Chapter 4. Possibility of Installation of Pumped Storage Power Plant

4.1 Roles and Functions of PSPP

PSPP stores electric energy when demand for electricity is low as at night time and uses this stored energy for peak hours, thus can adjust the demand-supply balance and reduce the gap between the peak and off-peak hour’s demand. That is PSPP plays a role of leveling ever-changing electric power consumption (Figure 4-1).

Owing to PSPP’s role of load leveling, the other power sources which frequently start up and shut down or adjusted output can operate continuously for long time at stable output, so fuel efficiency can increase. Moreover share of base power sources with low generation unit costs can be increased, thus the overall generation cost of the power system becomes lower, and economic efficiency increases.

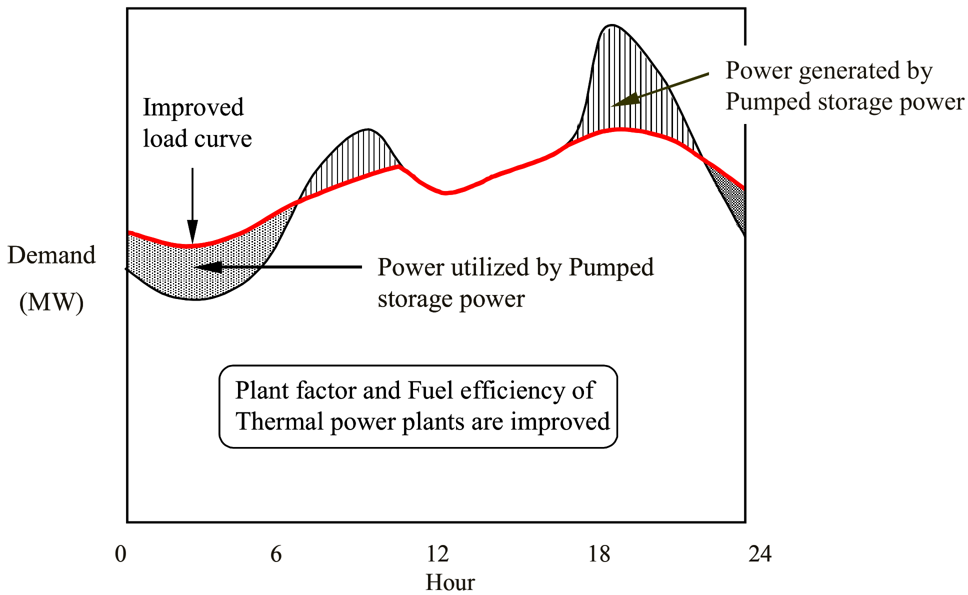


Figure 4-1 Leveling load curve by pumped storage power plant

4.2 Project Finding of PSPP

There are various alternatives for peaking power supply such as thermal power and conventional and pumped storage of both existing and planned. It is thus necessary to select peaking supply projects by study and evaluation of those alternatives. Therefore, data such as adjustment capacity, efficiency, and generation costs of alternatives are collected for building optimization of the power development plan.

(1) Establishment of Criteria for Project Finding of PSPP

There is no pumped storage in Vietnam and the planning study has just begun using new criteria for pumped storage in Vietnam which were determined as shown in Table 4-1.

Table 4-1 Criteria for Pumped Storage Project Finding in Vietnam

Issue		Item	Criteria	Status
Technical	Generation plan	- Peak duration time - Installed capacity	- 7hrs - More than 400 MW	○ ○
	Limit of manufacturing of Power facility	- Design head - K Value - Max. utilizing water depth of pond	- Less than 750m of maximum head - Less than 1.25 - Less than 30m (40m in case of full facing pond type)	○ ○ ○
	Location / Layout	- Catchment area - Dam crest length - Dam height - Length of water way - L/H - Overburden of underground power cavern	- More than 30km2 (total of upper, lower dams and diverted) - Less than 500m - Less than 180m (Rockfill type) - Less than 10km - Less than 15 - Less than 500m	○ ○ ○ ○ ○ ●
	Geological conditions	- Active fault - Base rock conditions especially for underground power cavern	- Avoid the zone of active faults and those of Quaternary Era - Avoid the area of Quaternary Era and weak and unconsolidated strata	● ●
Environmental	Natural	- Protected Area (e.g. Natural Parks) - Endangered species	- Beyond the confines of Protected Areas (Natural Parks and Nature Reserves) - Avoid the critical habitats of important fauna and flora	○ ●
	Social	- Mining right - Historical and Cultural heritage - Houses to be submerged	- Avoid the area of mining concession - Avoid being submerged - Necessary to consider	● ● ●

○ : considered in primary project finding ● : necessary to confirm the situation by site survey

(2) Map Study of PSPP

Study Team reviewed the master plan of pumped storage power plants in Vietnam and carried out fresh potential site findings with using 1: 50,000 scale topographical maps. As a result, thirty eight (38) potential sites were found in Vietnam.

Preliminary prioritization of the candidate site was carried out according to the criteria.

Firstly, location / area of national parks and nature reserves were surveyed and then checked as whether the pumped storage potential site is in the area or not.

Secondary, eleven (11) sites were set as reserved grade due to technical criteria. Therefore twenty six (26) sites were nominated as the candidate sites.

Ten (10) promising sites were selected for the first site survey under a series of discussions between both parties considering various factors, such as construction costs, distance from the high power demand area / the nearest 500kV Substation, approaching road conditions and distance from existing and proposed protected areas (Table 4-2).

Table 4-2 Ten Promising Sites for the First Site Survey

No.	Location	map	East Longitude	North Latitude	Elevation of reservoir Upper HWL	Upper LWL	Lower HWL	Lower LWL	Max. head	longitudinal length(L)	L/H	Cost (M US$)	Dam Vol. UP (*1000m3)	Dam Vol. LOW	Dam Vol. Sub	K Value
JN18	N	6050-IV	105:13	20:50	700	670	115	80	620	6100	9.8	740	800	HoaBinh	0	1.19
P5	N	5950-I	104:54	20:57	660	620	115	80	580	2250	3.9	760	Pond	HoaBinh	0	1.22
JN5	N	5951-III	104:32	21:08	750	720	150	120	630	2800	4.4	770	2,700	1,600	700	1.18
JS11	S	6531-I	107:51	11:18	1040	1010	400	370	670	5000	7.5	780	2,100	1,700	0	1.17
P11B	N	5950-I	104:50	21:00	650	610	115	80	570	2650	4.6	780	Pond	HoaBinh	0	1.23
JN6	N	5951-IV	104:39	21:19	800	770	300	270	530	5600	10.6	810	3,200	1,900	0	1.20
JN3	N	5951-II	104:47	21:13	900	870	360	330	570	3350	5.9	820	2,400	5,000	0	1.19
JS6	S	6732-I	108:47	11:57	620	580	200	180	440	2600	5.9	840	Pond	1,400	0	1.23
JN1	N	5950-I	104:50	20:59	1000	960	300	270	730	2450	3.4	880	Pond	10,600	0	1.18
JN9	N	5851-I	104:20	21:20	1200	1170	500	470	730	4600	6.3	890	9,300	3,000	0	1.16

(3) The First Field Survey

Reconnaissance study is conducted for the promising candidates of PSPP (about 10 sites) to confirm the conditions, which are identified by the desk study, such as topographical/geological conditions, hydrological conditions, and natural and social environment conditions.

Based on the site survey, project conceptual design and project cost of each site were reviewed. The following evaluation was made:

1) Economic analysis in comparison with gas turbine thermal power plant (B/C method)
2) Preliminary evaluation for Natural/Social environmental impacts
3) Priority ranking (refer to Table 4-4)

C/P and the Study Team discussed the above review works, and both parties agreed to select three or four sites from the following six project sites; P5, P11B, JN3, JN5, JN6 and JS6. The selected four sites were visited at the second site survey.

Table 4-3 Prioritization according to the 1st Site Survey Results

Project Site Name	(P5)	(P11B)	(JN1)	(JN3)	(JN18)	(JN5)	(JN9)	(JN6)	(JS6)	(JS11)
Economic Value (US$/kW)	750	770	910	760	790	680	820	760	730	820
B / C	1.10	1.08	0.93	1.09	1.05	1.20	1.02	1.09	1.13	1.02
Tentative eveluation scores of Environmental Assesment	1.0	1.0	2.0	1.2	1.9	1.2	1.7	1.4	2.0	1.4
Priority Rank	AA	A	C	AA	B	AA	B	A	A	B

Table 4-4 Criteria for Priority Ranking

Priority Rank	Criterion
AA	It is economically superior and there is no significant natural / social environmental impacts expected.
A	It is economically superior, and there are natural / social environmental impacts or technical problems expected
B	It is economically feasible and there are natural / social environmental impacts or technical problems expected
C	It is uneconomical or there is significant natural / social environmental impacts or technical problems expected.

(4) The Second Field Survey

The second site survey on the priority candidate sites was carried out especially to identify obstructions of the project, which was found by the first reconnaissance survey, and to collect data for preliminary design.

a. Survey Results and Selection of Priority Pumped Storage Sites

Based on the results of the second site survey, the main issue of each project site was abstracted and further actions for each issue were clarified as shown in Table 4-5.

As a result, the P5 project site has a significant situation in the geological conditions and was removed from the priority projects. Three other projects (JN3, JN5, JS6) remained as priority projects.

b. Reviews of Project Design based on the Second Site Survey

Study team reviewed the design of promising three project sites based on the results of the second site survey. Throughout the review study, layout of the project structures such as dam type, route of waterway, location of underground powerhouse and approach route have been adjusted considering the features of each project.

Additionally, Study team renamed the three selected projects tentatively, which is derived from the district name.

