Chapter 4 Electricity Demand Forecast in the Java-Bali Region

4.1 Historical Trend Economic Activity and Electricity Demand

4.1.1 Historical Trend of Economic Activities (RGDP, Regional GDP)

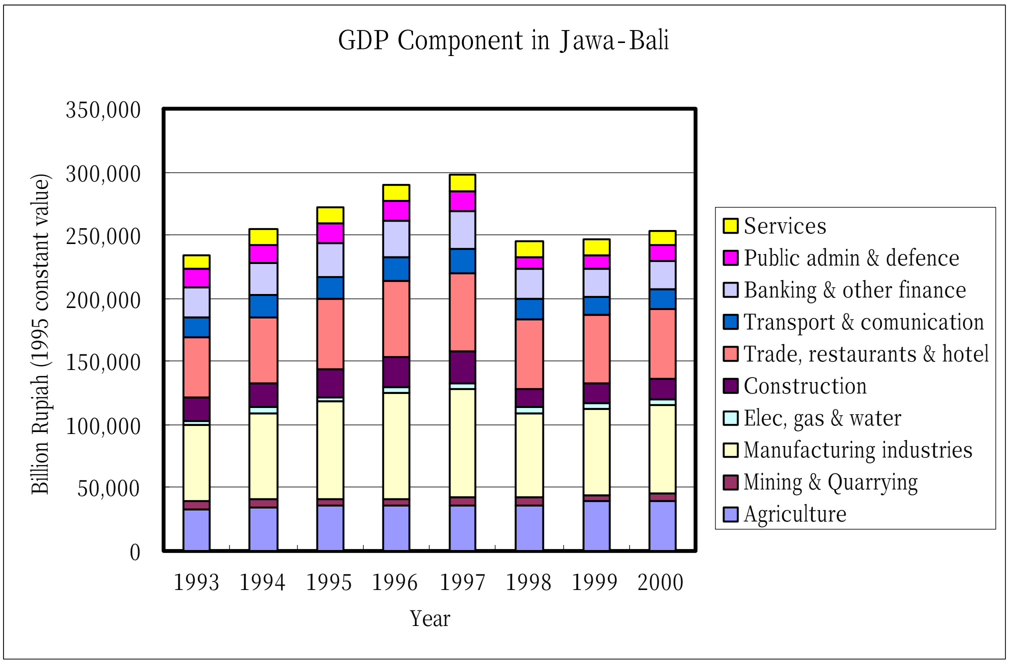
Figures 4.1.1 (a) and (b) show the historical trends of the real RGDP (Regional GDP at 1995 constant price) with its factor cost components and its structure since 1993 in the Java-Bali Region. During the economic crisis in 1998 the real RGDP of the Java-Bali Region recorded a minus (-) 17.7 % growth. Afterwards, although the economy began to recover, to date the real RGDP has still not reached the level of 1995-1997.

Comparing RGDP in the Java-Bali Region with GDP in the entire Indonesia described in Chapter 2 (See Figure 2.1.2), the historical trend of RGDP in the Java-Bali Region shows a tendency similar to that of the GDP of the entire Indonesia. The Java-Bali Region has such characteristics that relatively compared to the entire country the share of the mining & quarrying sector is small, while the role of trade, restaurants and hotel is large.

As for the structure of RGDP component shown in Figure 4.1.1 (b), the share of each component has not changed much since 1993 excluding the agricultural and manufacturing sectors. The agricultural sector had decreased its share of the RGDP until 1997 when the share was 12 %. However, in 1998 the share recorded was 15 %. This implies that agricultural sector did not suffer much from the impact of 1998's economic crisis. On the other hand, the share of the manufacturing industry was down from 29 % in 1997 to 27 % in 1998. The trade, restaurants & hotel sector has maintained the share of 20–22 %, the banking & other finance intermediaries of 9-10 %, and the transport & communication of 6-7 %. The mining & quarrying sector has a decreasing tendency from 2.6 % (1993) because output from this sector is not so much changed, and the public admin & defense sector decreased the share from 6.3 % (1993) to 4.9 % (2000).

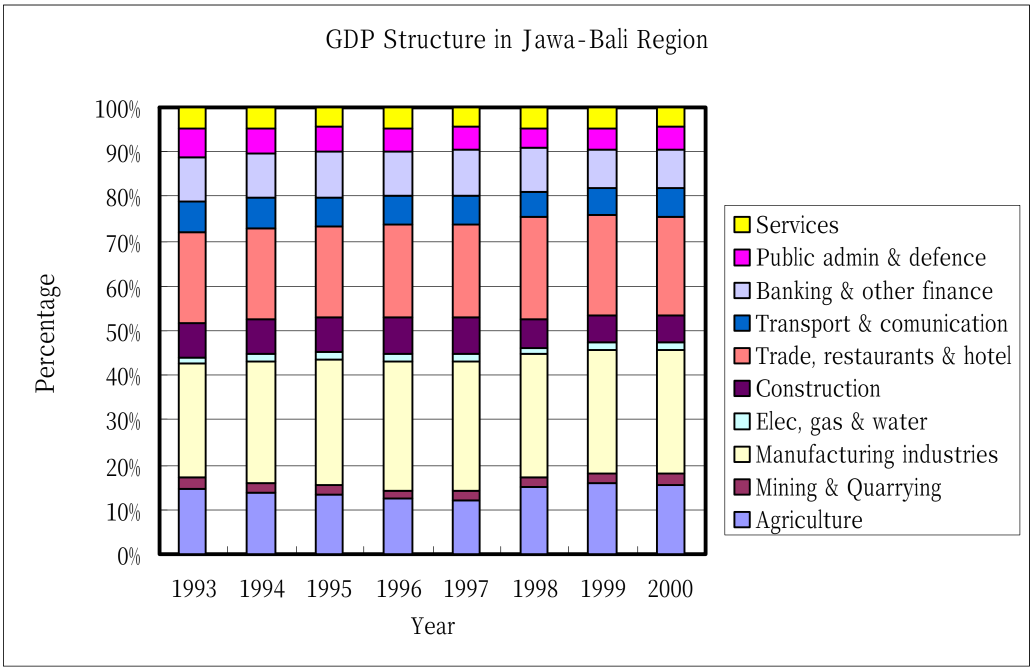
Figures 4.1.2 (a) and (b) show the RGDP classified by sector and its structure. In the Figures, the classification of the RGDP corresponds to electricity sector's category except others. The "industry" in the electricity sector corresponds to the manufacturing industries, the "commercial" sector corresponds to the restaurants & hotel, banking & other finance intermediaries and the "public" sector corresponds to the public admin & defense and services. The share of the classified electricity sector (except others) accounts for about 67 % of the total RGDP in 2000.

Figure 4.1.1 (a) Historical Trend of RGDP in the Java-Bali Region



(Source) DGEEU & BPS

Figure 4.1.1 (b) Historical Trend of RGDP Structure in the Java-Bali Region

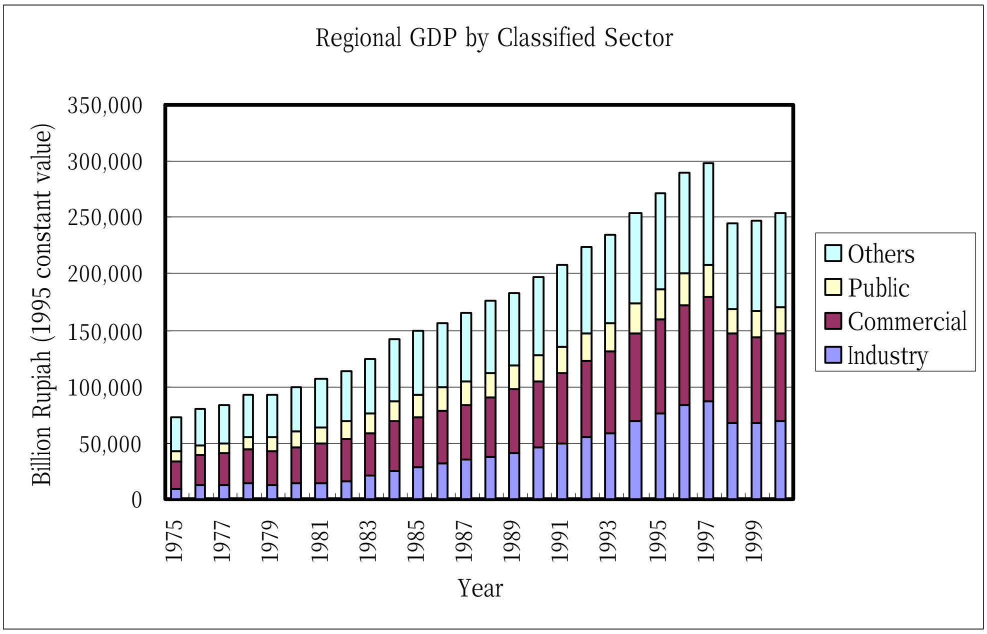


(Source) DGEEU & BPS

Until 1997, the industrial and commercial sectors had pushed up the RGDP in the Java-Bali Region. However, after 1998 the RGDP growth is still stagnant (See Figure 4.1.2 (a)). Regarding RGDP structure, the industrial sector expanded its share during 1983-1997. After

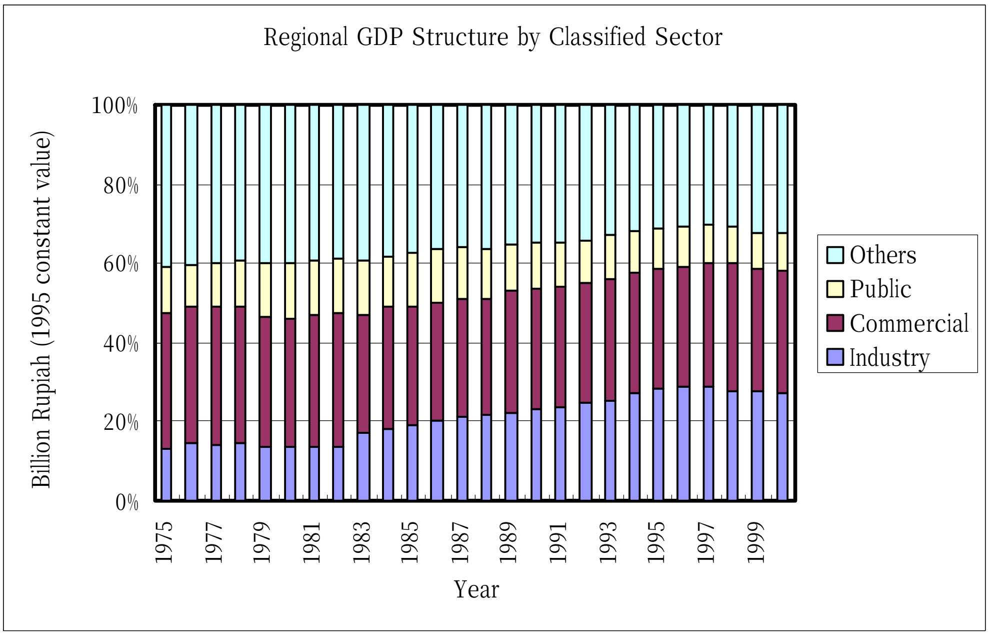
1998 we cannot find out the RGDP structure change from Figure 4.1.2 (b). The others and public sectors have been gradually shrinking their share, since 1983 (See Figure 4.1.2 (b)).

Figure 4.1.2 (a) Historical Trend of RGDP by Sector in the Java-Bali Region



(Source) DGEEU & BPS

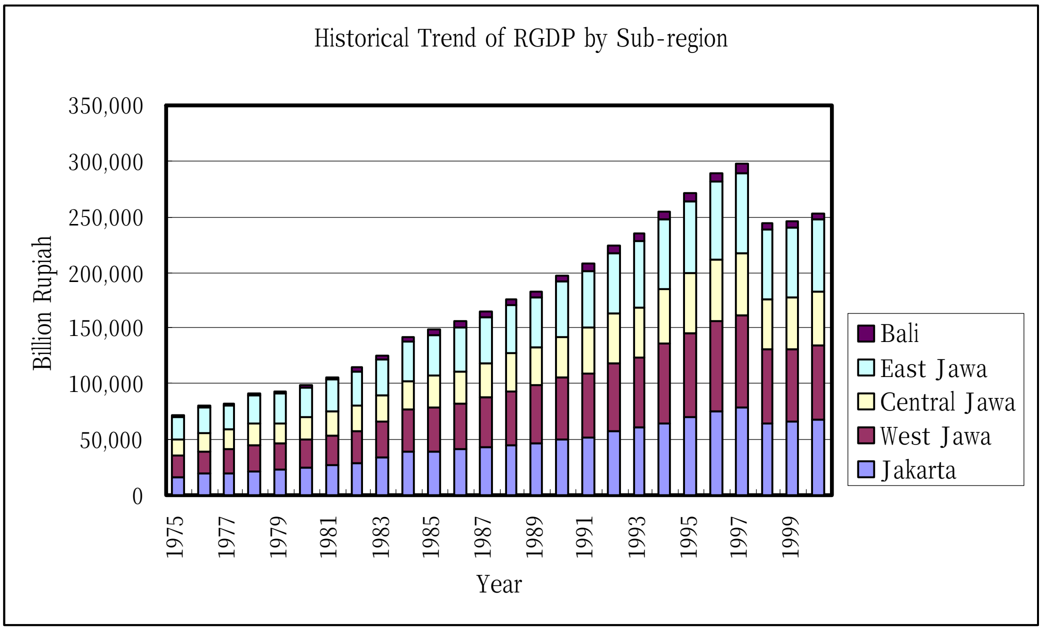
Figure 4.1.2 (b) Historical Trend of RGDP Structure by Sector in the Java-Bali Region



(Source) DGEEU & BPS

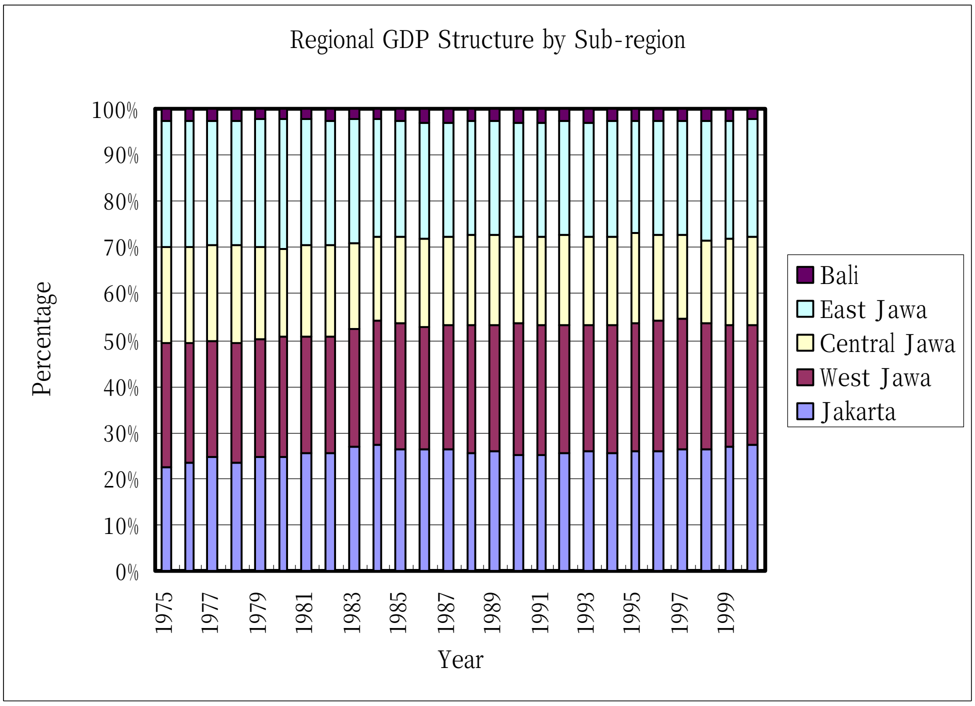
Figures 4.1.3 (a) and (b) show the regional GDP by sub-region and the share of each sub-region in the Java-Bali Region. As shown in Figure 4.1.3 (b), the share of each sub-region is not much changed. The economic structural shift among sub-regions is not considered in the past 10 or 15 years from the Figure.

Figure 4.1.3 (a) Historical Trend of RGDP by Sub-Region



(Source) DGEEU & BPS

Figure 4.1.3 (b) Historical Trend of RGDP Structure by Sub-Region



(Source) DGEEU & BPS

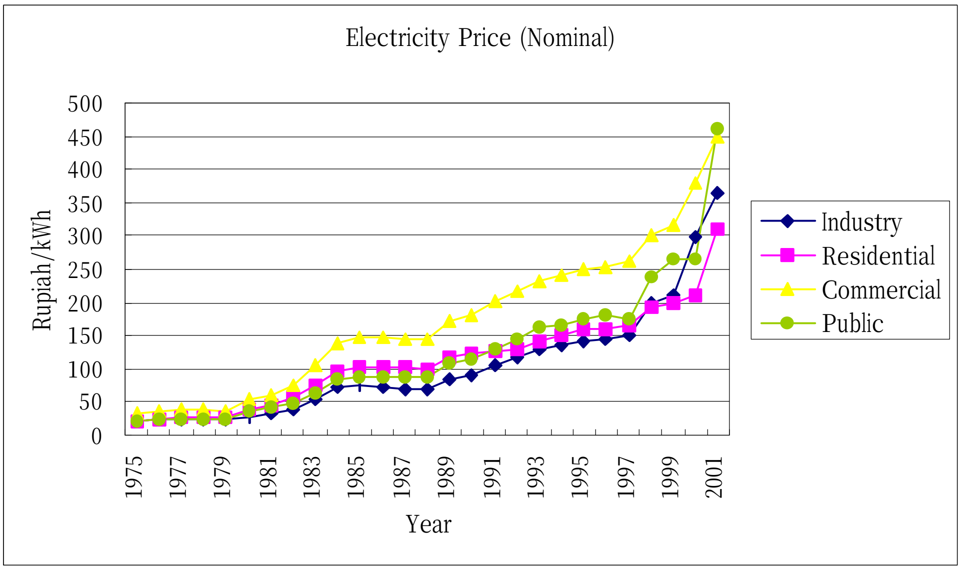
4.1.2 Electricity Price

Figures 4.1.4 (a) and (b) show the trends of electricity prices (nominal and real) in each sector since 1975 in the Java-Bali Region. The polygonal lines show prices for the commercial sector, the government/public sector, the industrial sector, and the residential sector. The nominal price rose during the period of 1980-1984 and after 1988. Average price of 88.7 Rupiah/kWh in 1988 increased by about 2.5 times by 1999 (222 Rupiah/kWh). Afterwards, the average price level reached 277 Rupiah/kWh in 2000 and 361 Rupiah/kWh in 2001.

On the other hand, although the real prices increased during the period of 1979-1985, they have maintained a decreasing tendency since 1990 (See Figure 2.1.2 (b)). The reason is due to the result that nominal prices increased in the period of 1988-1999, however, the consumer price index (CPI, 1995=100) during 1988-1999 increased 3.8 times from 56.9 to 218.9. Although nominal prices rose in both years of 2000 and 2001, as of today real prices have not reached the price level of 1997 under the circumstances of the high inflation ratio.

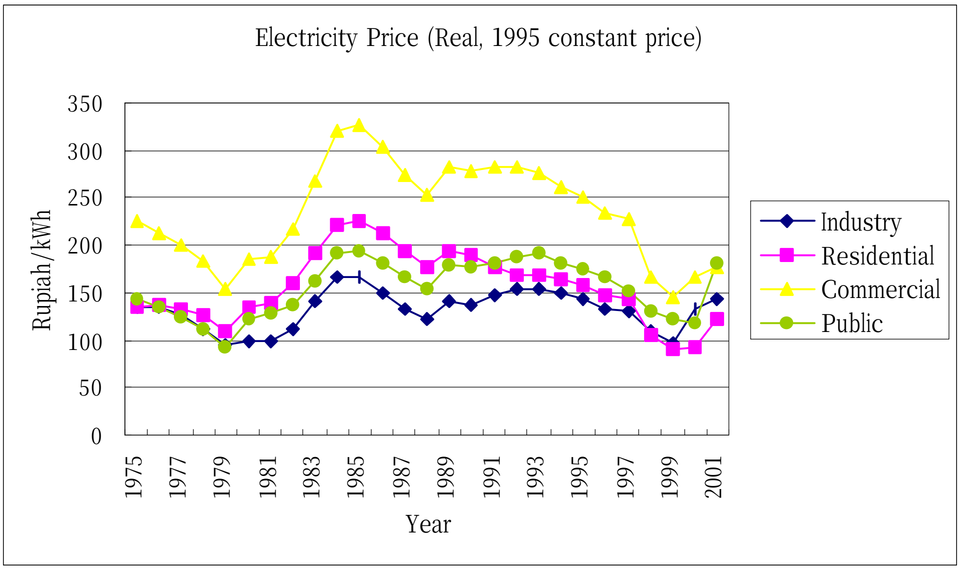
Figure 4.1.5 shows the historical trends of CPI (consumer price index) and WPI (wholesales price index). WPI includes petroleum sector. Both values are expressed at 1995 constant price (1995=100). Both indicators have a similar tendency until 1997, and the growth rates were about 8.5 % during 1980-1997.

Figure 4.1.4 (a) Historical Trend of Nominal Electricity Price



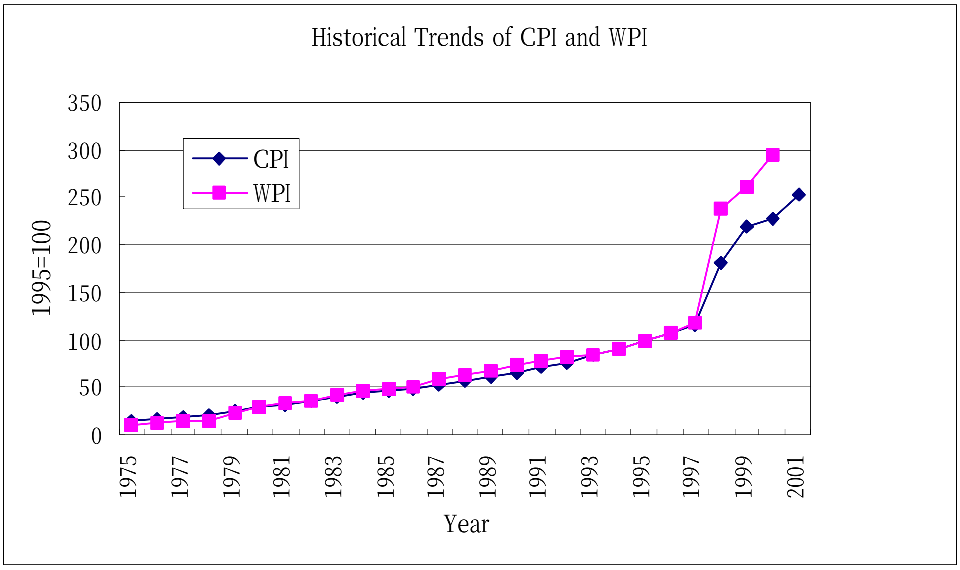
(Source) DGEEU and PLN

Figure 4.1.4 (b) Historical Trend of Real Electricity Price



(Source) IMF, DGEEU and PLN

Figure 4.1.5 Historical Trends of CPI and WPI



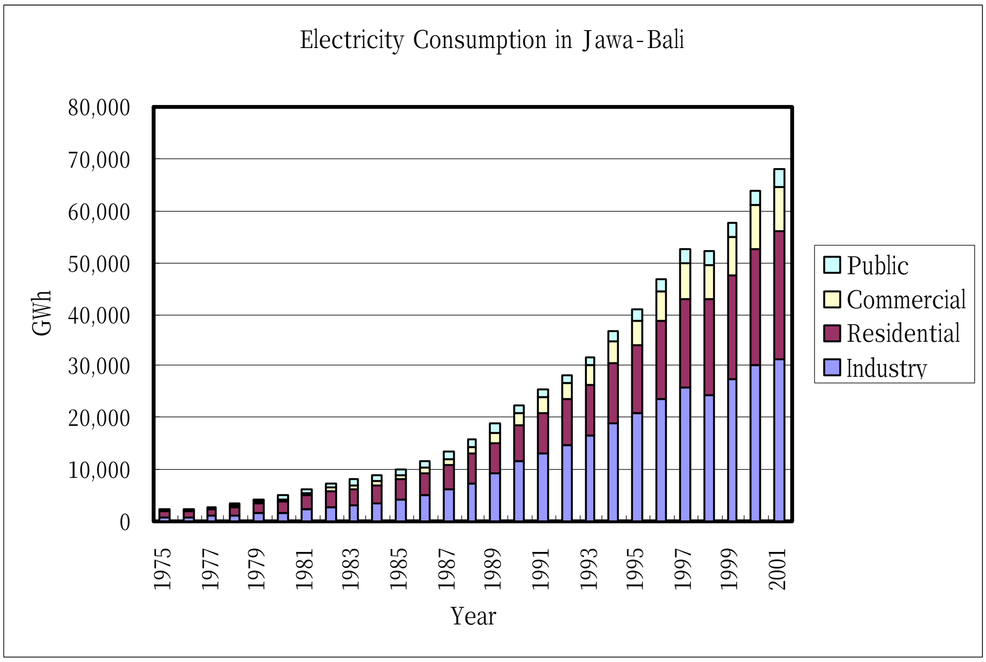
(Source) IMF

4.1.3 Electricity Demand

Figures 4.1.6 (a) and (b) show the historical trends of electricity consumption and its consumption structure by sector in the Java-Bali Region. Electricity demand in the Region has rapidly increased from 2,258.7 GWh in 1975, to 5,112.0 GWh in 1980, to 18,759.6 GWh in 1985, and to 63,871.8 GWh in 2000. The actual recorded value in 2001 was 67,927.2 GWh. Looking at the contribution by sector, the industrial sector, followed by the residential sector have pushed up the regional electricity demand. Annual average growth rates of electricity demand were 14.3 % in 1975-1980, 15.7 % in the 1980's and 11.25% in the 1990's. Each growth rate by consuming sector is shown in Table 4.1.1.

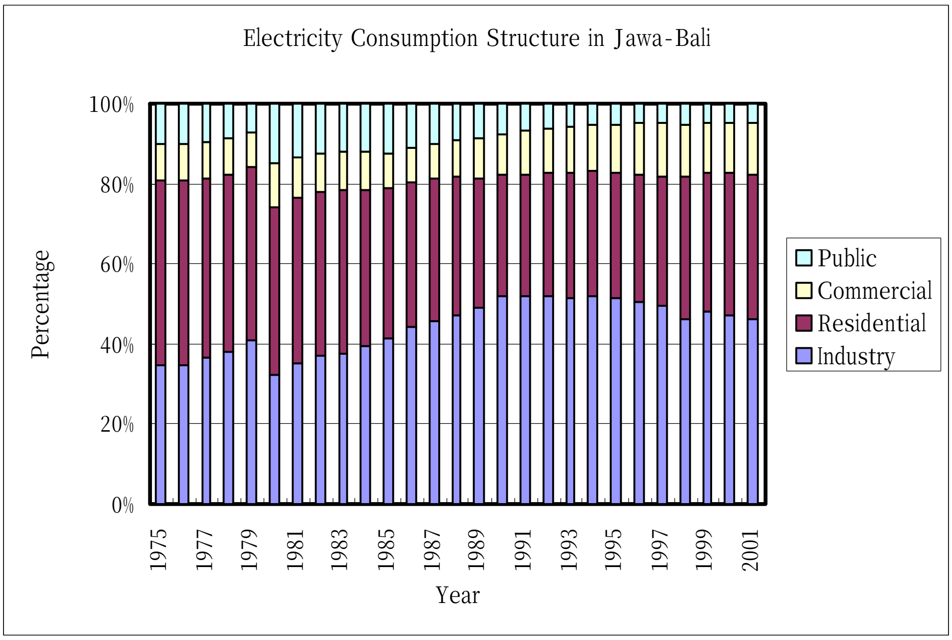
As shown in Figure 4.1.6 (b), the industrial sector expanded its share from a level of a little over 30 % to a level of 50 % [level] in the 1980's. After the latter half of 1990s, however, the share of the industrial sector shrunk and the residential and the commercial sectors recovered that share. As for the share of the consuming sector, in 2001, the industrial sector accounted for 46 %, the residential sector for 36 %, the commercial sector for 3 %, and the government/public sector for 5 %.

Figure 4.1.6 (a) Historical Trend of Electricity Demand by Sector (Java-Bali)



(Source) PLN

Figure 4.1.6 (b) Historical Trend of Electricity Demand Structure (Java-Bali)



(Source) PLN

Table 4.1.1 Average Growth Rate of Electricity by Sector During Each Period

		1975-1980	1980-1990	1990-2000
Electricity Demand	Java-Bali Total	14.3	15.7	11.5
	Industry	15.4	21.6	10.5
	Residential	14.9	12.1	13.1
	Commercial	19.3	13.8	14.1
	Public	8.0	8.1	5.8
Peak Load	Java-Bali System		13.8	11.0

Historical trend of peak load is shown in Figure 4.1.7. Peak load (gross) has increased from 1,181 MW in 1980 to 7,777.3 MW in 1995, and to 12,231 MW in 2000. Annual average growth rate was 13.8 % in the 1980s and 11.0 % in the 1990s (See Table 4.1.1). In 2001, the peak load in the Region reached 13,041 MW.

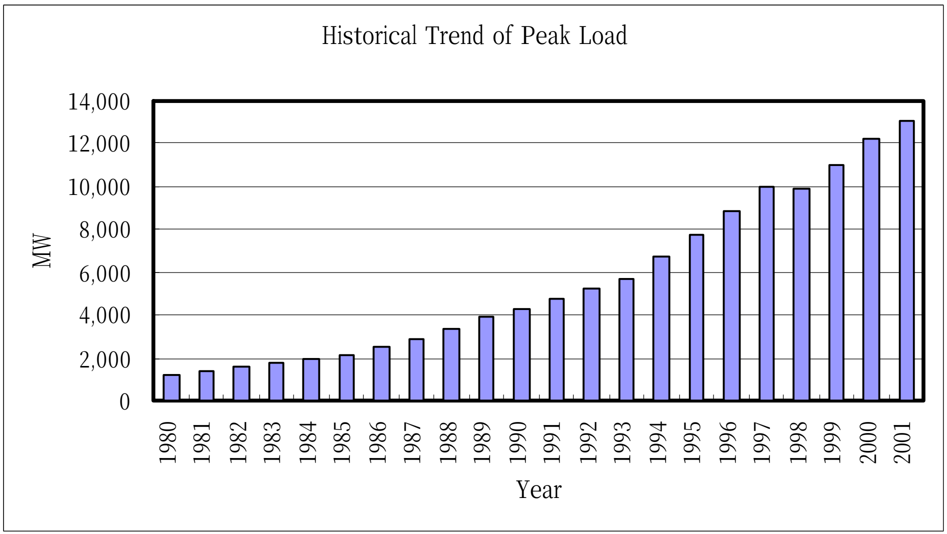
Table 4.1.2 shows the historical trends of load factor and total losses in the Java-Bali system since 1990. Total losses are represented in terms of ratio (%), and include the plant own-use and transmission/distribution losses. As a recent trend, the plant own-use is about 4 %, and the transmission /distribution loss is about 12 %. Load factor is about 70 %.

Table 4.1.2 Load Factor and Total Losses in the Java-Bali System (Unit: %)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Load Factor	70.2	72.8	78.0	79.7	70.2	70.5	68.4	70.7	71.9	70.3	69.9	68.5
Total Loss	17.9	17.2	16.4	16.1	12.7	14.8	11.5	15.3	16.0	15.5	14.7	13.2

(Source) PLN

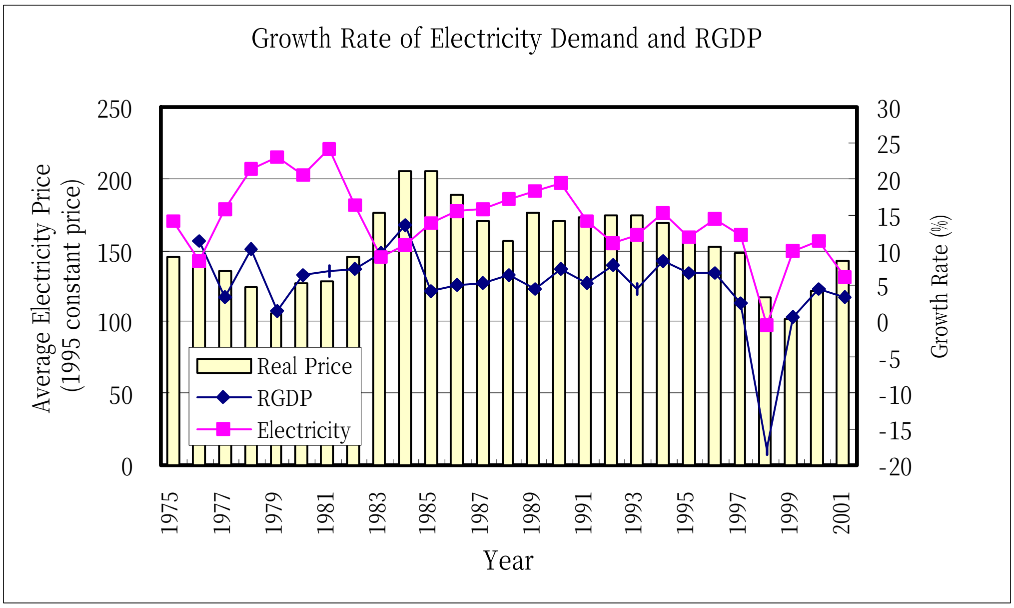
Figure 4.1.7 Historical Trend of Peak Load in the Java-Bali System



(Source) PLN

Figure 4.1.8 shows the historical trend of electricity demand and economic activities in the Java-Bali Region. In the Figure, polygonal lines show annual growth rates of electricity demand ("Electricity" in Figure 4.1.8) and the RGDP respectively, and the bar graph shows the real price (at 1995 constant value) in each year. According to Figure 4.1.8, we can see general characteristic that before 1997 the growth rate of electricity demand increases when the real price decreases. In 1998, the demand growth rate dropped drastically due to the economic crisis and it recorded a minus growth. Although signs of recovery begin to appear after 1999, the economic driving force is still weak.

