during the first half of the 1980s. Presented in Table 5.5-3 are electric power demand/supply growth of several countries in Asia. To enable comparisons with Viet Nam, picked out was a particular period when a given country registered per capita consumption of around 100 kWh. Percent (%) means average annual growth rates during target period (See Appendix in detail).

Demand forecast results obtained this time show per capita electricity consumption will be 206 kWh, 227 kWh and 241 kWh in 2000, and 484 kWh, 592 kWh and 689 kWh in 2010, in the low, base and high cases respectively. Generation per capita in each case will be 257 kWh, 290 kWh and 301 kWh in 2000, and 574 kWh, 705 kWh and 821 kWh in 2010. Even the 2010 consumption projected at 592 kWh/capita in the base case fails to reach 1992 levels in Thailand (992 kWh/capita) and Malaysia (1,608 kWh/capita) (See Appendix).

By region, per capita consumption in the South will be 604 kWh, 759 kWh and 888 kWh as of 2010 in the low, base and high cases respectively (or 727 kWh, 914 kWh and 1,070 kWh in generation terms). Likewise, as of 2010, per capita consumption of 464 kWh, 535 kWh and 614 kWh (545 kWh, 629 kWh and 723 kWh in generation terms) is expected in the North. In the Central region, per capita consumption is likely to remain at 263 kWh, 363 kWh and 433 kWh (309 kWh, 423 kWh and 510 kWh in generation terms).

5.5.2 Factors to Increase Electric Power Consumption and Electricity Intensity

(1) Results by Factor Analysis

As described in Chapter 3, Vietnamese electric power demand has grown more than 9% per year on the average since 1980. Analyzing what have contributed to the growth from macro standpoints, and making relevant comparisons with some Asian countries, what characterizes Viet Nam is briefly examined.

Factors subject to the analysis are electricity intensity with respect to GDP (electricity consumption per GDP), economic growth and population growth. Basic equation for factor analysis is expressed below.

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

Where, E = Electric power consumption
I = E/GDP (electricity intensity factor)
G = GDP/capita (economic growth factor)
P = Population (population growth factor)
dE = Incremental electric power consumption
(dI/I)•E = Consumption increase or decrease due to changes of intensity factor
(dG/G)•E Increase of consumption due to economic growth factor
(dP/P)•E = Increase of consumption due to population growth factor

The population growth factor, divisible into two components, the number of electricity users and the electrification ratio, were left intact as a single factor taking into consideration data availability as well as comparisons made with other countries.

Of the factors mentioned above, it is electricity intensity that forms the most important factor from energy conservation aspect. When the consumption due to electricity intensity factor (dI/I)•E is downward, or shifting toward the negative value, efficiency of end-use consumption of electric power is improving. In short, it means energy conservation is in advance. Reversely, increase of (dI/I)•E means that socio-economic structure shifts to a more energy-intensive consumption pattern, or to increasing energy-gulping economic activities.

(a) Viet Nam

Figure 5.5-3 shows what have contributed to the increase of electricity consumption during the past decade (integrating of contribution rate of each factor). It is noted that electricity intensity factor (dI/I)•E was the primary "contributor" to pushing up electric power consumption in 1985-91. From 1992 onward, the economic growth factor (dG/G)•E occupied the principal position in the factors. The (dG/G)•E was down (namely improved) in 1992 and 1993, then up again in 1994. In 1985-94 period, electricity intensity factor contributed 31.7% to end-use consumption increase, economic growth factor 44.4%, population growth factor 23%, and the remaining 2.3% attributable to the mixed.

Table 5.5-4 summarizes factor-by-factor shares during pre- and post-1986 years, when Doi Moi policy was hammered out, and among others. As shown in the Table, incremental consumption due to electricity intensity factor held a protruding share in the total increase during 1986-90. As a reason of this, it is assumed that electricity consumption has temporarily grown in reflection to the shift from a planned economy to a market economy. Because it can not be considered that industrial structure has undergone drastic changes leading to the rise of electricity-intensive industries over this period. The greater consumption from 1990 onward, or from 1992 onward in more exact terms, is attributable to stimulated economic activities. In short, the economic growth factor became the primary contributor.

Table 5.5-5 shows results obtained by the factor analysis that was carried out for the base case of demand forecast results up to 2010. It provides a scenario where the contributed share of electricity intensity factor is expected to decline gradually from past 30% to around 25% in the future, while the contribution of the economic growth factor is expected to have a rising share to 50-60%.

(b) Comparisons with Asian countries

To begin with, Thailand and Malaysia are picked out and reviewed as representative ASEAN members (see Appendix for the two countries' factor-specific integrating contribution rates since 1973). The economic growth factor has been the primary contributor to growing electric power consumption since 1978 in Thailand, and since 1976 in Malaysia. In the two countries alike, the incremental consumption due to electricity intensity factor dropped in 1987-89, but resumed rising later. Table 5.5-6 summarizes incremental electric power consumption by period and by factor for the two countries. Tables 5.5-4 and 5.5-6 reveal that electricity intensity factor has been contributed around 30% to total consumption increase in the long run (1973-92 in Thailand and Malaysia; 1980-94 in Viet Nam). Vietnamese per capita consumption (112 kWh/capita) is almost identical to the Thai 1970 level, and likely to follow the Thai pattern ahead.

On the other hand, Japan, the Republic of Korea (ROK, South Korea) and Taiwan reveal completely different situations with the two oil crises in 1973 and 1979 as a turning point. Table 5.5-7 shows incremental electric power consumption by period and contribution rates of each factor for these countries (see Appendix for their charting). Table 5.5-7 presents, in the three countries all, the share of electricity intensity factor nosedived after 1973, hit by the first oil shock, as a result of strenuous energy conservation efforts. Particularly, since 1973 in Japan, since 1979 in Taiwan, and since 1980 in the ROK, decrease of electricity intensity has contributed to energy saving, and played a key role in reducing electric power demand, on the rise as strongly as the economic growth.

(2) Electricity Intensity with respect to GDP

The preceding section examined to what extent factor changes have been contributed to incremental end-use electricity consumption. It was already mentioned the oil shocks triggered sharp declines in the contribution of electricity intensity in Japan, the ROK and Taiwan. In this section, the electricity intensity (Wh/GDP) itself is examined.

(a) Viet Nam

Electricity Intensity in the country (Wh/US$, 1989 constant price) has been on the rise as shown below. The figures in parenthesis show annual average growth rate.

Year	1980	1986	1990	1994
Electricity Intensity	346	386	463	502
		(18%)	(4.7%)	(2.0%)

According to the demand forecasting results (base case) this time, electricity intensity is calculated to be:

Year	2000	2005	2010
Electricity Intensity	589	687	787
	(2.7%)	(3.1%)	(2.8%)

To sum up, this scenario means Vietnamese electricity intensity will keep rising in the years to come as well.

(b) Comparisons with Asian countries

Historical trends of electricity intensity with respect to GDP (1989 US$) in selected Asian countries subject to comparison can be described as follows.

In Thailand, electricity intensity increased from 320 Wh/US$ in 1973 to 427 Wh/US$ in 1980, and to 649 Wh/US$ by 1992. In Malaysia, it rose from 311 Wh/US$ in 1973 to 401 Wh/US$ (1980) and to 552 Wh/US$ (1992). On the other hand, it in Taiwan, having kept climbing from 189 Wh/US$ in 1952 to 307 Wh/US$ (1960), 466 Wh/US$ (1970) and 612 Wh/US$ (1980), turned downward gradually to 599 Wh/US$ in 1992. In the ROK, it was up from 96 Wh/US$ in 1962 to 243 Wh/US$ (1970) and to 499 Wh/US$ (1980), then has been virtually flat during 1980s, turned upward to 641 Wh/US$. In Japan, it has been on the rise from 156 Wh/US$ in 1946 to 169 Wh/US$ (1955), 224 Wh/US$ (1965) and 277 Wh/US$ (1970), then made a downturn and recorded the lowest value of 247 Wh/US$ in 1986. In recent years, Japan's electricity intensity has been on the rise a bit.

Figure 5.5-4 plots the trends described above in relation to economic levels (GDP/capita). On top of the countries mentioned above, Figure 5.5-4 also contains actual data on Indonesia, Pakistan and Bangladesh. In the Figure, the lines of Bangladesh, Viet Nam and Pakistan are found left most, and those of Indonesia and Thailand adjoining them immediately right. From now on, Viet Nam is likely to have its line shifting right along with the economic growth, though the magnitude of the shift would greatly depend on future changes in electric power demand and industrial structure. The relationship between electric intensity and economic level in 2000, 2005 and 2010, which can be easily calculated from demand forecasting results of the base case, are shown by circles with arrows in the chart. Namely, the Vietnamese future line is assumed to decouple from the Bangladesh - Viet Nam - Pakistan lines and approach the Indonesia - Thailand ones. The likelihood of the assumption to become real is strong, because the economic growth has become the primary contributor to electric power consumption growth in recent years, and because Vietnamese by-factor contribution patterns are akin to those in Thailand and Malaysia, as shown in the results of factor analysis in the preceding section. In order to make this scenario real requires considerable efforts, including introduction of foreign capital and technologies, improving efficiency of energy use and to modernize industrial structure.