Table 4-5 Main Issues and Further Actions of Each Project

Site		Main issues to be considered	Further actions	Evaluation
JN3	Geology / Design	➢ River inflow at the lower dam site is little. First pooling of the reservoir may take a long time.	➢ Monitoring and evaluation of the river inflow.	○
	Environment	**Social environment** ➢ One village (37 households, 140 persons) at the lower dam / reservoir site will incur significant impacts because the houses and the agricultural lands will be submerged. ➢ One village at lower dam and another at upper dam are expected to incur significant impacts because of their proximity to the sites. **Natural environment** ➢ One tributary with small basin on the Mua river will disappear by the lower dam. ➢ Relatively good forest around the upper dam / reservoir site is expected to incur secondary impacts.	**Social environment** ➢ Social environment investigation to clarify impacts **Natural environment** ➢ Natural environment investigation to clarify impacts	
JN5	Geology / Design	➢ Since there is a highly weathered col in the left side of the upper reservoir, measures for stop the leakage, such as saddle dam/curtain grouting, will be required.	➢ Up-grade of the topographic maps and review design of the countermeasures	○
	Environment	**Social environment** ➢ At the lower dam / reservoir site, four villages (306 households, 1680 persons in total) will incur significant impacts because the houses and the agricultural lands will be submerged. One of the villages moved to the current site when Hoa Binh dam project was implemented. ➢ Four villages along the planned approach road to the lower dam are expected to incur significant impacts. **Natural environment** ➢ It is likely that the aquatic ecosystem of Sapriver incurs significant impacts by the lower dam / reservoir.	**Social environment** ➢ Social environment investigation to clarify impacts ➢ Design review taking mitigation measures into consideration, such as road layout separate from houses/fields **Natural environment** ➢ Natural environment investigation to clarify impacts	
P5	Geology / Design	➢ Since permeability around the underground powerhouse is high, construction/maintenance is incredibly difficult. ➢ There exists thick, huge secondary sediment around the planned outlet area. It is technically impossible to construct the outlet in this area.	➢ **Give-up on the current plan. Drastic change of the layout plan**	×
	Environment	**Social environment** ➢ One village (15 households, 60 persons) at the upper dam / reservoir site will incur significant impacts because the houses and the agricultural lands will be submerged. They moved to the current site at the time of the Hoa Binh dam project. ➢ Two villages along the planned approach road to the outlet are expected to incur significant impacts.	**Social environment** ➢ Social environment investigation to clarify impacts	
JS6	Geology / Design	➢ An irrigation dam project is planned and is scheduled to be completed at the conclusion of this study.	➢ Coordination with irrigation dam project.	○
	Environment	**Social environment** ➢ One village (63 households, 330 persons) at the lower dam / reservoir site will incur significant impacts because the houses and the agricultural lands will be submerged. **Natural environment** ➢ Internationally recognized important terrestrial ecosystem will incur direct (limited scale) and secondary impacts. ➢ The aquatic ecosystem of Cai River will incur significant impacts. The impacts may reach to the downstream of the river.	**Social environment** ➢ Social environment investigation to clarify impacts **Natural environment** ➢ Natural environment investigation to clarify impacts	

○: It is possible to go on to the next stage. ×: There are fatal issues.

4.3 Preliminary Structural Design of the First Priority PSPP

To conduct a preliminary structural design and to identify rough development costs for the most preferred site among the candidate PSPPs selected in Section 4.2. The design of Phu Yen East site was carried out based on topographical maps on a scale of 1/50,000.

The design and the cost estimation of Phu Yen West and Bac Ai sites were carried out based on the condition that output is 1,050MW like Phu Yen East.

(1) Optimum Installation Capacity

The case of 1,200MW (400MW*3 units) and 7 hours (active storage) indicated in the above table for Phu Yen East site was selected as the optimal development scale, since it has the maximum B/C values (coal; 1.17, conventional hydropower; 1.47).

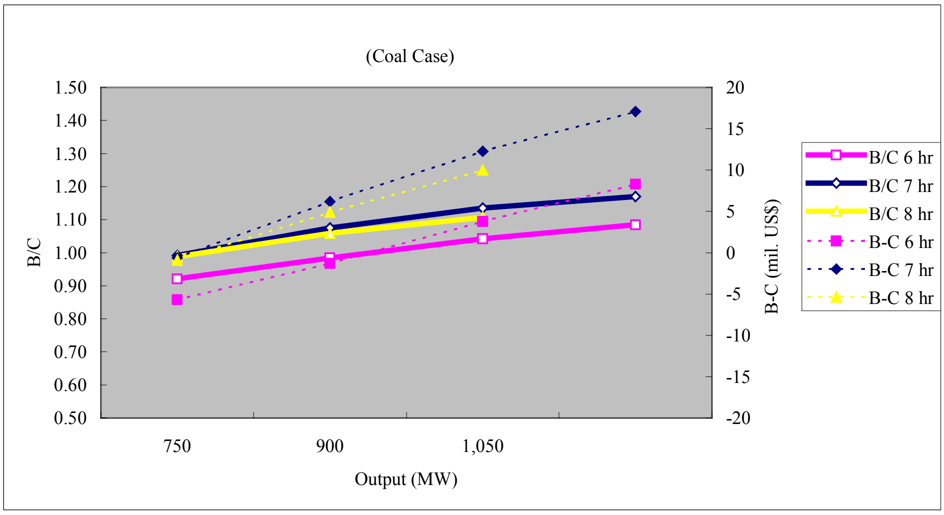


Figure 4-2 Results of the Optimal Development Scale (Coal Case)

(2) Preliminary Design

The preliminary design of Phu Yen East site was carried out with the above graph. The outline of the main features is shown in Table 4-6.

The difference of the previous design is as follows.

1) The shortest route was selected between the upper reservoir and the lower reservoir for the tunnel alignment of waterway.
2) The location of the underground powerhouse was shifted the upstream in order to minimize the overburden of it.
3) According to the 2), the penstock became shorter.

Table 4-6 Main Features of Phu Yen East site

Description		Unit	Phu Yen East PSPP
General			
Installed Capacity	P	MW	1,200
Designed Discharge	Qd	m^3/s	271
Effective Head	Hd	m	559
Peak Duration Time		hr	7
Upper Reservoir			
Type		—	Full Face Pond (Asphalt)
H.W.L. / L.W.L. / Usable Water Depth		m	880 / 850 / 30
Effective Reservoir Capacity		mln. m^3	6.9
Lower Reservoir			
Type			Concrete Gravity
H.W.L. / L.W.L / Usable Water Depth		m	277 / 270 / 7
Effective Reservoir Capacity		mln. m^3	6.9
Waterway			
Penstock	L (m)×n	m	5.9×1,400×1
Tailrace	L (m)×n	m	7.3×2,300×1
Total Length	Lt	m	3,700
Powerhouse			
Type		—	Egg-shape (Underground)
Cavern Volume		m^3	185,000
Pump-Turbine			
Type		—	Single-Stage Francis
Number		Unit	3
Unit Generation Capacity		MW	400
Lt / Hd			6.6

(3) Preliminary Cost Estimation

The JICA study team developed an efficient method for estimating the preliminary cost of the PSPP project, based on the information and data obtained from the 1/50,000 topographic maps.

Table 4-7 Cost Estimation of Phu Yen East PSPP

(Unit; 1,000US$)

Cost Items	Cost	Note
Ⅰ.Construction Cost	575,574	
1.1 Preparation Works	17,125	
1.2 Civil Works	259,016	
1.3 Hydromechanical Works	43,123	
1.4 Hydroelectrical Works	256,310	
Ⅱ.Engineering Service	43,168	
Ⅲ.Administration Expense	2,878	
Ⅳ.Land Compensation and Resettlement	2,898	
Ⅴ.Others (VAT)	29,943	
Ⅵ.Physical Contingency	65,446	
Total Project Cost	719,907	Except transmission lines
Unit Cost (US$/kW)	600	Output; 1,200MW

(4) Financial Evaluation

In addition to the function of a power source for peak power demand, Phu Yen East PSPP project could generate annual average energy of 960GWh. FIRR of the PSPP project was preliminary calculated by observing power revenue (power tariff applied at 12 ¢/kWh) from 960GWh as the financial benefit of its project.

FIRR resulted in 6.1 in the coal case for pumping energy and resulted in 7.8 in the conventional hydropower case for pumping energy. Consequently, it can be said that PSPP project has high viability in financial aspects.

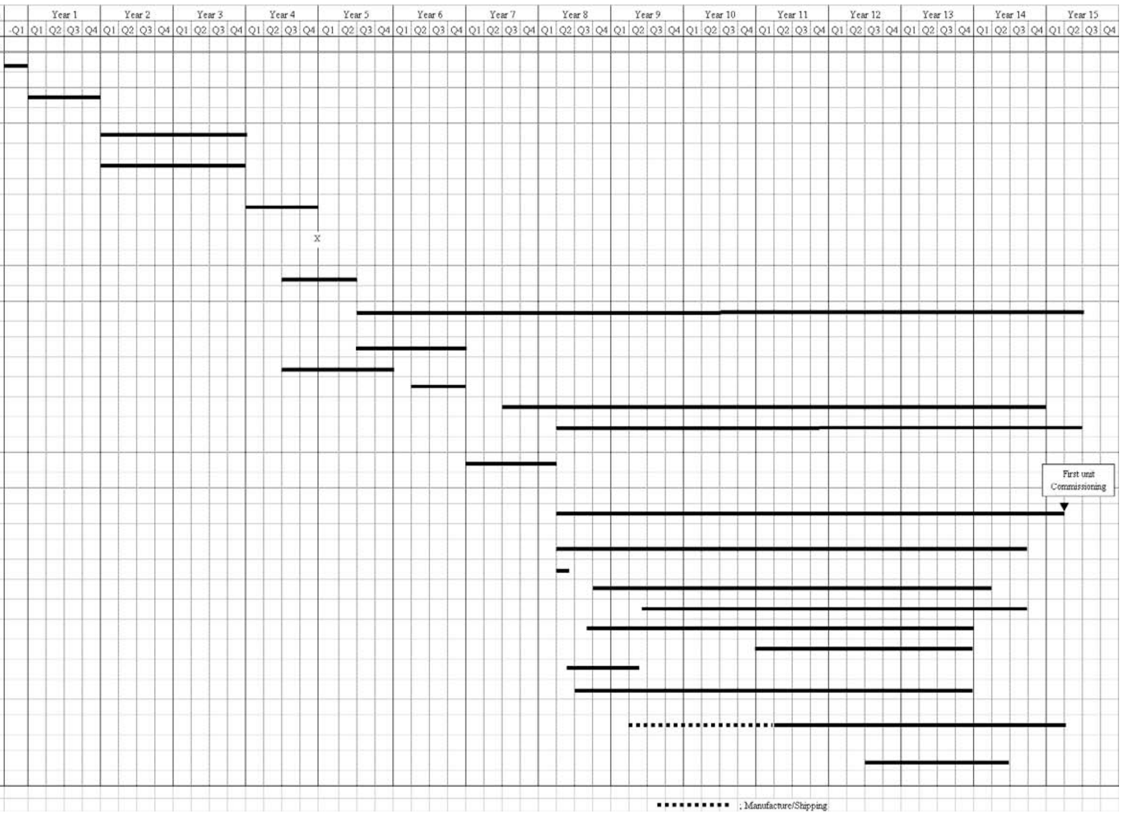
(5) Proposed Development Schedule

The proposed development schedule for the PSPP project is shown in Table 4-8.

