trends in each major island grid are shown below.

Luzon grid:

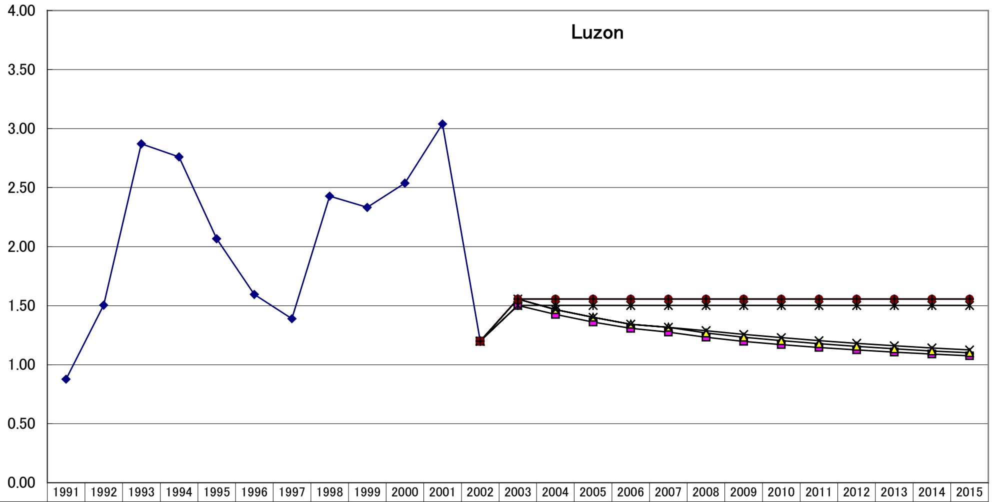
Through the 90s, Luzon experienced 1.0 – 1.5 of elasticity. Recent elasticity may be around 1.5. If the declining trend continues, elasticity may drop to nearly 1.0 in 10 years' time (Figure 3.31).

Visayas grid:

The declining trend was very clear in the Visayas through the 90s. Recent elasticity may be around 1.6. If the declining trend continues, elasticity may drop to nearly 1.0 in 10 years' time, the same as in Luzon (Figure 3.32).
Mindanao grid:

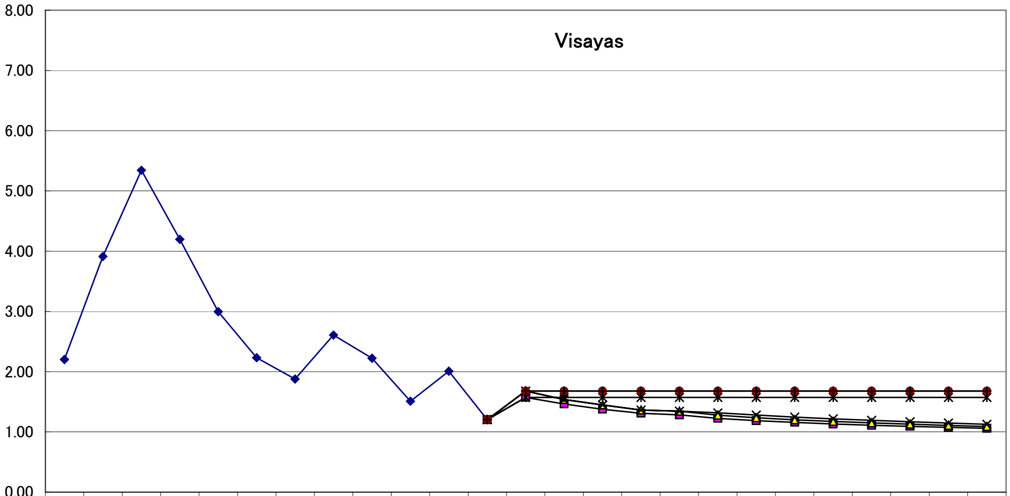
There has been local high elasticity, but there has been low elasticity near large load centers, such as Davao, influencing the total elasticity in Mindanao. Recent elasticity may be around 1.7. If the declining trend continues, elasticity may drop to nearly 1.0 in 10 years' time (Figure 3.33).

Fig. 3.31 Past four-year moving average and future GDP elasticity in Luzon



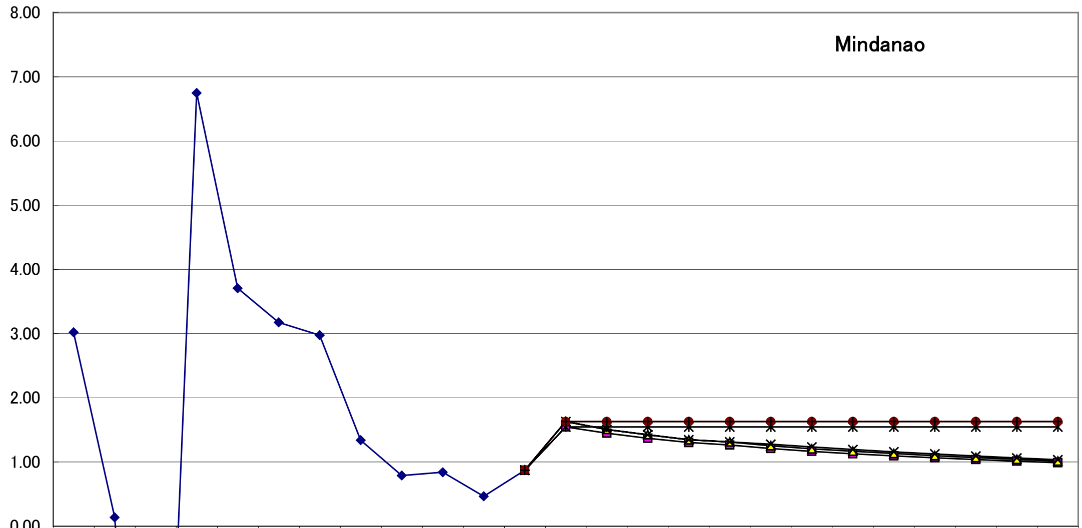
	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Actual	0.88	1.50	2.87	2.76	2.07	1.59	1.39	2.43	2.33	2.54	3.04	1.20													
P-H												1.20	1.50	1.42	1.36	1.31	1.28	1.23	1.20	1.17	1.15	1.12	1.11	1.09	1.07
P-L												1.20	1.56	1.47	1.40	1.34	1.32	1.27	1.23	1.20	1.18	1.15	1.13	1.12	1.10
P-Modified												1.20	1.56	1.47	1.40	1.34	1.32	1.29	1.26	1.23	1.20	1.18	1.16	1.14	1.12
C-H												1.20	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
C-L												1.20	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56
C-Modified												1.20	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56

Fig. 3.32 Past four-year moving average and future GDP elasticity in the Visayas



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Actual	2.20	3.91	5.34	4.20	3.00	2.23	1.88	2.61	2.22	1.51	2.01	1.20													
P-H												1.20	1.57	1.46	1.38	1.31	1.28	1.22	1.19	1.16	1.13	1.11	1.09	1.07	1.06
P-L												1.20	1.68	1.54	1.44	1.36	1.34	1.28	1.23	1.20	1.17	1.15	1.13	1.11	1.09
P-Modified												1.20	1.68	1.54	1.44	1.36	1.34	1.31	1.28	1.25	1.22	1.19	1.17	1.14	1.13
C-H												1.20	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57
C-L												1.20	1.68	1.68	1.68	1.68	1.68	1.68	1.68	1.68	1.68	1.68	1.68	1.68	1.68
C-Modified												1.20	1.68	1.68	1.68	1.68	1.68	1.68	1.68	1.68	1.68	1.68	1.68	1.68	1.68

Fig. 3.33 Previous four-year moving average and future GDP elasticity in Mindanao



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Actual	3.02	0.14	-8.35	6.75	3.71	3.17	2.98	1.34	0.79	0.84	0.46	0.87													
P-H												0.87	1.55	1.45	1.37	1.30	1.26	1.21	1.17	1.13	1.10	1.07	1.04	1.01	0.99
P-L												0.87	1.63	1.51	1.42	1.35	1.31	1.25	1.20	1.17	1.13	1.10	1.07	1.04	1.01
P-Modified												0.87	1.63	1.51	1.42	1.35	1.31	1.28	1.23	1.19	1.16	1.12	1.09	1.06	1.03
C-H												0.87	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55
C-L												0.87	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63
C-Modified												0.87	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63

3.4 Issues in Future Data Collection and Demand Forecasting

(1) Comparison of the Philippine and the United States Power Sector Structures and Experiences

This section discusses the liberalization problems that may occur in the local power sector, basing from several experiences in the U.S., which has a more advanced liberalized regulatory regime

Under the U.S. setting, Federal Energy Regulatory Commission (FERC) receive filing data including a ten-year demand forecast by utilities at the federal level, or the nationwide level. It bears noting that the status of liberalization in the U.S. power sector varies among states.

Based on this data, the Energy Information Agency (EIA)—an organization within the U.S. DOE—predicts energy and power demand and conducts supply analysis. In fact, the Lawrence Berkeley National Laboratory is responsible for forecasting work, using a demand-forecasting tool called NEMS (described in Chapter 3.2.2).

This data collection scheme, which FERC has adopted, will be less reliable after the liberalization of the power sector if there are newcomers in the utility's franchise. Fortunately, the National Laboratory has already surveyed potential problems, thereby minimizing possible problems.

An evaluation of the US and Philippine power sector structures shows that the two are largely similar. FERC is the equivalent of the ERC; U.S. DOE is DOE in the Philippines; EIA has a counterpart division in DOE; and Lawrence Berkley is the JICA team (the structure shown in Fig. 3.34).

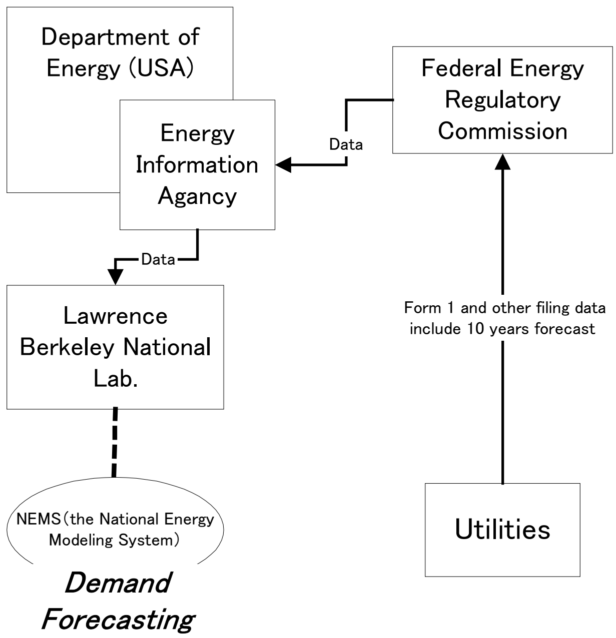
Data collection for demand forecasting in the US is likewise similar to the process being employed in the Philippines. Thus, problems now being faced by the US in its data collection may be experienced in the Philippines when its deregulated power industry matures.

Data requirement for demand forecasting (as shown in Figure 3.3 –6) are not so different prior to and after the deregulation. With the deregulation, the status of the franchises of electric utilities became unclear, making it very difficult to estimate utilities' demand vis-à-vis the demand in a particular area or region.

Also, for deregulated industries, some market models must be introduced in their respective forecasting models, showing the share of sales in the area or the region.

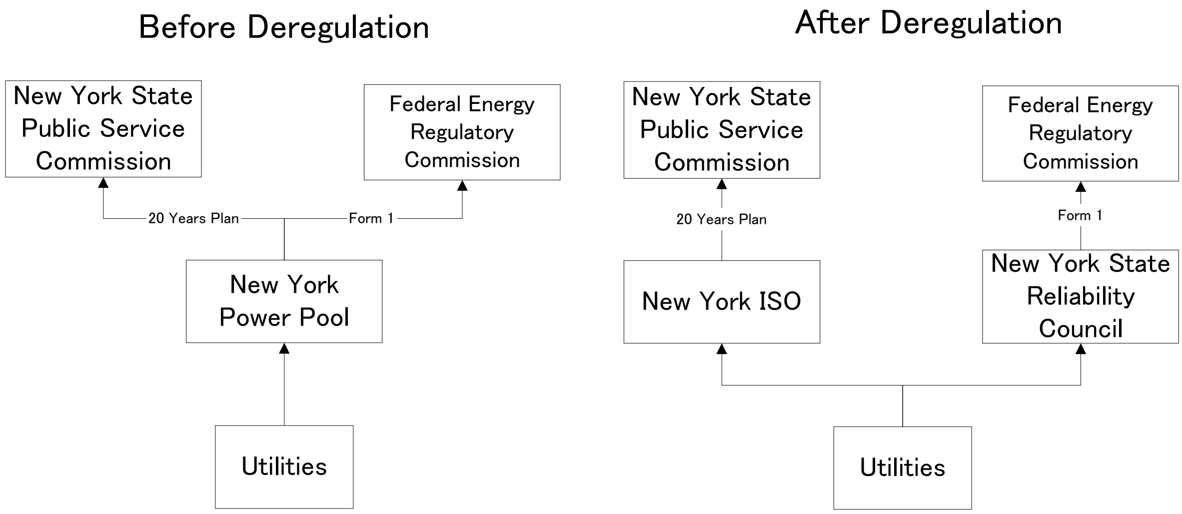
Moreover, there are no professional organizations in the Philippines that are comparable to the Lawrence Berkley National Laboratory in the U.S. so inheriting planning technologies may be problematic. Notwithstanding the budget problems confronting the Philippine government and considering the US experience, external organizations closely supervised by the DOE should be established for the sole purpose of conducting demand forecasting.

Fig. 3.34 Demand forecasting scheme at the federal level in U.S.



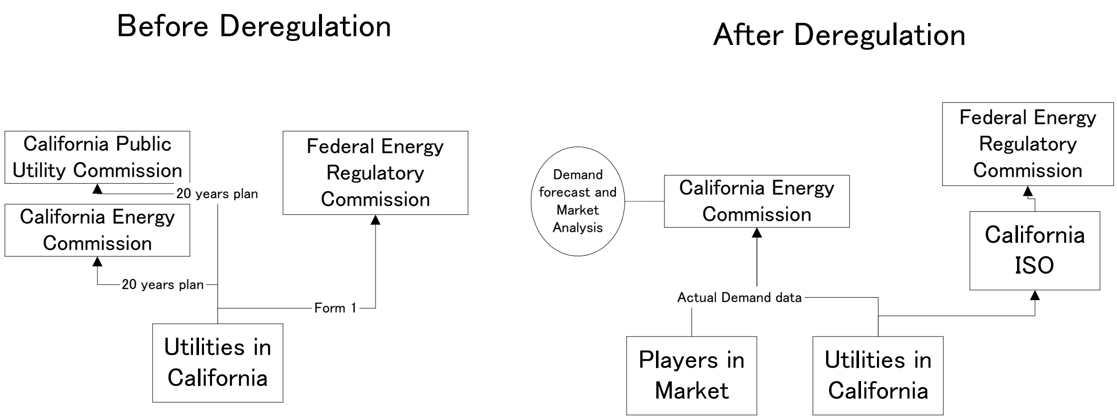
And examination of the differences in planning schemes before and after the liberalization of the power sector in major states in the U.S. reveals that planning schemes vary from state to state. In New York State, for instance, the New York Power Pool has been reformed to New York ISO when the New York power industry was deregulated. Therefore, the 20-year planning scheme has not changed after deregulation. However, the scheme for checking supply reliability was changed by creating an organization named NYSRC and the utilities filings' to FERC is now submitted through this new organization.

Fig. 3.35 Data flow-related demand forecasting before and after deregulation in NY State



On the other hand, California estimates future demand by itself because utilities have refused to submit a 20-year plan to state-regulation bodies since the mid 90s. Oversight responsibility for the California power sector falls on the California Energy Commission.

Fig. 3.36 Data flow-related demand forecasting before and after deregulation in California State



From these examples, it is evident that government organizations must become more responsible in planning and forecasting, compared to their roles prior to liberalization and deregulation of the industry. To understand the actual supply and demand dynamics, market operators such as NYISO must contribute their share. In some cases, it is imperative that the regulator forces market participants to submit information on trades and other pertinent and relevant data.

(2) Considerations in Instituting Reforms in the Philippine Power Sector

As mentioned above, NPC used to be the only organization responsible for wholesale sales. In addition, NPC could easily collect the retail sales data from distribution companies by correlating wholesale sales data and retail data. However, after liberalization, NPC's vertically-integrated functions were broken down and delegated to other entities including the TRANSCO and several GENCOs, making it difficult to assess the wholesale situation of nascent IPP trade for NPC. (Figure 3.37 shows the physical power flow among organizations after liberalization.)

With the separation of transmission and generation functions, TRANSCO has a direct knowledge of the physical power flow, but does not have direct knowledge on the identity of either the seller or the buyer of electricity. Therefore, TRANSCO principally has knowledge on the transmission peak in each main grid and the smaller grids.

Under a liberalized environment, several trade styles are mixed, such as market trading and bilateral contract; spot, future and forward transactions are also mixed. (Figure 3.38 shows the relation between transactions in the market after liberalization.)

Therefore, it is most important that the regulator does not double count traded energy, confusing real and virtual trade, by collecting the amount of settled real energy transactions by WESM.

WESM can monitor generated and consumed energy daily and hourly with known traders, and all trades can be monitored using its scheduling and settlement systems.

In the PDP 2004-2013 planning, there was no data collection through market operators since WESM was not yet in operation.

In the U.S., the amount of this virtual traded volume of energy including resale and reservation of sales was 10 times larger than the real amount of traded energy, in the worst-case scenario.

Since the same situation may occur in the Philippines, the planned WESM must accurately collect the real traded volume of real energy transactions to address such a concern.

The WESM should coordinate a day-ahead generation schedule including bilateral trading. In addition, it should monitor real-time operation and the accounting transmission fees to industry players.

In sum, WESM should serve as the organization that can recognize the final volume of real traded energy while at the same time specifying the identity of the market players.

In the PDP 2004-2013 process, data collection from the market players dealt only with the past annual sales data from the annual reports of PIOUs and ECs. Direct data collection by DOE using the DDP scheme has not been completed. Efficient and extensive data collection using this scheme is important for future demand forecasting work.

In particular, if TRANSCO is responsible only for planning, operation and maintenance, there will be no organization that recognizes embedded generation at the distribution level. This function used to be partially conducted by NPC. Basically, TRANSCO only understands the "TRANSCO PEAK," which means the only real peak power flow in the transmission system.

Therefore, DOE must directly collect information on embedded generators using the data collection scheme of DDP.

Fig. 3.37 Structure of physical power flow and its measuring point after liberalization

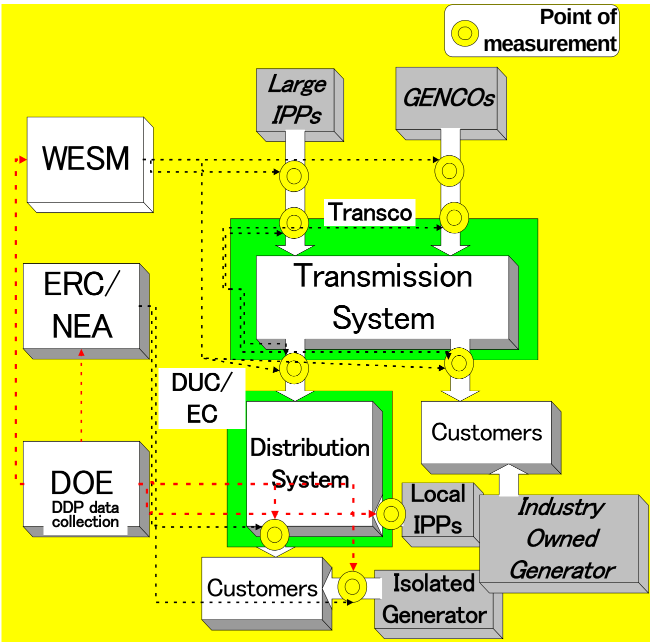
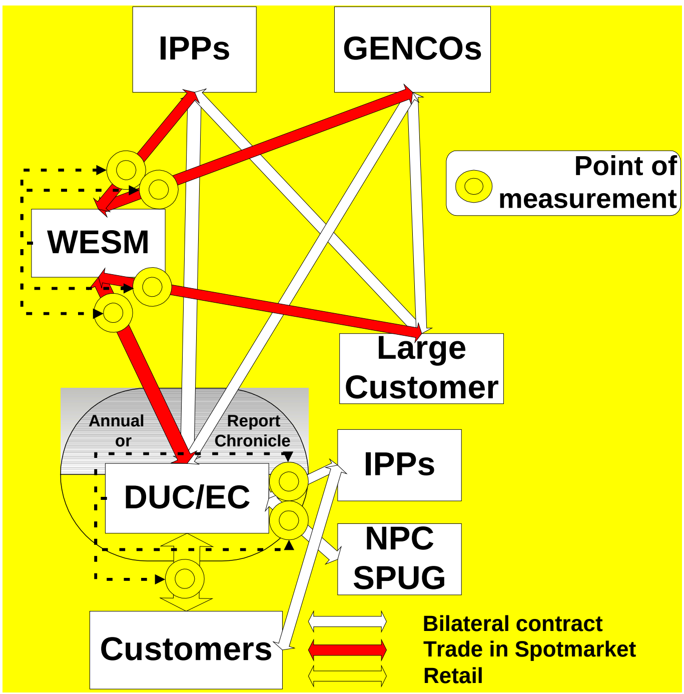


Fig. 3.38 Structure of the relation between the transaction and the measuring point after liberalization



(3) Recommendation for the data collection scheme for the next plan

In the formulation of PDP 2004-2013, the DOE collected historical sales data of PIOUs and ECs from Annual Reports and Chronicles published by NEA. On the other hand, data regarding the "System Peak (not the TRANSCO Peak)" was collected from TRANSCO.

Given the difficulty of gathering data needed in demand forecasting from other agencies (considering changes in the energy sector structure), a new data collection should be adopted.

The new data collection scheme should cover:

- Collection of sales and purchases from IPP by DISCOs (PIOUs and ECs) through the DDP scheme

  In the first quarter of every year, DOE should collect actual sales from the previous year and power purchase from IPPs directly from each DISCO. Sales data are needed in updating the historical sales database for demand forecasting.

  Purchased power data from IPPs is likewise needed to determine the system peak. This data is obtained by adding the supplied capacity from embedded generators to the TRANSCO Peak.

- Collection of real traded energy from WESM

  Collecting data on real traded energy, including bilateral trading on transmission systems, from the records held by WESM in the future when it becomes operational is necessary. These data are important for updating the Adjustment Factor (AF), which is used to convert from forecasted sales data at the distribution level to Gross Generated Energy.

- Collection of peak data from TRANSCO

These peak data are the base of calculation of "System Peak". In formulating PDP 2004-2013, TRANSCO could prepare "System Peak" data. However, there is no guarantee that TRANSCO will prepare the same kind of data for the next demand forecast. Thus, the DOE must recognize that TRANSCO, principally, will only prepare the TRANSCO peak , which can be physically measured by TRANSCO.

(4) Recommendation for upgrading the demand forecasting model

This study simulated demand forecasting using multiple regression with population and GDP per capita for the residential sector, and single regression with GDP for the non-residential sector. To increase the efficiency and effectiveness of its demand forecasts, the DOE should undertake the following measures:

- Expansion of historical sales data

  This study could only collect the sales data of DISCOs for the past ten years, which are the most important data for demand forecasting. The data was sourced from the Energy Regulatory Board (ERB), the precursor of the ERC. The ERB had less authority, and was saddled with data administration problems. Likewise, only information after 1990 is available is available from the DOE. Usually, for the next ten years of forecasting, at least 20 or 30 years' of data is required. In particular, the Philippines experienced capacity shortage in the early 90s, and this rebounded in the mid 90s. This indicates that there are too many disturbance factors in the 90s to be able to make accurate forecasts the future. Therefore, expanding the period covered for data analysis should be considered. As a countermeasure, PIOUs sales data, for which a lot of data is lacking, should be collected again directly from these companies.

- Upgrade of the demand forecasting model

  As external variables, population and GDP were used in previous demand forecasting by NPC. These variables have a strong correlation with electricity demand. Some developed countries, however, have adopted average personal income or the average price of electricity as external variables in macro demand forecasting, creating more complex models.

Moreover, end-use models are also used to establish an advanced forecasting model, aside from macro-econometric models.

Implementation of Demand Side Management (DSM) is also advantageous in the Philippines. To evaluate the effect of DSM, the development of the end-use model is necessary. This updating of the forecasting model mentioned above is prospective in the DOE.

However, if these complex models are created, several social and economic data are required.

But there is still the problem of collecting and storing these data. For instance, the development of the most basic data, such as the adopting rate of electric equipment, is needed in the Philippines.

Price elasticity, etc, has been a topic of discussion in demand forecasting methodology. Recently, by analyzing price behavior in the spot market such as the troubled California spot market, it was found that electricity is a commodity that has less price elasticity.

For example, even though the supply was short, demand did not decrease considerably. Thus, prices spiked often, and finally the market collapsed. This means electricity price has significant fluctuation.

Tools for forecasting such phenomena have not amply advanced, even in developed countries. This issue should be resolved when WESM becomes operational so that data such as the historical price and demand data are properly collected and stored.

- Analysis of the demand structure

  In the forecasting method applied in this study, energy demand was derived using a load factor to calculate peak demand. Because the load factor used in each grid has not changed significantly over the 10-year period, the same load factor is applied to each grid as in previous forecasting.

  The fact that the load factor has not changed in the last 10 years is principally due to the non-inclusion of the electricity demand from almost all the new industrial customers in the computation of the total electricity demand for the PDP, since these firms generates their own power requirements.

To promote these types of analysis, applying end-use models based on load surveys might be important. In the Philippines, implementation of these kind of survey were not done enough in the past, and moving forward, building experience from the results of load survey are sorely needed.

Considering the above-mentioned issues, the following items should be taken into account, for updating the model used in PDP 2004-2013 and reusing this model in the next demand forecasting cycle:

- Time horizon of data used in regression process;
- Possibility of adopting an end-use model equipped with a more detailed demand structure analysis; and
- Analysis of demand characteristics, such as price elasticity which is determined through an analysis of historical market price.

Chapter 4 Power Development Program

4.1 Review of the PDP 2003-2012

4.1.1 Preparation of the PDP

Prior to the enactment of EPIRA, the state-owned NPC prepares the PDP and the TDP, thus, providing consistency in data collection, analysis and results. After EPIRA was enacted in July 2001, the responsibility of preparing the PDP was transferred to the DOE.

With the transfer of responsibility for preparing the PDP, NPC found the means to slowly yield the responsibility so that during the preparation work for the PDP 2003-2012, DOE started to take the lead while NPC was delegated to a support role. Formulation of the PDP 2003-2012—which was submitted to Congress as part of the PEP—was a collaboration between the DOE and NPC.

The demand forecast was prepared by the DOE, in close coordination with NPC, using the model employed by NPC in previous demand forecasting computations.

The over-all power expansion plan was likewise done by a team composed of representatives from the DOE and NPC. The team conducted data collection, data processing and simulations. A new generation software, Prosym, was used in the said planning exercise.

Through this collaboration work, a way of preparing PDP was transferred tothe DOE. However, it was forecasted on the operation of the simulation software, and did not cover the fundamental data preparation for the simulation sufficiently.

The following were the software used by NPC and DOE for the last PDP:

<NPC>

EGEAS : Long-term Power Development Plan
Promode : Short- Medium-term Power Supply Plan
Prosym : Short- Medium-term Power Supply Plan
(NPC is planning to replace Promode with Prosym)

<DOE>

Prosym: Short- Medium-term Power Supply Plan[1]

4.1.2 Review of PDP 2003-2012

(1) Existing Capacities

As of September 2002, the Philippines' total installed capacity stood at 14, 702 megawatts (MW). This figure is based on the capacity of generating facilities owned by NPC; NPC-contracted IPPs; and distribution utilities-contracted IPPs (including MERALCO IPPs). The generating capacity of plants serving small-island grids and isolated grids are not included in the computation of the total installed capacity.

Table 4.1 shows the respective capacities of existing power generation plants included in the PDP 2003-2012. Figures shown in Table 4.1 have already been evaluated and reviewed as table 4.4 by the JICA study team to prepare the PDP 2004-2013.

On the other hand, the country's dependable capacity stood at 12,909 MW, or 87.8% of installed capacity. "Dependable capacity" refers to the deterioration and/or temporary derating of power thermal plants, as well as the seasonal derating of hydro power plants. The DOE uses dependable capacity in preparing the PDP to reflect the actual condition of the facilities.

Table 4.1 Capacity of Existing Facilities by Fuel Type (Unit: MW)

Fuel Type	Installed	Dependable
Bunker Fuel (Thermal)	758.60	752.90
Diesel	1,837.97	1,524.70
Coal	3,963.00	3,680.00
Gas Turbine	930.00	720.00
Geothermal	1,931.48	1,564.38
Hydro	2,518.07	1,964.07
Natural Gas	2,763.00	2,703.00
Total (Installed=100%)	14,702.12 (100%)	12,909.05 (87.8%)

Source: DOE

[1]The DOE utilizes the Prosym software as an extended licensee of NPC.

(2) Capacity Additions

The power development plan was prepared based on the low GDP case demand forecast. However, the JICA team in this study prepared power development plans based on both high GDP case demand forecast and Low GDP case demand.

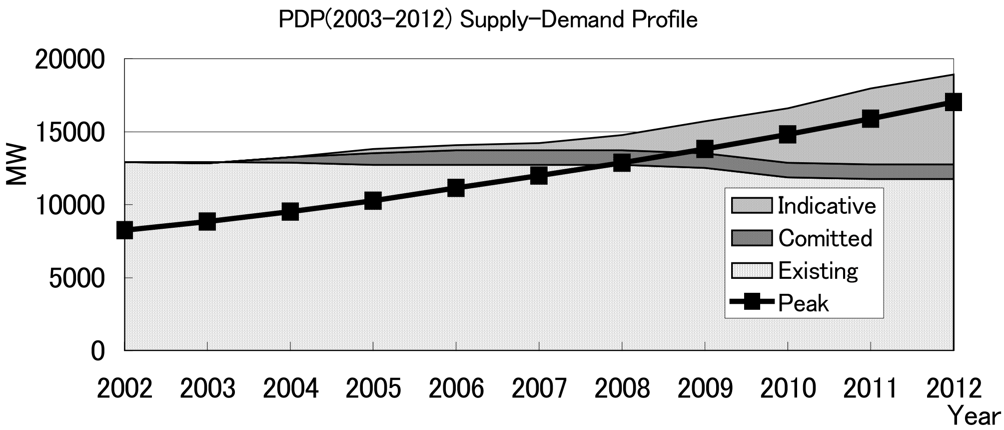
Based on the PDP 2003-2012, an additional generation capacity (or the total capacity of committed and indicative plants) amounting to 7,150 MW is needed to be installed into the system. This additional capacity is needed to sufficiently meet the electricity demand throughout this period, considering the retirement schedule of certain plants from 2003-2012.

Within the period covering 2003-2012, a total of 1,145 MW of existing generation capacity are due for retirement/decommissioning. Most of these plants are diesel-fed, and have been operating for more than 20 years.

Figure 4.1 shows the necessary capacity addition for the entire Philippines from 2003-2012, as stated in the PDP 2003-2012.

It likewise bears noting that the country's total actual generation reserve margin (GRM) as of 2002 stood at 56%. However, the looming power crisis in the Visayas grid, particularly in the Panay and Negros sub-grids, indicates that the reserve margin in the region is at a critical level.

Fig. 4.1 Necessary Capacity Additions: PDP (2003-2012)



Year	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Peak	8,248	8,833	9,519	10,277	11,139	11,997	12,869	13,813	14,814	15,889	17,033
Total	12,910	12,840	13,259	13,824	14,074	14,224	14,774	15,714	16,614	17,965	18,915
Existing	12,910	12,910	12,874	12,724	12,724	12,724	12,724	12,514	11,864	11,765	11,765
Retirement			37	150				210	650	99	
Addition	0	-70	385	1,100	1,350	1,500	2,050	3,200	4,750	6,200	7,150
Comitted		-70	455	415	200	0	0	0	0	0	0
Indicative				300	50	150	550	1,150	1,550	1,450	950
Reservr Margin	56.52%	45.36%	39.28%	34.51%	26.34%	18.56%	14.80%	13.76%	12.15%	13.06%	11.05%

Year	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Peak	8248	8833	9519	10277	11139	11997	12869	13813	14814	15889	17033
Existing	12910	12910	12873.5	12723.5	12723.5	12723.5	12723.5	12513.5	11863.5	11764.7	11764.7
Comitted	0	-70	385	800	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Indicative	0	0	0	300	350	500	1,050	2,200	3,750	5,200	6,150

To address these area-specific issues and concerns, the study used GTMax in the preparation of the PDP 2004-2013.

The Generation Reserve Margin is expected to be at 11% by 2012, which is lower than the standard generation reserve margin in Japan which is estimated to be about 20%. Table 4.2 shows the difference in the generation reserve margins.

Table 4.2 Comparison of the reserve margin in %

Items	Japan	Philippines	Remarks
Operational Spinning Reserve	8-10	Ditto	Same as Japan
Own Use in Power Station	4	0	N/A (Philippines uses the gross peak demand)
Seasonal Derating of Hydro Power Station	4	2	Already considered as a pat of dependable capacity
Maintenance	2	2	Already considered as a pat of dependable capacity
Fluctuation of Demand	1-2	0	Not considered in the LOLP Method
Generation Reserve Margin	20	10-14	

Source: JICA Study Team

In order to clarify the difference in the reserve margin between the two countries, adjusting the generation reserve margin in 2012 from the dependable capacity base to installed capacity base can be conducted as follows:

-Difference between Installed and Dependable Capacity = 14,702 – 12,910

= 1,792 MW

-Generation Reserve Margin = (18,915 – 17,033)/17,033

(Dependable Capacity Base: in the Philippines) = 11.05%

- Generation Reserve Margin = (18,915+1,792- 17,033)/17,033

(Installed Capacity Base: in Japan) = 21.6%

The Generation Reserve Margin of 11.05% in the Philippines is the same as that of 21.6% in Japan. (The difference between the installed capacity and the dependable capacity of retired plants was ignored to simplify the calculation.)

4.1.3 Indigenous Energy

(1) Potential of Indigenous Energy and Energy Policy

The Philippine government has given priority to the development and effective use of indigenous energy sources in the formulation of its energy policies, considering the fact that the country has a limited source of indigenous energy.

The difficulties surrounding the construction of environmentally-sensitive power facilities—particularly coal- and diesel-fired plants—have also placed a large premium in the development and utilization of these types of power facilities.

Therefore, further development of "clean" energy sources such as geothermal and natural gas as clean energy sources and utilization of these energy sources is seen to increase in the future.

Table 4.3 shows the potential of indigenous energy in the Philippines. The Philippines does not have much indigenous energy.

Table 4.3 Potential of Domestic Energy

Area	Oil (MMB)	Natural Gas (BCF)	Coal (MMT)	Geothermal (MW)	Hydro (MW)
Luzon	5,378-5,418	2,966-8,346	455	2,326	6,051
Visayas	1,105	2	747	1,670	493
Mindanao	1,599-2,066	6,870-8,964	1,163	542	2,619

Source: DOE

4.1.4 Current Status of and Issues affecting the Use of Indigenous Energy

As previously mentioned, difficulties are foreseen in the development of coal-fired power plants in view of strong opposition from the residents living in the potential site. Moreover, a lot of potential sites are covered by the National Integrated Protected Area System (hereinafter referred to as "NIPAS"). NIPAS severely restricts large-scale development—including certain forms of energy development—in protected areas.

The country's dependence on indigenous fuel, particularly natural gas, has increased with the commissioning of the Santa Rita, San Lorenzo, and Ilijan natural gas plants in Batangas between 2001 and 2003. These three power facilities have a combined capacity of 2,700 MW. The natural gas is sourced from the Malampaya field in Palawan. It is estimated that the Malampaya field can generate enough natural gas to fuel power plants with a combined capacity of 3,000 MW for approximately 30 years.

Since estimates show that the Malampaya natural gas reserves are more than enough to supply the three power facilities, downstream markets utilizing natural gas are visualized to be created to optimize the use of the Malampaya gas. Thus, a pipeline from Batangas to

Manila (dubbed "Bat-Man I) is seriously being considered to transport the fuel from its source in Palawan nearer to its users in Central Luzon.

A huge drawback in the utilization of natural gas as an energy source, however, is the relatively high cost of the gas. The high gas price is primarily due to the huge investment costs to develop the Malampaya field, and the cost of transporting the gas to Batangas via the pipeline.

Although the dispatch of the three above-mentioned natural-gas power plants is guaranteed by a minimum off-take contract, the plant's actual load factor is below the contracted level. The discrepancy is due to constraints in the transmission lines between Batangas and Manila. The constraints are expected to continue until the transmission line enforcement project is completed by 2005.

As far as renewable energy is concerned, DOE has adopted the policy of encouraging the construction of plants in Panay Island that are fueled by renewable energy sources. Notwithstanding this policy, a base load plant needs to be built in Panay or Negros in the very near future to forestall a power shortage in this particular area.

4.2 Existing Power Plants

4.2.1 Installed Capacity, Dependable Capacity

At present, the difference between installed capacity and dependable capacity is notably great between geothermal and diesel power plants.

The reasons are considered as follows:

- The portion of the old diesel unit operated for over 20 years is relatively great; and
- Some geothermal power plants have been in maintenance or not in service for long periods because of deterioration. Rehabilitation is planned for a number of plants.

Table 4.4 shows the installed and dependable capacity data which was used in the formulation of PDP 2004-2013. The table was prepared by integrating the annual supply plan (2003) by TRANSCO, and the System Operation Report of NPC (2002, 2001), among others.

However, these figures could not be independently validated by the JICA study team due to unavailability of data.

Table 4.4 Installed and Dependable Capacity

(Unit:MW)

Type of Plant	Total Philippine		Luzon		Visayas		Mindanao	
	Installed	Dependable	Installed	Dependable	Installed	Dependable	Installed	Dependable
Hydro	2,530	2,225	1,535	1,342	7	7	987	876
Pumpud Storage	300	300	300	300	0	0	0	0
Coal	3,927	3,699	3,738	3,517	189	183	0	0
Oil	650	633	650	633	0	0	0	0
Diesel	2,003	1,713	987	935	458	366	558	412
GT	675	584	620	529	55	55	0	0
Combined Cycle	2,790	2,790	2,790	2,790	0	0	0	0
Geothermal	1,880	1,396	856	427	916	860	108	108
Total	14,756	13,340	11,477	10,472	1,626	1,470	1,654	1,397
*WASP-IV	–	13,644	–	10,666	–	1,470	–	1,508

*WASP-IV = Hydro Install +Thermal Dependable

Source: JICA study team

4.2.2 Generation/Production Mix

DOE and NPC data on the shares of various generation plants (by type) in the energy mix indicate that coal-fired and geothermal plants account for the bulk of the Philippines' energy generation. As of 2002, cheap coal-fired facilities and geothermal plants combined account for nearly half of the country's total power generation.

However, with the government's policy of pushing the development and utilization of indigenous fuels in power generation, an increased share of natural gas-fired plants in the energy mix is expected.

Table 4.5 shows the actual power generation (2002) and tentative plan of actual generation (2003). The table likewise shows that natural gas would have surpassed the share of geothermal plants by 2003.

Table 4.5 Generation

(Unit:GWh;%)

	2002 (Actual)		2003 (Plan)	
Hydro	7,033	14.5%	6,258	12.5%
Coal	16,128	33.3%	18,638	37.1%
Natural Gas	8,771	18.1%	12,264	24.4%
Geothermal	10,242	21.1%	8,457	16.8%
Oil Base	6,293	13.0%	4,598	9.2%
Total	48,467	100.0%	50,215	100.0%

Source: DOE/NPC

4.2.3 Interconnection Issues

The Luzon and Visayas regions are connected via an HVDC transmission line. The Mindanao region, however, is still yet to be connected to these two islands.

Among these three island grids, Visayas is facing the severest transmission problem. Five power grids are located with the Visayas region—including Leyte-Samar, Cebu, Bohol, Negros and Panay grids.

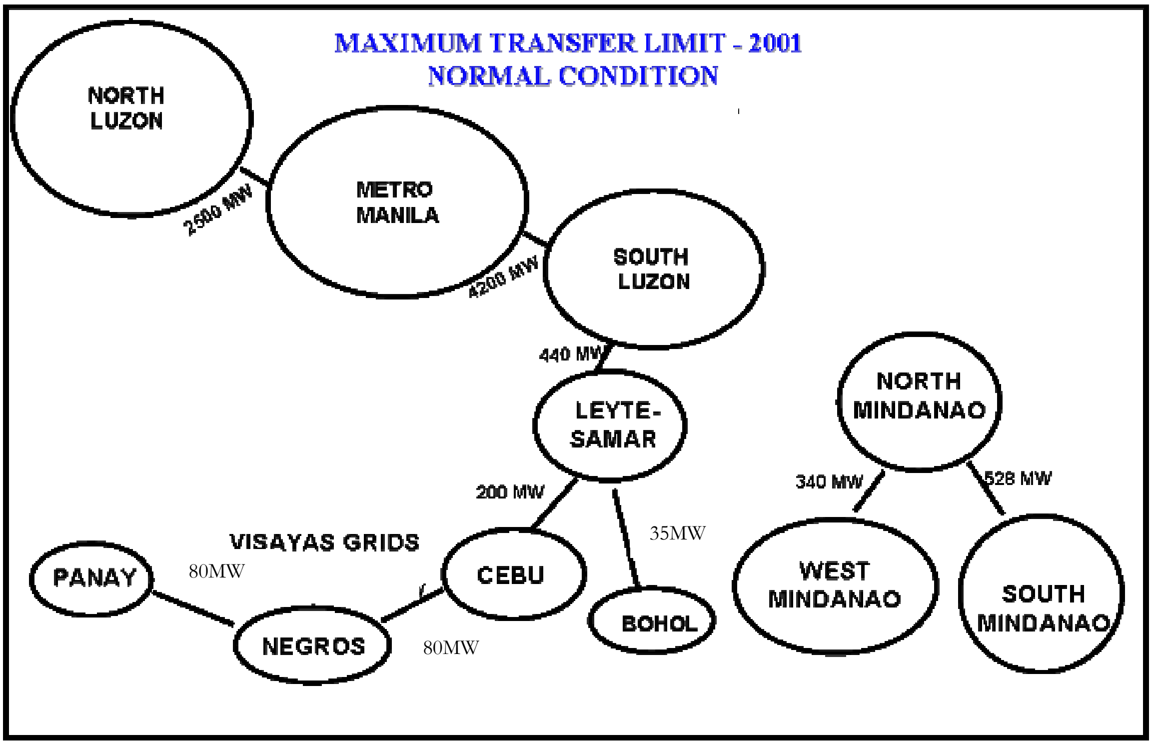
As previously mentioned, the Visayas area has a relatively greater proportion of geothermal power plants. However, most of geothermal power is concentrated in the Leyte-Samar grid. Constraints in the interconnection system, however, have prevented the transmission of electricity generated in Leyte to the Panay and Negros islands, thus contributing to the likelihood of a power shortage in these two island grids.

In order to address this looming power shortage, new interconnection projects are planned, as follows:

- Upgrading of Leyte-Bohol: 35 MW to 100 MW (2005)
- Additional one circuit of Leyte-Cebu: 200 MW to 400 MW (2005)
- Additional one circuit of Cebu-Negros-Panay: 80 MW to 160 MW(2005)
- HVDC of Leyte-Mindanao: No authorized plan.

Figure 4.2 shows the outlines of interconnection in the Philippines.

Fig. 4.2 Outlines of Interconnection



Source: DOE

4.3 Preparation for/Simulation for PDP (2004 –2013)

4.3.1 Software

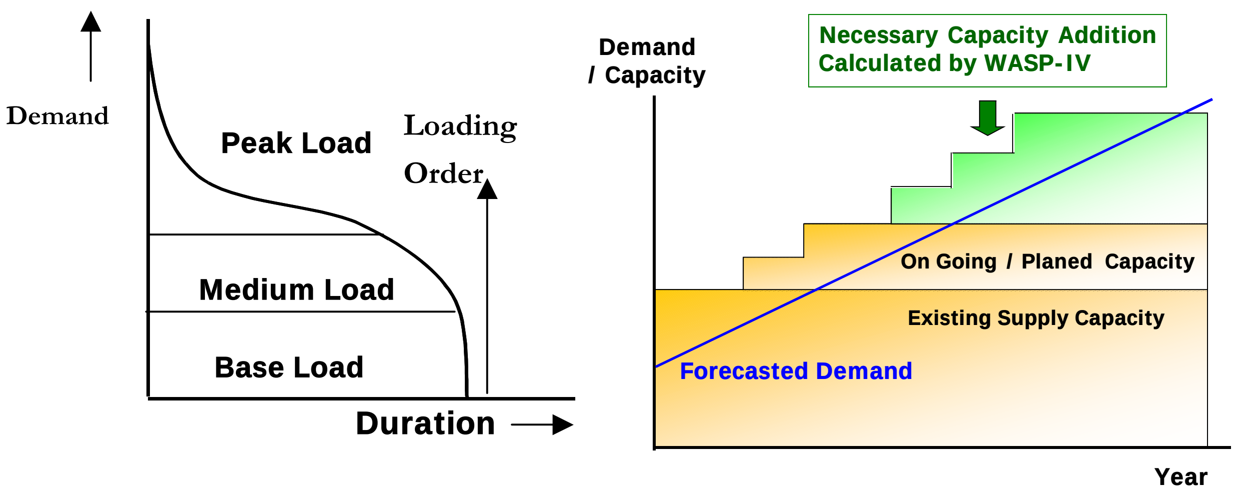
In order to facilitate the preparation of future PDPs, the JICA study team conducted a technical transfer on the WASP-IV and GTMax for the DOE. The outline of the software and the capability-building status of the DOE are described in this section.

(1) WASP-IV

This software is used to determine the least cost power development. The internal methodology of calculation consists of:

- Least cost dispatching by duration method;
- Dynamic program to determine the least cost development plan taking into account the construction and operation costs; and
- Reliability criteria set in terms of both LOLP and generation reserve margin.

Fig. 4.3 Duration Method/Output image of WASP-IV



*Merit – Demerit

- Because of the continuous upgrades by IAEA, the latest version can be used in future;
- The output is relatively reliable as the World Bank also uses WASP-IV;
- Although the registration with IAEA is required, the software is free.

- Complete Software Manuals are readily available;
- Since the input data files are in the form of text files, they can be sent by electronic mail;
- The calculation speed is sufficiently fast; and
- The multi area concept cannot be treated directly.

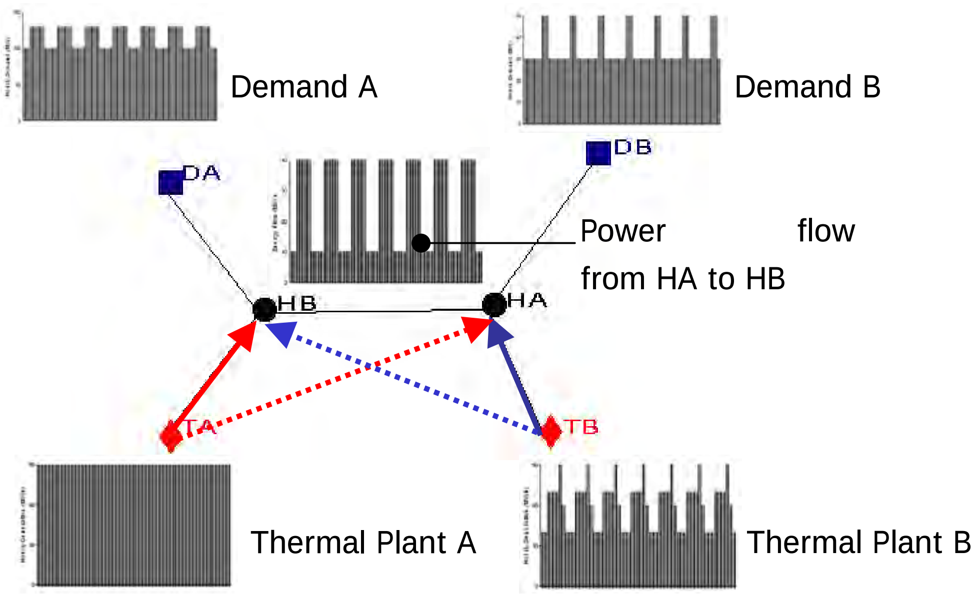
* Situation of capacity building

DOE can handle the fundamental simulation by using the WASP-IV, and manage the output files. However, since it is only its first year to use the software, supplemental technical assistance is necessary in terms of input data management, checking calculation results, and proficiency in software handling.

(2) GTMax

This system is used for determining optimal location and interconnection analysis. The least cost dispatch for regional demand is determined by linear programming. Interconnection of power flow is calculated automatically in this process. As the total system operating cost can be calculated, optimal location of indicative power plants can be determined by switching the connected point to the system, specifically by comparing the operation cost of both "real line connection" and "break line connection" as shown in Figure 4.4.

Fig. 4.4 Outline of the GTMax



*Merit – Demerit

- Developed by the Argonne National Laboratory in the U.S., GTMax has a close relationship with WASP-IV.
- Chronological power flow can be analyzed.
- The minimum operation cost can be calculated considering transmission line constraints.
- A lifetime license can be acquired at low cost.
- Complete Software Manuals are readily available.
- Using the given model is easy. However, it is a little difficult to prepare a whole model.

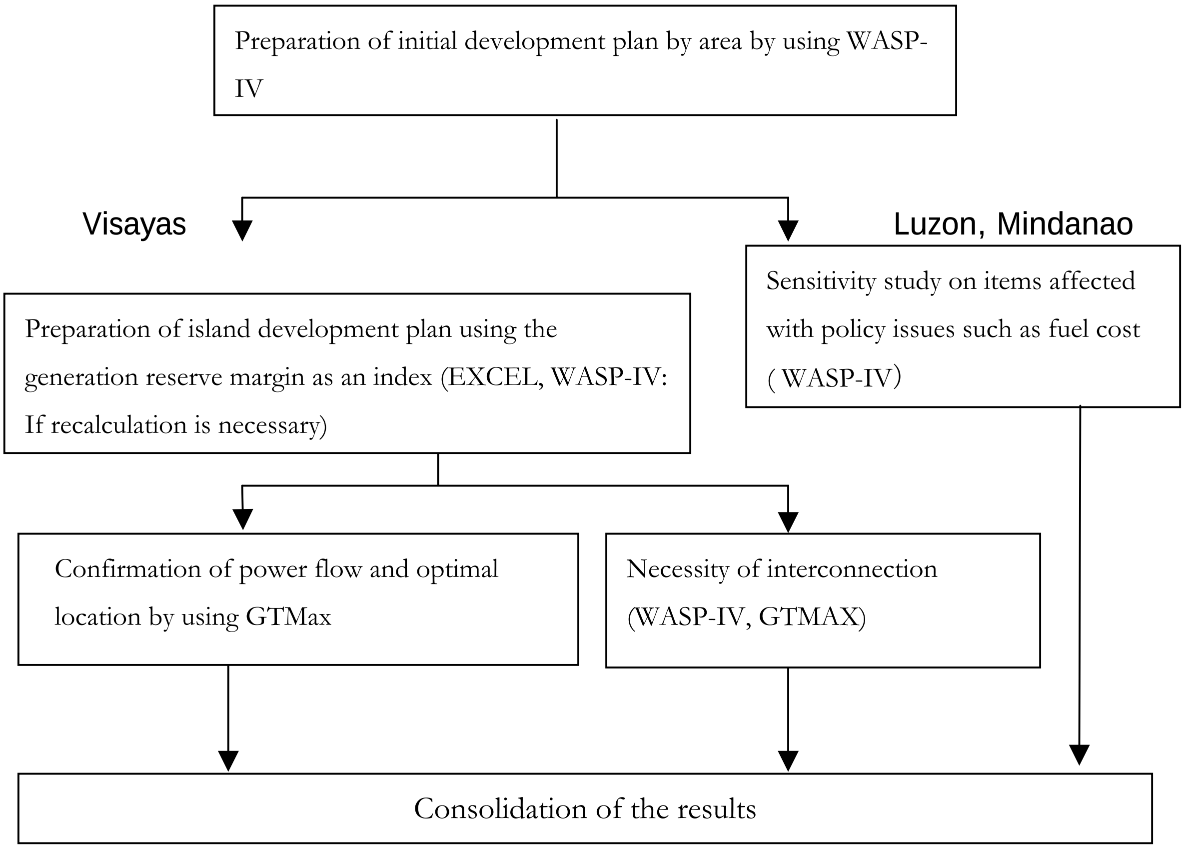
* Status of Capability Building

Presently, DOE has the competence to conduct an analysis of the impact of transmission constraints by using the given model. It likewise has the proficiency to conduct studies on optimal location and interconnection. However, supplemental technical transfer is necessary for the preparation of the new model and the replacement of demand data such as load shape.

4.3.2 Work flow for Simulation

Figure 4.5 shows the simulation workflow transferred in this study. The details are described the ensuing section.

Fig. 4.5 Simulation Work Flow



4.3.3 Condition

(1) Fundamental Condition, Existing Facility Data

Table 4.6 shows the basis of fundamental condition and existing facility data for the PDP 2004-2013.

Table 4.6 Basis of Fundamental Condition

	Items	Previous Simulation	PDP(2004-2013)	Remarks
1	General Index			
	LOLP	1day / year (Eageas)	1day /year	
	Discount Rate	12%	12%	NEDA released base
2	Plant Data			
a	Supply Capacity			
	@ For plants of which data is available			
	Thermal Plant	Installed Capacity	Dependable Capacity	Replace to the average of actual(2001-2002)
	Hydropower Plant	Nominal Year (1996)	Probabilistic Data	Replace to the weighted average of actual(1996,2001&2002)
	@ For plants of which data is NOT available			
	Thermal Plant	N/A	Dependable Capacity	Assumption based on the above plants
	Hydropower Plant	N/A	Probabilistic Data	Assumption based on the above plants
b	Heat Rate of the Thermal Plant			
	@ For plants of which data is available			
	Thermal Plant	Design Curve	Revised Design Curve	Revised curve based on the actual(2001-2002)
	@ For plants of which data is NOTavailable			
	Thermal Plant	N/A	Dependable Capacity	Assumption based on the above plants
c	Forced Outage Rate			
	Coal	3%	5.5%	Replace to the average of actual(2000-2002)
	Oil	3%	3%	Apply the previous data
	C/C	3%	3%	Apply the previous data
	GT	3%	3%	Apply the previous data
	Diesel	3%	4.5%	Replace to the average of actual(2000-2002)
	Geothemal	0-1%	10%	Replace to the average of actual(2000-2002) : For Luzon
		0-1%	1%	Replace to the average of actual(2000-2002) : For Vis-MiN
d	Maintenance Rate			
	Coal	6-7%	6-7%	Apply the previous data
	Oil	5%	5%	Apply the previous data
	C/C	6%	6%	Apply the previous data
	GT	6%	6%	Apply the previous data
	Diesel	5-6%	6%	To be scrutinized (Planned outage seems to be too long)
	Geothermal	8.20%	8.20%	Apply the previous data
e	Spinning reserve			
	Thermal			
	Coal	NA	5%	Governor free rate
	Oil	NA	5%	Governor free rate
	C/C	NA	2%	Governor free rate
	GT	NA	NA	
	Diesel	NA	NA	
	Geothermal	NA	5%	Governor free rate
	Hydro			
	Pumped Storage Type	NA	50%	Assumption of JICA based on the experience of CEPCO
	Others	NA	NA	
3	Fuel Cost in initial ear			
	Coal	25-30US$/MT	54-30US$/MT	Replace to the contract cost of NPC(2002)
	Oil	25US$/bbl	9.2-13.0 Php/L	Replace to the contract cost of NPC(2003)
	Natural Gas	Contract Base	<=	Previous Data (Contract Base)
	Geothermal	Contract Base	<=	JICA estimated (Contract Base)

*Apply the previous data: Validity of the data has been confirmed by JICA.

The data were prepared with the following policy as approved by the DOE:

a. Data for Existing Facilities

- Actual Operation Data for 2001 and 2002.
- The average data of similar facilities, if reliable data are unavailable
- Since data for PDP 2003-2012 were used to maintain consistency, the JICA study team evaluated their validity.

b. Fundamental Condition for Economic Evaluation

- Reliability Criteria: LOLP = 1 day/year
- Discount Rate: 12%
- Depreciation: Straight Depreciation Method

(2) Committed Projects and Retirement Schedule

Table 4.7 shows the committed projects considered in the simulation. Coordination of these projects is conducted by the DOE. The JICA study team merely commented on the schedule of each project.

Table 4.7 Committed Projects

Plants	Inst. Capacity (MW)	Com. Year	Location
Luzon			
CBK (Kalayaan 3&4)	350	2004	Laguna
PNOC-EDC Wind Power	40	2006	Ilocos Norte
Northwind Power	25	2006	Ilocos Norte
	415		
Visayas			
Pinamucan transfer from Luzon	110	2004	Panay
Mirant Diesel	40	2004	Panay
Northern Negros Geo	40	2005	Negros
PNOC- Palinpinon Geo	20	2005	Negros
Victorias Bioenergy	50	2005	Negros
	260		
Mindanao			
Transfer of PB103 & 104	64	2004	
Mindanao Coal (2 x 100)	200	2006	Misamis Or.
Total	***939***		

Source: DOE

Table 4.8 shows the projected retirement schedule for certain plants. The JICA study team suggested the appropriate retirement schedule of certain plants, given the demand-supply balance. Final conclusions were made by the DOE.