Table 5.5-1 Results by Regression Analyses (GWh - GDP)

Country	Period	Coefficient a	Coefficient b	R-Squared R^2
Viet Nam	1980-94	4.94	1.44	0.989
Indonesia	1973-92	1.67	1.98	0.978
Malaysia	1973-92	2.89	1.44	0.996
Thailand	1973-92	2.06	1.48	0.998
Pakistan	1973-92	4.78	1.55	0.996
Bangladesh	1973-92	1.77	2.27	0.977
South Korea	1962-72	1.06	2.27	0.996
	1973-92	2.21	1.37	0.992
Taiwan	1952-72	2.01	1.57	0.992
	1973-92	6.11	1.06	0.995
Japan	1946-65	1.58	1.22	0.996
	1965-73	1.16	1.29	0.993
	1973-93	6.21	0.92	0.975

Note: GDP values used are US$ at 1987 constant price excluding Viet Nam (US$, 1989 constant price).

Table 5.5-2 Results by Regression Analysis (GWh/capita - GDP/capita)

Country	Period	Coefficient a	Coefficient b	R-Squared R^2
Viet Nam	1980-94	-4.42	1.68	0.975
Indonesia	1973-92	-9.95	2.47	0.965
Malaysia	1973-92	-6.23	1.72	0.989
Thailand	1973-92	-5.25	1.67	0.993
Pakistan	1973-92	-6.51	2.09	0.988
Bangladesh	1973-92	-15.27	3.67	0.947
South Korea	1962-72	-13.55	2.76	0.991
	1973-92	-4.10	1.44	0.989
Taiwan	1952-72	-7.33	1.88	0.977
	1973-92	-1.14	1.07	0.992
Japan	1946-65	-3.85	1.26	0.995
	1965-73	-4.48	1.33	0.989
	1973-93	1.71	0.69	0.917

Note: GDP values used are US$ at 1987 constant price excluding Viet Nam (US$, 1989 constant price).

Table 5.5-3 Per Capita Electric Power Consumption in given Period

	Period	Consumption (kWh/capita)	Consumption AGR (%)	Generation (kWh/capita)	Generation AGR (%)	GDP/Capita AGR (%)
Indonesia	1982-89	99-216	11.8	108-234	11.7	4.1
Thailand	1973-83	166-351	7.8	178-379	7.9	4.0
Pakistan	1973-90	115-320	6.2	145-391	6.0	2.8
South Korea	1966-75	104-502	19.1	134-562	17.3	6.8
Taiwan	1952-62	132-353	10.3	175-408	8.8	3.8
Viet Nam	1993-20	112-227	10.6	150-290	9.9	6.6
(Base Case)	2000-10	227-592	10.0	290-705	9.3	6.9

Note: AGR = Annual Growth Rate (%)

Table 5.5-4 Increase of Power Consumption and Share of each Factor (Viet Nam)

Period	1980-1986	1986-1990	1990-1994	1980-1994
Increase in perdio (GWh)	1,199	2,041	3,011	6,528
Share of each factor (%)				
Electricity intensity	23.4	43.7	23.4	30.1
Economic growth	50.8	29.4	53.2	44.4
Population increase	23.4	23.8	21.7	23.1
Residual term	2.4	3.1	1.7	2.4

Table 5.5-5 Forecast of Share of each Factor (Viet Nam)

Period	1993-2000	2000-2005	2005-2010
Increase in perdio (GWh)	10,624	14,510	22,808
Share of each factor (%)			
Electricity intensity	28.0	25.3	24.6
Economic growth	52.7	60.0	59.8
Population increase	15.7	11.6	12.8
Residual term	3.6	3.1	2.8

Table 5.5-6 Increase of Power Consumption and Share of each Factor (ASEAN)

Period	1973-1979	1979-1986	1986-1992	1973-1992
Thailand				
Increase in period (GWh)	6,418	10,144	28,600	45,162
Share of each factor (%)				
Electricity intensity	36.6	37.6	29.0	32.0
Economic growth	38.8	36.8	56.4	49.5
Population increase	20.9	23.0	11.0	15.1
Residual term	3.7	2.6	3.6	3.4
Malaysia				
Increase in period (GWh)	4,121	5,588	13,089	22,798
Share of each factor (%)				
Electricity intensity	34.3	37.4	25.9	30.3
Economic growth	43.1	25.7	50.4	43.0
Population increase	19.6	35.5	20.2	23.8
Residual term	3.0	1.4	3.5	2.9

Table 5.5-7 Increase of Power Consumption and Share of each Factor

Japan

Period	1946-1955	1955-1965	1965-1973	1973-1979	1979-1986	1986-1993
Increase in period (GWh)	32,339	115,677	252,947	107,302	72,738	202,887
Share of each factor (%)						
Electricity intensity	8.5	20.8	25.2	0.5	-83.5	18.4
Economic growth	74.4	68.2	60.5	72.5	150.6	72.0
Population increase	16.1	8.3	11.6	26.2	34.8	8.7
Residual term	1.0	2.7	2.7	0.8	-1.9	0.9

Taiwan

	1952-1960	1960-1965	1965-1973	1973-1979	1979-1986	1986-1990
Increase in period (GWh)	2,060	2,536	13,242	18,131	22,348	34,168
Share of each factor (%)						
Electricity intensity	46.2	19.9	27.1	23.4	-4.2	30.0
Economic growth	24.9	51.3	54.7	57.8	81.8	82.0
Population increase	24.9	25.4	14.1	16.0	21.5	14.2
Residual term	4.0	3.4	4.1	2.8	0.9	0.8

S. Korea

	1962-1965	1965-1973	1973-1979	1979-1986	1986-1990
Increase in period (GWh)	994	11,234	19,398	28,110	62,712
Share of each factor (%)					
Electricity intensity	54.1	54.1	35.0	16.5	30.2
Economic growth	27.1	31.2	50.4	68.9	58.9
Population increase	14.0	8.6	10.3	13.6	8.0
Residual term	4.8	6.1	4.2	1.0	2.9