The entire implementation period of the project will take approximately 14 years at the earliest after the start of the Feasibility Study. Provided that the preliminary study for the Feasibility Study will be started in the next year following the completion of this master plan study, the completion will be in 2019 and the operation of the first power plant will be commenced in the same year.

Table 4-8 Proposed Development Schedule

Description	Duration Quarter Months
Evaluation M/P Study	4
Preliminary Study for F/S	12
Feasibility Study	24
Environmental Impact Assessment	24
Project Financing Procurement	12
Preject Approval to Proceed	0
Financing Study for ES	12
Engineering Services	120
1.Tender Design	18
2.Additional Investigation	18
3.Preparation of Tender Documesnts	9
4.Detailed Design	66
5.Construction Supervision	75
Tender Procedure	15
Construction	72
(Civil Works)	66
1.Mobilization	2
2.Upper Dam & Reservoir	54
3.Waterway & Underground Structure	50
4.Service Tunnel	52
5.Switch Yard	24
6.Road Works	12
7.Lower Dam & Reservoir	54
(E & M Works)	48
(Transmission Line)	18



Chapter 5. Feasibility of Developing Peaking Power Supply

5.1 Feasibility of developing Conventional Hydropower for Peaking Power Supply

(1) Situations and Development Plan of Conventional Hydropower

In Vietnam, eight (8) large hydropower plants (the total capacity of about 3,945MW) are in operation. Some of them have to release water through a spillway without generation in the rainy season. This is called ineffective discharge.

In order to utilize ineffective discharge, JETRO conducted a feasibility study of the Thac Mo extension project in the Be river system. As a result, an extension plan with the additional capacity of 75MW has been incorporated in the revised 5th master plan.

From the view point of utilization of the hydropower resources, feasibility of the extension of Tri An, which is the second largest existing hydropower station next to Hoa Binh, is carried out in this study. In addition, economic advantages of large conventional hydropower plants planned for peaking supply, which are Huoi Quang and Ban Chat, are compared with other peaking sources including PSPP.

(2) Preliminary Study for Tri An Hydropower Station Extension Project

a. Existing Tri An Hydropower Station

The existing Tri An hydropower station (Tri An PS) is located in the middle reach of Dong Nai River in Dong Nai province. The Tri An PS has been operated in full capacity since 1991. The major features of the existing Tri An PS comprise of the main dam on the Dong Nai River together with a spillway, three earthfill dike dams, four underground penstocks and a 400 MW power station. The reservoir has a surface area of 323 km^2 and an effective storage capacity of 2,547million m^3.

Table 5-1 Main Project Feature of Existing Tri An PS

Installed capacity (MW)	400
Plant Discharge (m^3/s)	880
Effective head (m)	52
Annual generated energy (GWh)	1,700
Plant Factor (%)	49

b. Reservoir Operation Study for Estimate of Power Outputs

In order to estimate power outputs (=90% firm peak power and annual average energy) from the extension project, reservoir operation study for the Tri An reservoir are carried out considering the hydropower projects, which are supposed to directly affect reservoir operation on the Tri An PS, and are under operation, construction and planning stage in the Dong Nai River basin as follows.

- Ham Thuan - Da Mi hydropower projects ·········· under operation from 2001
- Dai Ninh hydropower project ····················· under construction
- Dong Nai No.3 & 4 hydropower project············ currently being planned

In this study, installed capacity for the extension project is preliminary assumed to be 100MW, which is the same as one unit capacity in the existing Tri An PS (400MW= 4 units×100MW).

Firstly, 95% firm discharge of the Tri An reservoir was calculated and resulted in 327m³/s. Then, the reservoir operation study was carried out for two cases of "Without Extension" and "With Extension" in order to estimate power output from each case. Results of the reservoir operation study are presented in the following table.

Table 5-2 Results of Reservoir Operation Study With and Without the Extension Project

	Without Extension	With Extension	Extension Project
95%Firm discharge (m^3/s)	327		
Min. operation hours (hours)	8.9	7.0	7.0
Installed capacity (MW)	400	500	100
Effective head (m)	52	52, 47	47
Maximum Discharge (m^3/s)	880	1,125	245
90% firm peak power (MW)	354	441	87
Generated energy (GWh/year)	1,863	1,952	89
Plant factor (%)	53	45	45
Rate of spillway discharge (%)※	9.4	3.4	3.4

※Rate of spillway discharge to total inflow volume

c. Project Evaluation

Regarding Phu Yen East PSPP project, economic viability was evaluated by means of the B/C method, which was the same method applied to economic evaluation of the extension project. The B/C of the extension project is shown to be 1.42. The B/C value of 1.42 is almost same as that of 1.47 for Phu Yen East PSPP project, whose pumping up resource is hydropower.

FIRR of the extension project was preliminary calculated by calculating power revenue which resulted in 9.1%. The FIRR value of 9.1% is higher than that of 6.8% in the Thac Mo Extension project. Consequently it can be said that the extension project has high viability in terms of not only economic and also financial aspects.

(3) Power Extension of Conventional Hydropower Plant in the Northern Region

a. Power Development Plan for the Da River Basin

Regarding to the power development plan of the Da River, four (4) new dams as shown in Table 5-3 are planned for power development including the Son La dam.

After commencement of Son La dam, 7 billion m³ of flood storage capacity in total is planned in the Da River, in which 4 billion m³ is bore by Son La and 3 billion m³ is designated to Hoa Binh.

Table 5-3 Power Development Plan for Da River Basin

Project Name	unit	Hoa Binh (Existing)	Son La	Nam Nhum	Ban Chat	Huoi Quang
River System	-	Da	Da	Da	Nam Mu	Nam Mu
Province	-	Hoa Binh	Son La	Lai Chau	Lao Cai	Lao Cai
Catchment Area	km^2	51,700	43,760	26,000	2,017	2,930
Installed Capacity	MW	1,920	2,400	1,200	200	560
Annual Energy	GWh	9,298	8,892	4,423	734	1,957
Effective head	m	109	99	96	96	181
Effective capacity of reservoir	10^6m^3	5,650	5,871	759	1,380	126
Flood capacity	10^6m^3	3,000	4,000	0	0	0
Dam type	-	Rock/Earth	Concrete	Concrete	Concrete	RCC

Source: PECC1

b. Simulation Study for Optimization of the Ban Chat and Huoi Quang Hydropower

95% firm discharge and annual generated energy of the Ban Chat and Huoi Quang hydropower were simulated based on the latest plans and river discharge data during the past thirty years from 1966 to 1995.

First, a 95% firm discharge of the upstream Ban Chat was calculated with the differential mass curve. Then reservoir operation study was carried out to estimate monthly generation. The calculation of firm discharge and reservoir operation study for the downstream Huoi Quang reservoir were carried out in the same way.

The monthly inflow of Huoi Quang reservoir has been defined as the value of the outflow of Ban Chat Dam Power Station (as a result of simulation), added with the inflow of tributaries between the dams, taking into consideration of the regulation of Ban Chat Dam.

c. Optimum Installed Capacity

The Optimum installed capacity varies with the pear duration hours, which is required by power network operation. In this study, the optimum installed capacity of which the maximum B/C value is evaluated for each case of the peak operation duration of 7,6,5 hours.

Evaluation results of B/C and B-C in case of seven hours of the required peak duration hours, which is evaluated by the simulation study for the peak power supply optimization and is described later, are presented in Figure 5-1.

The left graphs show the optimum installed capacity of Huoi Quang hydropower when the capacity of Ban Chat hydropower is 200MW. The right graphs show the optimum installed capacity of Ban Chat hydropower when the capacity of Huoi Quang hydropower is 540MW.

In conclusion, the respective installed capacities of the current development plan, which are 200MW of Ban Chat and 540MW of Huoi Quang, are deemed the best choice.

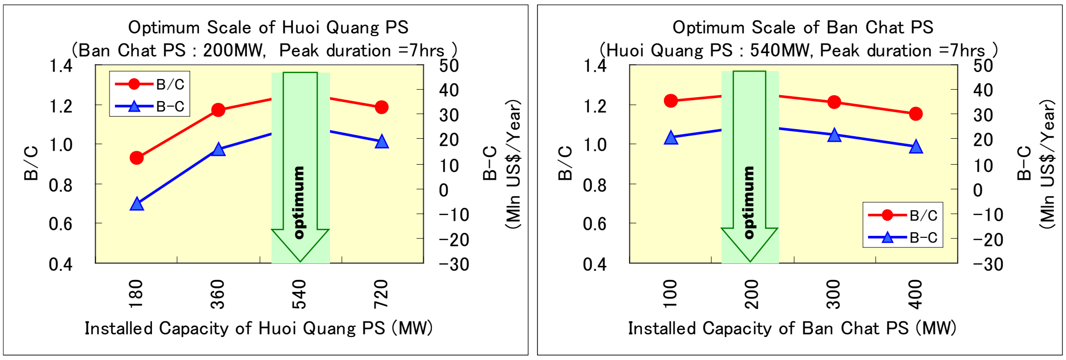


Figure 5-1 Optimum Installed Capacity of Ban Chat and Huoi Quang Hydropower Projects in Case Peak Duration of 7 hours

5.2 Other power sources

(1) Applicability of gas TPP Development in the North

The potential of gas in the north region has not been found as sufficient for generation. Thus, it is assumed that gas thermal power development is applicable only in the central and south region.

(1) Applicability of coal TPP Development in the South

Since gas TPPs have been planned and developed as a main power source in the south, early depletion of the gas resource and the possible appreciation of gas prices due to an increase of exploitation and transport expenses of gas is a concern. Therefore, the JICA Team studied that economical efficiency of coal TPP development in the south using domestic coal in the north. In case that coal TPPs are developed in the south as a basic power source, gas TPP can be back on form and operated as a middle and/or peaking power source.

A geographical study of the seacoast from lat. 45° N to the south was carried out using topographical map of 1/50,000 and seven candidate sites were nominated (refer to Fig 5-2).

JICA Team selected three sites of Phong So, Vinh Hy, and Son Hai which have favorable conditions among seven nominated sites, and drew up a layout of the plant facilities and estimated the construction costs. Then the unit generation cost of each power plant at the busbar was calculated under the following assumptions.

Two kinds of coal, anthracite and sub-bituminous coal reserved under the Red river delta, were considered. Port and harbor facilities such as breakwater, berth, reclamation and ash disposal are designed assuming that 30,000 – 50,000DWT tanker is used for transportation of coal from the north to the south. The transportation fee from Haiphong port to the site is estimated based on that to Ho Chi Minh City of 7US$/ton as stated by Vinacoal.