Figure 4.1.8 Historical Trend of Electricity Demand and Real Price in the Java-Bali Region



(Source) DGEEU and PLN

4.1.4 Factor Analysis on Electricity Demand Contributor

(1) Macroscopic factors on the increase/decrease of electricity demand

We attempt to analyze factors behind the increase of electricity consumption by use of three factors: 1) electricity intensity per GDP, 2) GDP per capita, and 3) population. The electricity intensity per GDP represents the energy volume required to produce a certain amount of value added. GDP per capita represents economic level (not economic size). In general, decreasing tendency of intensity means the improvement of energy efficiency or productivity. GDP per capita and population's increase pushes up energy demand. The formulas for analysis are as follows.

Fundamental Formula $E = I*G*P$ ($E = (E/GDP)*(GDP/P)*P$)

Where, E=Electricity Consumption

I=E/GDP (Electricity Intensity Factor)

G=GDP/capita (Economic Growth Factor)

P=Population (Population Growth Factor)

Equation for Factor Analysis

$$dE = dI*(E/I) + dG*(E/G) + dP*(E/P)$$

dE	Incremental Electricity Consumption
dI*(E/I)	Increase/Decrease Factor due to Changes of Electricity Intensity
dG*(E/G)	Increase factor due to Economic Growth
dP*(E/P)	Increase factor due to Population Growth

or $\triangle E = \triangle I*(E/I) + \triangle G*(E/G) + \triangle P*(E/P) + \text{Residual}$

or $\triangle E = \triangle I*G*P + I*\triangle G*P + I*G*\triangle P + \text{Residual}$

Figure 4.1.9 (a) and (b) show the historical trend of each factor's contribution and its contribution ratio. According to the Figures, economic growth and population growth's factors pushed up the electricity demand except 1998, this is common result in these kinds of analysis. As for the electricity intensity, this factor acted on the minus (-) side in 1993 and 1994, which means the improvement of energy efficiency or the effects of energy conservation. And also the time of 1993 and 1994 corresponds to the period of the real price rising (See Figure 4.1.8). In the period except 1993 and 1994, the intensity factor is the plus (+) side, which means socioeconomic activities involve energy waste structure.

Year 1998 is the time that recorded electricity demand of - 0.5 % growth by the influence of economic crisis of - 17.7 % growth. As shown in Figures 4.1.9 (a) and (b), the economic growth factor contribute to the minus (-) side in 1998. Therefore, the electricity demand should shift to much minus side. On the other hand, the electricity intensity factor pushed up the electricity demand. As the result, the decrease and increase of electricity demand was offset together. It can be interpreted that the intensity worsening and the real price falling constrained the rapid electricity demand drop in 1998.

Figure 4.1.9 (a) Factor's Contribution to Electricity Consumption

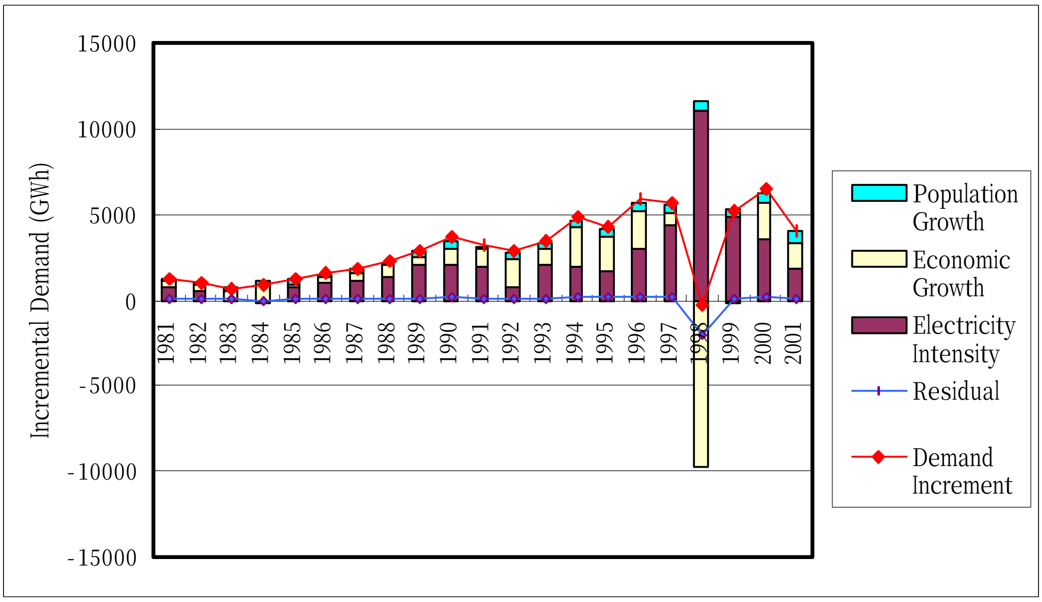
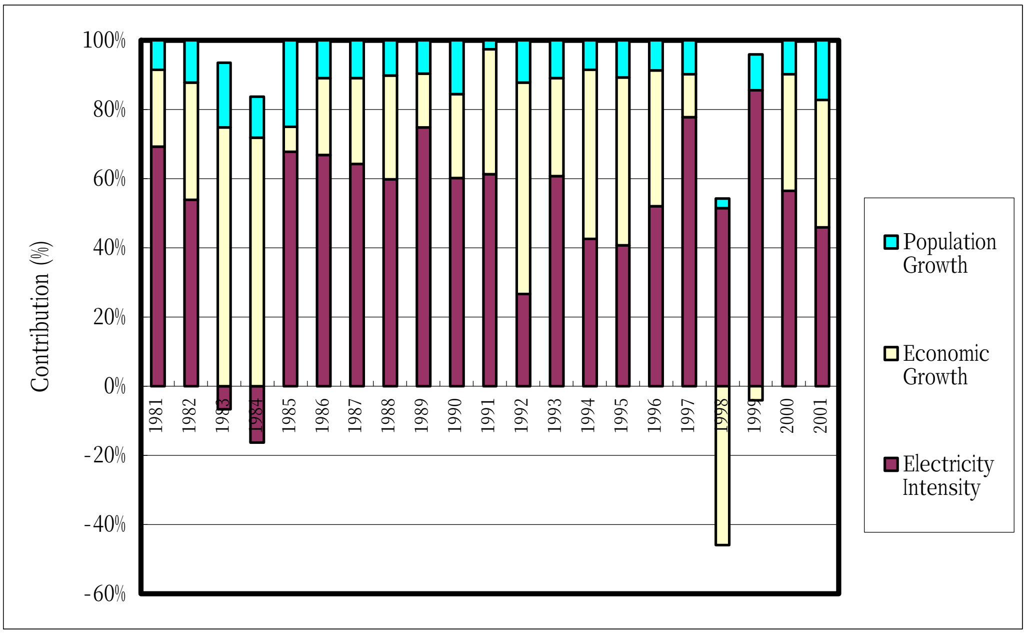


Figure 4.1.9 (b) Factor's Contribution Ratio to Electricity Consumption



(2) Consumer factors on the increase/decrease of electricity demand

This analysis is also to examine the factors that caused changes in the electricity consumption. We disaggregate for this analysis into three factors: 1) change of electricity intensity in each sector (manufacturing, residential, commercial and public/government sectors), 2) share change of number of consumer in each sector, and 3) increment of customer. The formulas for analysis are as follows.

$$\triangle E = \text{Sigma}(\triangle Ei)$$

$$= \text{Sigma}(\triangle Ii*Si*C) + \text{Sigma}(Ii*\triangle Si*C) + \text{Sigma}(Si*Ii*\triangle C) + \text{Residual}$$

Where, Ei = Electricity consumption of i-sector

Ii = Ei / Ci (Electricity consumption per i-sector's consumer)

Si = Ci / C (Share change of i-sector's consumer)

Ci = Number of customer of i-sector

C = Number of total customer

$\triangle E$ = Incremental electricity consumption (Demand Increment)

$\triangle Ii*Si*C$ = Increase or decrease due to changes of intensity per consumer (Intensity Change)

$\triangle Si*Ii*C$ =Increase or decrease due to share changes of number of consumer (Sales Structure Change)

$\triangle C*Si*Ii$ = Increase factor due to consumer increment (Customer Increment)

Figure 4.1.10 Factor's Contribution to Electricity Consumption

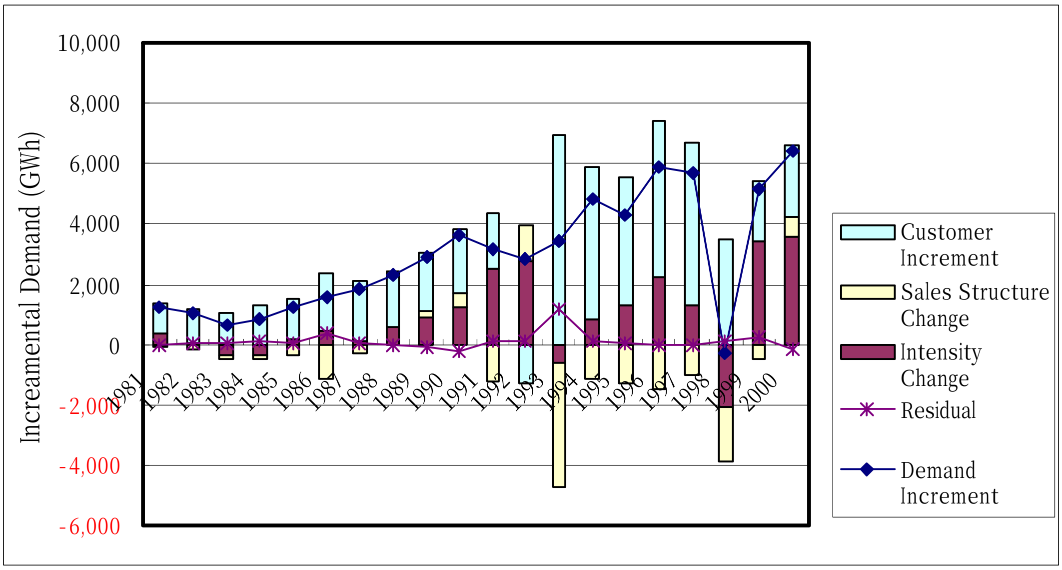


Figure 4.1.10 shows the results of an analysis. As shown in the Figure, electricity demand increment is basically dependent on the increase of the number of consumer (Customer

Increment) and the electricity consumption per consumer (Intensity Change). However, the values in 1983 & 1984, 1993, and 1998 are different from its historical trends. Factor of Intensity Change is the minus (-) side and contributes to the decreasing side of electricity demand, especially in 1998.

Figure 4.1.11 shows the result analyzing the consumer factor by sector on the electricity demand increase/decrease in 1998. From the Figure, we can see that Intensity Change (change of the electricity consumption per consumer) contributes to fall the electricity demand in the industrial, commercial and public/government sectors (except the residential sector). The increase of customer (Customer Increment) act on the plus (+) side to all classified sectors and pushed up the electricity demand, as a matter of course. As for the residential sector, residual term is the minus (-) factor, which cannot be explained only by the factors tried this time.

Table 4.1.3 shows actual values of consumer and electricity consumption per consumer, just mentioned above. According to the figures of growth rate in the Table, the industrial (manufacturing) sector decreased the electricity consumption (-6.7 % growth) because of the decrease of the number of customer (-0.1 %) and the consumption per customer (-6.5 %). The commercial sector also decreased the electricity consumption (-1.1 %) by the consumption per customer (-6.9%). The drop of electricity consumption in the residential sector is due to the slow down of both number of customer and the consumption per customer.

Figure 4.1.11 Factor Analysis by Sector

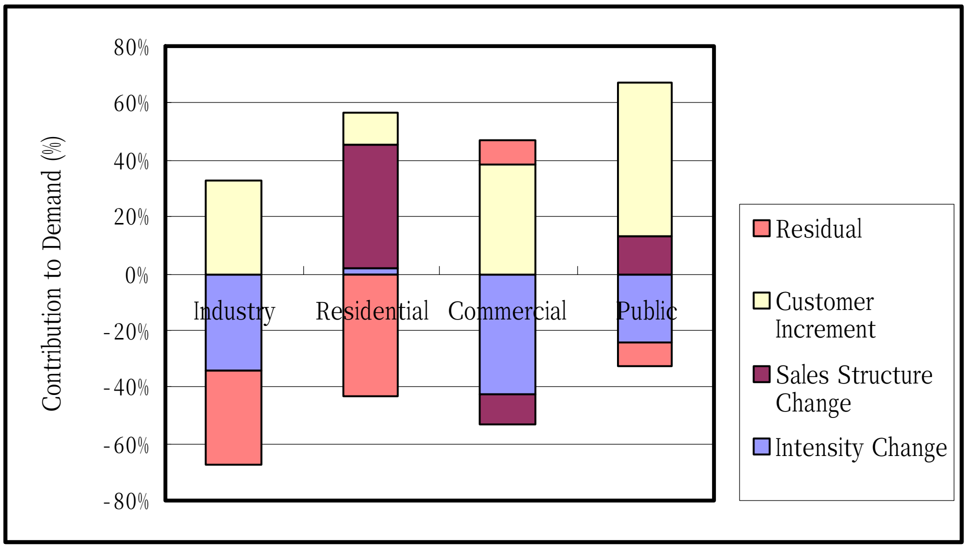


Table 4.1.3 Number of Customer and Electricity Consumption per Customer

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Electricity Consumption (GWh)											
Total	22,402	25,566	28,389	31,819	36,639	40,941	46,828	52,533	52,266	57,437	63,872
Industry	11,619	13,255	14,750	16,434	19,038	20,999	23,720	25,910	24,179	27,611	30,045
Residenti	6,795	7,779	8,790	9,948	11,423	12,913	14,752	17,107	18,536	19,949	22,629
Commerc	2,294	2,813	3,107	3,653	4,258	4,926	6,004	6,936	6,856	7,141	8,277
Public	1,694	1,719	1,742	1,784	1,921	2,103	2,352	2,580	2,695	2,736	2,921
Growth Rate (%)											
Total	19.4	14.1	11.0	12.1	15.1	11.7	14.4	12.2	-0.5	9.9	11.2
Industry	26.0	14.1	11.3	11.4	15.8	10.3	13.0	9.2	-6.7	14.2	8.8
Residenti	13.3	14.5	13.0	13.2	14.8	13.0	14.2	16.0	8.4	7.6	13.4
Commerc	17.4	22.6	10.5	17.6	16.6	15.7	21.9	15.5	-1.1	4.2	15.9
Public	7.0	1.5	1.3	2.4	7.7	9.5	11.8	9.7	4.4	1.5	6.8
Number of Customer (thousand)											
Total	7,951	8,554	8,188	10,484	12,167	13,563	15,234	16,975	18,187	18,827	19,554
Industry	24	24	24	25	28	30	31	33	33	33	34
Residenti	7,500	8,068	7,659	9,898	11,511	12,847	14,430	16,071	17,223	17,747	18,388
Commerc	248	268	288	314	346	373	419	474	504	604	671
Public	179	195	217	246	283	314	354	396	426	443	461
Growth Rate (%)											
Total	10.6	7.6	-4.3	28.0	16.1	11.5	12.3	11.4	7.1	3.5	3.9
Industry	15.5	-1.9	0.2	6.6	10.7	5.9	5.6	6.8	-0.1	-1.3	4.5
Residenti	10.6	7.6	-5.1	29.2	16.3	11.6	12.3	11.4	7.2	3.0	3.6
Commerc	8.0	8.0	7.7	9.0	10.1	8.0	12.1	13.3	6.2	19.9	11.1
Public	12.2	9.2	11.1	13.6	15.0	10.8	12.8	12.0	7.6	3.9	4.1
Electricity Consumption per Customer (kWh/customer)											
Total	2,818	2,989	3,467	3,035	3,011	3,019	3,074	3,095	2,874	3,051	3,266
Industry	482,797	561,184	623,453	651,791	682,234	710,818	760,601	777,707	726,790	841,175	875,741
Residenti	906	964	1,148	1,005	992	1,005	1,022	1,064	1,076	1,124	1,231
Commerc	9,260	10,509	10,778	11,627	12,314	13,191	14,345	14,623	13,611	11,823	12,336
Public	9,486	8,816	8,044	7,248	6,788	6,708	6,649	6,510	6,319	6,173	6,333
Growth Rate (%)											
Total		6.1	16.0	-12.5	-0.8	0.2	1.8	0.7	-7.1	6.2	7.1
Industry		16.2	11.1	4.5	4.7	4.2	7.0	2.2	-6.5	15.7	4.1
Residential		6.4	19.0	-12.4	-1.3	1.3	1.7	4.1	1.1	4.4	9.5
Commercial		13.5	2.6	7.9	5.9	7.1	8.8	1.9	-6.9	-13.1	4.3
Public		-7.1	-8.8	-9.9	-6.3	-1.2	-0.9	-2.1	-2.9	-2.3	2.6

(Source) PLN

4.2 Electricity Demand Forecasting Model

4.2.1 Energy Models applied in Indonesia

In Indonesia, various models and development tools are distributed and applied.

1) DGEEU (Director General for Electricity and Energy Utilization, Ministry of Energy and Mineral Resources)

    NERA Electricity Demand Forecasting Model 2.0 or
    JICA (IEEJ) model, Simple-E

2) BATAN (National Atomic Energy Agency)

    MAED (Model for Analysis of Energy Demand) and WASP

3) BPPT (Agency for the Assessment & Application of Technology)

    MARKAL (Market Allocation Model)

4) PLN (State Enterprise for Electricity).

    DKL (Dinas Kebutuhan Listrik) and Sihombing Model (similar WASP)

In these models, MARKAL, MAED and WASP, in which MAED and WASP are modules of The Energy and Power Evaluation Program (ENPEP), are distributed by international institutions / organizations. Main characteristics of these models are briefly shown in Table 4.2.1. Users can examine and study input / output from models, however cannot manipulate the model themselves because of Black Box system.

Table 4.2.1 Outline of Models

Model	Developer	Characteristics (model itself is black box)
MARKAL	IEA (PC version: Brookhaven National Laboratory)	Detailed energy flow is solved by Linear Programming Method (LP). Electricity demand (useful energy) is solved by sub-model DEMI and supply sector is optimized by LP under constraints such as cost and environment. Frame computers are usually used.
ENPEP	Argonne National Laboratory	ENPEP consists of nine modules including MAED and WASP.
MAED		MAED calculates final energy demand as a function of the socio-economic indicators and energy efficiencies of end-use equipments.
WASP		WASP is a probabilistic simulation model to evaluate the power generating expansion plans that meets the given power demand under constraints of plant factors and cost etc..

In the models above, DKL model was developed by Electric Power Demand Section of PLN. The DKL model consists of equations of four sectors such as 1) residential sector, 2) commercial sector, 3) public sector, and 4) industrial sector. The same model of each sector is applied to eleven (11) districts designated by PLN. As for the concept of the DKL model, electricity demand is calculated as the function of both the demand of the previous year and the elasticity of power demand with respect to RGDP (Regional GDP). The elasticity is estimated from the electricity demand and the RGDP growth rates. Residential electricity demand (energy sales) is obtained from the sum of the demand of old consumers and new consumers.

4.2.2 Electricity Demand Forecasting Model

(1) General approaches for model building

The model is required to be easy in operation and to be transparent and flexible in understanding the methodology and the logic employed. The model also should be built on a flexible system so that the user can revise the data and the model based on annual or quarterly additional data and changes of specific requirements from government energy policy.

Speaking of energy demand forecasting methods in general, there are two different approaches. One is a process-engineering method (a kind of bottom-up system), while the other is an econometric method. Naturally each has its own advantages and disadvantages. Regarding data collection as an example, the former involves a wide variety of data, but few time-series data. In contrast, the latter requires few data of this kind but time-series data in the long run (ten years or longer).

The results of the engineering approach are easily understood, since it will provide huge data and explanation. In the case of an econometric method, however, the background of forecast results can hardly be explained in detail because macro economic/social indicators are incorporated as exogenous (external) variables. With recognition of these merits and demerits, we usually apply the econometric approach and combination of both concepts using energy intensities and efficiencies excluding intentional judgment for setting the parameters.

The characteristics of both approaches are completely different from viewpoints of several categories, such as, data collection, handling, scientific points, and results. Typical functional formula of both approaches can expressed as described below.

1) Process Engineering Approach by Stock Type Demand Function

$$\text{Demand (D)} = \text{SUM}(Ei) = Si \cdot Qi \cdot Ri, \quad i = 1, n$$

Ei = energy consumption of i – equipment

Si = energy consuming equipment stock

Qi = equipment efficiency

Ri = equipment operating rate

Taking electricity consumption in the residential sector as an example, S represents the number of equipment such as refrigerator, air conditioner, lighting fixture, television, electric cooker, vacuum cleaner, electric carpet and so on. Q represents the efficiency of equipment and R represents the using time of equipment. S (equipment stock), Q (efficiency) and R (availability) each has its own function that is determined from the following functional formula, for instant;

$$S_t = S_{t-1} + I_t - S_{t-1} \cdot \gamma$$

$$I_t = f(P_{it}, P_{et}, Y_t, S_{t-1})$$

$$Q_t = f(P_{et}, Q_{t-1}, T_t)$$

$$R_t = f(P_{et}, R_{t-1})$$

Where, S_{t-1} is the number of stock in previous year or previous period. I_t is the newly purchased number and $S_{t-f}\ \gamma$ is the disposed number. P_{it} ; price of equipment, P_{et} ; price of energy, Y_t ; income, T_t ; time trend

2) Econometric Approach by Regression Analysis

$$\text{LOG}(D) = a + b \cdot \text{LOG}(Y) - c \cdot \text{LOG}(P) + d \cdot \text{LOG}(D(-1)) + e \cdot \text{Time}$$

Y = Income Index

P = Price Index

D(-1) = Demand for previous year

Where,

b = Income elasticity (short period)

c = Price elasticity (short period)

1-d=Time adjustment term

e = Technical improvement term

b/(1-d) = Long term Income elasticity

c/(1-d) = Long term Price elasticity

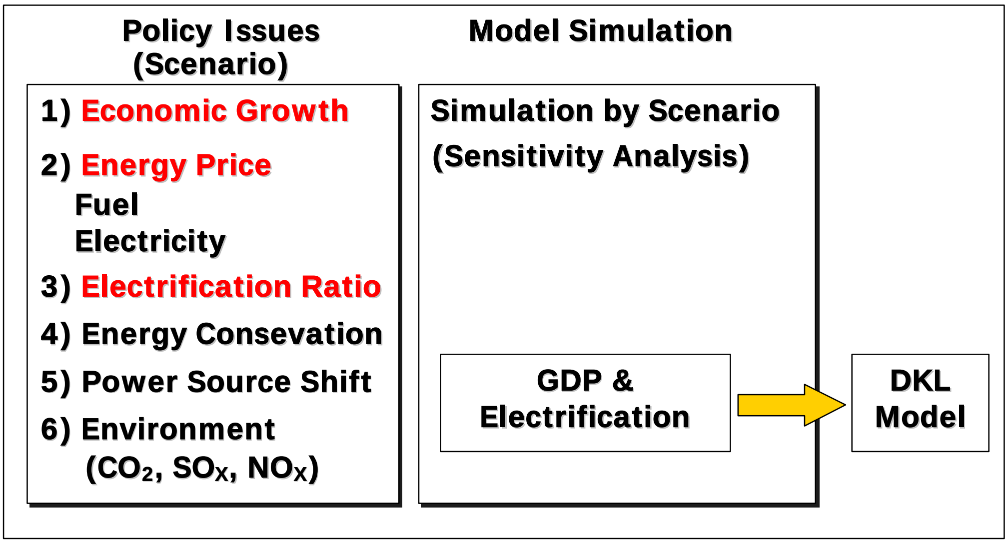
In the econometrics, energy demand is expressed by the function of Income (or GDP) and Price in general. Energy intensities can be also introduced in the sub-sector in manufacturing industry.

As described above, there are various options for energy model building, however, we cannot chose the system engineering approach for the energy model building in this time. Because it is difficult to get such kind of complex data and to estimate the efficiencies of equipment in the future. In addition, the system engineering method has the risk that data can be manipulated intentionally. On the other hand, the econometric approach can be easily applied to the model building by the preparation of time-series data and can introduce the concept of GDP elasticity usually used. The model building and data revise are easily handled as well. From these kinds of reasons, the Team applied the econometric method for the Study.

(2) Concept of electricity demand forecasting model

Power demand forecasting model is one of the tools for policy decision, and the methodology of model building was transferred to experts of DGEEU and PLN through Workshop. Attention is paid to economic growth (Regional GDP by sector) and electricity price. Demand function is expressed by Income (GDP) and Price basing on econometrics principle. As shown in the following diagram (Figure 4.2.1), models includes functions for analyzing the impact of energy policy issues such as electricity price and rural electrification.

Figure 4.2.1 Schematic Diagram of Proposed Model



Main scenarios related to policy issues can be applied to 1) economic growth (RGDP), 2) electricity price, 3) household electrification, 4) energy conservation, 5) power source shift (fuel shift), and 6) environmental constraints. In this report, 1) economic growth, 2) electricity price, and 3) household electrification are given as scenarios (external variables). Sensitivity analysis by simulation is focused on electricity price and other analysis such as household electrification and energy conservation are added as applied examples.

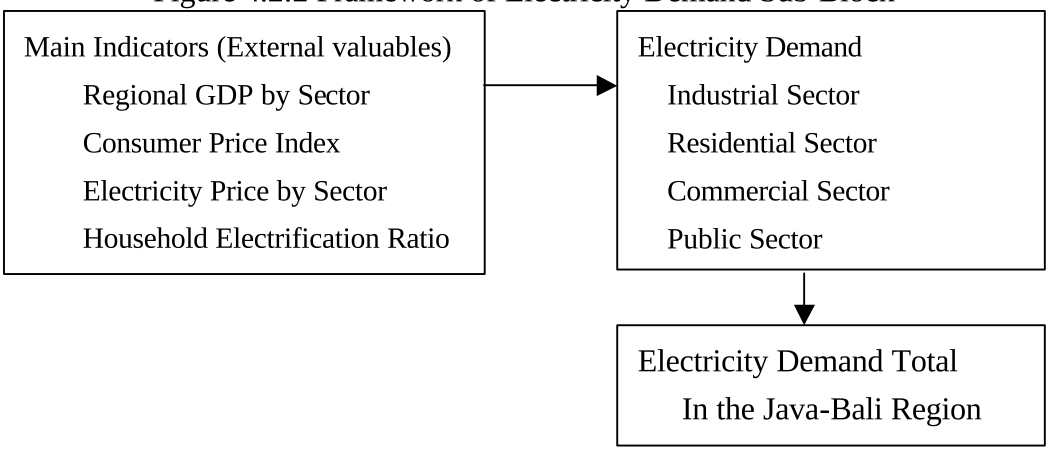
4.2.3 Model Structure and Data Source

(1) Electricity demand by sector

Figure 4.2.2 shows the framework of the end-use electricity sub-sector (electricity demand sub-sector). In this case, macro indicators consist of four items; (1) regional GDP by sector, (2) consumer price index, (3) electricity prices by sector and (4) household electrification ratio. In the electricity demand forecasting, the former items described above are treated as external variables in order to simulate the impact of price and GDP growth.

The end-use electricity demand sub-block comprising of each sector creates the system equations by sector and calculatesboth the sectoral demand and the total. The demand function is estimated by regression analysis for each sectoral demand for the manufacturing, residential, commercial, and government/public sectors. The total demand is obtained by adding each of the sectoral demand.

Figure 4.2.2 Framework of Electricity Demand Sub-Block



Basically, system equations by sector were created as the following functional relation.

1) Industrial (manufacturing) sector

Electricity demand = f (GDP of industrial sector, Price for industrial sector)

2) Residential sector

Number of customer = f (Electrification ratio)

Electricity demand = f (Electricity consumption/Customer, Price for households, Number of customers, Previous year's demand)

3) Commercial sector

Electricity demand = f (GDP of commercial sector, Price for commercial sector)

4) Government/Public sector

Electricity demand = f (GDP of public sector, Price for public sector, Previous year's demand)

Equations obtained by the regression analysis are shown below. In the equations, variables with lag1 mean previous year' value. Dummy variable (dum.---) is set as one (1) to only relevant year and as zero (0) to the other years in the past. In the future, dummy variable is set as zero (0). Values in ( ) mean t-value and so the value is not the coefficient of explainable variables (right term). In the system equations below, INEL, REEL, CMEL and PUEL represent the electricity demand for the industrial, residential, commercial and government/public sectors respectively. GDP, GDPIN, GDPCM and GDPPU also mean the regional GDP total, the industrial GDP, the commercial GDP and the public GDP respectively in real term. PINEL, PREEL, PCMEL and PPUEL mean the nominal electricity price of each industrial, residential, commercial and public sector. CPI is the consumer price index.

1) Industrial (manufacturing) sector

Ln (INEL)= -16.67 (-4.48) +1.49 (7.22)*Ln (GDPIN) -0.76 (-2.75)*Ln (PINEL/CPI)
-0.20 (-1.34)*dum.1997 -0.22 (-1.48)*dum.1996

Where, R square = 0.93
Durbin Watson ratio = 1.17

2) Residential sector

CUST (Number of customer) = (Population/Number of Family)* Electrification ratio

Ln (REEL)= -6.36 (-6.92) +0.47 (6.79)*Ln (GDP/CUST) -0.28 (-7.23)*Ln (PREEL/CPI)
+0.49 (6.95)*Ln (CUST) +0.69 (12.8)*Ln (lag1.REEL)

Where, R square = 0.99
Durbin Watson ratio = 2.39

3) Commercial sector

Ln (CMEL)= -25.72 (-8.08) +1.91 (11.2)*Ln (GDPCM) -0.699 (-5.35)*Ln (PCMEL/CPI)

Where, R square = 0.98
Durbin Watson ratio = 1.36

4) Government/Public sector

Ln (PUEL)= -2.78 (-2.81) +0.28 (3.67)*Ln (GDPPU) -0.80 (-3.24)*Ln (PPUEL/CPI)
+0.81 (7.64)*Ln (LAG1.PUEL) -0.13 (-3.49)*dum.1999 -0.13 (-2.73)*dum.2000

Where, R square = 0.99
Durbin Watson ratio = 2.24

(2) Power generation and peak load

Figure 4.2.3 shows the framework of electricity generation sub-block. In this sub-block, total electricity demand forecasted is received from the end-use electricity demand sub-block. Considering total losses (gross) by adding both the transmission /distribution (T/D) losses and own use (in plant use), the total electric power generation required is calculated. Thermal power generation is obtained by subtracting hydropower and geothermal power generation from the total. Peak load is calculated by use of a load factor.

In this forecasting model, all variables are handled whether internal variables or external variables. From the technical point of view, the ratios of T/D loss and own use, hydropower generation and the thermal efficiency can be input as external variables. In the case of long-long term forecasting model, the model should uptake the figures of national policy and power development plan including hydropower and fuel supply as external valuables.

In this simulation, total losses are handled as an external variable (scenario). The load factor is calculated by the model itself, that is, a structural equation by a regression analysis. The load factor obtained by regression is as follows. In the equation below, lag1 mean previous year' value and dummy (dum.--) is set as zero (0) in the future . The load factor will increase with industrial demand and decrease with residential demand.

Load Factor (ELLF) = f (Industrial Demand (INEL), Residential Demand (REEL))

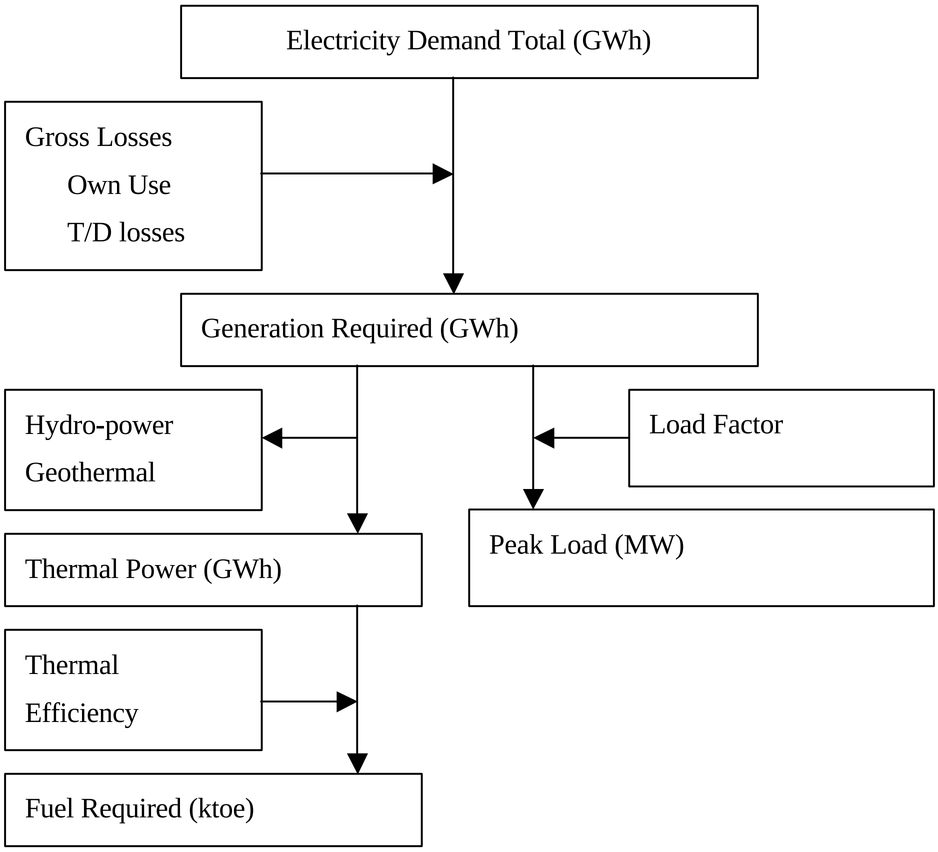
Ln (ELLF)= 4.16 (34.5) +0.127 (2.86)*Ln (INEL) -0.122 (-2.21)*Ln (REEL)
-0.28 (-7.57)*dum.1987 +0.11 (2.92)*dum.1993

where, Figures in ( ) = t-value, not coefficient

R square = 0.85

Durbin Watson ratio = 1.98

Figure 4.2.3 Framework of Power Generation Sub-Block



(3) Applied or referred data source

Time series data applied or referred for the Java-Bali electricity model building are as follows;

RGDP	DGEEU、BPS
GDP Deflator	IMF
Consumer Price Index	IMF
Wholesales Price Index	IMF
Population	DGEEU
Electricity Price	DGEEU & PLN
Electricity Consumption & Generation	DGEEU & PLN
Household Electrification	PLN
Load Factor	PLN
No. of Customers	PLN
Fuel Consumption	IEA

As for power generation, the generated output and the purchased power by PLN are handled, because we have not the time series data on captive power.