Table 4.8 Retirement Projects

PLANT	MW	DE-COMMISSIONING YEAR	REMARKS
Luzon			
Malaya 1	300	2010	
Malaya 2	350	2010	
Hopewell GT	210	2009	Contract expires 2003. Plant economic life is good for another 6 years.
	860		
Visayas			
Panay DPP1	36.5	2004	To be postponed until new plant comes
Bohol DPP	22	2004	Retirement contingent upon completion of Ormoc-Maasin Double-Circuit line, which is also contingent to the completion of Leyte-Bohol uprating (stage 2)
Power Barges (101-104)	128	2005	To be postponed until new plant comes
Cebu Land-Based GT	55	2011	
Cebu DPP 1	43.8	2011	
	285.3		
Total	***1,145.3***		

(3) Model Project

Table 4.9 shows the condition of model projects as candidates.

Table 4.9 Condition of Candidate Plants

Unit Type	Steam Turbine Unit		Combined Cycle Unit	Gas Turbine Unit		Diesel Unit
Fuel	Coal		Natural Gas	Diesel Oil		Bunker C
Life Time (Years)	30		20	15		15
Construction Period (Years)	4		3	2		2
Abbreviation	CL30	CL05	CC30	GT15	GT05	DSL
Capacity (MW)	300	50	300	150	50	50
Construction Cost ($/kW)	1520	2370	820	260	390	1140
Fuel cost (US$/Gcal)	4.8	5.4	Existing Contract	27.1		17.7
Heat Rate (kcal/kWh)	2,630	3340	1,650	3,400		2,340

Source: JICA Study Team

The total system capacity of the Luzon grid, where demand is concentrated, is much greater than that of the Visayas or Mindanao grids. Therefore, the smaller projects are applied only to the Visayas or Mindanao considering the stability of system. Table 4.10 shows the candidate plants by area.

Table 4.10 Candidate Plants by Area

Area	Base	Medium	Peak
Luzon	CL30	CC30	GT15
Visayas - Mindanao	CL05	DSL	GT05

Source: JICA Study Team

Figures 4.6 and 4.7 show the screening curve of projects by area.

Fig. 4.6 Screening curve of projects for Luzon

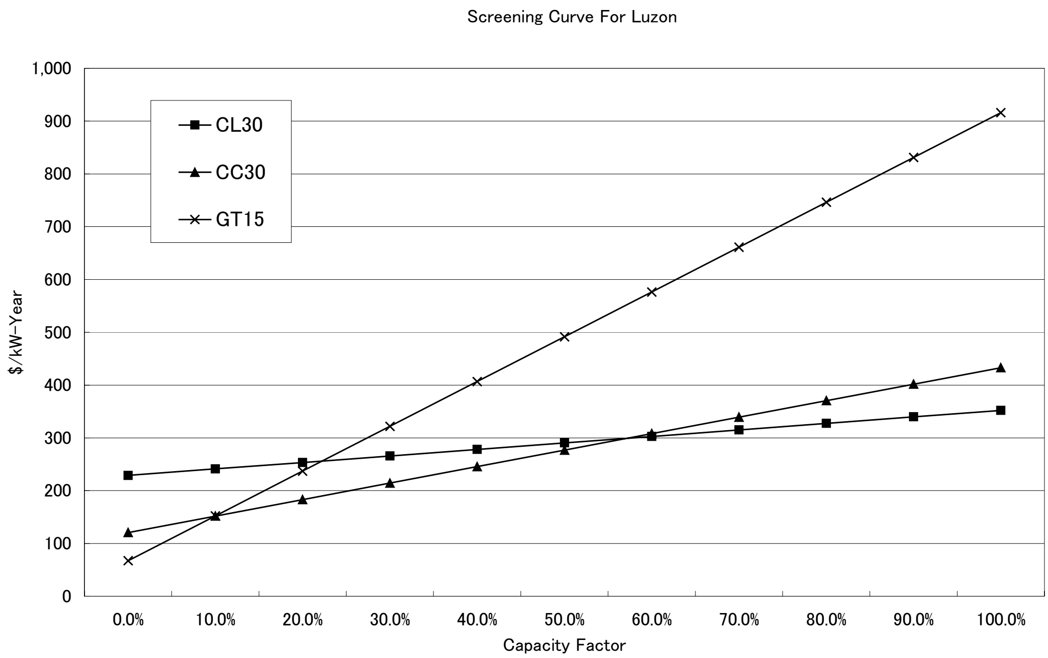
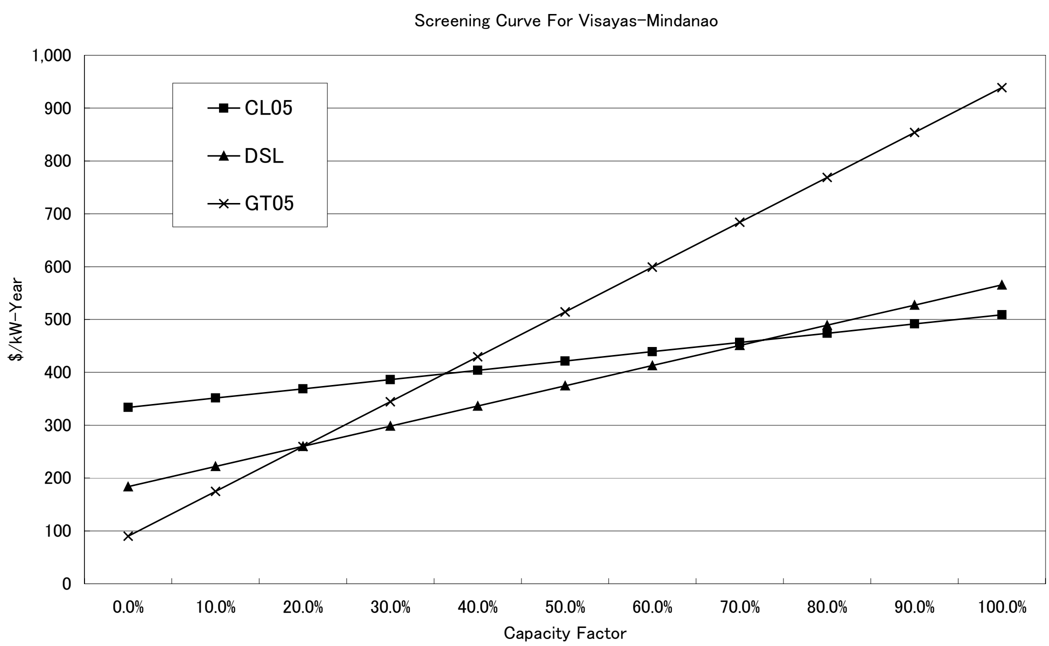


Fig. 4.7 Screening curve of projects for Visayas and Mindanao



4.3.4 Simulation Results

(1) Condition

Simulation was conducted for two demand scenarios: the high GDP case and the low GDP case. However, the PDP is prepared only for the low GDP case which is explained in this section.

Table 4.11 shows the specification of demand used in the simulation under the low GDP scenario.

Table 4.11 Simulation Demand (Low GDP, Declined Elasticity)

	Luzon	Visayas	Visayas Islands (Coincident Peak)					Mindanao
			Cebu	Panai	Negros	Bohol	Leyte-Samar	
2002	6,039	936	379	170	184	37	166	995
2003	6,454	1,006	406	182	194	41	182	1,049
2004	6,937	1,085	438	196	205	46	200	1,112
2005	7,473	1,172	472	212	218	51	220	1,181
2006	8,076	1,269	510	229	232	56	242	1,259
2007	8,662	1,363	547	246	244	62	264	1,331
2008	9,323	1,469	588	264	258	69	289	1,412
2009	10,036	1,582	633	284	273	76	317	1,498
2010	10,786	1,702	679	305	288	83	346	1,586
2011	11,575	1,827	728	327	303	92	378	1,676
2012	12,406	1,959	779	350	318	100	411	1,769
2013	13,280	2,097	833	374	333	110	447	1,864
2014	14,201	2,243	889	400	349	120	486	1,960
2015	15,171	2,397	948	426	365	131	527	2,060
2016	16,285	2,576	1,016	457	384	144	575	2,178
2017	17,480	2,770	1,089	490	404	159	627	2,304
2018	18,764	2,977	1,168	525	426	174	685	2,436
	7.3%	7.5%	7.3%	7.3%	5.4%	10.1%	9.3%	5.8%

The electricity demand figures used for the Luzon, Visayas, and Mindanao regions are the same, as explained in the previous chapter. In the Visayas, the coincident peak was prepared and used instead of the non-coincident peak to reflect the actual demand for the entire region. The following are the conditions of the coincident peak:

- The portion of each island demand against the total demand is the same as the non-coincident peak; and
- The total demand of each island demand is the same as the Visayas demand.

Although the PDP 2004-2013 covers a 10-year period, the basic simulation was set for 15 years (2004-2018) to avoid the termination effect of a dynamic program and to study the necessary infrastructure for fuel.

(2) Power Development Plan for Luzon

As was previously described, the simulation was made by area, such as Luzon, Visayas, and Mindanao. Table 4.12 shows the power development plan for the Luzon grid.

Table 4.12 Power Development Plan (Luzon)

Luzon									
	Demand	Ex.Cap	Install Cap.				Total	G.R.M
			GT15	CC30	CL30	Acc		
2003	6,454	10667				0	10667	65.3%
2004	6,937	11017				0	11017	58.8%
2005	7,473	11017				0	11017	47.4%
2006	8,076	11020				0	11020	36.4%
2007	8,662	11020				0	11020	27.2%
2008	9,323	11020	150			150	11170	19.8%
2009	10,036	11020	150		600	900	11920	18.8%
2010	10,786	10387	150		1200	2250	12637	17.2%
2011	11,575	10387			900	3150	13537	16.9%
2012	12,406	10387	150		600	3900	14287	15.2%
2013	13,280	10387	150		900	4950	15337	15.5%

Here GT15 : Gas Turbine (150MW)
CC30 : Combined Cycle (300MW／Gas)
CL30 : Coal (300MW)

The following committed projects are included in the column for existing capacity. Only about 5% of the generating capacity of PNOC and Northwind Power wind power projects is counted as dependable capacity considering the instability of windmill generation.

- Kalayaan 3 & 4 350 MW(2004)
- PNOC Wind 40 MW(2006)
- Northwind Power 25 MW(2006)

The required indicative capacity based on the planning period is pegged at 4,950 MW. Based on the fuel type, base load power plants (Coal: CL30) and peak load power plants (oil gas turbine: GT15) are planned. Given the high price of natural gas, middle load power plants (combined cycle: CC30) were not considered as indicative projects. The sensitivity of the gas price is studied and explained in this chapter.

The reliability index is set at LOLP=1 day/year. Satisfying the reliability criteria, the generation reserve margin should be more than 15.5 % of the dependable capacity and 21.3% of the installed capacity as seen below:

Necessary Generation Reserve Margin (in Installed Capacity Base)

-Difference between Installed and Dependable Capacity = 11,477 – 10,666
= 811 MW

- Generation Reserve Margin (15,337 + 811-13,280)/13,280
(Installed Capacity Base) = 21.3%

(3) Power Development Plan for the Visayas

The generation reserve margin of the entire Visayas grid stood at over 50% in 2003. However, this reserve margin—particularly in the Panay and Negros island grids—is less than the ideal level due to transmission constraints. The necessary capacity additions calculated by WASP-IV is about 50 MW for each island in 2003; thus, countermeasures against the expected power deficit should already be prepared and carried out in an urgent manner.

Table 4.13 shows the power development plan for the Visayas grid. The following committed projects are included in the column for existing capacity.

- Pinamucan Transfer from Luzon 110 MW(2004)
- Mirant Diesel 40 MW(2004)
- Northern Negros Geothermal 40 MW(2005)
- PNOC Palimpinon Geothermal 20 MW(2005)
- Victorias Biomass 50 MW(2006)

Regarding Victorias Biomass, 17 MW of the 50 MW is counted as supply capacity.

On the other hand, the fuel type for the indicative plants is mainly for peak load power plants (Oil Gas Turbine: GT05) and middle load power plants (Diesel: DSL). Base load power plants (Coal: CL05) are planned in 2013. Much of the capacity of current geothermal power plants were also considered.

The same reliability criterion (LOLP = 1 day/year) was applied in the Visayas region. Under this reliability criterion, the system operator requires that the generation reserve margin should not be lower than 13.2%.

While the Visayas has a lower reserve margin than Luzon (15%), its margin is still above the required reserve margin threshold. In addition, since hydro power plants have a very minimal share in the region's total installed capacity, hydropower seasonal derating is not seen to affect the installed capacity in the Visayas region.

To further satisfy the reliability criteria, the generation reserve margin should be more than 13.7% of the dependable capacity and 21.1% of the installed capacity, which are computed as follows:

Necessary Generation Reserve Margin (in Installed Capacity Base)

-Difference between Installed and Dependable Capacity
= 1,625 – 1,470 = 155 MW
- Generation Reserve Margin = (2,385 + 155 – 2097)/2,097
(Installed Capacity Base) = 21.1%

The following is the interconnection development plan considered in this PDP.

- Leyte- Bohol Upgrading 35 MW--->100 MW (2005)
- Leyte-Cebu double circuit 200 MW--->400 MW (2005)
- Cebu-Negros- Panay double circuit 80 MW--->160 MW (2005)

The importance of these projects is described later in this chapter.

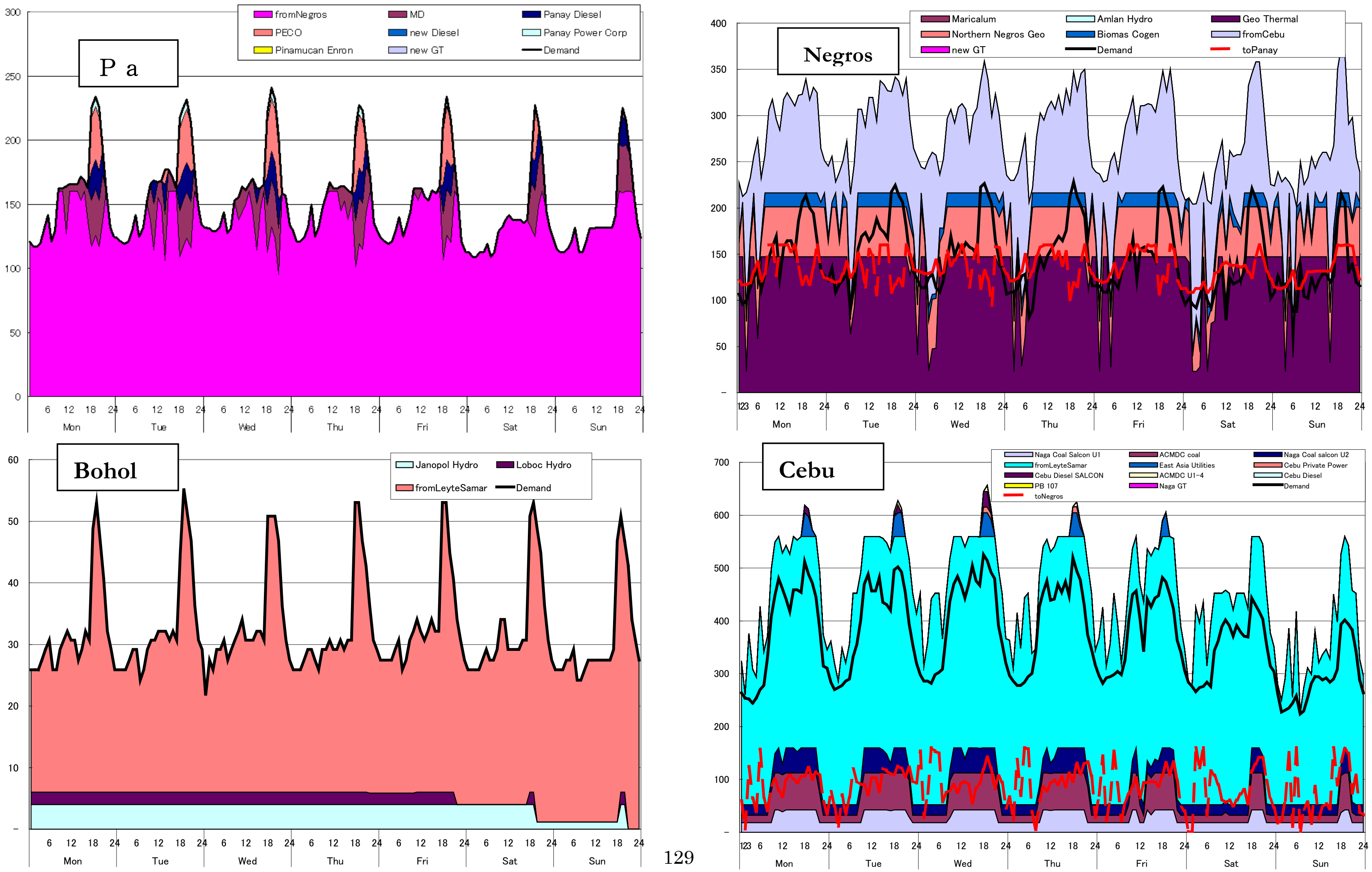
Table 4.13 Power Development Plan (Visayas)

	Leyte-Samar Grid								Bohol										Cebu Grid										
	Demand	Ex.Cpa	Install		I.C.	Total	G.R.M	TL	Demand	Ex.Cpa	Install				I.C.	Total	G.R.M	TL	Demand	Ex.Cpa	Install				I.C.		Total	G.R.M	TL
				Acc	Out						DS	GT05	CL05	acc							DS	GT05	CL05	acc	in	out			
2003	182	695		0	-155	540	196.7%	440	41	49				0	2	52	25.0%	35	406	427.5				0	153	-72	508	25.0%	200
2004	200	695		0	-134	561	180.8%	440	46	49				0	8	57	25.0%	35	438	427.5				0	126	-6	547	25.0%	200
2005	220	695		0	-184	510	132.5%	440	51	6				0	57	64	25.0%	100	472	427.5				0	127	36	590	25.0%	400
2006	242	695		0	-227	468	93.5%	440	56	6				0	64	71	25.0%	100	510	427.5				0	163	47	637	25.0%	400
2007	264	695		0	-343	352	33.1%	440	62	6				0	72	78	25.0%	100	547	427.5				0	271	-15	684	25.0%	400
2008	289	695		0	-355	340	17.4%	440	69	6				0	75	81	17.5%	100	588	427.5				0	280	-17	691	17.5%	400
2009	317	695		0	-329	365	15.3%	440	76	6				0	81	87	15.4%	100	633	427.5		100		100	248	-46	730	15.4%	400
2010	346	695		0	-293	402	16.0%	440	83	6		50		50	41	97	16.1%	100	679	427.5		50		150	252	-41	789	16.1%	400
2011	378	695		0	-264	431	14.1%	440	92	6				50	48	105	14.1%	100	728	336.7		150		300	215	-21	831	14.1%	400
2012	411	695		0	-225	469	14.1%	440	100	6				50	58	115	14.1%	100	779	336.7	50			350	167	35	889	14.1%	400
2013	447	695		0	-186	508	13.7%	440	110	6				50	69	125	13.7%	100	833	336.7		50		400	117	93	947	13.7%	400

	Negros											Panay										Total								
	Demand	Ex.Cap	Install Cap.				I.C.		Total	G.R.M	TL	Demand	Ex.Cap	Install Cap.				I.C.	Total	G.R.M	TL	Demand	Ex.Cpa	Install				I.C.	Total	G.R.M
			DS	GT05	CL05	Acc	in	out						DS	GT05	CL05	Acc							DS	GT05	CL05	acc			
2003	194	166		50		50	72	-45	242	25.0%	80	182	132.6		50		50	45	228	25.0%	80	1,006	1,470		100		100	0	1,570	56.1%
2004	205	166				50	6	35	257	25.0%	80	196	230.5				50	-35	246	25.0%	80	1,085	1,567				100	0	1,667	53.6%
2005	218	243				50	-36	16	273	25.0%	80	212	230.5				50	-16	265	25.0%	80	1,172	1,602				100	0	1,702	45.2%
2006	232	243				50	-47	44	290	25.0%	160	229	230.5	50			100	-44	286	25.0%	160	1,269	1,602	50			150	0	1,752	38.1%
2007	244	243				50	15	-2	306	25.0%	160	246	204.8				100	2	307	25.0%	160	1,363	1,576				150	0	1,726	26.6%
2008	258	243				50	17	-6	304	17.5%	160	264	204.8				100	6	311	17.5%	160	1,469	1,576				150	0	1,726	17.5%
2009	273	243				50	46	-23	315	15.4%	160	284	204.8				100	23	328	15.4%	160	1,582	1,576		100		250	0	1,826	15.4%
2010	288	243				50	41	0	334	16.1%	160	305	204.8		50		150	0	354	16.1%	160	1,702	1,576		150		400	0	1,976	16.1%
2011	303	243				50	21	32	346	14.1%	160	327	204.8	50			200	-32	373	14.1%	160	1,827	1,485	50	150		600	0	2,085	14.1%
2012	318	243	50			100	-35	55	363	14.1%	160	350	204.8	50			250	-55	399	14.1%	160	1,959	1,485	150			750	0	2,235	14.1%
2013	333	243	50			150	-93	79	379	13.7%	160	374	204.8			50	300	-79	426	13.7%	160	2,097	1,485	50	50	50	900	0	2,385	13.7%

Here DS : Diesel (50MW)
GT05 : Gas Turbine (50MW/Oil)
CL05:Coal (50MW)

Fig. 4.8 Regional Supply –Demand Balance in the Visayas Grid in 2006



By implementing PDP 2004-2013, stable power demand-supply will be guaranteed even in Panay and Negros Island. In Bohol and Cebu, most of the power requirement will be supplied from the cheaper geothermal power plant of Leyte-Samar. Surplus geothermal power will be supplied to Cebu, Bohol, and Luzon.

Figure 4.8 shows the regional demand-supply balance for the Visayas grid. While Figure 4.9 shows the demand-supply balance in Leyte-Samar.

Fig. 4.9 Demand Supply in Leyte-Samar in 2006

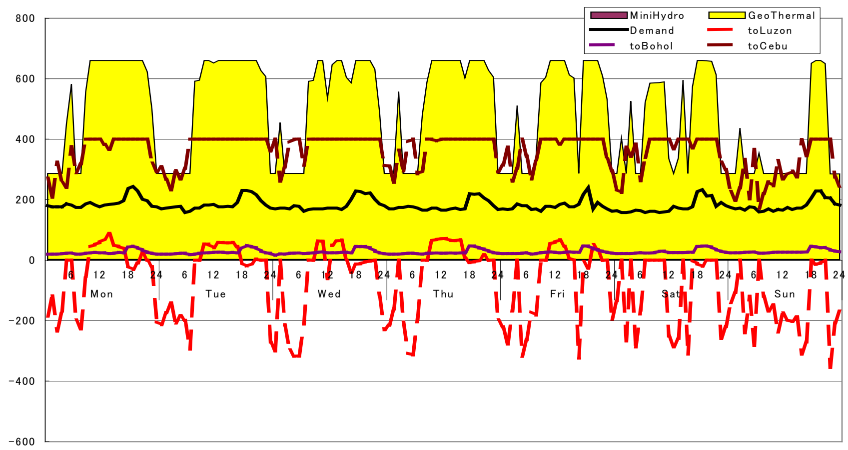


Figure 4.10 shows the interconnection power flow between islands. As far as the Leyte-Cebu interconnection is concerned, the power flows at almost its limit despite the upgrading of the Leyte-Cebu interconnection.

Fig. 4.10 Interconnection Power Flow in 2006

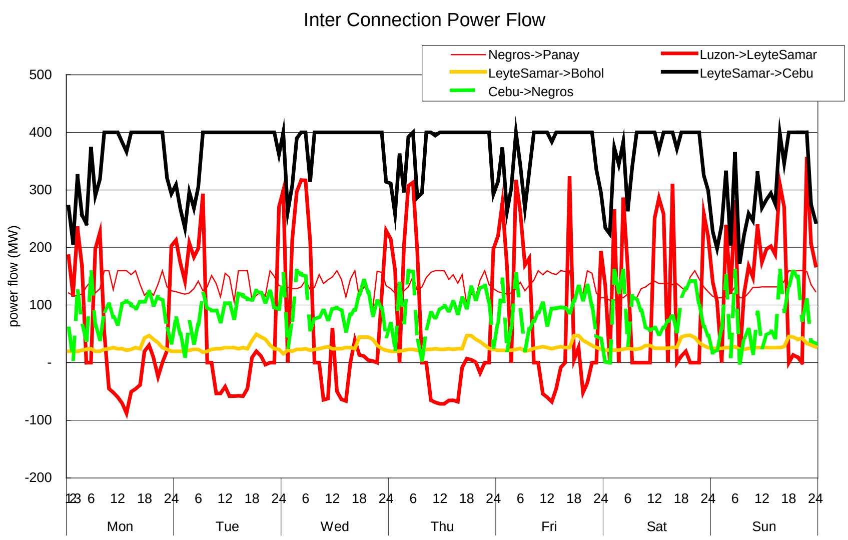


Table 4.14 shows the power development plan in Mindanao.

Table 4.14 Power Development plan in Mindanao

Mindanao								
	Demand	Ex.Cap	Install Cap.				Total	G.R.M
			DS	GT05	CL05	Acc		
2003	1,049	1509				0	1509	43.9%
2004	1,112	1561				0	1561	40.4%
2005	1,181	1561		50		50	1611	36.4%
2006	1,259	1761				50	1811	43.9%
2007	1,331	1761				50	1811	36.0%
2008	1,412	1761				50	1811	28.2%
2009	1,498	1709		100	50	200	1909	27.4%
2010	1,586	1709			100	300	2009	26.7%
2011	1,676	1709			50	350	2059	22.8%
2012	1,769	1709			100	450	2159	22.1%
2013	1,864	1709		50	50	550	2259	21.2%

Here DS：Diesel（50MW）
GT05：Gas Turbine（50MW/Oil）
CL05:Coal（50MW）

The following projects are included in the existing capacity.

- PB 103, 104 Transfer 52 MW (Dependable)/64 MW (Installed 2004); and
- Mindanao Coal 200 MW (2006)

From an economic perspective, base load power plants (CL05) and peak load power plants (GT05) are required for the next ten years; however, middle load power plants (DSL) are not included in the plan. Much of the capacity of current diesel power plants may contribute to installing base load and peak load plants to achieve less cost.

The same reliability criterion (Loss of Load Probability or LOLP = 1 day/year) was also used for the Mindanao grid. Generation reserve margin in Mindanao is relatively higher than those in Luzon and the Visayas, due to the large amount of hydropower capacity in Mindanao. However, seasonal derating should also be considered in the computation of Mindanao's reserve margin because of the large share of hydro power plants in the region's generation mix.

Satisfying the reliability criteria, the generation reserve margin should be more than 21.2 % of the dependable capacity, or 29% of the installed capacity.

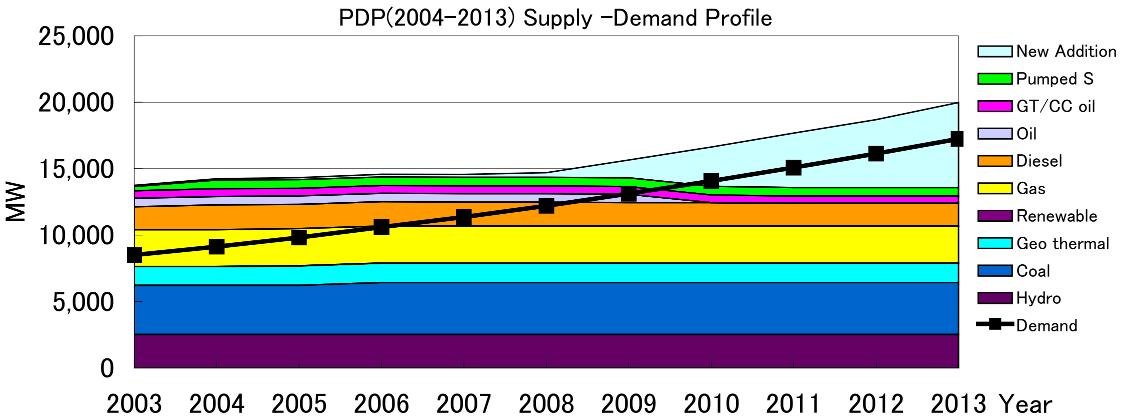
Necessary Generation Reserve Margin (in Installed Capacity Base)

-Difference between Installed and Dependable Capacity
= 1,654 – 1,509 = 145 MW
- Generation Reserve Margin (Installed Capacity Base) = (2,259 + 145 – 1,864)/1,864 = 29.0%

(3) The kW and kWh Balance of the total Philippines

Required capacity additions amount to an aggregate 6,400 MW. Figure 4.11 shows the kW balance of PDP 2004-2013, while Figure 4.12 shows the kWh balance.

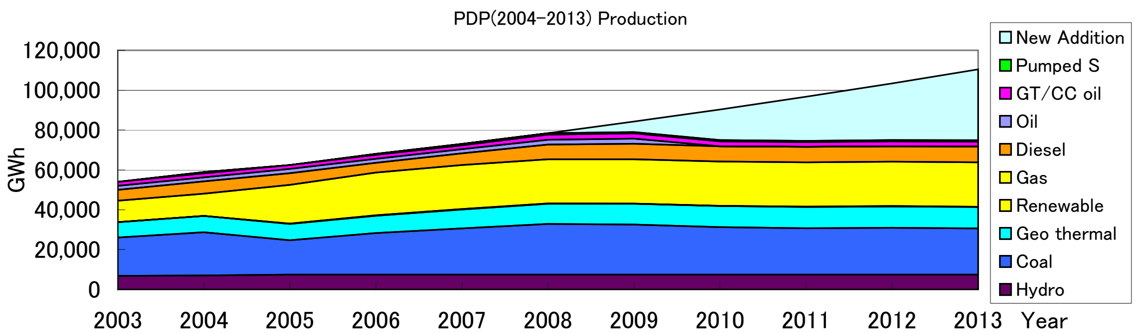
Fig. 4.11: kW balance of the total Philippines (PDP 2004-2013)



(Unit:MW)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Demand	8,508	9,134	9,827	10,604	11,357	12,204	13,117	14,074	15,079	16,133	17,241
Total Supply	13,746	14,246	14,330	14,583	14,557	14,707	15,655	16,622	17,681	18,681	19,981
New Addition	100	100	150	200	200	350	1,350	2,950	4,100	5,100	6,400
Hydro	2,529	2,529	2,529	2,529	2,529	2,529	2,529	2,529	2,529	2,529	2,529
Pumped S	300	650	650	650	650	650	650	650	650	650	650
Coal	3,700	3,700	3,700	3,900	3,900	3,900	3,900	3,900	3,900	3,900	3,900
Oil	633	633	633	633	633	633	633	0	0	0	0
Diesel	1,714	1,864	1,821	1,821	1,795	1,795	1,743	1,743	1,707	1,707	1,707
GT/CC oil	584	584	584	584	584	584	584	584	529	529	529
Gas	2,790	2,790	2,790	2,790	2,790	2,790	2,790	2,790	2,790	2,790	2,790
Geo thermal	1,396	1,396	1,456	1,456	1,456	1,456	1,456	1,456	1,456	1,456	1,456
Renewable	0	0	17	20	20	20	20	20	20	20	20
Reserve Mergine	61.6%	56.0%	45.8%	37.5%	28.2%	20.5%	19.4%	18.1%	17.3%	15.8%	15.9%

Fig. 4.12 kWh balance, total Philippines (PDP 2004-2013)



Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Total Supply	54,074	58,911	62,450	68,118	73,045	78,438	84,243	90,337	96,726	103,445	110,497
New Addition	0	0	10	1	13	52	5,253	15,353	22,157	28,447	35,637
Hydro	6,751	7,102	7,454	7,454	7,454	7,454	7,454	7,454	7,454	7,454	7,454
Pumped S	0	647	0	540	647	647	647	647	647	647	647
Coal	19,382	21,613	17,245	20,890	23,197	25,385	25,082	23,797	23,272	23,471	23,159
Oil	2,101	2,100	2,086	2,100	2,101	2,417	2,585	0	0	0	0
Diesel	5,389	6,136	5,838	4,820	5,835	7,311	7,722	7,577	7,744	7,760	7,947
GT/CC oil	2,021	1,981	1,980	1,982	1,981	2,600	2,644	2,484	2,333	2,463	2,457
Gas	10,768	11,132	19,482	21,466	22,119	22,238	22,259	22,270	22,273	22,275	22,275
Geo thermal	7,662	8,200	8,217	8,712	9,542	10,177	10,440	10,599	10,690	10,772	10,765
Renewable	0	0	138	153	156	157	157	156	156	156	156

4.3.5 Technical Issues --- Study on Natural Gas Price Sensitivity

(1) General

Considering the fact that the Philippines does not have an abundance of indigenous energy sources, there should be a policy pushing for the maximum use of natural gas to fuel power plants. Natural gas is not only available locally in large quantities, but is also considered "environment-friendly."

While coal is an important source of energy, heightened environmental awareness and concerns among residents of prospective plant sites have made it difficult to establish coal-fired plants.

Although plants that run on renewable energy such as wind and biomass have already been committed, the amount of electricity that could be generated from these projects is limited.

Considering these factors, the prospect of developing natural gas-fired plants is favored by prospective investors over coal-fired plants for the following reasons:

Construction cost in US dollar per kW of gas-fired power plants (including gas turbine and combined cycle power plants) is lower than that of coal-fired power plants. Moreover, the minimum installed capacity can be smaller than that of coal-fired power plants. Considering these factors, the initial investment can be minimized, hence, reducing investment risks.

The construction period of about two years for natural gas-fired plants is shorter than that of coal-fired power plants (about four years). Therefore, the latest information can be taken into account to evaluate when to start construction.

The environmental impact is smaller than coal-fired power plants. Therefore, consensus with residents on power plant construction is relatively easy.

These advantages posed by natural gas plants over coal-fired plants are, however, negated by the high price of natural gas. This factor is impeding the development of natural gas plants in the Philippines.

It bears noting that the existing price of natural gas from Malampaya is higher when compared to the price of LNG in the international market.

Using the current natural gas price, simulation revealed that the construction of natural gas-fed combined cycle plants is uneconomical. In order to enhance the optimum use of natural gas, the impact of the gas price on the optimal power development plan was studied.

Specifically, power development in a reduced gas price scenario, set at 90%/80% of the current price, was studied for the Luzon grid.

(2) Scenario

Table 4.15 shows the scenarios used in the sensitivity analysis.

Table 4.15 Reduced Gas Price Scenario (Unit: US$/Gcal)

Fuel Type	Base Case	Gas Price 90% Case	Gas Price 80% Case
Coal	4.8	<- Ditto	<-Ditto
Gas	Existing Contract	90% of Existing Contract	80% of Existing Contract
Diesel oil	27.1	<- Ditto	<-Ditto

(3) Results of the Simulation

a. Gas Price set at 90% of the Current Price

If the gas price can be set at 90% of the current price, the development of combined cycle plants with an aggregate capacity of 1,500 MW can be economically justified. Table 4.16 shows the least cost power development plan in the Gas Price 90% Case.

Table 4.16 Power Development Plan (Gas Price 90% Case)

90% of Present Gas Price

Luzon								
	Demand	Ex.Cap	Install Cap.				Total	G.R.M
			GT15	CC30	CL30	Acc		
2003	6,454	10667				0	10667	65.3%
2004	6,937	11017				0	11017	58.8%
2005	7,473	11017				0	11017	47.4%
2006	8,076	11020				0	11020	36.4%
2007	8,662	11020				0	11020	27.2%
2008	9,323	11020	150			150	11170	19.8%
2009	10,036	11020	150		600	900	11920	18.8%
2010	10,786	10387	150	300	900	2250	12637	17.2%
2011	11,575	10387		600	300	3150	13537	16.9%
2012	12,406	10387	150		600	3900	14287	15.2%
2013	13,280	10387	150	600	300	4950	15337	15.5%

Here GT15 : Gas Turbine (150MW)
CC30 : Combined Cycle (300MW／Gas)
CL30 : Coal (300MW)

b. Gas Price set at 80% of the current price.

In this case, replacing all of the coal-fired power plants with natural gas-fed combined cycle plants would make economic sense. Table 4.17 shows the power development plan in the Gas Price 80% Case.

Table 4.17 Power Development Plan (Gas Price 80% Case)

80% of Present Gas Price

Luzon									
	Demand	Ex.Cap	Install Cap.				Total	G.R.M
			GT15	CC30	CL30	Acc		
2003	6,454	10667				0	10667	65.3%
2004	6,937	11017				0	11017	58.8%
2005	7,473	11017				0	11017	47.4%
2006	8,076	11020				0	11020	36.4%
2007	8,662	11020				0	11020	27.2%
2008	9,323	11020	150			150	11170	19.8%
2009	10,036	11020	150	600		900	11920	18.8%
2010	10,786	10387	150	1200		2250	12637	17.2%
2011	11,575	10387		900		3150	13537	16.9%
2012	12,406	10387		900		4050	14437	16.4%
2013	13,280	10387		900		4950	15337	15.5%

Here GT15：Gas Turbine（150MW）
CC30：Combined Cycle（300MW／Gas）
CL30：Coal（300MW）

(4) Considerations

Results of simulations conducted by the JICA team show that the construction of gas-fired combined cycle power plants would not be economical if computations would be based on the current gas price.

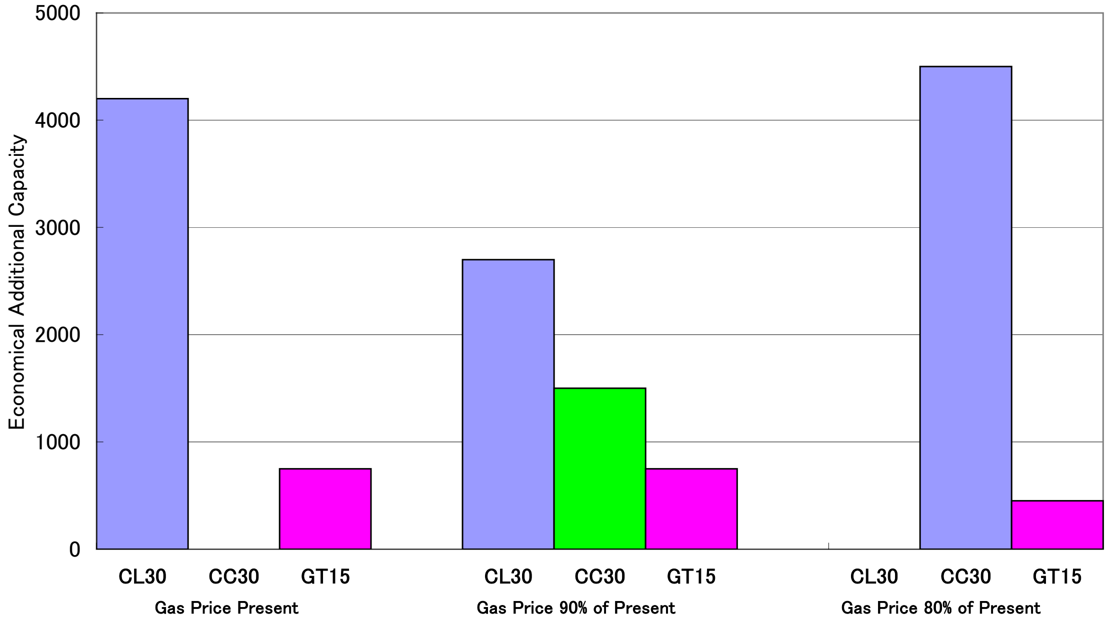
However, if gas price can be discounted to 90% of the current price, then the gas-fired combined cycle power plant would turn out to be economical.

Similarly, if gas price can be discounted to 80% of the current price, all coal-fired power plants are replaced by gas-fired combined cycle power plants. Figure 4.12 shows the needed power development in all cases, with total power development yielding a result of 4,950 MW in all cases.

Since the utilization of natural gas is still at its nascent stage in the Philippines, the price may be relatively high since initial investment costs are still being recovered. The current price of the gas should be accepted.

However, continuous efforts should be taken to reduce the price of the gas, since competitively-priced natural gas would justify the construction of natural gas plants in the future. These efforts may include the construction of the necessary distribution infrastructure, with the national government taking the lead.

Fig. 4.13 Gas Price and Power Development



(2) Evaluation of the interconnection Projects

a. Interconnection projects in the Visayas grid

<Rationale of the Study>

As previously adverted to, the Philippines is composed of many islands. Therefore, interconnection projects materially affect the power development plan.

In the Visayas grid, for example, interconnection reinforcement projects are planned for the following reasons:

As countermeasures for the expected power deficit in Panay and Negros (Cebu–Negros–Panay interconnection); and
For effective use of surplus geothermal energy in Leyte-Samar (Leyte-Cebu, Leyte-Bohol Interconnection).

While the Leyte-Cebu and the Leyte-Bohol Interconnection are already classified as committed projects, it bears noting that the Cebu–Negros–Panay interconnection is not yet committed.

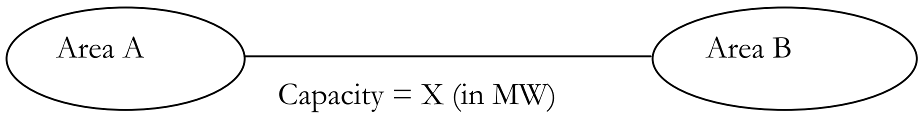
In this study, the necessity of the Cebu–Negros–Panay interconnection was studied from an economic viewpoint.

< Study Methodology>

Figures 4.14 and 4.15 show the methodology of the study, with the GTMax used as simulation software.

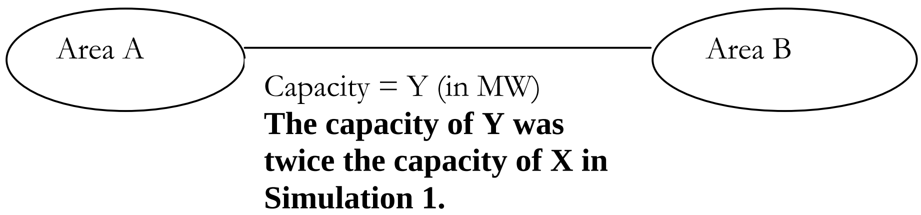
Simulation 1: To calculate the supply cost for Area A and Area B considering the constraints of the transmission capacity X as Cost 1.

Fig. 4.14 The methodology of the study: (Simulation 1)



Simulation 2: To calculate the supply cost for the same area considering the transmission reinforcement as Cost 2

Fig. 4.15 The methodology of the study: (Simulation 2)



Merit of Transmission line reinforcement is calculated by the equation below:

Merit of Transmission line = Cost 1 – Cost 2

Table 4.18 shows the condition of the economic evaluation.

Table 4.18 Condition of Economic Evaluation

Discount Rate	12%
Life of Interconnection	30 years
Duration for Economic analysis	15 years

<Study Result>

Table 4.19 shows the result of economic evaluation of the Cebu-Negros-Panay interconnection reinforcement. Since the net present value of this reinforcement is negative, this reinforcement is therefore uneconomical.

Table 4.19 Results of economic evaluation of Cebu-Negros-Panay interconnection reinforcement (Unit: Million US $)

Commissioning Year of Upgrading	Net Present Value
2005	-31.5
2006	-31.1
2007	-30.7

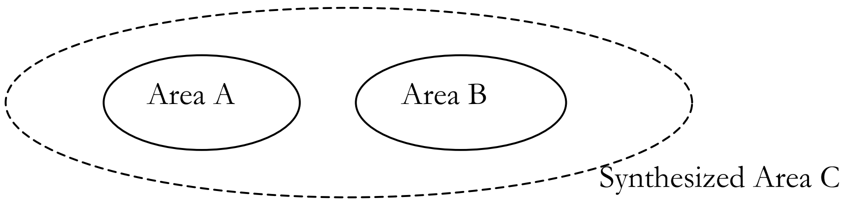
However, the actual cost is affected by the status of actual power development including the location of a new plant. Therefore, the importance of the project should be evaluated, considering not only economic factors other factors as well—including the need to address a looming power shortage and system reliability, among others.

b. Leyte-Mindanao Interconnection

< Methodology >

As is shown in Figure 4.16, initial evaluation was conducted by using WASP-IV. Then the GTMax was used in the same way as in the Cebu-Negros-Panay simulation.

Fig. 4.16 Study Areas by WASP-IV



The following is the study flow using WASP-IV.

1) The total system cost for Area 1 and Area 2 is calculated individually. (Cost 1)
2) System cost for synthesized Area C is calculated. (Cost 2)
3) The economic merit of interconnection reinforcement can be calculated by:
   Economic Merit = Cost 1 – (Cost 2 + Necessary Investment)
4) Further study is conducted by using the GTMax.
   (Indicative plant is determined by WASP-IV.)

<Study Results >

Computations show that the net present value of the Leyte-Mindanao interconnection reinforcement project is negative. As such, this particular interconnection reinforcement project is considered uneconomical.

Table 4.20 shows the results of the economic evaluation of the Leyte-Mindanao interconnection reinforcement.

Table 4.20 Results of economic evaluation of Leyte-Mindanao Interconnection Reinforcement
(Unit: Million US $)

Commissioning Year of Upgrading	Net Present Value
2007	-85.3
2008	-67.7
2009	-52.1
2010	-49.1
2011	-44.9
2012	-37.9

As with the reinforcement of Cebu-Negros-Panay interconnection, the actual cost is affected by actual power development, including the location of the new plant.

Therefore, the project should be evaluated not only based on economic merits. Evaluation of the project should likewise factor in political considerations as well as the possibility of a power shortage and reliability, among others.

C. Considerations

Interconnection issues are materially affected by the power development plan so that if power development, including the optimal siting goes well, there is no need for the reinforcement of the interconnection lines.

However, problems in power development—including regional issues on potential plant locations and fuel availability—could result in poor plant siting, delays in commissioning, or even the cancellation of power projects.

Thus, these considerations should be factored in the formulation of interconnection projects. In addition, the experience of the planner should also be considered carefully.

Although these issues should be determined along with policy, the methodology of the study in this report is an effective guide for future studies to be conducted by the DOE.

4.4 Technical Issues for Preparation of the PDP

4.4.1 Data Gathering System

Various government agencies and private organizations—including generation companies, NPC, TRANSCO and distribution utilities—are required by the EPIRA to submit pertinent information and reports to the DOE, being the lead agency on energy matters.

Data needed in the formulation of the PDP are mostly culled from these submissions. Thus, the DOE should establish a data gathering system to facilitate the collection, collation and dissemination of data obtained from these agencies. Among the concerns under the DOE's existing data collection set-up include:

- Submitted data are in the form of paper documents, making it inconvenient to arrange and integrate them for integration into the PDP; and
- All data required for preparation of the PDP cannot be collected.

To address these concerns, the JICA study team attempted to collect the necessary data for the PDP 2004-2013 by distributing a questionnaire to related organizations and proposed the adoption of the following basic policy for data gathering:

- Effective arrangement and integration is conducted by using the integrated format; and
- Electronic format should be used to aid in data arrangement, which will be useful for the data posting system in the future.

In the study, the JICA team applied its proposed data gathering system on DUs. For the following reasons, data were gathered from DUs:

- The data of generation facilities that are owned or contracted by distribution utilities is necessary for preparing the PDP in addition to the facilities that are owned or contracted by NPC;
- Since distribution utilities report their sales data to the ERC every month, the basic data flow is considered to be the same as the data gathering system; and
- The necessary data for preparing the PDP will be collected as a part of DDP submitted by the distribution utilities in future in order to aid in the data gathering work.

The following are the results of the data gathering:

a. Data Submission

- 15 out of 19 companies replied to the questionnaire.
- 4 out of 15 companies replied in the form of electronic data. The remaining replied in paper documents.
- 1 company submitted the data in its own format.

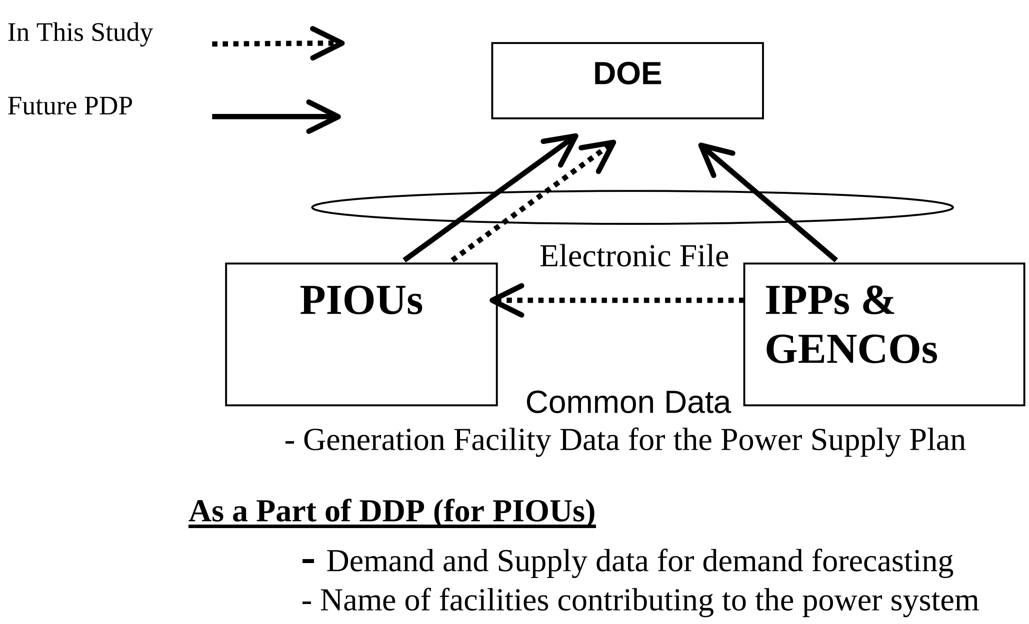
b. Contents

- 1 company disclosed cost data on its facility.

➢ As expected, IPPs did not disclose their cost/performance data.
➢ IPPs submitted only the net data, and excluded gross data

Considering the foregoing situation, the data gathering system must be established and confirmed again for the formulation of the PDP 2004-2013. The outline of the data gathering system is shown in Fig. 4.17.

Fig. 4.17 Data Gathering system



4.4.2 Schedule of the PDP Preparation (Preliminary Study)

As stated in Chapter 1, the GDP forecast is released in April of every year by NEDA. Consequently, the demand forecasting cannot help confirming behind the schedule. Since all power development plans should start with demand forecasting, the early confirmation of the demand is the most important milestone. In addition to delays in the demand simulation, the demand forecast was modified twice in preparation for PDP 2004-2012.

Considering these factors, preliminary studies should be thoroughly conducted for the PDP 2005-2014 by drawing an output image of the PDP.

4.4.3 Training system in the DOE

Despite the limited training on PDP preparation, the unit in charge of the task has the competence to conduct the basic PDP study in house. However, under-staffing is a severe problem, although this may be address by assigning additional staff for the PDP preparation.

While technologies employed in the PDP formulation are already widely used and that materials explaining the methodology of planning are generally available, it is now relatively easy to develop proficiency in preparing the PDP.

To attain full proficiency in this undertaking—particularly in demand forecasting and power supply planning—experience and on the job training (OJT) are important requirements.

Therefore, a systematic training program—which integrates the use of available manuals and allow OJT—for members of the unit tasked to formulate the PDP would be helpful to increase proficiency in this undertaking.

4.5 Integration with subordinate programs

4.5.1 Integration Policy in PDP (2004-2013)

Pursuant to the EPIRA, the PDP should integrate subordinate programs. These programs include:

a. TDP;
b. DDP; and
c. MEDP.

Considering the contents and schedule of the PDP, the following policy is applied to the subordinate programs:

- TDP: Integration and coordination of all projects

  All newly planned power development projects and transmission projects should be integrated.

- DDP: Data integration

  DDP may be used as a data gathering tool. The necessary data for preparing the PDP, such as demand in each franchise data and facility data, are collected as a part of DDP and reflected in the PDP.

- MEDP: Integration of document

  The PDP, which is the national grid plan, differs from the MEDP, which is the energization plan for the unenergized areas. The data is too overwhelming to be integrated.

Ideally, the MEDP should be considered in the simulation exercises in the preparation of the PDP. However, process flow and methodology has yet to be established for this purpose.

Therefore, the integration may be conducted only on paper. In the future, the effective grid extension methodology may be integrated.

4.5.2 Integration of TDP

As previously described, the integration of TDP with the PDP should be conducted on all power development projects and transmission development projects. Table 4.21 shows the necessary items to be arranged by relevant organizations.

Table 4.21 Items to be arranged for TDP integration

Items	Contents	Dataflow
a. Demand - Actual Peak Demand - Demand Forecasting	- Data Submission - Demand forecast Result	- TRANSCO to DOE - DOE to TRANSCO
b . Power Development Projects - On Going Projects - Committed Projects - Retirement Projects - Indicative Projects	- Projects List - Projects List - Projects List - Necessary Capacity Addition by Fuel Type and Area	- DOE to TRANSCO
c. Transmission Development Projects - First Draft Plan - Evaluation Results	- First Draft Plan - Evaluation Result (Projects List to be considered)	- TRANSCO to DOE - DOE to TRANSCO

4.5.3 Integration of DDP

The DDP, which is submitted by DUs to the DOE on March 15 of every year, contains information necessary in PDP formulation.

DDP has two components—the Distribution System Development Plan, and the Power Demand and Supply Plan—the latter, which includes demand forecasting and the supply plan, is particularly useful in PDP formulation.

Thus, the DDP may be used as a data gathering tool by the DOE since necessary data from the DUs throughout the country—including basic information on their respective franchise areas—are found in this document. Table 4.22 shows the data that can be collected from the DDP.

In addition, since existing island grids or independent grids may be connected to the national grid in the future, the integration of the DDP into the PDP is important. As such, the DDP should be treated as one of the major components of the PDP.

Table 4.22 Data that can be collected from the DDP

Items	Integration with the PDP
a. Demand for Franchise Area - Actual Peak Demand - Demand Forecasting	- Reference Data for Demand Forecast
b. Power Supply Plan - By Supply contract with NPC - By Own Facilities - By Supply contract with IPP - Data of Embedded Generator	- Basic Data for Power Development Plan

4.5.4 Integration of MEDP

Since the MEDP covers the most important and sensitive issues, the MEDP it self should be attached to the PEP/PDP, possibly even as an independent part.

In the future, the grid extension may become more important not only to supply across the country, but also to save on operating expenses. Therefore, the current practice should observe the electrification situation and to arrange a database for future PDP that integrates the unenergized area with the national grid by using grid extension methods.

Chapter 5 Transmission Development Plan

Under EPIRA, TRANSCO is obliged to prepare and update the TDP and to submit it for DOE's approval every year.

In this report, the JICA study team examined the TDP drafted by TRANSCO in the last two years.

The study team specifically outlined the results of the review of TDP 2003 which was initially submitted to the DOE in September 2002 but was later revised to consider its impact on TRANSCO's sale. The revision was made by a consulting company that had a contract with PSALM. The TDP was then re-submitted and officially approved by the DOE in March 2003.

The team likewise outlined the results of the study on the interconnection projects that were conducted in conjunction with the PDP 2004 preparation.

Delayed by the late finalization of the demand forecast and power development planning by the DOE, the TDP 2004 missed its completion target and consequently delayed the finalization of the PEP which was not submitted to Congress by September 15.

5.1 Review of TDP 2003

5.1.1 Current Status of the Power System in the Philippines

The Philippine power system is divided into three major island grids—the Luzon, Visayas and Mindanao grids.

At present, the Luzon and the Visayas grids are connected by HVDC (Leyte-Luzon Interconnection: 350 kV, 440 MW).

The Mindanao grid at present is independent from the two other major island grids. Under TDP 2003, the Mindanao grid is expected to be connected with the Visayas grid via HVDC (Leyte-Mindanao Interconnection: 250 kV, 500 MW) in 2011. This transmission project is seen to link these three major island grids, with the exception of small-island systems.

Among the three major island grids, power demand is highest in the Luzon grid which accounts for 5,823 MW, or 75% of the country's total peak demand.

The Visayas grid accounts for 903 MW, or 12% of the total peak demand while the Mindanao grid's demand is slightly higher as it accounts for 995 or 13% of the total peak demand

The load center in the Luzon grid is Metro Manila, which has a peak load of 56% compared to the peak loads of the Northern and Southern Luzon which both stand at 22%.

In terms of power generation, however, Metro Manila accounts for only 3% of Luzon's total generation capacity. Bulk of power generation is concentrated in Southern Luzon which accounts for 61% of the total generation in the region, and Northern Luzon which accounts for the remaining 36% generating capacity.

Therefore, a lot of electric power is transmitted from both Northern Luzon and Southern Luzon to Metro Manila, to meet the load center's electricity demand. To accommodate this transfer, 500 kV and 230 kV transmission systems linking Metro Manila to these two generation centers have been constructed.

Some of the existing 500 kV transmission lines were operating at a lower voltage of 230 kV. They were only upgraded to 500 kV in 2002. In particular, the 500-kV transmission system from the Labrador substation in North Luzon to the Dasmariñas substation in South Luzon via the San Jose substation in Central Luzon was completed in recent years.

A high-voltage 230 kV transmission system was constructed to surround Metro Manila. A number of large-scale power plants are connected to the transmission system.