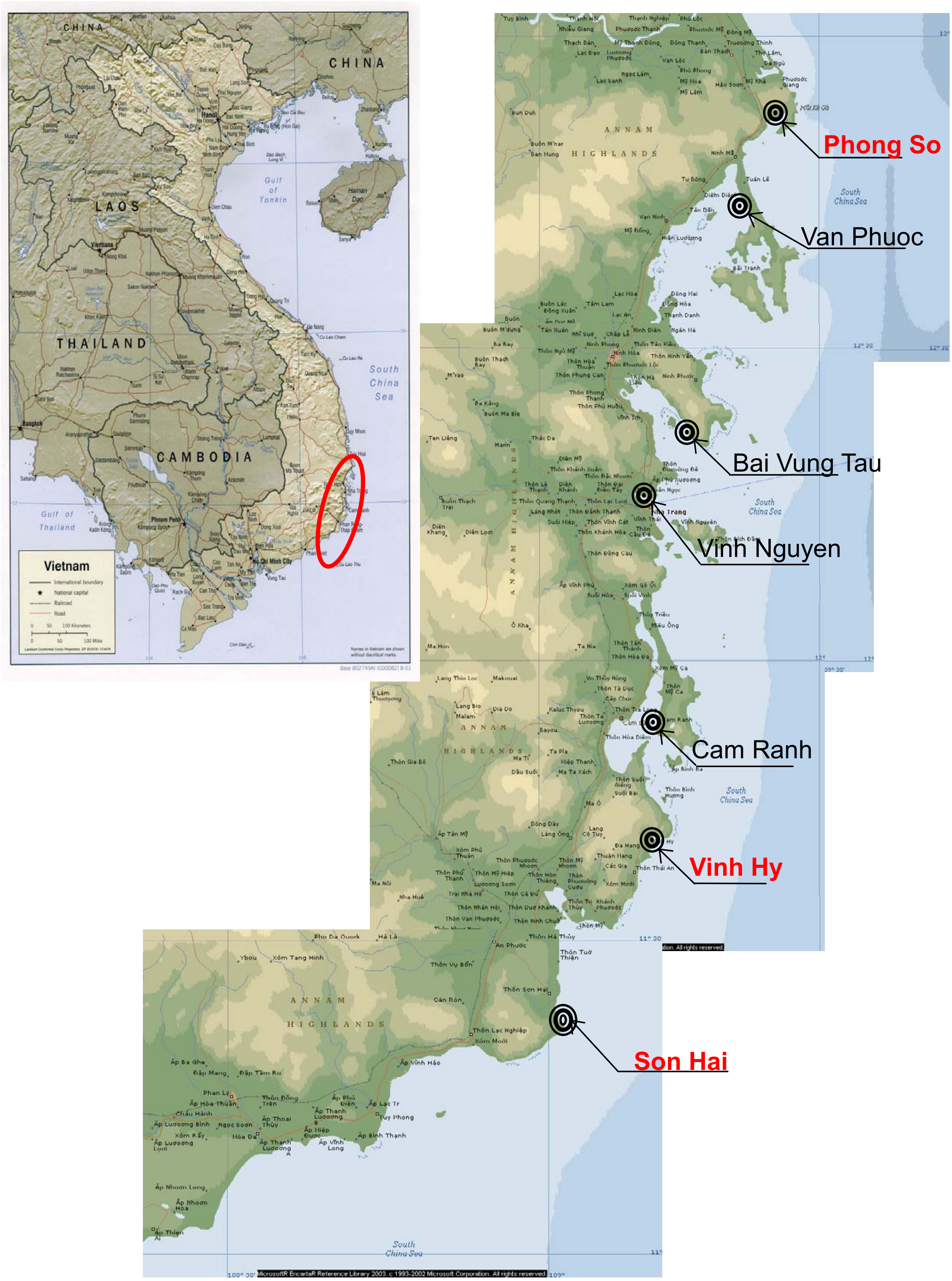


Figure 5-2 Location of 7 Candidate Sites of coal TPP in the South

Unit generation cost at the busbar of each power plant as of 2003 is shown in Table 5-4. Order of economical efficiency is Pkong So, Son Hai and Vinh Hy. Every unit generation cost is cheaper than GTCC's 3.75 UScents/kWh.

Table 5-4 Unit Generation Cost

Capacity factor= 75.0% Station service rate = 7%

Coal	Heat value (Kcal/Kg)	Coal price FOB(VND/t)	Total Cost (USc/kWh)								
			Phong So			Vinh Hy			Son Hai		
			case1	case2	case3	case1	case2	case3	case1	case2	case3
Hon Gai #3	7,100	432,040	3.54	3.46	3.50	3.74	3.67	3.70	3.67	3.61	3.64
Hon Gai #4	6,050	332,000	3.49	3.40	3.44	3.69	3.61	3.65	3.62	3.55	3.58
Hon Gai #5	5,500	305,000	3.53	3.42	3.47	3.72	3.63	3.68	3.65	3.57	3.61
Red River V3	5,100	305,000	3.28	3.16	3.22	3.47	3.38	3.42	3.40	3.32	3.36

transportation cost /Haiphong to Son Hai: 1,100 km
case1: 7.0US$/t (same as Haiphong to Ho Chi Minh City:1,500km by 6,000DWT)
case2: 5.1US$/t (=7/1,500*1,100)
case3: 6.1US$/t (=7/2+7/2/1,500*1,100)
/Haiphong to Vinh Hy: 1,050 km
case1: 7.0US$/t (same as Haiphong to Ho Chi Minh City:1,500km by 6,000DWT)
case2: 4.9US$/t (=7/1,500*1050)
case3: 6.0US$/t (=7/2+7/2/1,500*1050)
/Haiphong to Phong So: 950 km
case1: 7.0US$/t (same as Haiphong to Ho Chi Minh City:1,500km by 6,000DWT)
case2: 4.4US$/t (=7/1,500*950)
case3: 5.7US$/t (=7/2+7/2/1,500*950)

In conclusion, coal TPP development in the south using domestic north coal can improve the whole power system efficiency in Vietnam.

Chapter 6. Master Plan on Optimization for Peaking Power Supply

6.1 Preliminary Study of Optimization of Peaking Power Supply

(1) Efficient Simulation Tool for Optimizing Peaking Power Supply

Vietnam terrain covers 1,650km from the North to the South, where electricity demand is concentrated in Hanoi in the North and in Ho Chi Minh City in the South. The primary energy resources such as coal in the North and gas in the South are often unevenly distributed.

WASP has been utilized for the power system development planning as a simulation tool for optimizing power sources composition so far, which can simulate only one power system at a time. Therefore, the above specific circumstances of Vietnam could not be taken into account in the simulation.

Since WASP can not simulate daily operations, it is impossible to build an optimum peak power supply plan when taking into account the daily capacity adjustment of each power source.

Accordingly, the JICA study team decided to use PDPAT II, developed by Tokyo Electric Power Co. (TEPCO) as a simulation tool for the peak power supply optimization study. PDPAT II claims many practical accomplishments in the power system development planning of TEPCO and can simulate various interconnected power systems and daily operations.

Table 6-1 Function of PDPAT II

	PDPAT II	WASP IV
Number of Systems	Max. 10	1
Unit of Simulation	Daily	Monthly
Simulation of PSPP	Yes (daily)	Yes (monthly)
Time for Simulation	< 1 sec.	< 1 hr

(2) Comparison of Generation Costs of Peak Supply

The screening curve analysis is conducted by the type of generation in 2020 for preparation of the development scenarios of peak supply in Vietnam.

In this examination, fixed costs consist of depreciation and O&M costs. Variable costs correspond to the fuel costs in 2020. The difference in heat rates by capacity factor is also considered. The efficiency of pumping for PSPP is 70%. The discount rate is 10%. Conditions for screening curve analysis are shown in Table 6-2.

Table 6-2 Conditions for Screening Curve Analysis

	Construction Cost	Life time	Annual O&M Cost Rate	Fuel cost	
PSPP	650US$/kW	40	1.0%	Hydro 0 ¢ /kWh	Coal 2.1 ¢ /kWh
GT	400US$/kW	20	5.0%	3.9 ¢ /kWh	
CC	600US$/kW	25	4.5%	2.4 ¢ /kWh	
Coal	938US$/kW	30	3.5%	1.5 ¢ /kWh	
Diesel	800US$/kW	15	3.0%	9.0 ¢ /kWh	

The results of screening within the capacity factor of 10% are as follows: (Figure 6-1, Figure 6-2)

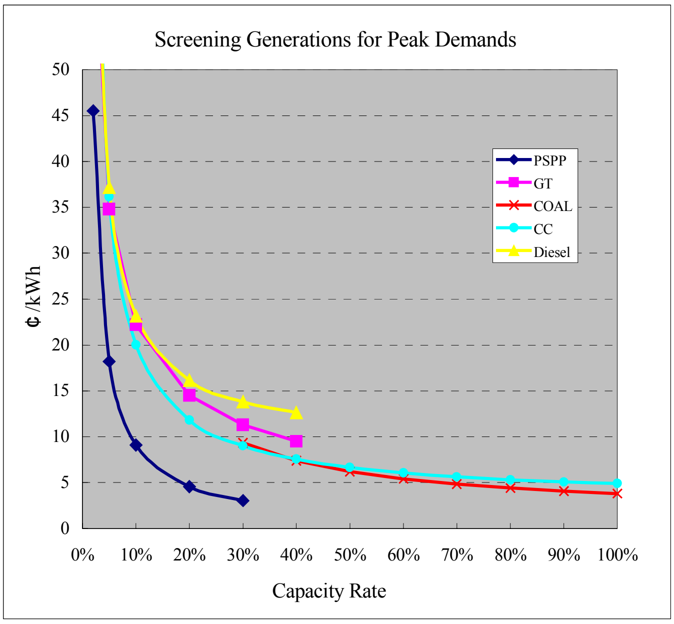


Figure 6-1 Generation Costs vs Capacity Rate in 2020

Pumping Energy; Coal case

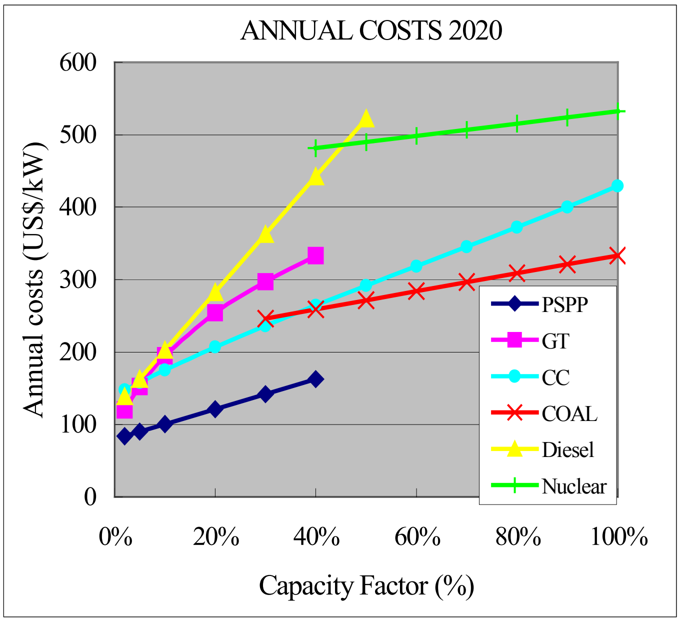


Figure 6-2 Annual Costs in 2020

Pumping Energy; Coal case

At the capacity factor of 5% or less, the pumped storage hydro power plant (PSPP) has an economic advantage as a peak power source, followed by gas turbines (GT) and combined cycle power plants (CC).