Figure 5.5-1 The Relationship between Power Consumption and GDP

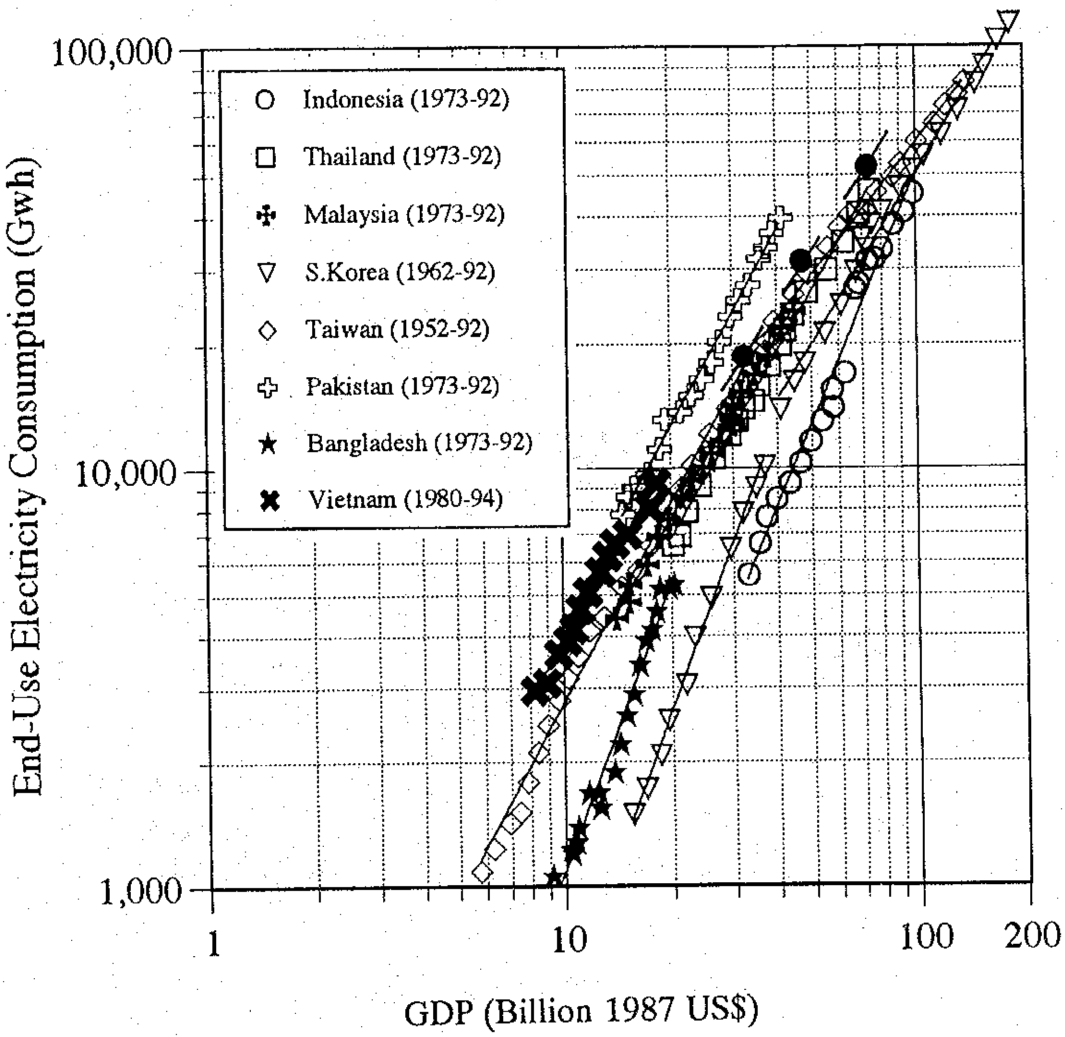


Figure 5.5-2 The Relationship between per capita Consumption and Economic Level

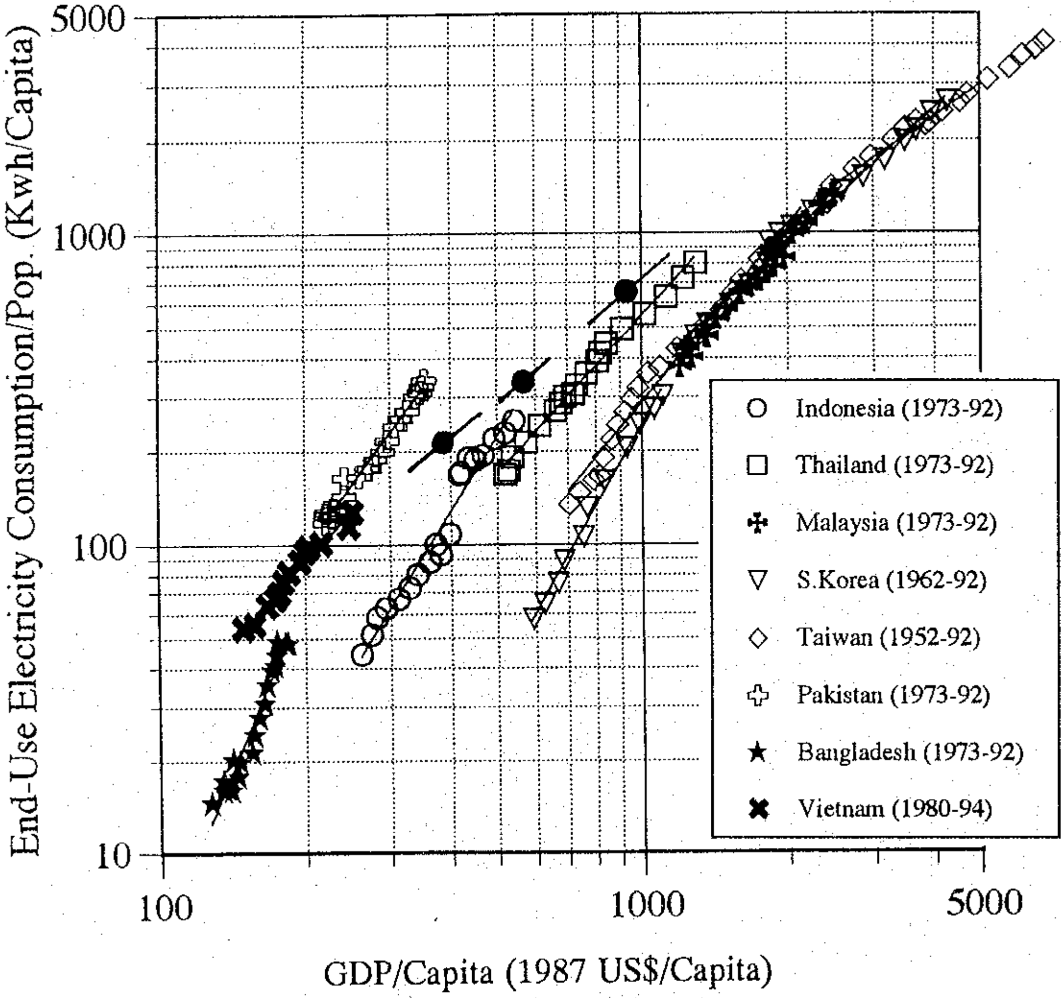


Figure 5.5-3 Factor Change in End-Use Consumption

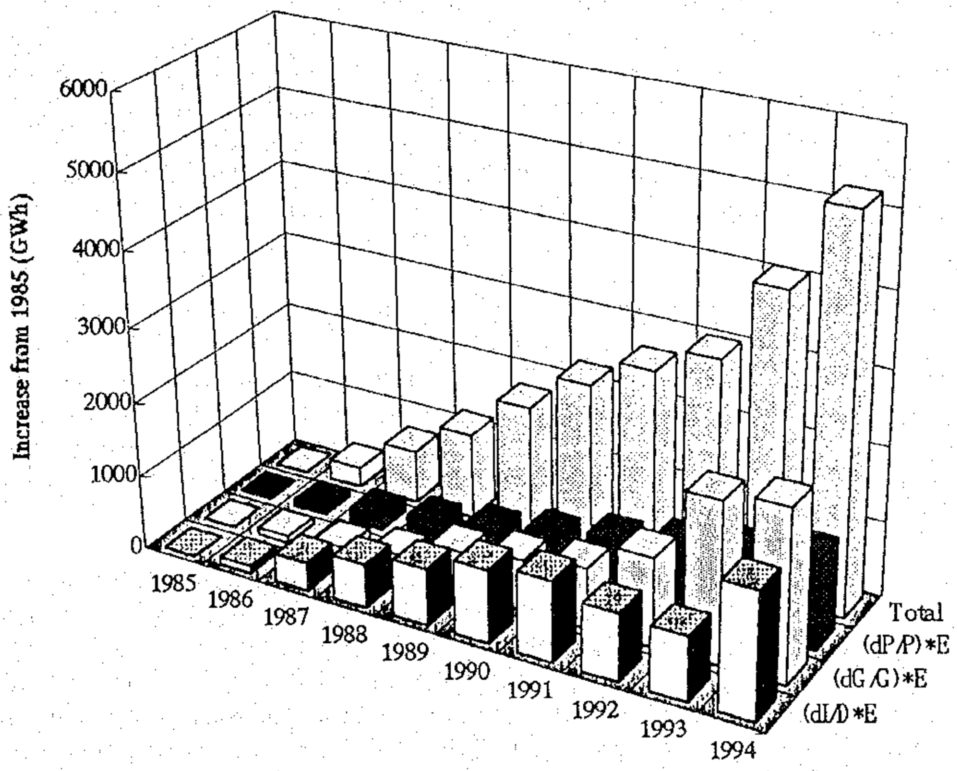
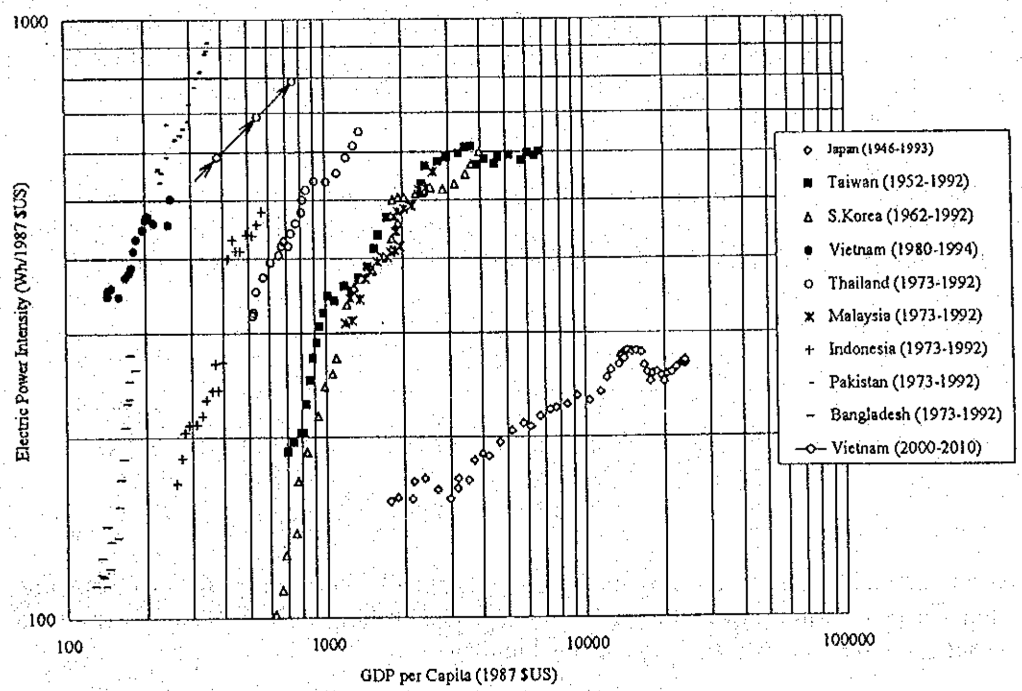


Figure 5.5-4 The Relationship between Electric Power Intensity and per capita GDP



5.6 Conclusions and Recommendations

In this study, an econometric approach was employed and economic scenario by region and by sector, each consisting of three cases, were prepared for demand forecasting model building. Vietnamese total GDP grew at an annual average pace of the 5% level during 1980s, and the 6~8% level from 1990 onward. Future GDP is estimated to be doubled by 2000 and also doubled by 2010 at over 8% annual growth rate of the base case. Following the scenario, GDP scale of Viet Nam will reach Singapore's level as of 1992 around 2000, Malaysia around 2005 and Thailand around 2010. The projected economic level, 754 (US$/capita) in 2010, is presumed being as almost similar as those of about 1963 of Taiwan, 1969 of South Korea and 1983 of Thailand.