(4) Observation year

The base year for the demand forecasting and the observation year of data are shown in Table 4.2.2. The base year is 2000, while the actual values for 2001 are input of electricity demand, generated output and peak load.

Table 4.2.2 Base Year and Observation Year

Observation Year	1980 – 2000
Base Year	2000, Excluding electricity demand
RGDP applied	1980 – 2000
Electricity consumption, Generation and Peak Load	1980 – 2001, Input 2001 actual values

As for other data, re-check is carried out and revised as follows;

1) As the published deflator (IMF Statistics) as one of macro indicators was changed, the deflator was revised in some years.
2) As the mismatch between the electricity demand total in the Java-Bali Region and the sum total by sub-region was found, the latter was adopt as the input data (mismatch period of 1992 - 1995).
3) As the dis-consistency was found in the historical RGDP data by sub-region, data before 1992 were adjusted, because the classification of RGDP component by sub-region (BPS Statistics) was changed between before 1992 and after 1993.

4.3 Forecasted Electricity Demand by Sector

In the first phase, electricity demand in the Java-Bali Region is forecasted until 2010, and the forecasted year is extended until 2015 in the second phase. Both forecasted results are the same until 2010. Electricity demand forecasting in the first phase was carried out for the purpose of preparing materials to examine whether power shortage is likely to happen in 2003 or 2004. In this report, both results are separately described and the details is the latter section.

4.3.1 Scenario

Main points of the scenario prepared as Case 1 and Case 2 are briefly shown in Table 4.3.1. GDP scenario is the same as PLN Low Case until 2010 with an annual average growth rate of 4.1 %. As for the price scenario, Case 1 raises the prices to the level of 6-7 cent/kWh (considering an exchange rate of Rp. 8000/ US$) until 2005, that is, nominal prices are doubled to current price levels. In Case 2, nominal prices are increased with inflation (consumer price index). Price scenario is shown in Table 4.3.2.

Table 4.3.1 Characteristics of Scenario (JICA/LPE)

<table>
<tr><td colspan="2"></td><td colspan="4">Scenario</td></tr>
<tr><td colspan="2" rowspan="2">GDP Growth (%)</td><td>2000-2005</td><td>2005-2010</td><td>2010-2015</td><td>2000-2015</td></tr>
<tr><td>3.8</td><td>4.3</td><td>4.5</td><td>4.2</td></tr>
<tr><td rowspan="2">Price</td><td>Case 1</td><td colspan="4">Nominal prices increase based on the new pricing schedule.</td></tr>
<tr><td>Case 2</td><td colspan="4">Real price constant
(Nominal prices increase with inflation)</td></tr>
</table>

Table 4.3.2 Price Scenario (JICA/LPE Case 1)

Price (Rupiah/kWh)	1999	2000	2001	2002	2003	2004	2005
Industry	210.3	299.6	365.2	429.3	480.8	533.7	587.1
G.R (%)		42.5	21.9	17.6	12.0	11.0	10.0
Residential	197.7	210.9	311.0	395.1	442.5	486.8	535.4
G.R (%)		6.7	47.5	27.0	12.0	10.0	10.0
Commercial	317.2	378.6	447.7	506.2	566.9	623.6	686.0
G.R (%)		19.4	18.3	13.1	12.0	10.0	10.0
Public	265.8	265.8	460.6	507.1	568.0	624.7	687.2
G.R (%)		0.0	73.3	10.1	12.0	10.0	10.0
Average	221.9	276.9	360.9	430.6	482.6	533.4	587.1
G.R (%)		24.8	30.4	19.3	12.1	10.5	10.1

The detailed scenario is shown in Table 4.3.3. As shown in the Table, the electricity demand, generation and peak load are input the actual values of 2001. As just mentioned above, the GDP scenario is the same as PLN Low Case until 2010. Also the growth rates of population and household electrification ratio were set as the same PLN scenario. Inflation is set between from 10 % to 8 %. In the Table 4.3.3, PLN scenario is also attached as a reference.

After 2011, the GDP growth rate is maintained at the 2010 level of 4.5 % and the price scenario adopts the real price constant case. Household electrification is set from 81 % in 2010 to 93 % in 2015, which is a time trend of annual average growth of 3 %. Inflation is set at 7 % per annum.

Table 4.3.3 Detailed Scenario (JICA/LPE and PLN)

PLN			2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
GDP	Low	G.R (%)		3.4	3.7	3.7	3.9	4.1	4.2	4.2	4.3	4.5	4.5
	Medium	G.R (%)		3.8	3.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
	High	G.R (%)		3.9	4.9	5.3	5.6	6.0	6.2	6.3	6.4	6.4	6.4
Population		G.R (%)	1.08	1.07	1.05	1.03	0.99	0.96	0.93	0.91	0.88	0.84	0.81
Electrification rati		%	58.3	59.2	60.2	62.2	64.4	66.7	69.1	71.8	74.6	77.5	80.6
Total Loss		%	14.7	15.2	13.8	13.8	13.5	13.3	13.2	13.1	13.1	13.0	13.0

JICA/LPE			2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
GDP	Case 1	G.R (%)	4.7	3.4	3.7	3.7	3.9	4.1	4.2	4.2	4.3	4.5	4.5	4.5	4.5	4.5	4.5	4.5
	Case 2	G.R (%)		the same as Case 1					the same as Case 1					Same to Case 1				
Price	Case 1	G.R (%)		18.3-73.3	11-27	12.0	10.0	10.0	Real value constant (the same as inflation)					Real value constant (the same as inflation)				
	Case 2	G.R (%)		Real value constant (the same as inflation)					Real value constant (the same as inflation)					Real value constant (the same as inflation)				
Population		G.R (%)	1.08	1.07	1.05	1.03	0.99	0.96	0.93	0.91	0.88	0.84	0.81	(Trend: Average 1.1% Growth)				
Electrification rati		%	58.3	59.2	60.2	62.2	64.4	66.7	69.1	71.8	74.6	77.5	80.6	83.1	(Trend: Average 3% Growtl			93.1
Inflation		%	3.7	10.0	10.0	10.0	10.0	10.0	9.0	9.0	8.5	8.0	8.0	7.0	7.0	7.0	7.0	7.0
Total Loss		%	14.7	13.2	13.8	13.8	13.5	13.3	13.2	13.1	13.1	13.0	13.0	13.0	13.0	13.0	13.0	13.0

4.3.2 Short-Medium Term Electricity Demand Forecasted Results (2001-2010)

Summary of simulation results is shown in Table 4.3.4 and the forecasted peak load is shown in Figure 4.3.1. In the Figure, examples of RUKN, Low Case of PLN, and Low/High Cases of World Bank are also shown as references.

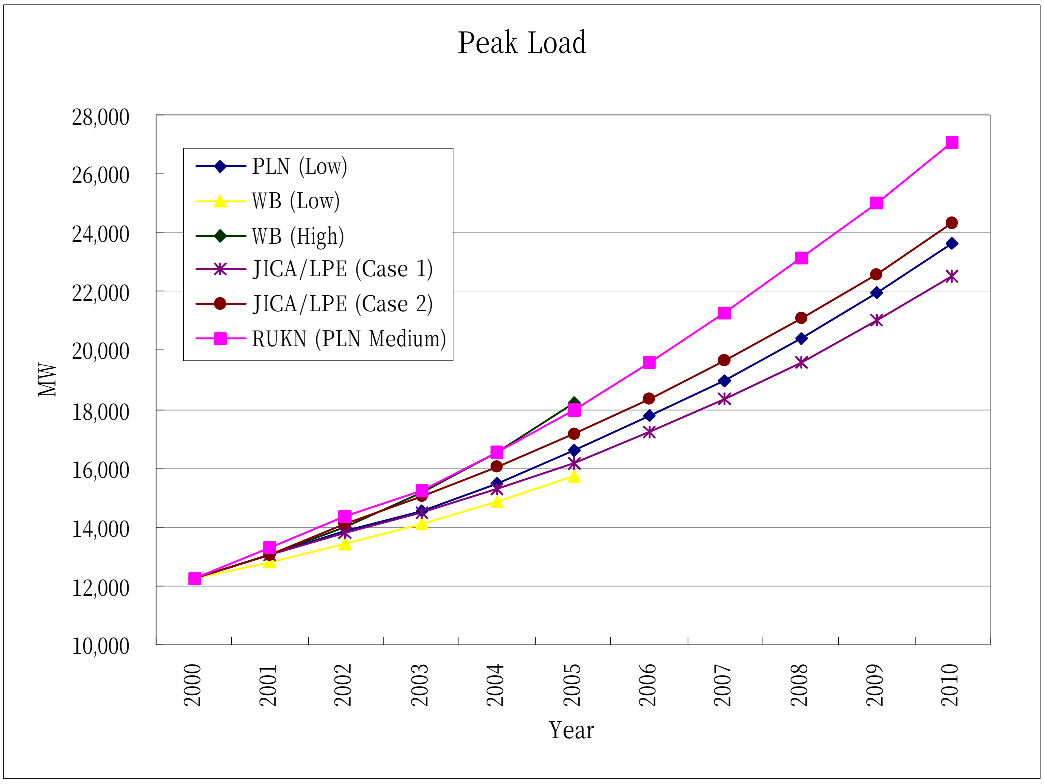
In Case 1, the electricity demand would grow from 67,927GWh in 2001 to 84,193 GWh in 2005 (5.7% growth in 2000/05) and to 118,704 Gwh in 2010 (7.1% growth in 2005/10). In Case 2, the electricity demand would grow from 67,927 GWh in 2001 to 89,461GWh in 2005 (7.0% growth in 2000/05) and to 127,669 GWh in 2010 (7.4% growth in 2005/10). The peak load, in Case 1, will increase 13,041 MW in 2001 to 16,185 MW in 2005 (2000/05 growth rate of 5.8%) and to 22,539 MW in 2010 (2005/10 growth rate of 6.9%). In Case 2, the peak load will increase to 17,170 MW in 2005 (2000/05 growth rate of 6.6%) and to 24,297 MW in 2010 (2005/10 growth rate of 7.3%).

Table 4.3.4 Summary of Simulation Results

				2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
						Forecasted								
PLN	Low Case	Demand	GWh	63,872	69,026	73,547	78,482	83,952	90,086	96,582	103,410	111,025	119,543	128,795
			G.R (%)		8.07	6.55	6.71	6.97	7.31	7.21	7.07	7.36	7.67	7.74
		Genaration	GWh	74,901	81,403	86,578	92,078	98,168	105,108	112,562	120,387	129,252	139,015	149,774
			G.R (%)		8.68	6.36	6.35	6.61	7.07	7.09	6.95	7.36	7.55	7.74
		Peak Load	MW	12,231	13,025	13,854	14,526	15,486	16,582	17,758	18,992	20,391	21,930	23,628
			G.R (%)		6.49	6.36	4.85	6.61	7.08	7.09	6.95	7.37	7.55	7.74
	Medium	Demand	GWh	63,872	70,387	75,899	82,092	89,272	97,469	106,223	115,550	125,463	135,973	147,088
			G.R (%)		10.20	7.83	8.16	8.75	9.18	8.98	8.78	8.58	8.38	8.17
		Genaration	GWh	74,901	81,717	88,811	95,952	104,119	113,675	123,749	134,468	145,845	157,890	170,610
			G.R (%)		9.10	8.68	8.04	8.51	9.18	8.86	8.66	8.46	8.26	8.06
		Peak Load	MW	12,231	13,326	14,344	15,245	16,523	18,000	19,595	21,292	23,119	25,028	27,073
			G.R (%)		8.95	7.64	6.28	8.38	8.94	8.86	8.66	8.58	8.26	8.17
	High	Demand	GWh	63,872	70,387	77,521	85,762	95,327	106,178	118,360	131,991	147,525	164,917	184,357
			G.R (%)		10.20	10.14	10.63	11.15	11.38	11.47	11.52	11.77	11.79	11.79
		Genaration	GWh	74,901	81,717	89,840	99,060	109,739	121,960	135,799	151,273	169,074	188,672	211,075
			G.R (%)		9.10	9.94	10.26	10.78	11.14	11.35	11.39	11.77	11.59	11.87
		Peak Load	MW	12,231	13,326	14,651	15,927	17,644	19,609	21,834	24,322	27,184	30,335	33,937
			G.R (%)		8.95	9.94	8.71	10.78	11.14	11.35	11.40	11.77	11.59	11.87
WB	Low Case	Demand	GWh	63,872	67,386	70,839	74,605	78,806	83,589					
			G.R (%)		5.50	5.12	5.32	5.63	6.07					
		Peak Load	MW	12,231	12,810	13,432	14,110	14,867	15,730					
			G.R (%)		4.73	4.86	5.05	5.36	5.80					
	High Case	Demand	GWh	63,872	68,517	73,773	80,093	87,668	96,743					
			G.R (%)		7.27	7.67	8.57	9.46	10.35					
		Peak Load	MW	12,231	13,025	13,989	15,148	16,539	18,205					
			G.R (%)		6.49	7.40	8.29	9.18	10.07					
JICA/LPE	Case 1	Demand	GWh	63,872	67,927	71,017	74,619	79,017	84,193	89,896	96,076	102,868	110,457	118,704
			G.R (%)		6.35	4.55	5.07	5.89	6.55	6.77	6.87	7.07	7.38	7.47
		Generation	GWh	74,901	78,273	82,386	86,544	91,328	97,087	103,543	110,534	118,348	126,933	136,410
			G.R (%)		4.50	5.26	5.05	5.53	6.31	6.65	6.75	7.07	7.25	7.47
		Peak Load	MW	12,231	13,041	13,821	14,497	15,266	16,185	17,220	18,348	19,612	21,000	22,539
			G.R (%)		6.62	5.98	4.89	5.31	6.02	6.40	6.55	6.89	7.08	7.33
	Case 2	Demand	GWh	63,872	67,927	72,860	77,969	83,468	89,461	95,940	102,861	110,378	118,697	127,669
			G.R (%)		6.35	7.26	7.01	7.05	7.18	7.24	7.21	7.31	7.54	7.56
		Generation	GWh	74,901	78,273	84,525	90,430	96,473	103,161	110,505	118,340	126,988	136,402	146,712
			G.R (%)		4.50	7.99	6.99	6.68	6.93	7.12	7.09	7.31	7.41	7.56
		Peak Load	MW	12,231	13,041	14,089	15,073	16,071	17,170	18,374	19,659	21,075	22,612	24,297
			G.R (%)		6.62	8.03	6.98	6.62	6.84	7.01	6.99	7.20	7.29	7.45

Forecasted

Figure 4.3.1 Forecasted Peak Load



4.3.3 Long Term Electricity Demand Forecasted Results (2001-2015)

According to the simulation results targeting the year 2015, the electricity demand is expected to rise at the average growth rates of 6.8 % in Case 1 and 7.2 % in Case 2 respectively in the period of 2000-2015. Peak load would increase at a 6.7 % growth rate in Case 1 and 7.2 % in Case 2 during same period mentioned above. Table 4.3.5 shows the outline summarizing the simulation results over a five span.

Table 4.3.5 Outline of Simulation Results

JICA/LPE		2000	2005	2010	2015	2000/2015
Java-Bali	Demand (GWh)	63872	84193	118704	171825	
Case 1	G.R (%)		(5.68)	(7.11)	(7.68)	(6.82)
	Generation (GWh)	74901	97087	136410	197455	
	G.R (%)		(5.33)	(7.04)	(7.68)	6.68)
	Peak Load (MW)	12231	16185	22539	32549	
	G.R (%)		(5.76)	(6.85)	(7.63)	(6.74)
Java-Bali	Demand (GWh)	63872	89461	127669	183674	
Case 2	G.R (%)		(6.97)	(7.37)	(7.55)	(7.30)
	Generation (GWh)	74901	103161	146712	211070	
	G.R (%)		(6.61)	(7.30)	(7.55)	(7.15)
	Peak Load (MW)	12231	17170	24297	34800	
	G.R (%)		(7.02)	(7.19)	(7.45)	(7.22)

Table 4.3.6 shows the actual values and the forecasted results of the peak load in the period of 2000-2015. The difference between the results of Case 1 and Case2 is 985 MW in 2005, 1,758 MW in 2010, and 2,251 MW in 2015. As described before in the Section 4.3.1 “Scenario”, the difference of scenario setting of both cases is the price scenario only. In the price scenario, values of year 2000 and 2001 is already input actual values, which was large difference in both price scenarios (See Table 4.3.4). Therefore the difference of the peak load was relatively small between both cases.

In this simulation, GDP scenario is only one example. In case that modelers change the GDP scenario, the difference is expected to become lager than the results shown.

Table 4.3.6 Forecasted Peak Load (JICA/LPE)

	2000	2001	2002	2003	2004	2005	2006	2007
Case 1 (MW)	12,231	13,041	13,821	14,497	15,266	16,185	17,220	18,348
Case 2 (MW)	12,231	13,041	14,089	15,073	16,071	17,170	18,374	19,659
	2008	2009	2010	2011	2012	2013	2014	2015
Case 1 (MW)	19,612	21,000	22,539	24,225	26,058	28,048	30,208	32,549
Case 2 (MW)	21,075	22,612	24,297	26,099	28,040	30,131	32,380	34,800

The followings show the simulation results of Case1 and Case 2. Figure 4.3.2 shows the forecasted electricity demand of Case 1 (Bar Graph) and Case 2 (Polygonal Graph). Figure 4.3.3 shows the forecasted electricity demand structure.

(1) Simulation results of Case 1

Regarding the electricity demand by sector, demand for the industrial (manufacturing) sector is likely to increase from 30.0 TWh in 2000 to 55.1 TWh in 2010 and to 79.8 TWh in 2015 (up 6.7% per year during 2000-2915). Demand for the commercial sector is projected to climb from 8.3 TWh in 2000 to 17.9 TWh in 2010 and to 27.8 TWh by 2015 (up 8.4% per year). Demand for the residential sector will increase from 22.6 TWh (2000) to 40.9 TWh (2010) and to 58.9 TWh in 2015 (up 6.6 % per year). Public sector demand will increase from 2.9 TWh (2000) to 4.7 TWh and to 5.3 TWh in 2015 at the average growth rate of 4.0 %..

As shown in Figure 4.3.3, presently the biggest consumer of electricity is the industrial sector, followed by the residential sector. In 2001, the industrial sector accounted for 46.3 % of the total demand, the residential sector for 36.0 %, the commercial sector for 12.9 %, and the government/public sector for 4.8 %. The share of the commercial sector shows an increasing tendency, i.e.,16.2 % in 2015 (Case 1), whereas the industrial sector maintains almost same share, while the share of the residential and the public sectors will decrease slightly.

(2) Simulation results of Case 2

Demand for the industrial (manufacturing) sector is expected to increase from 30.0 TWh in 2000 to 59.2 TWh in 2010 and to 85.7 TWh in 2015 (up 7.2 % per year during 2000-2015). Demand for the commercial sector is projected to climb from 8.3 TWh in 2000 to 18.5 TWh in 2010 and to 28.7 TWh by 2015 (up 8.7 % per year). Demand for the residential sector will increase from 22.6 TWh (2000) to 44.9 TWh (2010) and to 63.6 TWh (2015) at the growth rate of 7.1 %. The public sector will show a 4.5 % growth from 2.9 TWh (2000) to 5.0 TWh and to 5.7 TWh (2015). The share by sector in Case 2 showed similar results to Case 1, however, the share of the commercial sector in 2015 at 15.3 % is slightly lower than the results of Case1.

Figure 4.3.2 Electricity Demand by Sector (JICA/LPE Case 1 &Case 2)

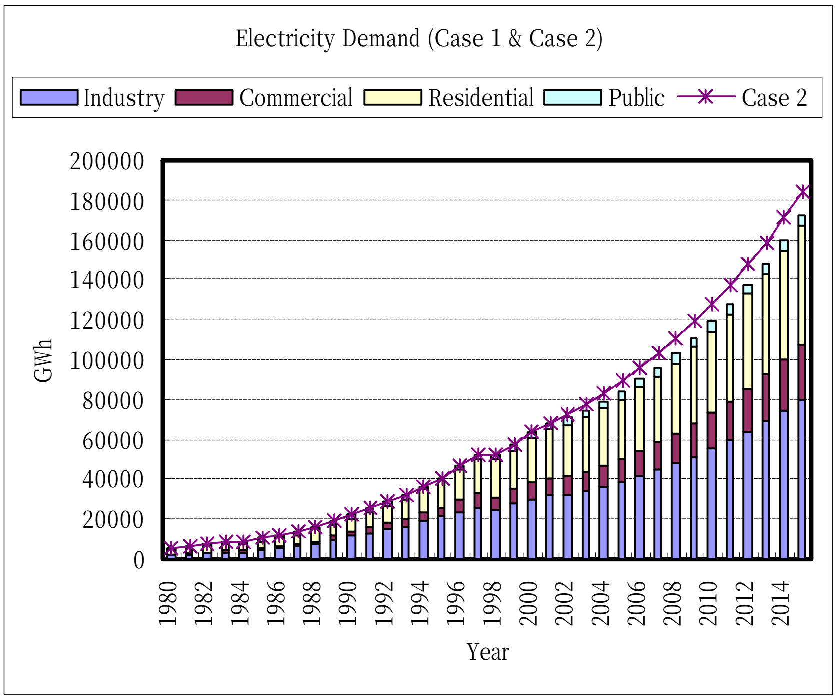
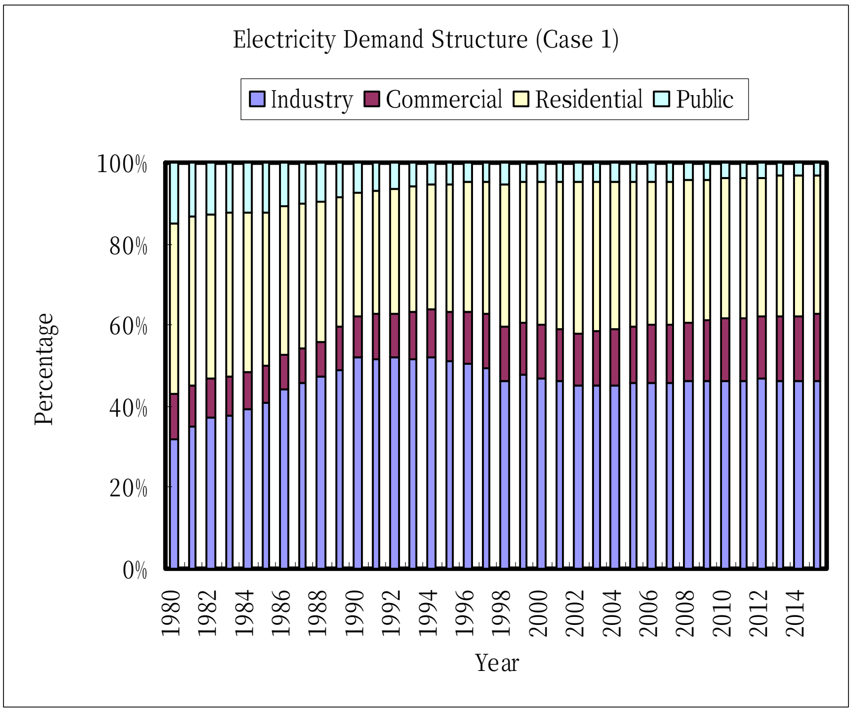


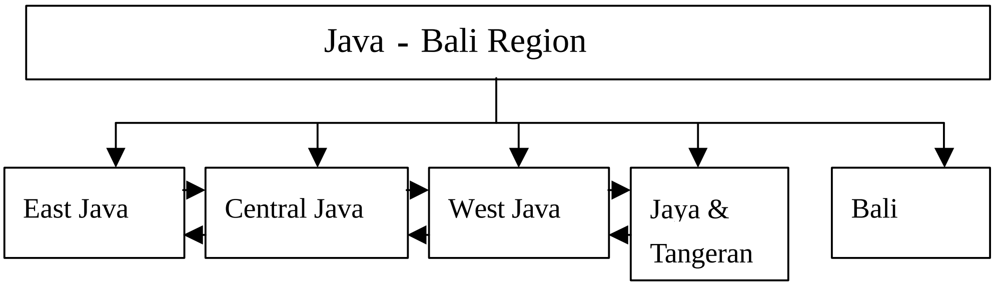
Figure 4.3.3 Electricity Demand Structure by Sector (Case 1)



4.4 Electricity Demand by Sub-Region

In this section, electricity demand in the Java-Bali Region is distributed into five (5) areas (sub-regions) taking into consideration the economic structure and electricity demand structure in each area. Each sub-region corresponds to the classification of PLN service area, which consists of Jakarta (Jaya & Tangeran), West Java, Central Java, East Java and Bali as shown in Figure 4.4.1. Figure 4.4.1 also shows the concept of regional economic activities and electricity demand shift.

Figure 4.4.1 Concept of Regional Demand Shift



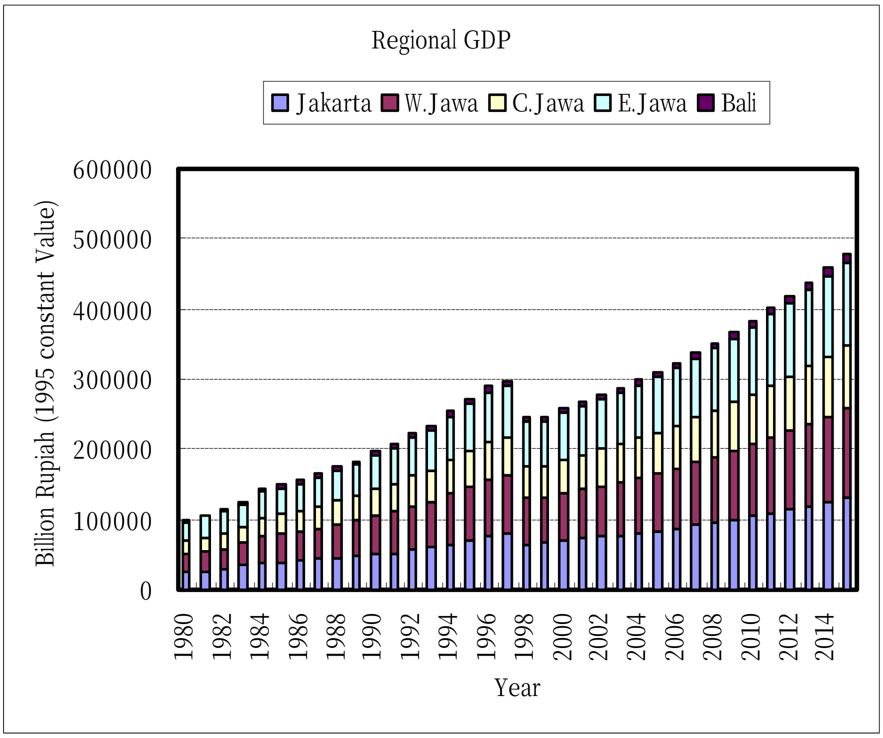
4.4.1 RGDP by Sub-Region (Area)

Figure 4.4.2 shows the historical trends and the forecasted results until 2015 of the targeted areas in the Java-Bali Region. In this model, the RGDP by area is obtained by the following procedure;

1) the RGDP total in the Java-Bali Region is set by the economic scenario (See Table 4.3.4);
2) the sectoral RGDP, comprising of the manufacturing industry, the commercial, the public and others, which basically corresponds to the classification of the electricity demand sector, is distributed by taking into consideration the historical trends of economic activities in each targeted area; and
3) finally the sectoral GDP is distributed to each area' GDP by sector using historical trend (logarithmic trend).

Figure 4.4.2 also shows the characteristics by Area. From the Figure, we cannot find out the clear shift between each Area. The annual growth rates of RGDP during 2001–2015 are projected at 4.2 % in the Jakarta Area, 4.4 % in the West Java Area, 4.2 % in the Central Java Area, 4.0 % in the East Java Area and 4.5 % in the Bali Area.

Figure 4.4.2 RGDP by Area



(1) Jakarta Area

Figure 4.4.3 shows the historical trend and the forecasted result until 2015 of the RGDP by sector in the Jakarta Area. The biggest contributor to GDP in the Area is the commercial sector, followed by the industrial sector and others. The commercial sector will continue to expand its share. The industrial sector and the others sector will maintain their share and the public sector will decrease its share.

As for the annual average growth rates during 2001 –2015, the industrial sector is expected to grow at 4.4 %, the commercial sector at 4.2 %, the public sector at 1.1 % and the others sector at 4.2 %.

(2) West Java Area

Figure 4.4.4 shows the historical trend and the forecasted result until 2015 of the RGDP by sector in the West Java Area. In the Area, the sectors of the industry and others account for major role at present. The industrial sector, especially, will continue to expand its share. The commercial sector will maintain its share and the others will decrease its share slightly.

As for the annual average growth rates during 2001 –2015, the industrial sector is expected to grow at 5.3 %, the commercial sector at 4.7 %, the public sector at 1.1 % and the others sector at 3.6 %.

Figure 4.4.3 RGDP in the Jakarta Area

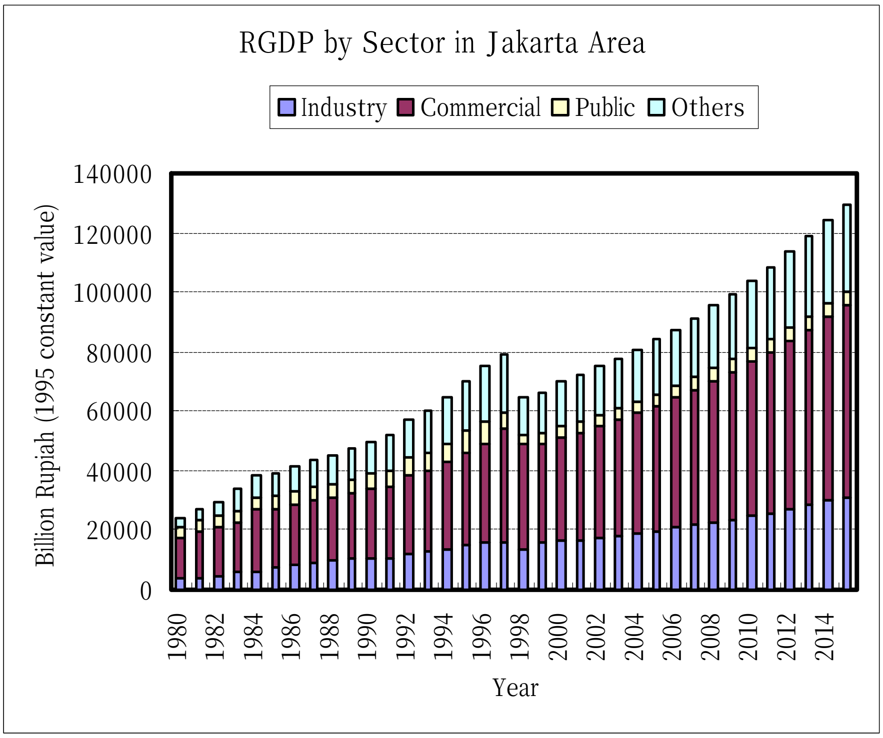
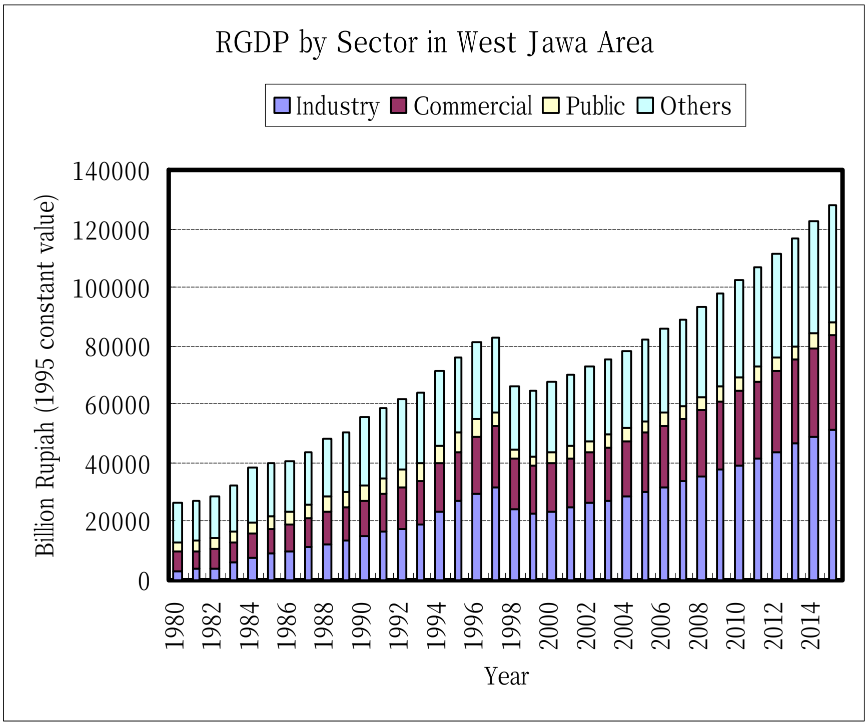


Figure 4.4.4 RGDP in the West Java Area

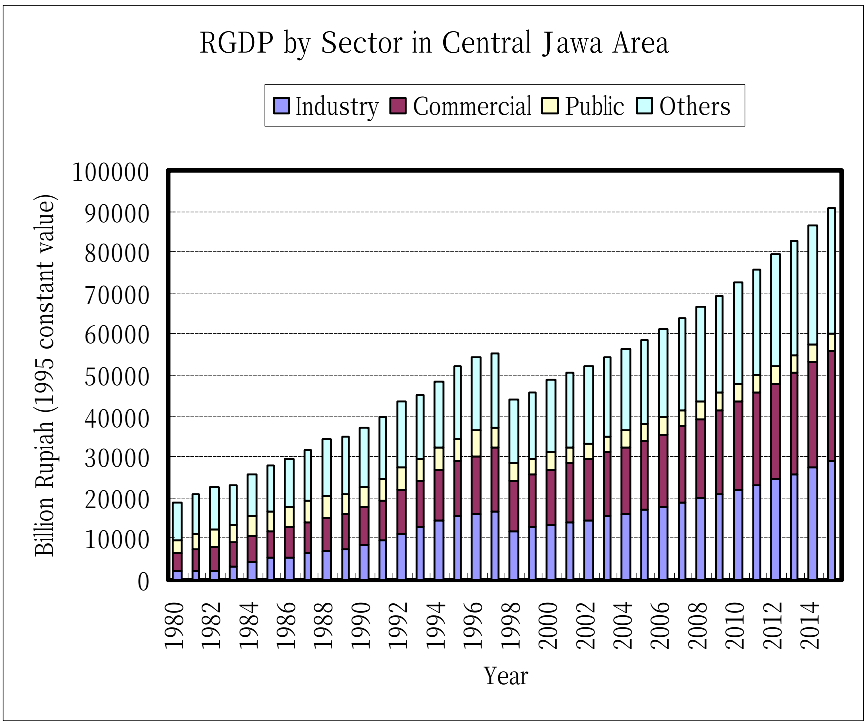


(3) Central Java Area

Figure 4.4.5 shows the historical trend and the forecasted result until 2015 of the RGDP by sector in the Central Java Area. In the Area, the sectors of industry and others account for slightly below 30 % respectively. The commercial sector accounts for about 20 % of the RGDP. The industrial and commercial sectors will expand their share slightly. On the other hand, the others will maintain its share and the public sector will decrease its share.