In addition, the existing constraints in the dispatch of electricity generated by power plants located in Southern Luzon are expected to be solved in 2005 upon the completion of the Batangas Transmission Reinforcement Project. Power facilities which will benefit from this transmission upgrade project include the Santa Rita, San Lorenzo, and Ilijan natural gas power plants, and the Calaca coal-fired power plant all in Batangas whose aggregate capacity is 1200 MW.

Metro Manila is currently supplied by the 115 kV transmission lines of Meralco from its five 230/115 kV substations—Sucat P/S, Araneta S/S, Balintawak S/S, Doroles S/S and Zapote S/S.

Meanwhile, the Visayas grid is further divided into five sub-grids, namely: Leyte-Samar, Cebu, Negros, Panay, Bohol sub-grids. These sub-grids are connected by 230 kV and 138 kV submarine cables; these transmission lines constitute the backbone of the Visayas grid.

The transmission design in the Visayas grid is radial, considering the relatively small electricity demand and inherent topographic constraints—a multi-island system—in the region. With this kind of transmission design for the Visayas grid, the reliability level of power transmission is proven to be low.

The load center for the Visayas grid is Cebu Island, which accounts for 42% of the region's peak load. The share of sub-grids in the Visayas region are as follows: Negros (19%), Leyte-Samar (18%), Panay (17%), and Bohol (4%).

The generation center is the Leyte-Samar sub-grid which accounts for 47% of the total generation capacity in the Visayas grid. The share of other sub-grids in the region's generating capacity is as follows: Cebu (29%), Negros (11%), Panay (9%), and Bohol (3%).

From Leyte Island, where large-scale geothermal power plants (total capacity of 723 MW) are located, power is transmitted to Cebu Island by the 230 kV transmission lines.

To sum up, power in the Visayas region flows from Leyte to Bohol and Cebu; Cebu to Negros; and Negros to Panay through the interconnection systems between these islands.

At present, one of the major concerns in the Visayas region is that power development in Panay has not caught up with the increase in demand, indicating a looming power shortage.

To address this concern, upgrading the existing single-circuit interconnection lines between Cebu & Negros, and between Negros & Panay is being considered. Another option being considered is the transfer of certain generating facilities from Luzon for re-utilization in the Visayas region.

Currently, the Visayas grid is being developed to comply with the Philippine Grid Code requirements of N-1.

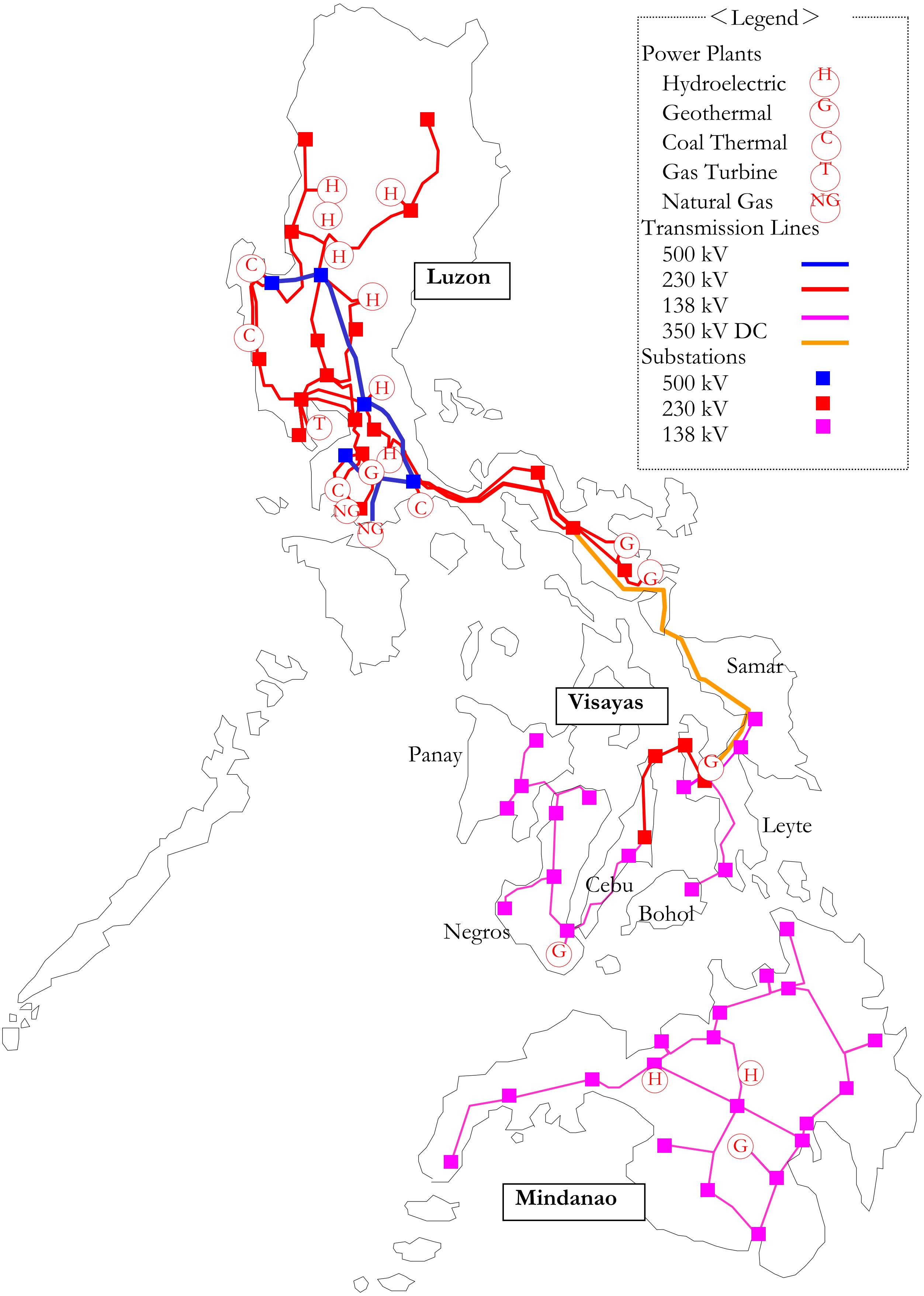
The N-1 rule means there should be no interruption or no continuous blackout in case of an N-1 contingency (i.e., a failure of one of the generators, transmission circuits or transformers), as well as no interruption without a contingency.

Since the Visayas grid is a radial system, the N-1 rule is currently not satisfied. All interconnections in the Visayas is consist of four submarine cables (one cable is extra). Table 5.1 shows the existing and planned submarine cables in the Visayas.

Table 5.1: Submarine cables in the Visayas

Interconnection	Voltage	Capacity	Remarks
Leyte-Cebu	230 kV	1 x 200 MVA	Upgrading in 2005
Cebu-Negros	138 kV	1 x 100 MVA	Under consideration For upgrading
Negros-Panay	138 kV	1 x 100 MVA	Under consideration For upgrading
Leyte-Bohol	69 kV	1 x 50 MVA	Upgrading in 2004 (from 69 kV to 138 kV)

Fig. 5.1: Philippine Power System



On the other hand, the Mindanao grid is divided into six major areas, namely: the Northwest Area, the Lanao Area, the North Central Area, the Northeast Area, the Southeast Area and the Southwest Area.

The load center in the Mindanao grid is the Southeast Area—where Davao City is located—accounting for 27% of the total demand in the entire region. Demand distribution in other major areas in Mindanao are as follows: Southwest Area (16%), North Central Area (15%), Northwest Area (14%), Northeast Area (13%) and Lanao (13%).

In terms of generation capacity, Lanao—where the Agus hydro-electric power plant is located—presently has the largest share, accounting for 727 MW or 53% of total generation in Mindanao.

Power generation plants in other areas in the region are as follows: North Central Area (17%), Southwest Area (11%), Southeast Area (9%), Northeast Area (5%), and Northwest Area (5%). Power plants in these areas are mainly low capacity diesel power plants except for the Pulangui hydroelectric power plant (225 MW) in Central Mindanao, and the Mt. Apo geothermal power plant (108 MW) located in Southwest Mindanao.

Under these circumstances, the Mindanao grid is interconnected by the 138 kV transmission lines like a mesh, wherein electricity flows from the Agus power plant in Lanao to Southern, Western and Eastern portions of Mindanao.

Since the 138-kV transmission lines are mostly composed of double circuits, the system almost satisfies the N-1 rule. However, in Southwest and Northeast Mindanao, some 138 kV substations are supplied with a single-circuit transmission line, and voltage sag will be severe in the event of an N-1 contingency. Therefore, upgrading the 138-kV transmission lines (from single circuit to double circuits) and second 138 kV transmission lines should be planned.

Section 7 of the EPIRA directed the ERC to "set the standards of the voltage transmission that shall distinguish the transmission from sub-transmission assets." The law likewise mandated the eventual disposal of sub-transmission assets to qualified DUs.

Table 5.2 shows the voltage levels adopted in the Philippine system.

Table 5.2: Voltage Levels in the Philippines

	Transmission Lines	Sub-transmission Lines
Luzon Grid	500 kV, 230 kV	115 kV, 69 kV
Visayas Grid	230 kV, 138 kV, 69 kV	69 kV*
Mindanao Grid	138 kV	69 kV

* When not forming part of the main transmission grid and being directly connected to the substation of the distribution utility

Table 5.3 shows a summary of the existing transmission lines and substations as of December 2003.

Table 5.3: Summary of Existing Facilities (as of December 2003)

Grid	Voltage Level	Transmission Lines (ckt-km)	Substation Capacity (MVA)
Luzon	500 kV	1,126	9,400
	350 kV	390	516
	230 kV	4,808	8,885
	115 kV& below	3,846	1,240
	Subtotal	10,170	20,041
Visayas	350 kV	564	516
	230 kV	375	420
	138 kV	1,670	1,208
	69 kV	2,261	25
	below	88	18
	Subtotal	4,958	2,186
Mindanao	138kV	3,211	1,965
	69kV& below	2,433	62
	Subtotal	5,645	2,027
Philippines	500 kV	1,126	9,400
	350 kV	954	1,032
	230 kV	5,183	9,305
	138 kV	4,882	3,173
	115 kV	293	615
	69 kV	7,988	712
	below	348	18
Grand Total		20,773	24,254

Note: Assumed the completion of 41.8 ckt-km of lines and 625 MVA of substation capacity for year 2003
Source: TDP (2004-2013) September 2003

5.1.2 Reliability Criteria

(1) Performance Indicator

Under Rule 6, Section 7 (c) of EPIRA's IRR, TRANSCO is mandated "to ensure and maintain the reliability, adequacy, security, stability and integrity of the grid in accordance with the performance standards for the operation and maintenance of the grid, as set forth in the Grid Code and the Distribution Code."

By checking the trends of the performance standards, the reliability levels and the power quality levels of the TRANSCO system may be evaluated.

1) Number of Interruption Events

Number of Interruption Incidents per year (caused by failure of the TRANSCO system)

2) Sustained Average Interruption Frequency Index (SAIFI)

$$\text{SAIFI} = \frac{\text{Summation of connected MVA affected by outages >10 min.}}{\text{Total connected MVA}}$$

3) Momentary Average Interruption Frequency Index (MAIFI)

$$\text{MAIFI} = \frac{\text{Summation of connected MVA affected by outage <=10min.}}{\text{Total connected MVA}}$$

4) Sustained Average Interruption Duration Index (SAIDI)

$$\text{SAIDI} = \frac{\text{Summation of (Outage MVA x minutes > 10 min.)}}{\text{Total connected MVA}}$$

5) System Interruption Severity Index (SISI)

$$\text{SISI} = \frac{\text{Total Delivery Point Unserved Energy (MWh)}}{\text{System Peak Load (MW)}}$$

6) Frequency of tripping per 100 c-km (FOT)

$$\text{FOT} = \frac{\text{Summation of Tripping Incidents}}{\text{Total Ckt length/100 ckt.km.}}$$

7) Average Forced Outage Duration (AOD)

$$\text{AOD} = \frac{\text{Summation of Outage Duration}}{\text{Sum of Frequency}}$$

8) Accumulated Time Error (ATE)

The yearly summation of the number of days whose accumulated time error is plus/minus 7.5 seconds or more.

9) Frequency Limit Violation (FLV)

The yearly summation of the number of days that the times of the violation of permissible frequency deviation (plus/minus 0.3 Hz, based on the Grid Code) are over 25 times (rainy season) and 30 times (dry season).

10) Voltage Limit Violations (VLV)

The yearly summation of the number of days that the voltages violate the permissible deviation (plus minus 5%, based on the Grid Code).

It should be noted that SAIFI and SAIDI in the Philippines are different from those applied internationally. Under international standards, SAIFI stands for System Average Interruption Frequency Index, which means the number of interruptions per customer; while SAIDI stands for System Average Interruption Duration Index, which means the duration of interruptions per customer.

The following tables show the historical performance indicators of the Luzon grid, the Visayas grid and the Mindanao grid.

Table 5.4: Performance Indicators of the Luzon Grid

	1993	1999	2000	2001	Average
Number of Interruption Events	270	192	301	400	291
SAIFI	1.99	0.72	124	1.37	1.02
MAIFI	0.53	0.28	0.22	0.17	0.22
SAIDI	739.45	147.56	392.29	564.81	352.09
SISI	6.02	9.65	15.42	10.52	9.73
FOT	13	12	14	15	13
AOD	183.07	571.77	265.38	369.13	344.31
ATE	111	37	1	7	39
FLV	126	32	3	14	44
VLV	212	37	9	14	111

Source: TDP (March 2003)

Table 5.5: Performance Indicators of the Visayas Grid

	2000	2001	Average
Number of Interruption Events	203	339	271
SAIFI	2.08	3.94	2.93
MAIFI	1.12	-	1.30
SAIDI	350.42	681.47	512.06
SISI	212.27	612.49	408.08
FOT	17	10	14
AOD	150.34	159.14	-
ATE	-	-	-
FLV	-	-	-
VLV	-	-	-

Source: TDP (March 2003)

Table 5.6: Performance Indicators of the Mindanao Grid

	1993	1999	2000	2001	Average
Number of Interruption Events	164	147	275	136	181
SAIFI	2.73	2.49	5.69	1.99	3.15
MAIFI	1.50	1.00	0.91	0.93	1.05
SAIDI	308.63	4,705	1,602	555	1,730
SISI	43.47	21.13	51.03	16.63	31.77
FOT	15	15	21	13	15
AOD	170.20	539.22	-	327.07	357.33
ATE	-	-	-	-	-
FLV	-	-	-	-	-
VLV	-	-	-	-	-

Source: TDP (March 2003)

While it is possible to calculate these numbers for the whole system, it is very complicated to calculate them for the regional systems and for each customer. In addition, although it is possible to evaluate the historical data, it is difficult to evaluate the future system.

Therefore, the N-1 rule is internationally applied for transmission planning.

(2) Criteria for Transmission Expansion

Considering the power development plan, the probabilistic method using LOLP (Loss of Load Probability) is established. However, with respect to the TDP, a probabilistic method is not established, and the N-1 rule is applied internationally.

The N-1 rule means no interruption or no continuous blackout in case of an N-1 contingency (i.e., a failure of one of the generators, transmission circuits or transformers), as well as no interruption without a contingency. In addition to the N-1 rule, large-scale and long-duration blackouts are not permitted in case of multiple failures, although partial blackout is permissible.

1) Grid Code

Under Rule 6, Section 9 of EPIRA's IRR, TRANSCO, or its buyer or concessionaire, is mandated to comply with the Grid Code in "improving and expanding its transmission facilities to ensure and maintain the reliability, adequacy, security, stability and integrity" of the grid.

Chapter 6 of the Grid Code outlines the responsibilities of TRANSCO with regard to the grid planning process. The law specifically directs TRANSCO to conduct analysis on the impact of the connection of new facilities such as generating plants and load.

The following items are spelled out in the Grid Code:

- Load Flow Studies
- Short Circuit Studies
- Transient Stability Studies
- Steady-State Stability Analysis
- Voltage Stability Analysis
- Electromagnetic Transient Analysis
- Reliability Analysis

However, the criteria for system expansion are not concretely stated in Chapter 6, while Chapter 7 (Grid Operations) states that the N-1 rule should be adopted for the grid operation criteria.

2) Criteria of TRANSCO

TRANSCO applies the N-1 rule for the TDP preparation to comply with the Grid Code. This means that the power flows of the transmission lines and the transformers are under rated capacity in their normal condition, and that there should be no interruptions or continuous blackouts in the case of the failure of one generator, transmission circuit or transformer.

The conditions of the N-1 Rule are as follows:

- The generators must remain stable;
- Under-frequency load shedding must not be allowed;
- The power flows must remain lower than the rating of the network equipment and must not overload the remaining elements; and
- The bus voltages must remain within limits.

Meanwhile, in the case of multiple failures, voltage collapse and cascaded outages are not allowed, although load shedding and generation shedding are considered acceptable.

Table 5.7 shows the transmission planning criteria of TRANSCO.

Table 5.7: Transmission Planning Criteria of TRANSCO

Acceptable Limits	Allowable Remedial Actions
1. Normal Condition	
- Transmission line loading: <100%	Line reinforcements
- Transformer loading: <100%	Transformers additions
- Steady-state voltage range: +/-5%	Reactive power dispatch or Compensation
2. Single-Line Outage (N-1) Contingencies	
- Transmission line loading: <110%	Line reinforcement
- Transformer loading: <110%	Line reinforcement
- Steady-state voltage range: +/-10%	Reactive power dispatch or Compensation
- Transiently stable for 3-phase fault with normal clearing	Generator control fine tuning, reactive power dispatch, compensation or additional Reinforcement
3. Severe contingencies	Automatic load dropping (ALD), generator tripping (GT), transfer tripping scheme (TTS)
- Transmission line loading: <120%	
- Transformer loading: <120%	
- No voltage collapse	
- No cascaded outages	
4. Load Rejection	Excitation system specification, reactive power compensation
- Dynamic overload: 30%	
- Peak Volts/Hertz ratio: 1.5p.u./p.u.	
- No self-excitation	
5. Line Restoration	Reactive power compensation
- Maximum voltage difference: 15%	
- Maximum open-end voltage: 120%	

Source: TDP 2002-2012 (September 2002)

However, the strict application of these criteria may not be practical or economical, given that the total power systems of the Philippines are evolving. Therefore, even though the N-1 rule is fundamentally applied, it is advantageous to expand the system step by step giving priority to the facility with the higher probability of failure and considering its effects in an event of a failure as well as the costs involved.

It would likewise be advantageous to develop a transmission plan for the long term, since projects in short-term transmission expansion planning may not be economical. Likewise, problems such as overlapping of transmission lines as well as right-of-way issues—which makes it difficult to implement the planned expansion—may be avoided.

5.1.3 Luzon Grid

(1) Reinforcement of the 230 kV Transmission Lines in North Luzon

1) Outline

Based on the PDP, some wind power plants, hydroelectric power plants, and mine-mouth coal power plants will be developed in the coming years. Therefore, the 230 kV backbone transmission line needs to be reinforced in accordance with the power development plan.

Table 5.8 shows the power development plan for North Luzon.

Table 5.8: Power Development Plan in North Luzon

	Year	Power Plant or Area	Capacity (MW)
Wind Power Plant	2004	PNOC-EDC Wind Power	40.0
	2004	Northwind Power	25.0
Hydroelectric Power Plant	2005	San Roque	345.0
	2009	Addalam	46.0
	2010	Diduyon	332.0
	2011	Agbulo	360.0
	2012	Abuan	60.0
Mine-Mouth Coal Power Plant	2006	Cauayan, Isabela (PNOC-EC)	50.0
	2008	Iguig, Cagayan	120.0
	2010	Cauayan, Isabela	90.0
	2011	Iguig, Cagayan	120.0

Source: PEP (2003-2012)

Problems in various transmission lines in parts of Luzon are foreseen, considering the future generating capacity additions in the region.

The San Roque hydroelectric power plant had been commissioned in 2003. The transmission line between the San Roque P/S and the 500-kV San Manuel S/S, meanwhile, will be completed in 2004.

The generated power, on the other hand, passes through a temporary facility.

The completion of the transmission line in 2004 will allow full dispatch of power from the San Roque plant starting 2005.

Once power from San Roque P/S is fully utilized, the 230kV transmission line between San Manuel S/S and Mexico S/S will be overloaded under normal conditions. Therefore, power from generation plants in North Luzon will not be fully transported to Metro-Manila.

Meanwhile, in the case of power development along the coast in Northwest Luzon, the 230 kV transmission line between Labrador S/S and Hermosa S/S will be overloaded under normal conditions.

In the case of the power development of the hydroelectric power plants and the coal mine-mouth power plants that are planned in North Luzon, the transmission lines between Pantabangan P/S and Cabanatuan S/S and Mexico S/S will be overloaded with an N-1 contingency.

To counter these problems, the necessary reinforcements shown in the Table 5.9 were planned by TRANSCO in the original TDP 2003.

However, TRANSCO revised TDP 2003 to reflect a reduction in investment needs. According to the final version, Project-2 will be prioritized, and the transmission lines will operate at 500 kV from the beginning, while Project-1 and Project-3 will be cancelled.

In this study, the JICA study team compared both the options presented in the original plan, and in the revised TDP 2003, using system analysis and economic analysis.

Table 5.9: Reinforcement of the 230 kV T/L in North Luzon (original plan)

Project	Outline	Commissioning Year
Luzon T/L Upgrading Projects-1	- San-Manuel-Concepcion T/L 230 kV ST-DC 2-795MCM TACSR, 80 km - Concepcion-Mexico T/L 230 kV SP-DC 2-795MCM TACSR, 37 km	Dec. 2006
Luzon T/L Upgrading Projects-2 (Designed for 500 kV and operated at 230 kV initially)	- Labrador-Botlan T/L 500 kV ST-DC 4-795MCM, 116 km - Botlan-Olongapo T/L 500 kV ST-DC 4-795MCM, 68 km - Olongapo-Hermosa T/L 500 kV ST-DC 4-795MCM, 26km	Jun. 2008
Luzon T/L Upgrading Projects-3	- San Manuel-Pantabangan 230 kV ST-DC 2-795MCM, 66 km - Pantabangan-Cabanatuan 230 kV ST-DC 2-795MCM, 53 km - Cabanatuan-Mexico 230 kV ST-DC 2-795MCM, 67 km	Dec. 2010

Fig. 5.2: Reinforcement Plan of 230 kV transmission lines in North Luzon (Original Plan)

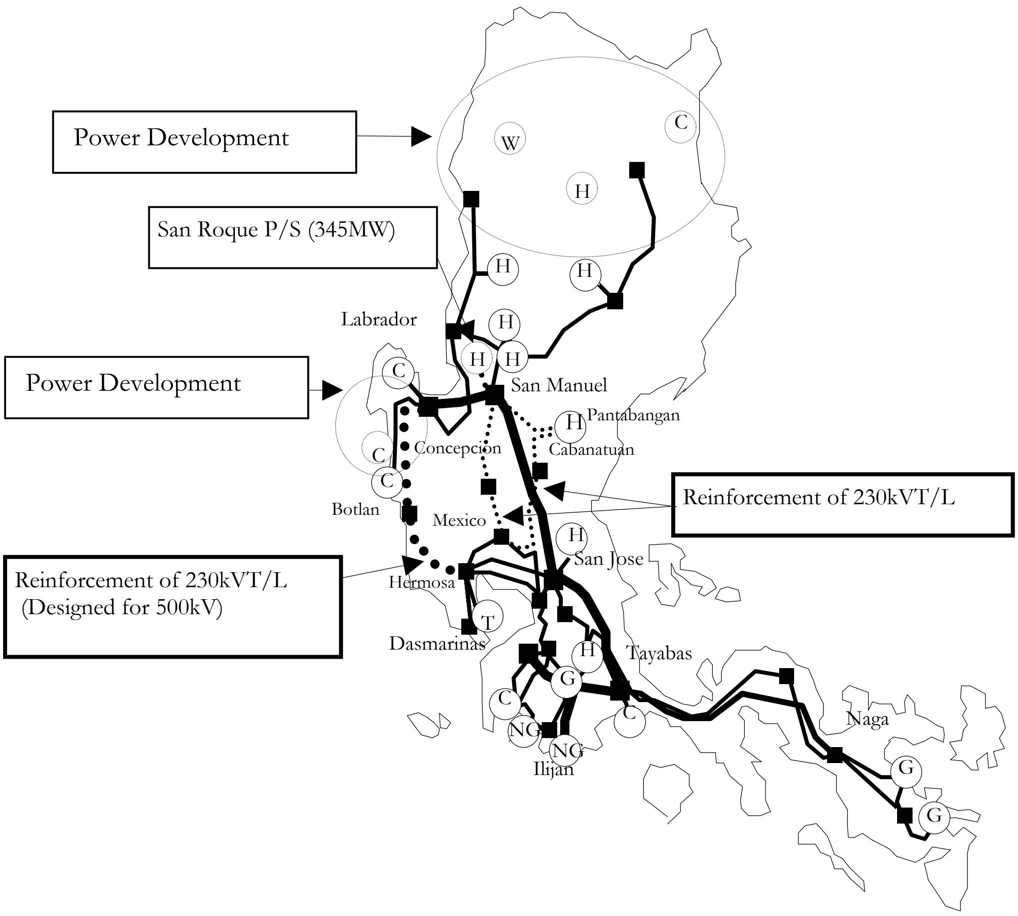
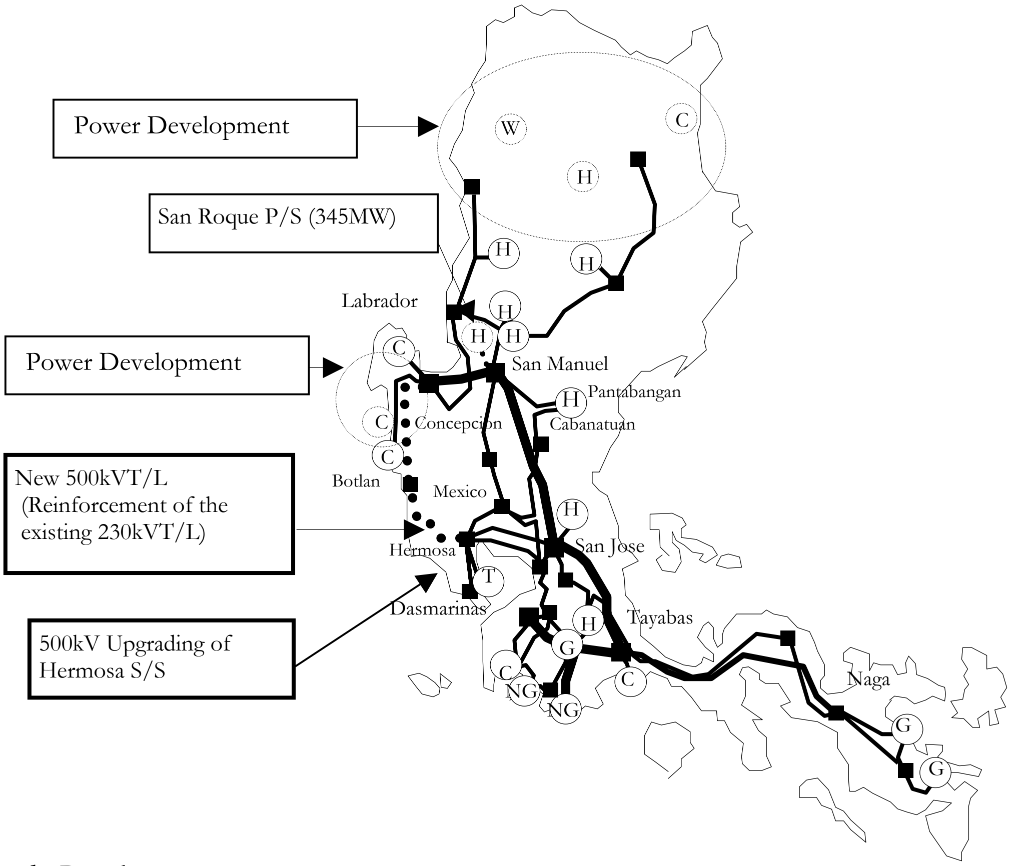


Fig. 5.3: Reinforcement Plan of 230 kV transmission lines in North Luzon (TDP 2003)



2) Study Results

Results of the power flow analysis indicate that new measures not included in TDP 2003 are necessary, such as the installation of 500/230 kV transformers at San Manuel S/S and the reinforcement of a 230 kV transmission line between Hermosa and Mexico.

Table 5.10 shows the results of the power flow analysis.

According to the TDP 2003, split operation of the 230 kV system will reduce the short circuit capacity, and the replacement of the circuit breakers will not be necessary.

However, as a result of short circuit analysis, even though the TDP 2003 plan is applied, the short circuit capacity will not be reduced, and replacement of the circuit breakers will be needed as originally planned.

In addition, in the case of split operation of the 230 kV single circuit transmission lines, the substations which are supplied by the single-circuit transmission line will suffer from interruption when there is a transmission line failure. Therefore, the reliability level will be worse than the current level.

In the economic analysis conducted by the team, a comparison of the net present values of investment of each plan showed that the original plan is more economical than the revised TDP 2003.

In addition, the initial investment of the TDP 2003 is very large because 500 kV transmission lines will initially be constructed. Meanwhile, the transmission lines will be reinforced in accordance with power development as in the original plan.

Further power development is expected for the 230 kV transmission lines between Labrador S/S and Botolan S/S and Hermosa S/S, because they are located near the coast. The design for this transmission system should be at 500 kV as originally planned.

Given these considerations, it would be more advantageous to apply the original plan (reinforcement of the three existing transmission lines), in conjunction with power development plan for North Luzon.

Table 5.10: Study Results

		Original Plan	TDP 2003
Outline of Plan		Reinforcement of the three existing 230 kV transmission lines	New 500 kV transmission line (Labrador- Botolan- Hermosa: Reinforcement of the existing 230 kV transmission line)
Measures	2006	- Reinforcement of 230 kV transmission lines (San Manuel- Concepcion- Mexico)	- New 500 kV transmission line (Labrador-Botolan-Hermosa: Reinforcement of the existing 230 kV transmission line) - Installation of 500/230 kV transformers at Hermosa (3 x 600 MVA) - Installation of 500/230 kV transformers at San Manuel (2 x 600 MVA) - Reinforcement of 230 kV transmission lines (Hermosa-Mexico)
	2008	- Reinforcement of 230 kV transmission lines (Labrador - Botolan - Hermosa) (Designed for 500 kV)	-
	2010	- Reinforcement of 230 kV transmission lines (San Manuel - Pantabangan - Cabanatuan - Mexico)	- Installation of 500/230 kV transformers at San Manuel (1 x 600 MVA) - Installation of 500/230 kV transformers at San Jose (1 x 600 MVA)
	2012	- 500 kV Upgrading (Labrador- Botolan- Hermosa) - Installation of 500/230 kV transformers at Hermosa (3 x 600 MVA)	- Installation of 500/230 kV transformers at Hermosa (1 x 600 MVA)
Economic Analysis	Initial Investment	P 1,666 million	P 11,660 million

		Original Plan	TDP 2003
	Total Investment	P 14,574 million	P 14,566 million
	NPV	P 10,571 million	P 13,520 million
Advantage		It is possible to reinforce the transmission lines in coordination with power development for North Luzon.	-
Disadvantage		-	The reliability level will be lower, because of split operation of the 230 kV transmission lines.
Remarks			The short circuit capacity of the 230 kV system will hardly be improved.

(2) Transmission Reinforcement in Batangas

1) Outline

There are serious transmission constraints with respect to the power generating facilities in Batangas—the Ilijan P/S (1,200 MW), Santa Rita P/S (1,200 MW) and San Lorenzo P/S (1,060 MW), which are all fueled by natural gas from Malampaya in northwest Palawan, as well as the Calaca coal-fired power plants (600 MW).

These constraints are due to the thermal capacity limit of the existing transmission lines.

To address these specific transmission constraints in the Batangas area, the following measures were drafted as part of the transmission development plan, as shown in Table 5.11.

Table 5.11: Transmission Reinforcement for power development in Batangas

Project	Outline	Commissioning Year
New Transmission Line (San Pascual-Batangas)	230 kV ST-DC 4-795MCM, 6.5 km 230 kV SP-DC 4-795MCM, 1.5 km	Jan. 2004
New Transmission Line (San Pascual-San Lorenzo)	230 kV SP-DC 4-795MCM, 1.2 km	Jan. 2004
Reinforcement of T/L (New Makban-Binan)	230 kV ST-DC 4-795MCM, 32 km	Nov. 2004
Reinforcement of T/L (New Batangas-New Makban A)	230 kV ST-DC 4-795MCM, 35 km	Feb. 2005
New Transmission Line (New Makban A-Makban C)	230 kV ST-SC 1-795MCM, 2.0 km	Dec. 2004
Reinforcement of T/L (Binan-Dasmarinas)	230 kV ST-DC 4-795MCM, 14.5 km	Sep. 2004
Reinforcement of T/L (Kalayaan-Calauan)	230 kV ST-DC 4-795MCM, 27.5 km	Dec. 2006
Reinforcement of T/L (Calauan-Makban)	230 kV ST-DC 4-795MCM, 14.4 km	Dec. 2006

Currently, the generated power at Ilijan P/S is transported by the 500 kV transmission lines from Ilijan P/S to Dasmarinas S/S and Tayabas S/S. TRANSCO is planning to build a new 500 kV switching station for the 500 kV transmission lines in 2006 as shown in Table 5.12.

Table 5.12: Outline of the Alaminos switching station

Project	Outline	Commissioning Year
Alaminos Switching Station	500 kV 10-500 kV PCB + S/S Acc.	Oct. 2006

In this regard, the JICA study team evaluated the need for the reinforcement of the 230 kV transmission line and the construction of a new 500 kV switching station.

Fig. 5.4: Transmission Development in Batangas

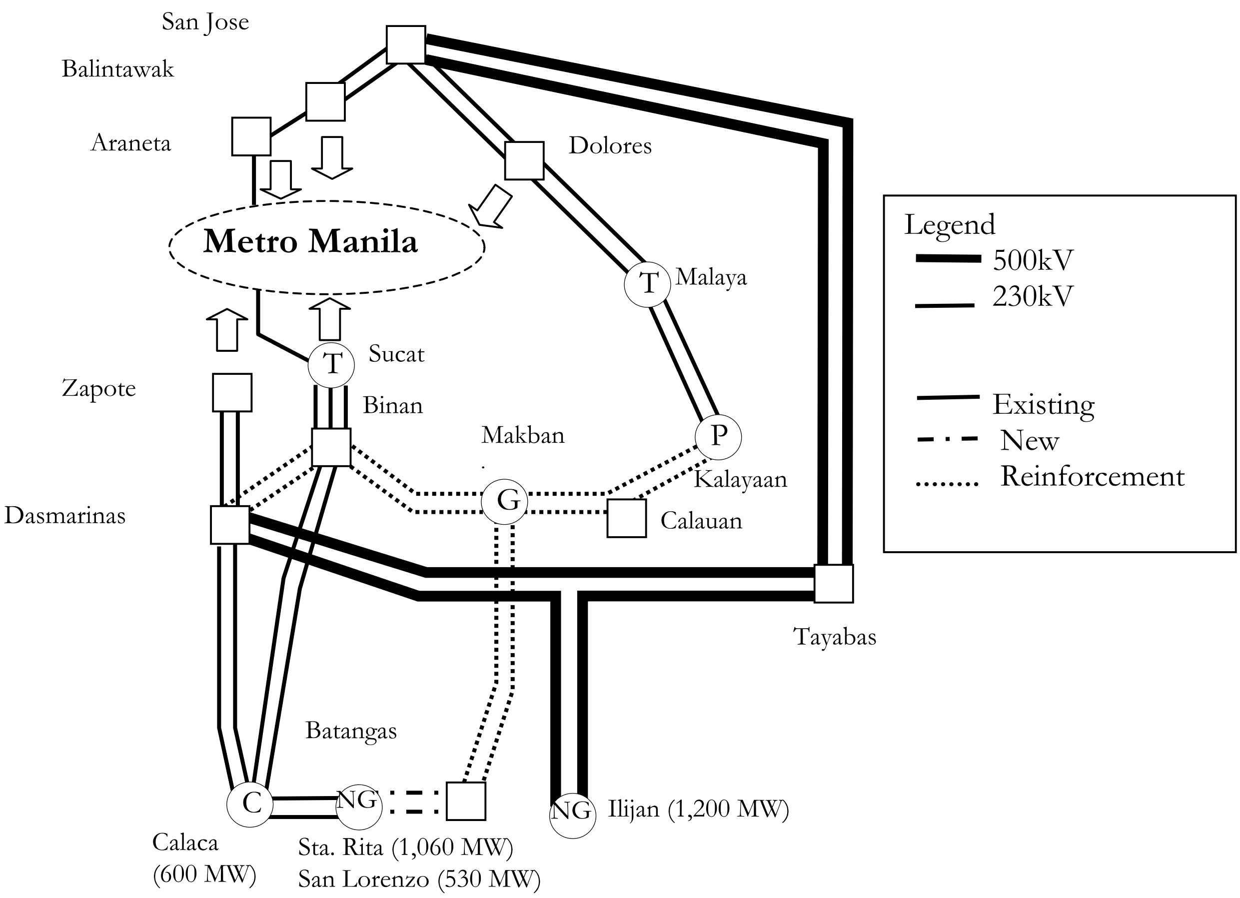
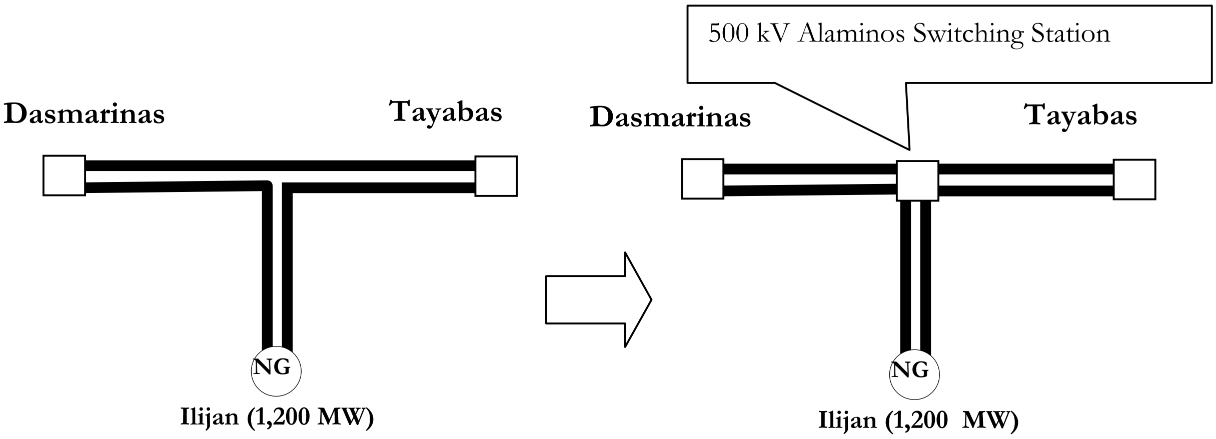


Fig. 5.5: Alaminos Switching Station



2) Study Results

The power flow analysis shows that the 230 kV transmission line between Binan S/S and Dasmarinas S/S will be overloaded under normal conditions if power generated from the Ilijan P/S, Santa Rita P/S, and San Lorenzo P/S are fully dispatched. In addition, the 230 kV transmission line between Calaca P/S and Binan S/S will be overloaded with an N-1 contingency.

Therefore, as planned by TRANSCO, the following measures are necessary:

A new 230 kV transmission line from Sta. Rita P/S to Batangas S/S; reinforcement of the 230 kV transmission line between Batangas S/S and Makban A P/S; reinforcement of the 230 kV transmission line between Makban P/S and Binan S/S; reinforcement of the 230 kV transmission line between Binan S/S and Dasmarinas S/S; reinforcement of the 230 kV transmission line between Makban P/S and Kalayaan P/S.

In addition, reinforcement of the transmission line between Makban A P/S and Makban C is necessary to satisfy the N-1 rule.

Examination, however, of the transmission line between Makban P/S and Kalayaan P/S indicates that a double-circuit cut-in to Calauan S/S is unnecessary.

The result of the power flow analysis and transient stability analysis shows that the 500 kV Alaminos switching station is unnecessary at present.

The study team likewise found that if further power development is pursued near the Ilijan P/S in the future, the Alaminos switching station will play a crucial role in ensuring the system's stability.

However, since no concrete power development is currently planned near Ilijan P/S, this project may be deferred.

(3) Transmission Reinforcement in South Luzon

1) Outline

The JICA team conducted an evaluation of TRANSCO's plan to install a 500/230 kV transformers at the Naga S/S and to operate the transmission line at 500 kV in 2004.

The Tiwi geothermal power plant (275 MW) and the Bacman geothermal power plant (150 MW) are both located in Southern Luzon.

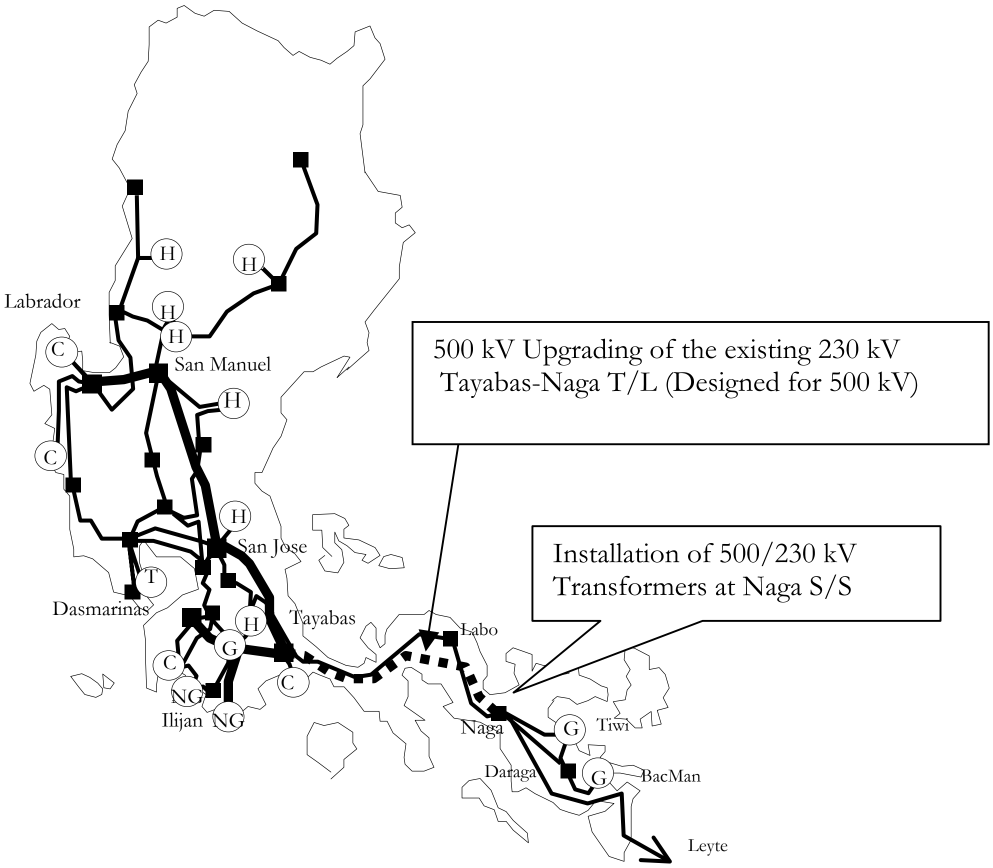
In addition to this, South Luzon—particularly Naga—is the site of a DC converter station (440 MW) which allows power generated from geothermal plants in Leyte to be transmitted to Metro Manila through the Leyte-Luzon Interconnection.

It bears noting that the 230 kV transmission line between Naga S/S and Tayabas S/S is designed for 500 kV to accommodate power development in South Luzon.

Table 5.13: 500 kV upgrading of Naga S/S

Project	Outline	Commissioning Year
500 kV upgrading of Naga S/S	Installation of 500/230 kV transformers (3 x 200 MVA)	Mar. 2004

Fig. 5.6: 500 kV upgrading of Naga S/S



2) Study Results

As a result of power flow analysis, South Luzon transmission lines—with the exception of the Batangas system—are not expected to be overloaded in the case of an N-1 contingency. Therefore, TRANSCO's plan to install 500/230 kV transformers at the Naga S/S and operate the line at 500 kV is not necessary at the moment.

This project can be deferred considering that there is presently no concrete power development plan except the rehabilitation of the Tiwi Geothermal power plant in Southern Luzon, while the Leyte-Mindanao Interconnection project is still in the pipelines.

However, this project may be necessary if new power plants are developed in South Luzon, or if the Leyte-Mindanao Interconnection is completed allowing power to be transmitted from Mindanao to Luzon.

5.1.4 Visayas Grid

(1) Leyte-Cebu Interconnection Upgrade

1) Outline

There is currently a surplus of power in Leyte because of the large-scale power generation from the geothermal power plants in the area.

In its previous transmission plan, TRANSCO originally identified the upgrade of the Leyte-Cebu Interconnection as one of its priority projects.

The planned upgrade of the Leyte-Cebu Interconnection from a single circuit (200 MW) to a double circuit (400 MW) is intended to allow the surplus power in Leyte to be transmitted to Cebu island, the load center in the Visayas region. The planned upgrade project is shown in Table 5.14.

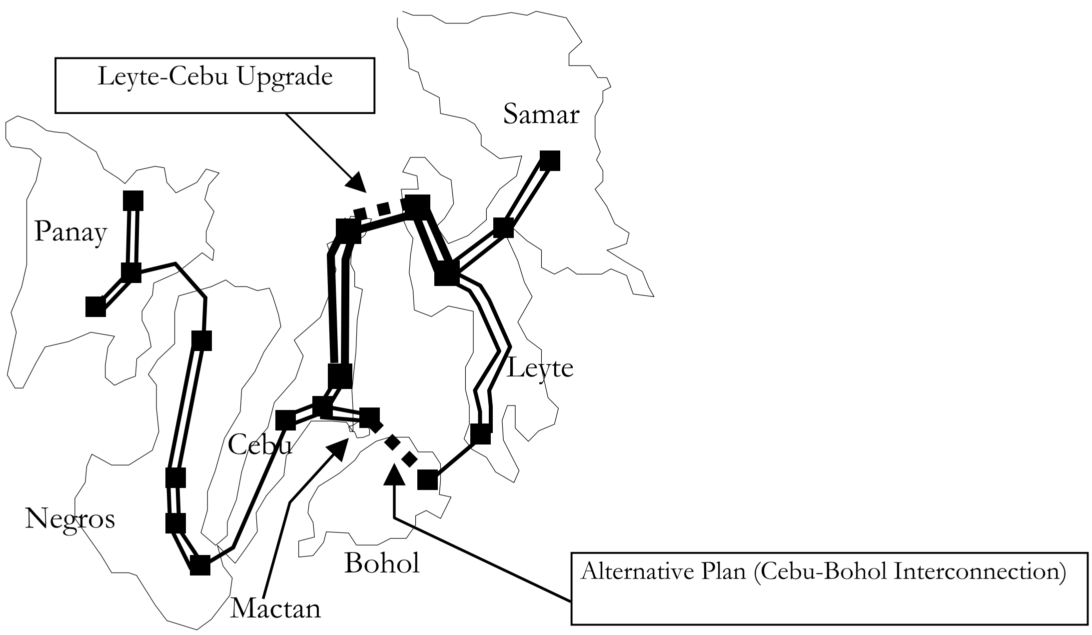
Table 5.14: Upgrade of Leyte-Cebu Interconnection (200 MVA→400 MVA)

Project	Outline	Commissioning Year
Leyte-Cebu Upgrade	3 x 630 mm2 230 kV Submarine cable (OF cable), 32.0 km	Feb. 2005
Compostela S/S Expansion	230/138 kV Transformer (1 x 150 MVA)	Feb. 2005

However, in TDP 2003, a new interconnection between Cebu and Bohol via Mactan was proposed in lieu of the original plan for the Leyte-Cebu upgrade.

The study group compared the two plans.

Fig. 5.7: Leyte-Cebu Upgrade and Alternative Plan



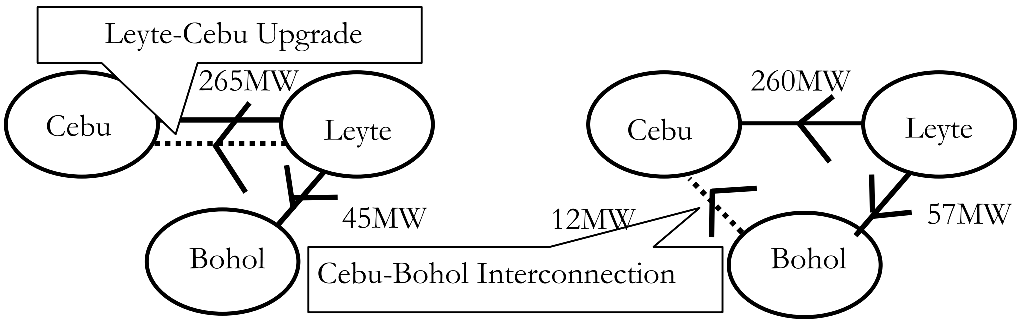
2) Study Results

Power flow analysis results reveal that even though a new interconnection between Bohol and Cebu is constructed, it will not help ease the transmission constraints resulting from the transmission of surplus power from Leyte to Cebu.

While this project is seen to improve the over-all reliability of the system in the long run, its implementation is not seen to contribute to the mitigation of the transmission problem in the short term.

Without an upgrade of the Leyte-Cebu Interconnection, the transmission line will be overloaded if surplus power from Leyte is fully transmitted to Cebu.

Fig. 5.8: Results of Power Flow Analysis



(2) Panay Grid

To address the looming power shortage in Panay, the transfer of the generators at Pinamucan P/S (110 MW) to Dingle S/S and a new diesel power plant are being planned.

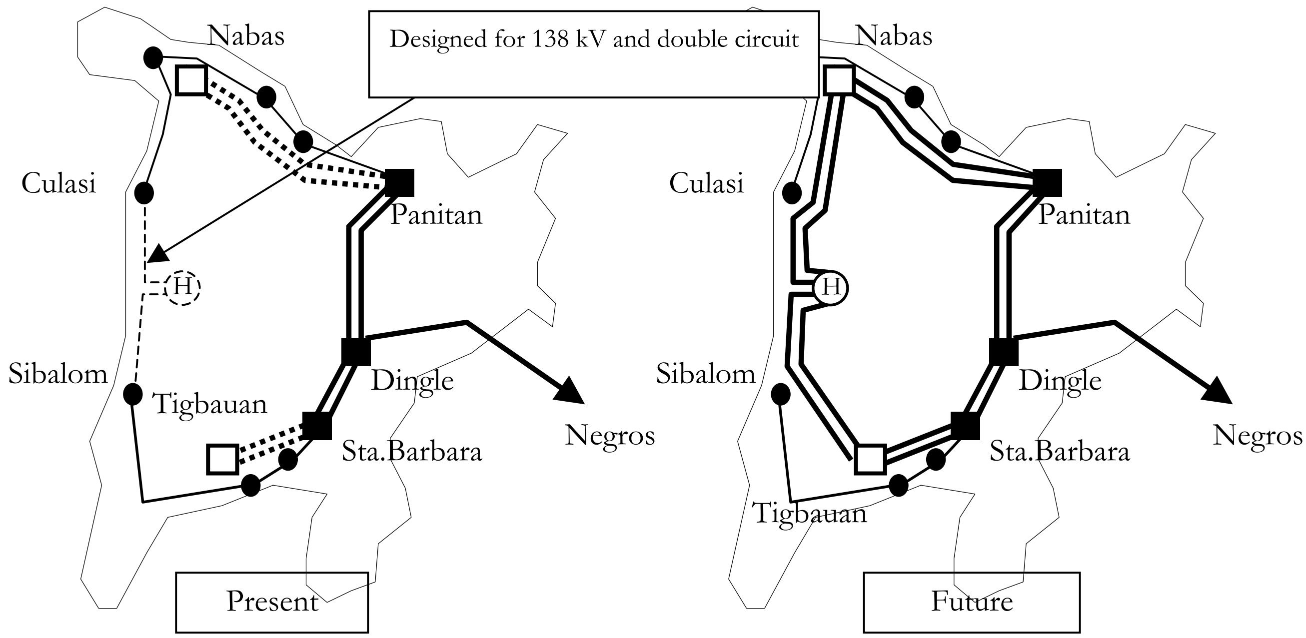
Therefore, it would be more feasible to construct a 138 kV ring in Panay to flexibly accommodate power development. Currently, although the new transmission line between Culasi S/S and Sibalom S/S is designed for 69 kV and is a single circuit, this should be designed for 138 kV and a double circuit to accommodate a 138 kV ring in the future.

Table 5.15 shows the transmission expansion plan in Panay.

Table 5.15: Transmission Expansion Plan in Panay

Project	Outline	Commissioning Year
Sta.Barbara-Tigbauan Transmission Line	138 kV ST-DC 1-795MCM, 47 km	Dec. 2005
Tigbauan Substation	138-/69-/13.8-kV transformer (2 x 50 MVA)	Dec. 2005
Panitan-Nabas Transmission Line	138 kV ST-DC 1-795MCM, 105 km	Dec. 2005
Nabas Substation	138/69/13.8 kV transformer (1 x 50 MVA)	Dec. 2005
Culasi-Sibalom Transmission Line	69 kV ST-SC 1-336.4MCM, 84 km	Dec. 2005

Fig. 5.9: Panay Grid



5.1.5 Mindanao Grid

(1) New 230 kV Transmission Lines

1) Outline

A major concern in the Mindanao System is the reliability of the power transfer from the northern portion of the region to the southern portion.

A large share in Mindanao's total generation capacity comes from the Agus hydro-electric power plant (727 MW) which is located in Lanao province (in the northern portion of the island).

However, bulk of the power generated from Agus needs to be transmitted to the southern part of the region where Davao City—Mindanao's load center—is located.

Currently, power generated from the northern portion is transported to the opposite end of the island through existing 138 kV transmission lines connecting Agus P/S and Kibawe S/S.

Table 5.16: New 230 kV Transmission Line Project in Mindanao

Outline		Year	Remarks
Abaga-Kirahon T/L	230 kV ST-DC 4-795MCM, 120 km	Dec. 2005	Initially operating at 138 kV
Kirahon-Pulangui 4 T/L	230 kV ST-DC 4-795MCM, 108 km	Dec. 2006	Initially operating at 138 kV
Pulangui 4-Bunawan T/L	230 kV ST-DC 4-795MCM, 102 km	Dec. 2006	Initially operating at 138 kV
Pulangui 4-Kibawe T/L	230 kV ST-DC 4-795MCM, 20 km	Jan. 2011	Initially operating at 138kV
Abaga Substation	230/138 kV Transformer 2 x 300 MVA	Jan. 2010	
Kirahon Substation	230/138 kV Transformer 2 x 300 MVA	Jan. 2010	
Pulangui 4 Substation	230/138 kV Transformer 2 x 300 MVA	Jan. 2010	
Bunawan Substation	230/138 kV Transformer 2 x 300 MVA	Jan. 2010	

However, the existing 138 kV transmission line between Agus P/S and Kibawe S/S passes a mountainous area, and are often the target of insurgents' sabotage efforts. This has significantly lowered the reliability of the existing system.

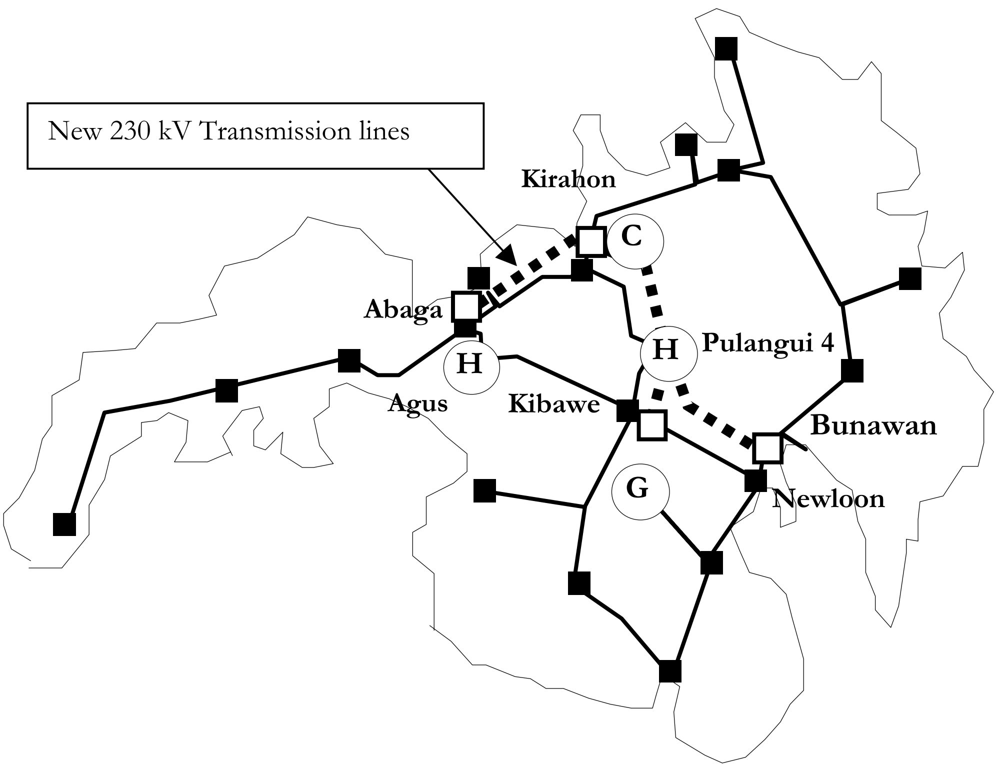
The demand in Mindanao is forecast to double in 10 years, but power development, such as a the construction of a coal-fired power plant (200 MW) and the expansion of the Agus hydroelectric power plant (225 MW), is concentrated in the North.