According to the latest case study, Vietnam's total electric power demand nationwide would increase at average growth rate of 12.8% per year from 8,007 GWh in 1993 to 18,631 GWh in 2000, up 2.3 times over the 1993 value. From 2000 to 2010, the total demand would increase 11.6% per year on the average and reach 55,948 GWh by 2010 (almost sevenfold demand of 1993) in the base case of economic scenario. In generation (in base case), 10,729 GWh recorded in 1993 is likely to rise to 23,289 GWh by 2000 (up 11.7% per year), and reach 66,600 GWh by 2010 (up 11.1% per year), each representing 2.2 times and 6.2 times over the 1993 record.

Examinations of by-sector demand in the country show that the industrial sector is likely to record the highest growth, followed by the residential/commercial sector. In the base case, industrial demand is assumed to grow from 3,645 GWh in 1993 to 9,795 GWh by 2000 (up 15.2% per year), and reach 34,572 GWh by 2010 (up 13.4% per year). They are 2.7 times and 9.5 times above the 1993 demand. As a result, the share held by the industrial sector in total demand will be up from 45.5% in 1993 to 52.6% in 2000, and to 61.8% in 2010. Residential and commercial demand is expected to rise from 3,236 GWh in 1993 to 6,689 GWh in 2000 (up 10.9% per year) and to 18,200 GWh in 2010 (up 10.5% per year), standing 2.1 times and 5.6 times each above the 1993 demand. The share in total demand will be down from 40.4% in 1993 to 35.9% in 2000, and to 32.5% in 2010.

Differences in demand structure between the South and North are that the demand for the industrial sector and others will be kept higher in the South than in the North, and that residential and agricultural demand is kept higher in the North than in the South. In other words, the industrial sector and others account for larger shares in region-wide demand in the South than in the North, while weight held by the residential and agricultural sectors in region-wide demand is heavier in the North than in the South.

Comparing the values by IEV (authorized by MOE) with JICA study results, JICA's high-case figures are virtually identical to IEV's base-case ones as of 2000. In regard to 2010, all the figures in IEV's three cases are found within the range between JICA's low and high cases as follows.

<Generation Base, GWh>

	2000			2010		
	Low	Base	High	Low	Base	High
JICA	21,129	23,289	24,722	54,722	66,600	77,535
IEV	(22,621)	(24,412)	(26,047)	56,061	68,369	75,203
MOE	-	25,310	27,465	56,061	68,369	75,203

The difference is due to demand forecasting methodology applied by both sides. IEV set economic projection and elasticity with respect to GDP as exogenous values. JICA Study Team used economic scenario and time series data for the model building.

In comparison with some Asian countries, long-term GDP elasticity of Viet Nam is similar to Malaysia and Thailand. In the relationship of power consumption per captia and economic level (GDP/capita), the Vietnamese future will be close to the Indonesia-Thailand lines. In relation between electricity intensity and economic level as well Viet Nam is assumed to decouple from Bangladesh-Viet Nam-Pakistan lines and approach the Indonesia-Thailand ones. By results of factor analysis, economic growth factor has become the primary contributor to power consumption increase in recent years, and Vietnamese by-factor contribution patterns are akin to those of Thailand and Malaysia. Electricity intensity factor is expected to decline gradually from past 30% to around 25% in the future, while the contribution of economic growth factor is expected to have a rising share to 50-60%. Judging from GDP elasticity, power consumption - GDP/capita, factor analysis and electricity intensity, the Vietnamese future will follow the Thai pattern.

Based on this study, following issues can be put forth.

(1) In order to prepare economic scenarios which set assumptions of the demand forecast, it is a matter of pressing need to establish a system which enables selection of prudent and realistic values. Demand forecast results largely depend on scenarios. Thus, an economic scenario must adopt, not a target, but an economic growth rate as realistic as possible. To this end, it appears necessary to develop, on top of electric power demand forecasting models, other models to help discussion on the macro economy and industrial structure.

(2) Related to the immediate above, Viet Nam changed its statistical system in 1989 from NMP (Net Material Product) system to SNA (System of National Account). Accordingly, past data need to be reviewed from various angles including their reliability. This is not an issue of a single government office but government-wide for Viet Nam. As an immediate measure, as many data as possible need to be organized from now on. Particularly if electric power demand be forecast by region, relevant data must be collected by region.

(3) It is desirable to collect region-by-region data helpful in explaining electric power demand structure and in analyzing contributors to growing demand. Viet Nam, now in the progress toward a market economy, is expected to unfold rapid economic development ahead. Electricity demand as well is shifting from traditional pattern, which demand is constrained by supply capacity, to an era of expecting supply capacity to meet demand (consumers' needs). Accuracy of demand forecast depends much on the quality and quantity of data to analyze electric power demand structure.

(4) In forecasting electric power demand, along with additional data and shifting years, models in use need to be renewed regularly, by updating model structure and equations. To this end, constant expert-training efforts are essential.

PART II STUDY ON POWER DEVELOPMENT PLAN AND IDENTIFICATION OF PRIORITY PLANS AND PROJECTS

CHAPTER 6

REVIEW AND ASSESSMENT OF POWER DEVELOPMENT PROJECTS

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Electric power generating projects to be developed during the study period (1996 - 2010) are reviewed for preparing the power development plan simulation studies.

Candidate thermal power projects are adopted from the Third Electric Power Development Plan (covering the period 1992 - 2000).

As for the projects to be developed after 2000, candidate projects are selected through discussions between IEV staff and JICA Study Team members taking into account the fuel supply condition and reinforcement of transmission line system.

Specified site locations of the projects would be carried over to their feasibility studies, as there is some flexibility for site selection in the case of thermal power projects.

21 hydropower projects are proposed by IEV and are adopted as candidate projects for the study. Generated annual energy of the projects is reviewed and economical comparative studies for the projects are implemented by JICA Study Team in this Chapter.

Location of planned projects are shown in Figure 6-1.