As for the annual average growth rates during 2001 –2015, the industrial sector is expected to grow at 5.3 %, the commercial sector at 4.5 %, the public sector at 1.0 % and others sector at 3.6 %.

Figure 4.4.5 RDP in the Central Java Area

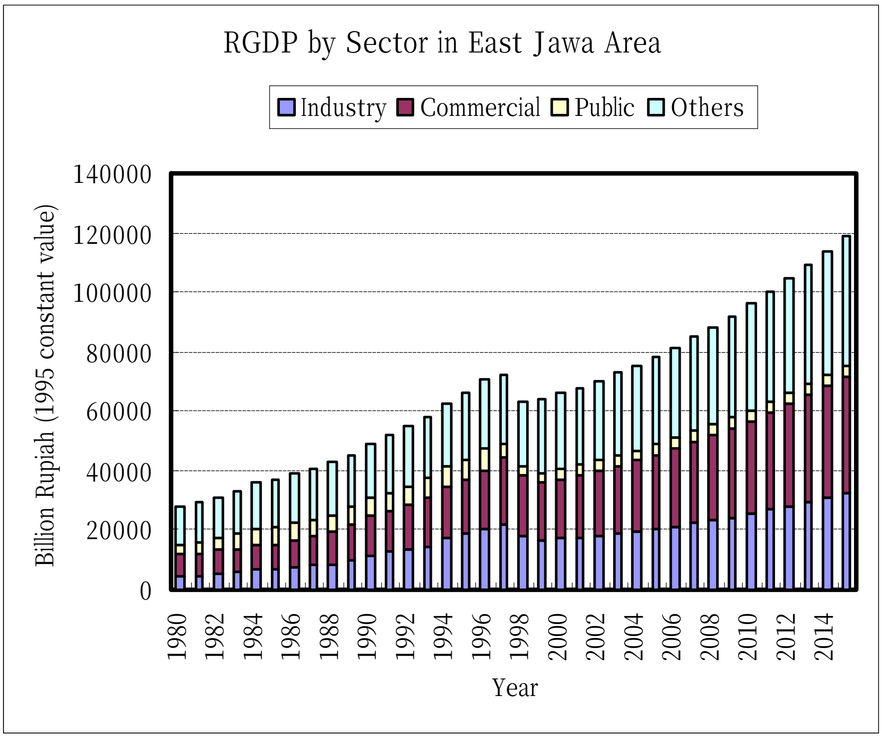


(4) East Java Area

Figure 4.4.6 shows the historical trend and the forecasted result until 2015 of the RGDP by sector in the East Java Area. The biggest contributor to the RGDP in the Area is the others sector, accounting for about 30 %, followed by the industrial sector and the commercial sector, accounting for about 20 % respectively. The industrial and commercial sectors will expand their share slightly. On the other hand, the other sectors will maintaine its share and the public sector will decrease its share.

As for the annual average growth rates during 2001 –2015, the industrial sector is expected to grow at 4.3 %, the commercial sector at 4.6 %, the public sector at 0.8 % and others sector at 3.6 %.

Figure 4.4.6 RGDP in the East Java Area

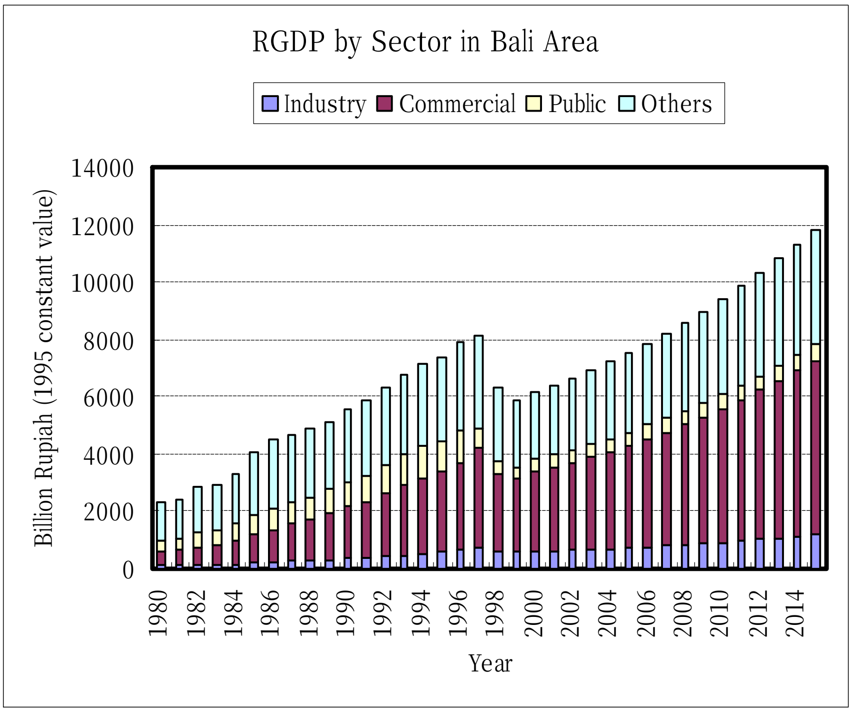


(5) Bali Area

Figure 4.4.7 shows the historical trend and the forecasted result until 2015 of the RGDP by sector in the Bali Area. In the Area, GDP of the commercial sector is as large as that of others at present. The commercial sector, however, is expected to grow rapidly in the future. The industrial GDP will keep its share. On the other hand, the others and the public sector will decrease their share.

As for the annual average growth rates during 2001 –2015, the industrial sector is projected to grow at 4.7 %, the commercial sector at 5.4 %, the public sector at 1.3 % and the others sector at 3.7.

Figure 4.4.7 RGDP in the Bali Area



4.4.2 Electricity Demand by Sub-Region (Area)

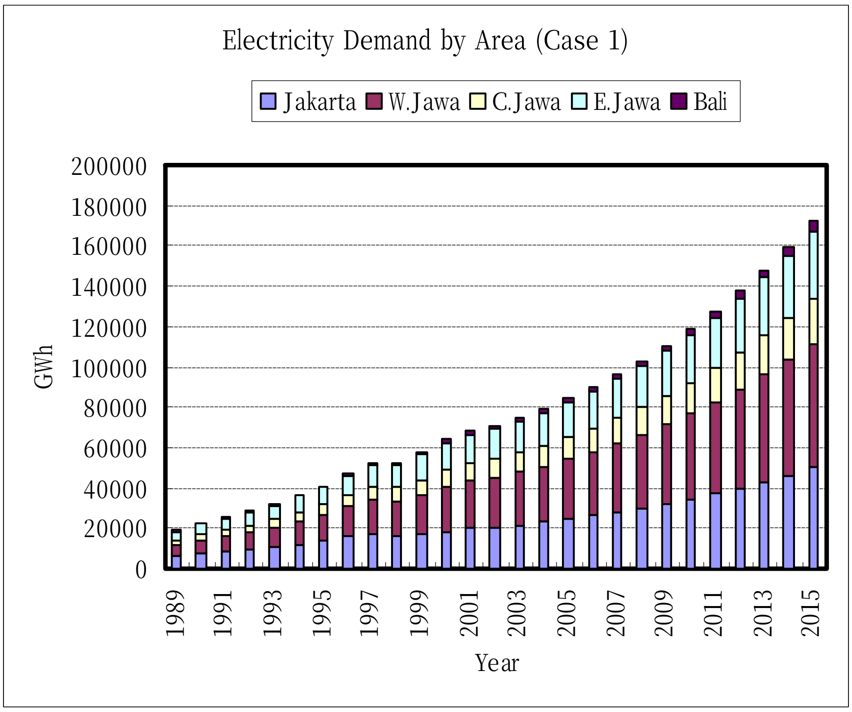
Electricity demand by sector and by area in the Java-Bali Region is forecasted by the following procedure;

1) firstly, the model runs under the premise that the regional demand by sector simulated in section 4.3 is maintained, that is, the demand by sector in the Java-Bali Region is not changeable;
2) secondly, electricity demand by sub-region (area) is obtained from the relationship between RGDP by area and by sector and, electricity consumption by area and by sector. Intensities are applied for electricity demand projection. The intensities are not fixed for reflecting on the industrial structure change in each area.; and
3) finally, peak load by area is distributed from the entire Java-Bali system to each area by use of historical trends of electricity demand and peak load by area in the past six (6) years, that is, the load intensity with respect to electricity demand that was adopt in each area. As described later, the area classification in the Java-Bali power system is based on P3B's service area.

Table 4.4.1 shows the electricity demand forecasted by sub-region (area) by sector and Table 4.4.2 shows the forecasted results in the Java-Bali Region by sector. In 2001, the electricity demand by area was 19,855 GWh in the Jakarta Area, 23,613 GWh in the West Java Area, 8,888 GWh in the Central Java Area, 13,941 GWh in the East Java Area, and 1,630 GWh in the Bali Area.

Figure 4.4.8 also shows the historical trend and the forecasted result of Case 1 until 2015. It is shown that the West Java Area expands its share and demand, and the East Java Area decreases its share. Regarding the share by area in 2015, the Jakarta Area is expected to account for 29 %, the West Java Area for 36 %, the Central Java Area for 13 %, the East Java Area for 19 %, and the Bal Area for2.8 %. AS for growth rates of electricity demand by sub-region (area), the order is Bali, West Java, Jakarta, Central Java and East Java from the top of the list in both cases for Case 1and Case2 (See Table 4.4.1).

Figure 4.4.8 Electricity Demand by Area (JICA/LPE Case 1)



Regarding the maximum demand (Peak Load), its area is classified into four (4) sub-region of areas 1, 2, 3, and 4 by the P3B service area, which is a little bit different from the PLN service area. Area 1 includes PLN service area Jakarta and a part of West Java. Area 4 consists of East Java and Bali.

The forecasted results are shown in Table 4.4.3. Peak load by area for the year 2001 was 5,495 MW in Area 1, 2,316 MW in Area 2, 2,057 MW in Area 3, 2,827 MW in Area 4 (excluding Bali), and 346 MW in Bali. In Case 1, it is expected that Area 1 will be 9,393 MW, Area 2 is 4,199 MW, Area 3 will be 3,401 MW, Area 4 (excluding Bali) will be 4,828 MW, and Bali will be 718 MW in 2010. In 2015, Area 1 will be 13,542MW, Area 2 will be 6,144 MW, Area 3 will be 4,919 MW, Area 4 (excluding Bali) will be 6,849 MW, and Bali will be 1,095 MW.

Figure 4.4.9 shows the historical trend and the forecasted results of peak load until 2015. In Figure 4.4.9,the bar graph shows the peak load by area for Case 1 and the polygonal graph shows the system peak load for Case 2. Peak load by area in the Java-Bali Region shows the characteristic that Area 1 accounts for a large share of about 40 %. In the case of adding Area 2 to Area 1, the share will reach 60 %.

Figure 4.4.9 Peak Load by Area (JICA/LPE Case 1 and Case 2)

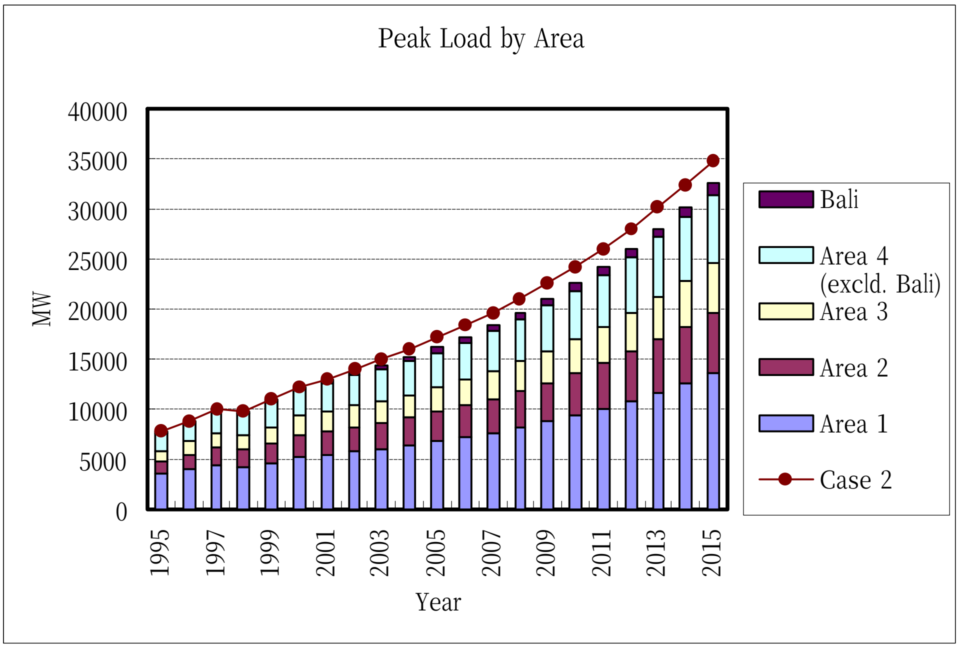


Table 4.4.1 Forecasted Electricity Demand by Sub-Region and by Sector

Demand by Sub-Region & Sub-Sector

				1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2000/05	2005/10	2010/15	2000/15
Case 1	Jakarta	Total	GWh	16720	18510	19855	20823	21867	23156	24649	26292	28069	30021	32205	34577	37162	39964	43000	46288	49847	5.89	7.00	7.55	6.82
		Residential		5767	6252	6768	7270	7575	7933	8345	8813	9339	9926	10583	11312	12128	13026	14011	15087	16262	5.94	6.27	7.53	6.58
		Industry		5541	6281	6706	6766	7082	7404	7986	8533	9116	9751	10460	11218	12031	12901	13833	14831	15899	4.92	7.03	7.22	6.39
		Commercial		4158	4689	5021	5304	5639	6091	6602	7166	7777	8433	9219	10052	10958	11943	13015	14180	15446	7.08	8.77	8.97	8.27
		Public		1255	1295	1360	1483	1570	1647	1717	1780	1838	1892	1944	1995	2044	2094	2142	2191	2239	5.79	3.05	2.34	3.72
	West Java	Total	GWh	19721	22070	23613	24572	25893	27500	29418	31520	33814	36325	39127	42169	45480	49066	52948	57148	61609	5.92	7.47	7.91	7.09
		Residential		5601	6615	7159	7700	8036	8428	8879	9393	9970	10614	11335	12137	13036	14025	15112	16302	17603	6.06	6.45	7.72	6.74
		Industry		12759	13856	14690	14982	15845	16912	18218	19643	21171	22840	24701	26705	28860	31179	33675	36359	39247	5.63	7.95	8.00	7.19
		Commercial		913	1112	1198	1272	1359	1476	1607	1752	1910	2084	2282	2498	2734	2991	3271	3576	3909	7.65	9.22	9.37	8.75
		Public		448	487	566	617	653	685	714	740	764	787	808	829	850	870	891	911	931	7.96	3.04	2.33	4.42
	Central Java	Total	GWh	7887	8709	8888	9371	9840	10400	11055	11779	12568	13438	14400	15468	16629	17893	19266	20757	22373	4.89	6.95	7.66	6.49
		Residential		3879	4319	4520	4853	5056	5294	5569	5883	6235	6628	7069	7558	8107	8711	9374	10100	10893	5.22	6.30	7.56	6.36
		Industry		2938	3202	3156	3218	3402	3630	3910	4214	4541	4898	5296	5724	6184	6680	7213	7786	8403	4.07	7.92	7.98	6.64
		Commercial		616	692	703	746	796	862	938	1021	1111	1211	1325	1448	1583	1730	1890	2064	2254	6.26	9.09	9.24	8.19
		Public		454	496	509	554	586	613	638	661	682	701	719	737	755	772	789	807	824	5.19	2.93	2.24	3.44
	East Java	Total	GWh	11849	13135	13941	14503	15164	15973	16933	17991	19135	20393	21795	23318	24977	26772	28714	30813	33080	5.21	6.61	7.24	6.35
		Residential		4182	4829	5280	5657	5880	6144	6449	6798	7191	7629	8120	8666	9278	9951	10689	11496	12376	5.96	6.09	7.39	6.47
		Industry		6292	6629	6844	6899	7215	7619	8123	8672	9257	9895	10606	11367	12181	13053	13987	14986	16055	4.15	6.95	7.15	6.07
		Commercial		854	1097	1077	1142	1220	1323	1440	1569	1709	1864	2040	2232	2441	2669	2918	3188	3483	5.59	9.16	9.31	8.01
		Public		521	579	541	805	849	887	921	951	979	1005	1029	1053	1076	1098	1121	1143	1165	9.71	2.71	2.05	4.77
	Bali	Total	GWh	1259	1441	1630	1748	1855	1988	2138	2306	2489	2692	2921	3172	3448	3750	4080	4441	4835	8.22	8.20	8.80	8.41
		Residential		519	613	710	765	800	840	886	939	998	1063	1137	1218	1309	1410	1520	1640	1772	7.66	6.56	7.79	7.34
		Industry		81	76	82	83	87	92	99	106	114	122	131	141	152	163	175	188	203	5.42	7.35	7.51	6.76
		Commercial		600	688	767	822	885	969	1063	1167	1280	1406	1550	1706	1878	2065	2271	2495	2740	9.09	9.93	9.94	9.65
		Public		59	64	71	78	82	87	91	94	97	100	103	106	109	112	115	118	120	7.12	3.26	2.52	4.28
Check	Jawa-Bali Total		GWh	57437	63872	67927	71017	74619	79017	84193	89896	96076	102868	110457	118704	127696	137446	148009	159447	171823				

				1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2000/05	2005/10	2010/15	2000/15
Case2	Jakarta	Total	GWh	16720	18510	19855	21279	22748	24327	26045	27900	29878	32025	34404	36968	39714	42672	45857	49285	52975	7.06	7.26	7.46	7.26
		Residential		5767	6252	6768	7269	7778	8307	8870	9476	10125	10825	11580	12417	13296	14244	15266	16365	17544	7.25	6.96	7.16	7.12
		Industry		5541	6281	6706	7118	7554	8038	8577	9164	9790	10473	11233	12048	12931	13855	14856	15928	17076	6.43	7.03	7.22	6.89
		Commercial		4158	4689	5021	5407	5822	6288	6816	7398	8028	8726	9517	10377	11312	12330	13436	14639	15946	7.77	8.77	8.97	8.50
		Public		1255	1295	1360	1484	1595	1693	1782	1862	1935	2002	2065	2126	2185	2242	2298	2354	2408	6.59	3.60	2.52	4.22
	West Java	Total	GWh	19721	22070	23613	25376	27218	29216	31405	33779	36322	39089	42156	45466	49017	52843	56965	61402	66178	7.31	7.68	7.80	7.60
		Residential		5601	6615	7159	7700	8251	8825	9439	10099	10809	11575	12412	13322	14290	15337	16466	17682	18991	7.37	7.13	7.35	7.28
		Industry		12759	13856	14690	15762	16900	18163	19566	21097	22737	24538	26529	28680	30995	33486	36166	39049	42150	7.15	7.95	8.00	7.70
		Commercial		913	1112	1198	1297	1403	1523	1659	1809	1971	2152	2356	2579	2823	3088	3377	3692	4035	8.33	9.23	9.37	8.98
		Public		448	487	566	618	663	704	741	774	805	832	859	884	909	932	955	978	1001	8.77	3.59	2.50	4.92
	Central Java	Total	GWh	7887	8709	8888	9553	10237	10964	11750	12597	13501	14480	15560	16725	17970	19313	20759	22315	23989	6.17	7.32	7.48	6.99
		Residential		3879	4319	4520	4853	5192	5544	5920	6325	6759	7228	7740	8296	8887	9526	10214	10955	11751	6.51	6.98	7.21	6.90
		Industry		2938	3202	3156	3385	3629	3899	4199	4526	4877	5260	5687	6147	6642	7174	7747	8363	9025	5.57	7.92	7.98	7.15
		Commercial		616	692	703	760	821	890	968	1054	1147	1250	1368	1495	1634	1786	1951	2131	2327	6.94	9.09	9.24	8.42
		Public		454	496	509	554	595	631	663	692	718	742	764	786	807	827	847	867	886	5.90	3.47	2.42	3.95
	East Java	Total	GWh	11849	13135	13941	14884	15855	16894	18022	19238	20533	21934	23482	25147	26924	28833	30883	33084	35445	6.53	6.89	7.11	6.84
		Residential		4182	4829	5280	5656	6038	6434	6856	7310	7796	8320	8892	9513	10171	10882	11647	12469	13352	7.26	6.77	7.02	7.01
		Industry		6292	6629	6844	7258	7696	8183	8724	9314	9942	10627	11390	12208	13083	14019	15032	16095	17243	5.65	6.95	7.15	6.58
		Commercial		854	1097	1077	1165	1259	1366	1486	1620	1764	1924	2106	2304	2520	2756	3012	3291	3596	6.27	9.16	9.31	8.24
		Public		521	579	541	805	862	912	956	995	1031	1063	1093	1122	1150	1176	1202	1228	1253	10.53	3.26	2.24	5.28
	Bali	Total	GWh	1259	1441	1630	1768	1912	2068	2239	2426	2628	2849	3085	3363	3653	3969	4311	4684	5088	9.22	8.47	8.63	8.78
		Residential		519	613	710	765	821	880	942	1009	1082	1160	1245	1337	1435	1541	1656	1779	1912	8.99	7.25	7.42	7.88
		Industry		81	76	82	87	93	99	106	114	122	131	141	151	163	175	188	202	217	6.94	7.35	7.51	7.27
		Commercial		600	688	767	838	914	1000	1097	1205	1322	1452	1600	1762	1939	2132	2344	2576	2829	9.79	9.93	9.94	9.89
		Public		59	64	71	78	84	89	94	98	102	106	110	113	117	120	123	126	129	7.92	3.81	2.70	4.79
Check	Jawa-Bali Total			57437	63872	67927	72860	77969	83468	89461	95940	102861	110378	118697	127669	137278	147629	158774	170769	183674				

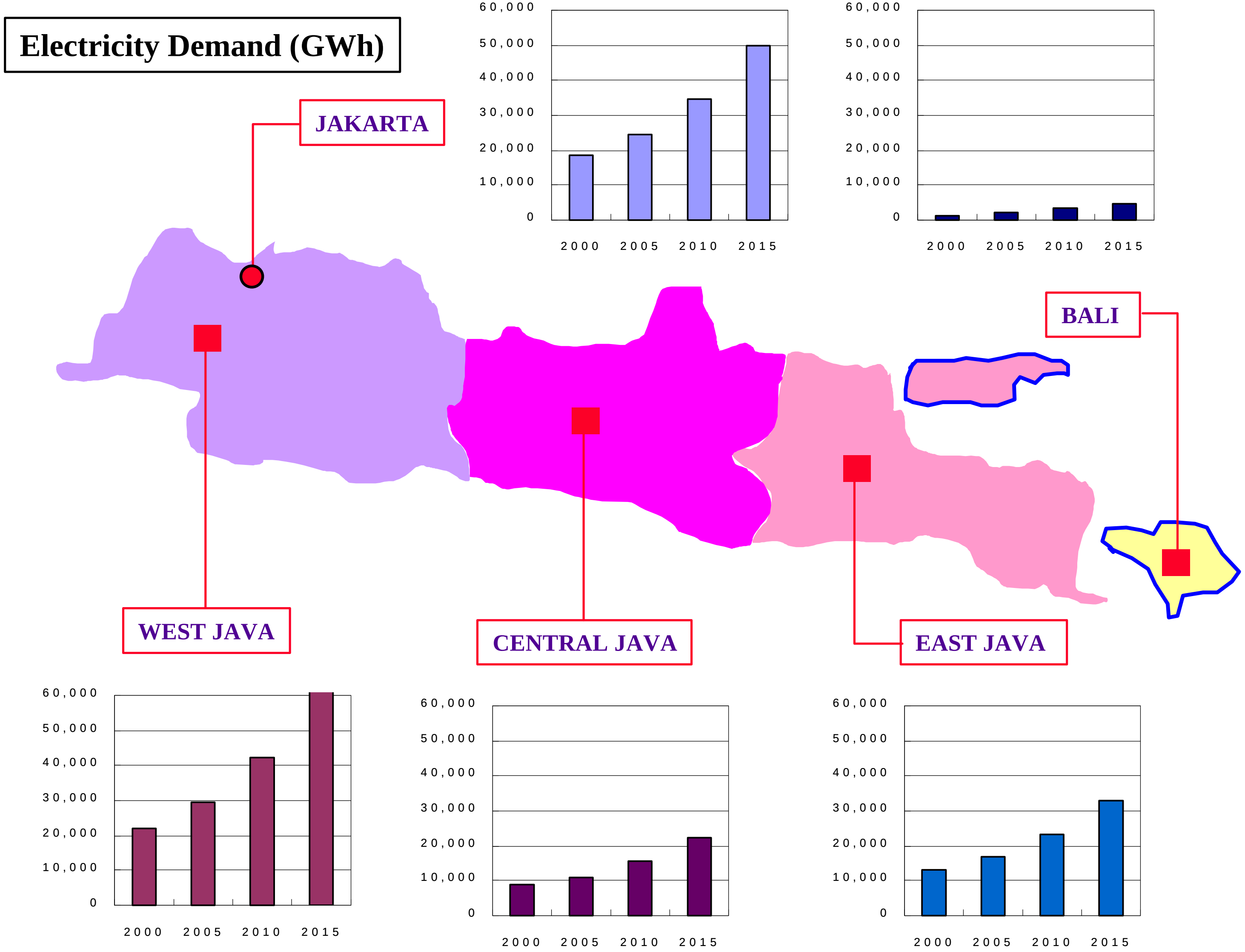
Table 4.4.2 Forecasted Electricity Demand by Sector

JICA/LPK				Actual			Forecast																		
				1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2000/05	2005/10	2010/15	2000/15
Case 1	Demand		GWh	57437	63872	67927	71017	74619	79017	84193	89896	96076	102868	110457	118704	127696	137446	148009	159447	171825				
			G.R.(%)			6.35	4.55	5.07	5.89	6.55	6.77	6.87	7.07	7.38	7.47	7.58	7.64	7.69	7.73	7.76	5.68	7.11	7.68	6.82
		Residential	GWh	19949	22629	24436	26245	27347	28639	30129	31826	33731	35860	38243	40891	43859	47124	50705	54624	58906	5.89	6.30	7.57	6.59
		Industry	GWh	27611	30045	31479	31948	33632	35738	38336	41169	44190	47506	51193	55154	59400	63977	68883	74151	79807	4.99	7.55	7.67	6.73
		Commercial	GWh	7141	8277	8766	9287	9899	10721	11649	12675	13787	15019	16416	17937	19594	21399	23364	25503	27833	7.07	9.02	9.18	8.42
		Public	GWh	2736	2921	3247	3537	3740	3919	4088	4226	4360	4484	4604	4721	4834	4947	5058	5169	5280	6.91	2.96	2.26	4.02
	Generation		GWh	67940	74901	78273	82386	86544	91328	97087	103543	110534	118348	126933	136410	146743	157947	170087	183230	197455				
			G.R.(%)			4.50	5.26	5.05	5.53	6.31	6.65	6.75	7.07	7.25	7.47	7.58	7.64	7.69	7.73	7.76	5.33	7.04	7.68	6.68
	Peak Load		MW	11032	12231	13041	13821	14497	15266	16185	17220	18348	19612	21000	22539	24225	26058	28048	30208	32549				
			G.R.(%)			6.62	5.98	4.89	5.31	6.02	6.40	6.55	6.89	7.08	7.33	7.48	7.57	7.64	7.70	7.75	5.76	6.85	7.63	6.74
Case 2	Demand		GWh	57437	63872	67927	72860	77969	83468	89461	95940	102861	110378	118697	127669	137278	147629	158774	170769	183674				
			G.R.(%)			6.35	7.26	7.01	7.05	7.18	7.24	7.21	7.31	7.54	7.56	7.53	7.54	7.55	7.55	7.56	6.97	7.37	7.55	7.30
		Residential	GWh	19949	22629	24436	26244	28079	29989	32028	34239	36570	39108	41870	44885	48079	51530	55249	59251	63551	7.19	6.98	7.20	7.13
		Industry	GWh	27611	30045	31479	33610	35872	38382	41172	44215	47468	51020	54981	59235	63804	68710	73979	79637	85712	6.50	7.55	7.67	7.24
		Commercial	GWh	7141	8277	8766	9467	10220	11008	12025	13085	14233	15505	16947	18517	20228	22091	24120	26328	28733	7.76	9.02	9.18	8.65
		Public	GWh	2736	2921	3247	3539	3799	4029	4235	4421	4590	4745	4892	5032	5107	5298	5426	5553	5678	7.71	3.51	2.45	4.53
	Generation		GWh	67940	74901	78273	84525	90430	96473	103161	110505	118340	126988	136402	146712	157754	169650	182457	196241	211070				
			G.R.(%)			4.50	7.99	6.99	6.68	6.93	7.12	7.09	7.31	7.41	7.56	7.53	7.54	7.55	7.55	7.56	6.61	7.30	7.55	7.15
	Peak Load		MW	11032	12231	13041	14089	15073	16071	17170	18374	19659	21075	22612	24297	26099	28040	30131	32380	34800				
			G.R.(%)			6.62	8.03	6.98	6.62	6.84	7.01	6.99	7.20	7.29	7.45	7.41	7.44	7.46	7.47	7.47	7.02	7.19	7.45	7.22

Table 4.4.3 Forecasted Peak Load by Sub-Region

Peak Load by Sub-Region																								
				1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2000/05	2005/10	2010/15	2000/15
Case 1	Jawa-bali System		MW	11032	12231	13041	13821	14497	15266	16185	17220	18348	19612	21000	22539	24225	26058	28048	30208	32549	5.76	6.85	7.63	6.74
		Area 1		4602	5253	5495	5765	6047	6371	6754	7185	7653	8178	8754	9393	10092	10852	11677	12572	13542	5.15	6.82	7.59	6.52
		Area 2		1951	2164	2316	2494	2625	2774	2955	3158	3380	3627	3899	4199	4528	4884	5271	5690	6144	6.43	7.28	7.91	7.20
		Area3		1643	1905	2057	2099	2202	2316	2451	2605	2773	2962	3170	3401	3655	3932	4234	4562	4919	5.17	6.76	7.66	6.53
		Area 4 (excld. Bali)		2557	2593	2827	3060	3196	3349	3536	3747	3976	4233	4515	4828	5169	5540	5943	6378	6849	6.40	6.42	7.25	6.69
		Bali		279	316	346	403	427	456	488	525	566	611	662	718	780	849	923	1005	1095	9.10	8.02	8.80	8.64
Case 2	Jawa-bali System		MW	11032	12231	13041	14089	15073	16071	17170	18374	19659	21075	22612	24297	26099	28040	30131	32380	34800	7.02	7.19	7.45	7.22
		Area 1		4602	5253	5495	5863	6270	6682	7136	7633	8163	8747	9381	10077	10820	11622	12485	13414	14414	6.32	7.15	7.42	6.96
		Area 2		1951	2164	2316	2563	2750	2942	3154	3388	3638	3914	4214	4543	4896	5276	5685	6126	6601	7.83	7.57	7.76	7.72
		Area3		1643	1905	2057	2130	2283	2437	2605	2789	2985	3201	3434	3689	3962	4257	4574	4915	5282	6.46	7.21	7.44	7.04
		Area 4 (excld. Bali)		2557	2593	2827	3126	3330	3536	3763	4011	4275	4566	4880	5224	5591	5985	6408	6862	7350	7.73	6.78	7.07	7.19
		Bali		279	316	346	406	439	473	511	553	598	648	703	764	830	901	978	1062	1154	10.10	8.36	8.59	9.02

Figure 4.4.10 Forecasted Electricity Demand by Sub-Region



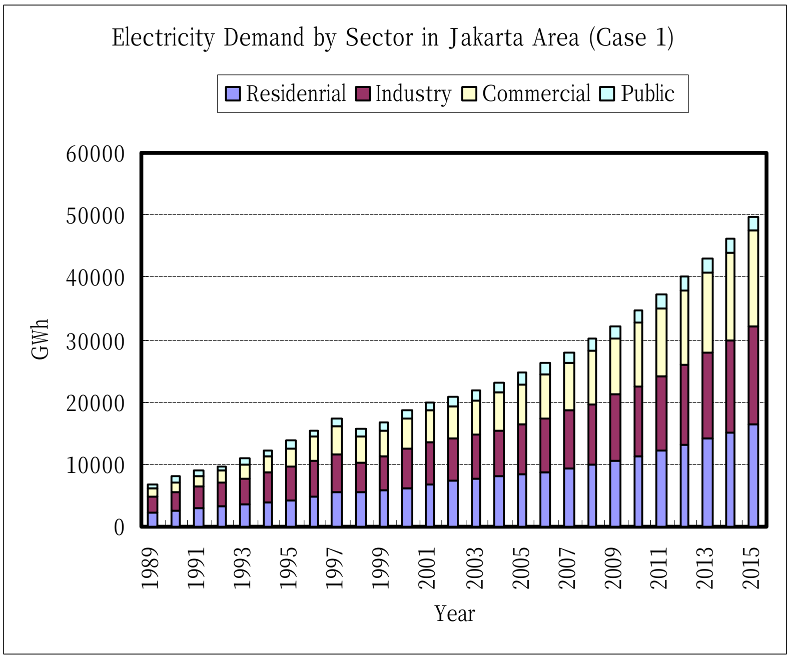
The followings show the forecasted electricity demand by sub-region (area) in JICA/LPE Case 1.