Considering these factors, TRANSCO had originally planned to construct new 230 kV transmission lines from Abaga S/S in North Mindanao to Bunawan S/S in South Mindanao, as shown in Table 5.16.

However, in TDP 2003, these projects have been removed from the investment plan, with the assumption that the national government would finance them because these projects are always the target of sabotage.

In this study, the JICA team evaluated the necessity of the new 230 kV transmission lines between Abaga S/S and Bunawan S/S.

Fig. 5.10: New 230 kV Transmission Lines in Mindanao



Likewise, the JICA team ran simulations on the 138 kV transmission lines connecting Agus P/S and Kibawe S/S, under two scenarios. The first scenario assumed that the line is functioning while the other one assumed that the line is out of service. The years 2006 (1,360 MW) and 2012 (2,041 MW) have been adopted for the case study.

Table 5.17: Study Cases

<table>
<tr><th></th><th>Power Development Plan</th><th>138 kV Agus2-Kibawe T/L</th></tr>
<tr><td>Case 1</td><td rowspan="2">All of the new generation will be developed in North Mindanao.
(1) 2006
- Coal (200MW): North
(2) 2012
- Hydro (Agus3, 225 MW): North
- Coal (200 MW): North
- HVDC (500 MW): North</td><td>In Service</td></tr>
<tr><td>Case 2</td><td>Out of Service</td></tr>
<tr><td>Case 3</td><td rowspan="2">470MW generation will be developed in South Mindanao.
(1) 2006
- Coal (100 MW*): North
- GT (70 MW): South
(2) 2012
- Hydro (Agus3, 225 MW): North
- Coal (200 MW): North
- Davao (200 MW): South
- Bunawan (100 MW): South
- General Santos (100 MW): South</td><td>In service</td></tr>
<tr><td>Case 4</td><td>Out of Service</td></tr>
</table>

* In 2006, if 70 MW GT is installed in Southern Mindanao, the 200 MW coal-fired power plant in Northern Mindanao would not be necessary, considering the demand and supply balance. Therefore, 100 MW has been adopted.

2) Study Results

(A) In 2006 (1360 MW)

In Case 1, the 138 kV transmission line between Kibawe S/S and Newloon S/S will be overloaded if there is a one-circuit failure of the line. As a precaution, a new 138 kV transmission line between Pulangui 4 P/S and Bunawan S/S is needed.

In Case 2, the transmission lines between Abaga S/S and Tagoloan S/S, and between Pulangui 4 P/S and Kibawe S/S are forecasted to be overloaded. As a precaution, new 138 kV transmission lines between Abaga S/S, Kirahon S/S, Pulangui 4 P/S and Kibawe S/S are needed.

In Case 3, even with the commissioning of a 70 MW generation plant in Southern Mindanao, no overloading of the transmission system even under normal conditions or in the case of an N-1 contingency is expected to occur. Therefore, no new transmission lines are needed.

In Case 4, if the transmission line between Agus 2 P/S and Kibawe S/S is to be excluded, the transmission line between Abaga S/S and Tagoloan S/S is seen to overload. As a precaution, new 138 kV transmission lines between Abaga S/S, Kirahon S/S, Pulangui 4 P/S and Kibawe S/S should be constructed.

(B) In 2012 (2041 MW)

In Case 1, the transmission lines between Pulangui 4 P/S and Kibawe S/S and between Kibawe S/S and Newloon S/S will be overloaded under normal conditions. To prevent overloading, a new 138 kV transmission line between Pulangui 4 P/S and Bunawan S/S is needed.

In addition, the projected expansion at Agus 3 P/S (225MW) is expected to result to an overload in the transmission line between Agus 2 P/S and Kibawe S/S in the case of a one-circuit failure of the line. To guard against this overload, new transmission lines between Abaga S/S, Kirahon S/S and Pulangui 4 P/S are needed.

In Case 2, the transmission line between Pulangui 4 P/S and Kibawe S/S will be overloaded. In addition, the transmission line between Abaga S/S and Tagoloan S/S will be overloaded in the case of an N-1 contingency. As a precaution, new 138 kV transmission lines between Abaga S/S, Kirahon S/S, Pulangui 4 P/S and Kibawe S/S are needed.

In Case 3, if a 470 MW generation plant is presumed to be on line in Southern Mindanao, there will be no overload in normal conditions or in the case of an N-1 contingency. Therefore, no new transmission lines will be needed.

In Case 4, as the transmission line between Agus 2 P/S and Kibawe S/S is excluded, new 138 kV transmission lines between Abaga S/S, Kirahon S/S, Pulangui 4 P/S and Kibawe S/S are needed.

(c) Summary

The results depend on power development in Southern Mindanao and the status of the transmission line between Agus 2 P/S and Kibawe S/S (included or excluded).

In all cases, the adoption of 230 kV lines will not be needed, and the transmission lines will have to operate only at 138 kV. However, the new transmission lines should be designed for 230 kV to accommodate future increases in demand and the addition of new plants.

After the completion of the Leyte-Mindanao Interconnection, if large power flows from Leyte, a voltage problem may ensue. Therefore, a detailed study for 230 kV upgrading is recommended.

Table 5.18 is a summary of the results of this exercise.

Table 5.18: Summary

Year	Case	Power Development in Southern Mindanao	Agus 2-Kibawe Transmission Line	Necessary Measures
2006	Case 1	None	In service	138 kV Pulangui 4-Bunawan
	Case 2	None	Out of Service	138 kV Abaga-Kirahon 138kV Kirahon-Pulangui 4 138 kV Pulangui 4-Kibawe 138 kV Pulangui 4-Bunawan
	Case 3	70MW	In service	None
	Case 4	70MW	Out of Service	138 kV Abaga-Kirahon 138 kV Kirahon-Pulangui 4 138 kV Pulangui 4-Kibawe
2012	Case 1	None	In Service	138 kV Abaga-Kirahon 138 kV Kirahon-Pulangui 4 138 kV Pulangui 4-Bunawan
	Case 2	None	Out of Service	138 kV Abaga-Kirahon 138 kV Kirahon-Pulangui 4 138 kV Pulangui 4-Kibawe 138 kV Pulangui 4-Bunawan
	Case 3	470 MW	In Service	None
	Case 4	470 MW	Out of Service	138 kV Abaga-Kirahon 138 kV Kirahon-Pulangui 4 138 kV Pulangui 4-Kibawe

5.2 Interconnection Projects

5.2.1 Cebu-Negros-Panay Interconnection Upgrade

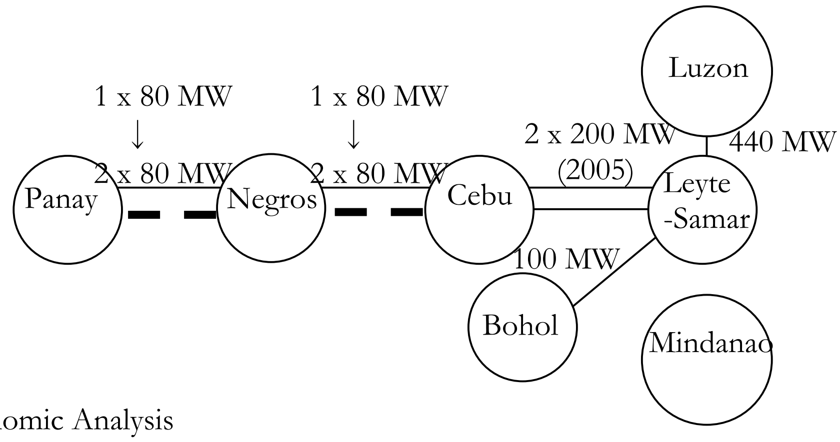
(1) Outline
The islands of Cebu, Negros, and Panay are currently connected by single-circuit 138 kV submarine cables, and power is transferred to Panay—where there is a power shortage—through these cables.

Since the power shortage is now becoming severe in Panay due to an increase in demand, the transfer of the generators from Pinamucan P/S (110 MW) in Luzon to Panay, and the construction of a new diesel power plant (40 MW) in the island by Mirant—an IPP—are being planned.

In addition to these capacity additions, upgrading the interconnection from single circuit to double circuits between Cebu and Negros, and between Negros and Panay—these projects are not included in TDP 2003—are under consideration.

The JICA study team evaluated the upgrade of Cebu-Negros and Negros-Cebu Interconnection, through economic analysis, as well as the demand and supply balance in that particular area.

Fig. 5.11: Cebu-Negros-Panay Upgrade



(2) Economic Analysis

There are two options to mitigate the power shortage in Panay. One is capacity addition in Panay, while the other is upgrading the Cebu-Negros and the Negros-Panay Interconnection. These two options are compared from an economical point of view.

The Cebu, Negros, and Panay islands have already been connected by single-circuit submarine cables. Therefore, it is not expected that the peak demand will decrease as a result of interconnection. Reduction in the reserve margin is not expected, either. The only advantage of the CNP interconnection is a reduction in fuel cost due to more economical operations.

In this study, an economic analysis was conducted, considering a reduction in fuel cost (which is calculated using GTMax) and the capital cost of the interconnection.

Table 5.19: Results of Economic Analysis (Comparison with "no upgrade")
(Unit: US $ million)

Commissioning Year *	Net Present Value (NPV)		
	Cebu-Negros-Panay Upgrade	Cebu-Negros Upgrade	Negros-Panay Upgrade
2005	-31.5	-28.9	-16.0
2006	-31.1	-24.8	-18.6
2007	-30.7	-21.2	-19.9

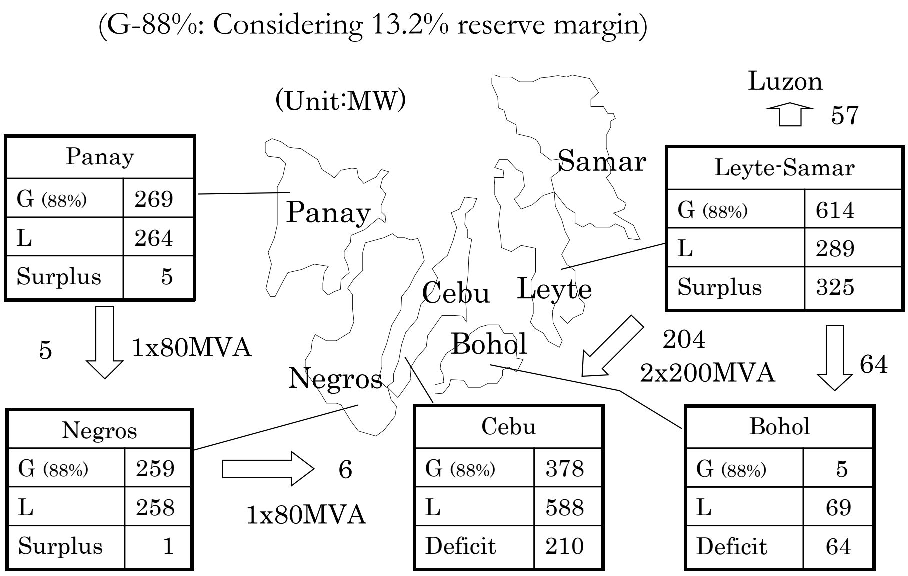
* According to TRANSCO, the year of commissioning is 2005. As the schedule is very tight, 2006 and 2007 are also considered. (Commissioning is assumed to take place at the end of the year.)

The study reveals that the net present values are negative in all cases. This means that a capacity addition in Panay and Negros is more economical than the Cebu-Negros-Panay upgrade. (However, it should be noted that the results could change largely depending on the assumptions, such as capacity addition.)

(3) Demand and Supply Balance at Peak Time

The economic analysis shows that capacity additions in Panay and Negros are indeed economical. Figure 5.2.2 shows the demand and supply balance in the case of optimized capacity addition.

Fig. 5.12: Demand and Supply Balance in 2008 (Optimal Power Development)



However, after the privatization of NPC, with heavier reliance on the IPPs to build plants, there is no guarantee that any capacity addition will be undertaken according to the plan.

The current committed capacity additions in Panay and Negros are shown in Table 5.20, while the old diesel power plants which are scheduled to be decommissioned in 2007 are shown in Table 5.21.

Table 5.20: Power Development Plan in Panay and Negros (Committed Projects)

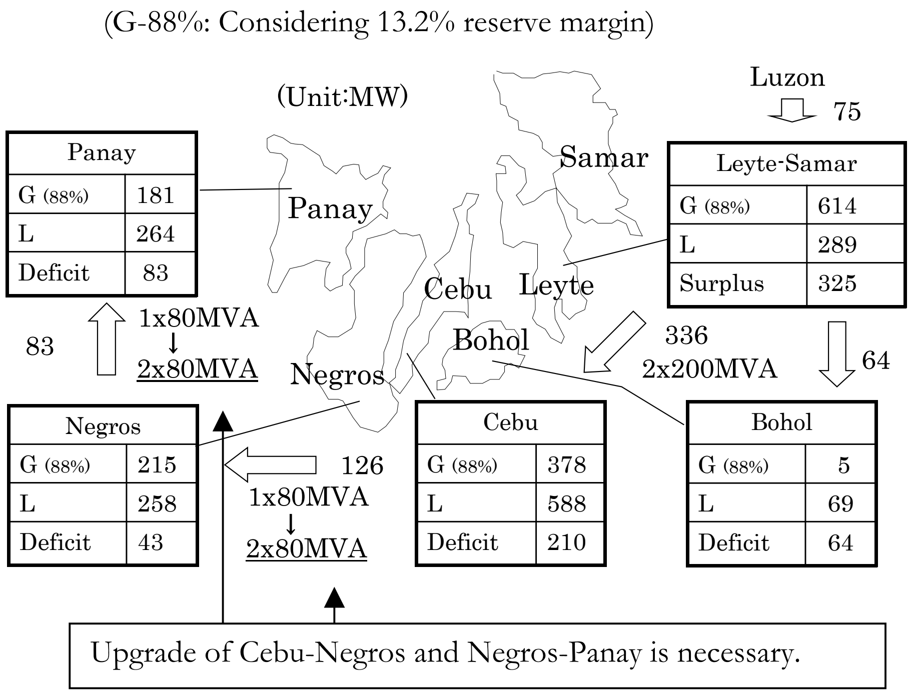
Power Development Plan	Capacity (MW)	Commissioning Year
Pinamucan (Transfer to Dingle)	110	2004
Mirant Diesel	40	2004
Northern Negros Geothermal	40	2005
PNOC-Palimpinon Geothermal	20	2005
Victorias Bioenergy	50	2005

Table 5.21: Decommission Schedule in Panay and Negros

Decommission Plan	Capacity (MW)	Year
Panay DPP1	36.5	2007

Figure 5.2.3 shows the demand and supply balance in the Visayas at peak time in 2008, in the case of no capacity additions, except committed projects to date. Thus, the upgrade of both the Cebu-Negros and Negros-Panay lines are needed.

Fig. 5.13: Demand and Supply Balance in 2008 (considering committed projects only)



(4) Summary

Although the upgrade of Cebu-Negros-Panay is not economical, there is a felt need to promote the projects to avoid a power crisis in Panay. Power shortage might occur again in Panay in 2008 in the event that there are no capacity additions aside from the current committed projects.

In addition, since the Cebu-Negros and Negros-Panay Interconnections consist of a single circuit, it is imperative to upgrade them into a double circuit to ensure reliability. Since one circuit of the submarine cables currently consists of four cables, power transfer can continue in case of a one-cable failure. However, power transfer cannot continue in case of a two- or three-cable failure. Moreover, as sections of the overhead line consist of a single circuit, the N-1 rule is not satisfied, and power transfer will cease in the case of a failure of the section.

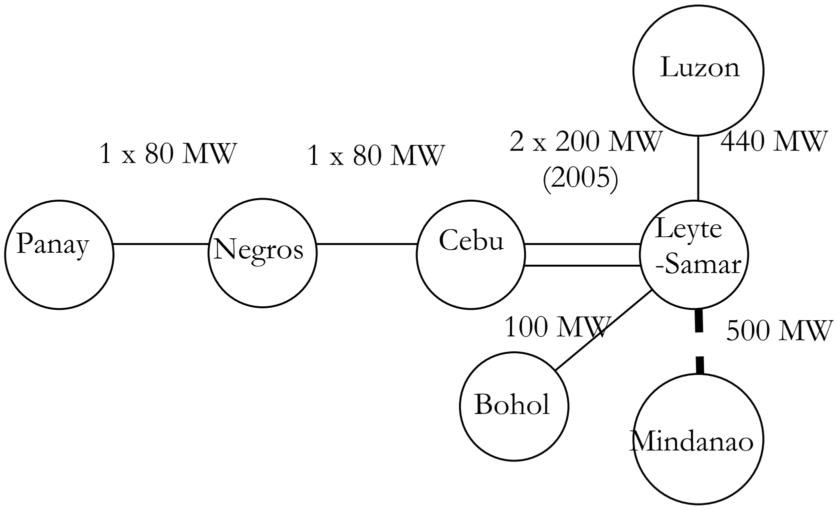
5.2.2 Leyte-Mindanao Interconnection

(1) Outline

As planned in TDP 2003, the construction of the Leyte-Mindanao Interconnection (DC +/- 250 kV 500 MW) is slated for 2011. The interconnection will connect the existing Ormoc S/S in Leyte and the new Kirahon S/S in North Mindanao.

The JICA study team evaluated the necessity of the Leyte-Mindanao Interconnection from both the economic and reliability viewpoint.

Fig. 5.14: Leyte-Mindanao Interconnection



(2) Economic Analysis

In the conduct of an economic analysis on the Leyte-Mindanao Interconnection, the following three points were considered:

- Peak reduction caused by the difference in the peak time of each system;
- Reduction in reserve margin; and
- Reduction in fuel cost.

Table 5.22 shows the non-coincident peak demand of Luzon, the Visayas and Mindanao; the coincident peak demand of Luzon and the Visayas; and the coincident peak demand of Luzon, the Visayas, and Mindanao in 1996.

Based on these data, the completion of the Leyte-Mindanao Interconnection will result to a peak demand reduction of about 0.2%. The time lag in the peak demand of the Luzon-Visayas system and the Mindanao system is not large, and the reduction with the interconnection is not great.

If the peak demand is reduced by 0.2%, a reduction of about 0.2% in capacity can also be expected. Therefore, the investment reduction is expected to be $17 million.

Table 5.22: Reduction in Peak Demand with Interconnection
(Unit: MW)

Non-Coincident Peak Demand			Coincident Peak Demand		Reduction in Peak demand	
Luzon (a)	Visayas (b)	Mindanao (c)	L+V (d)=a+b	L+V+M (e)=d+c	(f)=c+d-e	(g)= f/(a+b+c)
4,258	632	828	4,852	5,671	9	0.2%

Table 5.23: Expected Power Development Reduction with Interconnection in 2011
(Unit: MW)

Non-Coincident Peak Demand				Power Development Reduction	
Luzon	Visayas	Mindanao	Total	Capacity	Cost
11,575	1,827	1,676	15,079	30 MW (0.2%)	$17 million*

* Unit price of gas turbine has been adopted.

The reduction in fuel cost is calculated using GTMax. Table 5.24 shows the results of the economic analysis considering the fuel cost and the capital cost of the interconnection and reduced capacity addition.

Table 5.24: Results of Economic Analysis (Comparison with "no upgrade")
(Unit: $ million)

Commissioning Year*	Net Present Value (NPV)
2007	-85.3
2008	-67.7
2009	-52.1
2010	-49.1
2011	-44.9
2012	-37.9

* According to TDP 2003, the year of commissioning is 2011. As the schedule can be advanced or deferred, the year of commissioning is considered to be between 2007 and 2012 (Commissioning is assumed to take place at the end of the year.)

The results of the study show that the net present values are negative in all cases. This means that the Leyte-Mindanao Interconnection is not economical.

(However, it should be noted that the results could change, largely depending on the assumptions, such as capacity additions.)

The results do not include the effect of reduction in the reserve margin. According to TRANSCO, the targets of the reserve margin in Luzon, the Visayas, and Mindanao are currently 13.2%. It is not clear whether TRANSCO will reduce the reserve margin after the completion of the Leyte-Mindanao Interconnection.

Therefore, in this study, the break-even point in reserve margin reduction by the Leyte-Mindanao Interconnection is calculated.

Table 5.25: Necessary Reduction in the Reserve Margin

Year of Commissioning	Non-coincident Peak L+V+M (MW) (a)	Interconnection Capacity (MW) (b)	Necessary Reduction in the Reserve Margin		Ratio against Peak Demand (c)/(a)	Ratio against IC Capacity (c)/(b)
			Investment ($ million)	Capacity (MW) (c)*		
2007	11,357	500	134	238	2.1%	47.6%
2008	12,204	500	119	212	1.7%	42.4%
2009	13,117	500	103	182	1.4%	36.4%
2010	14,074	500	109	192	1.4%	38.4%
2011	15,079	500	111	197	1.3%	39.4%
2012	16,133	500	105	186	1.2%	37.2%

* Unit price of gas turbine is adopted.

Results of the study reveal that the necessary reduction in the reserve margin is about 1.5%. Therefore, if the reserve margin can be reduced from 13.2% to around 11.7%, investment for the Leyte-Mindanao Interconnection will be recovered by fuel-cost reduction and a reduction in capacity additions.

(3) Summary

As previously discussed, the economic analysis indicated that the Leyte-Mindanao Interconnection is uneconomical. However, the interconnection project could avoid any risk of delay in capacity addition projects or an unexpected increase in demand.

For example, if power development in Mindanao is delayed or demand in Mindanao increases more sharply than originally forecasted, it will be possible to transmit power from the Luzon System or the Visayas System to the Mindanao System through the Leyte-Mindanao Interconnection.

In addition, the interconnection will improve reliability and will enhance the establishment of the spot market.

However, the capacity of the interconnection (500 MW) project is relatively large compared with the peak demand in Mindanao (1,676 MW in 2011), and the impact of interconnection failure on the system needs to be studied (especially when power is transferred from Luzon to Mindanao).

These factors—including economics, risk avoidance, reliability, the establishment of the spot market, and the impact of the project on transmission charges—should be considered in the planning for the Leyte-Mindanao Interconnection project.

5.3 Issues and Recommendations in Preparing and Evaluating the TDP

5.3.1 Organization for TDP Evaluation

EPIMB is responsible for evaluating and approving the TDP, and its integration into the PDP.

The TDP staff covers a lot of work, such as TDP evaluation (including checking the contents and system analysis using PSS/E), planning interconnection projects (mainly using GTMax); integrating the TDP in PDP and PEP (documentation and so on); public consultation; coping with specific problems (such as power crises in Panay and system planning for Mindoro); coordination with staff in charge of demand forecasting; and power development.

Currently, while 4 staff positions were approved for the TDP formulation, only one staff member is assigned to the TDP section.

Under the current set-up, the staff is overworked, leaving little opportunity for technical knowledge and skills transfer among DOE staff.

In addition, the staff is also in charge of not only TDP but also DDP. Therefore, the number of staff responsible for TDP should be increased, and the staff responsible for DDP should be assigned by the DOE leadership as soon as possible.

5.3.2 Schedule

To start the TDP formulation process, the DOE first prepares demand forecasts and power development. TRANSCO then prepares the TDP based on the demand forecast and power development, and submits it to DOE. After this submission, DOE evaluates and approves the TDP and integrates it to PDP and PEP. Considering the time which the DOE begins demand forecasting and power development, and the submission of the PEP to Congress, the schedule for the TDP formulation process is expected to be very tight.

For this reason, the study group proceeded to evaluate the individual projects based on the previous TDP (TDP 2003), and planned to evaluate this year's TDP by checking the points changed from the previous TDP.

Based on its original schedule, the DOE was to finalize the demand forecast at the end of May, and finalize the power development plan by the third week in June. TRANSCO was to submit the TDP in the middle of July. Then, the DOE was to evaluate and approve it, and integrate it to the PDP and PEP. PEP was to be submitted to Congress by September 15.

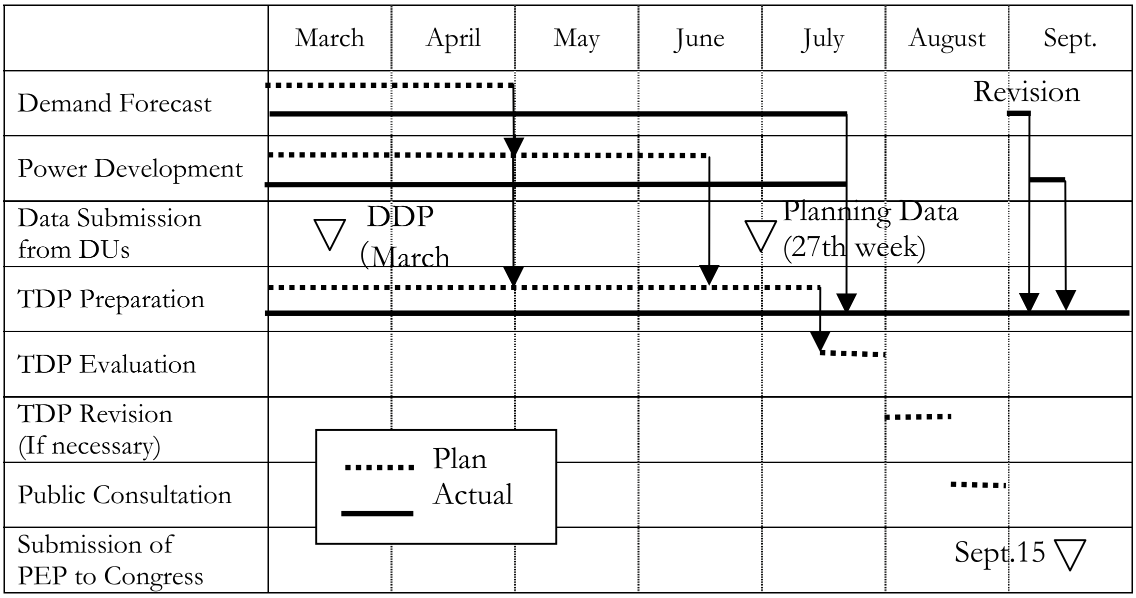
The demand forecast was however finalized only in the middle of July. The DOE revised it at the beginning of September. Therefore, the preparation of the TDP by TRANSCO was greatly delayed. As a result, the DOE failed to the submit the PEP to Congress by September 15.

Considering this year's actual chain of events, next year's demand forecast should be finalized at the end of May, the power development plan should be finalized in the middle of June, and TRANSCO should submit the TDP to DOE in the middle of July.

Meanwhile, all grid users—including distribution utilities—need to submit planning data to TRANSCO annually for five succeeding years by calendar Week 27 of the current year (July) under Grid Code 6.2.2.2. However, the timing is too late, in view of the TDP preparation schedule. Therefore, the data needs to be submitted earlier. As the distribution utilities need to submit DDP to DOE by March 15 under Rule 7, Section 4 (p) of EPIRA's IRR, they can submit the planning data to TRANSCO at this time.

Considering this situation, TRANSCO needs to undertake efforts to collect the planning data for TDP preparation before calendar Week 27, and grid users, including distribution utilities, need to cooperate with TRANSCO regarding the early submission of the data.

Table 5.26: Schedule for TDP preparation and evaluation (in 2003)



5.3.3 Coordination with the Power Development Plan

Transmission development planning is closely related to power development planning. It is thus impossible to prepare the TDP independently from the PDP, considering that to address demand increase in an area, there is an option to either pursue power development in the location; or undertake transmission line expansion projects.

Therefore, DOE and TRANSCO need to cooperate and decide which option should be taken.

Concretely, DOE needs to provide data on committed power development projects so TRANSCO could prepare the TDP. In addition, DOE needs to provide data on indicative projects that should be included in TDP from a political viewpoint, considering the possibility of the projects. The data to be provided from DOE to TRANSCO are the location of the site, fuel type, capacity, year of commissioning, among others.

DOE needs to identify preferred/potential locations for capacity additions from a transmission viewpoint based on the information from TRANSCO, and utilize the information for the promotion of power development projects.

On the other hand, TRANSCO needs to apply the power development plan provided by DOE on the TDP. Regarding indicative projects, TRANSCO assumes locations and capacities based on the information that TRANSCO receives directly from IPPs, taking into consideration the ideal transmission system in the future.

Information also needs to be submitted to DOE on the indicative projects that TRANSCO assumes for TDP preparation. This information also needs to be evaluated by DOE.

To coordinate the power development plan and transmission development plan, exchanging of a lot of data and feedback of the results of the study are necessary between DOE and TRANSCO. Therefore, holding periodic meetings and clarifying contact persons is necessary during TDP preparation.

In addition, generating companies (such as NPC and IPPs) and distribution utilities (such as MERALCO) need to attend the meetings, if necessary.

The DOE and TRANSCO should also discuss the interconnection plan in the meeting as coordination is also necessary between DOE and TRANSCO (in some cases with the generating companies and the distribution companies).

5.3.4 Planning Interconnection Projects between Islands

Prospective interconnection projects between islands need to be thoroughly evaluated to determine which option is more advantageous considering a number of factors—including reliability, economics, environment, and site possibility, among others.

Before its privatization, NPC was responsible for the power development plan, the transmission development plan, and the construction of both the power plants and the transmission lines. Therefore, NPC coordinated the power development plan and the transmission development plan in house.

With NPC divided and responsibility for transmission planning was solely transferred to TRANSCO, coordination between TRANSCO and DOE—which is, in turn, responsible for power development—is necessary.

A lot of work is necessary to plan interconnection, such as demand forecasting for each island, power development for each island, and power flow analysis (if there is already an existing interconnection).

Table 5.27 shows the roles of DOE and TRANSCO regarding interconnection.

Table 5.27: Roles of the DOE and TRANSCO regarding Interconnection

DOE	TRANSCO
➢ Demand Forecast (each island) ➢ Power Development (each island) ➢ Economic analysis (GTMax) ➢ Policy Making ➢ Planning measures in case of delay in power development	➢ Power Flow Analysis (PSS/E) ➢ Feasibility Study ➢ Schedule ➢ Cost ➢ Reliability Check (N-1 rule)

Under a deregulated regime, the private sector is expected to be at the forefront of the implementation of power development projects, while the DOE merely provides the indicative PDP.

Since the project implementation is passed on to the private sector, it is possible that power development may be delayed or even canceled. In this case, DOE needs to formulate a contingency plan to cope with such situations.

Chapter 6 Rural Electrification Plan

Under the EPIRA, DOE is required to prepare the MEDP for missionary areas and to integrate each DU's DDP. To assist in the MEDP and DDP preparation, the JICA team conducted an assessment of the current program for the formulation of these plans.

The workflow was drawn and responsibilities of the related organizations were delineated to prepare plan. Moreover, a GIS database for MEDP and data collection format for DDP were created.

6.1 Assessment of the O-Ilaw Program

6.1.1 Outline of the O-Ilaw Program

Poverty reduction in rural areas as well as closing the gap between urban and rural communities is a big challenge in the Philippines. The energy sector, including DOE, considers electrification of unenergized areas as a crucial element in rural development and in improving the lives of the people. For 30 years, total rural electrification has been a moving target because of financial and geographical constraints.

To accelerate rural electrification, an inter-agency task force composed of the DOE, NEA, NPC-SPUG and PNOC-EDC organized the O-Ilaw Program Team in 2000. In 2001, the Project Management Office (PMO) was organized as a unit in DOE to provide overall policy direction, project implementation/monitoring, and evaluation of the program.

The O-Ilaw Program aims to energize 100% of 41,995 barangays by 2006. To achieve this goal, stable and sustainable energy is supplied to help improve the lives of the people in the rural areas. The components of the O-Ilaw Program are as follows:

1) Programs by government agencies

    - DOE
        - Locally-funded projects using new and renewable energy
        - Projects funded by Grants-in-Aid programs
        - Projects funded by Energy Regulation 1-94, as amended

    - Electrification projects funded by NEA/ECs
        - Island electrification by NPC
        - Environmental Improvement for Economic Sustainability project by PNOC
        - Community Relations projects by PNOC-EDC
        - DAR Solar Power Technology Support (SPOTS) Project for Agrarian Reform Communities

2) Projects funded by Private Investor-Owned Utilities (PIOUs) such as MERALCO
3) Projects funded by LGUs
4) Projects funded by IPPs
5) Adopt-a-Barangay program
6) Projects funded by Rural Electrification Service Companies (RESCOs)

These projects are implemented either through grid extension or the utilization of new and renewable energy. Grid extension is implemented by NEA/ECs and PIOUs/LGUs.

On the other hand, DOE and NPC-SPUG implement off-grid electrification projects by introducing individual power systems such as SHS, BCS, micro-hydro and wind power systems.

A barangay is considered energized if the:

- Power is supplied to more than 10 houses in a barangay; and
- Distribution lines pass through a barangay such that a household that has no electricity can tap the wires.

6.1.2 Implementation of the O-Ilaw Program

Following the creation of the O-Ilaw team, the status of barangay electrification in the Philippines has tremendously improved as shown in Table 6.1.

From only 755 barangays energized in 1999, the number of barangays electrified rose to 1,699 in 2002, increasing by 125%. As of end December 2002, there were only 5,409 barangays still without electricity.

Table 6.1 O-Ilaw program implementation steps
As of December 2002

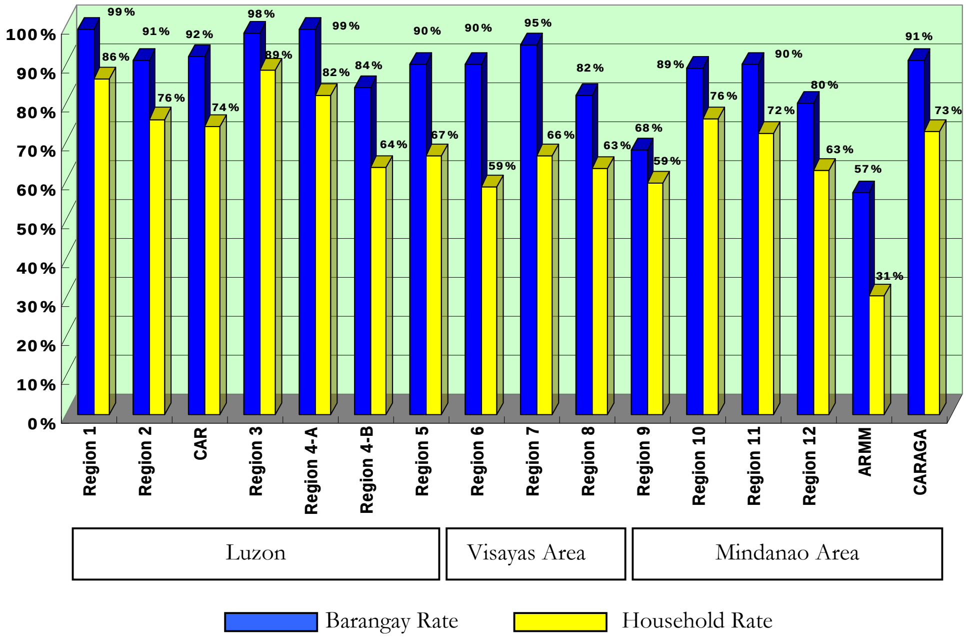
Year	Target Number of Electrified Barangays	Actual Number of Electrified Barangays	Cumulative Number of Electrified Barangays	Remaining Number of Electrified Barangays	Level (%) of Barangays Electrified
1999	900	755	32,281	9,718	76.9
2000	1,621	1,366	33,647	8,352	80.1
2001	1,353	1,244	34,891	7,103	83.1
2002	1,636	1,699	36,590	5,409	87.1

Source: O-Ilaw Program Team Terminal Report

A number of entities in the Philippine power sector are involved in implementing the rural implementation program. These entities include NEA; the electric cooperatives ECs; PIOUs; and LGUs.

On the other hand, a total of 119 ECs act as distribution utilities in 15 areas across the country. The electrification rate (as of November 2002) of barangays, including households in the 15 areas, are indicated in Fig. 6.1.

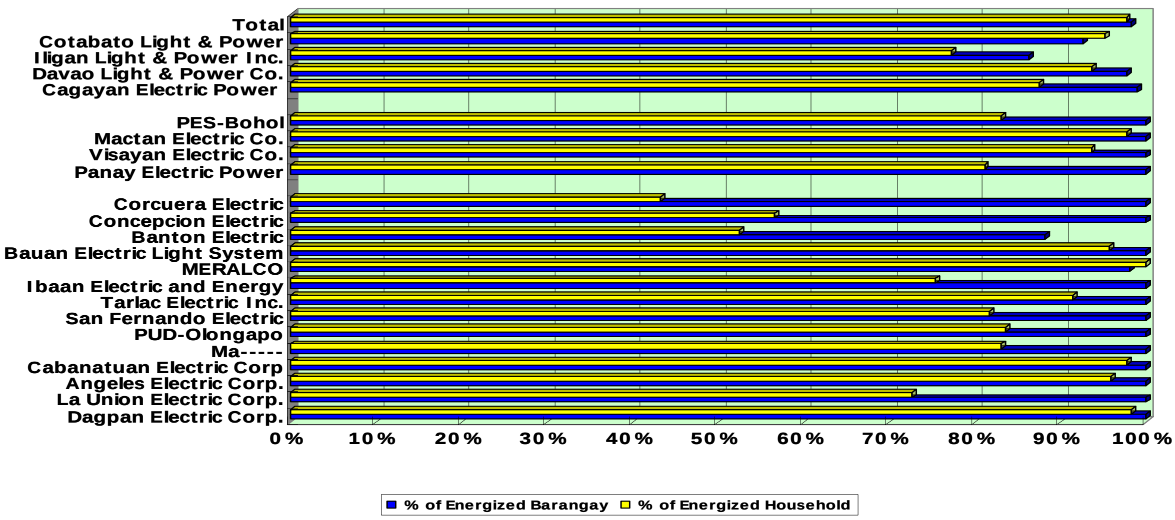
Fig. 6.1 Electrification rate of barangays and households in 15 regions



About 36,076 barangays are located within EC franchise areas. Currently, the average barangay electrification rate in Luzon stands at 92.7%, in the Visayas at 85.1%; and Mindanao at 73%. The electrification rate in Mindanao is relatively less than the other areas since a number of areas in this region are difficult to reach. A prime example is the Autonomous Region in Muslim Mindanao (ARMM) in Western Mindanao which has a low electrification rate. Needless to say, electrification in these areas is vital to develop the region and empower the people.

The electrification rate for PIOUs is shown in the Fig. 6.2.

Fig. 6.2 Electrification rate for PIOUs



On the other hand, PIOUs cover about 5,894 barangays with a record rate of about 98%, compared with the 85% electrification rate of the ECs. The largest PIOU is Meralco, which has 4,313 barangays in its franchise or equivalent to about 10% of the total number of barangays nationwide. It should be noted that the electrification rate within the Meralco franchise area is higher than in the other areas because the number of barangays it has energized is factored in the calculation.

6.2 Framework for the Rural Electrification Plan

6.2.1 Formulation of the Rural Electrification Plan

The rural electrification plan is pursued along three fronts, namely:

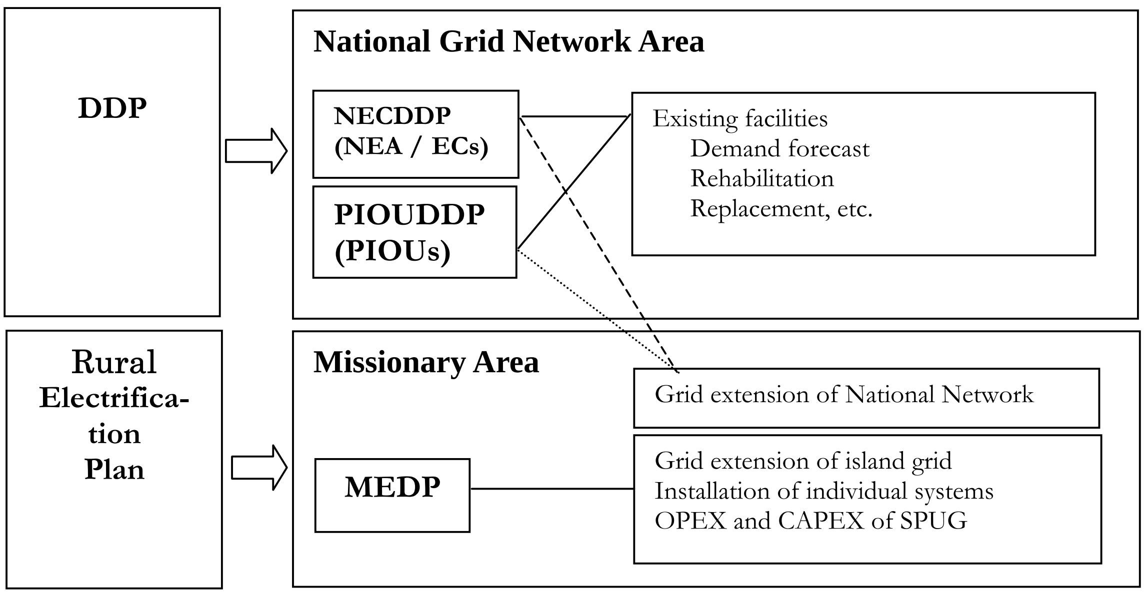
1) Grid extension project by NEA/ECs and PIOUs;
2) Management of existing diesel generators and installation of new power stations in rural areas by SPUG.
3) Introduction of individual power systems in rural areas with funds from the DOE budget; and
4) Privatization of SPUG.

An overall Rural Electrification Plan is needed to coordinate these three programs. Currently, the rural electrification plan has two major components, the MEDP, and the DDP Distribution Development Plan.

The MEDP includes the management of SPUG, SPUG's existing facility operation, and the installation of individual power systems.

The DDP, on the other hand, includes the management of the existing grid network and electrification through grid extension by NEA/ECs and PIOUs.

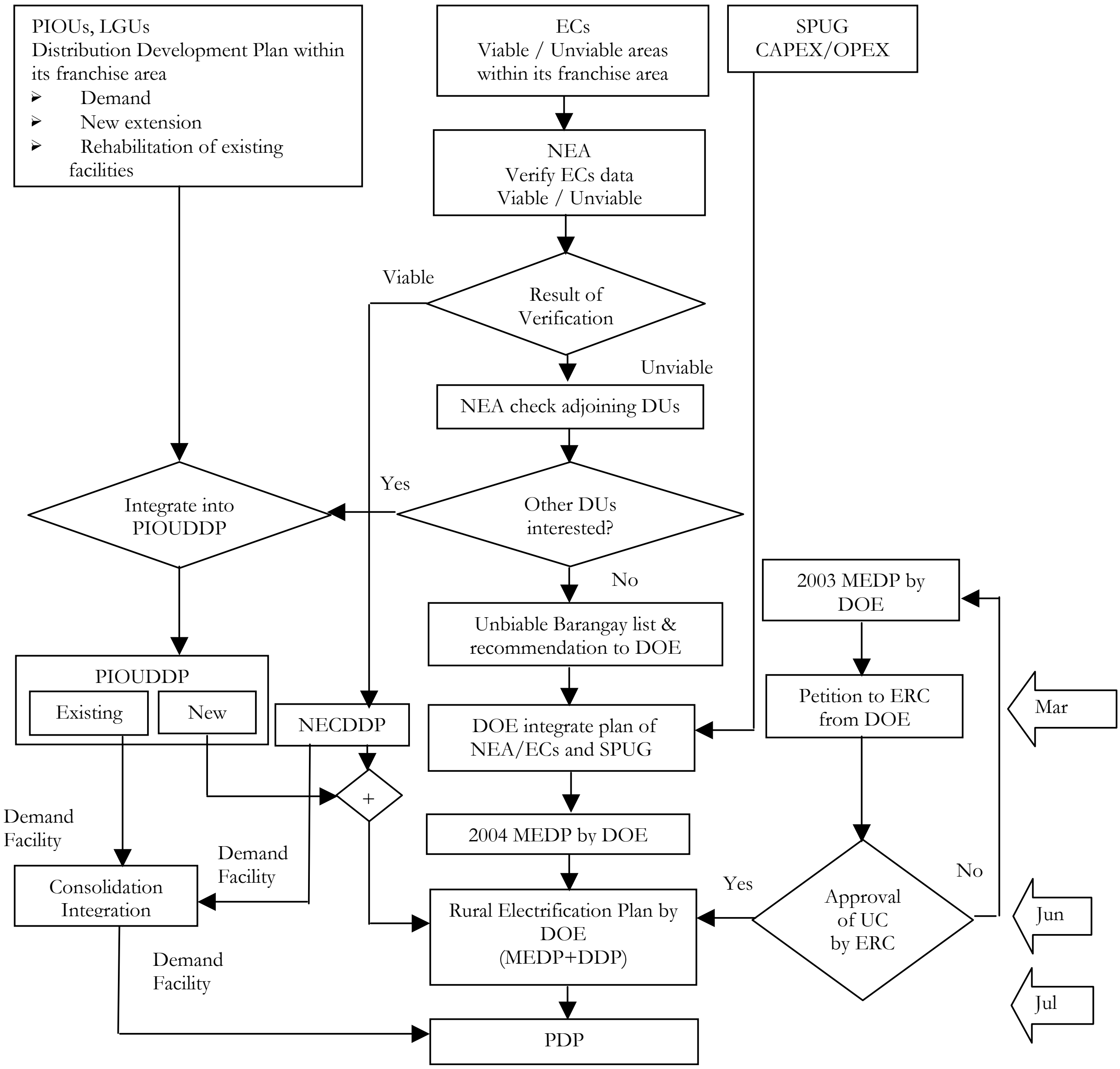
Fig. 6.3 Formulation of the rural electrification plan



6.2.2 Workflow in Preparing the Rural Electrification Plan

The workflow in preparing the rural electrification plan is shown in Fig. 6.4.

Fig. 6.4 Workflow in the preparation of the rural electrification plan



Based on this workflow, the key points are:

Data collection

➢ By March 15th, NEA/ECs and PIOUs (Private Investor-Owned Utilities) submit their respective DDPs to the DOE.

- NEA evaluates the projects to be undertaken by the ECs based on the viability of the project. Barangays that are considered to viable to energize are listed in the NECDDP (grid extension plan), while unviable barangays are classified under missionary electrification for inclusion in the MEDP.

- PIOUs, on the other hand, prepare their own plans, which would include, among others, electrification of unenergized areas and the rehabilitation of existing facilities. These plans form part of their submission to the DOE. This will be integrated to the DOE's comprehensive rural electrification plan. Decisions on the viability of the area for electrification are left with the PIOUs.

- SPUG, meanwhile, prepares a management and operation plan of the existing facilities, taking into account the operating expense (OPEX) and capital expense (CAPEX). SPUG also prepares a plan that will involve installation of new facilities. This is also submitted to the DOE for integration in the MEDP.

Evaluation of subordinate programs

- The DOE consolidates the list of unviable barangays submitted by NEA/ECs and PIOUs with the necessary CAPEX/OPEX and expense for the new installation of SPUG's new facilities.

- The consolidated REP is finalized in July and incorporated into the formulation of the final PDP.

Promotion of rural electrification

- DOE submits the PEP to the Congress of the Philippines on September 15 of each year. In parallel, the new MEDP list and SPUG's existing facility list are opened to Qualified Third Parties (QTPs) and DUs.

- If the QTP can assist financially, electrification of these areas will be more than possible, thereby deleting the specific projects assigned outlined in the MEDP. If a QTP does not participate, SPUG, given its mandate, is required to energize barangays under the MEDP list, using the funds from the missionary electrification component of the universal charge (ME-UC).

- The MEP is submitted to the ERC to obtain its approval for funding using the ME-UC component of the universal charge (ME-UC). When ERC approves withdrawals from the ME-UC petition, rural electrification is implemented.

- If, however, the ERC does not approve the use of ME-UC for projects listed in the submitted MEP/MEDP, these projects are again included in the MEDP's list of areas targeted for energization for the following year.

6.2.3 Components and Concept of the MEDP

(1) Components

EPIRA reinforces the goal of total electrification of the country by increasing maximum private sector participation using indigenous and renewable energy resources. EPIRA states that the DOE—along with NPC-SPUG and NEA—is required to prepare a five-year MEDP. The following items are planned out in the MEDP:

1) Total electrification level of the Philippines (Electrification of unserved and unviable areas);
2) Reduction in the governmental subsidy;
3) Increased participation of the private sector;
4) Privatization of SPUG's existing areas; and
5) Responsibilities of organizations involved in rural electrification.

(2) Concept

At its core, MEDP consists of managing existing diesel power systems by SPUG; installing new power sources in areas not connected to the grid and introducing individual power systems in unviable areas; and finally privatizing SPUG assets. To attain these ends, DOE needs to prepare a rolling five-year plan.

1) Management of existing diesel power systems by SPUG

SPUG is responsible for supplying stable and reliable power in missionary areas (or areas considered economically unviable) such as islands and the hinterlands mostly through high-cost diesel-fired power facilities.

To sustain SPUG's operations and to address the increasing costs of fuel, a higher tariff needs to be imposed in unviable areas, relative to other areas. Imposing higher tariff in unviable areas, however, has limitations. Thus, to compensate for the difference between the revenues generated and the expenses incurred, a form of subsidy is being imposed. Imposition of a subsidy is one of the items discussed in this study.

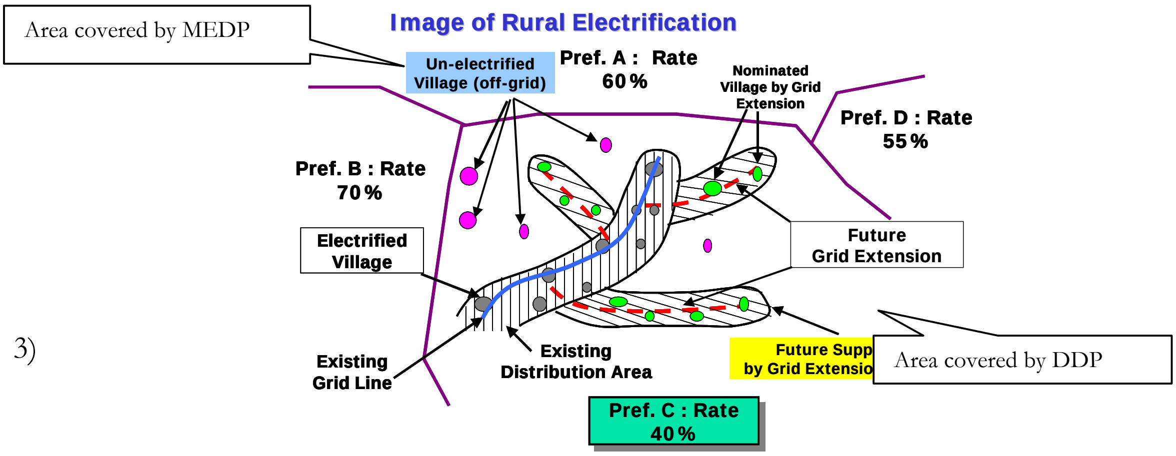
2) Introduction of new power sources in rural areas

In determining the basic concepts for rural electrification, a three-year grid extension plan should first be considered for unenergized areas covered by DDP. Individual power (i.e., off-grid) systems, on the other hand, need to be introduced in areas not covered by the DDP. As a result, these same areas will be covered by the MEDP.

Funds for rural electrification are sourced from: ER 1-94, which primarily benefit communities hosting energy resources (e.g., geothermal steam fields) and generation facilities; the universal charge; and allocations by Congress in the national budget. Funds from ER 1-94 and the universal charge are administered by DOE and PSALM, respectively.

However, with the expected participation of private entities such as QTPs in funding the rural electrification program, the five-year plan should seriously consider how these funds could be managed efficiently, judiciously, and effectively. It bears noting that the funds from ER 1-94 and the universal charge are held in trust by DOE and PSALM, respectively.

Fig. 6.5. Image of Rural Electrification



3) Privatization of SPUG assets

The privatization of SPUG assets, which are power generation facilities and a power delivery system, is the objective of missionary electrification. SPUG will develop several businesses for privatization, and these businesses are included in MEDP.

6.2.4 Plans for Promoting Barangay Electrification

As already stated, about 5,409 barangays are still to be unenergized as of December 2002 to achieve 100% rural electrification by 2006. The yearly plan for achieving this target is indicated in Table 6.2.

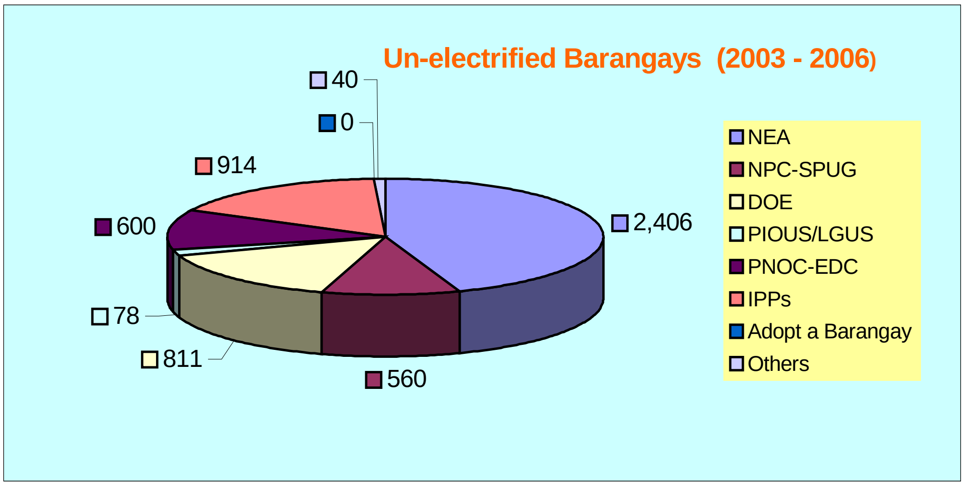
Table 6.2 Barangay electrification plan 2003 – 2006

Year	Target Number	Remaining Number	Cumulative Number	Rate (%)
2003	1,619	3,790	38,209	92.4
2004	1,258	2,532	39,467	94.4
2005	1,304	1,228	40,771	97.2
2006	1,228	0	41,999	100.0

Source: The President's State of the Nation Address, July 2003

The number of barangays to be electrified by each entity involved in rural electrification is shown in Fig. 6.6. But of the 5,409 barangays that need to be energized, the largest portion falls on NEA with about 2,406 barangays. This is followed by NPC/SPUG with 914 barangays; DOE with 811 barangays; PNOC-EDC with 600 barangays; and IPPs, with 560 barangays.

Fig. 6.6 Number of energized barangays by each entity



Source: O-Ilaw project team terminal report

Based on the terminal report of the O-Ilaw project team, the average electrification cost per barangay is approximately P 1 million. Given this scenario, about P 6 billion is needed to energize 5,409 barangays. This estimate is on top of the expenses incurred in the installation and rehabilitation of the transmission substation facilities.

Out of P 6 billion, NEA would require P 2 billion per year to extend grid lines. Table 6.3 shows the yearly electrification schedule by each organization.

The O-Ilaw terminal report also identified some items necessary to help achieve 100% electrification, including:

(1) Private sector participation

- Advance financing by independent power producers (IPPs);
- Adopt-a-Barangay program (Grant financing project); and
- Participation of QTPs in MEDP.

(2) Grants from financial institutions

(3) Developing cooperative efforts with the beneficiaries and the local government units

(4) Livelihood and financial assistance programs

- Provision of livelihood programs to be pilot tested in areas that host energy projects;
- House wiring assistance program; and

➢ Community relations energy resource fund development project.

(5) Institutionalization and streamlining of government procedures

Table 6.3 Yearly electrification schedule by each organization

				Indicative Barangay Schedule								
Year	Target (as submitted to DOE-NECDDP)			NEA/ECs	NPC-SPUG	DOE	PNOC-EDC	PIOUs/LGUs		Target No./Y	Sitios	
	ECs	PIOUs/LGUs	Total			DOE Total			Total IPPs/QTPs		NEA	PNOC-EDC
2003	2,561	20	2,581	841	25	193	225	0	334	1,618	320	47
2004(a)	1,139	20	1,159	140		125	34	0	187	486		
(b)			0	400		100		132	855	1,487		
2005	641	20	661	400		100				500		
2006	936	72	1,008	400		100				500		
Total	5,277	132	5,409	2,181	25	618	259	132	1,376	4,591		

Assumptions:

2003 GAA will be released to NEA and DOE nlt June 2003
2003 GAA of DOE-BEP, 50 Barangays are "Unprogrammed "
2004(a) spill-over projects with NCA release
2004(b) 2006 fund sources are indicatiuve
NEA - PHP 500 million annual subcidy from the National Government
DOE-BEP - PHP 134 million annual subcidy from the National Government
2004-2006 IPPs are all adopted
No Universal Charge
Privatization of SPUG areas (13 islands)
DOE ER1-94 will strictly follow the "radiating " policy
No disruption of work during the 2004 election

Unenergized	5,409
W/O funding souurce	818
Est Fund Rerts (PHP'm)	1,063

W/O funding souurce	3,305
Est Fund Rerts (PHP'm)	4,297

Potential Fund Source:

Universal Charge
SIP-Australia
Bridge Financing
USAID ($20m)
3 of oil firms
San Roque Power Corporation (adopt 6 Barangays and 111 Sitios est cost PHP 81.519 million)

The sample of an unenergized barangay list is shown in Table 6.4.