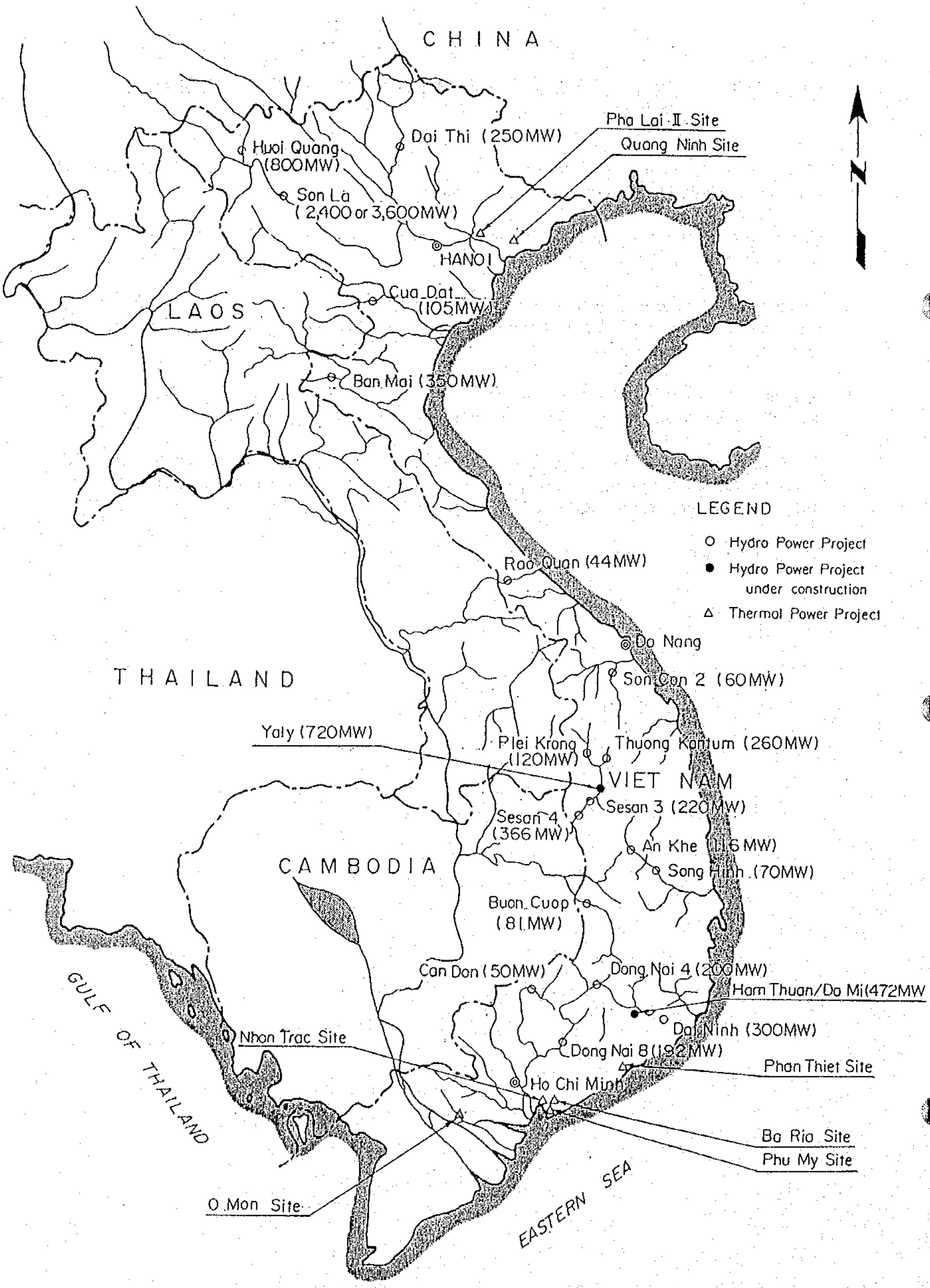

Figure 6-1 Location of the Facilities

6.1 Thermal Power Generating Facilities

There are two kinds of fuel resources for thermal power generation, which are now being recovered. First one is abundant coal resource situated in Quang Ninh Province of Northern region. Second one is natural gas and oil associated gas situated in the sea-bottom of Southern region. Therefore JICA Study Team planned to install coal fired power plants in Northern region. And in Southern region JICA Study Team planned to install both gas fired plants and coal fired plants which utilize northern coal through ocean transportation. In this master plan study, after taking consideration of estimated maximum total demand of whole country, existing power generating capacity, amount of hydropower plants development and necessary reserves, the Study Team estimated about 7,000MW of additional thermal power plants should be constructed by 2010.

The Study Team took into account the power development projects now underway, and thereafter in order to simplify the simulation, the Study Team planned to add the unit numbers of Quang Ninh coal fired thermal power plant in Northern region and in Southern region the Study Team planned to add units at Nhon Trac combined cycle (C/C) and Phan Thiet coal-fired thermal power plant. 300MW unit size is adopted for simulation, but suitable unit size should be decided according to power system size growth.

6.1.1 Electric Power Development Projects

The electric power development projects which are incorporated into the Third Electric Power Development Plan (covering the period from 1992 to 2000) prepared by IEV and approved by the Vietnamese government are as presented below.

(1) Pha Lai II Thermal Power Project (2 x 300 MW)

Two, 300 MW coal fired units will be additionally constructed adjacent to the existing Pha Lai thermal power plant (coal fired, 440 MW) in the Northern region. The project is scheduled for commissioning in 1999 and is in the engineering stage under the ODA fund.

Pha Lai II thermal power plant will contribute to the increase of power supply capability in the northern power system from its commissioning in 1999 with annual plant factor exceeding 60%.

The old power plants such as Ninh Binh and Uong Bi will be retired after full operation of Pha Lai II plant.

(2) Quang Ninh Thermal Power Project (N x 300 MW)

In order to deal with the projected power requirement in the Northern region after Pha Lai II project, a new coal fired thermal power plant will be constructed in and around coal mines in Quang Ninh province including BOT/BOO scheme.

Though the project is in a planning stage, it is promising to contribute to the northern power system not only for the increase of supply capability after Pha Lai II and before Son La hydropower project, but also for balancing the best mix of generating sources in the power system. Early studies on the site selection including engineering or environmental aspects are expected.

(3) **Phu My Thermal Power Project (3 x 200 MW)**

This is a project planned to deal with the anticipated power supply shortage in the Southern region in late 1990s.

It is planned to commission three, 200 MW units by 1998. The project site is located approximately 75 km to the east of Ho Chi Minh City, nearby Vung Tau port town. This site is approximately 3 km to the west away from national highway 51, where there are few houses. The foundation conditions for building and other structures are good. As a deep inlet is located at 1.5 km from the site, the cooling water facility and a private harbor can be easily constructed.

It has been planned to use the associated gas which gushes off Vung Tau. A gas pipeline extending for 140 km from Vung Tau to Thu Duc thermal power plant is under construction branching to Phu My thermal power plant site.

It is planned to retrofit the boilers in order to convert the fuel from gas to oil when the associated gas production will be exhausted. It is being contemplated to use fuel oil if the gas is not produced as expected.

Proposed main fuel for the Phu My project is associated gas in the first 11 years from 1998 to 2008. Standby fuel is FO. If after 2008, there will be no more added gas volume supplied, the plant would be converted into an oil fired power plant.

It is also being contemplated to construct additional 2 x 300 MW units after year 2000.

(4) **Phu My C/C Project (5 x 300 MW)**

A new thermal power plant is being contemplated to construct additional 300 MW units in C/C system after the Phu My thermal power project. The fuel used is associated gas from the offshore wells. The number of units will be decided depending on the amount of gas resources. According to the information of drilling activities on the offshore wells, at least 3 billion m3 annually of gas supply is expected until 2010, which means, 5 units of the C/C system are possibly developed besides of consumption for Phu My thermal power plant, Bạ Ria thermal power plant and Thu Duc thermal power plant.

(5) **O Mon Thermal Power Project (3 x 300 MW)**

O Mon project site is located at riverside along the Mekong delta area near Can Tho. The project is planned to deal with the increasing power demand in the area. Coal is chosen for the project due to limitation of gas supply from the offshore wells. Therefore, when a large amount of new gas resources are confirmed in the near future, project selection study will become necessary on the economy between the coal thermal O Mon thermal power project and the new C/C project which will be located seashore and transmit its power and energy to the Mekong delta area by transmission lines.

(6) **Conversion of Gas Turbines to C/C system at Ba Ria Thermal Power Plant**

It is being planned to convert three gas turbine units to the combined cycle system. The earlier commissioning of the C/C system is scheduled in 1997, and it will contribute to the power shortage in the region expected in 1997 and 1998. The funding for the project is committed by World Bank.

(7) Other Candidate Thermal Power Projects

For the long term power development planning study two other candidate projects are chosen, after discussion with IEV staff.

One is Nhon Trac C/C project which is located near Phu My site. The project is an option as more gas production was realized than expected in Nam Con Son Basin.

The other is Phan Thiet coal thermal power project which is located at around Phan Thiet town east of Ho Chi Minh city. The project is an option when natural gas doesn't reach its targeted figures after 2000. Choice of fuel, domestic/imported coal, will be decided after the site selection study and F/S.

6.1.2 Technical Assessment of Thermal Power Generation System

Three types of thermal power generation system to be applied to the Vietnamese power system are reviewed from technical point of view. The summary of the review is described as below, and details are shown in Appendix.

(1) Coal (Anthracite) Fired Thermal Power Generation

Typical components of Vietnamese anthracite are as follows,

Fuel ratio (fixed carbon/volatile content)	7.8~8.1
Volatile content (dry, ash-free basis)	10.9~11.4
Fixed carbon (dry, ash-free basis)	88.6~89.1

With a lesser volatile content and higher carbon content, anthracite has essentially the following characteristics.

(a) Difficult to ignite
(b) Requires a long combustion time
(c) Requires a high combustion temperature

In general, bituminous coal combustion starts with the volatile content, changing to carbon combustion. Anthracite combustion starts with the carbon combustion with no combustion of the volatile content. Also, anthracite requires a higher temperature atmosphere than bituminous coal.

There are several types of anthracite burning systems to adjust to the above mentioned characteristics depending on the manufacturers' designing concept.

Anthracite has difficulty to be completely burned. To achieve good combustion, anthracite requires several specific burning technology methods, such as to supply ultra fine pulverized coal, to improve the dust separator, to provide many relatively small capacity burners. Unburnt carbon makes its combustion efficiency lower compared to the bituminous coal boiler.

Anthracite fueling-boiler performance is 95~97% for combustion efficiency and 84~88% for boiler efficiency.

Circulating Fluidized Bed Combustion (FBC) Technology

Conventional pulverized coal boiler has high (1,400~1,500°C) combustion temperature due to fast gas flow speed (11~15 m/s) and small coal particles (under 80 μm).

On the other hand FBC boiler has low combustion temperature (approximately 850°C) due to lower gas flow velocity (4~8 m/s) and medium sized coal particles. Thus, FBC boiler has better coal burning characteristics than that of conventional boiler.

Following countermeasures against the characteristics of anthracite are expected for FBC boiler.

Anthracite characteristics	Features of circulating fluidized bed method
Poor ignitability	No accidental miss fire due to fluidized medium
Long combustion completion time	Long stay time in furnace due to particle circulation enables relatively efficient combustion regardless of poor coal combustibility
High temperature combustion to reduce the unburnt content	Long stay time in furnace due to particle circulation enables relatively efficient combustion regardless of poor coal combustibility

However, FBC boiler is the state-of-the-art technology with some problems unresolved, currently 300~350 MW class is the largest available.

(2) Gas Fired Power Generation

A gas fired power plant consists of boiler, turbine, generator and other components similar to that of conventional coal-fired or oil-fired power plant. The fuel, gas/oil/coal, can be selected flexibly by installing fuel supply systems and burners together. There is very minimal difference between the fuels in their gross thermal efficiency. When the net thermal efficiency is compared, however, the efficiency of gas fired power generation is the highest followed by oil fired and then by coal fired as the lowest in efficiency. The difference is caused by the auxiliary power difference including the fuel preparation equipment, ash treatment equipment, environmental control equipment, etc.