(1) Jakarta Area

Figure 4.4.11 shows the historical trend and the forecasted result of the sectoral electricity demand until 2015 in the Jakarta Area. In the Area, the demand for the residential, industrial and commercial sectors are same level. The commercial sector will continue to expand its share. The industrial sector will keep its share and the public sector will decrease its share after 2005.

As for the annual average growth rates during 2001–2015, the residential sector is expected to grow at 6.5 %, the industrial sector at 6.4 %, the commercial sector at 8.4 %, and the public sector at 3.6 %.

Figure 4.4.11 Electricity Demand by Sector in the Jakarta Area

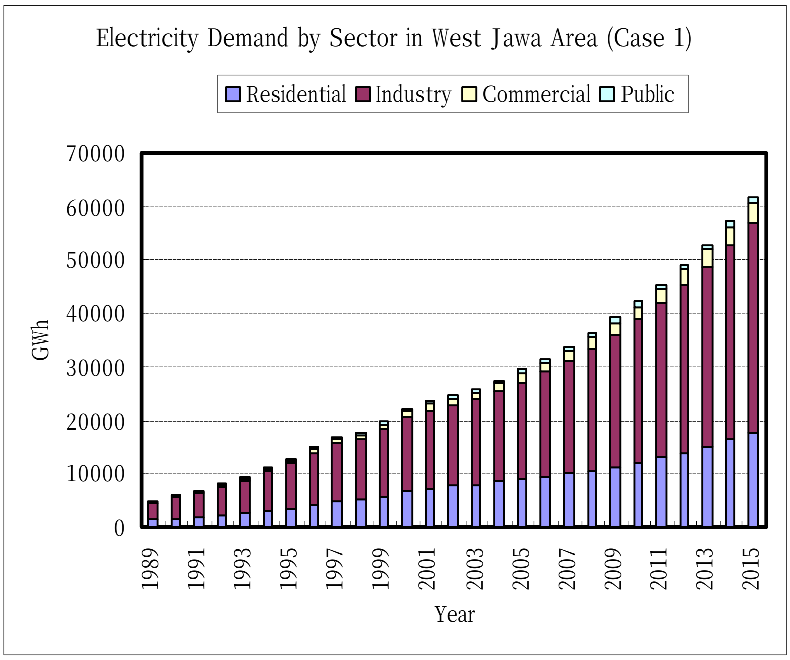


(2) West Java Area

Figure 4.4.12 shows the historical trend and the forecasted result until 2015 in the West Java Area. In the Area, the industrial sector accounts for major part, followed by the residential sector. The industrial sector, especially, will continue to expand its share. The Area is characterized by the industrial sectoral demand.

As for the annual average growth rates during 2001–2015, the residential sector is expected to grow at 6.6 %, the industrial sector at 7.3 %, the commercial sector at 8.8 %, and the public sector at 3.6 %.

Figure 4.4.12 Electricity Demand by Sector in the West Java Area



(3) Central Java Area

Figure 4.4.13 shows the historical trend and the forecasted result until 2015 in the Central Java Area. In the Area, the residential and industrial sectors play the major role in the electricity demand. Both sectors show the expanding tendency in their share.

As for the annual average growth rates during 2001–2015, the residential sector is expected to grow at 6.5 %, the industrial sector at 7.2 %, the commercial sector at 8.7 %, and the public sector at 3.5 %.

(4) East Java Area

Figure 4.4.14 shows the historical trend and the forecasted result until 2015 in the East Java Area. The Area shows a similar demand structure to the Central Java Area, that is, the biggest contributor is the residential and industrial sectors.

As for the annual average growth rates during 2001–2015, the residential sector is expected to grow at 6.3 %, the industrial sector at 6.3 %, the commercial sector at 8.7 %, and the public sector at 3.3 %.

Figure 4.4.13 Electricity Demand by Sector in the Central Java Area

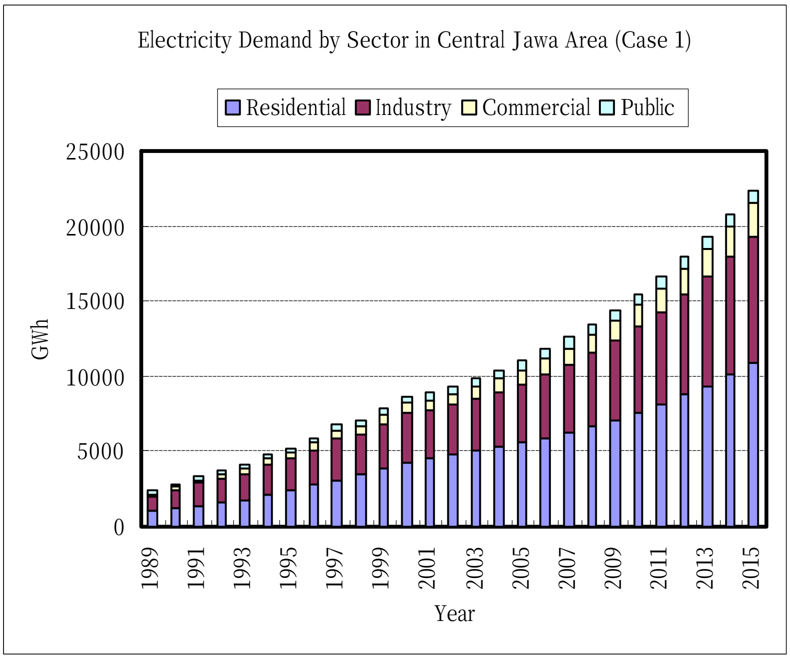
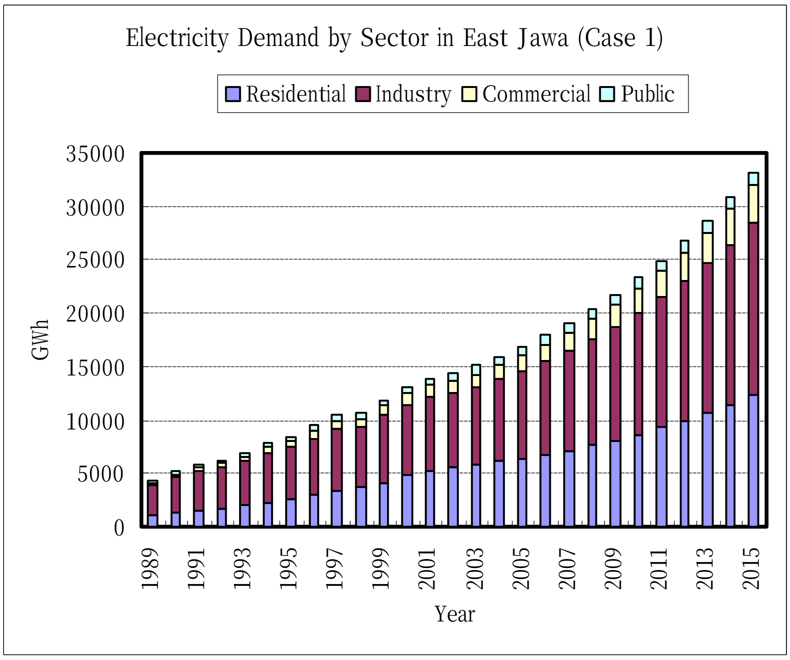


Figure 4.4.14 Electricity Demand by Sector in the East Java Area

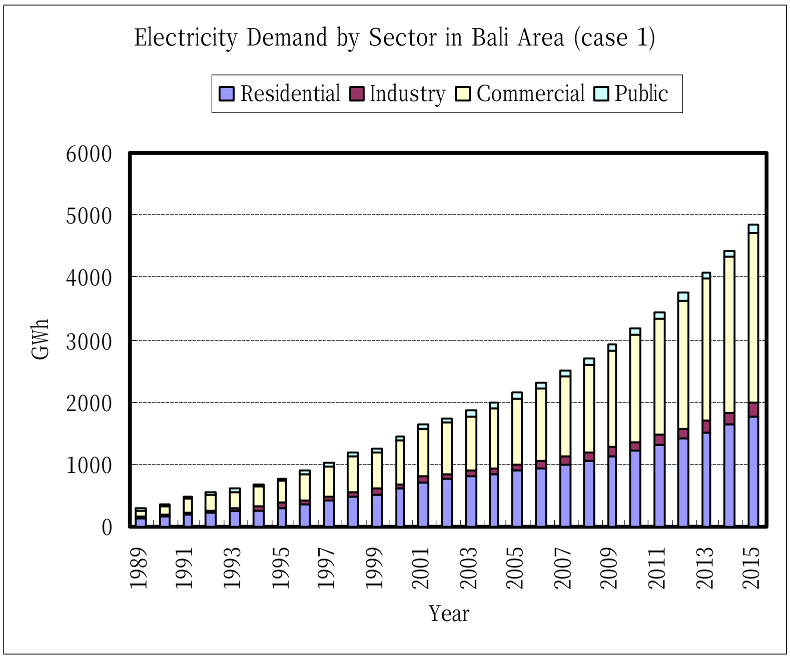


(5) Bali Area

Figure 4.4.15 shows the historical trend and the forecasted result in the Bali Area. The Area is characterized by the commercial sector. The share of the commercial sector and the residential sector is almost same level in the demand structure at present. The commercial sector, however, will continue to expand its share in the future.

As for the annual average growth rates during 2001–2015, the residential sector is expected to grow at 6.8%, the industrial sector at 6.7 %, the commercial sector at 9.5 %, and the public sector at 3.8 %.

Figure 4.4.15 Electricity Demand by Sector in the Bali Area



4.5 Examples of Model Application

4.5.1 Household Electrification

In JICA/LPE scenario, the electrification ratio is based on the governmental scenario of DGEEU and PLN until 2010, and afterwards, the electrification ratio in the Java-Bali Region is adopted at about three (3) % of the time trend (See Table 4.5.1) as external variables (scenario). Needless to say, electrification is one of the integrated energy policies. In this section, we tried to simulate the electrification by itself by the use of macro indicators as a Reference scenario, that is, the electrification ratio is internalized as a function of government expenditure. Results are shown in Table 4.5.1 and Figure 4.5.1 as a Reference scenario.

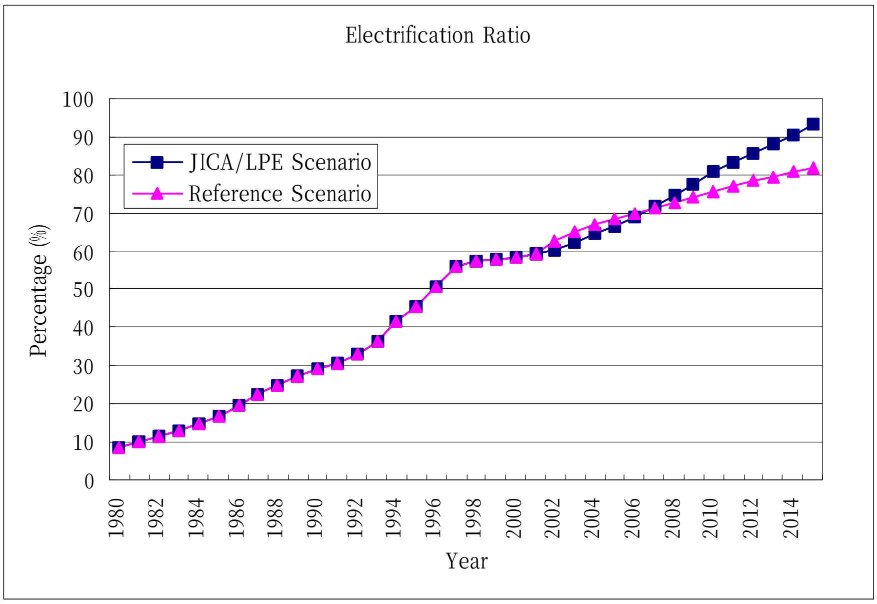
Table 4.5.1 shows results of both the JICA/LPE scenario and the Reference scenario. Figure 4.5.1 shows the historical trend and the forecasted results of both scenarios. Household electrification in the Java-Bali Region has been progressing from 8.6 % in 1980, to 16.8 % in 1985, to 29.4 % in 1990, to 45.7 % in 1995 and 58.3 % in 2000. Furthermore, DGEEU has a target that Indonesia achieves the electrification ratio of 80.6 % in the Java-Bali Region until 2010.

In the Reference scenario the household electrification ratio is a little bit higher than in the JICA/LPE scenario until 2006, however, it is lower than the JICA/LPE scenario after 2007, as shown in Table 4.5.1.

Table 4.5.1 Scenario s of Household Electrification

	2001	2002	2003	2004	2005
JICA/LPE Scenario	59.2	60.2	62.2	64.4	66.7
Reference Scenario	59.2	62.6	64.9	66.8	68.4
	2006	2007	2008	2009	2010
JICA/LPE Scenario	69.1	71.8	74.6	77.5	80.6
Reference Scenario	70.0	71.4	72.9	74.3	75.7
	2011	2012	2013	2014	2015
JICA/LPE Scenario	83.1	85.6	88.1	90.6	93.1
Reference Scenario	77.0	78.4	79.6	80.8	81.9

Figure 4.5.1 Household Electrification by Scenario



The electrification ratio influences only the residential electricity demand, as described Section 4.2.3. From the simulation results, the peak load by price scenario is summarized in Table 4.5.2. According to the Table, Case 2 will not create as much difference between the JICA/LPE scenario and the Reference scenario. In Case 1 the difference between both scenarios is 522 MW in 2010 and 1144 MW in 2015. In Case 2, the difference between both scenarios will be 51 MW in 2010 and 135 MW in 2015.

Table 4.5.2 Forecasted Peak Load by Scenario

Price Scenario (JICA/LPE)	Electrification Scenario	Year			
		2001	2005	2010	2015
Case 1	JICA/LPE Scenario	12,231	16,185	22,539	32,549
	Reference Scenario	12,231	15,904	22,017	31.405
Case 2	JICA/LPE	12,231	17,170	24,297	34,800
	Reference	12,231	17,183	24,246	34,665

Equations obtained by a regression analysis are as follows. In the equations below, lag1 mean previous year' value and dummy (dum.--) is zero (0) in the future.

Government expenditure (GC) = f(Regional GDP, Previous year's GC)

Ln (GC) = 0.839 (1.16) +0.245 (2.9)*Ln (GDP) +0.467 (3.21) *Ln (lag1.GC)

-0.313 (-5.69)*dum.1998 -0.123 (-2.31)*dum.1987

where, Figures in ( ) = t-value

R square = 0.928

Durbin Watson ratio = 1.87

Electrification ratio (ELEC) = f(GC)

$$\mathrm{Ln}\,(ELEC/(1-ELEC)) = -39.269\ (-11) + 3.724\ (10.7)*\mathrm{Ln}\,(GC) + 1.790\ (6.18)*dum.1998 + 1.262\ (4.38)*dum.1999 + 0.8410\ (2.87)*dum.2000$$

where, Figures in ( ) = t-value

R square = 0.918

Durbin Watson ratio = 1.25

4.5.2 Energy Conservation Case

In this section, the developed model is applied to examine whether energy conservation policies and targets can be handled. The following is an example for policy making.

The scenario is set as follows.

1) Residential sector : Energy saved from 2007 achieves energy savings of 10 % in 2015.
2) Industrial sector : Energy saved from 2008 achieves energy savings of 15 % in 2015.
3) Commercial sector : Energy saved from 2010 achieves energy savings of 10 % in 2015.

Figures 4.5.2 and 4.5.3 show the simulated results of electricity demand and peak load. Case 1 and Energy Conservation Case applied to Case 1 are treated. The results show that in 2010 it is expected that the electricity demand will decrease from 118,704 GWh to 115,447 GWh and the peak load from 22,539 MW to 26,912 MW. Further in 2015, the electricity demand will decrease from 171,825 GWh to 151,906 GWh and the peak load from 32,549 MW to 28,867 MW.

Figure 4.5.2 Electricity Demand in the Java-Bali Region
(Case 1 and the Energy Conservation Case)

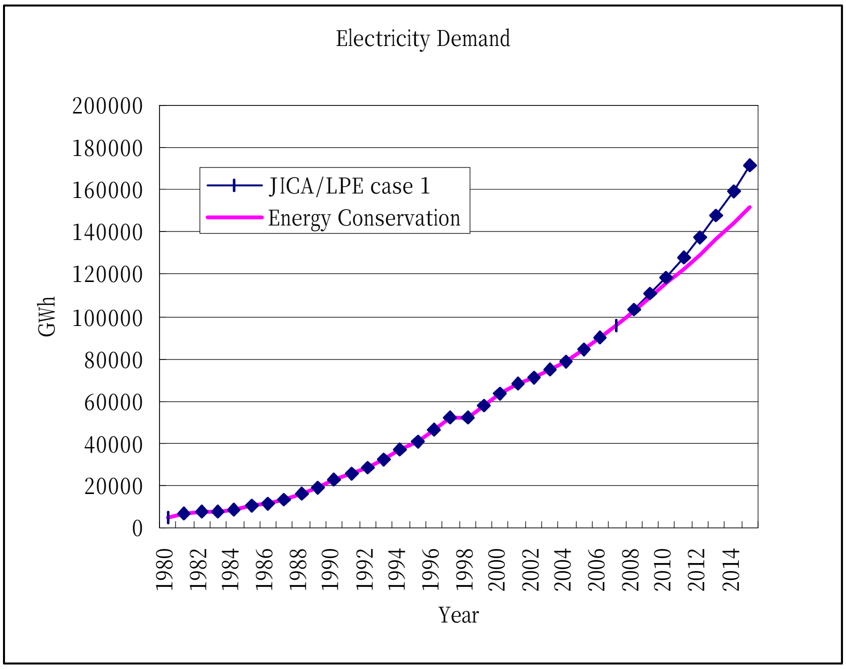
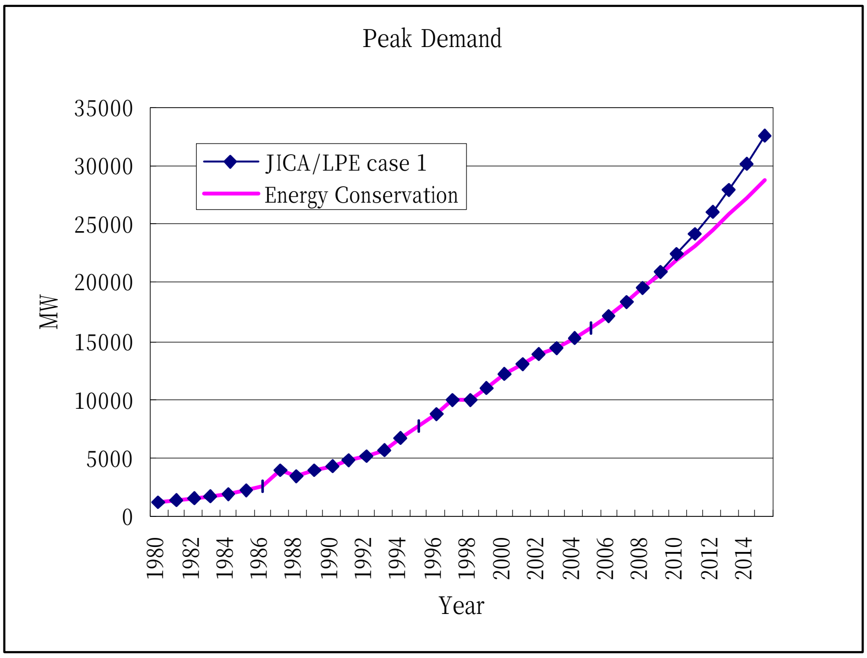


Figure 4.5.3 Peak Load in the Java-Bali Region
(Case 1 and the Energy Conservation Case)



4.5.3 Captive Power

Traditionally, captive power, accounting for relatively large share, has played an important role in Indonesia. As of December 2000, the installed capacity by captive power is15,220 MW, of which Java accounts for 7,325 MW and Bali for 65 MW (DGEEU annual Report, 2001). Actual capacity, however, is not grasped in statistics, which should include rated capacity, its reserve, and generated output, etc,. In this section, we tried to estimate the captive power generation for a model simulation, because consumer shift between PLN and Captive is supposed to depend on electricity prices and fuel prices in the near future.

(1) Estimation of power generation data

At this time, data is estimated from a published paper (Half-Day Joint Seminar on Captive Power in Indonesia, Development, Current Status and Future Role, PT PLN and The World Bank, Tuesday, July 6, 1999) and the DGEEU annul report. Time series data (1980-2000) of captive power generation is estimated through the following procedure.

1) Creation of time series data (1980-2000) of the installed capacity and generated output in entire Indonesia
2) Calculation of the actually utilized capacity and the utilization ratio of installed capacity from data above
3) Estimation of the Java-Bali portion from the power generation of entire Indonesia by use of the report of “Half-Day Joint Seminar”
4) Estimation of the generated output by captive power in the Java-Bali Region

Figure 4.5.4 Installed Capacity, Utilized Capacity and Utilization Ratio (Indonesia)

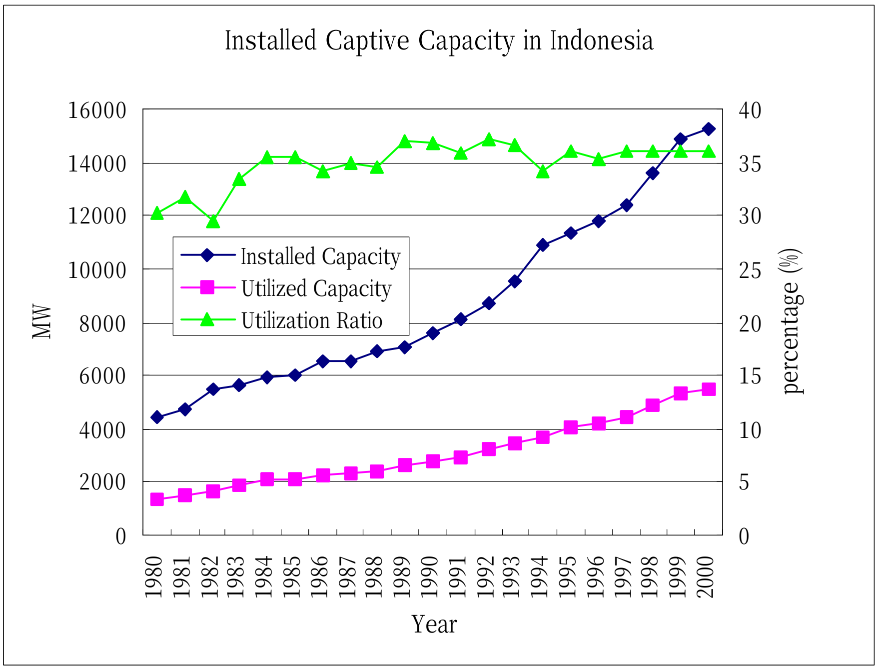


Figure 4.5.5 Captive Power Generation in Indonesian and in the Java-Bali Region

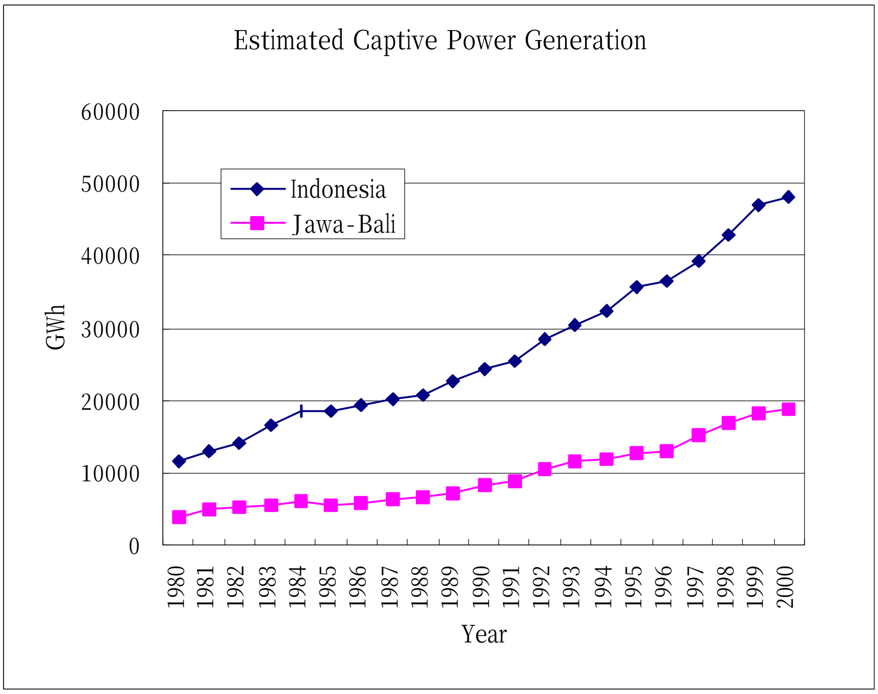


Figure 4.5.4 shows the historical trends of installed capacity, utilized capacity and utilization ratio. The utilization ratio is assumed to be maintained about 36 % in recent years. Figure 4.5.5 shows the historical trends of the estimated captive power generation in entire Indonesia and in the Java-Bali Region. The share of captive power generation in the Java-Bali Region accounts for about 30 % of entire Indonesia.

(2) Scenario

In addition to the electricity price scenario (See Table 4.3.2), we prepared a fuel price scenario represented by diesel oil price. The scenario applied this simulation is summarized in Table 4.5.3. Electricity price scenario is the same as Case 1 of the JICA/LPE scenario. Scenario setting for population, GDP growth rate, inflation and household electrification ratio is based on the previous section (See Table 4.3.3). The aim of this scenario is to simulate the impact of fuel price.

Table 4.5.3 Scenario on Electricity Price and Fuel Price

	Electricity Price	Fuel Price
Scenario 1	Real price up (Same as Case 1 of JICA/LPE scenario, which nominal price increase until 2005 as shown Table 4.3.2)	Real price up (Nominal price increase the growth rate of 15 % until 2004)
Scenario 2	Real price up (Same as Case 1 of JICA/LPE scenario, which nominal price increase until 2005 as shown Table 4.3.2)	Real price constant (Nominal price increase with inflation)

(3) Model

In this model, a modification is done only to a system equation for industrial sector. Electricity demand for industry is set as the sum of PLN (industrial demand) and captive power generation. The functional relationship is as follows;

Industrial demand total = f (Industrial GDP)
Captive power generation = f (Industrial GDP, Relative value of fuel price and electricity)
PLN's industrial demand = Industrial demand total – Captive power generation
PLN's electricity demand total = Residential demand + Industrial demand (PLN) +Commercial demand + Public demand

The system equations obtained by a regression analysis are as follows. In the equations below, lag1 mean previous year' value and dummy (dum.--) is zero (0) in the future. GDPIN means industrial GDP. PDO.N and PINEL represent fuel price and electricity price respectively.

1) Industrial demand total (TLIN)

Ln (TLIN)= -12.11 (-11) +1.25 (20)*Ln (GDPIN) +0.38 (3.42)*dum.1999 +0.39 (3.47)*dum.2000

where, Figures in ( ) = t-value
R square = 0.974
Durbin Watson ratio = 1.42

2) Captive power generation (CAPTIVE)

Ln (CAPTIVE)= -4.83 (-5.26) +0.83 (14.8)*Ln (GDPIN) -0.71 (-4.3)*Ln (PDO.N/PINEL) +0.338 (2.55)*dum.1999

where, Figures in ( ) = t-value
R square = 0.94
Durbin Watson ratio = 1.46

(4) Simulation results

Figure 4.5.6 shows the forecasted captive power generation by scenario. Captive power generation varies depending on price scenario. The result of Scenario 1, in which real fuel price increased until 2004, shows a drop in the generated output. The difference between Scenario 1 and Scenario 2 is shown in Table 4.5.4. According to the results of this simulation, about 10 % of the captive power generation is shiftable and this in turn will affect PLN sales.

Table 4.5.4 Captive Power Generation by Scenario

(Unit: GWh)

	2000	2005	2010	2015
Scenario 1	18,719	23,906	29,256	35,918
Scenario 2	18,719	26,276	32,159	39,479
Difference	0	2,370	2,901	3,561

Figure 4.5.6 Captive Power Generation Forecast by Scenario

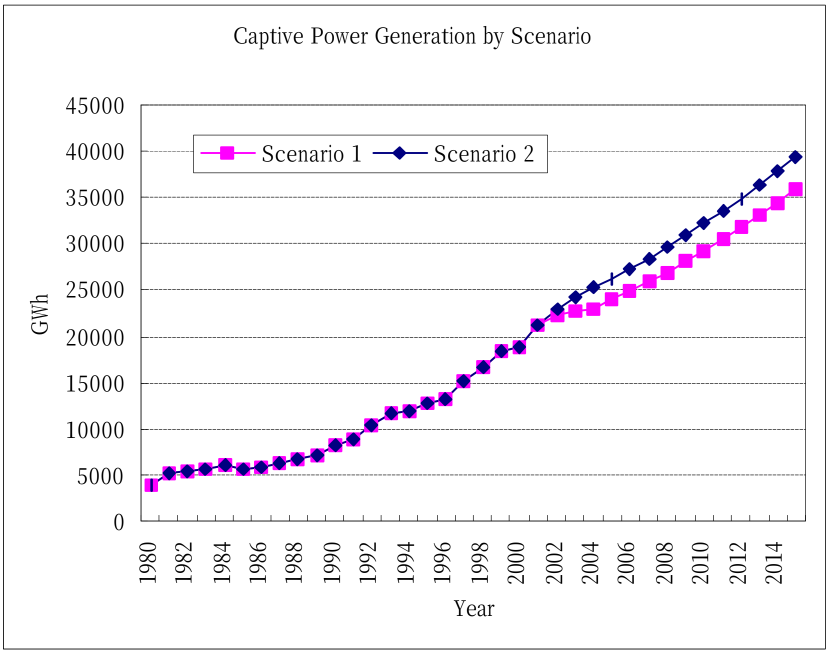
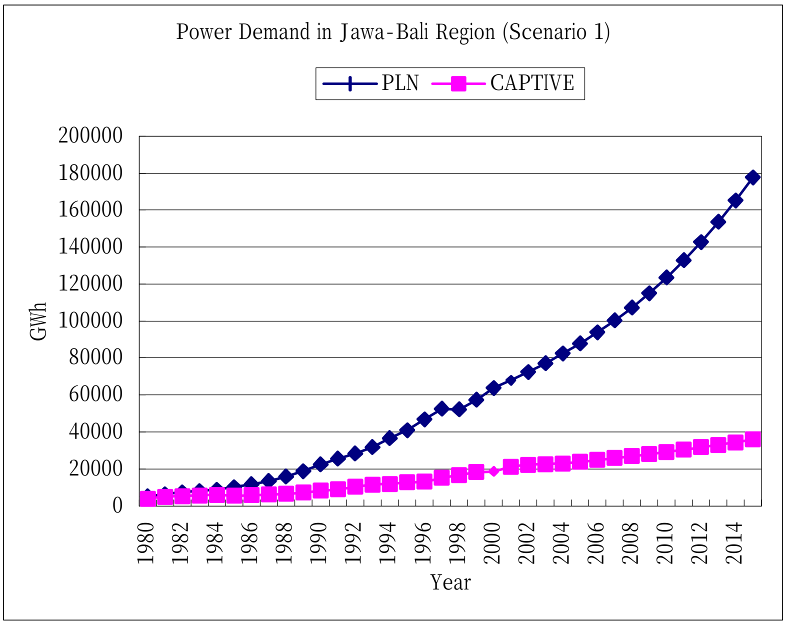


Figure 4.5.7 shows the forecasted PLN sales and the captive power generation in the Scenario1of real fuel price up. In this case, the growth rate of the captive power will slow down and the PLN sales of power will increase. PLN sales will grow at the average growth rate of 7.1 % during 2001-2015, which exceeds the growth rate of 6.8 % forecasted in the

previous section. Both results do not compare unconditionally, because data source, data availability and scenario are different from the previous section. It is recommendable to study in detail the captive power including data gathering, scenario setting of fuel price depending on energy policies.