Table 6.4 Sample List of Unenergized Barangays

YEAR	NO.	BARANGAY	MUNICIPALITY	CONG'L DIST.	INITIAL CON	KMS. OF LINES				POWER SO	
						3Ph	1Ph	OS	UB	GRID	NRE
2002	1	CANDAMI	LIBMANAN	1st, Cam. Sur	28		1.39	0.42	0.24	1	
2002	2	VILLADEMA(Sta.Cruz)	LIBMANAN	1st, Cam. Sur	31		3.94	0.49	0.80	1	
2002	3	VILLA SOCORRO	LIBMANAN	1st, Cam. Sur	28		9.60	0.60	0.48	1	
2002	4	CAWAYAN	LIBMANAN	1st, Cam. Sur	48		2.50	0.80	0.96	1	
2002	5	SALVACION	LIBMANAN	1st, Cam. Sur	25	1.72		0.50	0.50	1	
2002	6	CALABNIGAN	LIBMANAN	1st, Cam. Sur	88		5.25	0.42	0.42	1	
2002	7	MANCAWAYAN	LUPI	1st, Cam. Sur	25		3.50	0.54	0.60	1	
2002	8	TIBLE	LUPI	1st, Cam. Sur	36		3.50	0.80	0.60	1	
2002	9	ALLEOMAR	LUPI	1st, Cam. Sur	17		1.90	0.38	0.42	1	
2002	10	BUENASUERTE	LUPI	1st, Cam. Sur	22		1.90	0.19	0.60	1	
2002	11	DEL CARMEN	LUPI	1st, Cam. Sur	17		2.50	0.18	0.42	1	
2002	12	HAGUIMIT	LUPI	1st, Cam. Sur	44		1.75	0.24	0.60	1	
2002	13	SALVACION	LUPI	1st, Cam. Sur	19		2.50	0.56	0.56	1	
2002	14	SAN RAFAEL NORTE	LUPI	1st, Cam. Sur	21		4.00	0.56	0.76	1	
2002	15	SAN VICENTE	LUPI	1st, Cam. Sur	32		1.80	0.24	0.56	1	
NEW BGY	**16**	**NAPOLIDAN**	**LUPI**	1st Cam Sur	40		1.01	0.13	0.52	1	
2002	17	SAN RAMON (Napolidan)	LUPI	1st, Cam. Sur	37		1.80	0.48	0.80	1	
2002	18	BELWANG	LUPI	1st, Cam. Sur	46		1.50	0.19	0.56	1	
2002	19	LOURDES	LUPI	1st, Cam. Sur	16		5.00	0.60	0.98	1	
2002	20	PULANTUNA	LUPI	1st, Cam. Sur	18		5.75	0.48	0.68	1	
2002	21	HUBO	PASACAO	1st, Cam. Sur	29		2.25	0.38	0.36	1	
2002	22	BAGONG SILANG	PASACAO	1st, Cam. Sur	60		3.56	0.85	1.59	1	
2002	23	SALVACION	PASACAO	1st, Cam. Sur	42		4.00	1.80	0.24	1	
2002	30	UPPER STA. CRUZ	RAGAY	1st, Cam. Sur	38		2.50	0.24	1.50	1	
2002	31	AGAO-AO	RAGAY	1st, Cam. Sur	39		5.75	0.90	0.80	1	
2002	32	CABADISAN	RAGAY	1st, Cam. Sur	29		6.25	0.90	1.20	1	
2002	33	CADITAAN	RAGAY	1st, Cam. Sur	32		4.00	0.56	0.76	1	
2002	34	INANDAWA	RAGAY	1st, Cam. Sur	32		4.75	0.60	0.79	1	
2002	35	PATALUNAN	RAGAY	1st, Cam. Sur	46		3.90	0.32	1.60	1	
2002	36	SAMAY	RAGAY	1st, Cam. Sur	53		4.00	0.72	0.84	1	
2002	37	PANAYTAYAN NUEVO	RAGAY	1st, Cam. Sur	85		1.40	0.18	0.18	1	
2002	38	SAN RAFAEL	SAN PASCUAL	1st,Masbate	18	9.34	0.60	0.80	8.10		1
2002	39	BOCA CHICA	SAN PASCUAL	1st,Masbate	15	3.50			3.50		1
2002	40	CUEVA	SAN PASCUAL	1st,Masbate	22	3.50			3.50		1
2002	41	DANGCALAN	SAN PASCUAL	1st,Masbate	27	3.50			3.50		1

Source: NEA

6.2.5 The DDP and the Role of the DUs

(1) Responsibilities of the DUs

Rule 7, Section 4 of EPIRA's IRR mandates each DU to prepare a five-year development plan every year, and to submit it to DOE by March 15 of each year. The ERC and DOE, on the other hand, are to prescribe the data to be submitted by the DU (and ask for the submission of data which the DU can submit in advance), particularly since the DDP will be integrated into the PDP and the PEP.

The DU is also expected to prepare a demand forecast for its franchise area. Chapter 6.2.5 of the Philippine Distribution Code (PDC) also requires the DU to determine the demand forecasts of key customers in its franchise area.

In addition, the DU is tasked under the PDC to draft a DDP annually, for submission to the Distribution Management Committee (DMC) and DOE. The DDP includes:

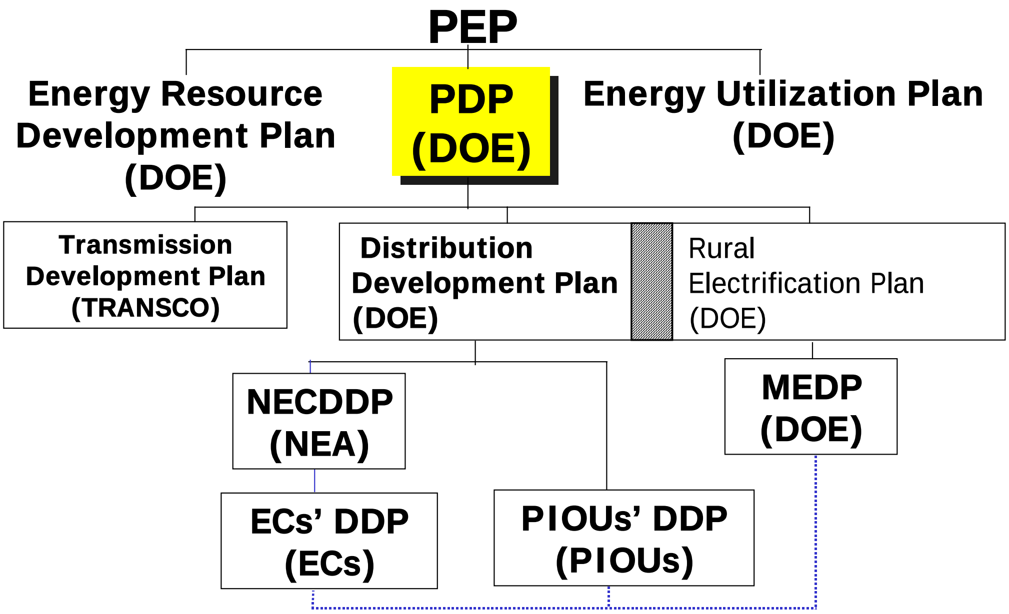
- Energy and Demand forecasts;
- Sub-transmission capacity expansion;
- Distribution substation siting and sizing;
- Distribution feeder routing and sizing;
- Distribution Reactive Power compensation plan;
- Other distribution reinforcement plans; and
- A summary of the technical and economic analysis conducted to justify the DDP.

The data-gathering format explained earlier was created to efficiently collect this wide range of data, which are vital in the formulation, DDP, particularly in:

- Analyzing the impact of the connection of new facilities such as embedded generators, loads, distribution lines, etc.;
- Planning the expansion of the distribution system to ensure its adequacy in meeting forecasted demand and connection of the embedded generator; and
- Identifying and correcting problems in power quality, system loss and reliability in the distribution system.

Each organization must exert efforts to carry out their respective roles. After considering their schedules, each organization should cooperate as much as possible with the organization concerned in crafting the DDP.

Fig. 6.7 Configuration of each organization and each plan



(2) Concept

The Philippine Distribution Code requires the inclusion of the following in the DDP: the Demand forecast; Supply Plan; Distribution Development Plan; Critical point; and the Budget and Subsidy Plan. These data are then integrated into the DOE's ten-year demand and supply plan, to provide long-term plan for the power sector.

An outline and an example of gathering data of each component are given below.

Demand forecast

The ten-year plan for demand is estimated based on the electricity demand patterns correlated by economic and demographic variables. It is further disaggregated into residential, commercial, and industrial customers. ECs, on the other hand, use the planning tool provided by NEA. Given this, it is very important to manage the data needed for a development plan in view of a large number of assumptions and the location of each customer.

Table 6.5 Example of gathering demand forecast data

Forecast/Planning Results	Units	Forecast						
		2003	2004	2005	2006	2007	2008	2009
10. ENERGY REQUIREMENT								
10a. Electricity Consumption								
Direct Sales To Customers	(1)							
Residential	MWH	8,116,844	8,360,349	8,611,160	8,869,495	9,135,579	9,409,647	9,691,936
Commercial	MWH	7,732,441	7,964,414	8,203,346	8,449,447	8,702,930	8,964,018	9,232,939
Industrial	MWH	6,550,689	6,747,209	6,949,626	7,158,114	7,372,858	7,594,044	7,821,865
Contractual Exports	MWH	274,380	282,611	291,089	299,822	308,817	318,081	327,624
Others	MWH	137189.82	141305.5146	145544.68	149911.0204	154408.3511	159040.6016	163811.8196
Public Bldgs	MWH	116,974	120,483	124,098	127,821	131,655	135,605	139,673
Street Lights	MWH	10,049	10,350	10,661	10,980	11,310	11,649	11,999
Others (Pls. specify, i.e., irrigation, etc.) Direct sale to XXX Corp	MWH	10,167	10,472	10,786	11,110	11,443	11,786	12,140
Total: Direct Sales to Customers	MWH	22,811,543	23,495,889	24,200,766	24,926,789	25,674,592	26,444,830	27,238,175
Utility's Energy Consumption	(2)							
Company/Office/Housing	MWH	1,420	1,463	1,507	1,552	1,599	1,647	1,696
Pumped Storage Requirement	MWH							
Utility's Station use: Distribution	MWH	843,781	869,095	895,167	922,022	949,683	978,174	1,007,519
Utility's System Losses	MWH	2,769,318	2,852,397	2,937,969	3,026,108	3,116,892	3,210,398	3,306,710
Subtotal: Utility's Energy Consumption	MWH	3,614,519	3,722,955	3,834,643	3,949,683	4,068,173	4,190,218	4,315,925

Supply facility plan

The ten-year supply plan is estimated considering the contents of the electric power purchase contract with NPC and IPPs and the increase or decrease in supply facilities, for instance. It is very important to manage these data, taking into account the demand-and-supply point at a particular time.

Table 6.6 Example of gathering supply facility data

		Forecast						
Supply Expansion Plan:		2003	2004	2005	2006	2007	2008	2009
13a. Power generating Facilities (Pls. use additional sheets as								
Name:								
Status:								
Fuel Requirement (liters, tons, etc.)								
Net Dependable Capacity	KW	500,000	500,000	500,000	500,000	500,000	500,000	500,000
Net Production	MWH	876,000	876,000	876,000	876,000	876,000	876,000	876,000
Name:								
Status:								
Fuel Requirement (liters, tons, etc.)								
Net Dependable Capacity	KW	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Net Production	MWH	131,100	131,100	131,100	131,100	131,100	131,100	131,100
Sub Total								
Net Dependable Capacity	KW	550,000	550,000	550,000	550,000	550,000	550,000	550,000
Net Production	MWH	1,007,100	1,007,100	1,007,100	1,007,100	1,007,100	1,007,100	1,007,100
13b. Supply from NPC:								
Contracted Demand	KW	1,917,808	1,198,630	799,087	399,543			
Load Factor	%	70%	70%	70%	70%			
Contracted Energy	MWH	24,000,000	15,000,000	10,000,000	5,000,000			

Distribution Development Plan

This item should ascertain the current number of facilities, which are closely related to expansion construction, such as the length of the distribution lines, the installed capacity of transformers, and the main peripheral devices. It is important to that these data be managed based on correlation with the growth rate of demand.

Table 6.7 Example of gathering distribution line length data

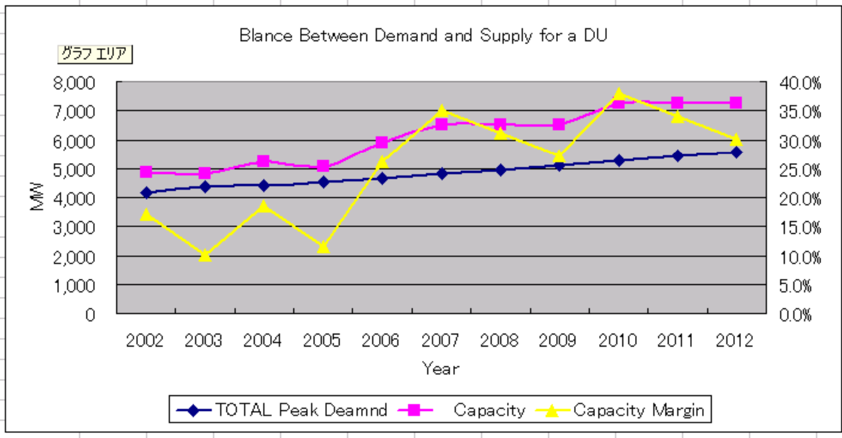
Forecast/Planning Results		Units	Historical								
			1998	1999	2000	2001	2002	2003	2004	2005	2006
Distribution/Subtransmission Facilities:											
16a. Distribution/Subtransmission lines circuit-kilometers											
Voltage, 230kV		Ckt-KM	0	0	0	0	0	0	0	0	0
Voltage, 138kV and less than 230kV		Ckt-KM	0	0	0	0	0	0	0	0	0
Voltage, 115kV and less than 138kV		Ckt-KM	0	0	0	0	0	0	0	0	0
Voltage, 69kV and less than 115kV		Ckt-KM	0	0	0	0	0	0	0	0	0
Voltage, 34.5kV and less than 69kV		Ckt-KM	0	0	0	0	0	0	0	0	0
Voltage, 13.8kV and less than 34.5kV		Ckt-KM	2045	2099	2150	2178	2196	2223	2299	2343	2389
Voltage, 6.2kV and less than 13.8kV (3 Phase)		Ckt-KM	5219.2	5247.4	5243.9	5266.7	5289.9	5312.6	5334.9	5357.6	5380.5
	(1 Phase and others)	Ckt-KM	11221	11320	11398	11462	11520	11577	11634	11692	11749
Voltage, 2.4kV and less than 6.2kV(3Phase)		Ckt-KM	125.81	128.27	130	131.43	132.64	133.83	135.03	136.22	137.41
	(1 Phase and others)	Ckt-KM	903.22	914.54	925.94	937.4	948.92	960.5	972.13	983.82	995.57
Rehabilitation Result and Plan (Replacement and Upgrading)											
16b. Distribution/Subtransmission lines circuit-kilometers											
Voltage, 230kV		Ckt-KM	0	0	0	0	0	0	0	0	0
Voltage, 138kV and less than 230kV		Ckt-KM	0	0	0	0	0	0	0	0	0
Voltage, 115kV and less than 138kV		Ckt-KM	0	0	0	0	0	0	0	0	0
Voltage, 69kV and less than 115kV		Ckt-KM	0	0	0	0	0	0	0	0	0

Critical point

The area in which there may be power supply outages is estimated by comparing demand and supply. In determining the possibility of a power crisis, precautionary measures should be discussed by concerned entities.

Fig. 6.8 Example of finding the critical point

		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
TOTAL Peak Deamn	MW	4,157	4,382	4,410	4,542	4,679	4,819	4,964	5,113	5,266	5,424	5,587
Capacity	MW	4,867	4,827	5,228	5,068	5,908	6,509	6,509	6,509	7,269	7,269	7,269
Capacity Margin	%	17.1%	10.2%	18.5%	11.6%	26.3%	35.1%	31.1%	27.3%	38.0%	34.0%	30.1%



Capital Plan

The capital plan should be adapted to the distribution expansion plan. It is very important to correlate the growth of distribution requirements with expansion and construction.

Table 6.8 Example of gathering capital data

Forecast/Planning Results	Units	Historical					Forecast					
		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
19. Capital Expenditures:												
Distribution/Subtransmission:												
Local (in Million)	Peso	68	70	61	58	55	56	61	58	59	61	65
Foreign (in Million)	Peso	0	0	0	0	0	0	0	0	0	0	0
Substation												
Local (in Million)	Peso	54	65	67	59	76	77	87	67	78	87	88
Foreign (in Million)	Peso	0	0	0	0	0	0	0	0	0	0	0
Electrification												
Local (in Million)	Peso	5	8	6	2	8	11	15	13	17	21	23
Foreign (in Million)	Peso	0	0	0	0	0	0	0	0	0	12	15
Grand Total:												
Local (in Million)	Peso	127	143	134	119	139	144	163	138	154	169	176
Foreign (in Million)	Peso	0	0	0	0	0	0	0	0	0	12	15

6.2.6 Outline of DDP

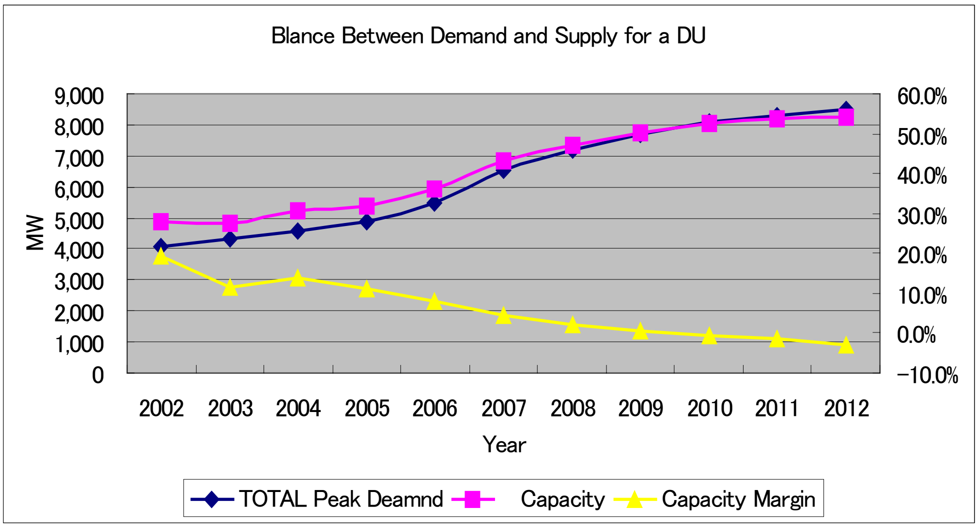
(1) Composition of DDP

The DDP is a five-year plan from 2004 to 2008. Its components include:

- Appropriate expansion construction based on demand; and
- A capital expenditure plan corresponding to construction work.

To check the balance of annual demand and supply for every area, using a comparison diagram as shown in the following figure is recommended.

Fig. 6.9 Example of balance comparison of demand and supply



Furthermore, it is necessary to consider the issue of adequate electric power supply in the future. To check the scale of distribution facilities (distribution lines length, installed capacity for distribution substation, etc.) by area (Luzon, Visayas, and Mindanao), and to check the balance with demand and supply as a rough estimate, using a comparison table is recommended. Table 6.9 is an example of the tables used to gather data of distribution line length by voltage level in Luzon.

Table 6.9 Data of the distribution line length of the expansion plan in LUZON(2003-2007)

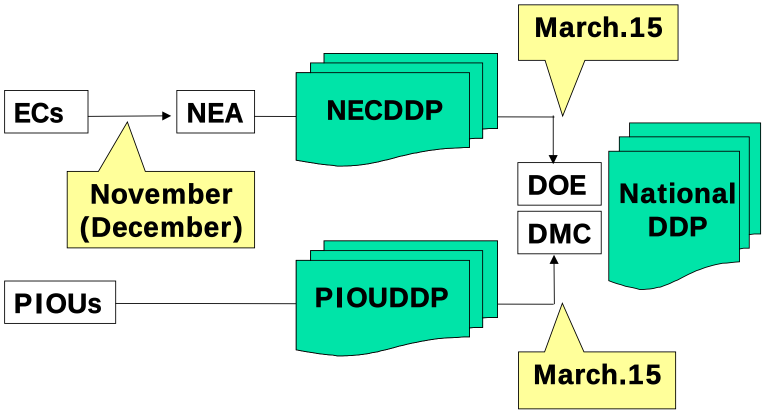
Area		2003	2004	2005	2006	2007
LUZON	230 kV and over					
	138 kV-230 kV					
	115 kV-138 kV					
	69 kV-115 kV					
	34.5 kV-69 kV					
	13.8 kV-34.5 kV					
	6.2 kV-13.8 kV					
	2.4 kV-6.2 kV					
	Sub-Total					

(Ckt-kms)

On the other hand, since the DDP also covers distribution line expansion, it should be consistent with the MEDP to facilitate the comparison of data, such as years and areas covered. Given this, the study group proposed the components shown below. The DDP drawing up manual was drafted on these premises, and was subsequently submitted to the DOE.

(2) Data gathering format

Fig. 6.10 Schedule for drafting DDP



ECs submit the data to NEA by November or December of each year. NEA collects the data of all of the ECs, and it is integrated into the NECDDP by March 15. The PIOU data is directly submitted to DMC and DOE as PIOUDDP by March 15. DOE will thereafter collect all data and complete the National DDP. In addition, the National DDP is expected to be ready for next year. A database can be built by repeating these processes every year. The schedule for drafting DDP is shown Figure 6.10.

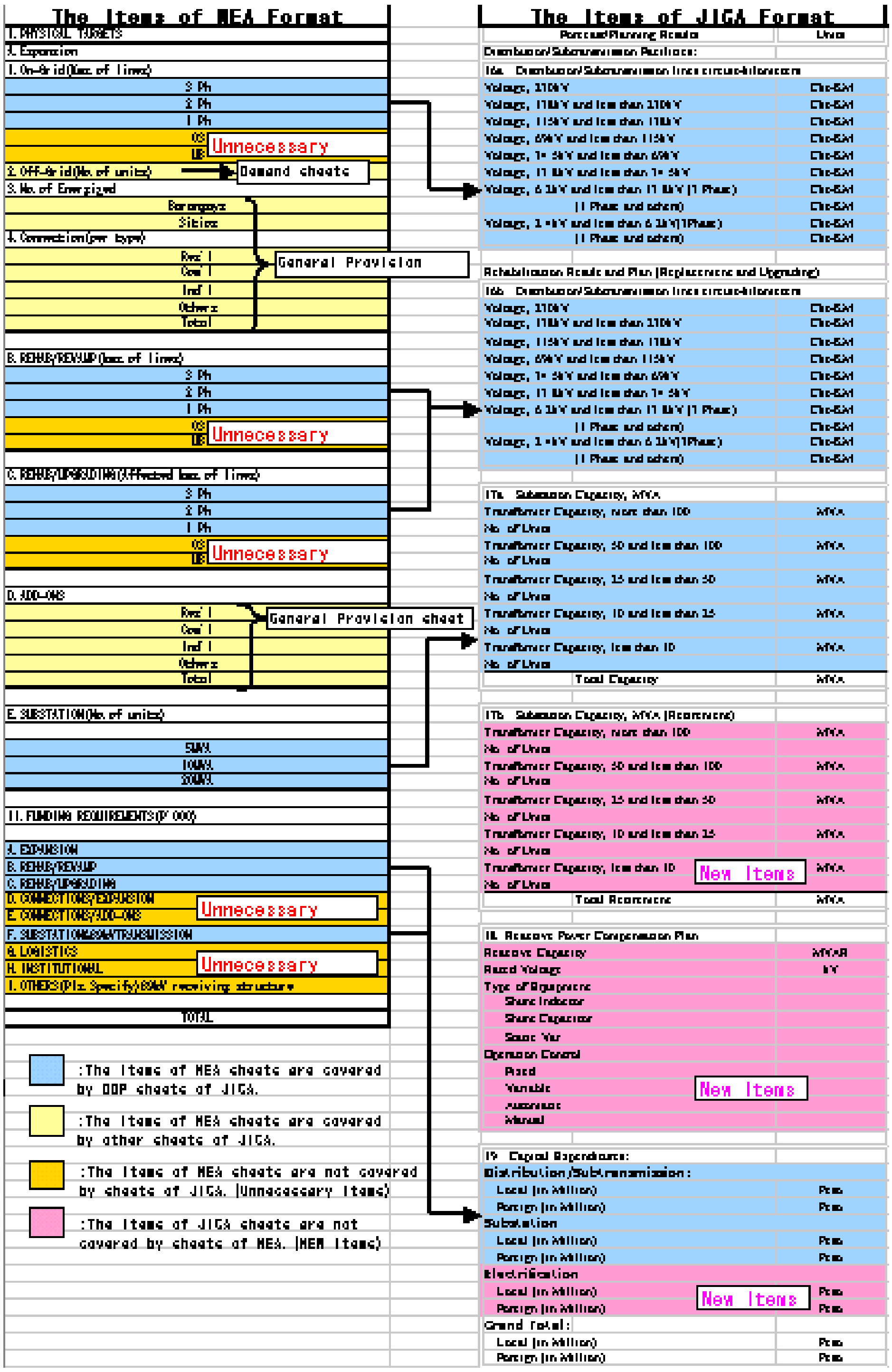
An education campaign in formulating the DDP is needed to solicit the required data from the stakeholders. Recognizing this, a workshop was held in Manila on July 7, 2003, where about 100 participants composed of representatives of all DUs and NEA, and the heads of each EC attended. Discussions centered on finalizing a template that meets the needs of all industry players.

Fig. 6.11 Audience at the workshop

Currently, a template issued by NEA being used by the ECs. It was suggested in the workshop that this template may not be changed at all in the preparation and submission of data from DUs/ECs.

The comparison between the NEA-drafted and JICA-drafted templates are illustrated in Fig. 6.12.

Fig. 6.12 Comparison of each template



6.3 Entities Involved in Promoting Rural Electrification

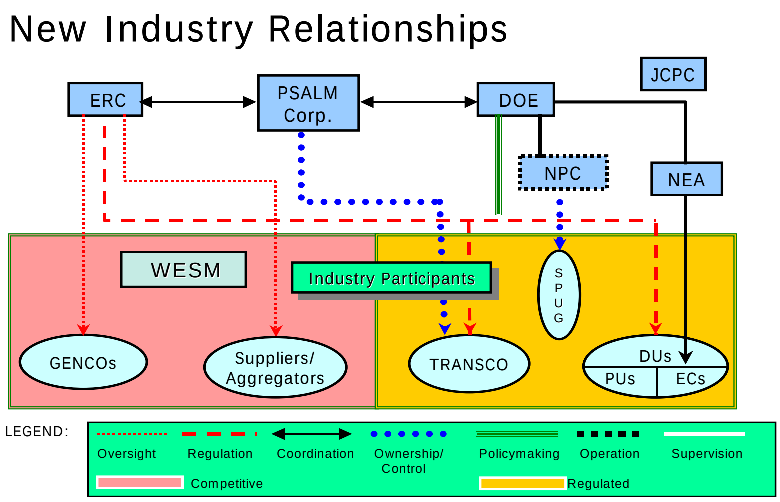
6.3.1 Organizations Involved in Promoting Rural Electrification

While there are different government agencies involved in the rural electrification, the responsibility of overseeing the electrification program in the countryside is significantly a task directed to NEA. The NEA oversees the operations of the ECs to provide distribution service to their franchise areas. NEA also serves as a government financial institution, providing funding requirements of the ECs.

While EPIRA mandates the privatization of NPC, it assured the continued existence of NPC-SPUG, whose main role is to provide electricity in the small islands.

The entities involved in the power sector under a restructured regime, is shown below.

Fig. 6.13 Stakeholders in a deregulated power industry



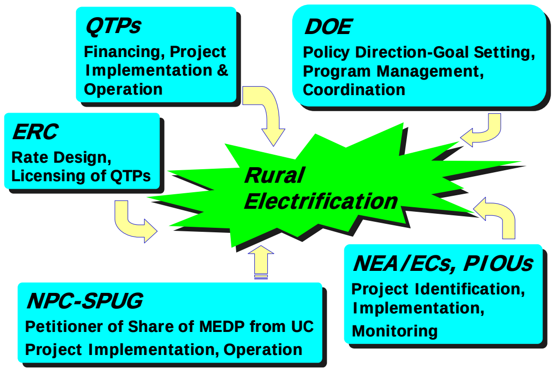
Source: PEP 2003-2012

EPIRA likewise reiterated DOE's pivotal role in promoting rural electrification and encouraged the participation of PIOUs, LGUs, and QTPs in the rural electrification program. EPIRA likewise allowed and encouraged QTPs to participate in the program.

It is expected that the bulk of funding for rural electrification will in the future be borne by the QTPs.

The different agencies involved in rural electrification are shown in Figure 6.14.

Fig. 6.14 Organizations involved in rural electrification



To concretize its policy of ensuring and accelerating the total electrification of the country, the DOE has targeted 100% barangay electrification by 2006. DOE and DOF jointly issued guidelines reiterating their commitment to total barangay electrification as well as the energization of about 90% of total potential households by 2017.

To achieve this goal, a review of the other electrification projects was undertaken to integrate these plans under MEDP.

As a result, DOE created an Expanded Rural Electrification (ER) Team to effectively manage and integrate the country's rural electrification program. The team is responsible for:

(a) Accelerating electrification through enhanced public-private sector partnership consistent with EPIRA's provisions on rural or missionary electrification;

(b) Implementing new mechanisms and provide innovative approaches to enhance operational efficiency and sustain services in connected areas;

(c) Promoting cost-effective uses of new and renewable energy for power generation and tap the private sector to provide technical, managerial expertise, and financial resources to achieve the goal;

(d) Recommending policy directions and guidelines on the implementation of the program; and

(e) Integrating all efforts and initiatives to achieve 100% barangay electrification by 2006 and 90% household electrification by 2017.

The ER team has two groups, namely the Oversight Committee (chaired by the DOE) and the Technical Working Group (chaired by NEA).

<ER Team Oversight Committee (ER Team-OC)>

Chairman
DOE Undersecretary
Cyril C. Del Callar

Program Manager

Julinette M. Bayking	NEA
Mylene C. Capongcol	DOE
Lorenzo S. Marcelo	NPC-SPUG

Members
PNOC-EDC
PNOC
NPC-SPUG
NEA
NEA
OSEC-DOE
NEDA
DOF

<ER Team Technical Working Group (ER Team-TWG)>

Head
Division Manager PPDD, Planning

Assistant
Division Chief, REAMD, EPIAB,

Members
Div. Mngr, PM, NPC-SPUG
Div. Mngr, SP, NPC-SPUG
RED, EUMB, DOE
PD, EPPB, DOE
CD, ERDB, DOE
NEA
NEA
PNOC

<Coverage of ER team>

(a) DOE's BEP
(b) DOE's ER 1-94 electrification funds
(c) NEA-funded subsidy
(d) NPC-SPUG Missionary electrification
(e) PNOC-EDC
(f) IPPs
(g) ODA (bilateral, multilateral, GEF)
(h) Electrification Projects of other Government Agencies
(i) Other Electrification Projects/Programs

6.3.2 Responsibilities of the Entities Involved

The responsibilities of each organization involved in rural electrification are described as follows:

<DOE>

The DOE prepares the MEDP, and integrates the same to the PDP. On top of this, it is the implementing agency in charge of the following:

- The overall management and coordination of rural electrification projects, with the end view of accomplishing the rural electrification targets based on SONA;
- The promotion of rural electrification to the private sector;
- Policy coordination among the organizations involved in rural electrification, such as NEA and NPC-SPUG; and
- The promotion of the development and use of indigenous and/or new and renewable energy utilization systems.

The newly-formed DOE ER team is primarily tasked to oversee and perform these functions.

<NEA>

NEA integrates, evaluates and coordinates electrification plans prepared by ECs, and drafts the NECDDP—a grid extension plan—which it submits to the DOE.

On top of these functions, NEA also serves as financing conduit to ECs for the electrification and maintenance of existing facilities. As a supervising agency, NEA evaluates the performance of the 119 ECs based on financial, technical, and operational standards.

ECs are classified into 6 categories from [A+] to [E], the former being the highest, and the latter being the lowest in rank, based on the condition of debt return, and systems losses, among others. NEA also assists in the rehabilitation of poorly-performing ECs by offering management expertise. A temporary take-over of management by NEA is also an option to help distressed ECs.

<ECs>

The 119 ECs each prepares its own electrification plan for unenergized areas within their respective franchise areas and implements this plan. The unenergized barangays which are identified for electrification by the ECs are prioritized on a practical basis.

Likewise, ECs not only ensure the continuous, stable, and reliable flow of power supply within their respective franchise areas, but also assume responsibility over the operation and maintenance of distribution system facilities.

<PIOUs/LGUs>

There are 21 PIOUs, and the largest is MERALCO with a franchise covering the metropolitan Manila area. Each PIOU takes charge of electrification of unenergized areas in its franchise. In addition, DUs owned by local LGUs also provide the same service as PIOUs. Each distribution company prepares DDP, which includes a facility plan and demand forecast, to be submitted to the DOE.

<IPP>

Under ER 1-94, IPPs are obligated to contribute P 0.01/kWh for the communities (*sitio*, barangay, city/municipality, province, and region) hosting a generation facility or energy resource. A total of 50% of this fund is utilized to promote rural electrification, 25% is for environmental protection, while 25% is allocated for livelihood improvement. Unenergized areas in the host communities will be energized using this fund.

For instance, PNOC-EDC generates power from geothermal fields, which is sold to NPC. A portion of PNOC-EDC's power sales will be set aside for rural electrification.

<NPC-SPUG>

NPC-SPUG is an organization that implements electrification and power supply in unviable rural areas. NPC-SPUG likewise carries out the operation, maintenance and management of existing power generation and transmission facilities in the small islands.

Parallel to the electrification efforts by the ECs in unenergized areas within their respective franchise areas, individual power systems such as diesel and photovoltaic (PV) systems were introduced by NPC-SPUG in unviable areas outside of the ECs' coverage.

However, since distributing electricity in economically unviable areas is uneconomical, it is difficult to operate efficiently with the revenue generated from power sales. This is because the operating expenses in areas being serviced by NPC-SPUG is often higher than the revenues generated from power sales.

Thus, to sustain NPC-SPUG's operations in economically unviable areas, a subsidy is required. With the mandate of EPIRA to establish the universal charge—a part of which is allotted for missionary and rural electrification—the SPUG can draw from this fund to subsidize its operations.

To draw from this fund, the NPC-SPUG needs to file a petition before the ERC, which has the exclusive jurisdiction of evaluating and approving such petitions.

<ERC>

As stated earlier, ERC is tasked by EPIRA with reviewing and approving the use of funds drawn down from the Special Trust Fund financed by the universal charge—including the ME-UC.

6.4 Database

The main issues that need to be considered in rural electrification are selection and prioritization of areas to be covered by the program. At the outset, unenergized areas targeted for grid extension should not be included in the list of areas for potential installation of individual systems. Therefore, close attention should be given to both the grid extension plans and the actual rate of electrification in the formulation of an electrification plan for a particular area.

On the other hand, managing the data involved, and actually promoting and implementing the rural electrification projects, are likewise important.

The following section thus presents the current situation, and a map to help promote, implement, and manage the program.

(1) Current database situation

The 2000 national census found the number of barangays throughout the Philippines to be 41,999. The O-Ilaw team, on the other hand, reported 41,995, while the National Statistics Office (NSO) notes 41,945.

The discrepancies in these data should be subject to verification.

Moreover, the number and exact location of unenergized *sitios* also remain unclear. It is, therefore, possible that some barangays are already energized.

To ensure the accuracy of the data included in drafting electrification plans, the DOE should therefore establish a database that will facilitate the promotion, implementation, and management of electrification programs. In particular, there is a need to update the implementation of the projects involving the construction of 41 micro-hydro and various types of PV systems—totaling 4,416—amidst reports that some energy systems are now missing.

(2) Map for project management

Implementing, promoting, and managing the rural electrification program requires extensive future planning. Consequently, a map that visually presents the status of the program, including the electrification rate of a particular area, is needed.

In the course of this project, the study team prepared a map of the Philippines, using different colors representing the electrification rate at the municipal/city level. While conducting this survey, the study team also found a map of the Philippines that shows the boundaries of each barangay. As a result, the study team will pick certain sample areas (based on NEA data) and prepare a sample map showing distribution network roots.

The study team will transfer these maps to DOE and ask it to complete these maps for the database.

Fig. 6.15 Map for the management of electrification rate by ECs and municipalities

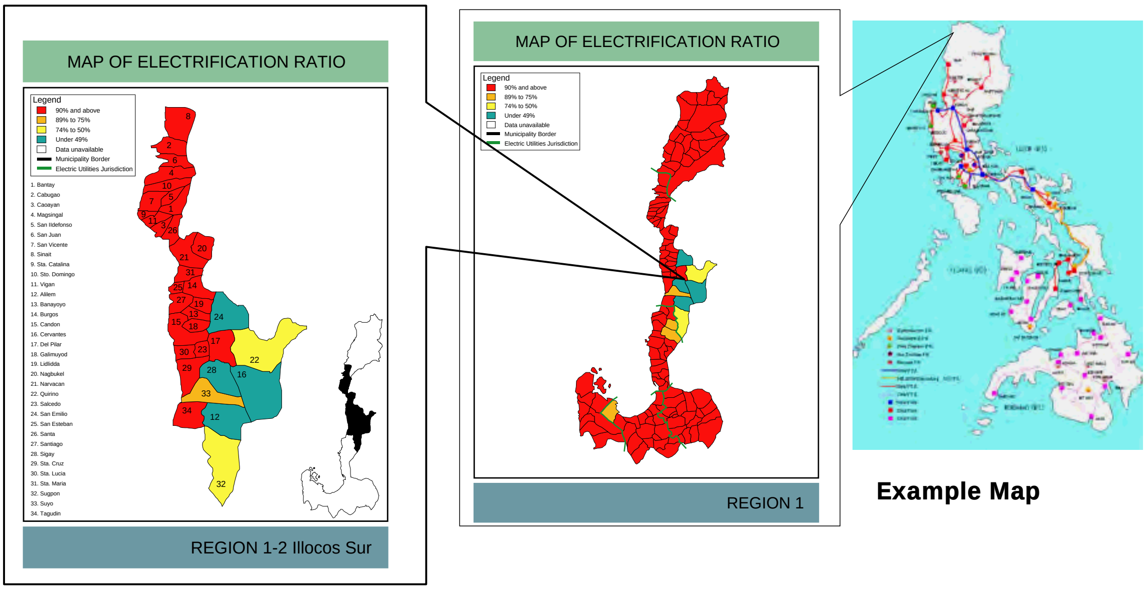
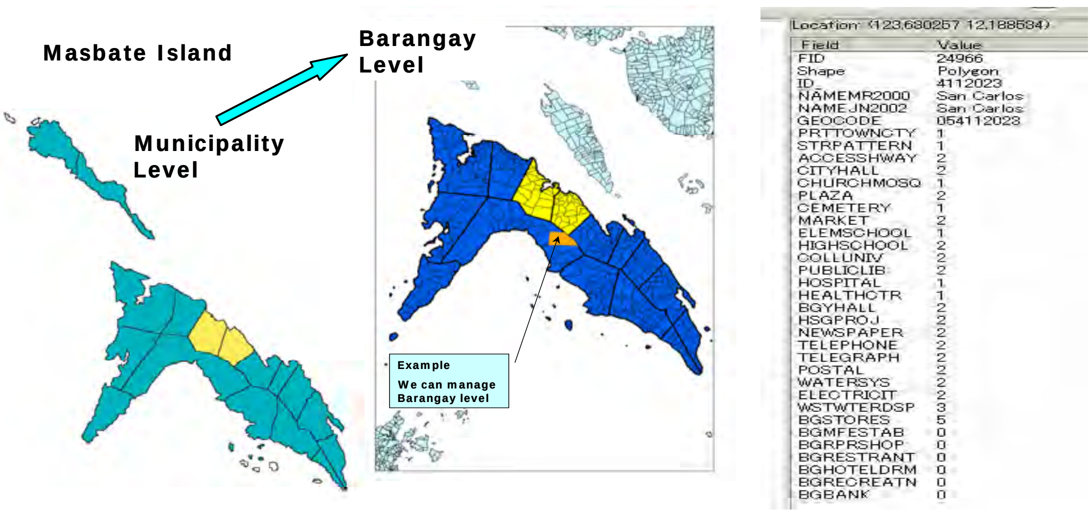


Fig. 6.16 Map for the management of electrification rate by barangay



The map, as shown in Figure 6.15, shows the electrification rate for each EC or municipality. Based on this map, the variance of the energization rate on a national scale can be appreciated. Hence, it would be easier to prepare a plan to address the variance.

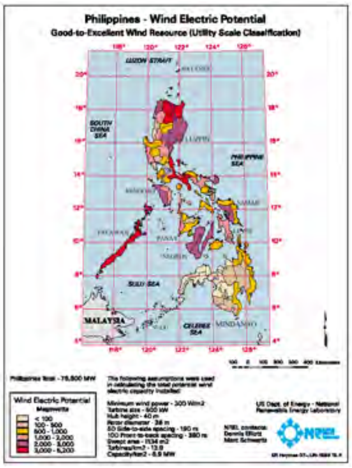
In parallel, the baseline data of a barangay can be included and thereafter viewed in the right-hand portion of the map, as shown in Fig. 6.16.

These maps will not only contribute to the implementation of future electrification plans after energization at the barangay level; they can also help in practical project management.

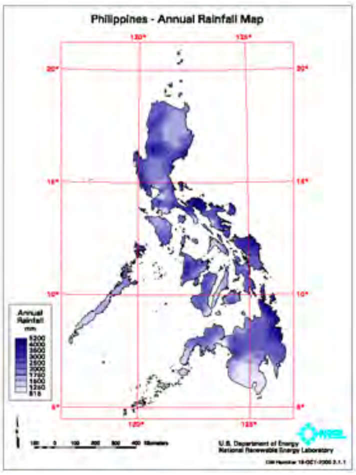
(3) Potential of renewable energy

Rural areas in the Philippines such as islands and mountainous areas are difficult to access, making it difficult to promote electrification by grid extension. Thus, individual power systems that use renewable energy are primarily considered in electrification plans for these areas.

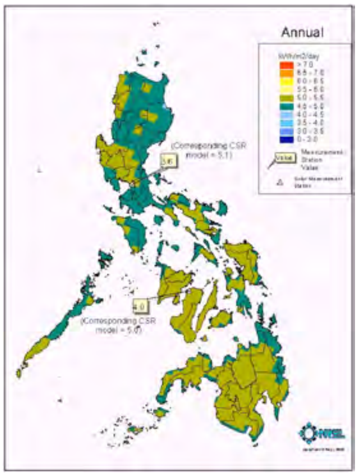
To utilize renewable energy most effectively, insolation; rainfall; and wind energy data described below must be considered.



Annual Average Wind Power



Annual Rainfall



Annual Average insolation

- The yearly average insolation is 4.5-5.5 kWh/m^2 in the Philippines. It is 50% or higher than Japan's average, which is about 3.5 kWh/m^2. These data indicate that the PV system is a useful tool for energizing barangays located far from the grid line.

- While the frequency of rainfall in the southern part of the Mindanao area and Palawan is relatively low, the average frequency of rainfall in other areas is relatively high, thus, making these areas as potential sites for micro-hydro systems, but still dependent on their geographical condition.

- The northern part of Luzon and Palawan are considered suitable locations for wind power generation because of high wind energy potential in these areas. However, the Mindanao area has few available locations suitable for wind energy.

In this phase of the study, data on renewable energy potential, a map of the existing grid network, and the location of energized barangay are compared. These data are useful for utilizing renewable energy for rural electrification.

6.5 Status of SPUG Operations

6.5.1 Current Situation of the Operation of Existing Facilities and their Management

Operations forecast made by SPUG for the next three years (2003-2006) indicates increasing power sales and revenues.

But while revenues and sales are seen to increase, operations and maintenance expenses are expected to grow faster. By 2006, operating expense would triple to P 16.17 billion from P 6.2 billion in 2002.

Thus, a greater subsidy amounting up to P 9.36 billion come 2006 would be needed to sustain SPUG's operations. In 2002, actual subsidy of P 3.98 billion was channeled to finance SPUG's operations.

Operating costs, particularly fuel costs, account for a large portion of SPUG's expenditures. Fuel costs for 2006 are projected to reach P 6.99 billion—three times the actual cost for 2002 of P2.10 billion.

SPUG's actual operations sales, revenues, and expenses for 2002, as well as its forecast for 2003 to 2006 are shown in Table 6.10. The data was sourced from the petition filed by SPUG before the ERC, seeking funds from the trust account funded by the universal charge.

Table 6.10 Actual results and forecast of SPUG operations

Items \ Year	2002	2003	2004	2005	2006
Phil. Energy Sales, GWh	47,917.00	52,093.00	56,978.00	62,459.00	68,625.00
SPUG Energy Sales, GWh	548.63	669.66	820.94	986.95	1,135.53
Projected Revenue (Million Pesos)	2,225.28	3,146.09	4,199.46	5,462.61	6,808.03
Total Cash Expenses	6,208.09	8,169.05	9,031.74	11,983.58	16,173.16
Operating Cost	3,451.32	4,817.57	6,184.81	7,942.27	9,914.65
Fuel	2,106.23	3,095.81	4,188.61	5,523.11	6,990.84
Lube	105.01	136.56	175.41	218.79	259.59
Purchased Power	484.72	647.02	856.96	1,177.21	1,592.06
Personnel Services	473.19	497.20	498.31	523.81	550.70
Other O&M	282.16	440.98	499.35	499.35	521.39
Capital Expenditure	2,756.78	3,351.49	2,846.93	4,041.31	6,258.51
Generation					
Grid Project	1,783.76	1,809.85	1,328.42	2,487.51	4,745.76
Off-grid Project	296.51	321.31	348.42	376.11	408.02
Transmission	327.21	598.23	532.33	485.36	384.44
Operations	349.30	622.10	637.76	692.33	720.29
Cash Subsidy (Million Pesos)	3,982.81	5,022.96	4,832.28	6,520.97	9,365.13
Total Levy (P/kWh)	0.0831	0.0964	0.0848	0.1044	0.1365
Operating Cost(OPEX)	0.0256	0.0321	0.0348	0.0397	0.0453
Capital Expenditure(CAPEX)	0.0575	0.0643	0.0500	0.0647	0.0912

Source: SPUG's ME-UC availment petition to the ERC

Fuel costs have a direct relationship on SPUG's implementation of the rural electrification program, since SPUG uses mostly diesel-fired plants for its power generation. SPUG's existing facilities and their respective operating hours are shown in Table 6.11.

Table 6.11 Existing SPUG Facilities

SMALL POWER UTILITIES GROUP

List of Existing Generating Plants as of June 30, 2002

Plt#	Grid#	Plant	Province	Installed Cap.,MW	Existing 24-hours	Less than 24-hours	For 12-hours
1	1	BASCO DPP	BATANES	1.254		x	
2	2	SABTANG DPP	BATANES	0.380			x
3	3	ITBAYAT DPP	BATANES	0.380			x
4	4	CALAYAN DPP	CAGAYAN	0.489			x
5	5	LUBUAGAN DPP	KALINGA	0.450			x
6	6	KABUGAO DPP	APAYAO	0.643	x		
7	7	PALANAN DPP	ISABELA	0.423			x
8	8	CASIGURAN DPP	AURORA	1.188		x	
9	9	BALONGBONG MHEP	CATANDUANES	1.800	x		
10	9	MARINAWA DPP	CATANDUANES	5.396	x		
11	9	POWER BARGE 110	CATANDUANES	2.240	x		
12	9	VIGA DPP	CATANDUANES	1.120	x		
13	10	RAPU-RAPU DPP	ALBAY	0.546			x
14	11	BATAN DPP	ALBAY	0.326			x
15	12	CAGRARAY DPP	ALBAY	0.326			x
16	13	BOAC DPP	MARINDUQUE	3.672	x		
17	13	TORRIJOS DPP	MARINDUQUE	1.568	x		
18	13	POWER BARGE 120	MARINDUQUE	7.200	x		
19	14	POLILIO DPP	QUEZON	1.748		x	
20	15	JOMALIG DPP	QUEZON	0.271			x
21	16	PATNANUNGAN DPP	QUEZON	0.326			x
22	17	PULANG LUPA DPP	MINDORO OCCIDENTAL	5.048	x		
23	18	MAMBURAO DPP	MINDORO OCCIDENTAL	3.164	x		
24	19	LUBANG DPP	MINDORO OCCIDENTAL	2.528		x	
25	18	CALAPAN DPP	MINDORO ORIENTAL	3.500	x		
26	18	POWER BARGE 102	MINDORO ORIENTAL	32.000	x		
27	20	TINGLOY DPP	BATANGAS	0.586			x
28	21	PUERTO PRINCESA DPP	PALAWAN	9.000	x		
29	21	POWER BARGE 106	PALAWAN	14.400	x		
30	21	NARRA DPP	PALAWAN	1.448	x		
31	21	BROOKES PT. DPP	PALAWAN	2.231	x		
32	21	EL NIDO DPP	PALAWAN	0.423			x
33	21	ROXAS DPP	PALAWAN	0.943	x		
34	21	TAYTAY DPP	PALAWAN	0.423			x
35	21	SAN VICENTE DPP	PALAWAN	0.326			x
36	22	BUSUANGA DPP	PALAWAN	1.508	x		
37	23	CUYO DPP	PALAWAN	1.391	x		
38	24	CULION DPP	PALAWAN	0.423			x
39	25	LINAPACAN DPP	PALAWAN	0.054			x
40	26	ARACELI DPP	PALAWAN	0.326			x
41	27	BALABAC DPP	PALAWAN	0.326			x
42	28	CAGAYANCILLO DPP	PALAWAN	0.217			x
43	29	AGUTAYA DPP	PALAWAN	0.217			x
44	30	MASBATE DPP I	MASBATE	2.500	x		
45	30	MASBATE DPP II	MASBATE	1.224	x		
46	30	POWER BARGE 105	MASBATE	14.400	x		
47	31	TICAO DPP	MASBATE	0.903		x	
48	32	TABLAS DPP	ROMBLON	4.516	x		
49	32	POWER BARGE 109	ROMBLON	2.240	x		
50	33	ROMBLON DPP	ROMBLON	2.864	x		
51	33	POWER BARGE 114	ROMBLON	2.240	x		
52	34	SIBUYAN DPP	ROMBLON	1.026		x	
53	35	BANTON DPP	ROMBLON	0.326			x
54	36	CORCUERA DPP	ROMBLON	0.326			x
55	37	CONCEPCION DPP	ROMBLON	0.326			x
56	38	SAN JOSE DPP	ROMBLON	0.326			x
		VISAYAS		Cap.,MW			
57	39	BANTAYAN DPP	CEBU	5.008	x		
58	39	POWER BARGE 116	CEBU	3.360	x		
59	40	GUINTARCAN DPP	CEBU	0.326			x
60	41	DOONG DPP	CEBU	0.326			x
61	42	CAMOTES DPP	CEBU	1.160	x		
62	43	PILAR DPP	CEBU	0.546			x
63	44	SIQUIJOR DPP	SIQUIJOR	3.172	x		
64	44	POWER BARGE 113	SIQUIJOR	2.240	x		
65	45	GIGANTES DPP	ILOILO	0.314			x
66	46	CALUYA DPP	ANTIQUE	0.326			x
67	47	MARIPIPI DPP	LEYTE	0.326			x
68	48	LIMASAWA DPP	LEYTE	0.326			x
69	49	DARAM DPP	SAMAR	0.326			x
70	50	ZUMARRAGA DPP	SAMAR	0.326			x
71	51	TAGAPUL-AN DPP	SAMAR	0.326			x
72	52	ALMAGRO DPP	SAMAR	0.217			x
73	53	STO. NIÑO DPP	SAMAR	0.326			x
74	54	SAN ANTONIO DPP	SAMAR	0.326			x
75	55	CAPUL DPP	SAMAR	0.326			x
76	56	SAN VICENTE DPP	SAMAR	0.163			x
77	57	BIRI DPP	SAMAR	0.326			x
		MINDANAO		Cap.,MW			
78	58	BASILAN DPP	BASILAN	2.232	x		
79	58	POWER BARGE 119	BASILAN	7.200	x		
80	59	SULU DPP	SULU	5.400	x		
81	60	SIASI DPP	SULU	1.080		x	
82	61	TAWI-TAWI DPP	TAWI-TAWI	2.940	x		
83	61	POWER BARGE 108	TAWI-TAWI	7.200	x		
84	62	BALIMBING DPP	TAWI-TAWI	0.326			x
85	63	CAG DE TAWI² DPP	TAWI-TAWI	0.520			x
86	64	MANUK-MANGKAW DPP	TAWI-TAWI	0.163			x
87	65	SIBUTU DPP	TAWI-TAWI	0.423			x
88	66	SITANGKAY DPP	TAWI-TAWI	0.217			x
89	67	WEST SIMUNUL DPP	TAWI-TAWI	0.108			x
90	68	TANDUBAS DPP	TAWI-TAWI	0.054			x
91	69	DINAGAT DPP	SURIGAO DEL NORTE	1.930		x	
92	70	HIKDOP DPP	SURIGAO DEL NORTE	0.326			x
93	71	LORETO DPP	SURIGAO DEL NORTE	0.440			x
94	72	KALAMANSIG DPP	SULTAN KUDARAT	1.520	x		
95	72	POWER BARGE 111	SULTAN KUDARAT	2.240	x		
96	73	N. AQUINO DPP	SULTAN KUDARAT	0.326			x
97	74	A. SANTOS DPP	DAVAO DEL SUR	0.423			x
98	75	BALUT DPP	DAVAO DEL SUR	0.326			x
99	76	TALICUD DPP	DAVAO DEL NORTE	0.326			x
					7	2	26

SUMMARY

NO. OF PLANTS	TOTAL	Land-based	Barges
TOTAL LUZON (OIL)	55	48	7
TOTAL LUZON (HYDRO)	1	1	
TOTAL LUZON	**56**	49	7
TOTAL VISAYAS (OIL)	21	19	2
TOTAL MINDANAO (OIL)	22	19	3
TOTAL VIS/MIN	**43**	38	5
TOTAL PHILIPPINES	**99**		

Note: Excluding 5 other Power Barges (PB Nos. 101, 103, 104, 107 & 115)

ISLAND SERVED 69 (including Tandubas w/c came online June 2002)

Isolated areas * (not connected to main grid) 7

* Cabugao, Lubuagan, Palanan, Casiguran, Kalamansig, N. Aquino & J.A. Santos

RATED CAPACITY (MW)	TOTAL	Land-based	Barges
TOTAL LUZON (OIL)	143.65	68.93	74.72
TOTAL LUZON (HYDRO)	1.80	1.80	
TOTAL LUZON	**145.445**	70.73	74.72
TOTAL VISAYAS (OIL)	20.092	14.49	5.60
TOTAL MINDANAO (OIL)	35.72	19.08	16.64
TOTAL VIS/MIN	**55.812**	33.57	22.24
TOTAL PHILIPPINES	**201.26**		

CUSTOMERS	TOTAL	Electric Coops	LGU
TOTAL LUZON	22	19	3
TOTAL VISAYAS	12	12	0
TOTAL MINDANAO	10	10	0
TOTAL PHILIPPINES	**44**		

Note:

Existing 24-hour operation	18	
Less than 24 hours	8	(Including 3 for 24-hour operation)
For 12 hours	53	
	79	(Including 3 plants in Palawan mainland)

6.5.2 Universal Charge

As earlier stated, SPUG is allowed to draw financing for missionary electrification from the universal charge.

In a petition it filed with the ERC, SPUG sought the amount of P 0.0575 per kWh. This amount will be used for electrification projects for 140 barangays; and the replacement of existing facilities to supply stable power to meet an increase in demand. Table 6.10 shows the amount requested by SPUG in its petition before the ERC to be drawn from the account funded by the universal charge.

However, ERC only approved the release of only P 0.0373 per kWh from the trust accounts funded by the universal charge. The breakdown of the ERC-approved drawdown is shown in Table 6.12.

In its decision, ERC considered SPUG's expenses to implement 44 of 88 prioritized projects within the remaining months of 2003.

However, SPUG did not consider any of the 140 barangays identified for electrification when it formulated the other 44 projects that are in its area of coverage. For ERC, the identification of unenergized areas slated for energization is a necessity before petitions requesting funds from the universal charge can be considered. The ERC stated took this tack in view of the transparency demanded by consumers in the funding of missionary electrification projects from the universal charge.

ERC therefore advised SPUG that its petitions before the commission should be within the framework of the MEDP.