With the capacity factor of 10%, PSPP and CC still maintains a cost advantage.

Coal and hydropower are considered for pumping energy. Even in Case 1, which uses coal for pumping, PSPP has an economic advantage over CC.

(3) Current and Forecasted Peak Demand

a. Daily Load Curve of the IE Forecast

The actual record of peak demand in 2002 was 6,552MW. The peak demand in 2020 is examined based on the actual data and forecasts prepared by IE[1].

The daily load curve on the day of peak demand on Dec. 6th, 2002 (Figure 6-3) shows two peaks; one in the morning and one in the evening. The duration of both peaks lasted for 4-5 hours, of which the evening peak was 1,722MW between 6,552MW and 4,830MW. This was equivalent to 26% of the peak demand, which is similar to that of the average weekday load curve in 2002 (Figure 6-4).

In order to meet this peak demand, it is necessary to consider peak power sources with the plant factor of 15 – 20%.

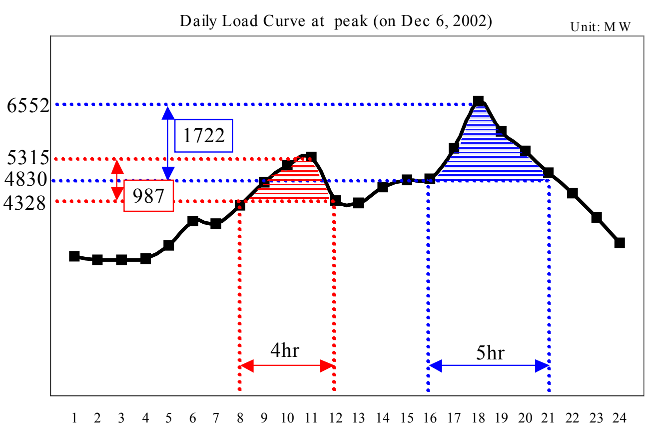


Figure 6-3 Daily Load Curve (peak demand day)

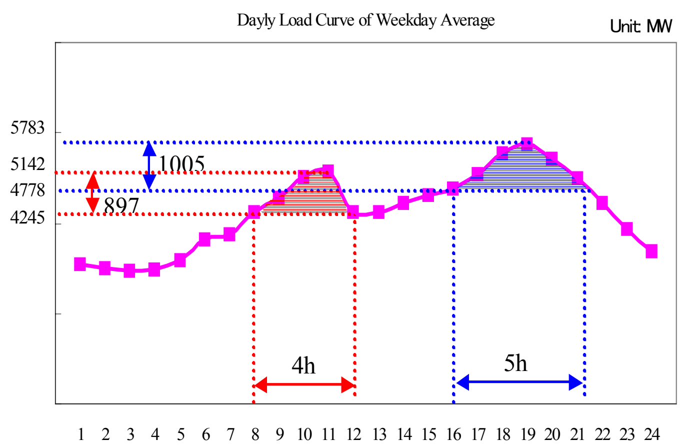


Figure 6-4 Daily Load Curve (weekday average)

IE's forecasted peak demand in 2020 is 32,375MW. That is five times as large as the actual peak demand in 2002. The load factor is forecasted to reach 71%, which is greater than the actual record of 64%. Seasonal demand fluctuations in the Vietnam system are less remarkable compared to daily fluctuations. Thus, although an increase in load factor could raise the daily bottom demand, its impacts on load profiles are limited. The load curve in 2020 is assumed to be similar to the actual record in 2002 (Figure 6-5).

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[1] The revised 5th MP in Jan. 2003 provided by IE.

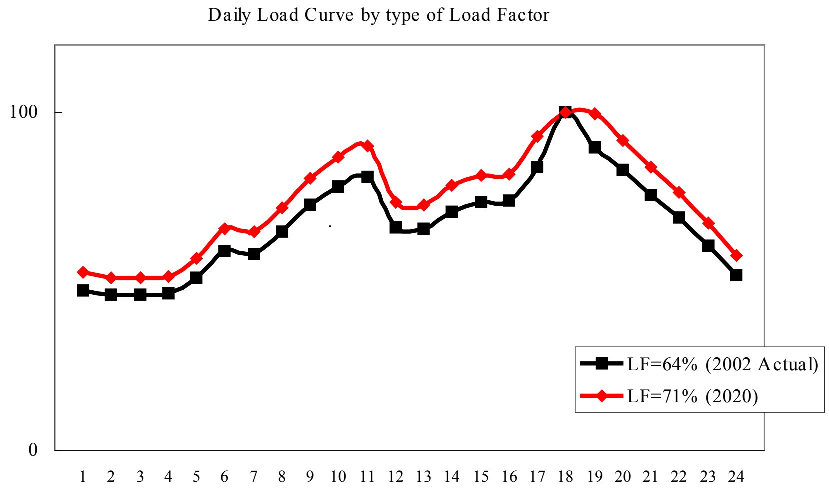


Figure 6-5 Estimation of Changing Load Profile

(Load Factor 64%vs.71%)

b. Impacts of the Peak Shift from Nighttime to Daytime

Considering the peak shift from nighttime to daytime, the necessary peak power supply is examined based on the daily load profiles presented in this study. The duration of peak demand is 3.5 – 7 hours in a day. These peak demands are between 1,400MW and 2,080MW, which are more concentrated in the daytime as a result of the peak shift.

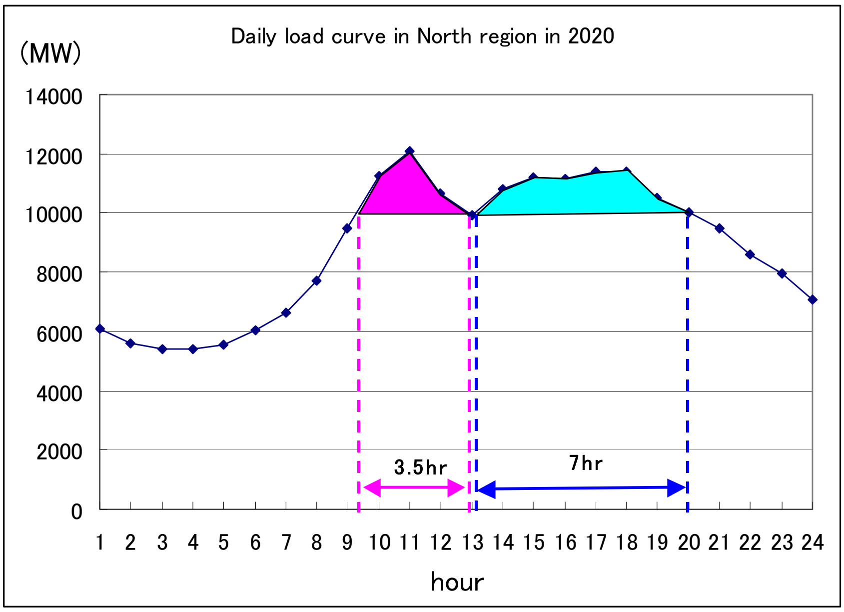


Figure 6-6 Daily Load Curve at Peak Demand in 2020 (in Peak Shift Demand)

(4) Appropriate Reserve Margin based on System Reliability Criteria

a. System Reliability Condition in the Revised 5th Master Plan

1) System Reliability of the Whole System

The relation between system reliability and the reserve margin is analyzed for the whole system in 2020 based on the revised 5th master plan. 9% of reserve margin, which is equivalent to 2,930MW, is necessary to satisfy the system reliability criteria. The supply capacity of 35,540MW is necessary to meet the system reliability criteria.

2) System Reliability of the Divided System

The analysis of system reliability in the divided systems is conducted based on the revised 5th master plan, the capacity of interconnection adopted two cases: 0MW and 2,200MW.

In the case of the interconnection capacity of 0MW in the N system, with a 19% reserve margin that is equivalent to 2,300MW, it is necessary to satisfy the system reliability criteria. In the C&S system, the 9% reserve margin that is equivalent to 1,850MW, it is necessary to satisfy the system reliability criteria. There is a difference of approximately 450MW of reduction in the reserve margin between that with and without the interconnection.

b. Relation between Capacity of Interconnection and Reliability Improvement

The relation between the amount of reduction in power development and interconnection capacity is analyzed. The increase in interconnection capacity brings the possibility of reduction in power development because demand diversity[1] among interconnected systems enhances the mutual generation utilization. The amount of reduction achieved by interconnection is calculated by RETICS as the tool of system reliability analysis (Fig 6-7).

The amount of reduction is saturated at approximately 450MW, when the interconnection capacity is at 1,000MW. Thus, the interconnection capacity of 1,000MW is the optimal capacity in which system reliability improvement should be made.

[1] The characteristic of a variety of electric loads vary, whereby individual maximum demands usually occur at different times due to differences in time and weather conditions. When a system is in peak demand, it is likely that the other systems do not have peak demands. Therefore, the system can use extra generation through interconnections. The interconnected systems can reduce their reserve margin together.