Figure 4.5.7 Electricity Demand Total in the Java-Bali Region (Scenario 1)



Chapter 5 Probability of Power Deficit - Short Term Development Plan -

5.1 Review of the Supply Capacity

Power plants can not always provide power at their installed capacities. The available capacities of hydropower plants decrease by the seasonal derating related to the seasonal water flows. The available capacities of thermal power plants can decrease due to temporary equipment defects or poor operating conditions at the plants. Therefore, the available capacity of the system is influenced by these conditions.

Table 5.1.1 shows the various items that can affect the system available capacity. In this table, derated capacity is defined as the reduction of capacity related to the power sources, and constrained capacity is defined as the reduction of capacity related to other reasons.

Table 5.1.1 Causes of Constraint

Items	Causes	Peak Load Ratio(%)
Derated capacity covered by *GRM	- Hydropower Seasonal Derating - Thermal Power Derating - Maintenance - Forced Outage - Essential Spinning Reserve	5% 2.7% 12% 6% 4.3%
Constrained capacity not covered by GRM	- Constraint due to transmission power flow limitation. - Long term outage - Special Contract Service	NA
Generation Reserve Margin (used in P3B)		30%

*GRM: Generation Reserve Margin

In order to evaluate the capacity deficit, the operational reserve margin is directly investigated using the following procedure:

Review of the Derated Capacity	The validity of the system derated capacity is examined.
⇩	
Review of the Constrained Capacity	The validity of the system constrained capacity is examined.
⇩	
Review of On-going / Planned Projects	The commission schedules of on-going and planned project are studied.

5.1.1 Review of the Derated Capacity covered by GRM

(1) Hydropower seasonal derating

Output of hydropower plants, especially run-off-river type power plants, depends on seasonal water flow. In Indonesia, there are two seasons: dry season and rainy season. Due to low rainfall during dry season, water flow is low. Consequently, the available capacity of hydropower plants decreases. "Hydropower derated capacity" is the difference of capacity between installed capacity and available capacity.

To forecast hydropower derated capacity accurately, P3B collects the data of seasonal water flow and available capacity of each hydropower plant. For making power supply plan, the average water flow and available capacity for the preceding 10 years is used usually.

Table 5.1.2 shows the hydropower derated capacity in 2000 and 2001. The maximum seasonal derating capacity was 5.4% of the peak load in 2000 and 5.1% of the peak load in 2001. Thus it is reasonable to assume that the hydropower seasonal derating is about 5% of the peak load as described in 3.3.3.

Table 5.1.2 Hydropower Derated Capacity (Unit: MW,%)

Year	2000		2001	
Maximum Derated Capacity (a)	657	5.4%	671	5.1%
Minimum Derated Capacity (b)	474	3.9%	377	2.9%
Difference (a)-(b)	183	1.5%	294	2.3%
Peak Load	12,231	100%	13,041	100%

* Based on the annual supply plan of P3B

** The moving average of 8 weeks.

(2) Thermal and geothermal power plant derating

The available capacity of thermal and geothermal power plants decreases caused by the temporary defects of equipment or the operating condition of plants. The difference of capacity between installed capacity and available capacity is called "derated capacity ". Derated capacity is classified into the following two groups:

- Permanent Derating: Derated capacity which is not able to recover to the installed capacity.
  e.g. Defective design of equipment (condenser, boiler)
  Power reduction of gas turbine against atmospheric condition.
- Temporary Derating: Derated capacity which is expected to recover to the installed capacity by maintaining or repairing its equipment.
  e.g. Power reduction due to using HSD oil
  Capacity reduction due to deterioration

Table 5.1.3 shows the derating capacity of the available capacity of thermal and geothermal power plants in February 2001. The derating capacity is reviewed every month. In February 2001, no geothermal power plants were derated.

Table 5.1.3 shows that the derated capacity is 326MW, accounting for 2.5% of the peak load. Thus it is reasonable to assume that the rate of derated capacity can be estimated at about 2.7% of the peak load as described in 3.3.3.

Analyzing the derated capacity in detail, permanent derating reaches 134MW because it is the total of derating caused by ambient air (84MW) by temperature and by defective design (50MW). On the other hand, temporary derating reaches 192MW because of derating caused by aging (153MW) and fuel (39MW).

Table 5.1.3 Derated Capacity of Thermal Power Plants

Owner	Power Plant	Unit Type	Unit No.	Fuel	Start of Operation	IC (MW)	AC (MW)	Breakdown of (IC - AC) (MW)						
								Derated by				long-term outage	transmission constraint	others
								fuel	temp.	design	aging			
Indo-nesia Power	Suralaya	PLTU	1	Coal	1984	400	400							
			2	Coal	1984	400	400							
			3	Coal	1988	400	400							
			4	Coal	1989	400	400							
			5	Coal	1996	600	600							
			6	Coal	1997	600	600							
			7	Coal	1997	600	600							
	Tanjung Priok	PLTU	3	MFO	1972	50	0					50		
			4	MFO	1972	50	0					50		
		PLTGU	Block1	NG	1993, 94	590	575			15				
			Block2	NG	1994	590	575			15				
		PLTG	1,3,4,5	HSD,NG	1976-77	150	130				20			
	Tambak Lorok (Semarang)	PLTU	1	MFO	1978	50	45			5				
			2	MFO	1978	50	45			5				
			3	MFO	1983	200	200							
		PLTGU	Block1	HSD	1993, 97	517	494	23						
			Block2	HSD	1996, 97	517	501	16						
	Perak	PLTU	3	MFO	1978	50	45			5				
			4	MFO	1978	50	45			5				
	Grati	PLTGU	Block1	HSD	1996, 97	462	462							
		PLTG	Block2	HSD		302	0					302		
	Sunyaragi	PLTG	1-4	NG	1976	80	68				12			
	Cilacap	PLTG	1-2	HSD	1976	55	41				14			
	Pesanggaran	PLTG	1-4	HSD	1985-93	125	107				18			
		PLTD	1-11	HSD	1982	76	43				33			
	Gilimanuk	PLTG	1	HSD	1997	134	134							
PJB	Muara Karang	PLTU	1	MFO	1979	100	95				5			
			2	MFO	1979	100	95				5			
			3	MFO	1980	100	95				5			
			4	NG	1981	200	190				10			
			5	NG	1982	200	190				10			
		PLTGU		NG	1993, 95	509	470		39					
	Gresik	PLTU	1	NG	1981	100	95				5			
			2	NG	1981	100	95				5			
			3	NG	1988	200	200							
			4	NG	1988	200	200							
		PLTGU	Block1	NG	1992, 93	526	526							
			Block2	NG	1992, 93	526	526							
			Block3	NG	1993	526	526							
		PLTG	1-3	NG	1977, 84	61	54				7			
	Gilitimur	PLTG	1-2	HSD	1994, 95	40	36				4			
	Piton	PLTU	1	Coal	1994	400	400							
			2	Coal	1994	400	400							
	Muara Tawar	PLTGU	Block1	HSD	1997	640	605		35					
		PLTG	Block2	HSD	1997	280	270		10					
IPP	Piton 1	PLTU	5	Coal	1998	615	total 615						total 615	
			6	Coal	1998	615								
	Piton 2	PLTU	7	Coal	2000	610	total 610						total 610	
			8	Coal	2000	610								
	Cikarang List	PLTG	1-4	NG		150	0							150
Total						15,307	13,203	39	84	50	153	402	1,225	150
								326						

IC : Installed Capacity AC : Available Capacity

(3) Maintenance (Periodical / Planned repair)

All power plants require adequate repair and maintenance to provide stable and high quality power to the system. Therefore, the reduction of capacity during maintenance has to be taken into account in determining the supply capacity.

Table 5.1.4 shows the maintenance capacity in 2000 and 2001. P3B calculates the maintenance capacity based on the actual maintenance plan for power plants. The average maintenance capacities were 9.6% of the peak load in 2000 and 11.3% in 2001. Thus it is reasonable to estimate that the rate of maintenance capacity is about 12% of the peak load as described in 3.3.3.

Taking the operational capacity as standard, average maintenance capacity is 9.9% of the capacity in 2000 and 10.0% in 2001, and standard deviations are about 3%.

Table 5.1.4 Maintenance Capacity (Unit: MW, %)

Year	2000			2001		
Average Maintenance Capacity (a)	1,171	9.6%	9.9%	1,468	11.3%	10.0%
Minimum Maintenance Capacity (b)	501	4.1%	—	785	6.0%	—
Difference (a)-(b)	670	5.5%	—	683	5.2%	—
Peak Load	12,231	100%	—	13,041	100%	—
Standard Deviation (c)	426	—	3.0%	493	—	3.3%
Operational Capacity (d)	14,455	—	100%	14,755	—	100%

* Based on the annual supply plan of P3B

** The moving average of 8 weeks

Operational Capacity is calculated using the formula shown below:

Operational Capacity = Installed Capacity

– (Forced Outage Capacity +Special Contract Service Capacity) --- 5-1

(4) Forced outage (unplanned repair)

Forced Outage Capacity is the derated capacity by unpredictable accidents. The forced outage of geothermal power plant doesn't have to be counted because of the small capacity. P3B collects data of the forced outage rate of each type of thermal power plant and calculates the forced outage capacity by the formula shown below:

Forced Outage Capacity
= Capacity of Operating Thermal Power Plant x 6%
= ((Installed Capacity - (Maintenance Capacity + Derated Capacity
+ Special Contract Service Capacity + Long Term Outage Capacity)) x 6%
= (Operational Capacity - (Maintenance Capacity + Derated Capacity)) x 6%
--- 5-2

Since the capacity of operating thermal power plants is nearly equal to peak load, forced outage capacity is calculated with the formula shown below. Thus it would be reasonable to assume estimate the rate of forced outage at about 6% of peak load as shown in 3.3.3.

Peak Load x 6% --- 5-3

(5) Essential spinning reserve

Essential spinning reserve is the necessary capacity for maintaining stable operation of the power system. When an operating power source accidentally stops, the frequency decreases to the critical level unless there is an alternative power source known as essential spinning reserve. Essential spinning reserve should be equal to or more than the capacity of the largest operating unit.

Currently, the maximum capacity in the Java- Bali system is 615MW of Paiton IPP I, which is about 4.7% of peak load in 2001. Therefore it would be reasonable to estimate the rate of essential spinning reserve to be at about 4.3% of peak load.

5.1.2 Review of the Constrained Capacity not covered by GRM

(1) Long term outage capacity

- Tanjung-Priok 3&4 (50MW x 2)

Commissioned in 1972, Tanjung-Priok 3 & 4 are two of the oldest units in the Java-Bali system. These units were rehabilitated under a Japanese ODA loan scheme in 1988. The turbine grand seal and super heating tubes were replaced through the rehabilitation work. However, the steam leakage from the boiler water wall still occurred frequently a few years later. For this reason, these units are no longer in use. Maintenance such as replacement of the entire water wall would be required to make the units usable.

- Grati Block II (302MW)

Despite the completion of the construction, PLN treats Grati block Ⅱ as stand-by unit, actually as a long term outage unit.

The first reason is the fuel problem. Since there is no contract to provide natural gas, Grati plant requires to use HSD oil. HSD oil is more expensive than natural gas. Moreover, using HSD oil causes problems such as the erosion damage to the equipment. The second reason is the power system problem. Due to the limitation of power flow in the 500kV trunk line, Grati block Ⅱ can not supply its full rated capacity.

(2) Special contract service

- Cikarang Listrindo (IPP/150MW)

Cikarang Listrindo is the IPP power plant located in the Cikarang industrial estate. The installed capacity reaches 150MW with the four gas turbines. Since the power is provided only to the industrial estate, the capacity can not be counted as a part of the supply capacity.

(3) Constrained capacity

Figure 5.1.1.shows the Java-Bali system in 2001. As is shown in Figure 4.4.10, the power demand in Java-Bali system is concentrated in the west, primarily in Jakarta, while some of large power sources such as Paiton and Gresik are located in the east. Consequently, a lot of power flows occur east to west through a 500kV trunk line.

The amount of power flowing on a trunk line is regulated by either the system stability or the thermal capacity of the transmission line. In the case of the existing 500kV transmission line, power flow between Krian - Ungaran is limited to less than 1,500 MW because of stability.

Figure 5.1.2.shows the power flow diagram of Java-Bali system in 2001. Due to the power flow limitation, 1,231 MW of capacity could not be dispatched in 2001, as shown below.

Table 5.1.5 Constrained capacity caused by limitation of 500kV trunk line in 2001

Unit name (a)		Maintenance capacity (b)	Peak Load in area 4 (c)	Limitation by transmission line (d)	Constrained Capacity (a)-(b)-(c)-(d)
Paiton(PLN)	800MW	Total 625MW	Total 3,173MW	1,500MW	1,231MW
Paiton1 (IPP)	1,230MW				
Paiton2 (IPP)	1,220MW				
Grati	462MW				
Gresik	2,222MW				
Others	595MW				
Total	6,529 MW				

These limitations will be moderated as demand increases in the eastern area. However, the completion of a southern 500kV trunk line is required to remove this capacity constraint completely.

Table 5.1.6 shows the constrained capacity expected in the near future. The constrained capacity will be decreased to 501MW in late 2002 since the 500kV trunk line between Paiton and Klaten is committed. In addition, the constrained capacity is expected to be removed completely in late 2004, once the remaining part of the 500kV trunk line between Klaten and DepokⅢ is completed.

Table 5.1.6 Constrained Capacity Expected in the near future

Conditions	Constrained Capacity
Present (2001)	1,231MW
Operation of Paiton - Klaten (1 cct) (2002)	501MW
Operation of Paiton - Klaten (2 cct) (2003)	0-300MW (depend on demand)
Operation of Klaten - DepokⅢ (2004)	0MW

Figure 5.1.1 The Java-Bali System in 2001

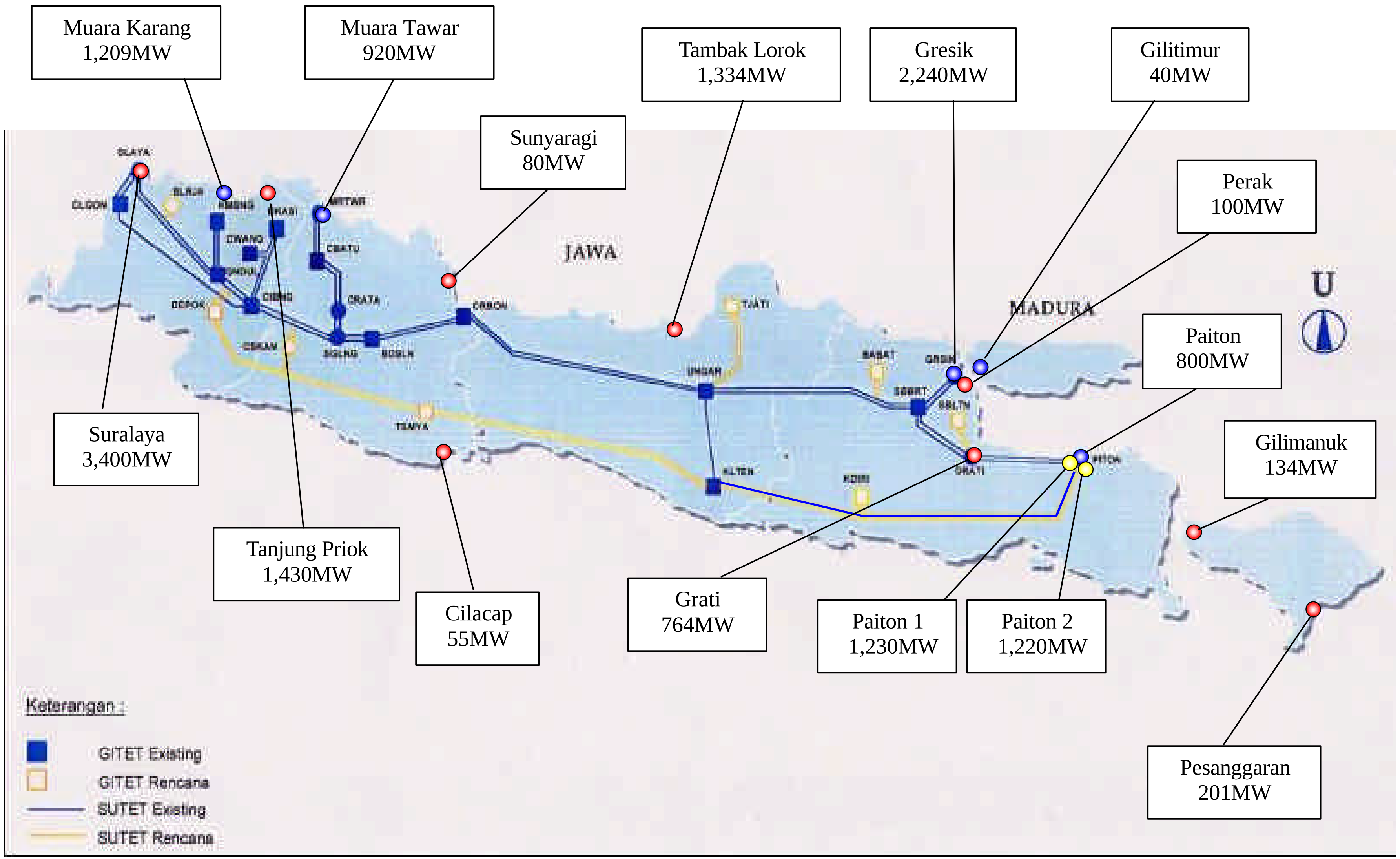
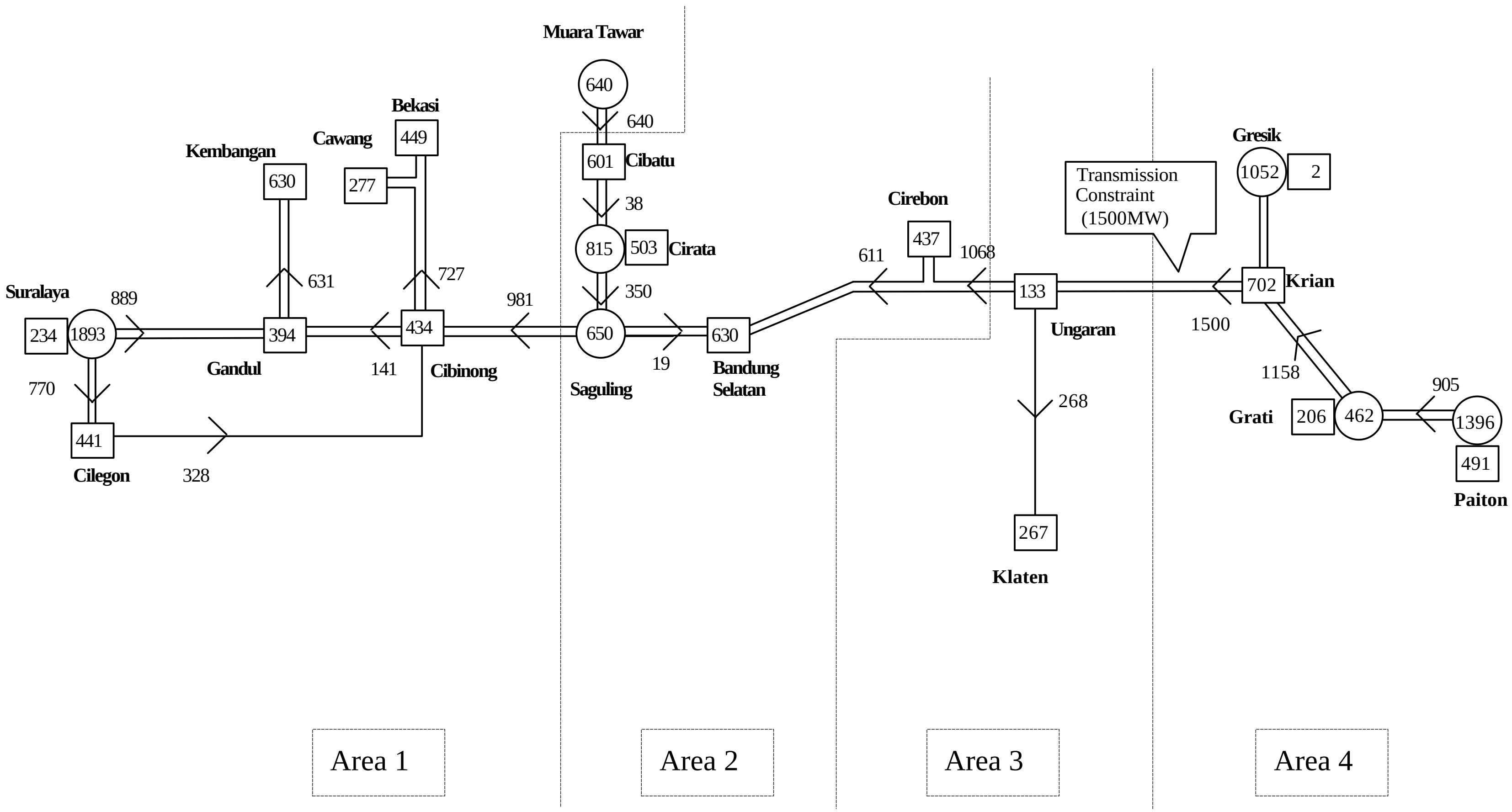


Figure 5.1.2 Power Flow Diagram of Java-Bali system in 2001

Unit:MW
The circles show the power stations,
and the rectangles show the substations.



5.1.3 Ongoing / Planned Projects

(1) Repowering project for Muara-Karang unit 1-3 (2006-2007)

Since the application for a Japanese ODA loan was submitted to the Japanese government in 2001, the Muara-Karang repowering project could not be adopted. This project consists of a few phases. In the first phase, gas turbines (250MW x 2) will be installed without stopping the existing 1-3 units. In the next phase, the existing boilers will be demolished and new heat recovery boilers will be installed. The existing steam turbines will be combined with the new gas turbine in the last phase.

The schedule is shown in Figure 5.1.3. The feasibility study report indicates the new gas turbines will begin operating in 2006, thus the project can be completed in 2007.

Table 5.1.7 shows the project cost of Muara-Karang Re-powering project. Total project cost is estimated at about US$ 405 million.

Figure 5.1.3 Overall Project Schedule of Muara Karang Repowering

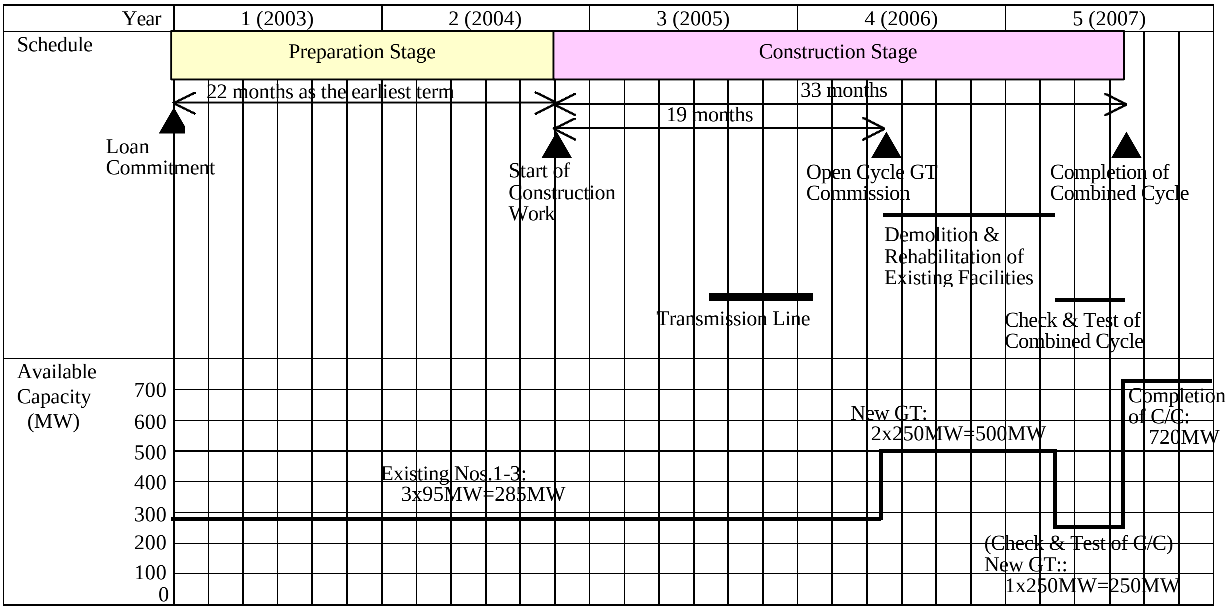


Table 5.1.7 Project Cost of Muara Karang Repowering (Unit: million US$)

Year			1st year	2nd year	3rd year	Total
Construction cost (403.2)*	Funds	Loans (Interest 0.75%pa) FC	41.4	134.7	166.7	342.7
		Own funds LC	7.3	23.8	29.4	60.5
Interest during construction LC			-	0.3	1.3	1.6
Total project cost			48.7	158.8	197.4	404.8

(2) Extension project of Muara-Tower Block III, IV thermal power plant (2006-2009)

The application for a Japanese ODA loan regarding engineering service of Muara Tower extension project, was submitted to the Japanese government and it was discussed in the CGI meeting as well as the Muara-Karang re-powering project.

There is space for extension power units (Block III and Block IV) at the site of the Muara-Tower thermal power plant. In the present plan, a 750MW combined cycle facility consisting of gas turbines (250MWx2) and a steam turbine (250MW) will be installed in each block. A total of 1,500MW will be installed.

Figure 5.1.4 shows the project schedule based on the feasibility study report. In this case the commissioning of the first gas turbine will be in 2006.

Meanwhile, the present installed capacity of the Muara- Tower power plant is about 1,000MW. After completing Block IV, the total capacity of the Muara-Tower power plant will be about 2,500MW. Since the total capacity of the Muara-Tower power plant would be bigger than the heat capacity of a single transmission line, it will be necessary to investigate how to transmit power flows stably.

Figure 5.1.4 Overall Project Schedule of Muara-Tawar Block **III**,**IV** Extension

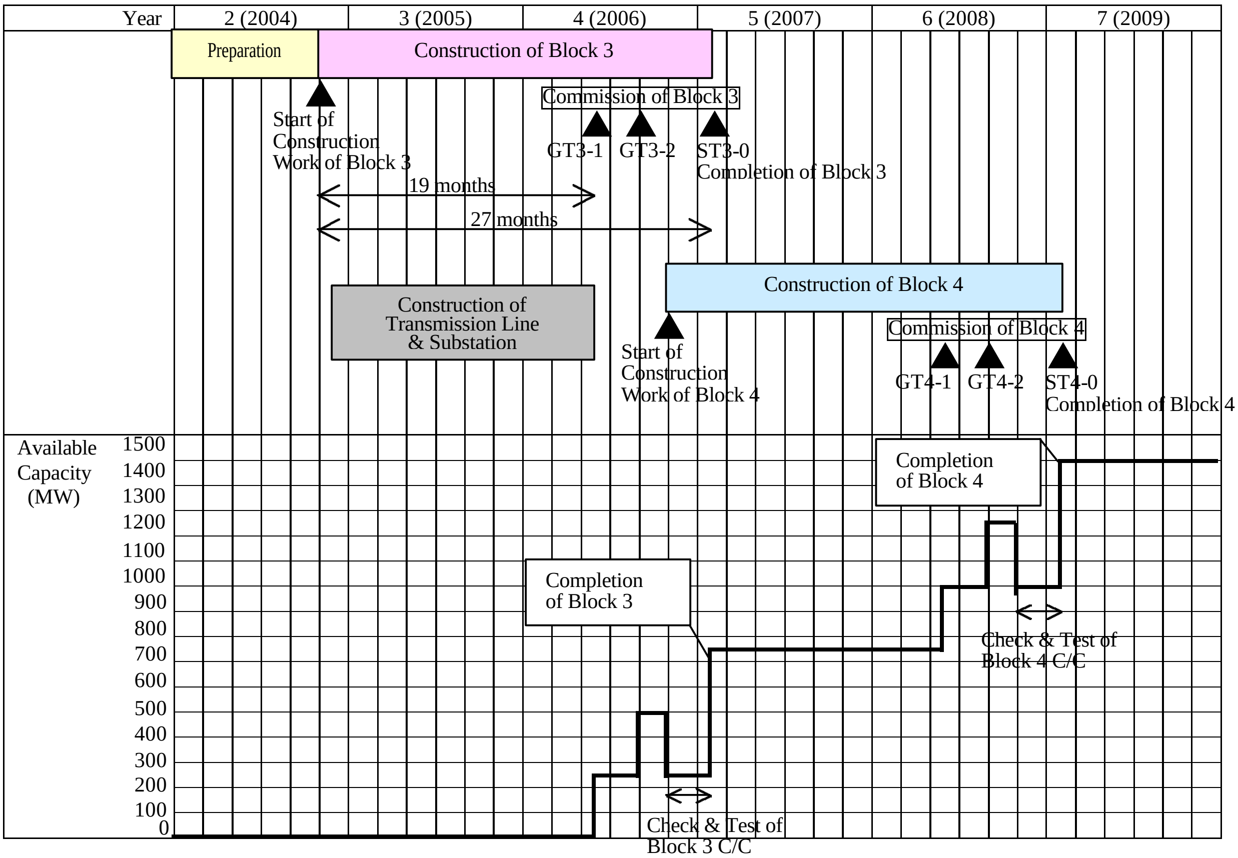


Table 5.1.8 shows the cost of the project. Total project cost is estimated at about US$ 979.1 million.

Table 5.1.8 Project Cost of Muara-Tawar Block III,IV Extension project (Unit: million US$)

Year			1st Y	2nd Y	3rd Y	4th Y	5th Y	Total
Construction cost (968.1)*	Funds	Loans(Interest 0.75%pa) FC	51.2	215.1	209.8	192.1	154.7	822.9
		Own funds LC	9.0	38.0	37.0	33.9	27.3	145.2
Interest during construction LC			-	0.4	2.0	3.6	5.0	11.0
Total project cost			60.2	253.5	248.8	229.6	187.0	979.1

(3) Muara-Tower Block II Added on Project (2006,2007)

Since the feasibility study was completed by the end of Mach, 2002, the Muara-Tower Block II Project is one of the candidate for the Japanese ODA loan. By installing a new gas turbine (145MW) and a new steam turbine (225MW), the existing open cycle gas turbines will become a combined cycle power plant. The total increased capacity is 370MW. Figure. 5.1.5 shows the project schedule estimated by reviewing the feasibility study report. The commissioning year of the gas turbine is expected to be in the beginning of 2006.

Figure. 5.1.5 Overall Project Schedule of Muara-Tawar Block II Added on

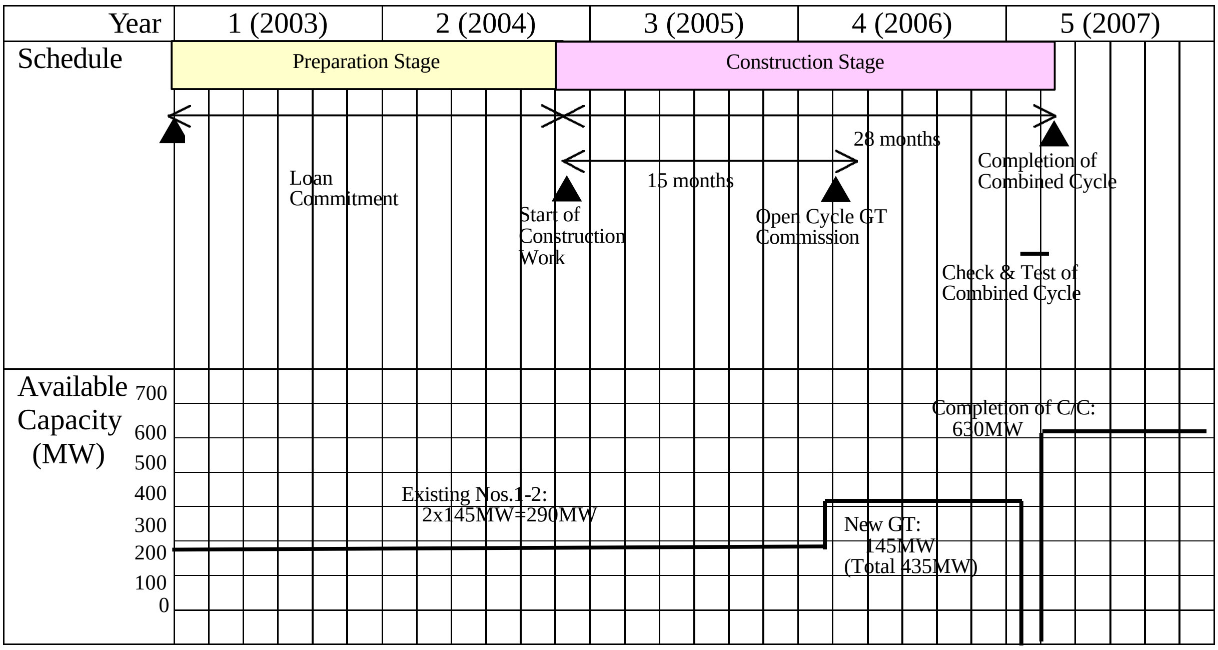


Table 5.1.9 shows the project cost of the Muara-Tower Block II added on project. The necessary project cost will be US$ 218 million.