(3) Combined Cycle Power Generation

A combined cycle power generation system is composed of gas turbine(s), heat recovery boiler and steam turbine(s). The gas turbine generation cycle and the steam turbine generation cycle are combined to make the best use of the high temperature of the gas turbine cycle and the low temperature of the steam turbine cycle.

The way of improving the thermal efficiency of a combined cycle power generation is the adoption of higher temperature of the gas turbine inlet. Although the currently available gas turbine unit of 1,100°C class in the system has a thermal efficiency of 43% or so (LNG fired, high calorific value base), but an efficiency of 47% (the same base) will be attained by the gas turbine unit of 1,300°C class which is being developed by various manufacturers.

Features of Combined Cycle Power Generation System

(a) High thermal efficiency with more than 43% level is expected as against 40% or so of conventional steam turbine cycle power plant.

(b) Thermal efficiency at partial load is good.

A combined cycle power plant of large capacity is constituted by a combination of relatively small capacity units. For this reason, a thermal efficiency as high as at the rated output can be realized in a wide range of output by reducing or increasing the number of units being operated.

(c) Start up/shutdown time is short.

A combined cycle plant can start up in approximately 1 hour, while a conventional steam turbine cycle plant of 600 MW class takes 2 and a half hours for start up at the shortest under the condition of daily stop operation mode.

(d) Discharge of condenser cooling water is small, 60~80% of a conventional steam turbine plant with similar output.

(e) Operating performance fluctuates by type of fuel.

A combined cycle power generation plant, especially an exhaust heat recovery plant, needs clean fuel.

The fuels used in the exhaust heat recovery type combined cycle power plants which are being operated, constructed or planned are limited to clean gas fuels such as LNG and LPG, or high grade kerosene having very low sulfur content. The reasons for this situation are explained below.

- The heavy metals, alkali metals and sulfur contents in the fuel cause substantial corrosion of gas turbine combustors and moving/stationary blades which are exposed to high temperature.

- Adhesion of unburnt carbon may adhere to gas turbine blades to reduce the thermal efficiency.

- Prevention of low temperature corrosion of heat recovery boiler tubes reduces the thermal efficiency

(4) Environmental Consideration

Coal Fired Thermal Power Generation

SOx content is determined by the sulfur content(s) of the anthracite. Since Vietnamese anthracite has a low sulfur content (max. 0.5%), the SOx at the boiler outlet is relatively low at approximately 400~500 ppm.

Since the nitrogen content (N) in anthracite is as low at max. 1% (approx. 0.9%), its fuel NOx generation is also low. Contrarily, the thermal NOx generation is higher than that of bituminous coal because its volatile content is low and, as previously described, only fixed carbon combustion is conducted. This requires an approx. 60°C higher ignition temperature and a relatively high combustion temperature.

Consequently, the total NOx generation (fuel NOx + thermal NOx) is higher than that of bituminous coal. NOx at the boiler outlet is expected to remain within 500~1,000 ppm.

Although the thermal NOx in the boiler NOx can be reduced by using a low NOx burner and 2-stage combustion method, it increases the facility cost . Due to the cost balance between the environmental restrictions and facility cost, it is, therefore, necessary to consider the exhaust restriction value when considering installation of a low NOx combustion system.

The coal dust is 30~50 g/m^{3}N at the boiler outlet. Max. 300~500 mg/m^{3}N (min. 99% dust collection efficiency) can be achieved at the stack outlet by installing an electric precipitator (EP).

As an example, the amount and falling distance of emission are estimated, using Bosanque-Sutton's equation. The result is shown below (see Appendix in detail).

(Unit: ppb)

	Capacity	300MW x 1	300MW x 2	300 MW x 1 + 300 MW x 2	300 MW x 2 + 300 MW x 2
Maximum Value	SOx	12.5	8.5	21.0	17.0
	NOx	20.4	13.9	34.3	27.8
Daily Average	SOx	7.4	5.0	12.4	10.0
	NOx	12.0	8.2	20.2	16.4

Note 1: Fuel is anthracite. Stack height is 150 m.
2. The most concentrated points on the ground are 12.0 and 14.9 km for 300 MW x 1 and 300 MW x 2, respectively, from the power plant.

These emissions satisfy following Vietnamese environmental criteria:

SOx	Max. Value	175 ppb	Daily Average	17.5 ppb
NOx	Max. Value	41.4 ppb	Daily Average	41.4 ppb

Accordingly, de-SOx and de-NOx facilities are not considered for the project in the PDP study.

FBC power generation system has an advantage from a point of view which enables desulfurization in the furnace and generates minimal NOx.

<u>Combined Cycle Power Generation</u>

The NOx generation in combustion of fuel with gas turbine tends to be larger as the thermal load in the combustor is higher and contains more excess air, particularly when fuels having high nitrogen content are used. The volume of exhaust gas is also larger than in a steam cycle plant of same capacity. For these reasons, the denitration system and the dust collector are larger in capacity.

Although the above problems exist when heavy oil, etc. is used, it is expected that the range of fuels usable in combined cycle power plants will be extended if the environmental performance and durability are further enhanced without reducing the economy by means of future technology development.

6.1.3 Economic Assessment of Thermal Power Generation Systems

Generating unit cost of each type of thermal power plant is estimated, and shown in Table 6.1-1.

In order to make cost estimation study, related parameters such as unit capacity, construction cost, load factor, efficiency, and so on were discussed between the JICA Team and IEV. Unit cost should be considered as a present cost. No inflations were taken into account in this study.

It is necessary to pay attention to some parameters, such as annual load factor, fuel price, interest, etc.

Annual load factor with 80% looks optimistic taking into account operation results. 10% decrease of load factor increases the fuel cost by 10%, and by 5% or more for the unit cost. And it also means, Gas or C/C plants would operate at its rated full load except the period for scheduled maintenance. Regarding the efficiency, gas turbines of C/C plants with 1,100°C level temperature at turbine inlet showed less than 43% at the sending end of the power plant. Higher temperature of gas turbines inlet would naturally bring higher efficiency. However, careful operation and maintenance works are needed for such sensitive power plants with 1,400°C class inlet temperature of gas turbines.

Fuel price and interest rate of the required fund are considered to be uncertain factors.

6.1.4 Available Commissioning Year of Projects

The commissioning year of Pha Lai II and Phu My projects are planned in 2000 and 1998/1999, respectively.

It is assumed 3 years will be spent for engineering studies including the contract procedure for the other thermal power projects. The periods of those constructions are also assumed to be 4 years for coal thermal power projects and for 3 years for C/C system power projects.

6.1.5 Findings and Recommendations

(1) Thermal power projects in Viet Nam are planned in the Northern and the Southern regions. The type of the plant depends on the fuel resources, coal thermal power projects in the North and gas fired power projects or combined cycle systems in the South.

Only Quang Ninh project is planned in the North after Pha Lai II project and it has an advantage in the site condition located near the coal mines. As the Northern power system has enough supply capability after commissioning of Pha Lai II, F/S the project will be finished before 2000.

(2) There are many options in the South for selection of the plant type. Combined cycle generating system is considered to be more advantageous taking into consideration utilizing associated gas, presently exhausted in flare.

However, as the amount and the cost of new gas resources are uncertain as discussed in Chapter 7, it is reasonable planning to study coal thermal project, O Mon in the near future and Phan Thiet in the future.

Rolling study of power development plan should be implemented according to new information on the natural gas production.

Domestic coal may be selected for O Mon due to its cheaper price than international market level.

(3) De-SOx and De-NOx facilities are not considered for the coal thermal projects in this study as SOx and NOx concentration in ambient environment estimated clear the Vietnamese environmental criteria.

However, it is recommended that EIS should be implemented for the site selection.

(4) In designing of equipment of the projects such as main units and auxiliary equipment of the power plant, it is recommended that power and energy reduction of station service should be considered from the view point of energy conservation.