Table 6.12 Approved UC

Items / Year	2002 Required	2002 Approved	2003 Required
Phil. Energy Sales, GWh	47,917.00	47,197.00	52,093.00
Total SPUG Revenue (Million Pesos)	2,225.28	2,223.04	3,146.09
Total Cash Expenses (Million Pesos)	6,208.09	3,566.35	8,169.05
Operating Cost	3,451.32	2,966.59	4,817.57
Fuel	2,106.23	2,106.23	3,095.81
Lube	105.01	105.01	136.56
Purchased Power	484.72	-	647.02
Personnel Services	473.19	473.19	497.20
Other O&M	282.16	282.16	440.98
Capital Expenditure (Million Pesos)	2,756.78	599.76	3,351.49
Generation			
Grid Project	1,783.76	599.76	1,809.85
Off-grid Project	296.51	-	321.31
Transmission	327.21	-	598.23
Operations	349.30	-	622.10
Estimated UC-ME (Million Pesos)	3,982.81	1,343.31	5,022.96
UC-ME for OPEX		743.55	
UC-ME for CAPEX		599.76	
Estimated UC-ME (P/kWh)	**0.0831**	**0.0373**	**0.0964**
Operating Cost (OPEX)	0.0256	0.0143	0.0321
Capital Expenditure (CAPEX)	0.0575	0.0230	0.0643

SPUG received a copy of the ERC decision on July 17, 2003. Within 60 days from receipt of the ERC decision, SPUG had to submit to the ERC a petition to avail of funds from the universal charge for 2004. The study team obtained a draft of the petition. The outline of the draft petition is as follows:

- Programmed utilization of the funds from the universal charge for five years (2004-2008);
- Flexibility in utilizing funds drawn from the universal charge; and
- Allow SPUG to use funds from the universal charge to bridge financing costs.

SPUG's programmed capacity addition from 2004 to 2008 to meet demand growth is shown in Table 6.13.

Table 6.13 Capacity addition of SPUG

2004-2008 Capacity Addition, In kW						
Area	2004	2005	2006	2007	2008	Total
Luzon	16,200	16,000	26,000	36,500	70,500	165,200
Visayas	4,150	12,000		1,000	7,500	24,650
Mindanao	19,108	10,150	5,750	1,500	1,750	38,258
Total	**39,458**	**38,150**	**31,750**	**39,000**	**79,750**	**228,108**

Table 6.14 shows SPUG's programmed power delivery system plan. The plan is meant to ensure the efficiency and stability of power supply.

Table 6.14 Power delivery system plan of SPUG

2004-2008 Transmission & Substation Projects						
Projects	2004	2005	2006	2007	2008	Total
69 V T/L (ckt.km.)	51	261	40	120	384	**856**
69 kV S/S (MVA)	5	100		30	30	**165**
138 kV T/L (ckt. km.)		76				**76**

SPUG intends to energize 1,249 barangays by 2006 to help meet the government's target of energizing 100% of the country's barangays by that year. The SPUG breakdown of SPUG's yearly targets is shown in Table 6.15.

Table 6.15 Unenergized barangays covered by MEDP

Number of Barangays to be Served				
Type of Service	2004	2005	2006	Total
Centralized	109	80	109	298
Decentralized	317	317	317	951
Individual	*159*	*159*	*159*	*477*
Communal	*158*	*158*	*158*	*474*
Total	**426**	**397**	**426**	**1,249**

The breakdown of SPUG's proposed fund utilization from the universal charge (as found in the draft petition) is shown in Table 6.16.

Table 6.16 Yearly universal charge calculation

In Million Pesos

YEAR	2003	2004	2005	2006	2007	2008	Total (2004-2008)
TOTAL SPUG, Revenues	**2,223.04**	**2,050.85**	**2,362.90**	**2,723.40**	**3,136.67**	**3,617.70**	**13,891.52**
Total Cash Expenditures	**3,566.35**	**7,749.59**	**9,117.25**	**9,654.14**	**10,488.44**	**13,855.71**	**50,865.12**
Operating Expenditures	**2,966.59**	**5,217.57**	**6,003.82**	**7,032.60**	**8,208.49**	**9,642.97**	**36,105.45**
Fuel	2,106.23	2,868.54	3,480.77	4,178.11	5,008.97	6,016.03	21,552.42
Lube	105.01	131.28	158.71	190.09	227.61	272.78	980.47
Purchased Power	-	912.00	982.27	1,214.68	1,496.14	1,851.28	6,456.37
Personnel Services	473.19	430.87	430.87	430.87	430.87	430.87	2,154.33
MOOE	282.16	843.47	886.18	914.23	940.29	967.40	4,551.57
New Areas		31.42	65.03	104.61	104.61	104.61	410.29
Capital Expenditures	**599.76**	**2,532.01**	**3,113.43**	**2,621.54**	**2,279.95**	**4,212.74**	**14,759.67**
Generation Projects	599.76	1,534.75	1,876.17	1,551.03	1,574.08	3,091.21	9,627.24
Grid Projects	599.76	960.16	1,301.58	976.44	1,274.08	2,791.21	7,303.47
Off-grid Proj (New Areas)	-	574.59	574.59	574.59	300.00	300.00	2,323.77
Transmission Lines & SS	-	568.92	787.50	600.51	217.06	613.18	2,787.17
Operations (Spares, etc.)	-	428.34	449.76	470.00	488.80	508.35	2,345.26
SPUG Energy Sales, MWH	**478,716.16**	**556,050.18**	**641,967.15**	**741,899.43**	**856,716.01**	**990,572.45**	**3,787,205.23**
Phil. Energy Sales, GWH	**52,093.00**	**49,457.00**	**53,211.00**	**57,422.00**	**61,504.00**	**66,096.00**	**287,690.00**
UC-ME (Exp-Rev), Mil P	**1,343.31**	**5,698.74**	**6,754.35**	**6,930.74**	**7,351.76**	**10,238.01**	**36,973.60**
UC-ME, P/kWh	**0.0373**	**0.1152**	**0.1269**	**0.1207**	**0.1195**	**0.1549**	**0.1285**
Bridge Finance							
Amt (50% of UC-ME Reqmt)		2,849.37	3,377.18	3,465.37	3,675.88	5,119.00	18,486.80
Interest, 8%/yr		227.95	270.17	277.23	294.07	409.52	1478.94
Additional UC-ME, P/kWh		**0.0046**	**0.0051**	**0.0048**	**0.0048**	**0.0062**	**0.0051**
UC-ME w/ Bridge Finance							
Amount, Mil P		**5,926.69**	**7,024.52**	**7,207.97**	**7,645.84**	**10,647.53**	**38,452.54**
P/kWh		**0.1198**	**0.1320**	**0.1255**	**0.1243**	**0.1611**	**0.1337**

6.5.3 Situation of SPUG operations

SPUG's power sales and revenue had increased annually in the last 10 years. The amount of subsidy allocated for SPUG's operating expense likewise increased.

On the other hand, subsidy for capital expenses over the years decreased, while operating expenses increased on an aggregate basis.

In sum, the total amount of subsidy grew during the period covering 1990 to 2000.

This trend can be traced to the increase in consumption of diesel fuel and the cost of maintaining SPUG facilities. It bears noting that SPUG uses diesel-fed plants for its rural electrification projects. At the same time, there has been a marked increase in the plants' operating hours.

Subsidy—the amount of which is even greater than the revenue—is still required over the next five years. The budget plan covering a five-year period (2002-2006) is shown in Table 6.16.

To find ways and means to reduce costs, there is therefore a need to determine the current condition of SPUG facilities.

The transition of power sales and revenue of SPUG from 1990 to 2000 is shown in Table 6.17. This table was taken from the 2002 MEDP, which was prepared by the DOE.

Table 6.17 Transition of power sales and revenue of SPUG

Year	Energy Sales (GWh)	Net Revenue (Million PHP)	Subsidy (Million Pesos)		
			Operating Expense	Capital Expenditure	Total
1990	83.70	113.50	59.29	122.78	182.07
1991	94.10	151.50	146.80	1,276.88	1,423.68
1992	119.40	213.40	193.46	1,518.10	1,711.56
1993	144.60	266.60	197.52	511.49	709.01
1994	165.30	325.10	292.57	785.83	1,078.40
1995	196.80	378.00	481.32	552.71	1,034.03
1996	224.10	432.00	616.50	147.51	764.01
1997	265.60	512.30	814.58	494.36	1,308.94
1998	310.60	605.00	1,183.53	250.35	1,433.88
1999	318.50	658.80	1,065.32	273.53	1,338.89
2000	347.40	773.90	1,905.90	287.34	2,193.24

Source: 2002 Missionary Electrification Development Plan

6.6 Applicability of Decentralized Power Systems in Rural Electrification

6.6.1 Concept and Application of the Decentralized Power System

In general, demand per household in rural areas is quite small, usually up to 100 watts. In these areas, people are likely to use electricity for small electric appliances such as lights, TV, and radio. Appliances of the direct current (DC) type are common in these areas.

In areas with such low demand, the photovoltaic (PV) system is one of the most effective and economical ways of electrification. However, when the income level of residents increases allowing them to purchase more appliances such as color TVs and refrigerators, the demand per household rises to a peak of 150 W. With these conditions, a large PV system is required, which would lose cost advantages since the system needs to be operated by alternating current (AC) with inverters. In this case, the introduction of an alternative generation methods such as diesel, micro-hydro and other effective systems that use indigenous energy (e.g., biogas, natural gas) is therefore encouraged.

The following are among the methods in electrifying unenergized areas in the Philippines:

<Diesel Generation>

The initial cost of installing this system is relatively low. Once the system is operational, however, maintenance becomes an issue. At the same time, fuel costs fluctuate. In addition, the costs of transporting and storing the fuel should be considered. Given the life span of this system, cost would be a disadvantage.

<Photovoltaic Generation>

The PV system is quite economical and effective in energizing areas where each household's demand is expected to be low (up to 100 W) and where the villagers will use DC-type electric appliances. However, when demand increases and inverters are needed to be able to use the DC-type appliances, this system will lose its cost advantage.

There are two ways to install this system, with each type dependent on the peculiarities of a particular area.

The first type is known as "Individual Type", while the second type is known as the "Centralized Type."

The Individual Type is suitable for areas where the number of households is low and the households are dispersed.

The Centralized Type, on the other hand, could cater to areas where households are clustered together.

<Micro-hydro Generation>

The economic efficiency of this system is highly dependent on an area's natural conditions such as geographical features and quantity flow of rivers. In the long term, this system is more cost effective than diesel generation systems, particularly if the installation site has the ideal conditions for logistics of fuel and other necessary materials. The initial cost, however, depends on the type of the system employed.

<Grid Extension>

Grid extension is the most favorable system as a social infrastructure that provides stable power supply. However, in remote areas that do not have sufficient demand, using this system outweighs the cost advantage.

Currently, unenergized areas in the Philippines are quite inaccessible. Therefore, it is essential that planning electrification projects for these isolated areas should consider the best combination of a decentralized system and grid extension.

On the other hand, in the process of developing electrification projects, the grid system should be extended to an area with an existing individual generation systems such as PV.

In this case, the existing facilities must be utilized in forming the new total system. Here are some examples:

(A) Transferring facilities to the targeted area for re-utilization

When the grid is extended, the existing individual system should be removed and transferred to another unenergized area. The transfer will contribute not only to a reduction in unenergized areas to some degree but also to cost reduction for the electrification program through the re-utilization of old facilities.

Even if the system to be transferred is PV, large systems can be dismantled into small parts, transferred, and reinstalled in other small villages with low demand.

(B) Connecting the individual system to a new grid line

The current high rate of electrification makes it possible to achieve the 100% electrification goal by 2006. Given this, it is practical to continuously operate the existing individual systems connected to the newly extended grid lines. In the newly formed system, the functions of the individual system would be as follows:

- Efficient use of energy resources;
- Lowered daytime peak demand; and
- Environment protection by restricting gas emission.

These functions of the decentralized system could be considered in the context of future commitments.

6.6.2 Interconnection of the Dispersed Generation System

To consider the dispersed generation system as a supply facility, checking and studying the interconnection technical requirements for the dispersed generation system currently utilized in Japan is recommended. The main study items are:

- Power capacity;
- Electric systems;
- Power factor;
- Protection coordination;
- Voltage fluctuation;
- Short circuit capacity;
- Emergency measures; and
- Consultation.

In Japan, when a customer applies for interconnection, the customer is required to submit various data on the interconnecting generator.

DUs ascertain facility data on the distribution network to be interconnected, as well as data on voltage fluctuation, and current change. These data are used at the time of application to judge the suitability of the interconnection of the dispersed generation system. Although there may be no need to conform to the level of interconnection requirement is used in Japan, technical requirements, particularly those relating to general public safety, are essential. Therefore, when at least one item regarding the guarantee of general public safety is not satisfied, the interconnection of that facility should not be permitted.

Although the interconnection of the dispersed generation system has many problems for both the customer and the distribution company, it could provide additional power supply to the system.

A study must be conducted to calculate the capacity that could be interconnected with the existing system. Further studies on the current condition of the facility; the application situation; and the installation situation of a protected cooperation system, are likewise required.

In the case of MERALCO, the firm conducted a study on interconnection of dispersed generation system. Results of the exercise are shown in Table 6.18.

Table 6.18 Results of the exercise on the interconnection of the dispersed generation system

Category	Items	Description
Protection cooperation	The kind of ground detection system and setting value	Ground fault relay detection. 1/3 of phase sensitivity.
	The kind of short-circuit detection system and setting value	SLG, phase-phase, 3-phase faults relay detection. 1/3 of phase sensitivity.
	Re-close system (re-close operation)	Fast reclosing. 2-sec & 15-sec delay.
Electric power quality	Fluctuation range of frequency in the distribution system	Between 59.7 Hz and 60.3 Hz

Category	Items	Description
	Fluctuation range of voltage in the distribution system (supply side voltage and demand side voltage)	At 115 kV supply - +/- 5%. At 34.5 kV distribution - +/- 10%, but in our planning practice, we want to maintain it at +/- 5% of the nominal voltage.
	Tolerance level of momentary voltage drop (%)	? Please give more details.
	Tolerance level of a flicker (for example △V10)	Below 1% voltage flicker
Actual condition of equipment	Line length (km) (an average and maximum)	Average circuit length is around 65 km and we have circuit that is approximately 350 km long.
	Line impedance (omega) (the average and the maximum)	For 795 MCM ACSR: 0.12880+j0.60595 ohm/mile For 336.4 MCM ACSR: 0.3060+j0.6581 ohm/mile For 4/0 AWG Cu: 0.3029+j0.7112 ohm/mile
	Breaking capacity of a breaker (switch MVA (supply side) (for a line)	At 115 kV ? 40kA
	Breaking capacity of a breaker (switch MVA (demand side) (for protection of a facility)	At 34.5 kV ? 16kA
	Permitted current at the time of a short-circuit of a conductor (example: 125 square: 22000A, 0.567 seconds)	? Please give more details.
	Permitted current of conductor (example: 125: 490A)	795 MCM ACSR ? 900A ; 336.4 MCM ACSR ? 530A ; 4/0 AWG Cu ? 480A (Our existing standard for main line is 336.4 MCM ACSR)
	Operation current of conductor (example: 125: 420A)	50%-80% loading
	Supply side voltage and current distribution map at the time of minimum load and maximum load (Line map that indicates line impedance, current distribution, and supply side voltage, for every average load, minimum load, and maximum load) (long line and average line)	---
	The minimum load capacity per substation bank (KVA, MVA)	Most of our major substations have a transformer capacity of 50/67/83 MVA, OA/FA1/FA2 rated at 110 kV Y grounded-34.5 kV Y grounded-13.8 kV Delta. Minimum allowable loading is around 36% of the FA2 rating or around 30 MVA.
	% impedance to bank secondary bus at the substation (Or % impedance by the primary side of the substation and % impedance of the bank of the substation)	% impedance of power transformer bank at 100 MVA base: At the 115 kV primary side = 1.25% At the 34.5 kV secondary side = 10.46%
	A loop system or a radial primary feeder system	Radial primary distribution system.
Actual condition of system interconnection	Kinds of the dispersed generation system in the current system?	---
	Conditions for interconnection (if you have)	---
	Generation capacity (KW, MW)	---
	Kinds of protective relay / setting value	---

These results were arrived at by using data on the average substation and the distribution line of MERALCO.

In this case, the possible interconnection amount by simulation is about 10% or less of the distribution line capacity. This amount is quite small, compared to the 100% distribution line capacity in Japan.

Furthermore, a study conducted on the Olongapo DU located in Central Luzon shows that uncertainty in the distribution system lowers the interconnection rate in a particular area.

The procedure in interconnecting dispersed generation systems can be classified into four groups, as follows:

- Deciding on the application criteria for an interconnection;
- Installing a system in collecting distribution line data;
- Preparing emergency measures, and providing information in the event of an emergency; and
- Installing protective devices to avoid problems, clarifying the cost sharing for installing them, and maintaining them properly.

Each item requires considerable time and expense for solving and fixing.

6.7 Factors to be Considered in Rural Electrification Projects

The promotion of a long-term electrification plan through grid extension and renewable energy is considered from the following point of view.

(1) Spread effect of electrification for rural development

In the Philippines, the population has been migrating from rural areas to the urban areas. This has produced an economic gap between the cities and rural areas suffering from poverty. Thus, the government is paying great attention to improving the standard of living and narrowing the economic gap.

The government sees rural electrification to be one of the most effective solutions for these problems, thus its adoption of a policy geared towards large-scale rural electrification.

Rural electrification will contribute to the creation of business opportunities and will reduce population shift. Furthermore, electrification has such domino effect, such as improvement in information accessibility, increase in educational opportunities and other benefits that will raise the standard of living of residents in the rural areas of the Philippines.

In short, planning electrification projects should strongly consider the economic development it will bring to targeted areas.

(2) Introduce private investment into rural electrification

To support the rural electrification program, EPIRA mandated the inclusion of rural electrification as one of the components of the universal charge. However, under current practice, these public subsidies are not sufficient in funding the rural electrification program.

A prime example would be SPUG, which is financially hard-pressed in maintaining its diesel-fired plants due to increasing fuel costs.

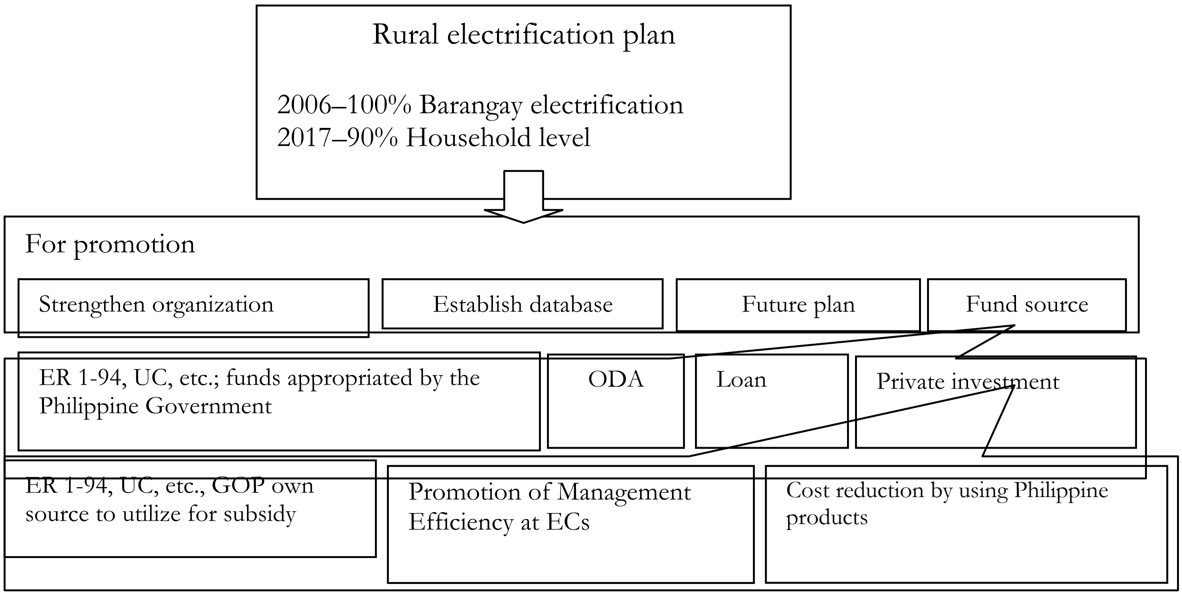
Likewise, ECs could not effectively implement electrification projects since subsidies from NEA are insufficient.

Therefore, for DOE to attain its goal of total electrification the country's barangays by 2006, an increased private investment in the program is imperative.

To introduce further private investment, they should undertake the following items, such as:

- Establishment an appropriate database for all unenergized barangays;
- Implementation of management improvement in EC and SPUG;
- Promotion of the utilization of potential renewable energy;
- Increase subsidies from ME-UC; and
- Creation of new tools to induce further private investment.

Fig. 6.17 Outline of steps to promote private investment



1) Need for government subsidy utilizing ER 1-94 and the ME-UC

DOE and SPUG have already begun trials to utilize a part of the universal charge to facilitate private sector participation in the rural electrification program. These schemes—if successful—will be beneficial not only for the government, but also for the private sector. Developing a system to verify the level of subsidy, among other factors would be crucial in attracting QTPs. In addition, the criteria for the QTPs' participation in the rural electrification program should be formulated by DOE, as part of its obligations under Rule 14, Section 4 of EPIRA's IRR.

2) Promotion of management efficiency at ECs

NEA has 12 regional offices throughout the Philippines. It oversees EC activity through these offices. NEA likewise provides management expertise to the ECs and classifies the 119 ECs into six ranks, from A+ to E using the following points:

- Repayment condition of financing;
- Current rate of system loss;
- Recovery rate of tariff;
- Conditions of payment for power purchased from NPC;
- Condition of power cost; and
- Other items.

Fig. 6.18 Situation of EC ranking(Based on *2001 NEA Chronicles*)

At present, NEA provides incentives to ECs ranked A+ for expanding their own area of coverage. However, for ECs ranked E, NEA dispatches staff to try to improve a distressed EC's management. The following figure indicates the situation of EC ranking based on NEA's *2001 Chronicles.*

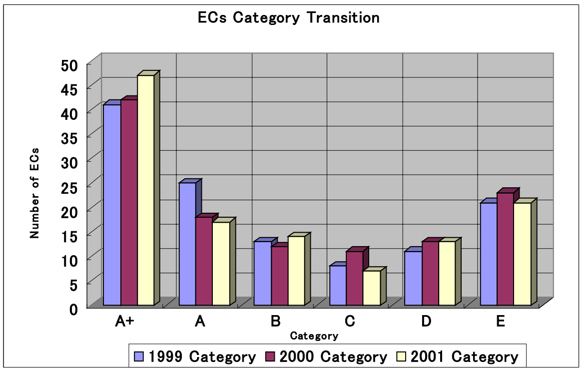


Fig. 6.19 Distribution Loss in each Region

Based on this figure, about 60% of ECs were ranked as A+ or A. On the other hand, about 30% of ECs were ranked as D or E. For example, the average distribution loss of ECs by region is indicated in Figure 6.19. This figure shows that the systems loss in the ARMM and Region 5 are higher than in other areas.

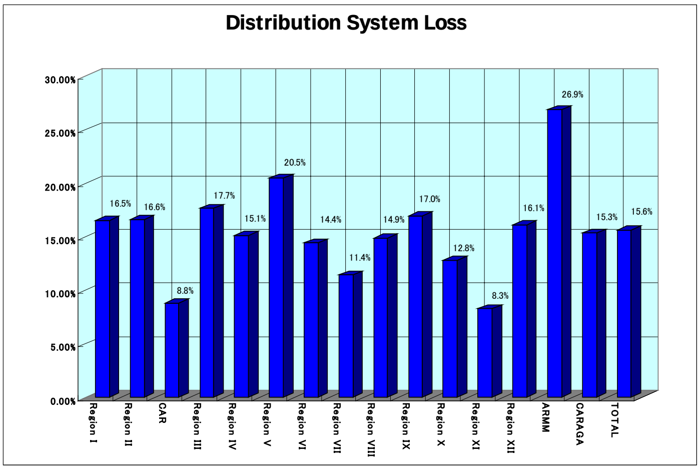
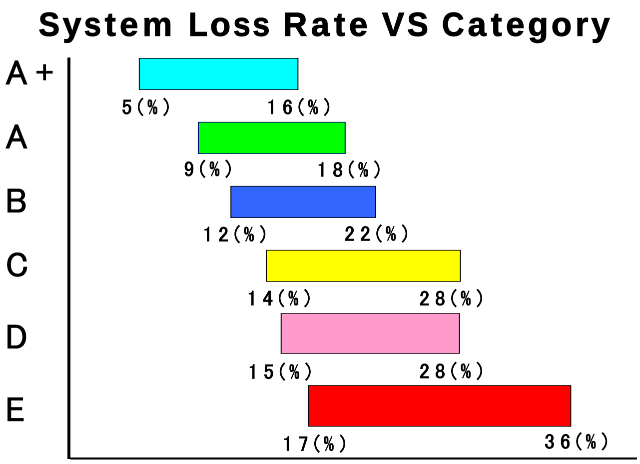


Fig. 6.20 Correlation between Distribution Loss and EC Ranking

On the other hand, the relation between distribution loss and EC ranking is indicated in the following figure. Based on this, the category of an EC rises when distribution loss is reduced. This would allow the management of EC to improve the EC's ranking.



As a result, improvement in management is connected to the private investor incentives.

(3) Provide expertise on a long-term basis to prepare a feasible and workable plan

To realize the concept of the rural electrification plan through this project and to assist database establishment, expertise should be provided on a long-term basis to facilitate the plan preparation.

Chapter 7 Investment Promotion

7.1 Promoting Investments in the Philippine Power Sector

This chapter will examine legislative and other measures—including investments incentives and procedures—that promote investments in the Philippine power sectors, as compared to those in the ASEAN countries.

Likewise, three issues in the local power sector will be analyzed and compared with other ASEAN countries. These issues include:

1. The structure of the Philippine power sector;
2. The current status of investment procedures in the Philippine power sector ; and
3. The current status of proposed incentives in the electric power business.

A resolution of these issues, as well as the recommendations of the study team, is also provided at the end of the chapter.

In comparing the Philippine model, three ASEAN countries were chosen: Thailand, Indonesia, and Vietnam. These countries were chosen by the study team since—like the Philippines—the liberalization of their respective electric power sectors is underway.

The table below shows the progress and status of the liberalization of the four countries' (Philippines, Thailand, Indonesia, and Vietnam) respective power sectors. Further details are also appended to this chapter.

Table 7.1 Privatization Status of Power Sectors in Different ASEAN Countries

	Philippines		Thailand		Indonesia		Vietnam	
Bill for privatization (○existing, Δplanned, — none)	○	EPIRA was enacted in June, 2001. Implementing rules (IRR) were approved on Feb., 2002	○	"Privatization Master Plan" (drafted in Apr. 98) (Already approved by the Cabinet.)	—	No privatization plan. New Electric Power Act was established in Sept. 2002	—	None
Separation of generation and transmission/distribution sectors (○partly or in progress, Δplanned, —no plan)	○	In progress	○	Separation in progress	Δ	Separation planned (Java/Bali system or Petam Island only)	—	Sector reform policy has been announced but no concrete plan/idea yet.
Power generation (○in progress, Δplanned, —no plan)	○	IPP/SPP have been introduced.	○	IPP/SPP have been introduced.	○	IPP/SPP have been introduced.	○	IPP is introduced through BOT contract.
Power transmission (○partly or in progress, Δplanned, —no plan)	○	Disposal of TRANSCO planned (Tender in Jul., 2003 failed)	—	Ownership and operation by EGAT will continue for a while.	Δ	Transmission is planned to be separated from PLN and privatized.	—	Separation by 2010 is announced but no concrete plan/idea yet.
Plan to establish a power pooling market (○planned, —none)	○	Establishment of WESM was being prepared as of Aug., 2003. A demonstration market is scheduled to be inaugurated in Nov.	○	EGAT proposed to the government to postpone the establishment of market till 2007.	○	It is planned to select the region to open a limited competition market for power generation in 2007.	—	Plan is reported to establish the market after 2010, but there is no concrete plan yet.
Power distribution (○in progress, Δplanned, — no plan)	○	Private distribution companies such as MERALCO are already in operation.	○	MEA/PEA are planned to be privatized in 2004 (by public offering of shares).	○	Separation of PLN is planned.	—	No plan presently.
Wholesale, retail and contracted transportation (○planned, —no plan)	○	Planned to approve the privatization for large consumers	○	Pooling of the wholesale electric power market planned	—		—	No plan presently.
Public offering of shares/sale of assets (Δin progress, ○planned)	Δ	Disposal of power generation assets being prepared. EPIRA encourages generation companies to broaden their ownership through public offering.	Δ	Privatization of EGAT is planned in 2004 (Shares of is the power generation subsidiary, EGCO, and a part of generation plants are offered to the public already.)	—	Power generation and transmission/distribution departments of PLN are planned to be privatized, but whether the shares will be sold is not known yet.	—	No plan presently.
Effect of currency crisis to privatization (○affected, —none or unknown)	○	The government renegotiated existing IPP contracts.	—	To reduce the burden of liability caused by the currency crisis, EGAT is preparing to revise PPA with IPPs.	○	PLN decided to revise the contracts with IPPs in view of heavy burden of liability due to the exchange losses.	—	Effect of currency exchange is minimal.
Opportunity for foreign capital to enter by privatization (○existing, Δscarce)	○	Already realized. Many candidates plan to participate.	○	Already in progress. Many candidates plan to participate.	○	Some foreign firms have already participated.	○	Some foreign firms have already participated.

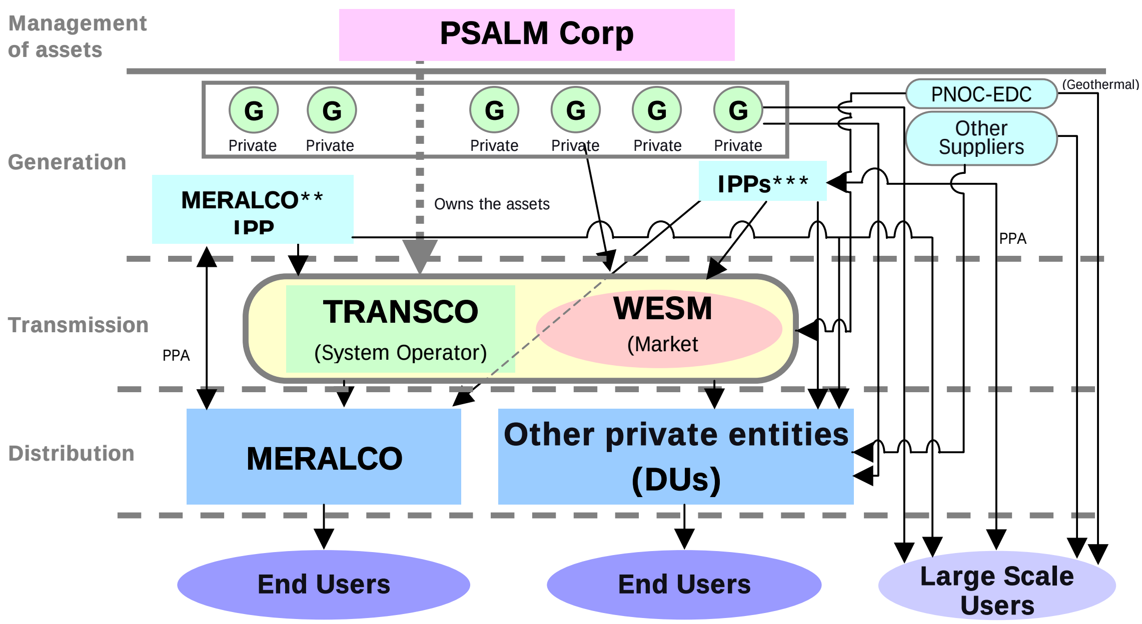
Source: Compiled from various reference materials

7.2 Status of the Investment Promotion Policy in the Philippine Power Sector

7.2.1 Structure of the Philippine Power Sector

The chart below shows the structure of the Philippine electric power sector as envisioned by EPIRA.

Fig. 7.1 Philippine Power Sector: after Privatization



* NPC IPPs refers to IPPs supplying exclusively to NPC including energy commission agreement (ECA)
** Meralco IPPs refers to IPPs supplying exclusively to Meralco
*** IPPs refer to 1) IPPs other than those supplying exclusively to Meralco or NPC 2) Incoming IPPs
Note :Missionary Electrification is excluded in this figure.

Source: Compiled from various reference materials

The implementation of the law is currently underway. The steps taken by the government to implement EPIRA include: (a) disposal of certain NPC generation assets; (b) establishment of TRANSCO; and (c) the establishment of WESM.

Unfortunately, the privatization is not proceeding as planned, as the entry of private investments in the Philippine power sector—which is the key to power sector reform—has stagnated.

The major factors for this hesitation of private investors to infuse capital in power sector reforms projects are:

a. Perceived political and regulatory risks; and
b. Increased business risks, especially for IPPs.

This chapter will therefore examine the investment environment, including the incentives offered in the Philippine power sector and the procedure in availing of these incentives.

They are then compared with the experience in other ASEAN countries—Thailand, Indonesia, and Vietnam.

7.2.2 Current Status of Investment Procedures in the Power Sector

The problems regarding the investment procedures (based on interviews with foreign corporations operating in the Philippines and government agencies such as BOI) for prospective investors in the power sector can be summarized as follows:

a. Approval period: The time line in securing a business license is unpredictable and long.
b. Unclear approval process: The number of approvals and the processes for approval are not systematic;
c. Uncertainty in the approval process indicated by discrepancy between the law provisions and the actual implementation of approval process indicating; and
d. Limited investment incentives granted by EPIRA.

As far as the approval periods are concerned, approval processes of national government agencies are relatively smooth.

However, the approval processes of the various local government units (LGUs) are left to the individual discretion of each LGU.

Besides, the approval processes and the requirements for the application of a business license differ from LGU to LGU.

It was pointed out that this situation is one of the causes of uncertainty in the investment environment, since investors are unable to predict the type of situation they may encounter until they actually apply for a business license.

On the approval process, the problems were raised on securing approval at the local government level, as was the case previously cited. For instance, one complaint raised during our interviews centered on the inconsistent laws/permits requirements of each LGU.

These inconsistent laws/permits often are the obstacles in obtaining the business license—particularly if the applicant is unfamiliar with the local regulatory environment.

Discrepancies were also noted between a law’s provisions and the actual implementation of the approval process.

For instance, the NEDA-ICC, which is tasked to evaluate BOT/BOO applications, is required to approve an application within 30 days. This target is not usually met, primarily due to the unavailability of ICC members.

As to the insufficient support on investors, the biggest problem is the absence of a system to support the smooth implementation of approvals processes.

To be more specific, the BOI's One-Stop Action Center has made available an investment flowchart dubbed "Investor Roadmap."

However, this so-called roadmap provides very limited descriptions of the basic procedures required by other national government agencies. These include, among others, the registration of a company's incorporation papers with the Securities and Exchange Commission (SEC); and the business permit application with the Department of Trade and Industry (DTI).

The roadmap likewise excludes the approval processes of the various LGUs.

This section of the chapter will be devoted to analyzing problems faced by prospective investors, and recommending solutions to these problems.

(1) Types of Categories of Investments in the Power Sector

The categories for prospective investments in the power sector can be categorized into:

1. Sale of NPC assets;
2. Sale of TRANSCO; and
3. Investment as an IPP.

With the planned privatization of the NPC, for example, the main approach of investing in the power sector will be: new capital investments by private investors; and the sale of NPC assets. This new approach is a departure from the previous approach, which was to use the Build-Operate-Transfer (BOT)/Build-Operate-Own (BOO) scheme.

The investment procedures for the new approach will be further classified into three, as follows:

a. Investment procedure related to the public sector, such as BOT/BOO contracts;
b. Direct investments by private sector (e. g., power plant that will trade in the electricity spot market; bilateral sales contract with a distribution utility); and
c. Sale of NPC assets.

(2) Investment Procedure under the BOT/BOO Scheme

Perhaps the most important approval process that needs to be secured under the BOT/BOO scheme is the approval from the NEDA. NEDA is responsible for approving practically all energy projects and investments in the power sector.

However, approvals of these projects are usually delayed. These delays could be traced to the inability of the committee members that approve these projects to meet periodically to evaluate these projects.

This problem is largely attributable to such physical conditions as the members of approving committee—which is composed mostly of Cabinet Members—having diverse schedules and, therefore, there is no effective way to solve this problem. Consequently, current situation involves potential risks of delaying the business development for the investors.

<Government agencies Involved in the Evaluation and Approval of Projects>

1) NEDA

NEDA is the agency tasked with screening, evaluating, and approving such projects as BOT/BOO schemes; and Overseas Development Assistance (ODA) projects.

Evaluation and approval of projects referred to NEDA are undertaken by the following units in this order:

a. NEDA Secretariat – Serves as the research and technical support arm of the NEDA Board. It also provides technical staff support and assistance, including the conduct of studies and formulation of policy measures and other recommendations on the various aspects of development planning and policy formulation, and the coordination, evaluation and monitoring of plan implementation.

b. NEDA ICC – Evaluates—through the ICC Technical Board—the fiscal, monetary, and balance of payments implications of BOT/BOO projects, and, on a regular basis, recommends to the President the timetable of their implementation. The ICC is chaired by the Secretary of Finance, co-chaired by the NEDA Secretary-General. The Executive Secretary, Central Bank Governor, and the Secretaries of Agriculture, Trade and Industry, and Budget and management serve as committee members. Under the IRR of Republic Act 6947, as amended by Republic Act 7718, the ICC approves projects costing up to P 300 million. The ICC also recommends to the NEDA Board the approval of projects costing more than P 300 million.

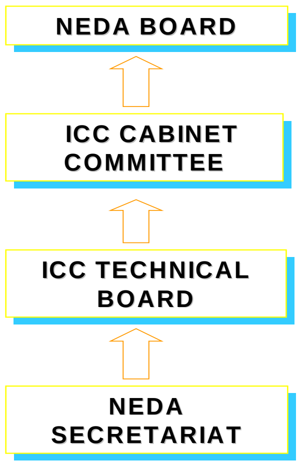
c. NEDA Board Executive Committee – Resolves policy issues without the necessity of convening the entire NEDA Board. It facilitates the decision-making process at the NEDA Board to ensure that projects or issues requiring NEDA Board discussion & decisions are immediately acted on. The NEDA Board Executive Committee is chaired by the Executive Secretary and is co-chaired by the NEDA Secretary-General.

d. NEDA Board – Chaired by the President and composed of 16 Cabinet Secretaries and the Governor of the central bank. The Board gives final approval for any BOT/BOO project in excess of P 300 million.

Approval period: Under the said IRR, the ICC is mandated to act on the final contract between the proponent and the national government agency within 15 working days upon submission of complete documentation. On the other hand, the ICC or the concerned Local Development Council (LDC) and the concerned Sanggunian (law-making body) of the LGU are required under the IRR to act on the project within 30 working days from satisfactory compliance by the concerned agency/LGU of the requirements. According further to Section 2.11 of the IRR, "Unless other wise notified in writing by the ICC or LDC, failure of the ICC or LDC and its Sanggunian to act on the projects within the specified period shall mean the project is deemed approved…"

This deadline, however, has been honored more in breach. This is because, as previously mentioned, the ICC meetings—where project discussions and evaluations are undertaken—which are held bi-weekly are not realized because ICC members' diverse schedules and the adjustment of their schedule is physically impossible in some occasions.

Fig. 7.2: NEDA – ICC approval process



Source: NEDA Secretariat

2) DENR
3) DOF – Undertakes financial review of the project.
4) Department of Justice (DOJ) – Undertakes a legal review of the project.
5) LGUs – For BOT/BOO projects implemented by LGUs, approvals are based on the cost of the project, as follows:

a. P 20 million and below – approval of the municipal development council;
b. Above P 20 million to P 50 million – approval of the provincial development council;
c. P 50 million and below – approval of the city development council;
d. Above P 50 million to P 200 million – approval of the regional development council; and
e. Above P 200 million – approval of the ICC.

<Approval process>

The basic legal framework for a BOT/BOO project is Republic Act 6957 (otherwise known as the BOT Law), as amended by Republic Act 7718.

The BOT Law, as amended, identified several key areas that an investor (also known as "project proponent") could enter. These areas cover projects, which include, among others: power plants, highways, airports, canals, dams, and hydroelectric power projects.

There are two categories of projects sanctioned by the BOT Law, as amended. These are:

a. Unsolicited proposal – undertaken by a project proponent on a voluntary basis; and
b. Priority project – where a government agency or LGU identifies a specific undertaking within its development plan.

In both cases, the basic approval process is similar.

However, if the project is unsolicited, the contract is awarded on a negotiated basis only if all the following conditions are met:

- Such projects involve a new concept or technology and/or are not part of the list of priority projects by a national government agency or LGU;
- No direct government guarantee, subsidy, or equity is required; and
- The government agency or LGU has invited by publication for three consecutive weeks, in a newspaper of general circulation, comparative proposals, and no other proposal is received for a period of 60 working days.

However, if another project proponent submits a lower priced proposal, the original proponent shall have the right, within 30 working days, to match the price.

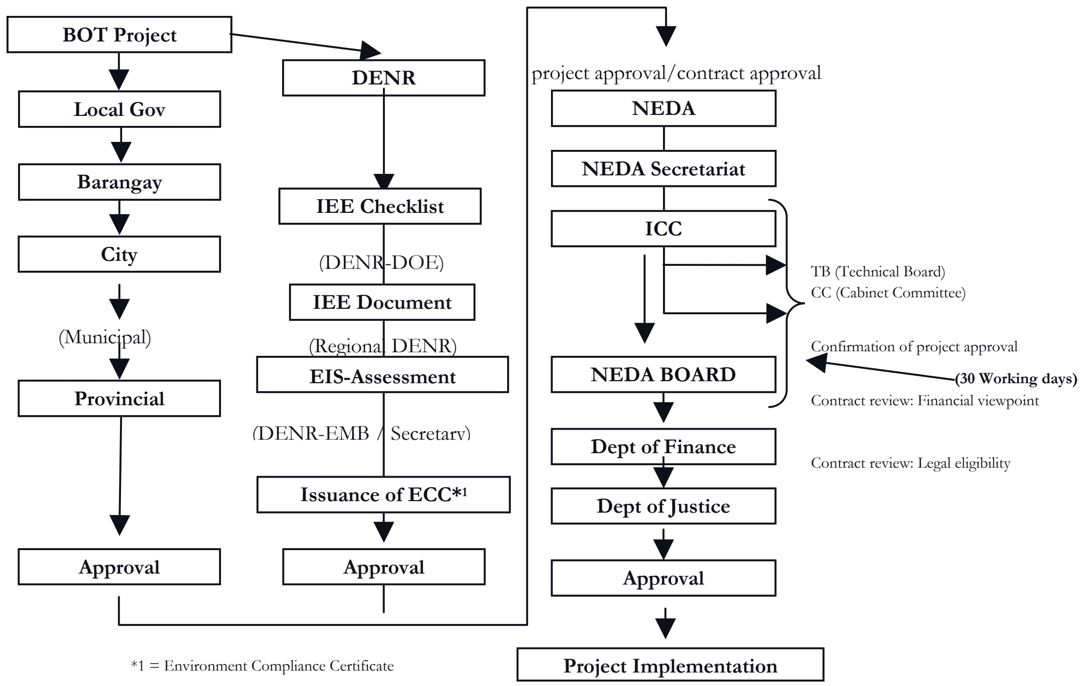
All told, final approval of any proposal under the BOT Law, as amended, is usually received after a year.

One of the problems pointed out during the study team's interviews with various IPPs is the issue of the application for the business alteration when the business plan is changed.

There was a specific case where despite the fact that the initial application was processed smoothly (as the application was made by NPC itself), when a lender who was financing the business management objected about the business scheme and a necessity arose to modify the scheme.

Modifying a business plan in the midst of the approval process consumes a tremendous amount of time—even when the initial application was approved quickly.

Fig. 7.3 Investment Procedure under a BOT/BOO scheme



Source: Based on interviews with NEDA/DENR

(3) Investment Procedure for Direct Investments by the Private Sector

With the restructuring of the power sector, new investments are expected in the generation sub-sector.

Thus, prior to its entry, a prospective investor needs to consult with the DOE and ERC to determine demand, as outlined in the PEP and PDP. After consulting the DOE and ERC, and if there is indeed a viable business, the business plan is formulated based on the PEP forecast. Thereafter, the environmental assessment should be undertaken. The approval of the local government (in case of BOT/BOO contracts) should also be secured before actually applying for the business license.

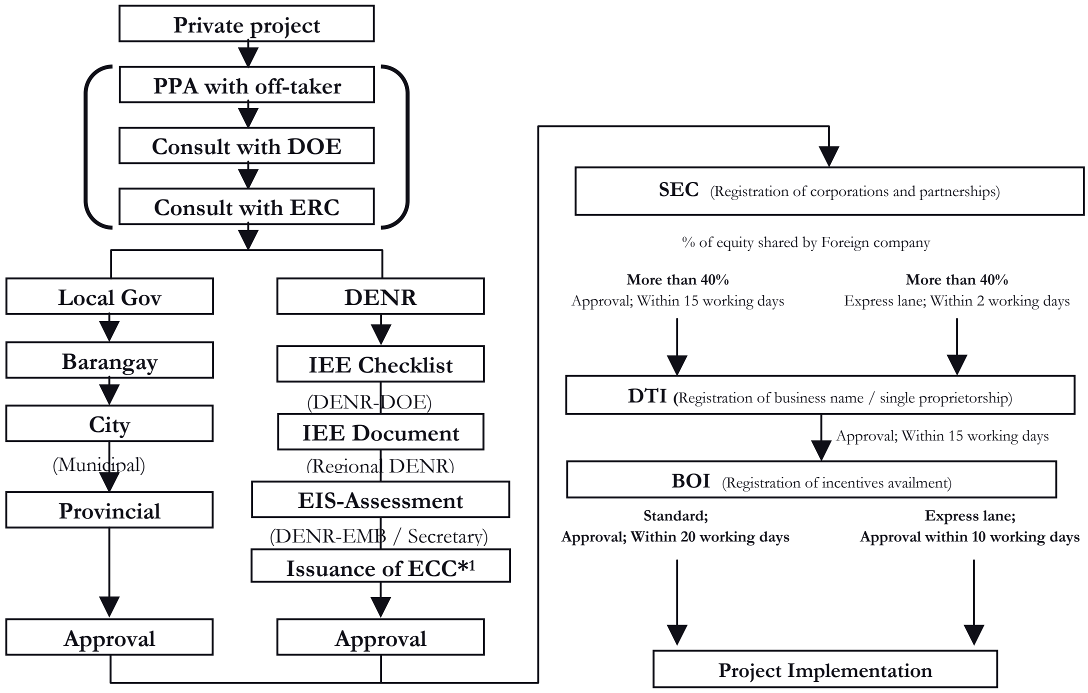
After completing these processes, registration with SEC and securing the business license from the DTI follow suit. The application for incentives can then be filed with the BOI. The timeframe for approvals from these three agencies is two to three weeks for each agency, depending on the magnitude and type of business.

Thus:

a. Time required at SEC: Within 15 working days for regular processing; within 2 working days if applying through the “Express Lane”. (It should be noted that power sector projects are rarely approved for processing through the “Express Lane” in view of the scale of the project and its impact on the national economy.)
b. Time required at DTI: Within 15 working days

c. Time required at BOI: Usually within 20 working days; within 10 working days in case of applying through the "Express Lane".

Fig. 7.4 Investment Procedure/Private project



*1 = Environment Compliance Certificate

Source: JICA Study Team

(4) Investment Procedure for Asset Sale of NPC (GENCOs)

The basic flow of the process can be divided into two: the first would be to obtain government approval for the procurement of the asset; while the second would be consummating the sale and the operation of the asset.

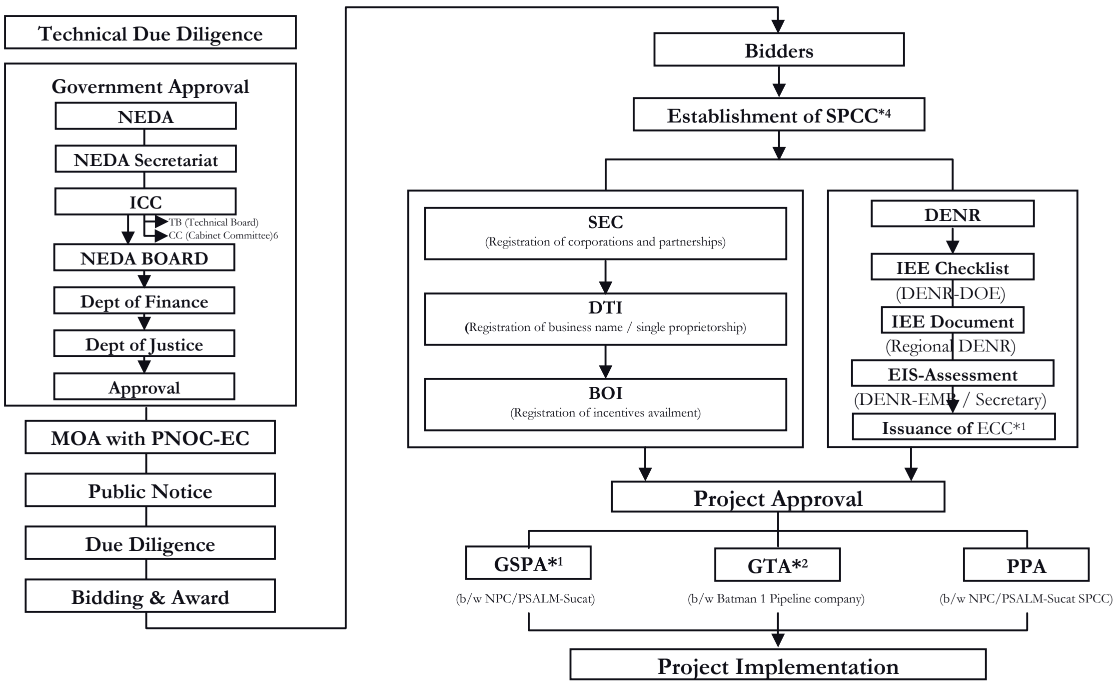
In other words, this process would be a hybrid of the two processes discussed above (i.e., BOT/BOO and direct investment).

The flow of the initial half of the entire process is quite similar to the process for a BOT/BOO project. However, after NEDA approval is secured, a public notice of tender; a tender; and due diligence follows in that order.

After the decision of purchaser is made, then the latter half of the process starts for the corporation (or entity), who is the successful bidder, to launch the business. When a SPC (Special Purpose Company) is to be established as the operator of power generation business, the establishment procedure of the company is to follow first and then securing environmental assessment clearance (from the DENR) and the applications for investment incentives (with SEC and BOI).

After the approval of the project, the preparation for the actual operation such as the fuel supply contracts and PPA will be made. The following chart shows the presumed flow of investment procedure particularly for the privatization of the Sucat Generation Plant:

Fig. 7.5 Investment Procedure/NPC asset (GENCO) sales (assumption)



*1 GSPA :Gas Sales & Purchase Agreement
*2 GTA :Gas Transportation Agreement
*3 PPA :Power Purchase Agreement
*4 SPCC:Special Purpose Company

Source: JICA Study Team

The process of concluding fuel supply contracts (such as GSPA and GTA) after the project approval in the above chart is particular to Sucat Generation Plant, which will be converted to a gas-fed combined cycle plant, but the other processes such as bidding, environmental assessment, and application for investment incentives are presumed to be same for other generation plants.

(5) Current Status of Environmental Assessment

Environmental Compliance Certificate (ECC)

DENR conducts the environmental assessment of energy related projects, promotion and support of renewable energy/natural gas business, etc., in cooperation with DOE.

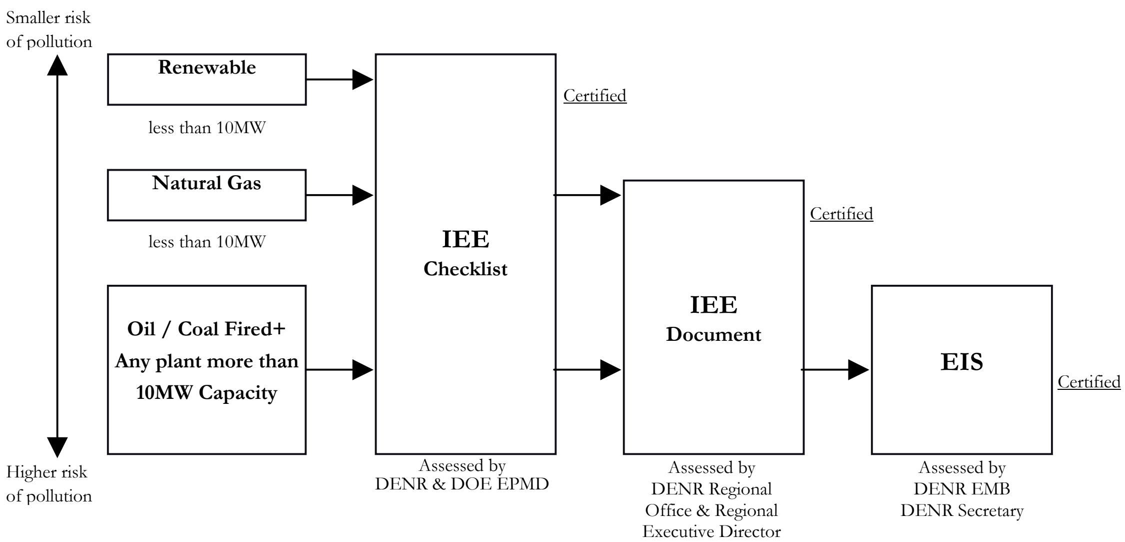
The monitoring activity during the implementation of project is also a function of DENR.

<EIS – Environmental Impact Statement System>

The process and kind of environmental assessment required for energy sector projects are different according to the type and scale of the project. However, when it comes to the last stage of implementation, the acquisition of EIS is essential for all projects. For the business which is assumed to impose a burden on the environment, it is also necessary to obtain an EIS or to obtain an approval for the exemption from EIS.

a. For the utilization of energy source that causes a big burden on the environment, such as the use of oil or coal, an Environmental Impact Assessment (EIA) is required.
b. For a business which imposes a relatively minimal burden on the environment, such as the natural gas business, an Initial Environmental Examination (IEE), which is the examination standard of EIS, is required.
c. In case of renewable energy, such as solar energy and biomass, the submission of a checklist in accordance with the above IEE is required.

Fig. 7.6 DENR evaluation procedure



IEE =Initial Environment Examination
EIS =Environmental Impact statement
EPMD =Environmental Protection and Monitoring Division
EMB =Environmental Management Bureau

Source：JICA study team (based on interview with DENR)

One of the concerns raised on the environmental assessment process is that a large amount of time is consumed before the approval is given. For example, there was a case that the award of the ECC took more than a year. The reasons are considered to be the slow rate of processing and the great number of approvals required within the DENR.

Another hazard is the necessity to go through the hierarchy of processes from the approval of local offices (city and regional) of DENR to the final approval by the central office.

(6) Current status of the approval process by local government units

The problems of business application process required by the local government level as listed below are often pointed out as the delaying the investment process required in the Philippine power sector:

a. Too many licenses/permits by the local governments are required.
b. It is necessary for the investors themselves to apply and obtain these licenses/permits, which increases business risks (such as the delay of business start-up schedule) at the stage of application for investment.
c. There are quite too few guidelines for the investors regarding the approval process (especially local government process) and investor support is insufficient.

These approvals/processes required by the LGU include business permit/s from the municipality/city. This business permit is different from the permit obtained from the DTI. The local permits have to be secured by the investor, thus, entailing additional, and often, substantial costs. The process of obtaining the permit in itself is time-consuming and when the approval of the permit is delayed, the construction of a plant is consequently delayed.

Given the autonomy of LGUs in the Philippines, each LGU has its own set o local laws. It is often the rule than the exception that these local laws can be very complicated.

In one case, a project was delayed because a little-known provision of a law was applied for the approval of the IPP to establish its plant.

In view of these conditions, securing a permit from LGUs is a very risky proposition for investors.

7.2.3 Existing Incentives and Problems Encountered in Securing Incentives in the Power Sector

This section will examine the incentives available to investors and the problems encountered in securing these incentives.

(1) Existing Tax Incentives and Flaws in Tax Incentives for the Power Sector

1) Income Tax Holiday (ITH)

Investors are usually granted an ITH of 4 to 8 years. Investments granted pioneer status are usually entitled to an 8-year exemption (with extension). (Please see <Appendix 2>, "Basic Philippine Framework on Foreign Investments".)

The following table compares the conditions for an investment to qualify for tax exemptions incentives in the Philippines and three of its neighboring countries.

Table 7.2 Conditions for an investment to qualify for tax exemptions incentives

Country	Conditions of Pioneer Status	ITH (100% Deduction)	Tax Deduction (After ITH)	Tax Incentives Other Than ITH and Deduction	Standard Rate of Corporate Income Tax
Philippines	Pioneer status: Scale of Investment (More than US $ 20 Million) Advanced Technology Certificate (Certified by DOST)	Pioneer – 6 years Non-pioneer – 4 years Modernization – 3 years	None	Additional deduction for labor expense: 50% of incremental direct labor cost deductible for the first 5 years	Standard: 32%
Indonesia	Targeted area a. Integrated Economic Development Zones (KAPET) b. Bonded Zones (KB) c. East Indonesia (KTI)	None	Preferential rate applied; 10-15% (whole period)	a. exemption of corporate tax of Article 22, freedom of choice for depreciation/amortization methods and other accounting methods b. 50% deduction of land/building tax	Standard: 25%
Thailand	Categorized by three different regions below and specified business fields a. First region b. Second region c. Third regions	a. 3 years b. 3 to 5 years c. 8 years	50% of Tax deduction; 5 years after tax holiday	None	Standard: 30%
Vietnam	Decided by targeted areas and business fields a. Industrial zones, Export processing zones and High-tech zones b. Business fields specified by the government	1~8 years depending on various conditions	50% of tax deduction after ITH; 2-4 Years	Application of preferential tax rate (10 to 25%) plus 10 to 100% reimbursement upon reinvestment to a project supported by the government	Standard: 25% for foreign companies and 32% for domestic companies

Source: Compiled from various materials of BOI, and related agencies of each country.