Table 5.1.9 Project Cost of Muara-Tawar Block II Extension project (Unit: million US$)

Year			1st Y	2nd Y	3rd Y	4th Y	Total
Construction cost	Funds	Loans(Interest 0.75% pa) FC	56.1	90.1	36.6	-	182.8
		Own funds LC	9.9	15.9	6.5	-	32.3
Interest during construction LC			-	0.4	1.1	1.4	2.9
Total project cost			66.0	106.5	44.2	1.4	218

(4) Tanjung-Priok thermal power plant repowering project

The feasibility study was completed by the end of Mach, 2002. The new combined cycle power plant consisting of two gas turbines (250MW x 2) and one steam turbine (250MW) will be installed after demolishing the existing No.3 and No.4 units (50MW x 2). Thus the increased capacity will be 650MW despite the total capacity (750MW). The further study on the transmission line and the sea water system should be required to realize this project. The total project cost will be estimated about US$455 million.

(5) Pemaron thermal power plant (2003&2004)

A new combined cycle power plant will be constructed by combining a new steam turbine with the gas turbines, which will be moved from Tanjung-Priok. The gas turbines (50MW x 2) will start operating in 2003 and completion (total 150MW) is expected in 2004. It is estimated that the installation work from design to commissioning requires at least two years. Since the procurement of the steam turbine and the heat recovery boiler are under negotiation, the commissioning of gas turbines will be in 2003 and the completion will be in 2004, according to the PLN. The project cost is expected to be about US$98million.

(6) Tanjung-Jati B (IPP: the second half of 2005)

According to the PLN, the PPA agreement between PLN and the owners is almost agreed. After completing the loan agreement between banks including the JBIC and the Indonesian government, the interrupted installation work will resume. The necessary construction period will 36 months for the No.1 unit and 39 months for the No.2 unit. According to the EPC contractors, the manufacturing of the equipment is about 70% completed. Some equipment is kept onsite, but most of it is kept in the manufacturer's storehouse. A new 500kV transmission line for Tanjung-Jati B is planned to connect to near the Purwodadi sub station of the existing northern 500kV trunk line. However, it is necessary to connect it with the Ungaran sub station directly because of the constraint of power flow.

(7) Upper Cisokan pumped storage power plant

The Upper Cisokan project is in the design stage by PLN, using a Japanese ODA scheme. The total capacity is 1,000MW. The operation of each plant is expected to start in 2009 (500MW) and 2010 (500MW).

(8) New 500kV trunk line (Southern route)

To reduce the power flow on the existing 500kV trunk line (Northern Route), a new 500kV trunk line (Southern Route) is expected to be commissioned in 2004.

*Paiton - Kediri - Klaten

The construction work for the Kediri sub station and Paiton GIL is behind the schedule due to funding problems. By commissioning this section, the constrained capacity of power plants in East Java would be relieved. Tentative commissioning is planed for the single transmission line in 2002, with completion slated for 2003.

*Klaten-Tasikmaralya- DepokIII

There are plans to commit a new trunk line between Klaten-Tasikmalaya-DepokIII in 2004. Since the acquisition of land around the DepokIII sub station is behind the schedule, the commission will be delayed for a few years. The commissioning of this section will completely remove the capacity constraints of the power plants in East Java.

5.1.4 Fuel Supply Issues

(1) Coal supply

Trouble caused by coal shortages can occur simultaneously in multiple units within the same power plant, thereby causing a more serious effect. That is why it is very important to prepare an infrastructure to ensure stable coal delivery. Table 5.1.10 shows the number of troubles such problems related to coal shortages occurred in 2000. The number of generation troubles due poor quality or shortage of coal stands at 183, about 28% of all troubles suffered.

Table 5.1.10 Number of Troubles by Shortage of Coal

	Total	Caused by Coal Supply	%
Number of Derated	652	183	28%

Source: P3B data

The coal used in Suralaya power plant is provided mainly by PT. Bukit Asam in Sumatra island. Due to the problem with train transportation, it is not possible to supply enough coal to operate units. According to the World Bank report, PT. Bukit Asam has enough coal to provide to PLN. However, it appears that they would prefer not to sell it to PLN because their coal commands a better price in the international market.

Table 5.1.11 shows the characteristics of coal used in Indonesia. Paiton power plant buys the coal from PT. Adaro in Kalimantan Island.

Table 5.1.11 Coal Characters in Indonesia Coal-fired thermal plants

Items	Sularaya TPP (Dec.1998)	Paiton TPP (Aug.2001)
Calorific Value (kcal/kg)	6,944	5,214
Total Moisture (wt%)	23.29	25.42
Ash (wt%)	5.79	0.94
Volatile Matter (wt%)	44.02	35.46
Fixed Carbon (wt%)	50.19	36.18
Total Sulfur (wt%)	0.41	0.06
Nitrogen (wt%)	-	0.74
HGI	58.2	-

Source：PJB, Indonesia Power

Table 5.1.12 shows the reserve ratio for each type of coal. Bituminous coal, which is of good quality, is currently used for thermal power plant. However, Bituminous coal can be traded in the international market, and its reserve is limited, Sub-bituminous coal is expected to be used in the near future from the viewpoints of energy security and economic price, in place of Bituminous coal.

Table 5.1.12 Reserve Ratio in each type of Coal

Classification	Anthracite	Bituminous	Sub-bituminous	Lignite	Total
%	0.36	14.38	26.63	58.63	100.0

Directorate of Coal, "Indonesian Coal Mining Development & Company Profiles 1007"

(2) Gas supply

Table 5.1.13 shows the number of troubles caused by fuel shortages in 2000. A reliable supply of fuel gas is very important in order to stabilize the power supply.

Table 5.1.13 Number of Troubles Caused by Gas Shortage in 2000

	Total	Caused by Gas Supply	%
Number of Forced Outage	529	5	1%
Number of Derated	652	112	17%

Source: P3B data

Table 5.1.14 shows the estimated gas deliverability of Pertamina and the committed and uncommitted gas demand between PLN and Pertamina. This table shows the supply capacity of gas per day. The upper half shows the gas deliverability and the lower half shows the estimated gas demand.

The gas supply contract for Muara-Karang and Tanjng-Priok will be terminated in 2004, but no procurement arrangements have been made for after 2004. Since production from existing gas field is, the enough gas is not expected to be provided from 2008. Meanwhile, the Muara-Karang No.1-3 units have a re-powering plan in place. After re-powering, the fuel consumption of the new unit will require an additional 700kton/year of natural gas. We can not but expect surplus gas from the existing project until 2008. However, in case of no additional fuel, MFO oil should be used at the existing units 4 & 5, which have facilities for the MFO oil. On the other hand, natural gas for the Muara-Tower thermal power plant is planned to be supplied through a future Java-Sumatra gas pipeline according to the Pertamina.

Table 5.1.14 Pertamina's Gas Supply Plan (Unit :MMSCFD)

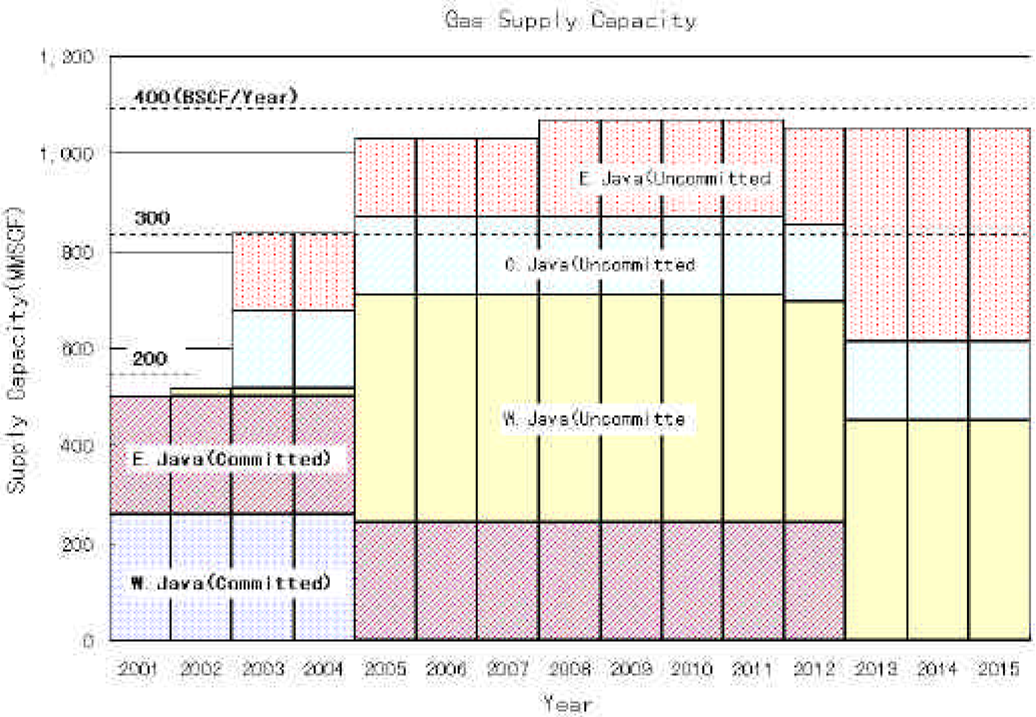
Area	South Sumatra	West Java	Central Java	East Java
Estimated Gas Deliverability				
Existing	± 200 – 275 (2002 – 2017)	± 200 – 350 (2002 – 2007) Declined from 190 to 30 (2008 – 2015)	None	± 150 – 300 (2002 – 2007) Declined from 120 to 40 (2008 – 2016)
Project	± 200 - 250 (2006 – 2017)	± 100 – 400 (2002–2015) Including 250MMSCFD from South Sumatra start at 2006.	± 5 – 15 (2003 – 2012)	± 20 – 350 (2002 – 2016)
Discovered Reserve	± 30 – 40 (2004 – 2017)	± 5 – 15 (2002 – 2015)	± 100 – 150 (2004 – 2012) Declined from 140 to 20 (2013 – 2020)	± 60 – 100 (2003 – 2016)
Estimated Gas Demand for Electricity				
Committed	*KRAMASAN ± 7 (2002 – 2010) *ASRIGITA ±22(2002 – 2017)	*M. KARANG ± 116 (2002 – 2004) *T. PRIOK ± 144 (2002 – 2004) *C.LISTRINDO ± 47 (2002 – 2014)	None	*GRESIK ± 242 (2002 – 2012)
Uncommitted	*ASRIGITA ± 8 (2004 – 2017)	*M. KARANG ± 186 (2005 – 2015) *M. TAWAR ± 267 (2004 – 2015) *SUNYARAGI ± 15 (2002 – 2011)	* T. LOROK ±160 (2003 – 2020)	*GRESIK – BP ±242 (2013– 2016) *GRESIK -KODECO ±39 (2008 – 2016) *GRATI ± 160 (2003 – 2016)

Source: Pertamina

Figure 5.1.6 shows the natural gas supply plan in Pertamina. The gas supply plan for the power sector calls for the provision of about 840-1050MMSCFD of fuel gas until 2015. It accounts for 330-380BSCF per year.

Because of no contract of fuel gas, Muara-Tower power plant (Block I, II), Tamba-Lorok power plant (Block I) and Grati power plant (Block I, II) use HSD oil at present although they have facilities for using natural gas. From environmental and economic aspects, HSD oil is inferior to natural gas, in addition, using HSD oil causes erosion problem. Moreover, the capacity of these plants would increase slightly by using natural gas, because of the higher calorific value of natural gas than HSD oil. Thus, it is important to study the fuel conversion of these plants from HSD oil to natural gas taking the fuel availability into account.

Figure 5.1.6 Natural Gas Supply Plan in Pertamina



(3) Take-or-Pay contract

Take-or-Pay Contract on gas fired power plants and geo thermal power plants has some problems to be solved for economical operation.

a. Gas Fired Thermal Power Plant

Gas fired power plants have to be operated at 62-70% in capacity factor because of Take-or-Pay contract on gas supply. Economically, these plants are expected to operate at around 50% in the capacity factor. Therefore, the rigid Take-or-Pay contract should be more flexible on the fuel supply.

b. Geothermal Power Plant

Similarly, geothermal power plants have to be operated at a capacity factor of 85% or more, because of the Take-or-Pay contract on steam supply. Although geothermal power plants are regarded as an economical power source on the point of fuel cost, as a matter of fact the actual generation cost is not cheaper than other power sources in Indonesia because of its low turbine efficiency as is shown in Table 5.1.15.

Since geothermal power is one form of renewable energy, ensuring energy security, it holds in an important position in energy policy in Indonesia.

Table 5.1.15 Generation Cost of Power Sources

Fuel Type	Coal (ST)	Gas(C/C)	MFO (ST)	HSD(C/C)	Geo Thermal
Cost (US$/Gcal)	4.2	10.0	10.1	14.5	6.3
Heat Rate (kcal/kWh)	2,400	2,100	2,606	2,350	7,308
Generation Cost (only Fuel Cost)	1.01	2.1	2.63	4.94	4.60
Loading Order	1	2	3	5	4

5.2 Probability of Power Deficit

5.2.1 Demand Scenario

The growth rate of power demand in RUKN is 8.2%. However, taking the price elasticity into account, the growth rate drops to about 5-7% as noted in 4.3. The difference of growth rate has serious effects on future demand. The only 1% difference would cause 200MW of the difference of forecasted demand in 2005. Two different scenarios are used to examine the power deficit in this section. Demands scenarios used in this report are shown below.

JICA/LPE_CASE 2	--- Real price constant scenario that is not required to take the price effect into account in determining the demand
JICA/LPE_CASE 1	--- Scenario in which the price effect is taken into account in determining the power demand. Planned prices for 2001 and 2002 are used. Finally the price increases to about 7 cents / kWh.

5.2.2 Supply Scenario

According to the results of the investigation on the generation reserve margin as reviewed in 5.1, each item of GRM adopted by P3B is almost adequate. However, the essential spinning reserve at 4.3% against the forced outage of one Paiton unit is overlapping with a forced outage at 6%. Therefore, by joining together the essential spinning reserve and forced outage, the new essential reserve margin can be set at 6%. Table 5.2.1 shows the proposed GRM in this report. It is reasonable to assume that the GRM used for a long-term power development plan would be about 25% if the constraints are relieved.

On the other hand, some constraints, such as the power flow limitations of transmission lines, still exist in the short-term planning. Thus, the supply capacity is evaluated by examining the operational spinning reserve directly in this report. The validity of the essential spinning reserve is examined in 5.2.2.(3) 3).

Table 5.2.1 Evaluation of GRM

Items	P3B	Proposed GRM	Reasons
Hydropower seasonal derating	5%	3-5%	Same as P3B
Thermal power derating	2.7%	2.7%	Same as P3B
Maintenance	12%	12%	Same as P3B
Forced outage	6%	N/A	Included in essential spinning reserve
Essential spinning reserve	4.3%	6%	Same as forced outage rate of P3B
Total	30%	25%	-

(1) Derated capacity

Table 5.2.2 shows the derated capacities used in this report.

Table 5.2.2 Derated capacity covered by GRM

Items	Capacity (MW)	Bases
Hydropower seasonal derating	671MW	Planning data in 2001 (3-5% of peak load)
Thermal power derating	326MW	Actual data in February 2001. (2.7% of peak load)
Maintenance	Calculate yearly	10% of Operational capacity (12% of peak load): equation 5-1
Essential spinning reserve	Calculate yearly	6% of peak load: equation 5-3

(2) Constrained capacity

Table 5.2.3 shows the constrained capacity used in this report.

Table 5.2.3 Constrained Capacity not to be covered by GRM

Items	Constrained Capacity	Remarks
(1) Long Term Outage		
a. Tanjung- Priok unit 3,4	100MW	*Refer to section 5.1
b. Grati BlockII	302MW	**To be removed in 2003-2004 by relieving the transmission constraint.
(2) Special Contract Service		
Cikarang Listrindo	150MW	*Refer to section 5.1
(3) Constrained Capacity caused by transmission line.		
a. Constrained capacity at present condition	1,000-1,250MW	*Result of the system analysis
b. Commissioning of 500kV southern trunk line (Paiton-Klaten)		
- Tentative commissioning (2002)	500-600MW	*Result of the system analysis
- Complete commissioning (2003)	0 – 300MW	
c. Commissioning of 500kV southern trunk line (Klaten-Depok III) -Complete commissioning (2004)	0MW	*Result of the system analysis

(3) Basic study for power development plan

Before examining the probability of power deficit, basic study would be made along the procedure shown below.

Study on Base Case

Power development plan including Muara-Karang repowering and Tanjung-Jati B is studied as base case

⇩

Study for Necessary Capacity

To evaluate the necessary capacity adequately, power development plan on the condition of "LOLP = 1 day /year" is studied as LOLP case.

1) Development scenarios

Table 5.2.4 shows the specific projects for each development scenarios.

Table 5.2.4 Development scenarios examined in this report

Project name	Capacity Increased (MW)	Base Case	LOLP Case
Muara- Karang Repowering	420 (720)	2006-2007	
Extension of Muara-Tower Block III, IV	1,500	NA	
Added on of Muara-Tower Block II	370 (660)	NA	
Tanjung-Priok Rehabilitation	650 (750)	NA	
Pemaron C/C	50 (150)	2003&2004	
Tanjung-Jati B	1,320	2005	
New Gas Turbine	120	NA	2004 -
New Combined Cycle	600	NA	2004 -
New Steam Turbine	600	NA	2004 -
Southern 500kV Trunk line (Paiton- Klaten: Tentative Commissioning)	According to the system analysis	2002	
Southern 500kV Trunk line (Paiton-Klaten: Partial Complete)		2003	
Southern 500kV Trunk line(Complete)		2004	

*Muara-Karang repowering project --- Review of the feasibility study report

*Muara-Tower Block II-IV project --- Review of the feasibility study report

*Pemaron project --- Not to count as the available capacity

*Tanjung-Jati B --- Result of the 4th-work Indonesia

*500kV trunk line (Southern Route) --- Result of the 4th-work Indonesia

*New Gas Turbine etc. --- (Please Refer to Chapter 7)

The constraining of southern 500kV trunk line calculated by the power system analysis of the each scenario is shown in Table 5.2.5. The constrained capacity of JICA/LPE_CASE 2 is smaller than that of JICA/LPE_CASE 1, because the forecasted demand of eastern Java is bigger than that of JICA/LPE_CASE 1.

Table 5.2.5 Constrained capacity of each case(MW)

	2001	2002	2003	2004	2005	2006
JICA/LPE_CASE 2	13,041	14,089	15,073	16,071	17,170	18,374
・Constrained Capacity	1,231	501	11	0	0	0
JICA/LPE_CASE 1	13,041	13,821	14,497	15,266	16,185	17,220
・Constrained Capacity	1,231	601	214	0	0	0

2) Study on base case

Table 5.2.6 shows the demand-supply balance for the base case. The operational spinning reserve will become smaller than the essential spinning reserve in 2003 and become negative in 2004. Therefor the short term countermeasures should be required for operating the system stably. The capacity deficit will reach 2,193MW in 2007.

Table 5.2.6 Demand- Supply Balance for Base Case - JICA/LPE Case 2- (Unit: MW)

Year	2001	2002	2003	2004	2005	2006	2007
a. Installed Capacity	18,608	18,608	18,608	18,658	19,978	20,178	20,398
・Existing capacity	18,608	18,608	18,608	18,608	18,608	18,308	18,308
・New capacity	0	0	0	50	1,370	1,870	2,090
b. Available capacity	14,292	15,082	15,572	15,900	17,088	17,268	17,466
・Hydropower seasonal derating	671	671	671	671	671	671	671
・Thermal power derating	326	326	326	326	326	326	326
・Maintenance	1,476	1,476	1,476	1,511	1,643	1,663	1,685
・Long term outage	462	402	402	100	100	100	100
・Special contract service	150	150	150	150	150	150	150
・Transmission constraint	1,231	501	11	0	0	0	0
c. Peak Load	13,041	14,089	15,073	16,071	17,170	18,374	19,659
・Essential Spinning reserve	782	845	904	964	1,030	1,102	1,180
・Operational Spinning reserve	1,251	993	*499	△171	△82	△1,106	△2,193
・LOLP (day / year)	0.1	1.4	5.5	NA	NA	NA	NA

* Years operational spinning reserves are smaller than essential spinning reserves.

The operational spinning reserve and the essential spinning reserve are calculated by the equations below:

*Operational Spinning Reserve = Available Capacity - Peak Load (MW).................. 5 - 4
*Essential Spinning Reserve = Peak load x 6%... 5 - 5

Essential spinning reserve calculated by equation 5-5 is about 800MW. It is almost the same as the capacity of the largest unit (615MW) plus an old power unit (100-200MW).

On the other hand, the operational spinning reserve should be evaluated by the following equation.

*O.S.R. ≧ E.S.R.	・The power system can be operated stably.
*O.S.R. < E.S.R.	・The power system can be operated. ・If a power plant stopped accidentally, some problems such as black outs for limited areas would occur.
*O.S.R. < 0	・Since the power system cannot be operated, counter measures such as rotational black outs, would be required.

**ESR: Essential Spinning Reserve, O.S.R: Operational Spinning Reserve

・・・5 - 6

3) Study for the necessary capacity

PLN uses the LOLP method to evaluate the system reliability. The LOLP method is to calculate the probability of power deficit by taking the capacity reduction, such as forced outage rate etc., into account. The LOLP standard of PLN is set at 1 day per year.

・JICA/LPE Case 2

Table 5.2.7 shows the demand-supply balance for LOLP case. LOLP case is calculated by WASP-IV on the condition that system reliability is kept at PLN standard from 2004. In this case, additional 1,800MW should be developed against the base case till 2005. This capacity is not realistic to be developed. Thus, the system reliability in the short term has to be reduced below the PLN standard.

Table 5.2.7 Demand- Supply Balance for LOLP(1day) Case - JICA/LPE Case 2 - (Unit: MW)

Year	2001	2002	2003	2004	2005	2006	2007
a. Installed Capacity	18,608	18,608	18,608	20,458	21,778	23,178	24,598
• Existing capacity	18,608	18,608	18,608	18,608	18,608	18,308	18,308
• New capacity	0	0	0	1,850	3,170	4,870	6,290
(Base Case Capacity)	0	0	0	50	1,370	1,870	2,090
(Additional Capacity)	0	0	0	1,800	1,800	3,000	4,200
b. Available capacity	14,292	15,082	15,572	17,520	18,708	19,968	21,246
• Maintenance	1,476	1,476	1,476	1,691	1,823	1,963	2,105
• Other Capacity to be Redacted)	2,840	2,050	1,560	1,247	1,247	1,247	1,247
c. Peak Load	13,041	14,089	15,073	16,071	17,170	18,374	19,659
• Essential Spinning Reserve	782	845	904	964	1,030	1,102	1,180
• Operational Spinning Reserve	1,251	993	*499	1,449	1,538	1,594	1,587
• LOLP (day / year)	0.1	1.4	5.5	0.7	0.7	0.8	0.9

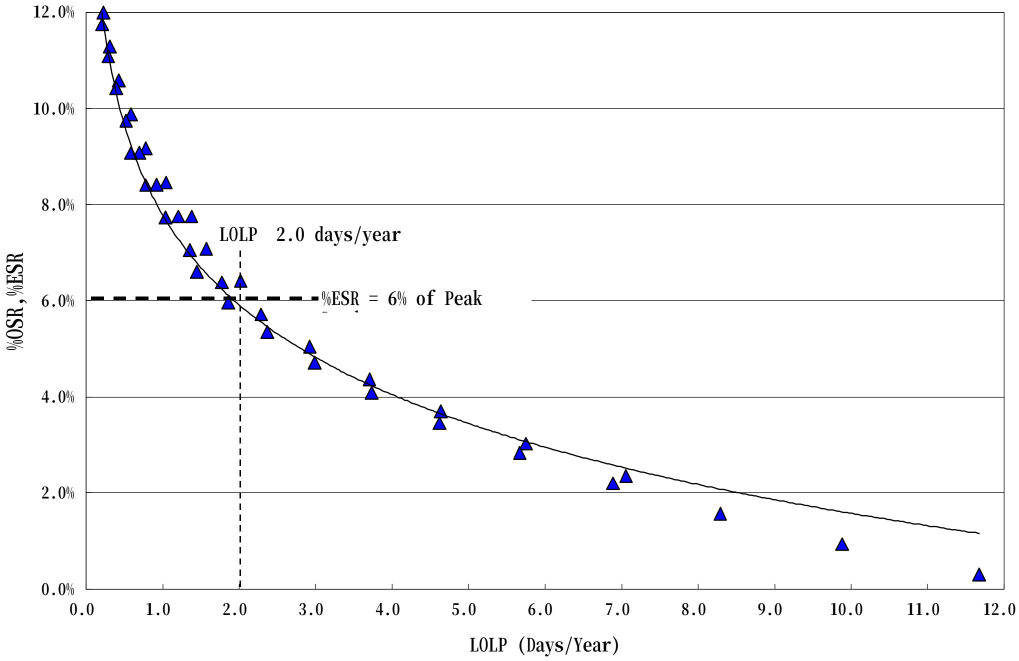
* Years operational spinning reserves are smaller than essential spinning reserves.

** Other Capacity to be Redacted ＝ Hydro power seasonal derating + Thermal Derating + Long Term Outage + Special Contract Service + Transmission constraint

(Each figure is the same as Table 5.2.6)

Figure 5.2.1 shows the relation ship among essential spinning reserve, operational spinning reserve and LOLP. The ESR (= 6% of peak load) deserves 2.0days / year in the power shortage probability.

Figure 5.2.1 The relation ship among %ESR,%OSR and %LOLP (2004,2005)



Meanwhile, there are other methods for evaluating system reliability, such as the "Loss of Largest Generating Unit" method. The E.S.R. has enough reserve against the forced outage of the largest unit plus an old unit capacity. Thus, although the system reliability is below the PLN standard, E.S.R. (= 6% of peak load) is used as the criteria of power deficit in this report. Table 5.2.8 shows the evaluation results for system reliability by the different evaluating methods.

Table 5.2.8 Evaluation of Essential Spinning Reserve

Items	LOLP	Spinning Reserve (MW)	Loss of Largest Generating Unit Method (615MW)
E.S.R 6%	2 days / year	964 - 1,030MW	Largest Unit (615MW) + Old Unit (200MW)
E.S.R 8%	1 day / year	1,286- 1,374MW	Largest Unit x 2

・JICA/LPE Case1

Table 5.2.9 shows the demand –supply balance of Base Case and LOLP Case at JICA/LPE Case 1.

Table 5.2.9 Demand- Supply Balance for LOLP(1day) Case - JICA/LPE Case 1 - (Unit: MW)

Year	2001	2002	2003	2004	2005	2006	2007
1. Base Case							
a. Installed Capacity	18,608	18,608	18,608	18,658	19,978	20,178	20,398
b. Available Capacity	14,292	14,982	15,369	15,900	17,088	17,268	17,466
c. Peak Load	13,041	13,821	14,497	15,266	16,185	17,220	18,348
・Essential Spinning Reserve	782	829	870	916	971	1,033	1,101
・Operational Spinning Reserve	1,251	1,161	872	*634	*903	*48	△882
・LOLP (day / year)	0.1	0.9	1.9	4.2	2.7	11.8	NA
2. LOLP Case							
a. Installed Capacity	18,608	18,608	18,608	19,378	20,698	22,618	23,038
(Additional Capacity to the Base Case)	0	0	0	(720)	(720)	(1,440)	(2,640)
b. Available Capacity	14,292	14,982	15,369	16,989	17,763	19,041	20,121
c. Peak Load	13,041	13,821	14,497	15,266	16,185	17,220	18,348
・Essential Spinning Reserve	782	829	870	916	971	1,033	1,101
・Operational Spinning Reserve	1,251	1,161	872	1,282	1,551	1,344	1,494
・LOLP (day / year)	0.1	0.9	1.9	0.9	0.6	0.7	0.9

*, **: Same as Table 5.2.7

In the base case, the operational spinning reserve will become smaller than the essential spinning reserve in 2004 and will be negative in 2007. However the system can operate anyway till 2006. The capacity deficit will reach 882MW in 2007. Based on the result of LOLP case, the necessary capacity to satisfy the PLN standard will be 720MW till 2005.

5.2.3 Sensitive Study for Demand-Supply Plan

(1) Development scenarios

Table 5.2.10 shows the development scenarios used for sensitive study. In this section, the demand-supply balance is explained only for the JICA/LPE Case 2. The result at JICA/LPE Case 1 is touched in section 5.2.4.

The Basis of cases are shown below:

1) Base Case
   The case taken Tanjung-Jati B and Muara-Karang Repowering into account
2) Base + Muara Tower BlockⅡ Case
   The case added Muara-Tower BlockⅡ Added On the Base Case
3) Base + Muara Tower BlockⅢ Case
   The case added Muara-Tower BlockⅢ Extension on the Base Case
4) Muara-Tower BlockⅡ Added On Case
   The case taken Tanjung-Jati B and Muara-Tower BlockⅡ into account.
   (Muara-Karang -Repowering is not considered in this case.)
5) Limited Development Case
   The case taken only Tanjung-Jati B into account
6) Slipped Base Case
   The case Muara-Karang Repowering will be slipped one year behind the Base Case

Table 5.2.10 Development Scenarios (Sensitive Study)

Item / Scenario		Normal Scenario					Slipped Scenario
Project Name	Capacity Increased (MW)	Base Case	Base + MT II Case	Base + MT III Case	MT II Added on Case	Limited Development Case	Slipped Base Case
Muara-Karang Repowering	420 (720)	2006&2007			NA		2007& 2008
Muara-Tower Block III Extension	750	NA		2006 &2007	NA		NA
Muara-Tower II Added On	370 (660)	NA	2006 &2007	NA	2006 &2007	NA	NA
Pemaron C/C	50 (150)	2003&2004					2003 &2004
Tanjung-Jati B	1,320	2005					2005
Southern 500kV Trunk line (Paiton- Klaten: Tentative Commissioning)	According to the system analysis	2002					2002
Southern 500kV Trunk line (Paiton-Klaten: Partial Complete)		2003					2003
Southern 500kV Trunk line (Completion)		2004					2004

Schedule of Normal Scenario

*Muara-Karang repowering project --- Review of the feasibility study report

*Muara-Tower Block III extension project --- Review of the feasibility study report

*Muara-Tower Block II Added on project --- Review of the feasibility study report

*Pesanggaran / Pemaron project --- Not to count as the available capacity

*Tanjung-Jati B --- Result of the 4th-work Indonesia

*500kV trunk line(Southern Route) --- Result of the 4th-work Indonesia

*New Gas Turbine etc. --- (Please Refer to Chapter 7)

(2) Sensitive study for the project development (Normal scenario)

・ Base + Muara- Tower Block II Case (JICA/LPE Case 2)

Table 5.2.11 shows the demand-supply balance for Base + Muara- Tower Block II Case. The operational spinning reserve will become smaller than the essential spinning reserve in 2003 and will be negative in 2004. The capacity deficit will reach 1,860MW in 2007.

Table 5.2.11 Demand-Supply Balance for Base + Muara- Tower Block II Case (Unit: MW)

Year	2001	2002	2003	2004	2005	2006	2007
a. Installed Capacity	18,608	18,608	18,608	18,658	19,978	20,323	20,768
・Existing capacity	18,608	18,608	18,608	18,608	18,608	18,308	18,308
・New capacity	0	0	0	50	1,370	2,015	2,460
b. Available capacity	14,292	15,082	15,572	15,900	17,088	17,399	17,799
・Maintenance	1,476	1,476	1,476	1,511	1,643	1,677	1,722
・Other Capacity to be Redacted	2,840	2,050	1,560	1,247	1,247	1,247	1,247
c. Peak Load	13,041	14,089	15,073	16,071	17,170	18,374	19,659
・Essential Spinning Reserve	782	845	904	964	1,030	1,102	1,180
・Operational Spinning Reserve	1,251	993	*499	△171	△82	△975	△1,860
・LOLP (day / year)	0.1	1.4	5.5	NA	NA	NA	NA

*, **: Same as Table 5.2.7

・ Base + Muara- Tower Block III Case (JICA/LPE Case 2)

Table 5.2.12 shows the demand-supply balance for Base + Muara- Tower Block III Case. The operational spinning reserve will become smaller than the essential spinning reserve in 2003 and will be negative in 2004. The capacity deficit will reach 1,518MW in 2007.

Table 5.2.12 Demand-Supply Balance for Base + Muara- Tower Block III Case (Unit:MW)

Year	2001	2002	2003	2004	2005	2006	2007
a. Installed Capacity	18,608	18,608	18,608	18,658	19,978	20,678	21,148
・Existing capacity	18,608	18,608	18,608	18,608	18,608	18,308	18,308
・New capacity	0	0	0	50	1,370	2,370	2,840
b. Available capacity	14,292	15,082	15,572	15,900	17,088	17,718	18,141
・Maintenance	1,476	1,476	1,476	1,511	1,643	1,713	1,760
・Other Capacity to be Redacted	2,840	2,050	1,560	1,247	1,247	1,247	1,247
c. Peak Load	13,041	14,089	15,073	16,071	17,170	18,374	19,659
・Essential Spinning Reserve	782	845	904	964	1,030	1,102	1,180
・Operational Spinning Reserve	1,251	993	*499	△171	△82	△656	△1,518
・LOLP (day / year)	0.1	1.4	5.5	NA	NA	NA	NA

*, **: Same as Table 5.2.7

・ Muara-Tower Block Ⅱ Added On Case (JICA/LPE Case 2)

Table 5.2.13 shows the demand-supply balance for Muara- Tower Block Ⅱ Added On Case. The operational spinning reserve will become smaller than the essential spinning reserve in 2003 and will be negative in 2004. The capacity deficit will reach 2,238MW in 2007.