Table 6.1-1 Cost Estimation of Thermal Power Plants

Item		Conventional Cycle (Coal*1)		Conventional Cycle (Gas)		Combined Cycle (Gas)		
Unit	-	2x300		2x300		2x300		
Output	MW	600		600		600		
Unit cost	$/kW	1,250		1,100		800		
Annual energy	GWh	3,570		4,200		3,780*3		
Load factor	%	68%		80%		80%		
Life	year	25		25		20		
Station service	%	6.0		3.0		1.5		
FOR	%	8.0		8.0		6.0		
Ave. efficiency	%	34.0		36.0		45.0		
Heat rate	kcal/kWh	2,529		2,389		1,911		
Heat value	kcal/kg	5,500		9,000		9,000		
O.M. cost	%	5.0		5.0		5.0		
C.R.F(i=10%)		0.1102		0.1102		0.1306 =0.1175/0.9*3		
Fuel price	$/t	(North) 24	(south) 34					
	$/MBTU			2.5	3.0	2.0	2.5	3.0
Capital cost	$/kW.Y	137.8	137.8	121.2	121.2	104.4	104.4	104.4
O.M. cost	$/kW.Y	62.5	62.5	55.0	55.0	40.0	40.0	40.0
Fixed cost	c/kWh	3.37	3.37	2.52	2.52	2.29	2.29	2.29
Fuel cost *4	c/kWh	1.10	1.56	2.37	2.84	1.52	1.90	2.28
Unit cost	c/kWh	4.47	4.93	4.89	5.36	3.81	4.19	4.57

*1: Anthracite coal
*2: With EP, without FGD and SCR
*3: Output is decreased in 10% due to higher ambient temperature
*4: (Fuel price)x(Heat rate)x1/(Heat value) for coal, (Fuel price)x(heat rate)x10^{-4} 0.252 for Gas and C/C plant

6.2 Hydropower Generating Facilities

6.2.1 Electric Power Development Projects

(1) General

Because of favorable natural conditions, Viet Nam in general has an enormous potential of hydropower. As described in section 3.5, 100,000 GWh of hydro-energy is considered to be economically feasible to be exploited, which is made up of 59,400 GWh kWh in the Northern region, 16,600 GWh in the Southern region, and 24,000 GWh in the Central region. Therefore, hydropower is one of the most important energy resources, and necessary to be developed positively, especially in the Northern region.

For future development of hydropower projects, PIDC1 and PIDC2, governmental agencies under MOE are in charge of project planning, investigation and designing. Many candidate sites are being studied under various stages of studies by PIDC1 and PIDC2. On the other side, the 4th Master/Plan for the future electric power development in Viet Nam is being made by IEV which is not only governmental agency under MOE, but also the counterpart agency for the JICA Study Team.

According to IEV, 20 of new hydropower projects are considered to be developed upto the year 2010 in the 4th Master/Plan as not only power generating facilities but also social-economical facilities, that is multipurpose projects, such as water supply, irrigation, and flood control. During the study, these 20 new hydropower projects are to be under discussion of power development planning, between IEV and JICA Study Team, and confirmed to be important.

As the result, these 20 new hydropower projects with some projects under construction are studied in this section. This study is made based on the specifications offered by IEV.

Salient features of the projects are listed in Table 6.2-1, and locations are shown in Figure 6-1. As shown in these tables and figures, there is a tendency that new hydropower projects are concentrated on the same river basin with abundant hydropower potential.

(2) Individual Projects in Northern Region

Five projects are considered to be developed in early stages, Son La (2,400 ~ 3,600 MW), Huoi Quang (800 MW) which are planned along the Da river basin, in upstream of existing Hoa Binh plant (1920 MW), Dai Thi (250 MW) along the Lo Gam river basin, Ban Mai (350 MW) along the Ca river basin, and Cua Dat (105 MW) along the Chu river basin.

F/S of Ban Mai project is now being made by French company.

(3) Individual Projects in Southern Region

Six projects which are all along the Dong Nai river basin are to be considered to be developed, Ham Thuan/Da Mi (300/172 MW), Dai Ninh (300 MW), Dong Nai 4 (200 MW), and Dong Nai 8 (192 MW) in upstream of existing Tri An plant (400 MW), and Cau Don (50 MW) in downstream of Thac Mo project on the Be river which is a tributary of the Dong Nai River.

Among them, Ham Thuan/Da Mi project is at the stage of definite design and planned to be completed in early 2000.

Construction work of Ham Thuan/Da Mi (300/172 MW) project will be started, soon.

(4) Individual Project in Central region

There is a considerable hydropower resource in the central region including Yaly project and Song Hinh project which are presently under construction.

Eight projects are studied to be developed, those are Sesan 3 (220 MW), Sesan 4 (366 MW), Plei Krong (120 MW), and Thuong Kontum (260 MW) planned along the Sesan river, An Khe (116 MW) planned along the Ba river, Sung Con 2 (60 MW) along the Thubon Bon river, Buon Cuop (81 MW) planned along the Srepoc river, Rao Quan (80 MW) planned along the Thach Han river.

(5) Expected commissioning year of the new projects by IEV

According to IEV, commissioning years of the new hydropower projects are expected as follows;

- Yaly 6/1999, 1/2000
- Song Hinh 1998
- Ham Thuan/Da Mi 1/2000, 4/2000

Also according to IEV, following projects are expected to be commissioned until 2010,

- Plei Krong after 2001
- Ban Mai after 2002
- Dai Ninh after 2003
- Sesan 3 after 2002
- Son La (L) 2007(#1)~2012
- Son La (S) 2007(#1,2)~2011(#9,10)

6.2.2 Review of the New Hydropower Projects along the Main River Basin

(1) Scope of the Review

(a) Energy generation

In the case that hydropower projects are developed from downstream to upstream step by step along the same river basin, electricity of the existing hydropower projects downstream can be influenced by the new project upstream in general. Though this matter is one of the most important factors for assessment of the hydropower project, it seems not to be taken into account for the new hydropower projects shown in Table 6.2-1, unfortunately. Therefore, it is necessary for the projects along the same river basin to be reviewed to estimate the influence of upstream development on reservoir operation and energy production of downstream projects.

Several series of hydropower projects along main river basins are reviewed. The main river basins reviewed are the Da river in the Northern region, the Dong Nai river in the Southern region, and the Sesan river in the Central region.

(b) Investment cost

The investment costs offered by IEV are also reviewed to make sure of validity of the cost. Though level of unit price can be different by local conditions, a set of unit price at an international tendering level is applied for all the projects to review the project cost offered by IEV.

(c) Construction period

Construction term is also reviewed, considering past records of existing projects in Japan and site conditions. Based on the reviewed construction term, development schedule of the individual new projects are also considered.

(d) Interest during Construction

Interest during construction (it is described as "IDC" hereafter) is also reviewed to make sure of the appropriateness of IDC offered by IEV.

(2) Review of energy generation

(a) Method of Review

The objective of the review is to estimate influence amount of incremental energy generated at downstream projects by improved river flow resume by upstream project development along the same river basin to evaluate new project and its priority. Input data for the reviewed project are derived from Table 6.2-1, showing the figures offered by IEV. Procedure of the review and input data used in this review are shown in Appendix 6.2.1.

Results of the review are shown in Table 6.2-2 through 6.2-4, respectively for each river basin. In these tables, difference of electricity of existing project caused by newly developed project is considered as electricity of newly developed project.

Monthly electricity of the reviewed projects are shown in Appendix 6.2.2. These data will be referred to for the input data of Power Development Planning simulation in Chapter 8.

(b) Review about the projects along the Da River Basin

Two hydropower projects, Son La and Huoi Quang located at the upstream of existing Hoa Binh hydropower plant are planned to develop along the Da river. Considering the method to access each project site, Son La hydropower project will be developed at first from downstream, and after it's completion, Huoi Quang hydropower project will be developed next.
The present planning features of the Huoi Quang hydropower project are designed only when the Son La hydropower project is planned in a small scale exploitation, that is 2,400MW. The case of "Son La (L) plus Huoi Quang" is not considered in

this review, because the planned Tailrace Water Level of Huoi Quang hydropower project is at under the reservoir water level of Son La (L) project.

In the case of the Da river, Son La (L) with annual generation energy of 15,000 GWh would increase that of Hoa Binh power plant by 2,300 GWh. When Son La(S) with annual energy of 9,900 GWh is completed, Hoa Binh power plant would increase its energy by 900 GWh. Additionally, Huoi Quang project with annual energy of 2,800 GWh will become possible to exploit increasing the energy at Son La(S) and Hoa Binh hydropower plants by 200 GWh all together.

(c) Review about the projects along the Sesan River Basin

Four hydropower projects, Plei Krong, Sesan 3, Thuong Kontum and Sesan 4 are planned along the Sesan river, besides the Yaly project now under construction.

The next project following Yaly would be Plei Krong according to the IEV' s plan. As the other three projects are at the studying stage on the desk, the order of exploitation of these projects is not certain at present. In this study, Thuong Kontum the most upstream, Sesan 3, and Sesan 4 projects are assumed to be developed in this order to estimate electricity under the situation that all these projects are completed.

It is considered in the review study that the Thuong Kontum project diverts its power discharge to the eastern area which is out of its catchment area and would decrease the energy generated by power plant located downstream of the river.

In the case of the Sesan river basin, Plei Krong power plant with annual energy of 560 GWh increases that of Yaly by 220 GWh. Thuong Kontum, however, would decrease that by 130 GWh in Yaly project downstream. As a result, 90 GWh of energy can be increased at Yaly project by developing upstream projects.

(d) Review about the projects along the Dong Nai River Basin

Four hydropower projects, Dai Ninh, Dong Nai 4, Dong Nai 8 and Ham Thuan/Da Mi projects are planned along the Dong Nai river basin. Existing hydropower plants are Da Nhim located at the most upstream and Tri An located at the most downstream along the Dong Nai river. According to IEV, Ham Thuan/Da Mi project which is located along La Nga river, a tributary of Dong Nai river will be developed soon, and the exploitation of projects would be Dai Ninh, Dong Nai 4, and Dong Nai 8 in order. In this study, projects are assumed to be developed in this order.

Discharge of Da Nhim and Dai Ninh projects are diverted into another catchment area for irrigation purpose. As Da Mi project has a role of regulating reservoir of Ham Thuan project, power discharge of Ham Thuan project is supplied to Da Mi project.