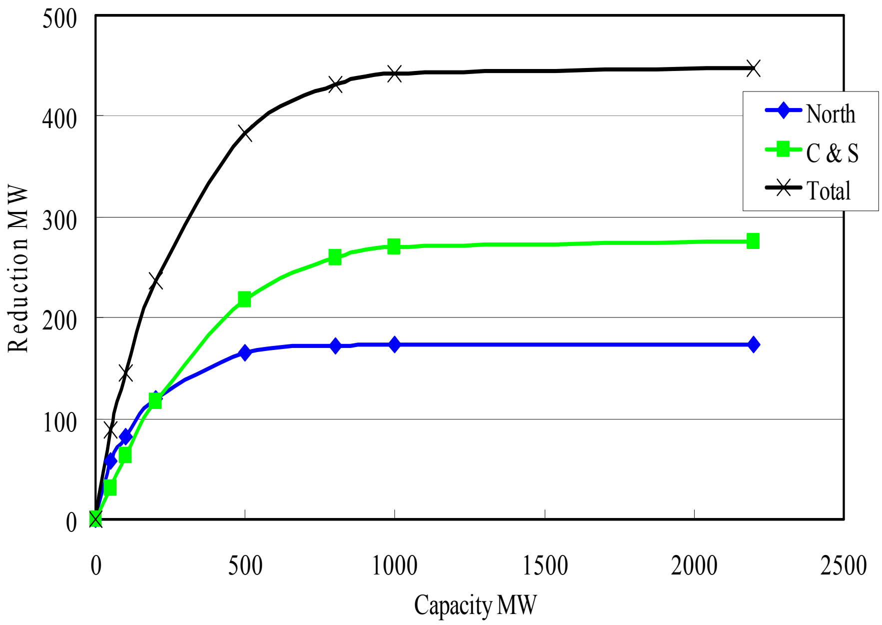


Figure 6-7 Relation between Amounts of Reduction in Power Development and Interconnection Capacity

6.2 Study on the Optimal Composition of Power Development Focusing on Peaking Supply

First, power development plans for the whole system of Vietnam which satisfy the LOLE 24 hours system for reliability criteria are made based on the 5th revised master plan. The most economical power development plans, functioning as minimum annual cost plans focusing on peaking supply, are examined by a supply and demand simulation of the power development cases using PDPAT II.

In the next step, power development plans for the systems, which are divided between the north and central and south, will be made to satisfy the system reliability criteria as well as the whole system. The power development plans for divided systems are examined by the simulation to find out the most economical cases focusing on peaking supply. The most economical capacity of interconnected facilities between the north and central and south systems is examined considering the optimal operation of power plants between the systems through the interconnection. The optimal power development plan is found through the examination as an economical aspect.

(1) Establishment of Power Development Plans for the Simulation

The scenarios are established considering the limitations of the Vietnam system in 2015 and 2020. The cases for simulation are based on the scenarios considering the alternatives such as the impact from the development of Son La hydro power station, a power purchaser from neighboring countries and the capacity of the interconnection. The cases are simulated considering the risks such as demand viability, soaring fuel prices and a delay of power purchasing from neighboring countries. It is evaluated in terms of the supply and demand simulation of how the risks affect annual costs.

Table 6-3 Scenarios for the Simulations

	Pumped storage hydro	Gas turbine	Combined cycle
Target years	2015, 2020	2015, 2020	2020
Power system	Whole, North, South	Whole, South	Whole, South
Installed capacity	0 - 10%	0 - 10%	14BCM– 16BCM*
Capacity of interconnection	800,1300,2200MW	800,1300,2200MW	800,1300,2200MW
Son La’s construction	2,400 or 0	2,400 or 0	2,400 or 0
Demand forecast	Base, Load Profile	Base, Load Profile	Base, Load Profile
Power Purchasing from China, Laos, Cambodia	Laos, None	Laos, None	Laos, None
Soaring fuel prices	Base, ×2	Base, ×2	Base, ×2

* Considering the limitation of Gas potential

The north system currently has insufficient gas potential. The sources of power development in the north system in the year 2020 are hydro and coal. The sources of power development consist of mainly gas-fired thermal power. The features of power supply are reflected in the simulation. The simulation is conducted considering the limitation of gas development[1] and the installing of coal power in the south system. The details of scenarios are described in the following section.

The basic scenarios of power development for the whole system are arranged with future power plants to meet the system reliability criteria based on the 5th revised master plan. The planned PSPP (1,000MW) and the power purchasing from neighboring countries, which is reflected in the interview with MOI, are excluded from the base case in order to conduct the sensitive analysis of peaking supply.

[1] Particularly, the limitation affects availability of GT installation in the north system.

(2) Necessary Supply Capacity to Secure the System Reliability Criteria

a. Balance between Supply and Demand in the 5th Revised Master Plan

First of all, the balance between supply and demand in the 5th revised master plan in 2020 is observed. The total supply capacity is 42,161MW. The system reliability is LOLE = 0.08hr. The reserve margin is 19.3%. The system reliability criteria are satisfied when the Vietnam system is treated as a mono system.

b. Appropriate Installed Capacity to Secure System Reliability

The installed capacity for whole system to meet the system reliability criteria is 5.0% less than that listed in the 5th revised master plan. In the case of divided systems with no interconnection, the necessary installed capacity to secure the system reliability is: in the north system 0.4%, the central and south system 5% and the system total 3% less than the 5th revised master plan. The changes in the reduction of 1,300MW in the central and south system and an additional 65MW in the north system are necessary for the divided system to secure the system reliability criteria.

c. Effects from Interconnection and Demand Forecast to Appropriate Installed Capacity

The adjusting of the development plan is necessary to secure the system reliability and to consider the limitations of interconnection. In the case of the IE demand forecast, thermal power development of the central and south system can be delayed by 5% to 6% of the present plan. In the case of the peak shift considering demand, an additional 4% of thermal power development is necessary for the north system to secure thesystem reliability. 2% of thermal power development can reduced in the central and south system.

In terms of the IE demand forecast, approximately 800 MW of additional coal thermal power development is necessary for the north system to compensate for reductions in the power purchase of 1,000 MW from China and Cambodia. The arrangement causes the annual costs to increase from US$9,230 mil to US$9,276 mil/yr in 2020. The increment is equivalent to 0.5% of fuel costs.

(3) Study on Peak Supplies in 2015

a. Results of Simulation of Balance of Supply and Demand

The results of the balance of supply and demand simulation are shown in Table 6-4.[1]

[1] The results are from the cases of installation of peak supplies respectively. They do not describe the cases of complex installation of peak supplies.

Three patterns of a peak supply installation are selected to install the systems. The pumped storage hydro is installed in the north system or in the central and south system. The gas turbine is installed in the central and south system. The gas turbine installed in the north system is not simulated because the gas potential is not in the north region.

The case of 2.0% PSPP installation in the north system is the most economical in the peak shift demand in 2015. There is no economical case of PSPP installation in 2015 for the IE demand forecast. The duration of daily peak demand of the peak shift demand forecast is longer than the duration in the IE demand forecast. The long duration of daily peak demands requires longer operation of hydropower. The long operating times of hydropower plants cause a latent output of hydropower. Additional peak power supply will be needed to compensate for the insufficient supply of hydropower.

Regarding the effects of the interconnection capacity, the benefits of peak supply installation are reduced because greater interconnection capacity among systems can utilize the peak supply.

Table 6-4 Appropriate Composition and Annual Costs

(Unit: %, US$ mil/y)

Scenario		PSPP in N		PSPP in S		GT in S	
Demand	Interconnection capacity	%	US$ mil/y	%	US$ mil/y	%	US$ mil/y
Peak shift	Whole system	1.6	6,546	1.6	6,546	0	6,582
	0MW	2.3	6,903	0	6,944	3.1	6,640
	800MW	1.8	6,644	0	6,692	4.2	6,368
	1,300MW	1.8	6,609	0	6,626	4.2	6,241
	2,200MW	0.6	6,586	0.6	6,587	4.1	6,245
IE	Whole system	3.4	6,320	3.4	6,320	5.1	6,314
	0MW	1.0	6,679	1.0	6,667	1.7	6,912
	800MW	0	6,489	2.1	6,457	3.6	6,606
	1,300MW	0	6,336	0	6,336	2.3	6,564
	2,200MW	0	6,328	0	6,328	2.4	6,532

Notes) PSPP in N: Case of PSPP installation in the north system
PSPP in S: Case of PSPP installation in the central and south system
GT in S: Case of GT installation in the central and south system

b. Effects of Son La's Construction

The effects of the development of Son La, with a 2,400MW capacity, are examined by the simulation of the balance of supply and demand in 2015. The development does not affect the composition of peak supply. PSPP installation shows significant benefits, with regards to peak shift demand with a 1,300MW interconnection.

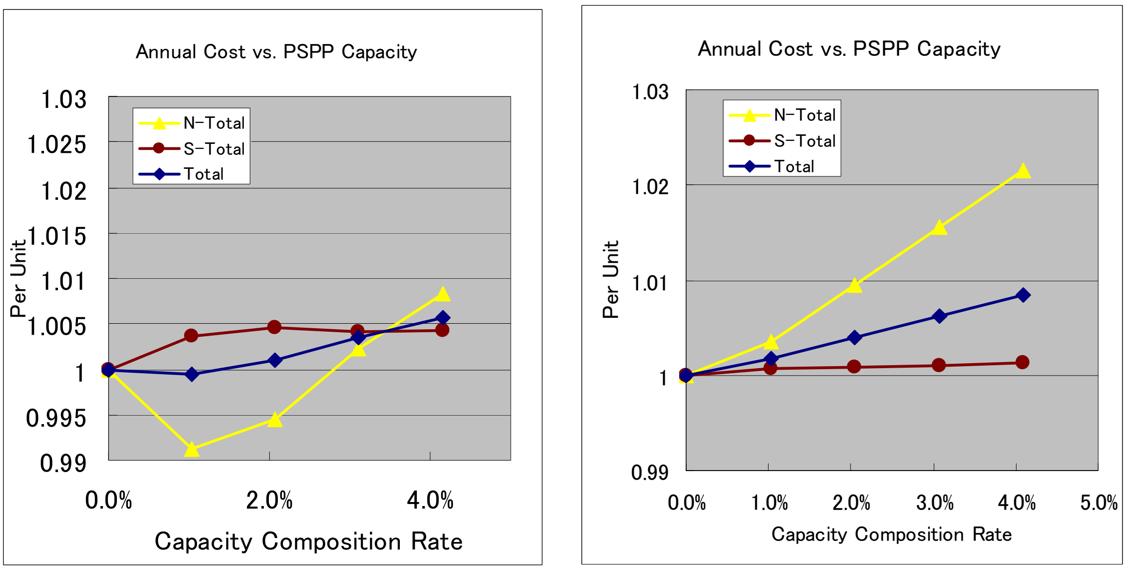
Table 6-5 Effects of Son La's Construction

Demand forecast	Interconnection	PSPP in N		PSPP in S	
		Installation rate	Annual costs US$ mil/y	Installation rate	Annual costs US$ mil/y
Peak shift	Whole system	0%	6,607		
	1,300MW	1.2%	6,538	0%	6,542
	2,200MW	0%	6,538	0%	6,538
IE	Whole system	0%	6,475		
	1,300MW	0%	6,285	0%	6,542

The reason for no change in the composition of peak supply installation is that coal thermal power is being developed for the compensation of Son La hydropower. Coal development can increase the base supply from 4.8GW to 5.8GW. In turn, the increase of the base supply can cause hydropower surplus supply to meet peak demand. Thus, the capacity of the additional peak supply is reduced.

c. Scenarios of Gas Turbine Installation

The gas turbine installation reduces annual costs in 2015, based on the results of the simulation. (Table 6-8) The reduction caused by the gas turbine heat rate is 2 to 5% better than that of alternative thermal power plants, of which the construction costs are 50% lower than the alternative. When the high heat rate of gas turbine installation takes the place of the planned thermal power plants during 2010 to 2015, the annual costs could be reduced by US$4 mil/Yr.