The application of the ITH can be extended from 6 to 8 years. However, to qualify for an extension, certain conditions need to be met, such as the utilization of a certain percentage of raw materials. Thus, it would be difficult for investments in the power sector to qualify for such an extension.

Given this, an investment in the power sector can only avail of an exemption for a maximum of 6 years. (Please see <Appendix 2>, "(5) Rules for Main Incentives" for more details on ITH extension.)

The disadvantages of a relatively short tax exemption period can be summarized as follows:

a. The 6-year maximum period is too brief, especially when compared to Thailand and Vietnam, which both offer an 8-year maximum period;
b. A discount in the tax rate is not available after the exemption period lapses, compared to a 50% discount for 2 to 4 years in Vietnam;
c. The actual exemption period is reduced in the event of unforeseen circumstances, such as a delay in the implementation of the project;
d. There is practically no incentive (such as a rebate on discount) to reinvest profits; and
e. The incentives are too general, and are mostly not applicable to the power sector.

2) Reduction/Exemption from Value-Added Tax (VAT)

Basically, a corporation will only benefit from a VAT exemption if 100% of its products are exported. Thus, the power sector is not exempt from VAT.

However, sales of electricity and fuel to NPC are not subject to VAT.

Nevertheless, transactions with NPC that are covered by VAT can be refunded through tax credit certificates (TCCs). That is, VAT is first paid and this payment can be applied as credit in the investor's income tax return. This process is however a complicated and time-consuming undertaking.

The following table compares the tax regime of the Philippines with other ASEAN countries.

Table 7.3 Comparison of Tax Regimes

Country	Tax Ratio	Exemption
Philippines	10%	1. 0% rate applied on 100% export manufacturer 2. VAT refund is available on power sector, though it takes much time 'til refund.
Indonesia	10%	VAT Exemption/Withhold payment of the importation and/or delivery of Selected Strategic Goods
Thailand	0 or 7% (will be 9% beginning Oct. 1, 2003)	0% rate applied on export industry
Vietnam	0-20%	Exemption from Excise Tax for: 1. Fixed capital goods of foreign corporations 2. Products for BOT project (Same rule as for exemption from import tariffs.)

Source: Compiled from various materials of BOI, and related agencies of each country.

3) Tariff Exemption

Capital equipment for power projects are slapped a tariff of 3% to 5%. With VAT and the tariff rate the project proponent thus pays a tax of 13% to 15%

4) Dividend tax ratio

The dividend tax ration is the rate of tax paid by non-resident foreign corporations. The standard tax rate for foreign corporations in the Philippines is 32%. However, for investments made by Japanese corporations, a tax rate of 15% is applied.

The lower rate for Japanese corporations is due to an agreement between the Philippines and Japan that specifically prescribes a reduced tax rate. The Tax Convention between these two countries also stipulates:

- Interest payment – 15% (10% for the interest paid to bonds & debentures)
- Dividends – 10% (when 25% or more of the outstanding shares or voting rights are held by foreign capital during a 6-month period immediately before the dividend payment date.
- Dividend paid in other cases – 15%
- Royalty, depending on the nature – 10% to 25%

It should be noted however that the tax for dividends paid by a domestic corporation to a non-resident corporation is exempted.

The table below shows a comparison of the Philippines' tax rates and those of its neighboring countries. Despite the reduced tax rate for Japanese companies in accordance with the bilateral tax convention, the Philippine tax rate is higher, compared to the Indonesian, Thai, and Vietnamese rates.

Table 7.4 Comparison of Tax Rates

Country	Dividends Tax Ratio
Philippines	15%[2]
Indonesia	15%[3]
Thailand	10%
Vietnam	3-7%

Source: Compiled from various materials of BOI, and related agencies of each country.

[2]Indonesia = Preferential tax rate under the mutual tax treaty with Japan (Standard Rate=20%).
[3]Can be reduced to 15%, depending upon the country of residence of the recipient (Standard Rate=32%).

5) Incentives for the Natural Gas Industry

The natural gas industry is included in the annual Investments Priorities Plan (IPP). The IPP is prepared by the BOI in accordance with Executive Order No. 226 (otherwise known as the "Omnibus Investments Code of 1987).

In preparing the IPP, the BOI determines the incentives available for each type of investment.

The construction of natural gas/compressed natural gas (CNG) pipelines are included in the IPP. As in the case of other industries, the menu of incentives in the natural gas industry would depend on the level of investment.

On the other hand, the tariff for imported liquefied natural gas (LNG) is pegged at 3% for LNG sourced from ASEAN countries, as opposed to the standard rate of 5%.

Based on interviews by the study team with local businessmen, the latter preferred to import from Middle Eastern countries (such as Kuwait) instead of ASEAN countries (such as Indonesia) in view of competitive prices from the former.

The table below shows the tariff rate and other data of the Philippines for LNG and compares this with data from Indonesia, Thailand, and Vietnam.

Table 7.5 Tax Regime and Incentives for Natural Gas

<table>
<tr><th>Country</th><th>Tax Rate</th><th>Incentives</th><th>Others</th></tr>
<tr><td>Philippines</td><td>LNG – 5%
In Gaseous State – 5%</td><td rowspan="4">A preferential tariff rate applies when the LNG is imported from ASEAN Countries.</td><td>Import Processing Fee – P 250 to P 1,000 (equivalent to US $ 4.7 to US $ 18.80)
Excise Tax of P 0.05 per Liter to P 1.63 per liter (Equivalent to US $ 0.001 to US $ 0.031)</td></tr>
<tr><td>Indonesia</td><td>LNG – 5%
In Gaseous State – 5%</td><td>None</td></tr>
<tr><td>Thailand</td><td>LNG – 0.001 Baht per kg.
In gaseous state – 0.001 Baht per kg. (Equivalent to US $ 0.000024)</td><td>Excise Tax of 36% or 3.15 Baht per liter (Equivalent to US $ 0.08)</td></tr>
<tr><td>Vietnam</td><td>LNG – 5%
In Gaseous State – 1%</td><td>None</td></tr>
</table>

Source: World Tariff Online Database 2003

(2) Status/Problems with Incentives and Guarantees for IPPs

1) Incentives and guarantees for IPPs

Prior to the enactment of EPIRA, and particularly at the height of the power crisis in the Philippines, NPC's PPAs with IPPs were backed by government guarantees.

However, with the enactment of EPIRA and the restructuring of the power sector, the Philippine government has been hesitant to provide any sovereign guarantees for IPPs or even NPC.

Under these circumstances, it is thus imperative to determine the business risks of investing as an IPP.

(a) Problems Confronting IPPs

The business environment for IPPs is becoming increasingly unfriendly. The perceived unfriendliness can be traced to the deterioration of the financial standing of distribution utilities, which is due in turn to the aversion of the national government for the utilities to increase rates, as well as the national government's efforts to renegotiate the IPPs entered into at the height of the power crisis.

Some actual cases will be discussed below.

a) Grid Rate Issues between IPPs and Distribution Utilities (DUs)

The price of electricity is the single determinant of the profitability of an IPP. However, due to its aversion to any increase in the price of electricity, the government has pressured both the IPPs and the DUs to absorb the incremental cost.

Whenever NPC buys power from an IPP, the costs of the fuel and the exchange rate fluctuation were collected by the DUs from the end-users. However, since EPIRA required the DUs to unbundle (or itemize) the components of their rates, the cost of power (purchased power adjustment) became more transparent to the end-user. Hence, there were calls from various sectors—particularly the end-users—to review these rates.

In addition, some problems prompted the ERC to review the purchased power adjustment, especially of the DUs.

These problems included charging the end-user without official approval of the ERC; and the calculation of the purchased power adjustment was not uniform.

In its decision of February 24, 2004, the ERC substituted the purchased power adjustment with the Generation Rate Adjustment Mechanism (GRAM).

GRAM is a system designed to adjust the fluctuation of costs associated with power generation alone. GRAM was formulated to adhere to the principle of itemized pricing of electricity. However, transmission costs, systems losses, and franchise fees—which had been included in the purchased power adjustment —were excluded from GRAM.

With the implementation of GRAM, the DU needs to obtain advanced approval from the ERC to revise or change the electricity charge. Likewise, the frequency of reviewing the charge was changed once a month to once every quarter.

The change of reviewing the frequency increased the time lag to recover costs to several months. In other words, GRAM forced the DUs to absorb the outstanding amount for several months; that is, until ERC approval was obtained. This situation effectively placed a heavy burden on the financial standing of the DUs, forcing them to supplement their cash flow by bank loans, among others.

For these reasons, the DUs have begun pressuring ERC to revise GRAM.

Given the instances cited above, investing as an IPP entails various risks, particularly in the pricing aspect. With the absence of any government guarantee, it is highly doubtful that the local power sector will be able to attract the much-needed foreign capital.

(For further elaboration and instances on problems encountered by IPPs, please see <Appendix 3>, "Problems Encountered by Independent Power Producers (IPPs) Operating in the Philippines".)

b) Perspective on the Sale of NPC Assets

Simultaneous with the privatization of TRANSCO, PSALM began laying the groundwork to sell the first of NPC's plant groupings. The first grouping, which includes the Sucat thermal and Limay combined-cycle pants, was scheduled to be sold by the end of August 2003. Thereafter, the sale of the other plant groupings would continue, followed by the other assets (as well as the liabilities) of NPC.

Investor response to the sale of these assets was however cold.

This lackluster response could be attributed to the unfavorable business environment that forces investors to shoulder all the risks, such as procurement of fuel; electricity pricing; and unforeseen/unpredictable demand for electricity.

c) Status of the Sucat Thermal Power Plant

The 600 MW Sucat Thermal Power Plant, which is located in the southern part of Metro Manila, has been identified by the DOE to be converted into a natural gas-fired plant. Thus, DOE has made the sale of the Sucat plant as the centerpiece of its foreign road shows.

While the DOE plans to have this plant privatized by the end of 2003, the response of potential foreign investors has been unenthusiastic due to the following reasons:

1) Although there are plans to construct the Batangas-Manila I (Bat-Man I) pipeline, the start-up schedule of the pipeline's construction has yet to be fixed;
2) The cost of the natural gas has not been made public; and
3) Middle- and long-term demand for the gas has yet to be determined.

Given these unknowns, it is therefore unclear whether the sale of the plant will push through as originally scheduled.

(b) Future prospects

In order to decide on investing in an IPP, it is important to determine if the procurement of fuel and the sale of electricity are secured steadily for a middle- to long-period, usually ranging from 5 to 10 years. Information on the asset value of the power generation facility is also a critical factor.

However, these types of information are insufficient. Thus, it is impossible to collect enough information to make a sound judgment on whether or not to invest.

In addition, the incomplete system to transfer the fluctuation risk of electricity price in a timely manner to end users (as stated above) and the consequent deteriorating financial conditions of distribution companies will obviously be perceived negatively by investors.

Furthermore, the more fundamental problem is the serious risks that exist in the short-sighted and ad hoc way of selling the assets sales, as depicted in the course of the privatization of TRANSCO.

Therefore, unless the Philippine Government takes the necessary remedial measures—taking the mindset of investors into account—the chance to realize the introduction of purely private capital to the power sector will be remote.

2) Proposed Incentives for Renewable Energy

To reduce the country's dependence on imported energy sources, the Philippine government has taken steps to promote renewable energy. To provide the legal framework for the incentives package for renewable energy programs, a bill has been introduced in the House of Representatives.

Currently pending with the House energy committee, House Bill 5771 also promotes the development of renewable energy resources such as biomass, geothermal, and solar energies. The bill further mandates the use of renewable energy in off grid barangays and rural areas.

The following table provides a glimpse of the existing incentives packages for the promotion and development of renewable energy in the Philippines, Indonesia, Thailand, and Vietnam.

Table 7.6 Investment Incentives on Renewable Energy-related projects

Country	Subsidy	Tax exemption	Power purchase guarantee	Low-interest loan
Philippines	None	Solar power system for houses – preferential rate of 3-15% Equipment related to Mini/Micro-hydro, Wind power and Biomass project – preferential rate of 3%. General BOI incentives applicable when listed in IPP (Investment Priorities Plan)	None	FITNESS Program 1. Low interest loan for renewable energy project; Minimum interest rate – 6%; Not to exceed maximum of 20% of total project cost. 2. Loan for pre-business activities (Feasibility Study/Business Plan needed); Maximum interest rate of 6%; Not to exceed maximum of 50% of total project cost. Others: PNOC Loan Minimum interest rate of 12%; Not to exceed maximum of 75% of total project cost.
Indonesia	None	None	Small Power Purchase Tariff (SPPT) sets the buy-rate of power from renewable energy rather than conventional sources.	None

Country	Subsidy	Tax exemption	Power purchase guarantee	Low-interest loan
Thailand	EGAT subsidy; 5000 Thai Baht subsidy per purchase of PV panel Subsidy for R&D/Demonstration project for renewable energy	None (General BOI incentive applicable)	Small Power Producers (SPP) or those that produce biomass, solar, wind power). Guarantees by EGAT on power purchase at a fixed rate. Minimum of 5 years' operation required.	EGAT Loan Interest rate at 3% with a repayment term of 10 years.
Vietnam	None	100% exemption on equipment related to solar power; biomass; micro hydro; and wind power.	None	None

Source: Compiled from various materials of BOI and similar agencies of each country.

Under the current set-up, applications for incentives will be screened and evaluated by DOE to determine the applicants' eligibility.

In addition, investors may avail of BOI incentives, depending of course on the type and amount of incentives.

7.3 Proposals to Improve Investment Policies and Procedures for the Power Sector

7.3.1 Proposal on Investment Procedures

Based on our inquiries, the problems besetting the investment policies in the Philippine power sector can be summarized as follows:

a. Approval period: The time required to obtain a business license is unpredictable and too long;
b. A time frame stipulated by law to approve a project is often ignored by the approving agency; and
c. There is insufficient support and guidance for investors.

Since these problems are mere reflections of Philippine domestic conditions (as well as other factors), it would be unrealistic for us to propose solutions to all of them.

Nevertheless, we will review the issues behind these problems and point out relevant points that affect investments for future projects in the power sector.

(1) Establishing effective investment procedures

To make the investment procedure "investment-friendly", the national government should proactively promote approval processes that will not unduly burden investors.

Approvals processes, including government and environmental protection should be streamlined and bundled as a package. Alignment of these procedures should be ascertained prior to proposing or advertising investment opportunities. Such a step would thus reduce the investors' business risks.

(2) Effectively disseminating information on investment procedures

A checklist outlining the approvals process of various government agencies involved in approving the various permits needed by a foreign investor should be readily available.

Although a flow chart outlining investment procedures is available at the One-Stop Action Center of the BOI, this checklist merely provides simple descriptions of the approval processes of the concerned national government agencies. This roadmap however fails to inform the prospective investor of the approval processes (and timeframe) in securing approvals from LGUs.

Thus, in addition to streamlining investment procedures, the wide dissemination of this information is crucial in reducing the burden of prospective investors.

For instance, in Japan, the website of each ministry/government agency contains an e-government section. This section offers a database service, enabling users to search for comprehensive applications for livelihood and business opportunities; applications for various licenses, permits, and requirements. The required criteria; evaluation standards;

application procedures; where to obtain the necessary documents and forms; and where to submit these documents, are all available in the website.

Including such data and information in the websites of government agencies would help prospective investors.

7.3.2 Improving the Tax Regime and Other Incentives

This section shall propose improvements to the tax regime and other incentives for the power sector.

Designing the ideal tax regime and a friendly menu of incentives should always consider that costs related to any investment are, at the end of the day, passed on to the end-user.

The proposals to be set forth in this section will be within the context of reducing risks to investors and at the same time minimizing costs for the power sector as a whole.

(1) Income Tax Holiday (ITH and Exemption from Corporate Income Tax)

1) Extension of the Period for Tax Exemption/Income Tax Holiday

Compared to other countries, the tax incentives for foreign investors in the Philippines are not attractive—since the tax exemption period is only for a maximum of 6 years—even if the investment is classified as "Pioneer" under BOI's IPP.

Likewise, once the ITH expires, the investor would not enjoy any preferential tax rate. While the exemption period may be extended for another 2 years after the sixth year (or a maximum of 8 years), such an extension is rarely granted. Given the life of power projects, therefore, the tax incentive regime is hardly applicable to a power project or an Independent Power Producer (IPP). (Please refer to <Appendix 2> "Basic Philippine Framework on Foreign Investments" 2) Rules for Extension of ITH.)

With the liberalization of the Philippine power sector, investors will assume a greater degree of risks, compared to the current environment. It is, therefore, imperative that the Philippine government help mitigate these risks through preferential tax incentives.

Extending the ITH to 10 years would be an important first step in this regard.

Offering a supplemental set of incentives—such as a preferential tax rate—for a certain period after the expiration of the ITH would also be helpful. It bears noting that this model has been successfully implemented in Thailand and Vietnam.

2) Flexibility in the Reckoning Period for ITH Availment

The reckoning period for availing of the ITH is also a thorny issue.

Under BOI's guidelines, the incentives become effective only upon the approval of the application.

For a project of such magnitude as a power plant, delays are inevitable. In the Philippines, however, delays can be encountered not only in the implementation (or construction stage) but in the pre-implementation stage as well. These include (as cited previously in this report) securing licenses and permits from LGUs. With such unforeseen delays, it often becomes necessary to delay the implementation of the project.

In this regard, the BOI Board (the agency's policy-making and decision-making body), only approves any modification in the reckoning period if the delay is attributable to force majeure such as floods.

Thus for delays due to licensing and permitting issues involving LGUs, for instance, the investors absorb a huge amount of risk. The BOI should revisit the practicability of the date of approval as the reckoning date for projects granted ITH incentives. A minimum grace period of one year would be a good starting point.

(2) VAT (Value Added Tax)

Although the VAT rate in the Philippines is at par with its neighboring countries such as Thailand (both at 10%), VAT exemptions do not serve their purpose as an incentive for investors—the implementation of the exemption has been cumbersome and time-consuming.

Likewise, the TCC system should be discontinued and in its stead, exemptions should be given at the outset

(3) Exemption from Tariffs and Duties

A tariff rate of 3% to 5% is currently levied on capital equipment for the power generation sector. When VAT is slapped on the equipment, the investor's tax burden becomes quite large (e. g., 10% VAT + 3% to 5% tariff).

Thus, there is a need to exempt capital equipment for power plants from the imposition of any tariff.

(4) Taxes on Dividends

As previously stated in this report, the tax rate on dividends is relatively high. Even if the special rate prescribed by the Philippine-Japan Tax Convention is applied, the Philippine rate would still be higher than its ASEAN counterparts such as Indonesia.

While reducing the dividend tax would be an effective tool to attract investors, a preferential rate or exemption from taxes on internal reserves of business corporations would perhaps be a more effective tool.

The tax exemption would not only reduce the tax burden on investors, but would also make it easy for them to effectively reinvest the funds locally.

(5) Tariff on Liquefied Natural Gas (LNG)

LNG imported from ASEAN countries is levied a tariff rate of 3% while LNG imported from non-ASEAN countries is slapped a tariff of 5%.

To reduce the tax burden on investors, the JICA team recommends the tariff for LNG imported from non-ASEAN countries should be lowered to a level at par with LNG imported from ASEAN countries.

(6) Incentives for IPPs

To entice IPPs to invest in the local power sector, the national government should minimize the investors' business risks, particularly in the absence of any government guarantee in a liberalized power sector.

To minimize these risks, the national government should widely disseminate its present and future plans—not only for IPPs, but for the entire power sector as well.

1) Strong Commitment of the Government

With the absence of a government guarantee, a prospective investor such as an IPP assumes a tremendous amount of risk. Likewise, the commitment of the government to all NPC's assets has been perceived as insufficient.

As has been previously stated in this report, the most important factors a prospective investor in the power sector would consider are:

1. Asset value of the power generation facility; and
2. Assurance of profitability based on measurable factors (such as consumption and customer base) for the middle and long term.

There are, however, certain issues that have surfaced, particularly the second item above.

A case in point would be the Sucat and Limay plants. While the DOE's plans to convert these plants into natural gas-fired plants, uncertainty remains high due to a number of factors.

The timetable for the construction and operation of the Batangas-Manila 1 (Bat-Man 1) and the Bataan-Manila (Bat-Man 2) pipelines remains unclear. How natural gas prices will fluctuate also remains a question.

Moreover, available data on future consumption—which is a fundamental factor in the determination of future profitability of project on sale—is insufficient. Thus, the potential investors will have to conduct the market research by themselves.

Given these factors, it is therefore inevitable that negative perceptions on the investment environment would be raised. Therefore, to reduce such risks, the government should provide a clearer and more predictable timetable for the disposition of the assets.

2) Flexibility in the Sale of NPC Assets

   The uncertainty spawned by both the unclear timetable for the construction of Bat-Man 1 and Bat-Man 2 pipelines, and the price natural gas has resulted in a bottleneck in the privatization process, thereby increasing investors' risks.

   Consequently, prioritizing the sale of other assets—such as coal-, thermal- and diesel-fired plants, which are perceived to have lower risks—should be considered.

   Since there is a growing perception that the sale of NPC's assets is not proceeding smoothly, the government should adopt more realistic plans to disabuse such perceptions. For instance, the grouping could be revisited to determine if these groupings would be more attractive to investors.

3) Support Mechanism for Investors

   The lack of readily available data such as demand and sales forecasts imposes an additional burden on investors. Thus, a prospective investor would not know where to start.

   Hence, it is imperative that DOE make these data readily available to enable the investor to calculate electricity sales income prospects, thereby reducing business risks.

7.4 Energy Investment Promotion Office

The promotion of energy development activities has always been the responsibility of DOE's Petroleum and Natural Gas Division. This office was supported by the Norwegian aid agency, NORDA.

However, the promotional activities had always been limited to the petroleum and natural gas exploration sectors.

To provide comprehensive information and promote investments in the power sector—including renewable energy and conventional and non-conventional energy sources—the EIPO was created.

This section of the report will examine EIPO's current functions and thereafter propose certain recommendations to enhance EIPO's functions.

7.4.1 EIPO's Current Status

As envisioned, EIPO would have three departments, namely:

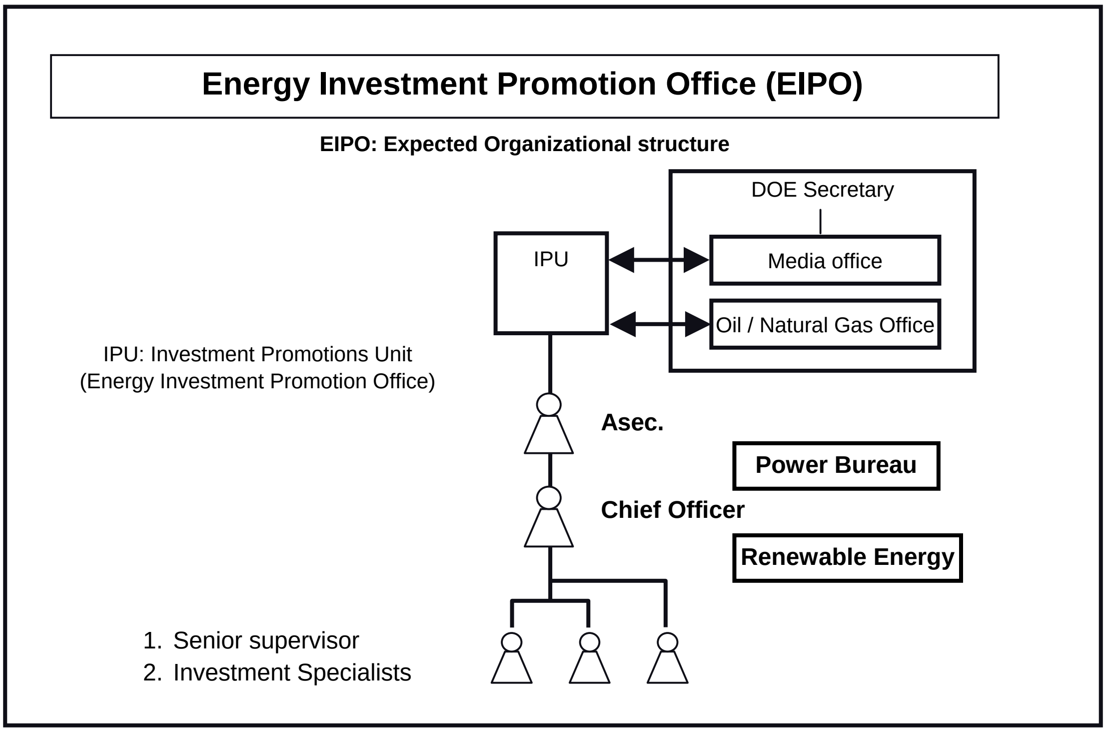
a) Petroleum and Natural Gas ;
b) Renewable Energy; and
c) Conventional Power Generation.

Two specialized officers were supposed to man each of these offices. But due to a shortage of staff within DOE, the original plan was partially modified.

As of August 2003, preparation to establish the office was still being undertaken.

The chart below illustrates EIPO's organization chart and staffing pattern.

Fig. 7.7 EIPO's Envisioned Organizational structure



Source: JICA Study Team (based on interviews with EIPO staff)

7.4.2. Status of Availability of Information to Prospective Investors in the Power Sector

DOE has posted a great amount of information on its website, such as the status of ongoing projects (such as those listed below). However, data management is poor at the DOE—due to the lack of data measurement tools—preventing the DOE from posting important information on the website. The lack of people to manage the website also has a bearing on its effectiveness as a tool to disseminate information.

Based on the study team's interviews with the EIPO staff, the office possesses a list of up to 2,000 prospective and actual investors, including these entities' respective profiles. Proper utilization of the information would make the data very useful to promote investments.

The status of the information provided by DOE on its website will be examined below.

Outline of Information Available in the DOE Website

Services for Other Departments and Government Agencies

1) Executive Information System (EIS)

This is a system for monitoring energy projects, and is available to personnel of DOE and its attached agencies who are registered users of the system. Registered users of this system can access the status reports that have been uploaded. At the same time, the registered user may update the information on a particular project to which he has access.

2) Online Reports Submission (ORS)

An online service for petroleum companies enabling them to submit the weekly and monthly reports that are required either by law or regulations.

Services for Investors and Business Firms in General

1) e-Bidding System

An electronic bidding system for various business tenders conducted by DOE. (However, since this section of the site has not been updated since June 2003, it is assumed that this section is rarely used or accessed).

2) Information service system for petroleum and natural gas

This system is part of the investment promotion activities of the Petroleum and Natural Gas Division, and is supported by NORDA.

In view of the following problems (including technical problems), however, it is highly doubtful whether the information posted on the website is efficiently utilized:

a. There is difficulty in accessing the website

It is unclear whether failure to access the website can be traced to an overloaded server. Downloading files can also be cumbersome, since connections to the website often time out or take an interminable time.

b. A great deal of project information is still on paper and have not been uploaded.

c. The number of site administrators is insufficient, both to maintain the website and to answer online inquiries.

In conclusion, while the preparation of information for dissemination is currently ongoing, this information has not been efficiently managed and fully utilized. This situation is caused by the absence of a favorable environment and the proper organization and systems to effectively provide investors and the public with the information they need.

7.4.3 Ideal Functions and Responsibilities of EIPO

Ideally, EIPO's function is to serve as a general information desk to promote investments in the energy sector. In particular, it should have the following functions and responsibilities:

a. To supply information on each and every energy project;
b. To seek potential investors and promote investment opportunities to these investors;
c. On a continuous basis, to provide information and updates on the status of investments, as well as to coordinate with other government agencies involved in investments promotion, such as the BOI; and
d. To provide an environment (such as a website) that would allow the free exchange of information with investors and prospective investors.

In addition to close coordination with several government agencies that are in one way or the other involved in investments in the energy sector, EIPO should be imbued with the following responsibilities to further enhance its role:

(1) EIPO as "One-stop shop"

EIPO should function as an organization that can supply the information needed by an investor.

For instance, the authority to grant investment incentives resides with BOI. However, BOI neither has the mandate nor the necessary information that are crucial in determining the viability of a particular project.

Information which should be supplied by EIPO include, among others: the power demand forecast; the potentially ideal sites for a power plant; sourcing information on power plants to be sold; and the procedures in preparing an environmental assessment.

In view of its mandate, the DOE possesses these and other data. Thus, a prospective investor would naturally contact DOE before touching base with other government agencies.

Hence, there is a felt need for DOE/EIPO to improve its working relationship with BOI to avoid any inconvenience on the part of prospective investors.

(2) Close cooperation with BOI and government agencies involved in the investment incentives process

(a) Current working relationships among government agencies

The current working relationship between BOI's One-Stop Action Center and each department/agency has yet to be systematically established. Based on the interviews conducted by the study team, the working relationship between personnel of these agencies are built on personal relationships and networking. Thus, the network needs to be rebuilt whenever staff are transferred or are separated from government service.

There is therefore a need to institutionalize the working relationship between these vital agencies.

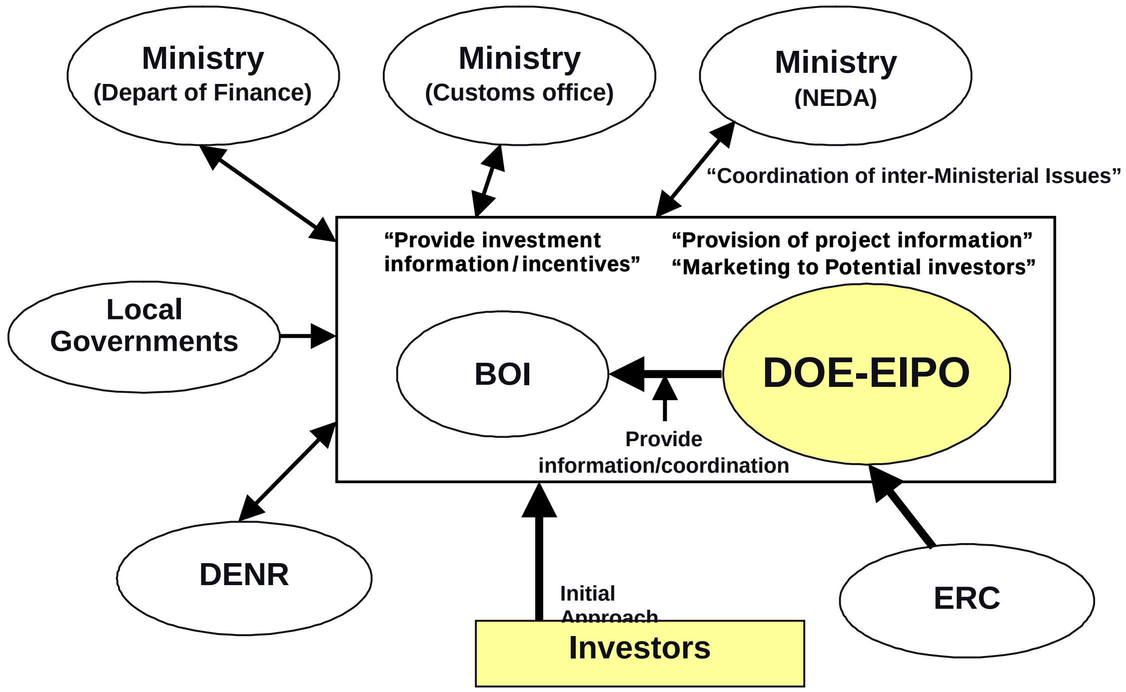
(b) Coordination between EIPO and BOI

When an investor needs to obtain and discuss detailed information on investment incentives, his time will be well spent if EIPO and BOI closely coordinate with each other.

Close coordination with BOI will enable EIPO to supply the information needed by the investor, without need for the latter to visit and/or consult so many government agencies.

The chart below illustrates the desired level of cooperation between agencies involved in promoting investments in the power sector:

Fig. 7.8 Coordination plan among power-related agencies



Source: Based on interview with EIPO / Philippine BOI (Board of Investment)

(3) Communication with investors via the World Wide Web

In view of its functions, EIPO needs to effectively supply investors throughout the world with the information they need. To attain this end, a functioning website that provides the needed information is paramount, to enable free and unhampered flow of information—regardless of time and distance.

7.5 Outline of a Proposed Information System for EIPO

In our discussions with EIPO, we recognized the importance and indispensability of a Web-based environment to effectively communicate with investors located in various parts of the world.

In the course of this study, the study team thus decided to support the development of an information distribution system for EIPO.

This section will explain the outline of the information system developed by the study team.

7.5.1 Objectives/Improving Efficiency

(1) Objectives

Information on local energy projects that need DOE's attention is currently stored in paper form. Thus, access to the information is quite limited; the time spent on reviewing information is too long—which can lead to both the deterioration and loss of the information.

These circumstances inevitably lead to questions on the proper safekeeping and management of documents.

There are likewise concerns on the accuracy of data on proposed investors and project proponents, considering that the data—which are stored in table/matrix format—are entered manually. It also bears noting that this database is not updated periodically.

The improper management of data on investors and energy projects is contrary to the objective of attracting investments and endangers the integrity of information on various investment promotion projects in the energy sector.

Thus, to help effectively promote investments in the Philippine energy sector, the integrity of this information should be safeguarded.

The objectives of this information distribution system, dubbed the "Department of Energy Investment Promotion System" are:

a) To effectively manage data concerning private investors and energy projects though advanced IT systems; and

b) To contribute to the promotion of future investments in the energy sector through smooth communication and information exchange with investors through a Web-based system.

(2) Improving Efficiency

1) Improving Efficiency at DOE

Data on projects managed by DOE; and data on prospective investors, which are all on paper, will be computerized. This process should result in:

- Improvement in the speed and accuracy of data entry;
- Improvement in convenience and speed in reviewing the data;
- Promotion of information sharing within DOE's various offices; and
- Reduction of possible deterioration and loss of the data.

2) Smoother communication between DOE and investors

Since the system will enable interested investors to input and upload data through a Web-based system, the project will eventually provide:

- Timely and accurate management of the investors' decisions;
- Improved convenience for investors; and
- Timely and accurate transmission of DOE's decisions to investors.

With this system in place, DOE will be able to plan and implement projects more efficiently. As a result of this expected improvement in efficiency, and smoother communication with investors, promoting investments in the Philippine energy sector will be enhanced.

7.5.2 Major Functions of the System

This system will consist of Web-based applications based on the Oracle database. It will have search, read, input, modify, and delete functions that can be accessed through the Internet.

(1) General users

Users such as the general public can access and read the profiles of projects registered in the system.

(2) Login users

By registering and logging in, an investor will have access to the following functions:

1) Search for Project Profiles and Investors

Users may search for and access data on registered projects.

2) Input, modify, and delete data on the user/investor

By logging in, to the system through a user ID and password issued by DOE, investors can enter data on their company. The user can also modify and even delete data through forms/fields provided within the system.

3) Input, modify and delete data on projects

By logging in to the system through a user ID and password issued by DOE, investors can enter data on their project/s. The user can also modify and delete data on the project through forms/fields provided within the system.

4) To express interest on a particular project

From the prospective projects listed on the site, a prospective investor may express interest by logging in through a user ID and password provided by DOE and accomplishing the form provided within the system.

(3) Data management, search, download, and print functions for DOE personnel

DOE personnel can access/utilize the following functions of the system:

1) Search for and access profiles on projects and investors

The system will enable DOE staff to search for and access data on projects registered on the system.

2) Input, modify, or delete data on profiles of investors

The system will allow DOE personnel to access the data of investors who request registration. If the request is in order, the data provided by the investor will be included in the database. The corresponding user ID and password will also be issued to the investor/requesting user.

However, if the DOE determines the investor's request to be incomplete or if the request is not in order, the DOE will inform the user—through email or through the system—to modify the data thus far inputted.

The DOE may, after examining the data provided by the investor, modify or delete the data through the system and at the same time notify the investor by email of the action taken on the latter's data.

3) Input, modify and delete data of project profiles

The system allows DOE personnel to input, suspend, and reject the entry by the investor of project profile data through the system administrator screen. This process follows the same sequence as that of the profile data of investors.

After examining the details contained in the investor's request to modify or delete project profile data, the DOE can modify or delete the data. The investor will be informed of the DOE's action both through the system administrator screen and email.

4) Harmonize and correlate data

The system will also allow DOE personnel to correlate the data provided by prospective investors with data on/profile of proposed projects.

5) Data management; and search, download, and print functions

The system will allow DOE personnel to effectively manage the profiles and data of projects and of investors. Correlation between these 2 sets of data on one hand and user IDs and passwords, on the other, is also possible through the system administration screen. Passwords can also be reissued through this screen.

Moreover, the system is designed to enable DOE personnel to access the data and profiles of investors and projects through a keyword search and through a fixed search. The DOE personnel may further choose between 2 formats in printing the data—either in the form of a data table or an individual data sheet.

The output of the search can be downloaded either in CSV format or to convert the same into print format (hard copies).

In addition to managing the project data and profile data stored in the database, the DOE's personnel will also manage the following information in HTML format:

- FAQ;
- Energy policy;
- Contact information; and
- Link list.

The following charts provide an insight into the system:

- Image of first page after log-in showing user interface;
- Flow of profile data and project data entry; and
- Data format of profile data and project data.

Fig. 7.9 EIPO Investors Log-in interface

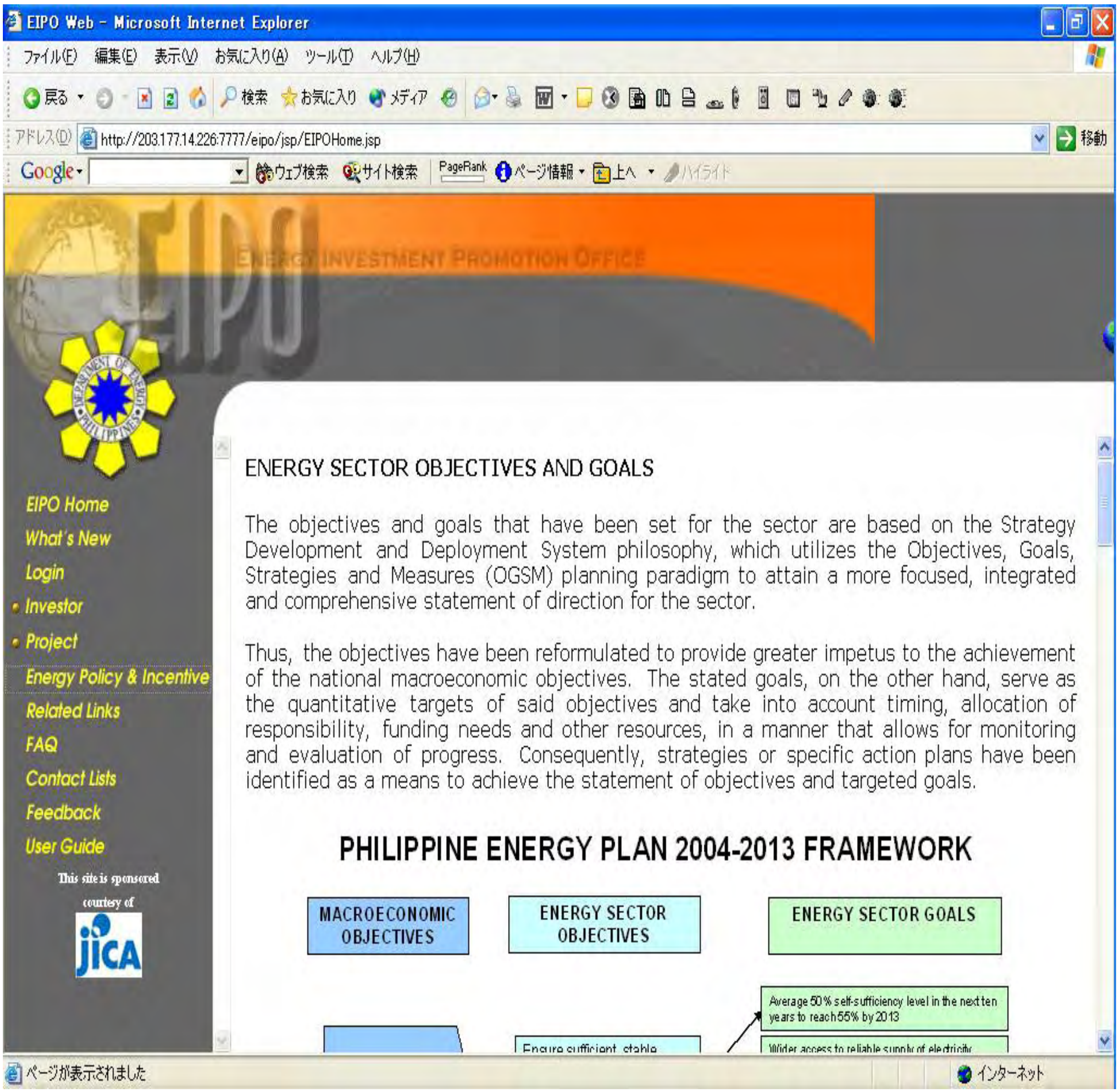


Fig. 7.10 EIPO Registration flow investors' profile

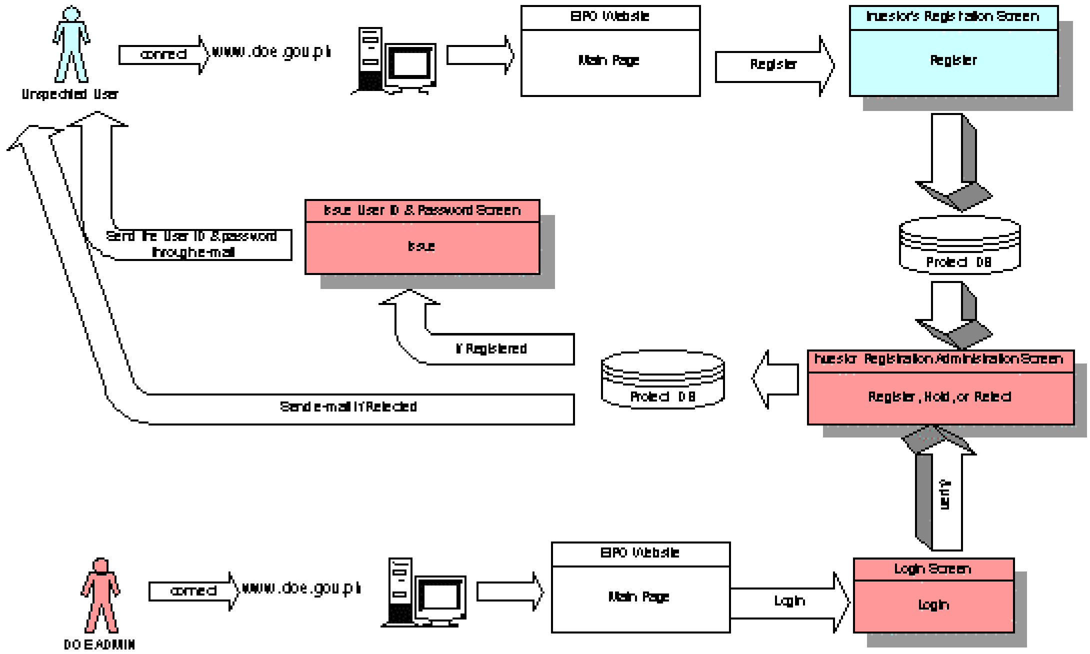
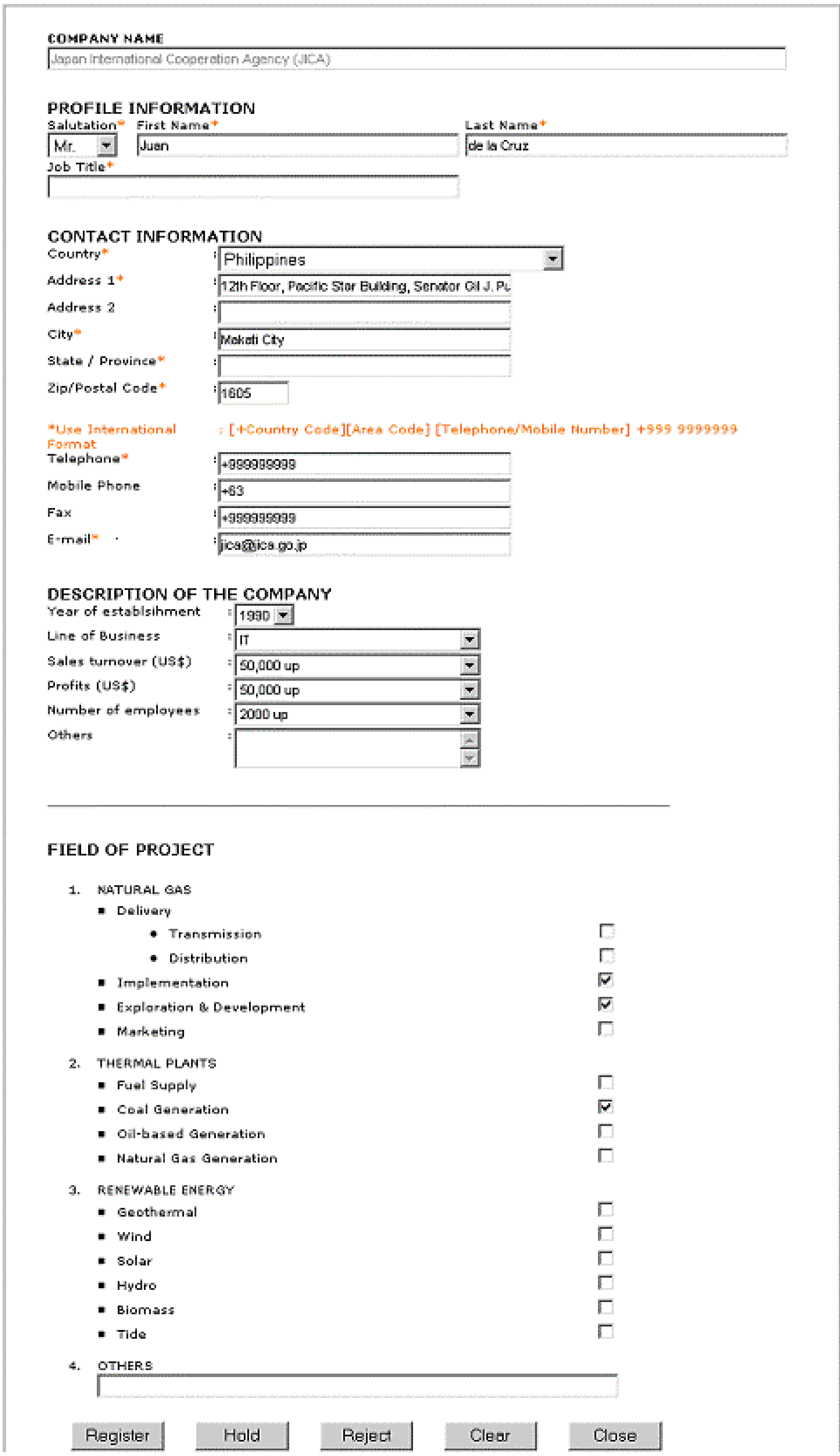


Fig. 7.11 EIPO Data format: Investors' profile



COMPANY NAME

Japan International Cooperation Agency (JICA)

PROFILE INFORMATION

Salutation* Mr.

First Name* Juan

Last Name* de la Cruz

Job Title*

CONTACT INFORMATION

Country* : Philippines

Address 1* : 12th Floor, Pacific Star Building, Senator Gil J. Pu

Address 2 :

City* : Makati City

State / Province* :

Zip/Postal Code* : 1605

*Use International Format : [+Country Code][Area Code] [Telephone/Mobile Number] +999 9999999

Telephone* : +999999999

Mobile Phone : +63

Fax : +999999999

E-mail* : jica@jica.go.jp

DESCRIPTION OF THE COMPANY

Year of establsihment : 1990

Line of Business : IT

Sales turnover (US$) : 50,000 up

Profits (US$) : 50,000 up

Number of employees : 2000 up

Others :

FIELD OF PROJECT

1. NATURAL GAS
   - Delivery
     - Transmission [ ]
     - Distribution [ ]
   - Implementation [x]
   - Exploration & Development [x]
   - Marketing [ ]
2. THERMAL PLANTS
   - Fuel Supply [ ]
   - Coal Generation [x]
   - Oil-based Generation [ ]
   - Natural Gas Generation [ ]
3. RENEWABLE ENERGY
   - Geothermal [ ]
   - Wind [ ]
   - Solar [ ]
   - Hydro [ ]
   - Biomass [ ]
   - Tide [ ]
4. OTHERS

Register | Hold | Reject | Clear | Close

Fig. 7.12 EIPO Registration flow: Project data

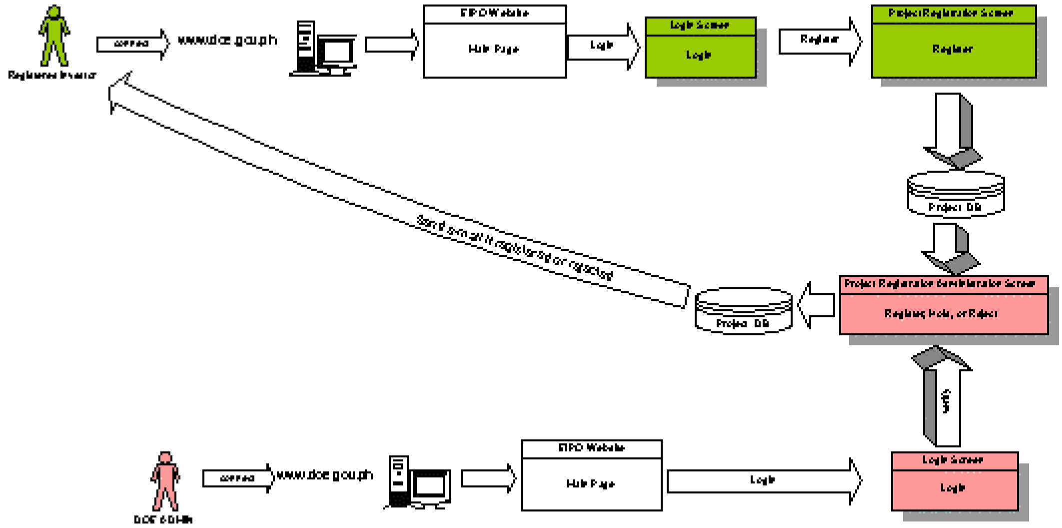
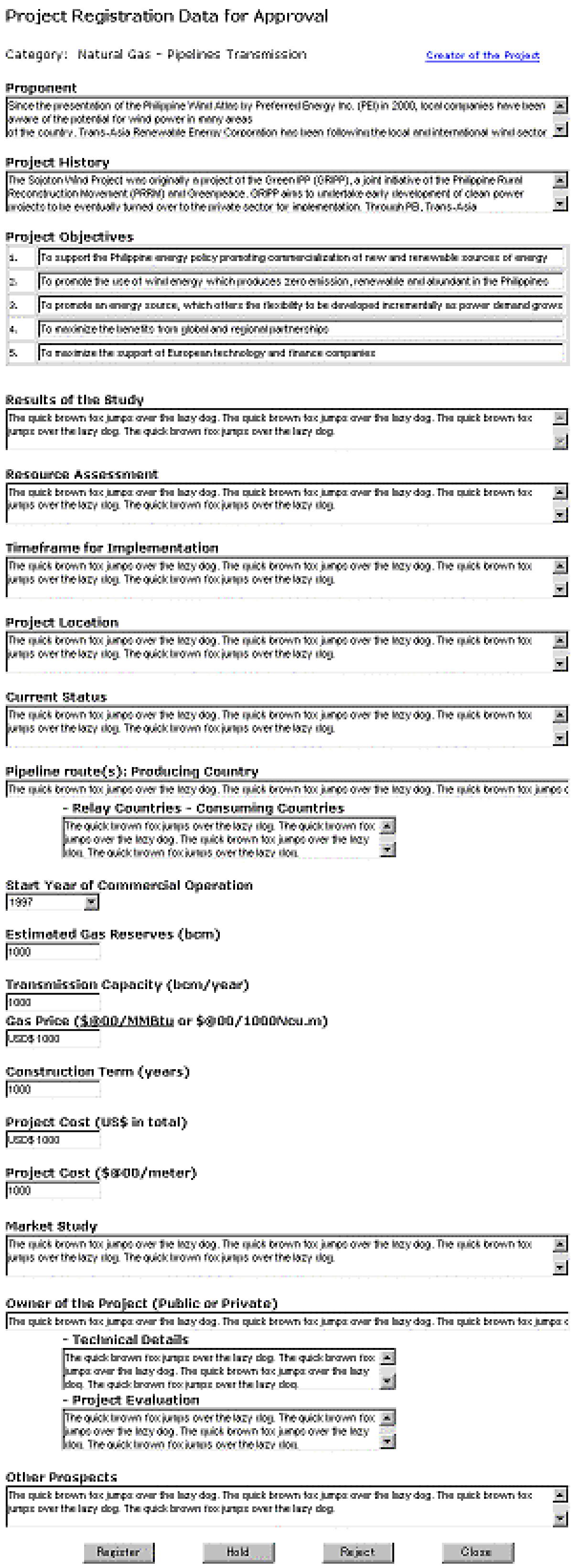


Fig. 7.13 EIPO Data Format: Project Data



Project Registration Data for Approval

Category: Natural Gas - Pipelines Transmission

Creator of the Project

Proponent

Since the presentation of the Philippine Wind Atlas by Preferred Energy Inc. (PEI) in 2000, local companies have been aware of the potential for wind power in many areas
of the country. Trans-Asia Renewable Energy Corporation has been following the local and international wind sector

Project History

The Sojoton Wind Project was originally a project of the Green IPP (GRIPP), a joint initiative of the Philippine Rural Reconstruction Movement (PRRM) and Greenpeace. GRIPP aims to undertake early development of clean power projects to be eventually turned over to the private sector for implementation. Through PEI, Trans-Asia

Project Objectives

1. To support the Philippine energy policy promoting commercialization of new and renewable sources of energy
2. To promote the use of wind energy which produces zero emission, renewable and abundant in the Philippines
3. To promote an energy source, which offers the flexibility to be developed incrementally as power demand grows
4. To maximize the benefits from global and regional partnerships
5. To maximize the support of European technology and finance companies

Results of the Study

The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog.

Resource Assessment

The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog.

Timeframe for Implementation

The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog.

Project Location

The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog.

Current Status

The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog.

Pipeline route(s): Producing Country

The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog. The quick brown fox jumps c

- Relay Countries - Consuming Countries

The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog.

Start Year of Commercial Operation

1997

Estimated Gas Reserves (bcm)

1000

Transmission Capacity (bcm/year)

1000

Gas Price ($@00/MMBtu or $@00/1000Ncu.m)

USD$ 1000

Construction Term (years)

1000

Project Cost (US$ in total)

USD$ 1000

Project Cost ($@00/meter)

1000

Market Study

The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog.

Owner of the Project (Public or Private)

The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog. The quick brown fox jumps c

- Technical Details

The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog.

- Project Evaluation

The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog.

Other Prospects

The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog. The quick brown fox jumps over the lazy dog.

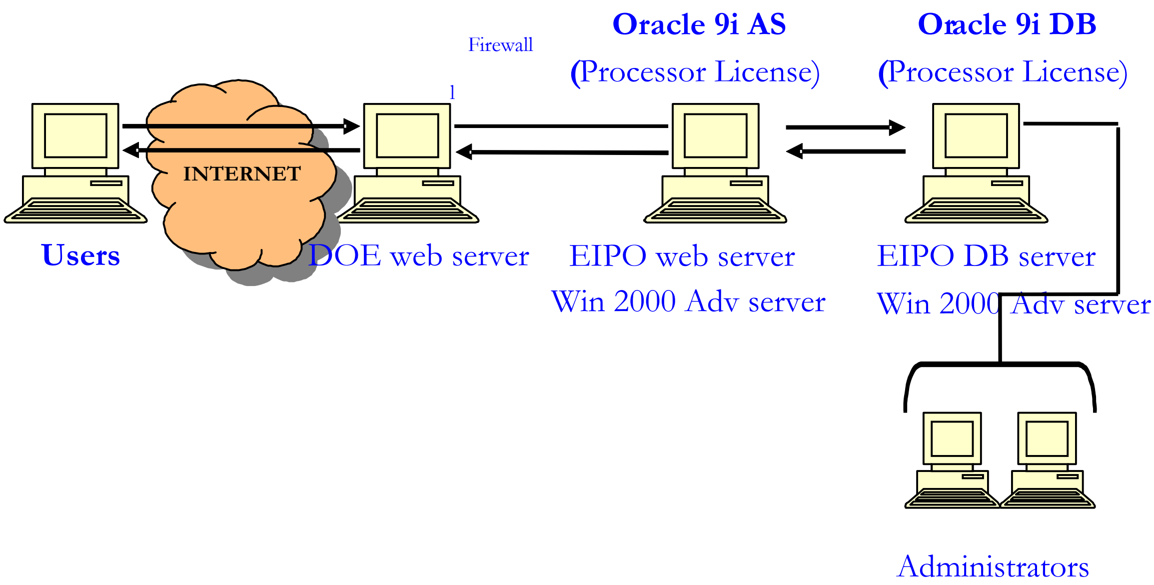
Register | Hold | Reject | Close

7.5.3 System Configuration

- Hardware: Proliant ML370 T03 (HP)
- OS: Windows 2003 Advanced Server
- Database: Oracle 9i (License: Processor License)
- Application Server: Oracle 9i AS (License: Processor License)

The server set-up is as follows:

Fig. 7.14 Server settings



<Appendix 1> Republic Act No. 9136, otherwise known as the "Electric Power Industry Reform Act" (EPIRA)

The measure was signed into law on June 8, 2001, and took effect on June 26 of the same year. It consists of nine chapters as shown below. The law's Implementing Rules and Regulations (IRR) were approved in February 2002.