In the case of the Dong Nai river, developing Ham Thuan/Da Mi projects would increase a small amount of the energy production at existing Tri An hydropower plant by 40 GWh, and developing Dai Ninh project would decrease a small amount of the energy production at existing Tri An hydropower plant by 40 GWh. As a result, electricity of existing Tri An hydropower plant is almost the same as the present situation.

(3) Review of the project investment costs

(a) Civil Work and Hydro-Mechanical Work

The Investment costs of new hydropower projects were offered by IEV. The figures of the investment costs are shown in Table 6.2-5 and 6.2-6.

For civil work and hydro-mechanical work, construction cost is estimated by using unit price at international tendering level and work quantities of the main structure offered by IEV. At first, quantities of civil work are reviewed using drawings of the project offered by IEV.

Quantities are reviewed for Son La hydropower project as the representative of all the new hydropower projects using project drawings. As the result of the review, there are small difference between quantities offered by IEV and reviewed quantities. Therefore, quantities of civil works are confirmed to be appropriate. Based on this fact, quantities offered by IEV are used for the review of the cost of civil work and the hydro-mechanical work for all the projects. Back ground of civil work cost review is shown in Appendix 6.2.3. Quantities of each work item of the main structures are shown in Appendix 6.2.4.

Adopted unit price for this review are as follows;

• Open excavation of soil	3.00 U$/m^3
• Open excavation of rocks	7.00 U$/m^3
• Tunnel excavation	108.00 U$/m^3
• Embankment of impervious core	3.00 U$/m^3
• Embankment of rock materials	6.00 U$/m^3
• Embankment of filter materials	15.00 U$/m^3
• Open concrete	130.00 U$/m^3
• Tunnel concrete	200.00 U$/m^3
• Rein-forcement bar	756.00 U$/t
• Access Road	1,253.00 U$/km
• Metal structure	7,000.000 U$/t
• Lifting machine	8,000.000 U$/t

Total civil work cost is composed of the items as follows;

• Civil Work Cost for main structure	A
• Service Facilities	A x 10%
• Diversion system	A x 15%
• Others	A x 10%

The ratio of each item is determined, considering past records of civil work for hydropower projects.

(b) Electro-mechanical work

The cost of electro-mechanical works is estimated, using past records of electro-mechanical work, which is determined by unit capacity of electro-mechanical work.

(c) **Social environmental cost to be required**

In order to investigate the tendency of the social environmental costs estimated by IEV for the whole candidate projects, the relationship between the cost and the surface area of HWL of reservoir of each project has been reviewed and plotted on a common logarithmic coordinate sheet. Figure 6.2-1 and Table 6.2-7 show the result of the plots of the whole candidate projects.

From the figure, it is found that the compensation costs are estimated based on a linear relationship with the surface areas of HWL of the reservoirs of the candidate projects.

On the other hand, when the compensation cost is compared with the total construction cost of each project, the whole projects can be categorized into the following three groups:

1) The projects of which the percentage of compensation cost reaches 15% to 20% of total construction cost

   Dai Thi (250 MW), An Khe (116 MW), Plei Krong (120 MW),
   Sesan 4 (366 MW), Dong Nai 8 (192 MW), Cau Don (50 MW)

2) The projects of which the percentage of compensation cost reaches 10% to less than 15% of total construction cost

   Cua Dat (105 MW), Song Hinh (70 MW)

3) The projects of which the percentage of compensation cost is less than 10% of total construction cost

   Son La (L) (3,600 MW), Son La (S) (2,400 MW), Huoi Quang (800 MW), Son Con 2 (60 MW), Buon Cuop (81 MW), Ban Mai (350 MW), Thuong Kontum (260 MW), others.

Generally speaking, when the area of HWL of a project reservoir becomes bigger, the percentage of the compensation cost will be higher. Especially, when we talk on the social environmental cost, it is also required to cover various costs for building enough social infra-structures to stabilize livelihood of the whole resettled people and thereby to stabilize or even to upgrade the social economy of the local society. These costs are required in addition to the compensation cost.

The compensation costs estimated for Son La (L) and Son La (S) are all about 8% of their total construction costs, respectively. On the other hand, the percentages of the cases of Dai Thi (21%) and Sesan 4 (about 18%) reached almost 20%.

From the above analysis, it is recommended that the percentage of the social environmental cost for Son La (L) or Son La (S) will be estimated to be not less than 15% of its total construction cost.

It is also important to investigate which project of Son La (L) and Son La (S) would be more preferable from view point of environmental considerations. Table 6.2-8 as attached is prepared to compare some main environmental factors between the two projects. From the table, the following results are derived:

1) The areas of cultivated land and forest to be submerged by Son La (L) project are all doubled when compared with those of Son La (S) project. This will mean that not only the potential socio-economic environmental impact will become twice, but also potential nature environmental impact would become doubled.

2) In spite of the additional number of people resettlement being 36% and that of compensation amount estimated being 85%, additional financial burden for building more social infra-structures to stabilize livelihood of the people and maintain or even upgrade the quality of the local society could become far bigger than these percentages.

3) From a few available data of Huoi Quang (800 MW) project, the following comparison can be made:

a. Ratio of surface areas at HWL = 508/(275 + 48) = 1.57
b. Ratio of compensation amount = $298.45 \times 10^6/[(161.56 + 28.18) \times 10^6]$ = 1.57

From these ratios, it is clear that even if Huoi Quang project is added to Son La (S), additional socio-economic and nature environmental impact of Son La (L) would become more than 50%.

From the above results and insight gained, it is reasonable to say that selecting Son La (S) should be more desirable than selecting Son La (L).

(d) Result of the cost review

The result of the review is shown in Table 6.2-9. The items of the reviewed investment cost are shown in Appendix 6.2.4. The difference ratio between civil work and the investment cost offered by IEV is between 2% and 30%, and that of hydro-mechanical works and electro-mechanical work is within 3%.

For Son La, Huoi Quang, Dai Thi, Plei Krong, Sesan 3, Sesan 4, Rao Quan, Dong Nai 8 projects, the difference ratio between reviewed investment cost and that offered by IEV is between 2% and 20%. The other project, except Ban Mai and Song Con 2 project, the difference ratio is about 30%. The projects of which difference ratio is less than 20% seem to be studied based on a price level of international tender.

For Ban Mai project, the compensation cost should be reconsidered. For Song Con 2 project, civil work cost should be reconsidered.

On the other hand, the projects of which difference ratio is about 30% are not seemed to be studied based on a price level of international tender by IEV, but domestic unit price is applied in cost estimation. Many of the projects in this group are considered to be developed not only for power generation, but also for irrigation and/or flood control. This may be considered to be the reason why domestic unit price is applied for this group.

In Table 6.2-9, the difference ratio of total investment cost of the new hydropower projects is about 7.0%. Therefore, the investment cost can be judged to be appropriate, comparing with reviewed investment cost at master plan study level. For Power Development Plan Study described in chapter 8, the investment cost of each project is necessary as input data for financial calculation. In this study, the investment cost offered by IEV is determined to be applied according to the above review result.

(4) Review of the construction term of the project

In Power Development Plan study in Chapter 8, construction term of each project is an important factor. In this section, construction term of each project is reviewed.

Generally, construction term of hydropower project relies mainly on the dam construction and road construction. In this review, construction term is considered by dam embankment volume as a parameter, based on the past records in Japan. Road construction term is not considered here. Though road construction is started besides main construction works in Viet Nam, 2 years is considered as a time lag, because distance of access road is larger than 20 km for some projects. Concept of the review is shown in Appendix 6.2.5.

In case of Son La project, a lag of construction work is considered to be 3 to 4 years, because generators are considered to be commissioned in order, looking at electricity demands in Viet Nam, after the first generator is commissioned.

The result is shown in Table 6.2-10. Total construction term of Son La projects is estimated to be 12 years for Son La (S) project, and 15 years for Son La (L) project. It is estimated that 6 years is generally appropriate for construction term of other projects except Huoi Quang project. Construction term of Huoi Quang project is estimated to be 7 years, considering the hard site access by ship after Son La (S) project is completed.

Using reviewed construction term, development work schedule for the new projects are prepared by JICA Study Team, taking into consideration expected commissiong year of the new projects by IEV. The result is shown in Figure 6.2-2. In this figure, progress of development work of each project is taken into consideration. Remarkable progress is as follows;

(a) F/S of Ban Mai project is now being carried out by French company.
(b) Sesan 3, Sesan 4, and Thuong Kontum projects are studied only at dsk level.
(c) F/S of Dai Ninh project by PIDC2 has been already finished.
(d) For other projects, pre-F/S work has been already finished.

From these figures, following matters are confirmed;

(a) Development schedule of Plei Krong and Sesan 3 project seems to be tight. It takes only one year for F/S and definite design for these projects. And for Sesan 3, Sesan 4, and Thuong Kontum projects, M/P study will be necessary before F/S.

(b) Construction work of Son La project should be started at beginning 2000's for expected first commissioned year by IEV. F/S should be started as soon as possible to complete F/S work and Definite Design work before construction work.

Therefore, F/S of Son La project should be started as soon as possible.