Zero power purchasing | Power purchasing from Laos, Cambodia

Figure 6-8 PSPP Installation vs. Annual Costs (Interconnection 1,300MW in 2015)

(4) Study on Peak Supply in 2020

a. Results of Simulation between Supply and Demand

The cases of simulations in 2020 are selected in the same manner as the simulations in 2015. The results of the simulation of balance between supply and demand are shown in Table 6-6.[1] In the case of peak shift demand, the composition of 3 – 4% of PSPP installation in the north system is the most economical in 2020. The case of 1 to 2% of PSPP installation in the north system is the most economical in 2020, in terms of the IE demand forecast.

Table 6-6 Relation between Appropriate Composition and Annual Costs in 2020

(Unit: %,US$ mil)

Scenario		PSPP in N		PSPP in S		GT in S	
Demand	Interconnection	%	US$ mil/y	%	US$ mil/y	%	US$ mil/y
Peak shift	Whole system	0	9,621	0	9,621	0	9,621
	0MW	3.7	9,875	0	9,956	0	9,973
	800MW	3.5	9,650	0	9,727	0	9,729
	1,300MW	3.5	9,618	0.6	9,663	0	9,667
	2,200MW	2.4	9,598	1.8	9,588	0	9,622
IE	Whole system	0	9,400	0	9,400	1.2	9,397
	0MW	1.2	9,546	0	9,592	0	9,592
	800MW	1.2	9,307	0	9,341	0	9,341
	1,300MW	1.2	9,260	0	9,276	0	9,276
	2,200MW	0	9,233	0	9,233	0	9,233

Notes) PSPP in N: Case of PSPP installation in the north system
PSPP in S: Case of PSPP installation in the center and south system
GT in S: Case of GT installation in the centrer and south system

b. Effects of PSPP Installation in the Peak Shift Demand to Reduce Annual Costs

1) Cases of PSPP Installation in the North System

In the cases of peak shift demand, the minimum annual cost is around 3.7% (1,500MW) of PSPP installation in the north system, excluding the interconnection capacity of the 2,200MW cases. In the case of interconnection capacity of 2,200MW, the most economical case is around 2.4% (1,000MW) of PSPP installation capacity. The amount of annual costs reductions are 24US$ mil/Yr to 97US$ mil/Yr. These are at most, 1% of the total annual costs.

[1] The results are in the cases of installation of peak supplies respectively. They do not describe the cases of complex installation of peak supplies.

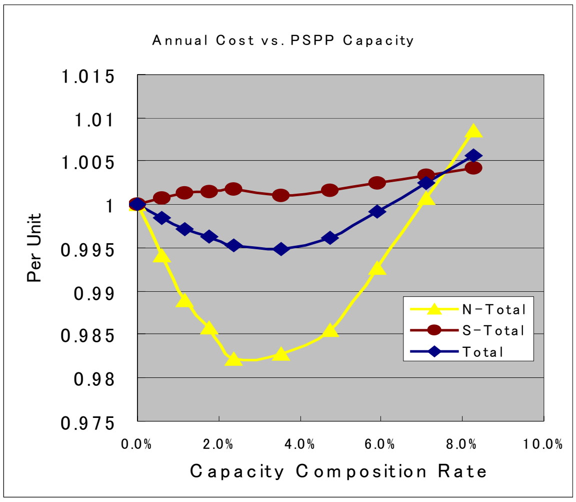


Fig. 6-9
Relation between PSPP Installed Capacity (North) and Annual Costs (Peak shift demand with interconnection of 1,300MW in 2020)

In the case of interconnection capacity of 1,300MW, annual costs will fall to 49US$ mil/Yr. (Fig. 6-9)

The benefits from PSPP installation in the north system are achieved by a reduction in fuel consumption. PSPP can use the off-peak surplus supply capacity to pumping energy in the daytime. The results of simulations indicate that the annual costs reduction is present in fuel costs of the north system, but the fuel costs increase in the center and south system after installing PSPP in the north. The utilization of the off-peak surplus power for pumping energy brings about a reduction in power exchange to the central and south system. Thermal power in the south system would increase supply after the PSPP installation in the north system.

The results indicate the utilization of spilled water to pump up energy to improve system efficiency.

2) Case of PSPP Installation in the Central and South System

In the case of PSPP installation in the central and south system, the annual costs do not change until the point of installation of 1.8% (750MW) due to the balancing of the construction costs of PSPP and alternative thermal power due to latent capacity of PSPP. (Fig. 6-10).

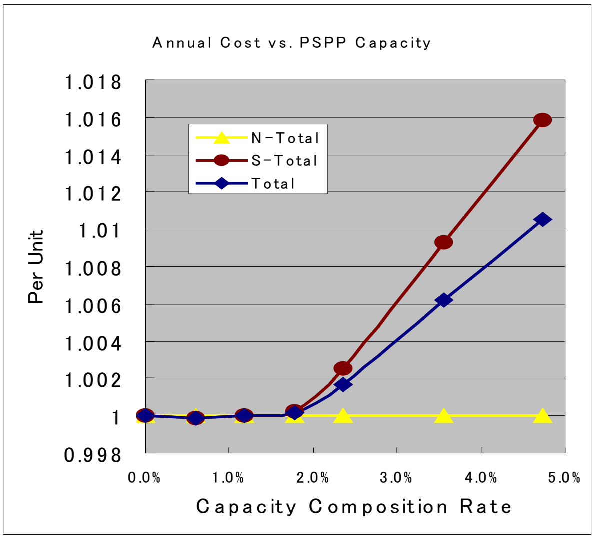


Fig. 6-10
Relation between PSPP Installed Capacity (C & S) and Annual Costs (Peak shift demand with interconnection of 1,300MW in 2020)

The construction costs per supply capacity of PSPP increase at 2.4% (1,000MW) of installation capacity because the insufficient capacity of PSPP increases as well. The increase of PSPP construction costs exceeds the construction costs of alternative thermal powers.

In the center and south system, the off-peak supply is also used for gas-combined cycles, just as the same for daytime supply. This means the PSPP generation costs are not competitive in the central and south system.

The reasons mentioned above show less economical situations after PSPP its installation in the central and south system.

3) Effects of GT Installation in the Peak Shift Demand

In the of peak shift demand in 2020, there is no benefit to be obtained from any case of GT installation in the central and south system.

c. Effects of Limiting Fuel Consumption

The gas thermal power development has a priority in the south system, which has been indicated as the limitation. The other supplies are installed long and middle term in the south system. The coal potential has been confirmed to be great enough to be supplied on a long term basis. The appropriate composition is examined considering the fuel limitations in the following section.

1) Conditions

The coal used in the south is transported from the north. The cost of transportation is 7.0US$/t.[1] The coal price including the freight fare equals the price of coal (in the south) as mentioned in the section on simulation condition. The construction costs of coal thermal power in the south system is 1,100US$/kW including the facilities of a port for the tanker of a 50,000DWT class.

2) Effects of Fuel Limitations

The annual costs are simulated by the coal installation rates as 20%-40% for the PSPP installation of 2.4% (1,000MW) 3.5% (1,500MW) and 4.7% (2,000MW) in the peak shift demand cases. The results indicate that coal is increasing in popularity and is taking the place of gas. The annual costs are decreasing for every case in the system.

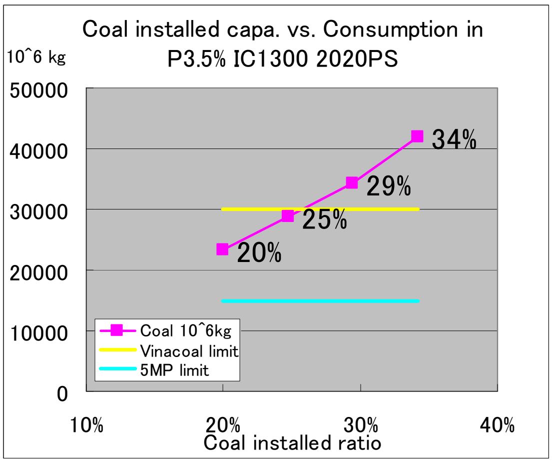


Fig 6-11 Coal Consumption vs. Coal Installed Capacity in 2020 (In Peak shift demand, PSPP 3.5% installed in the north system, Interconnection 1,300MW)

[1] Data from the interview with Vinacoal

The reduction in fuel costs exceeds the increase of fixed costs from higher coal thermal plant construction costs and gas thermal energy. When the coal installation rate is greater than 25%, and its total capacity of 10,000MW includes the capacity of 3000MW in the south, the coal consumption exceeds the limit. (Fig 6-11) Thus, the appropriate coal installation capacity in 2020 is 7,000MW installed in the north system and 3,000MW installed in the south system. This results in a total of 10,000MW.

The appropriate coal thermal installed capacity scenario has a 25% coal installation rate and a 24% gas installation rate (10,000MW). The gas consumption of every case does not exceed the limitation.

(5) Appropriate Peak Duration Time of PSPP

The PSPP sometimes operates at a lower output because of demand and availability of other power supplies. The latent capacity is easily found as hydropower occupies a large share of power supplies. The duration time at the maximum output of PSPP is examined considering the situation of the Vietnam system. (Figure 6-12)

The appropriate maximum operating duration of PSPP is 7 or 8 hours under conditions of installed 3.5% (1,500MW) of PSPP in the north system, interconnection capacity of 1,300MW and the peak shift demand. The difference of annual costs is insignificant when operating between 7 and 8 hours at a time.