Table 5.2.13 Demand-Supply Balance for Muara-Tower Block Ⅱ Added on Case (Unit: MW)

Year	2001	2002	2003	2004	2005	2006	2007
a. Installed Capacity	18,608	18,608	18,608	18,658	19,978	20,123	20,348
・Existing capacity	18,608	18,608	18,608	18,608	18,608	18,608	18,608
・New capacity	0	0	0	50	1,370	1,515	1,740
b. Available capacity	14,292	15,082	15,572	15,900	17,088	17,219	17,421
・Maintenance	1,476	1,476	1,476	1,511	1,643	1,657	1,680
・Other Capacity to be Redacted	2,840	2,050	1,560	1,247	1,247	1,247	1,247
c. Peak Load	13,041	14,089	15,073	16,071	17,170	18,374	19,659
・Essential Spinning Reserve	782	845	904	964	1,030	1,102	1,180
・Operational Spinning Reserve	1,251	993	*499	△171	△82	△1,155	△2,238
・LOLP (day / year)	0.1	1.4	5.5	NA	NA	NA	NA

*, **: Same as Table 5.2.7

・ Limited Development Case (JICA/LPE Case 2)

Table 5.2.14 shows the demand-supply balance for Limited Development Case. The operational spinning reserve will become smaller than the essential spinning reserve in 2003 and will be negative in 2004. The capacity deficit will reach 2,571MW in 2007.

Table 5.2.14 Demand-Supply Balance for Limited Development Case (Unit: MW)

Year	2001	2002	2003	2004	2005	2006	2007
a. Installed Capacity	18,608	18,608	18,608	18,658	19,978	19,978	19,978
・Existing capacity	18,608	18,608	18,608	18,608	18,608	18,608	18,608
・New capacity	0	0	0	50	1,370	1,370	1,370
b. Available capacity	14,292	15,082	15,572	15,900	17,088	17,088	17,088
・Maintenance	1,476	1,476	1,476	1,511	1,643	1,643	1,643
・Other Capacity to be Redacted	2,840	2,050	1,560	1,247	1,247	1,247	1,247
c. Peak Load	13,041	14,089	15,073	16,071	17,170	18,374	19,659
・Essential Spinning Reserve	782	845	904	964	1,030	1,102	1,180
・Operational Spinning Reserve	1,251	993	*499	△171	△82	△1,286	△2,571
・LOLP (day / year)	0.1	1.4	5.5	NA	NA	NA	NA

*, **: Same as Table 5.2.7

(3) Sensitive study for the project slippage (Slipped Scenario)

・ Slipped Base Case (JICA/LPE Case 2)

Table 5.2.15 shows the demand-supply balance for Slipped Base Case. The operational spinning reserve will become smaller than the essential spinning reserve in 2003 and will be negative in 2004. The capacity deficit will reach 2,391MW in 2007.

Table 5.2.15 Demand-Supply Balance for Slipped Base Case (Unit: MW)

Year	2001	2002	2003	2004	2005	2006	2007
a. Installed Capacity	18,608	18,608	18,608	18,658	19,978	19,978	20,178
・Existing capacity	18,608	18,608	18,608	18,608	18,608	18,608	18,308
・New capacity	0	0	0	50	1,370	1,370	1,870
b. Available capacity	14,292	15,082	15,572	15,900	17,088	17,088	17,268
・Maintenance	1,476	1,476	1,476	1,511	1,643	1,643	1,663
・Other Capacity to be Redacted	2,840	2,050	1,560	1,247	1,247	1,247	1,247
c. Peak Load	13,041	14,089	15,073	16,071	17,170	18,374	19,659
・Essential Spinning Reserve	782	845	904	964	1,030	1,102	1,180
・Operational Spinning Reserve	1,251	993	*499	△171	△82	△1,286	△2,391
・LOLP (day / year)	0.1	1.4	5.5	NA	NA	NA	NA

*, **: Same as Table 5.2.7

5.2.4 Probability of Power Deficit

Table 5.2.16 summarizes the operational spinning reserve examined in the sensitive study. Short-term countermeasures against the deficits will be proposed in chapter 6.

(1) Effect of fluctuation of demand growth

・JICA/LPE CASE 2

The operational spinning reserve will be below the essential spinning reserve in 2003 and will be negative from 2004 in all cases. Therefore short-term countermeasures should be taken in order to operate the power system stably. The deficit of the Operational Spinning Reserve in 2004 and in 2005 will reach about △171MW and △82MW, thus the deficit capacity is contribute to estimate the necessary capacity for the short term countermeasures.

・JICA/LPE CASE 1

The operational spinning reserve will be below the essential spinning reserve in some years but the power system can be operated until 2005 in all cases. The power system can be operated until 2006 in the Base Case, the Base + Muara-Tower Block II and the Base +

Muara-Tower BlockⅢ Case, and also can be operated until 2005 in the Muara-Tower Added On Case, the Limited Case and the Slipped Base Case without short term countermeasures.

(2) Effect of project development

The years in which the operational spinning reserve will become smaller than the essential spinning reserve are 2006 for the Base Case and 2005 for the Limited Development Case. The effect of project development is about one year for the Muara-Karang re-powering in JICA/LPE CASE 1. Since the operational spinning reserve will be negative from 2004, the project development will not influent on the years of power deficit in JICA/LPE CASE 2

(3) Effect of Project Slippage

The years in which the operational spinning reserve will be negative will be in 2007 in the Base Case and in 2006 in the Slipped Base Case, the effect of project slippage is only one years in JICA/LPE CASE 1. On the other hand, the project slippage will not influent on the year of power deficit in JICA/LPE CASE 2, since the operational spinning reserve will be negative from 2004.

Table 5.2.16 Operational Spinning Reserve for All Development Scenarios (Unit:MW)

Year	2001	2002	2003	2004	2005	2006	2007
1. JICA/LPE CASE 2							
1) Peak Load	13,041	14,089	15,073	16,071	17,170	18,374	19,659
2) Essential Spinning Reserve	782	845	904	964	1,030	1,102	1,180
3) Operational Spinning Reserve							
・Base Case	1,251	993	*499	△171	△82	△1,106	△2,193
・Base+Muara-Tower BlockⅡ Case	1,251	993	*499	△171	△82	△975	△1,860
・Base+Muara-Tower BlockⅢ Case	1,251	993	*499	△171	△82	△656	△1,518
・Muara-Tower BlockⅡ Added on Case	1,251	993	*499	△171	△82	△1,155	△2,238
・Limited Development Case	1,251	993	*499	△171	△82	△1,286	△2,571
・Slipped Base Case	1,251	993	*499	△171	△82	△1,286	△2,391
2. JICA/LPE CASE 1							
1) Peak Load	13,041	13,821	14,497	15,266	16,185	17,220	18,348
2) Essential Spinning Reserve	782	829	870	916	971	1,033	1,101
3) Operational Spinning Reserve							
・Base Case	1,251	1,161	872	*634	*903	*48	△882
・Base+Muara-Tower BlockⅡ Case	1,251	1,161	872	*634	*903	*179	△549
・Base+Muara-Tower BlockⅢ Case	1,251	1,161	872	*634	*903	*498	△207
・Muara-Tower BlockⅡ Added on Case	1,251	1,161	872	*634	*903	△1	△927
・Limited Development Case	1,251	1,161	872	*634	*903	△132	△1,260
・Slipped Base Case	1,251	1,161	872	*634	*903	△132	△1,080

*, **: Same as Table 5.2.7

Supplementary Discussion:

Comparison of Merits Between the Base + Muara-Tower BlockⅡ Case and the Base + Muara-Tower BlockⅢ Case

For comparing the merits of projects, the system costs and the system reliability etc. often are calculated by using simulation programs. Here, merits of two Muara-Tower projects, such as the Base + Muara-Tower BlockⅡ Case (herein after referred as M.T.ⅡCase) and the Base + Muara-Tower BlockⅢ Case (herein after referred as M.T.ⅢCase), are compared by using WASP-IV as an example, from the view point of the economical impact mainly.

1. Study Cases & Conditions

These 3 cases shown in Table 5.S.1 were studied with two types of demand.

(1) Study Cases

Table 5.S.1 Study Cases

Projects	Installed Capacity	Base Case	Base + Muara-Tower Ⅱ Case	Base + Muara-TowerⅢ Case
Muara-Karang Repowering	420MW (720MW)	2006:+200MW GT Commissioning (500MW) Demolishes Existing 1-3 Boilers(△300MW) 2007: +220MW Full Commissioning		
Muara-Tower Block Ⅱ Added-On	370MW (660MW)	NA	2006: +145MW GT Commissioning 2007: +225MW Full Commissioning	NA
Muara-Tower Block Ⅲ Extension	750MW	NA	NA	2006: +500MW GT Commissioning 2007: +250MW Full Commissioning
Tanjung-Jati B	1,320MW	2005		

(2) Conditions

*Calculation Period:	10 Years (From 2002 to 2011)
*Demands:	JICA/LPE CASE 2 and JICA/LPE CASE 1
*Discount Rate:	12%
*Reliability Index:	LOLP = 1day/ year (From 2006)
* Construction Costs	Muara-Tower Block II Added on PJT. = US$ 220 million Muara-Tower Block III Extension PJT. = US$ 500 million
*Model Projects:	The following projects will be opened from 2006: ST - 600MW Steam Turbine (Coal) C/C - 600MW Combined Cycle (Gas) GT - 120MW Gas Turbine (HSD) PS - 250MW Pumped Storage Unit
*Others:	Muara-Tower Block I will be converted from HSD to Gas in year 2007 except for the Base Case

2. Simulation Results

(1) JICA/LPE CASE 2

Table 5.S2 shows the simulation results of each case in JICA/LPE CASE 2. The necessary capacities to be installed until 2011are about 12,000MW in all cases.

From the viewpoint of the power development, the numbers of ST and C/C in the M.T.Ⅱ Case are as same as that in the M.T.Ⅲ Case. However, the number of GT in the M.T.Ⅱ Case (12 units) is 3 units more than that of the M.T.Ⅲ Case (9 units). Thus the difference of increased capacity between Muara-Tower Block Ⅱ (370MW) and Muara-Tower Block Ⅲ (750MW) is covered with three gas turbines (120MW x 3 units).

From the viewpoint of the total system cost, the Base Case is the most expensive of the three cases. It is considered that the M.T.Ⅱ Case and the M.T.Ⅲ Case include the fuel conversion from HSD to Gas at existing Muara-Tower Block Ⅰ. The difference of the total system cost between the M.T.Ⅱ Case (US$15,428million) and the M.T.Ⅲ Case (US$15,473million) is US$45million, it is also 0.3% (=45 / 15,428) of the total system costs

Table 5.S.2 Simulation Results from 2002 to 2011 (JICA/LPE CASE2)

Case	Base Case				Muara-Tower Block Ⅱ Added-on Case				Muara-Tower Block Ⅲ Extension Case			
Candidates	ST	C/C	GT	PS	ST	C/C	GT	PS	ST	C/C	GT	PS
Numbers of necessary units	13	5	6	2	12	5	12	0	12	5	9	0
Necessary Capacities	7,800	3,000	720	500	7,200	3,000	1,440	0	7,200	3,000	1,080	0
Necessary Capacites with Muara-Tower PJTs.	Total 12,020 MW				Muara-Tower Block Ⅱ Added on 370MW				Muara-Tower Block Ⅲ Extension 750MW			
					Total 12,010 MW				Total 12,030 MW			
*System Costs (million US$)												
Construction Costs	5,780				5,513 (**145)				5,534 (**330)			
Salvage Value	3,225				3,066 (** 62)				3,113 (**141)			
Operation Costs	12,709				12,717				12,787			
E.N.S costs	264				264				265			
Total Costs	15,528				15,428				15,473			

* Capacities and Construction costs of Muara-Karang Repowering & Tanjung-Jati B is Not included in this table.

**Construction costs and salvage values of Muara-Tower PJTs. are shown in ( ).

*** Please refer to Supplementary Discussion 1 of Chapter 7

(2) JICA/LPE CASE 1

Table 5.S.3 shows the simulation results of each case in JICA/LPE CASE 1. The necessary capacities to be installed are about 9,800MW in all cases. The necessary capacity will decrease by 2,200MW from 12,000MW in JICA/LPE CASE 2 in accordance with the demand decrease.

On the other hand, the total system cost will decrease by US$1,555million (15,528 – 13,973) as well as the necessary capacity. The trend is almost same as JICA/LPE CASE 2, so the Base Case is the most expensive of the three cases. The difference of the total system cost between the M.T. Ⅱ Case (US$13,885million) and the M.T.Ⅲ Case (US$13,943million) is US$58million, it is also 0.3% (=48 / 13,885) of the total system costs (the cost in M.T. Ⅱ case is cheaper than that in the M.T.Ⅲ Case.) However the difference will become bigger in accordance with the demand decrease.

Table 5.S.3 Simulation Results from 2002 to 2011 (JICA/LPE CASE1)

Case	Base Case				Muara-Tower Block Ⅱ Added-on Case				Muara-Tower Block Ⅲ Extension Case			
Candidates	ST	C/C	GT	PS	ST	C/C	GT	PS	ST	C/C	GT	PS
Numbers of necessary units	10	5	7	0	9	5	9	0	9	4	10	0
Necessary Capacities	6,000	3,000	840	0	5,400	3,000	1,080	0	5,400	2,400	1,200	0
Necessary Capacities with Muara-Tower PJTs.	Total 9,840 MW				Muara-Tower Block Ⅱ Added on 370MW				Muara-Tower Block Ⅲ Extension 750MW			
					Total 9,850 MW				Total 9,750 MW			
*System Costs (million US$)												
Construction Costs	4,495				4,247 (**145)				4,242 (**330)			
Salvage Value	2,577				2,511 (** 62)				2,493 (**141)			
Operation Costs	12,002				12,095				12,140			
E.N.S costs	53				54				54			
Total Costs	13,973				13,885				13,943			

*,**,***: Same as Table 5.S.2

3. Consideration

(1) Total System Cost

Muara-Tower Power Plant uses HSD oil, although it has gas fired facilities. By realizing the M.T.ⅡCase and /or the M.T.Ⅲ, fuel gas, it is cheaper than HSD oil, will be delivered to the Muara-Tower Power Plant. Thus the existing Muara-Tower BlockⅠ can use the fuel gas. By using the cheaper fuel, the total system cost can be expected to decrease by US$50-100million for 10 years consequently.

(2) Demand Fluctuation

The difference between M.T.Ⅱ(370MW in actual) and M.T.Ⅲ(750MW) is 380MW. Thus in case that the demand growth becomes rather lower and the necessary capacity to be installed becomes 400MW or less, it will be said the M.T.Ⅱ Case is more reasonable. In contrast, in case that the demand growth becomes rather higher and the necessary capacity to be installed becomes 400MW or more, it will be said the M.T.Ⅲ Case is more reasonable, because the M.T.Ⅱ Case should be required other power sources making up for this 380MW

(3) Conclusion

Since the difference of total system cost between the M.T.Ⅱ Case and the M.T.Ⅲ Case is not so large, it difficult to put the priority on these project. It should be decided by the demand forecast, the development policy and the availability of the investment.

Chapter 6 Short-term Countermeasures against Power Deficit

As described in chapter 5, the operational spinning reserve will fall below the essential spinning reserve in 2003 and, show the negative figures from 2004 in the JICA/LPE_CASE2. Moreover, generation troubles occur frequently because of the shortage of fuels. In this chapter, sort-term countermeasures to avoid or relieve power deficit are discussed.

6.1 Effective Operation of Existing Facilities

6.1.1 Fuel Supply

Operating the existing power plant is certainly the most effective and important short-term countermeasures. Specifically, Problems must be avoided by securing fuel, reducing the forced outage rate by operating and maintaining outage, and shortening the maintenance period by carrying out proper periodical inspection.

(1) Coal supply

As mentioned in chapter 5, generation derating often occurs in coal fired power plants, such as Suralaya and Paiton, due to the shortage of fuel coal. Thus, it is important to revise coal contracts supply in order to secure needed coal fuel.

(2) Gas supply

The contract on the gas supply for the power station located in west Java will be terminated in 2004. Therefore, the new contract for the gas supply after 2005 should be concluded as soon as possible. However, since the resources of the existing gas well begins to decrease, the amount of supplied gas is expected to decline after 2008. Thus, the new gas project, such as Sumatra-Java gas pipeline, should be carried out to ensure a stable supply of fuel gas.

6.1.2 Reduction of Forced Outage Rate

The forced outage rate of thermal power plant is about 6% in Indonesia. It is higher than the 2% forced outage rate in Japan. Procedure shown below has been used in Japan in order to avoid similar troubles expected at other power stations. And it will be useful in Indonesian case.

To report the troubles	Report the date, time, reason etc. to the government.
⇩	
To analyze the factors	Investigate the cause of the troubles thoroughly and analyze it.
⇩	
To study the preventive measures	Study the preventive measures against recurrence, and carry them out.
⇩	
To spread the protection system to other power stations	Apply the same preventive measures to other power stations to avoid the same troubles

6.1.3 Proper Repair and Inspection of Adjustment of Periodical Inspection

(1) Proper scheduling of periodic inspection

As described in 3.2, the maximum peak load appears between October and December. In addition, the available capacity of hydropower plants decreases during dry season as described in 5.1.1. To make up for this reduction, the periodic repair of thermal power plant could be shifted to the period when maximum demand does not occur.

Adjustable capacity by shifting (shift capacity) is expect to be 3% of operational capacity, based on the standard deviation shown in Table 5.1.4. However, as shown in Table 5.1.5, the maintenance capacity of the thermal power plants in Area4 is excluded during the period when transmission constraint of 500kV trunk line exists. Therefore, the shift capacity should be calculated for the thermal power plants in Area1 to Area3. The formula used for calculation is shown below.

*During the period with no constraint in the 500kV trunk line

The shift capacity = Operational Capacity x 3% ----- 6-1

*During the period with constraint in the 500kV trunk line

The shift capacity
= (Operational Capacity - Operational Capacity in Area 4) x 3% ----- 6-2

Since the maintenance capacity is 10% of the operational capacity, the maintenance capacity will decrease to 7% during the period when maximum peak load is expected.

(2) To maintain and shorten the work schedule for periodical inspection

The periodical inspection requires for about a few weeks or months. On the other hand, there are many troubles of generators due not to keep the period of the periodical inspection. Thus, it is very important to carry out the periodical inspection along the working schedule, to complete it on schedule and to shorten its period.

(3) Extended operation of power plants

New power sources such as Muara-Karan re-powering, Muara-Tower extension and Tanjun-Jati B are expected to be completed in or after 2005. Consequently, the supply capacity for 2003 and 2004 will be slightly tighter than that for other years. To relieve the tight situation, the interval of thermal power periodical repair could be extended during this period. Thus, the capacity under maintenance is reduced as shown below.

-Target Power Plant ---- Located in the western Java.
No GT nor C/C plants which has the combustor exposed to high temperature gas.

-Target capacity ---- Muara-Karang P/P unit 4,5 400MW
Suralaya P/P unit 1-7 3,400MW
Total 3,800MW

-Estimated effect ---- By extending the interval of thermal power periodical repair to 1.5 times as long as the present interval, the maintenance rate (7%) can be reduced to 5% (7% x 2/3) .
3,800 x (7% - 5%) = 76MW

6.1.4 Rehabilitation

Rehabilitation of aged power plants is one of the effective short-term countermeasures against a power deficit. However, when investing in an aged power unit, cost performance and its remaining life time have to be considered. Moreover, the improvement in performance through rehabilitation is rather limited.

On the other hand, because of the transmission constraint, increased capacity in the east Java will not contribute to power supply to west Java in the a short-term. Thus the rehabilitation in west Java is very effective.

Therefore, the target aged power plants for rehabilitation are ones located in west Java, such as Muara- Karang unit #4-5 and Sralaya Power plant 1-4.

(1) Muara-Karang power plant unit #4,5

- Content : Replacement of High Pressure Feed Water Heater.
- Expected Effect : The available capacity is expected to increase about 10MW per unit. (Total 20MW)
- Present Condition: Since many capillaries of HP(E)HTR are plugged because of its leakage, the heater is under repair at a factory. Without using a HP(E)Heater, these units can be operated at no more than at 190MW against the installed capacity of the 200MW.

Table 6.1.1 Rehabilitation for Muara-Karan unit 4-5

No.	Rehabilitation work	Estimated Capacity Recovered
Unit 4,5	Capillaries of HP(E)HTR will be replaced with new ones. Own financing	10**MW** per unit
Total		20**MW**

(2) Suralaya power plant unit 1-4

- Content : Replacement of steam turbine blade
- Expected Effect : The available capacity is expected to increase by about 20MW per unit. (Total 80MW)
- Present Condition: Turbine blade replacement is proposed by the manufacturer. By the replacement of the turbine blade to the latest model, available capacities is expected to increase by 20MW.

Table 6.1.2 Rehabilitation for Suralaya 1-4

No.	Rehabilitation work	Estimated Capacity Recovered
Unit 1-4	Turbine blades will be replaced with the latest model	20MW x 4 unit
Total		80MW

Meanwhile, the rehabilitation is expected to recover the thermal efficiency as well as the improvement of operation as described in the next section. Above all the jet cleaning of HP heater and the chemical cleaning of boiler is considered to improve the thermal efficiency drastically. The method and effect of the rehabilitation will be mentioned in Chapter 9 in detail.

6.1.5 Improvement of Operation

Since inadequate operation causes problems such as dropping thermal efficiency or output derating, it is important to optimize operation of power plant.

In the case of Suralaya Power plant, thermal efficiency has recovered about 0.3 % by improving the operational method of GRF and the quality control of boiler feed water. As a result, coal consumption can be reduced by 6,000 tons and CO_2 emissions can be reduced by 14,000 tons. However, output is not expected to recover by operational improvement according to the first investigation at 1st work-in-Indonesia.

The thermal efficiency of many power plants can be improved at by operational improvement. Thermal efficiency affects fuel consumption and primary energy consumption in Indonesia. Therefore, the theory and method of operational improvement should be introduced and carried out in all power plants.

6.2 Operational Control of a Power System under Power Deficit

6.2.1 Brown Out

Brown out is an operational method dropping the voltage of the power system to 90% - 95% of its normal voltage. Consequently, power consumption of the system could be reduced. Brown out affects electrical equipment. For example, an electric- magnetic switch would open because its magnetic contact power turns off. It is said that these troubles happen if the voltage drops to 90% or less. Thus, it seems reasonable to determine that the target voltage could be set to 90% of its normal voltage in case of brown out.

According to P3B's study, 188MW of demand can be relieved by using the Brown Out in 36 small areas. Therefore, the maximum effect of brown out is considered to be 188MW. Since there were the cases the Brown Out was applied to some areas in the system operation actually, the effects of demand reduce was confirmed. However it is considered an emergency countermeasures with low reliability.

6.2.2 Rotational Black Out

Rotational black out would be carried out only in the case that the power system can not be operated stably. The basic concept is as follows:

*Divide supply areas into some groups in advance.
*If a power deficit occur, power supply to one of groups would be stopped.
*Black out is carried out in rotation among these groups.

Table 6.2.1 shows an example of the rotational black out

Table 6.2.1 An example of Rotational Black Out

	Area (A)	Area (B)	Area(C)	Area (D)	Area (E)
Days	Mon.	Tue.	Wed.	Thu.	Fri.

6.2.3 Demand-Side Measures

(1) Captive buyout

Captive power supplies have large supply capacity, and are extremely important in the context of Indonesia's electrical power supply and demand. Table 6.2.2 shows the captive supply capacity connected to the system. Electricity is received constantly from PLN, but captive sources, which are used as backup against power outages, amount to 5,756MW in the Java-Bali system. Therefore there is the potential to buy these sources out and make effective use of them. PLN has set a target of 250MW, in total, to buy out for the time being.

Table 6.2.2 Captive capacity connected to the PLN system (unit：kVA)

Type of customers	Pure captive	Reserve captive	Total	Reserve captive connected with PLN
East Java	187,811	1,304,394	1,492,205	1,236,608
Central Java	68,968	852,510	921,478	585,958
West Java	1,274,164	2,250,801	3,524,965	2,468,416
Bali & Others	111,237	1,348,471	1,459,708	1,711,672
Total	1,642,180	5,756,176	7,398,356	6,002,655

Source: PLN Statistics

(2) Energy-saving information for large-scale clients

Until the supply and demand adjustment menu is in place, it is important to request that large-scale consumers save energy in cases where the capacity of the supply operation is likely to fall short. In 2001 there were cases of users cooperating in energy saving on a voluntary basis. The specific effects are unclear, but it is important to ensure that users are well informed on the importance of energy saving and peak cutting.

(3) Load adjustment contracts

Japanese power companies sign Load Adjustment Contracts with specific users in order to manage demand at times when the supply and demand situation is tight. Clients signing such contracts gain discounts on electricity tariff in return for taking on the responsibility to control their demand. As mentioned above, there have also been cases of voluntary cooperation in energy saving, which indicates that there is a high potential for users to agree to Load Adjustment Contracts. Supply and demand adjustment based on captive sources is anticipated, and therefore no specific quantity is forecast, to avoid overlap with the captive buyout mentioned above. In this connection, Load Adjustment Contract is explained in Chapter 11.

(4) Adjustment of new users

In cases where it is anticipated that growth in demand will exceed planned levels, and supply capacity will not keep pace, measures for demand control will be necessary, such as a temporary freeze on contracts with new users. This chapter is based on the assumption that there are no controls on new demand, and therefore this will not be included in the short-term measures.

6.3 Short -Term Countermeasures against Power Deficit

6.3.1 Effects of Short - Term Countermeasures

Table 6.3.1 summarizes the items and effects of the short-term countermeasures described in the previous section. All counter measures have to be reviewed and carried out considering the cost performance.

Table 6.3.1 Effects of short-term countermeasures

Countermeasures	Estimated Effects	Policies
(1) Fuel Supply	-	Avoid generating troubles by securing fuel
(2) Reduction of the Forced Outage	-	Apply protection systems widely against common troubles
(3) Effective scheduling of periodic repair a. Shift of Periodical Repair	3% of operational capacity	*Reduction of Average maintenance rate(10%→7%) (refer to 6-1 and 6-2)
b. Shortening and strict observation the Periodical Repair on Schedule	-	Increasing the availability
c. Extended Operation	76MW	*Reduction of maintenance rate(7% →5%), of Muara-Karan 4,5 and Suralaya 1-7.
(4) Rehabilitation		
a. Muara-Karang unit 4,5	20MW	Exchange a HP Heater
b. Suralaya unit 1-4	80MW	Exchange turbine blades
(5) Improvement of Operation	N/A	Improve only the thermal efficiency
(6) Brown Out	188MW	Based on the analysis of P3B
(7) Rotational Black Out	N/A	—
(8) Buy out of Captives	Maximum 250MW	Based on the plan of PLN
(9) Request customers to Reduce Power Consumption	-	
(10) Contract for Control of Demand – Supply Balance	-	
(11) Control of Connection of New Customer to the System	-	—

6.3.2 Effect to the Power System Reliability

To confirm the effect of the short-term countermeasures described before, trial calculation for the improved capacities in Base Case and Slipped Base Case are carried out.

(1) Improved capacity of the countermeasures

Table 6.3.2 shows the maximum improved capacity brought about by short-term countermeasures.

Table 6.3.2 Maximum Improved Capacity by Short - Term Countermeasures (unit:MW)

Year	2001	2002	2003	2004	2005	2006	2007
(1) Rehabilitation							
• Muara-Karang 4 & 5	0	20	20	20	20	20	20
• Suralaya 1 – 4	0	0	80	80	80	80	80
(2) The Maintenance Shift							
*Base Case	246	246	442	453	492	498	505
*Slipped Base Case	246	246	442	453	492	492	498
(3) Extended Operation	0	0	76	76	76	76	76
(4) Brown Out	188	188	188	188	188	188	188
(5) Buy out of Captives	0	50	100	150	200	250	250
(6) Total Improvement A. Base Case							
• Counter Measures(100%)	434	504	906	967	1,056	1,112	1,119
• Counter Measures (50%)	217	252	453	483	528	556	559
B. Slipped BaseCase							
• Counter Measures(100%)	434	504	906	967	1,056	1,106	1,112
• Counter Measures (50%)	217	252	453	483	528	553	556

(2) Effect of short term counter measures

1) JICA/LPE_CASE 2

Table 6.3.3 shows the effects of the short-term counter measures

・Base Case

In the case that all (=100%) of the countermeasures are achieved, the time in which a power deficit is expected to occur will be delayed for three years. In the case that half (=50%) of the countermeasures are achieved, the time in which a power deficit is expected to occur will be delayed for two years. Thus, the short-term countermeasures should be carried out to avoid power deficits.

・Slipped Base Case

Countermeasures (=100%&50%) is expected to contribute to delay the time in which a power deficit is expected to occur for two years. Thus, the short-term countermeasures should be carried out to avoid power deficits.

Table 6.3.3 Operational Spinning Reserve after taking countermeasures-JICA/LPE Case2-

Year	2001	2002	2003	2004	2005	2006	2007
1. JICA/LPE CASE 2							
1) Peak Load (MW)	13,041	14,089	15,073	16,071	17,170	18,374	19,659
2) E.S.R (MW)	782	845	904	964	1,030	1,102	1,180
A. Base Case							
3) a Operational Situation before Countermeasures.							
・O.S.R (MW)	1,251	993	*499	△171	△82	△1,106	△2,193
・LOLP (Day / year)	0.1	1.4	5.5	NA	NA	NA	NA
4) a Effect of Short term countermeasures (100%)							
・Improved Capacity (MW)	434	504	906	967	1,056	1,112	1,119
・O.S.R after countermeasures (MW)	1,685	1,497	1,405	*796	*974	*6	△1,074
・LOLP (Day / year)	0.0	0.3	0.6	2.7	2.1	12.2	NA
5) a Effect of Short term countermeasures (50%)							
・Improved Capacity (MW)	217	252	453	483	528	556	559
・O.S.R after countermeasures (MW)	1,468	1,245	952	*312	*446	△550	△1,634
・LOLP (Day / year)	0.0	0.7	2.0	7.2	6.2	NA	NA
B. Slipped Base Case							
3) b Operational Situation before Countermeasures.							
・O.S.R. (MW)	1,251	993	*499	△171	△82	△1,286	△2,391
・LOLP (Day / year)	0.1	1.4	5.5	NA	NA	NA	NA
4) b Effect of Short term countermeasures (100%)							
・Improved Capacity (MW)	434	504	906	967	1,056	1,106	1,112
・O.S.R. after countermeasures (MW)	1,685	1,497	1,405	*796	*974	△180	△1,279
・LOLP (Day / year)	0.0	0.3	0.6	2.7	2.1	NA	NA
5) b Effect of Short term countermeasures (50%)							
・Improved Capacity (MW)	217	252	453	483	528	553	556
・O.S.R after countermeasures (MW)	1,468	1,245	952	*312	*446	△733	△1,835
・LOLP (Day / year)	0.0	0.7	2.0	7.2	6.2	NA	NA

* : The year operational spinning reserve is smaller than essential spinning reserve.

2) JICA/LPE_CASE 1

Table 6.3.4 shows the effects of the short-term counter measures.

・Base Case

In the case that all (=100%) of the countermeasures are achieved, the time in which a power deficit is expected to occur will be delayed for a year. In the case that half (=50%) of the countermeasures are achieved, the operational reserves and LOLP from 2003 to 2006 will be improved.

・Slipped Base Case

In the case that all (=100%) of the countermeasures are achieved, the time in which a power deficit is expected to occur will be delayed for a year. In the case that half (=50%) of the countermeasures are achieved, the operational reserves and LOLP from 2003 to 2006 will be improved.

Table 6.3.4 Operational Spinning Reserve after taking countermeasures-JICA/LPE Case1-

Year	2001	2002	2003	2004	2005	2006	2007
1. JICA/LPE CASE 1 demand							
1) Peak Load (MW)	13,041	13,821	14,497	15,266	16,185	17,220	18,348
2) E.S.R (MW)	782	829	870	916	971	1,033	1,101
A. Base Case							
3) a Operational Situation before Countermeasures.							
・O.S.R (MW)	1,251	1,161	872	*634	*903	*48	△882
・LOLP (Day / year)	0.1	0.9	1.9	4.2	2.7	11.2	NA
4) a Effect of Short term countermeasures (100%)							
・Improved Capacity (MW)	434	504	906	967	1,056	1,112	1,119
・O.S.R after countermeasures (MW)	1,685	1,665	1,778	1,601	1,959	1,160	*237
・LOLP (Day / year)	0.0	0.2	0.1	0.3	0.2	1.4	9.0
5) a Effect of Short term countermeasures (50%)							
・Improved Capacity (MW)	217	252	453	483	528	556	559
・O.S.R after countermeasures (MW)	1,468	1,413	1,325	1,117	1,431	*604	△323
・LOLP (Day / year)	0.0	0.4	0.5	1.3	0.7	4.7	NA
B. Slipped Base Case							
3) b Operational Situation before Countermeasures.							
・O.S.R (MW)	1,251	1,161	872	*634	*903	△132	△1,080
・LOLP (Day / year)	0.1	0.9	1.9	4.2	2.7	NA	NA
4) b Effect of Short term countermeasures (100%)							
・Improved Capacity (MW)	434	504	906	967	1,056	1,106	1,112
・O.S.R after countermeasures (MW)	1,685	1,665	1,778	1,601	1,959	*974	*32
・LOLP (Day / year)	0.0	0.2	0.1	0.3	0.2	2.2	12.2
5) b Effect of Short term countermeasures (50%)							
・Improved Capacity (MW)	217	252	453	483	528	553	556
・O.S.R after countermeasures (MW)	1,468	1,413	1,325	1,117	1,431	*421	△524
・LOLP (Day / year)	0.0	0.4	0.5	1.3	0.7	6.6	NA

* : The year operational spinning reserve is smaller than essential spinning reserve.