Chapter 1	Introduction Rationale for the law, Scope and Coverage, Definition of Terms, etc.
Chapter 2	Structure of the Power Industry Division of power industry into generation, transmission and distribution, establishment of TRANSCO and WESM and other topics are covered to streamline the power sector structure under EPIRA.
Chapter 3	Role of the Department of Energy (DOE) Outlines the role of DOE, such as the formulation of PDP and investment promotion policy.
Chapter 4	Oversight Over the Electric Power Industry Specifies the function, authority and organization of the Energy Regulatory Commission (ERC) and sets the basic guidelines for setting power rates
Chapter 5	Privatization of NPC Assets Specifies the basic policy on the privatization of NPC assets.
Chapter 6	Structure of the Power Sector Assets and Liabilities Management (PSALM) Corporation The functions, responsibilities, and organization of PSALM, a special purpose company to sell assets of NPC, to exist for a period of 25 years, are stipulated.
Chapter 7	Promotion of Rural Electrification This Chapter prescribes the role of National Electrification Administration (NEA) and assumption of debts of Electric Cooperatives.
Chapter 8	General Provisions
Chapter 9	Final Provisions

<Appendix 2> Basic Philippine Framework on Foreign Investments

(1) Qualifications for Investments

As a general rule, the Philippine government welcomes investments from all countries and in almost all fields of economic activity. One hundred percent-owned foreign companies are also allowed to invest but certain economic activities are limited to Filipinos. The list of economic activities reserved for Filipino investors is updated and published annually by the BOI. The list is known as the Foreign Investment Negative List.

(2) Types of Investment

Executive Order No. 226 (otherwise known as the *Omnibus Investments Code*) lists the types of investments and corresponding incentives package. Promulgated on July 16, 1987, the order was subsequently amended by Republic Act Nos. 7042, 7888, 7916, 7918, 8179, 8748, and 8756.

Executive Order 226, as amended, categorized the types of investment and incentives as followed:

Executive Order No. 226	Categories of Investment and Incentives
Book I	Investment with incentives (Preferred areas of Investment)
Book II	Foreign Investment without Incentives (repealed by Republic Act No. 7042 (or the Foreign Investments Act of 1991, as amended by Republic Act 8179).
Book III	Amended by Republic Act 8756 – provides incentives to multinational companies establishing regional operating headquarters in the Philippines
Book IV	Amended by Republic Act 8756
Book V	Special Investors Resident Visa（SIRV）
Book VI	Incentives for companies locating in export processing zones – amended by Republic Act 7916 as amended by Republic Act 8748.

Source: Website of the Embassy of the Philippines in Japan

(3) Form of Investment

Investments under E.O. 226 as amended may take two forms. These are:

a. Equity investments in the form of foreign exchange; or
b. Equity investments in the form of other assets (capital equipment, patents, formula, plans, and technology, among others).

In both instances, the transfer of equity should be registered with the central bank and the BOI, which shall appraise the value of the assets other than foreign exchange.

(4) Incentive Available

According to Book I of the code, investors may avail of incentives if they invest in a particular activity listed in the annual Investment Priorities Plan (IPP). The IPP, which is drawn up annually by the BOI in consultation with various government agencies and the private sector, enumerates the economic activities that the government wants foreign investors to invest in.

An activity not listed in the IPP may however still be eligible for incentives if it satisfies the following conditions:

At least 50% of production is for export, if a Filipino-owned business; and
At least 70% of production is for export, if a majority foreign-owned business.[4]

However, even if a particular economic activity is included in the IPP, the BOI may partly or fully withhold the incentives.

(5) Salient Points on Incentives Under E.O. 226, as amended

1) Exemption from Income Tax (Income Tax Holiday)

Investment classified as "pioneer" – 6 years from start of operation;
Investment classified as "non-pioneer" – 4 years from start of operation;
Expansion project – 3 years' exemption, based on incremental sales/volume;
New or expansion projects in areas classified as "less developed" – 6 years;
Modernization projects – 3 years' exemption, based on incremental sales/volume.

On the other hand, exporters may be entitled to the ITH only on their income obtained from the following activities:

Export of new products (i. e., those which have not been exported in excess of US $ 100,000 in any of the two years preceding the filing of the application for registration; and

[4]A business is considered foreign-owned if 40% or more of its equity is owned by non-Filipinos.

Exports to new markets (i. e., to a country where there has bee no recorded import of a specific export product in any of the two years preceding the filing of the application for registration.

Newly registered pioneer and non-pioneer enterprises and those located in areas classified as "less developed" may avail themselves of an additional year for ITH in each of the following cases:

a. The indigenous raw materials used in the manufacture of the registered product must at least be 50% of the total cost of raw materials for the preceding years prior to the extension, unless the BOI Board prescribes a higher percentage; or

b. The ratio of total imported and domestic capital equipment to the number of workers for the project does not exceed US $ 1,000 to 1 worker; or

c. The net foreign exchange savings or earnings amount to at least US $ 500,000 annually during the first 3 years of operation.

* Criteria for Availing of Pioneer Status

Under E.O. 226, as amended, pioneer activities may be owned one hundred percent by foreign nationals, subject to limitations imposed either by the Philippine Constitution and/or by law. These foreign investments may avail of incentives and qualify for "Pioneer" status if the investment:

a. Will engage in the manufacture, processing, or production and not merely in the assembly or packaging of goods, products, commodities, or raw materials that have not bee nor not being produced in the Philippines on a commercial scale; or
b. Will use a design, formula, scheme, method, process, or system of production or transformation of any element, substance or raw material into another raw material or finished goods, which are new and untried in the Philippines; or
c. Will engage in the pursuit of agricultural, forestry and mining activities and/or services, including the industrial aspects of food processing whenever appropriate, predetermined by the BOI in consultation with the concerned department, to be feasible and highly essential to the attainment of the national goals, in relation to a declared specific national food and agricultural food and agricultural program for self-sufficiency and other social benefits of the project; or
d. Will produce non-conventional fuels or manufacture equipment which utilizes non-conventional sources of energy; or use or convert or other non-conventional fuels/sources of energy in their production, manufacturing, or processing operations.

In any of the foregoing circumstances, the final product should involve or will involve, substantial use and processing of domestic raw materials, whenever available, taking into account the risks and magnitude of investments.

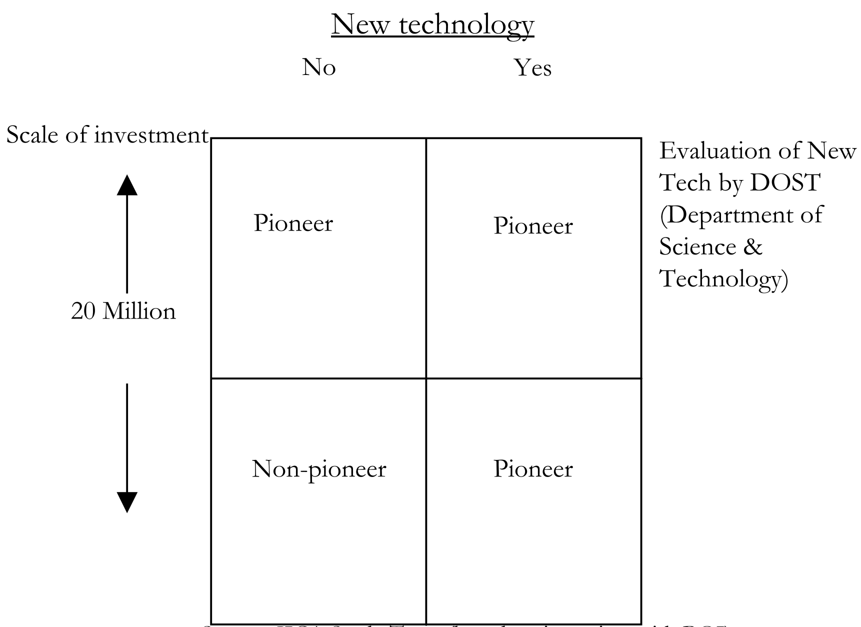
Activities with pioneer status are required to become majority Filipino-owned (or have equity of 60% owned by Filipinos) within 30 years or such longer period as the BOI may determine. However, export enterprises whose products are 100% geared for exports, are exempted from this requirement.

As far as emerging technology is concerned, the type of technology is subject to evaluation by the Department of Science and Technology (DOST).

DOST's evaluation hinges on the project's innovation, production efficiency and innovation. The guidelines however are quite general, and do not include criteria applicable to the power sector.

Moreover, as far as the power sector is concerned, no investment has been made for the past 2 years, according to DOST. Thus, it is difficult to determine whether technology specific to the power sector would qualify for pioneer status using these criteria.

Fig. 7.15 Qualification for BOI Pioneer Status



Source : JICA Study Team (based on interview with BOI)

2) Rules Governing the Extension of ITH Incentives

Under the executive order, investments classified as "non-pioneer" will enjoy an ITH incentive for 4 years, while investments classified as "pioneer" will enjoy an ITH incentive for 6 years.

The BOI may extend the ITH for a year if at least one of the following conditions is met:

a. The indigenous raw materials used in the manufacture of the registered product must at least be 50% of the total cost of raw materials for the preceding years prior to the extension, unless the BOI Board prescribes a higher percentage; or

b. The ratio of total imported and domestic capital equipment to the number of workers for the project does not exceed US $ 1,000 to 1 worker; or

c. The net foreign exchange savings or earnings amount to at least US $ 500,000 annually during the first 3 years of operation.

3) Other Income Tax-Related Incentives

Additional Deductions from Taxable Income

The code also allows the following incentives:

a. The ratio—as prescribed by BOI—of workers and amount of invested capital is satisfied for the first 5 years from the time of registration with BOI – Additional deduction from taxable income equivalent to 50% of the taxable income of workers.
b. Projects located in areas classified by BOI as "less developed" – The additional deduction rate as described in (a) is increased from 50% to 100%.
c. Project in areas classified as "less developed" and in areas that are deficient in infrastructure (except mining and forestry-related projects) – The cost of constructing the infrastructure may be deducted from the taxable income.

4) Import Duty

The code allows import duty exemption to apply to the following activities:

a. Duty-free import of spare parts for a registered enterprise with a bonded warehouse;
b. Exemption from wharfage dues and export tax, impost and fees for 10 years for all enterprises registered under the IPP;
c. Exemption from all taxes and duties on importation of breeding stocks and genetic materials within 10 years from the date of registration or commercial operation; and
d. Tax Credits

   Tax Credit on Tax and Duty Portion of Domestic Breeding Stocks and Genetic Materials – For agricultural producers, a tax credit equivalent to 100% of the value of the national internal revenue taxes and customs duties on local breeding stocks within 10 years from the date of registration or commercial operation.

   Tax Credit on Raw Materials and Supplies – For a registered enterprise, a tax credit on the national internal revenue taxes and duties paid on raw materials, supplies, and semi-manufacture of export products and forming parts thereof.

5) Others

The Philippine Economic Zone Authority (PEZA) grants more favorable incentives than BOI. For the power sector, the following incentives—as offered by PEZA—may be considered more attractive:

a. Exemption from income taxes of up to 8 years;
b. Special preferential tax of 5% after the expiration of the original income tax exemption period;
c. Exemption from customs duties on the importation of capital equipment, spare parts, raw materials, wharfage, export duties, and handling charges, among others.
d. Deduction of taxes paid for capital equipment procured locally;
e. Additional deduction for incremental wages; and
f. Additional deduction for employee training cost.

Incentives Offered by Subic Bay Metropolitan Authority (SBMA) and Clark Development Corporation (CDC)

Aside from the incentives package offered by PEZA, SBMA, and CDC also offer the following incentives:

a. 5% income tax from the initial fiscal year;
b. Others are the same as the measures offered by Philippine Economic Zone Authority; and
c. Exemption of income tax (must be registered with BOI).

<Appendix 3> Problems Encountered by Independent Power Producers (IPPs) Operating in the Philippines

The price of electricity has always been a major social issue in the Philippines. But this issue became more prominent recently when a dispute erupted between the Visayan Electric Company (Veco)—a distribution utility in Cebu—and the Cebu Private Power Corporation (CPPC), an IPP.

Philippine media outfits reported that due to the breakdown of negotiations on June 15, 2003 over its power price to Veco, CPPC would not supply power to Veco by July 25, 2003.

The dispute centered on CPPC's power price to Veco, which is pegged at 98% of NPC's power price to Veco. However, with the activation of the Purchased Power Cost Adjustment (PPCA) mechanism on May 2002, the price of power became cheaper by P 0.40 per kWh. The PPCA is pegged to NPC's purchase price of power from its IPPs.

As a result of the PPCA, CPPC's power price to Veco dropped, adversely affecting CPPC's financial performance.

Since CPPC supplies 23% of the 62 MW that Veco distributes to end-users, power supply in central Cebu would drop to the critical level of 20MW, leading Cebu media outfits to predict power outages.

It should be noted that after Metro Manila, Cebu has been quickly developing as the second most favorable location for call centers. Investments in call centers in Cebu have been increasing at a steady rate. Thus, uncertainty in power supply would adversely affect call centers—which need electricity on a 24-hour basis—located in Cebu. As a result, trade associations such as the Call Center Federation, government agencies such as the Cebu Investment Center, as well as other business groups, urged the government to undertake measures to resolve the looming power crisis brought about by the CPPC-Veco dispute.

In response, the ERC ordered NPC to immediately charge a lower rate of P 2.2412 per kWh with the GRAM as basis. The new rate, which was already determined on May 15, 2003 (a month before the dispute occurred), was higher than the old rate by P 0.16 per kWh. Since NPC considered this particular rate increase as insufficient, it did not apply the new rate—even in June. Hence, CPPC did not benefit from the ERC-sanctioned rate.

In a bid to avert a power shortage, ERC, NPC, and CPPC officials met on July 24 (a day before the scheduled shut down of CPPC's services to Veco), and were able to arrive at a compromise.

The CPPC-Veco dispute has highlighted the following issues:

1. NPC's selling price to distribution companies is quite cheap. Thus, IPPs are unable to charge the true cost of electricity if their selling price to distribution utilities is linked to NPC's selling price.
2. The cost of fuel and the foreign exchange fluctuation risk had been previously passed on by the DUs to the end-users. The implementation of GRAM effectively made the DUs absorb these costs—resulting in disputes and confusion between the IPPs and the DUs.

<Appendix 4> Structures of the Thai, Indonesian, and Vietnamese Power Sectors

(1) The Thai Model

The generation, transmission, and distribution sub-sectors of the Thai power sector have been progressively liberalized.

With the Electricity Generating Authority of Thailand (EGAT) suffering from perennial budget deficits as a result of foreign currency-dominated loans, the National Energy Policy Office (NEPO) began formulating the master plan to liberalize the Thai energy sector. NEPO released the master plan in August 1998.

The plan provides for the privatization of state-owned energy companies such as EGAT (power generation and distribution); 2 distribution utilities, namely the Metropolitan Electricity Authority or MEA and the Provincial Electricity Authority or PEA; and the state oil company, Petroleum Authority of Thailand or PTT.

The plan also mandated the separation of EGAT's generation and transmission functions, with the end in view of restructuring the power sector through the establishment of a market pool for electricity.

However, as of August 2003, the reform and restructuring of the power sector has been facing some delays, with some quarters recommending the postponement of the establishment of the market pool to 2007.

Fig. 7.16 Current power sector structure in Thailand

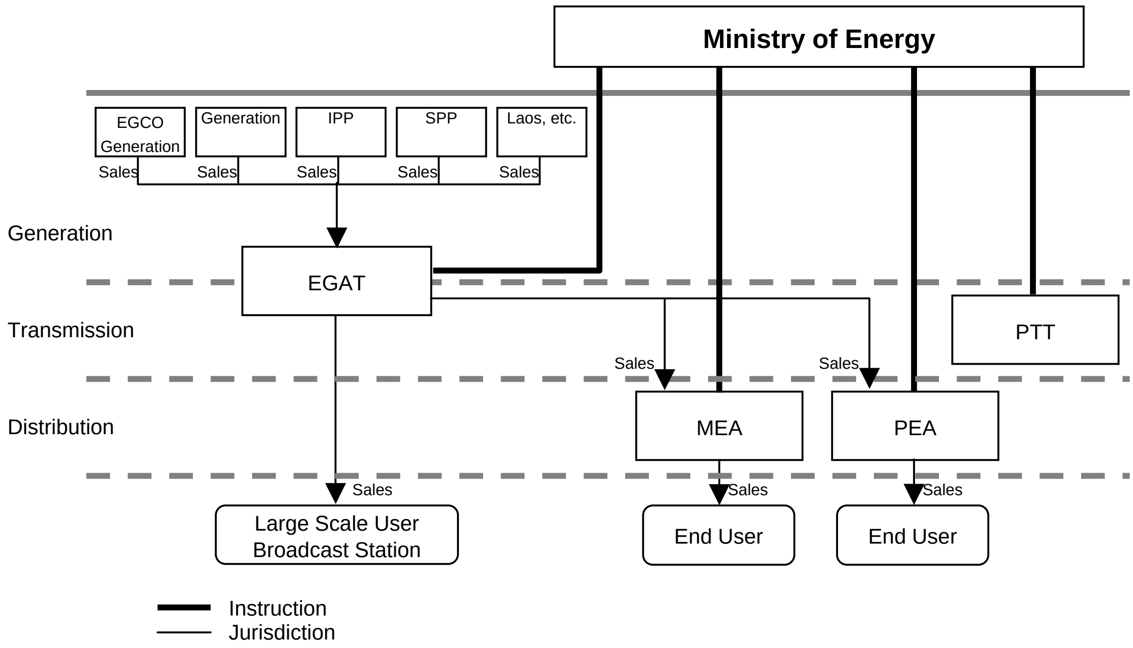
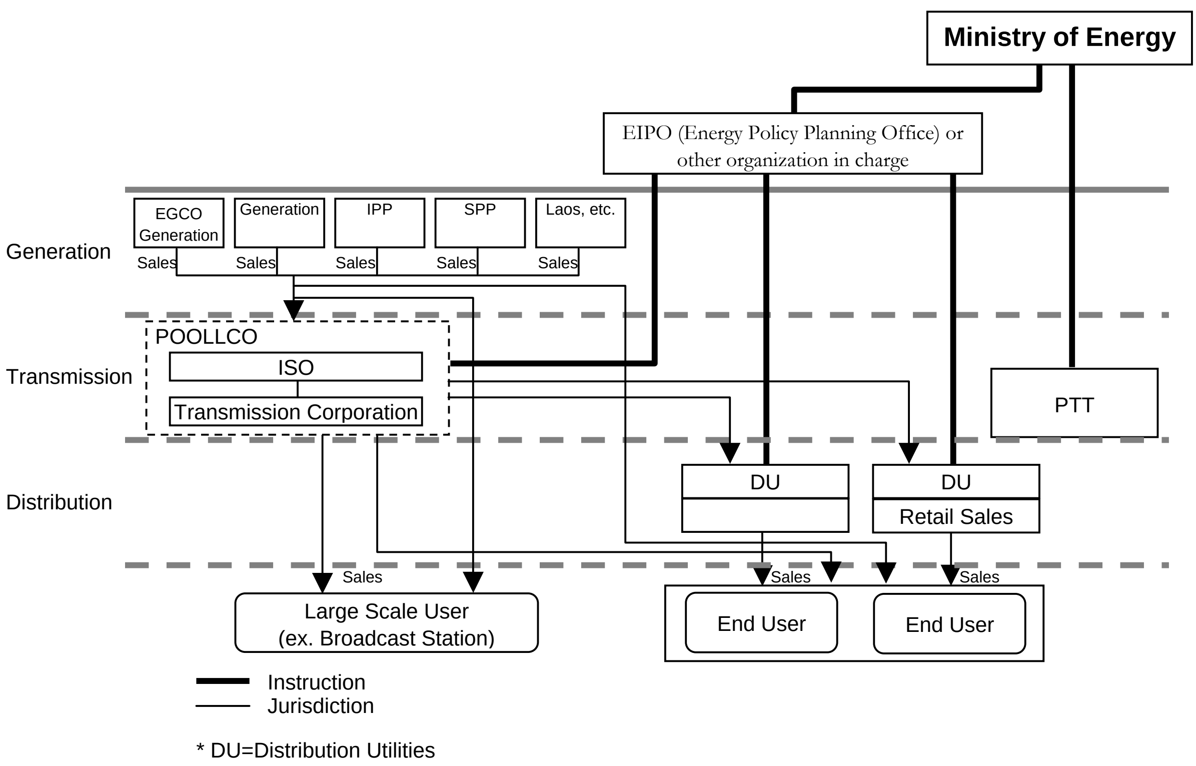


Fig. 7.17 Power sector structure in Thailand after restructuring



(2) The Indonesian Model

Indonesia is currently restructuring its power sector. The enabling legislation was enacted on September 4, 2002, after four years of deliberation. Specifically, the law mandates: (1) the complete liberalization of power generation, introduction of retail competition in designated areas, and the abolition of the vertical monopoly previously enjoyed by the state-owned National Electricity Corporation (PLN); (2) the continued management by PLN of the power transmission and distribution system, with the rates to be determined by the Electric Power Supervising Committee; and (3) the establishment of the Electric Power System Manager and the electric Power Market Manager.

The law also provides that a year after its passage, the government should establish the Electric Power Market Supervising Committee. The committee is mandated to promote a competitive playing field. The law further requires the committee to identify areas or locations where competition will be gradually introduced over a staggered period of 5 years.

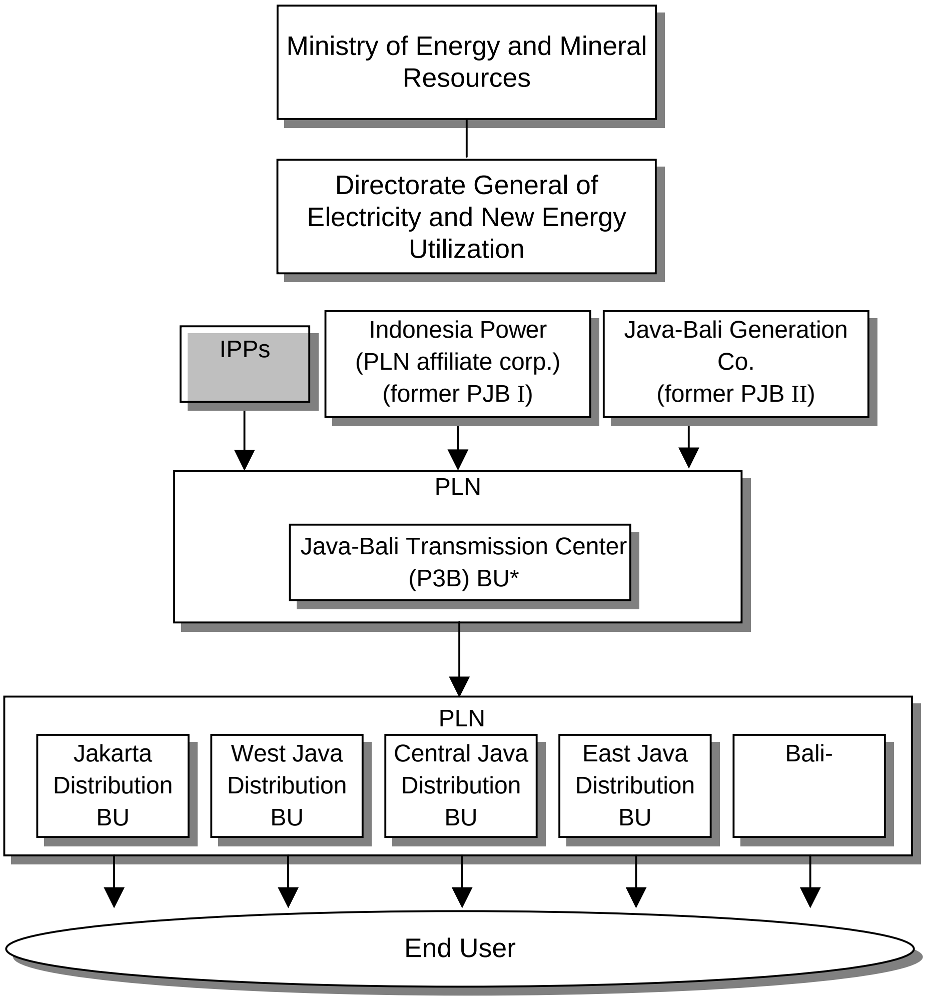
The geographic breakup of PLN is envisioned to provide further momentum for the restructuring of the power sector. However, the pace of transition to a truly competitive environment may vary depending on the geographic cluster or area.

Under the government's timetable, restructuring will first commence with the Java and Bali systems, since these areas are—compared to other areas in Indonesia—characterized by mostly integrated transmission systems and power plants with huge nameplate capacities. Early restructuring of the Batam system is also contemplated in the initial phase of the power industry's liberalization.

To ensure competition, the Electricity Market Supervisory Agency (EMSA) will be established, and will be independent of the government.

The following diagrams show the current and future structures of the Java and Bali systems.

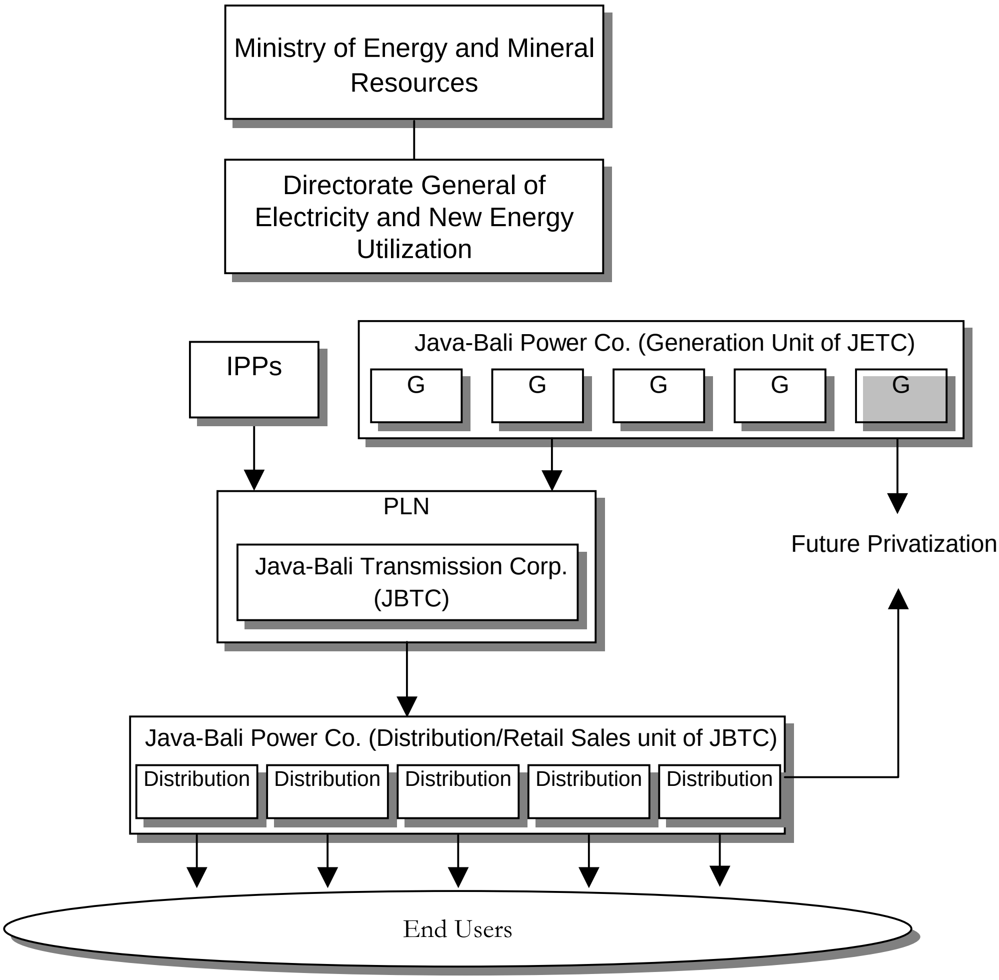
Fig. 7.18 Current Power sector structure in Indonesia



*BU＝Business Unit

Source: PLN, etc.

Fig. 7.19 Power sector structure in Indonesia after restructuring



Source: PLN, etc.

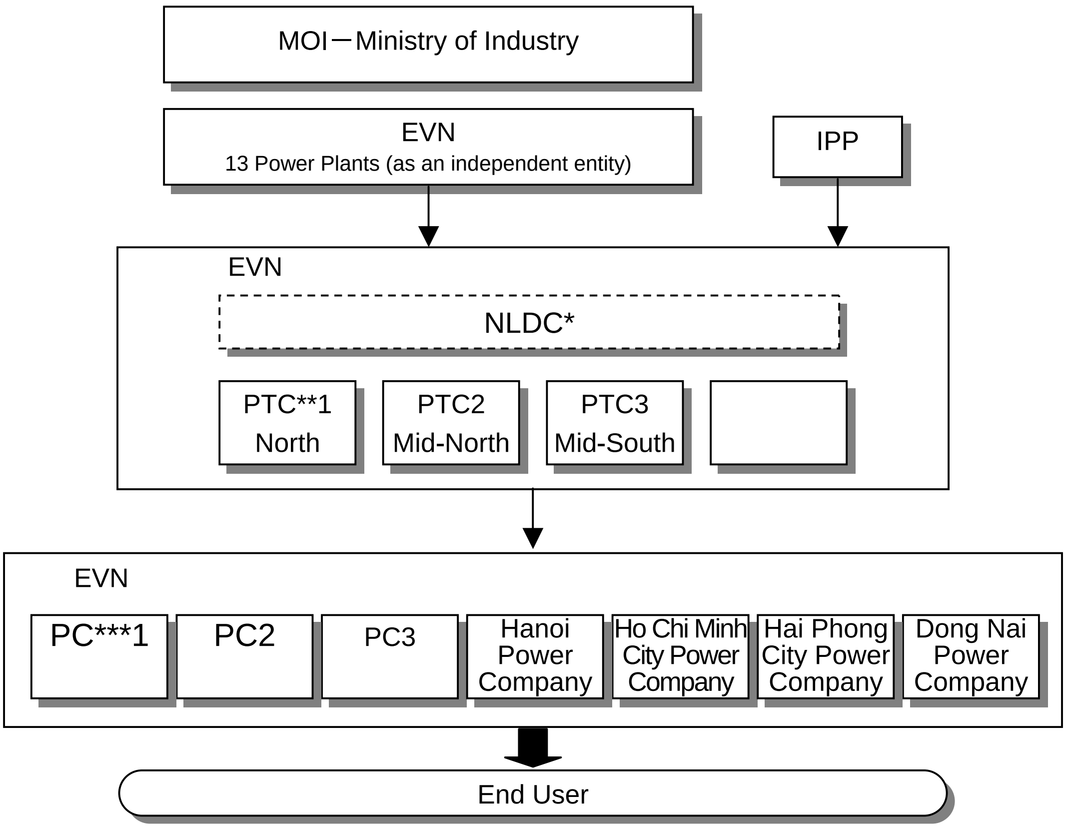
(3) The Vietnamese Model

Electricity of Vietnam (EVN) is the state-owned company charged with generation and transmission functions in the Vietnamese power industry.

An agency under the jurisdiction of the Ministry of Industry, EVN sells electricity to 7 DUs throughout the country. Thus, it is a vertically integrated company.

The Vietnamese government has already declared its intention to restructure its power industry but has yet to provide specific details on this policy.

Fig. 7.20 Current structure of the power sector in Vietnam



* National Load Dispatching Center
** Power Transmission Company
*** Power Company

<Appendix 5> Investments Promotion in the Thai, Indonesian, and Vietnamese Power Sectors

(1) Thailand

To assure open access to the industry players, EGAT will continue to promote investments in the power sector. Thus, foreign investments will be limited to the generation side through IPPs.

Investment incentives in Thailand depend on the location of the investment, since the government has divided the country into 3 geographic areas—Zones 1 to 3.

The incentives however are most attractive in Zone 3. Investments in this area are entitled to an ITH of 8 years, and a 50% reduction in income tax for the next 5 years.

Notwithstanding the government policy to locate investments by geography, investments classified as belonging to the "Priority Sector" would qualify for the most liberal incentive package—which is Zone 3—regardless of the location of the investment.

The areas and the respective incentive packages are shown in the table below.

Investment Promotion Zones

Zone 1	(Bangkok and 5 provinces) – Bangkok, Samut Prakan, Samut Sakhon, Nakhon Pathom, Nonhtaburi and Pathum Thani
Zone 2	Ang Thong, Ayutthaya, Chachoengsao, Chon Buri, Kanchanaburi, Nakhon Nayok, Phuket, Ratchaburi, Rayong, Samut Songkhram, Saraburi, and Suphanburi (12 provinces)
Zone 3	remaining 58 provinces

Investment Incentives

Incentives	Zone 1	Zone 2	Zone 3
Exemption of Corporate income tax	Corporate income tax exemption for 3 years for projects located within industrial estates or promoted industrial zones,	Corporate income tax exemption for 3 years, increased to 5 years for projects located within industrial estates or promoted industrial zones	1. Corporate income tax exemption for 8 years; Plus 50 per cent reduction of corporate income tax for 5 years after the exemption period; 2. Double deduction from taxable income of transportation, electricity and water costs for 10 years from the date of first revenue derived from promoted activity 3. Deduction can be made from net profit of 25 per

Incentives	Zone 1	Zone 2	Zone 3
			cent of the project's infrastructure installation or construction cost for 10 years
Exemption of Import duty on machinery	50 per cent reduction of import duty on machinery that is subject to import duty of not less than 10 per cent	50 per cent reduction of import duty on machinery that is subject to import duty of not less than 10 per cent	Exemption of import duty on machinery
Import duty on raw or essential materials	Exemption of import duty on raw or essential materials used in the manufacturing of export products for 1 year.	Exemption of import duty on raw or essential materials used in the manufacturing of export products for 1 year	Exemption of import duty exemption on raw or essential materials used in the manufacturing of export products for 5 years

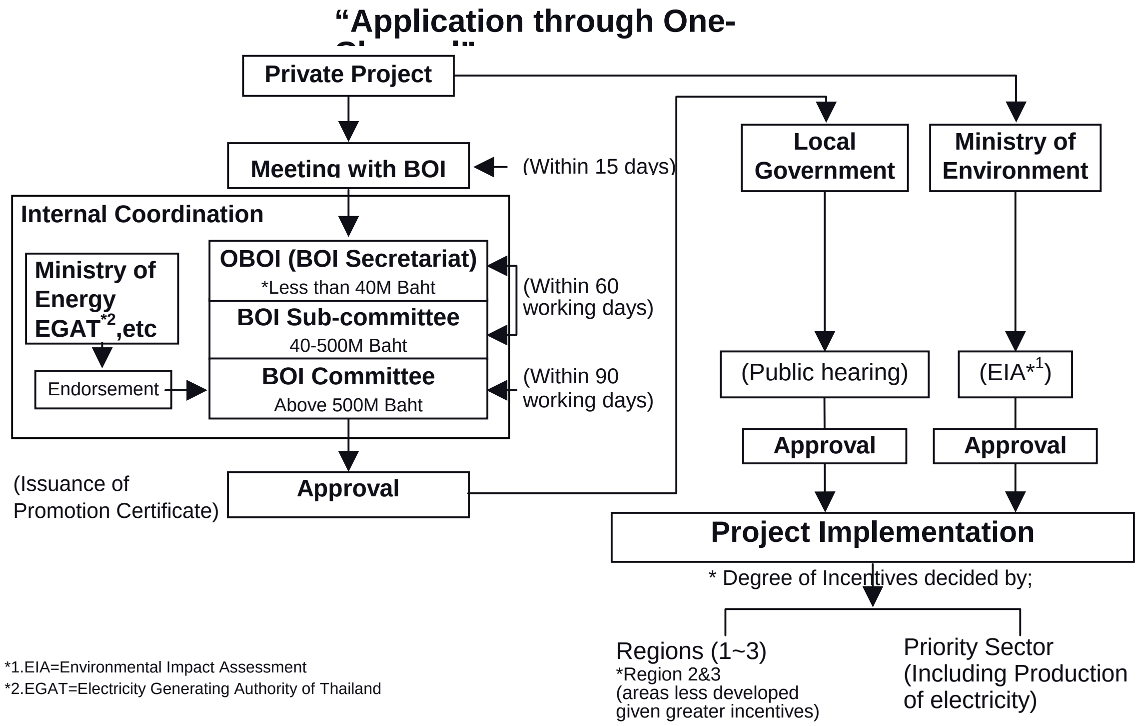
Source: Thailand Board of Investment (BOI)

(Other investment incentives in the Thai power sector are described in comparison with those of the Philippines in Paragraph 7.1.1 (4), "Incentives for Investment in Power Sector.")

Thailand's Board of Investment (BOI) is the sole agency that grants investment incentives. It also coordinates with other government agencies that issue licenses and permits.

The following diagram shows the procedure in applying for investment incentives in the Thai power sector.

Fig. 7.21 Procedure for Availing of Incentives from Thailand's BOI



Source: JICA Study Team

<Other Agencies Involved in Availing of Investment Incentives in the Thai Power Sector>

a. Ministry of Energy –
b. National Energy Policy Office (NEPO) – formulates policies on energy sources; and
c. Electricity Generating Authority of Thailand (EGAT) – determines ratios of IPPs, demand, etc.

The processing and approval of incentives for investments in excess of 500 million Baht take 90 days while processing and approval of investments of up to 500 million Baht take 60 days.

While the processing and approval for incentives in Thailand take longer compared to the Philippines, it is the Thai BOI and not the investor that coordinates with the other agencies (NEPO, EGAT) to seek the these government agencies' evaluation, assessment, and approval for the investment.

This, given that prior to applying for the incentives, the investor should have already coordinated with the Thai energy agencies.

Upon submission of the application, the project's feasibility study and the power purchase agreement with EGAT are required attachments.

To evaluate investments less than 500 million Baht, the BOI secretariat meets once a week while members of the BOI board meet once a month to evaluate investments greater than 500 million Baht.

Once the application has cleared BOI, it goes to the Cabinet, which grants final approval.

On the other hand, the project's Environmental Impact Assessment (EIA) may be submitted before or after the application for investment, but the EIA must have been approved once implementation of the project commences. The Office of Environmental Policy and Planning needs 30 days to conduct a preliminary assessment of the project, followed by an evaluation by another panel—which takes at least another 45 days. However, depending on the magnitude of the project's impact on the environment, the 45-day evaluation may even be longer.

Once the Promotion Certificate is issued by BOI, the project undergoes another series of approvals, this time for construction, environmental impact (if not yet secured), local government acceptability, and construction permits (also from the local government).

The local government units usually conduct public hearings on the project, and require the proponent to be present therein.

In case of substantial and vehement opposition to the project, the local government is likely to deny a permit for the project. The proponent is therefore left with no other choice but to scuttle the project.

Should the local government refuse to grant a permit, the Thai government or its agencies will not intervene in the proponent's behalf.

Therefore, the issuance of the Promotion Certificate does not constitute a blanket approval—there would still be various approvals that will need to be secured.

(2) Indonesia

IPP investments promotion in Indonesia began in 1992.

Currently, however, IPPs are required to renegotiate the renewal of their respective power purchase agreements with the National Electricity Corporation (PLN), which is in dire financial straits. By June 2003, PLN succeeded in renegotiating the power purchase agreements of 27 IPPs, resulting in a reduction of power purchase costs by more than US $ 5 billion.

The second stage of promoting IPP investments is expected to begin soon. This time, however, the Indonesian government declared that it will only enter into power purchase agreements with "solicited IPPs," or IPP projects planned with the approval of the Indonesian government.

Thus, before an IPP can actually secure approval to enter the Indonesian power sector, it will need to consider the master plan prepared by PLN. The master plan specifies the location, size, fuel type, and start-up date of the power plant. PLN will then invite interested IPPs to invest in the power sector in accordance with the master plan.

However, with the devolution of powers to Indonesian LGUs (particularly the provincial governments), some IPPs have instead opted to negotiate directly with the LGUs. Some IPPs, on the other hand, chose to negotiate and contract with PLN.

This situation has bred confusion, with the IPPs left in the dark as to which agency to approach—the LGU or PLN. Likewise, with the lack of coordination on the implementation of investment policies among the LGUs, the Ministry of Energy and Mineral Resources, and PLN, difficulties have arisen in promoting investments in the Indonesian power sector.

Compared to the Philippines, therefore, the investment climate in Indonesia is no better. Aside from the confusion mentioned earlier, the Indonesian investment framework is archaic.

The Foreign Investment Act of 1976 (revised in 1970) and the Domestic Investment Act of 1968 (revised in 1970) are the laws that provide incentives.

Another problem is that possible investment opportunities have not been actively promoted.

To complicate matters, new foreign investments in Indonesia dropped sharply after the 1997 Asian economic crisis. The investment climate fell to an all-time low with the Bali bombing in October 2002 and the terrorist attacks that immediately followed, prompting foreign investors to pull out of Indonesia.

As a consequence, Indonesian President Megawati Sukarno-Putri declared 2003 as the Year of Investment to demonstrate her administration's resolve to improve the country's foreign investment climate.

The presidential declaration has compelled the Investment Coordinating Board (BKPM) to work with the Indonesian parliament to enact the New Investment Act. The measure provides for the Investment Advisory Committee to reinforce the strategic orientation-setting function of the investment department. The measure likewise mandates the streamlining of procedures for applications for investment incentives by introducing the "One-Stop Shop" concept.

No incentives specific to foreign investment are, however, available in Indonesia. Incentives are given, regardless of nationality, to investors with bonded warehouses (KB), Integrated Economic Development Zones (KAPET), and less-developed eastern Indonesia (KTI).

The table below lists the incentives available in Indonesia. (Please refer also to Section 7.1.1 (4) of this chapter, for specific investments in the Indonesian power sector, which are compared to Philippine incentives.)

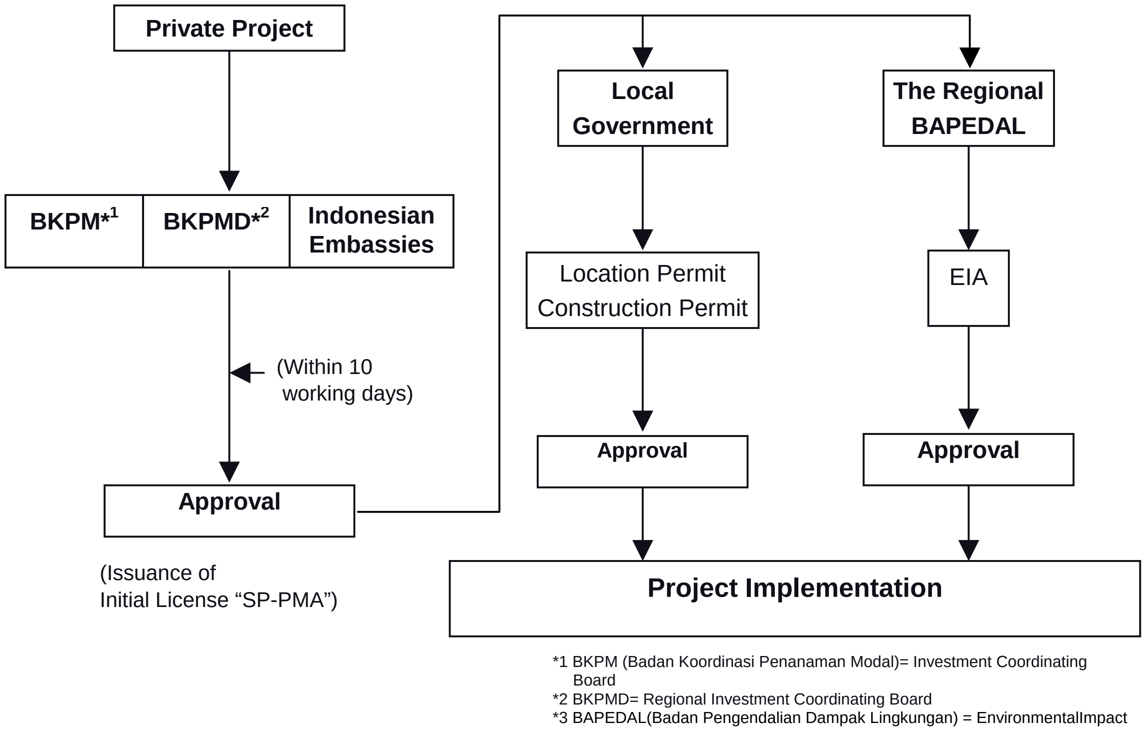
Table 7.7 Major Investment Incentives in Indonesia

General Provisions	Incentives for Industries with Bonded Warehouses Kawasan Berikat (KB)	Incentives for Industries located in Integrated Economic Development Zone Kawasan Pengembangan Ekonomi Terpadu (KAPET)
Relief from import duty so that the final tariffs become 5 %. In the case of tariffs of import duty which are mentioned in the Indonesian Customs Tariff Book (BTBMI) being 5% or lower, the effective tariffs shall be those in BTBMI a) On the importation of capital goods namely machinery, equipments, spare parts and auxiliary equipments for an import period of 2 years, starting from the date of stipulation of decisions on import duty relief. b) On the importation of goods and materials or raw materials regardless of their types and composition, which are used as materials or components to produce finished goods for the purpose of two years full production (accumulated production time).	a. Exemption from import duty, excise tax, and income tax under Article 22, Value Added Tax on Luxury Goods, the importation of capital goods and equipment including raw materials for the production process. b. Exemption of Value Added Tax and Sales Tax on Luxury Goods on the delivery of products for further processing from bonded zones to their subcontractors outside the bonded zones or the other way around as well as among companies in these areas. c. Refund of custom and import surcharge when business approved by BINTEK (a department under the Ministry of Finance, in charge of refund of customs duties) sells the materials to business inside KB d. Reservation of customs, import surcharge, VAT, luxury tax related to the goods transfer between KB and outside, rental of machinery, equipment	1. Exempted from the net income within 30% of total investment 2. Right to choose Accelerated depreciation / abbreviation k\in the computation/amortization of income tax 3. Maximum and consecutive 10 years of balance of deficit from next year of taxable year 4. Non-resident Less than 10% of income tax rate on the dividend on stock 5. Exemption of tax (provided in Article 22 of the Income Tax Law) Import of capital goods/raw materials and other equipment directly related to the manufacturing activities 6. Appropriation of the act which won't be accounted as income, such as payment in-kind to employee 7. Exemption of VAT, luxury tax under certain conditions (capital goods related to manufacturing, domestic import of other equipment, import of tax-free goods for the purpose of manufacturing and transfer of goods within the parties concerned.)

Source: BKPM-JICA Publication [Investment guide to Indonesia]

The investment approval process in Indonesia is shown in the figure below.

Fig. 7.22 Investment procedure in Indonesia



Source: JICA Study Team

In 1999, applications for incentives for foreign investments began to be accepted in Indonesian embassies and in the Regional Coordinating Boards (BKPMD). This move was taken by the government to attract more foreign investment.

As was stated earlier, the Indonesian government recently began to broaden the autonomy of LGUs. As part of the devolution process, the BKPM has, in coordination with the provincial Investment Boards (IPMP) and the regional/municipal Investment Boards (IPMK), drawn up the respective responsibilities of these agencies as far as investment promotion is concerned.

For instance, the regional power demand and supply plans were previously drawn up by PLN. With the expansion of the LGUs' autonomy, formulating these plans are now the responsibility of the LGUs—specifically the various provincial governments.

While the Indonesian government has taken steps to more proactively attract foreign investments, it still needs to address a lot more problems, including the smooth transfer of devolved functions to LGUs, as well as the implantation of investment promotion programs.

(3) Vietnam

The Vietnamese government liberalized its foreign investment regime in 1988. However, the expected foreign investments failed to materialize due to the inadequate incentives packages that were offered then.

To address the issue and further entice foreign investors to enter the country, the Vietnamese government in 1999 enhanced the double-price system and abolished the foreign exchange balance obligation. To streamline the approvals processes, the government implemented a new business registration system in 2000 to replace the approvals and licensing system that was previously in place.

As a result of these initiatives, IPPs—as in other countries—active participants in the Vietnamese power sector. Prospective IPPs can enter the sector through several modes, and in contract with the Vietnamese government: BOT; Build-Transfer-Operate (BTO); and Build-Transfer (BT).

With the entry of more foreign investors, Vietnam has experienced high economic growth, with the demand for power steadily increasing.

To further attract foreign investors, the Vietnamese government welcomes foreign investments in all fields of activity, with the incentives packages classified by field and area of activity. The fields of activity where foreign investments are solicited are classified under the "Special Incentive Business" and the "Investment Incentive Business", where a wide range of incentives are offered.

On the other hand, locators in industrial parks and complexes and export processing zones may also avail of incentives. However, the incentives for locators in these areas are designed with exporters in mind.

Incentives are also available for investors who choose to invest in particular areas in Vietnam—which are categorized as Zone A and Zone B. The areas in these zones have been identified by the Vietnamese government having particular need of development.

As far as investments in the power sector are concerned, an IPP with a BOT, BTO, or BT contract and which locates in an Investment Incentive Zone will be entitled to an 8-year ITH.

But perhaps the most attractive incentive for investors is the refund of paid income taxes for an investor that reinvests its profits or revenues in an active business or a new concern. Under this scheme, the government will refund the amount of income taxes equivalent to the amount reinvested.

Another major investment incentive is the partial or total exemption of expenses from the rental or lease of land. This incentive is particularly attractive to foreign investors since foreigners in Vietnam are prohibited from owning land. In the case of IPPs with BOT, BTO, or BT contracts, the land rental expenses are partly or wholly exempted.

(Investment incentives in Vietnam for activities in the power sector are compared with those in the Philippines in 7.1.1 (4), "Incentives for Investments in the Power Sector".)

From a process point of view, applications for investment incentives in Vietnam need the approval of the Ministry of Planning and Investment (MPI).

On the other hand, BOT, BTO, and BT projects, as well as projects in the power sector worth US $ 40 million or more will need the approval of the prime minister's office after the application is received and endorsed by MPI. Such projects are collectively known as "Group A" projects.

The procedure for applying for incentives is illustrated below.

Table 7.8 Major Investment incentives in Vietnam

	Corporate Income Tax rate	Term of preferential tax rate (Note 1)	Term of incentive availment (Note 2-3)	Refund rate of corporate income tax by reinvestment
1. Service industry inside industrial zones	20%	10 years	1 Ex 2 De	50%
2. Manufacturer other than the applied tax rate are 10/15/20%	20%	10 years	1 Ex 2 De	50%
15% / when satisfies one of the following criteria				
1. Manufacturing precision mechanical equipment, equipment for safety examination and control; manufacturing jig and dies for metal and non-metal products	15%	12 years	2 Ex 3 De	75%
2. Investment on Group B	15%	12 years	2 Ex 3 De	75%
3. Service industry inside export processing zones	15%	Whole period	2 Ex 3 De	75%
4. Business inside Industrial zones, and satisfies the condition that the export of not less than 50% of production	15%	Whole period	2 Ex 3 De	75%
5. Business which will transfer its assets free after its operation	15%	12 years	2 Ex 3 De	75%
10% / when satisfies one of the following criteria				
1. when satisfies 2 conditions of 15% criteria	10%	15 years	4 Ex 4 De	100%
2. Specially encouraged investment sector	10%	Whole period	4 Ex 4 De	100%
3. Investment on Group A	10%	Whole period	4 Ex 4 De	100%
4. Infrastructure construction of industrial zones, export processing zones, hi-tech zones, urban areas	10%	Whole period	4 Ex 4 De	100%
5. Manufacturer inside Export Processing Zone	10%	Whole period	4 Ex 4 De	100%
6. Culture; publication, press; radio and television broadcasting; medical examination and treatment establishments; education and training; scientific research and production of medicine for human diseases	10%	Whole period	4 Ex 4 De	100%

(Note 1) Incentive shall be effective when the business commences its operation (manufacturing, sales) / 25% of standard tax rate shall be applied when the incentives expire.

(Note 2) Ex.=Exemption / De=50% deduction from preferential tax rate. For example, 1Ex / 2 De means that 1 years of exemption and 2 years of deduction will be applied from the year when the business makes a profit.

(Note 3) The following activities can enjoy 8 years of tax exemption

- Investment on encouraged investment sectors by the form of BOT, BTO and BT projects
- High-tech industry
- Investment on high-technology service industry inside high-tech zones
- Tree Plantation business
- Infrastructure construction / management business in the Group A region
- Investment on specially encouraged investment sectors, when the scale is respectively large enough to influence on economy / society.
- Exploration of Oil / Gas / other natural resources will be subject to the tax rate decided by The Oil/Gas Law, and other related legislation.

Source: Website of Vietnam MPI – Ministry of Planning and Investment

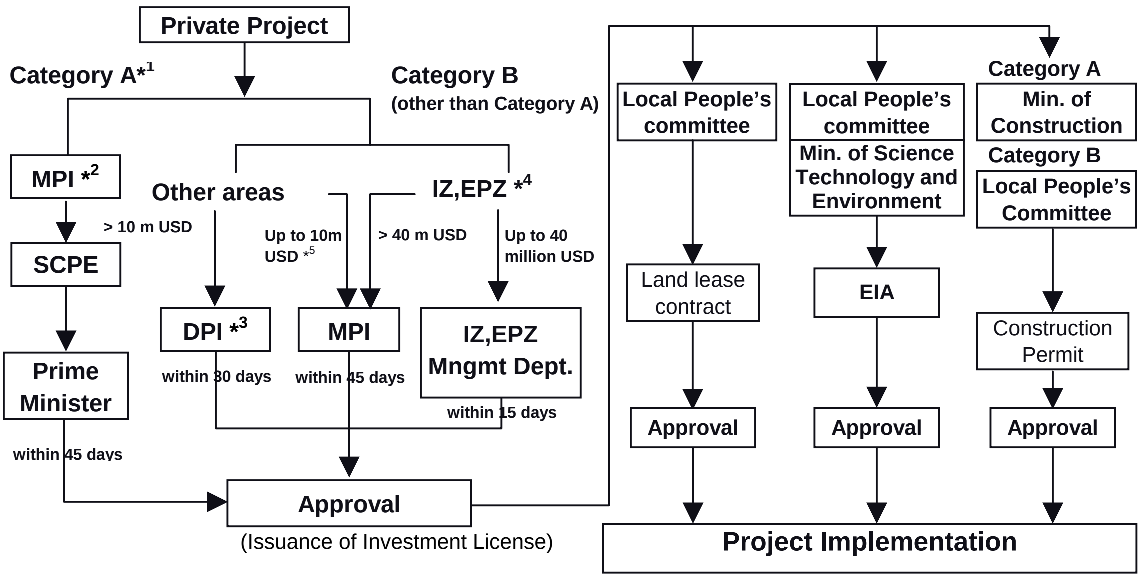
In applying for incentives for Group A projects, the investor submits the application for an investment license to MPI. Upon receipt of the application, MPI contacts and coordinates with the ministries and agencies which have regulatory jurisdiction over the project, as well as the local People's Committee.

The MPI usually sends a copy of the application and the relevant documents (accompanied by MPI's letter) to each ministry and/or agency.

After a lapse of 15 days and the ministry/agency does not reply to MPI, the latter construes this lack of reply to mean the ministry/agency does not object to the project. The MPI then endorses the application to the prime minister for his final approval.

The procedure in securing investment incentives is shown below.

Fig. 7.23 Investment Procedure in Vietnam



*1:Projects for Category A includes;
- BOT·BTO·BT Project
- Infrastructure Construction on the specified area
- Oil & Gas, Post & Telecommunication
- Culture, Media & Publishing, Broadcasting
- More than 40 million USD investment of power, mining, metallurgy, cement, etc.

*2 MPI :Ministry of Planning and Investment
*3 DPI :Department of Planning and Investment (Local Office)
*4 IZ: Industrial Zone / EPZ: Export Processing Zone
*5 Border for Hanoi and Hoh Chi Min City. For other cities it is 5m USD.
*6 State Evaluation Council on Investment Projects

Source: Website of Vietnam MPI – Ministry of Planning and Investment / T. Lefevre, J.Todoc, B. D. Thanh, *"Power in Viet Nam – Market prospects and investment opportunities"*, Financial Times Energy, 1999

The process however does not stop for thermal power projects with a nameplate capacity of 200 MW or more; or hydroelectric plants that require volumes of 100 million m^3 or more of water.

Proponents of these types of projects need to secure an Environmental Impact Assessment (EIA) once the proponent secures the Investment License. The EIA is filed with and approved by the People's Committee and the Ministry of Science, Technology and Environment (MOSTE). The evaluation of the application in this case takes 60 days from receipt of the documents. If the application is approved, the permit will be issued 10 days thereafter.

In view of an anticipated power shortage, EVN had committed eleven new power plants for construction in 2004. Thus, the Vietnamese government may undertake activities to further attract foreign investors in the power sector. However, Japanese and other foreign investors have sought the further liberalization of Vietnam's packages of foreign investor incentives before participating in power projects in the country.