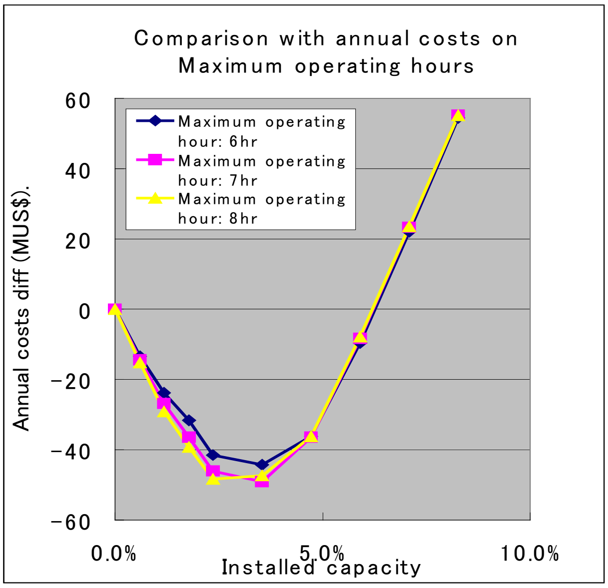


Figure 6-12 PSPP Operating Hours vs. Annual Costs

When the PSPP operating hour is over 8 hours, the pumping hour can not be obtained in one day considering the pumping efficiency. The weekly operation is necessary for a reservoir to increase its volume. The construction costs increase rapidly for the weekly operation. The appropriate maximum operating duration is 7 hour or 8 hours. The 7-hour shift can be selected considering the increase of construction costs for 8 hours.

(6) Effects of Interconnection between the North System and the C&S System

The Vietnam system has limitations in interconnection capacity between the north and the central and south system. The limitation and features of the composition case shows the benefits of interconnection. The benefits of interconnection consist of two aspects; one as an improvement in system reliability and the other as an economical power exchange. A reduction in fixed costs is provided by the improvement in system reliability. The reduction in fuel costs is obtained from the economic power exchange through interconnection. The reduction in fixed costs is saturated in 400MW of reserve capacity reduction and approx. 1,000MW of interconnection capacity. The reduction in fuel costs is more than 1,000MW of the interconnection capacity.

The reduction in annual costs increases because of the interconnection as its capacity increases. The difference between the interconnection capacity of 0MW and 2,200MW in 2020 is US$359 mil/Yr for in the IE demand.

Table 6-7 Interconnection Capacity vs. Annual Costs

(Unit: US$ mil/y)

Capacity of Interconnection (MW)	Interconnection IE demand in 2020	Interconnection Peak shift demand in 2020	Interconnection Peak shift demand in 2015
0	0	0	0
800	251	246	198
1,300	316	306	350
2,200	359	350	359

Note: Based on the case of interconnection 0MW, PSPP installation of 0MW

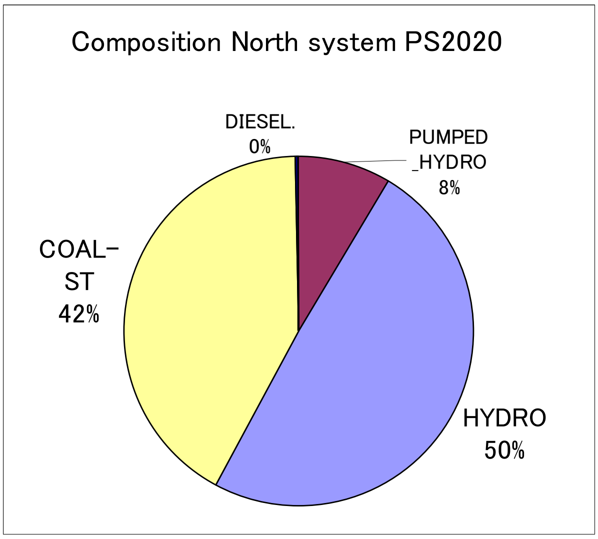
(7) Appropriate Composition in 2020

a. Appropriate Composition based on the Scenarios of Peaking Supply

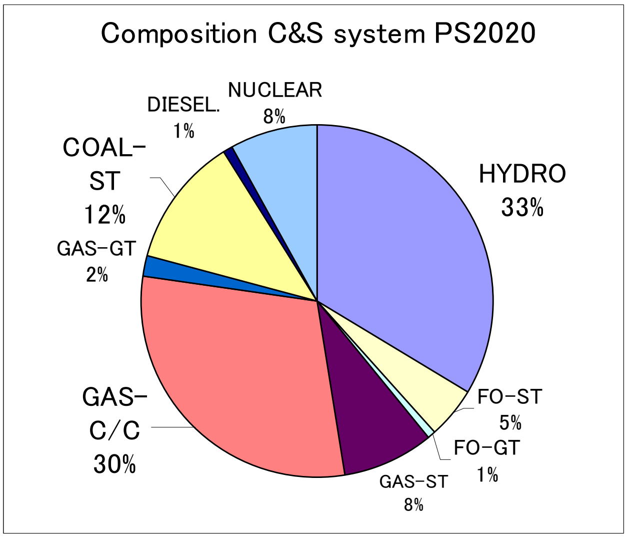
In the aforementioned discussion, the appropriate scenarios in the peak shift demand are the scenario of 2% (250MW) of PSPP installation in the north system in 2015 and the scenario of 3–4% (1,500MW) of PSPP installation in 2020. (Fig. 6-13)

The examination of the limited fuel supply of oil and gas provides the appropriate composition of gas and coal thermal power. The appropriate composition consists of 25% (10,000MW) of coal installation and 21-30% (9,000MW) of gas installation.

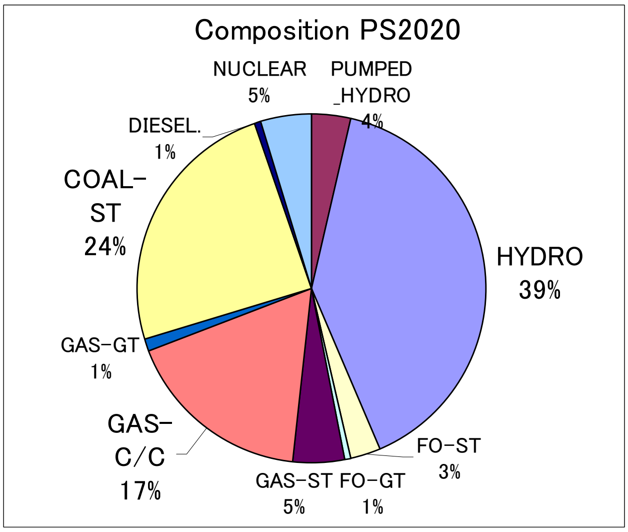
The North System



The Central and South System



Total



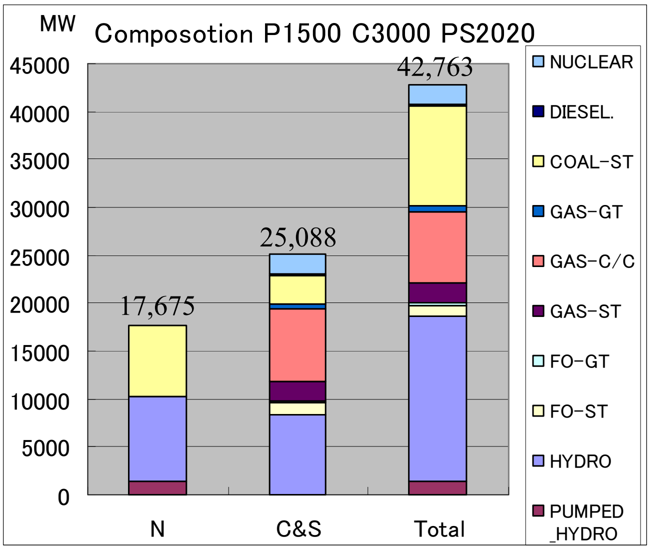


Fig 6-13　The Appropriate Composition in the Peak Shift Demand

b. Development Schedule of the Appropriate Scenario of Peak Supply in the Peak Shift Demand

The development schedule of appropriate scenario of peak supply in peak shift demand is shown in Table 6-8. The features of the scenario are as follows:

Interconnection capacity: 1,300MW

Installation capacity of PSPP in the north system: 3.5%（1,500MW）

Installation capacity of coal thermal in the south system: 3,000MW

Reserve margin in the north system: 14%,　Central and south system: 8%

Table 6-8 The Development Schedule of Appropriate Scenario of Peak Supply in Peak Shift Demand

PS2020 P3.5% IC1300 (Unit: MW)

FY	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Power Development Plan											
			Hua Na						New Coal1		
			195						500		
	Coal1,2		Nam Chien						PSPP2	New Coal2,3	
	600		140						250	1,000	
	Coal3,4	Coal5	Huoi Quang 2	Nam Thuen3(Laos)		Ban Uon		Coal6	PSPP1	PSPP4	PSPP6
	600	500	270	400		250		500	250	250	250
PDP North	Ban Chat	Huoi Quang 1	Son La 1	Son La 2,3	Son La 4,5	Son La 6,7,8	Nam Nhun1,2	Nam Nhun3,4	Bac Me	PSPP3	PSPP5
	200	270	300	600	600	900	550	550	280	250	250
PDP N total	1,400	770	905	1,000	600	1,150	550	1,050	1,280	1,500	500
N Peak Demand	6,022	6,456	6,921	7,420	7,955	8,529	9,144	9,803	10,510	11,268	12,080
N Supply	7,042	7,719	8,312	8,968	9,361	10,443	10,479	11,199	12,052	13,206	13,848
RM 13.9%	16.9%	19.6%	20.1%	20.9%	17.7%	22.4%	14.6%	14.2%	14.7%	17.2%	14.6%
	Dong Nai 3										
	240										
	Upper Kon Tun	Upper Kon Tum				New Coal4	Gas CC2	Gas CC3			Dien nguyen tu 2
	110	110				500	600	480			1,000
	Song Con 2	Song Ba Ha	New Coal1	Gas CC 1	New Coal2,3	Dong Nai 2	New Coal5	Se Kong5(Laos)	Gas CC4	Gas CC5	Duc Xuyen1
	70	250	500	750	1,000	78	500	250	720	240	100
PDP C&S	Se Kaman(Laos)	Dak My4	Nam Kong(Laos)	Se San 4	Song Bung4	Dong Nai 5	Se Kong4(Laos)	Song Bung2	New Coal6	Dien nguyen tu 1	Dak My1
	260	210	240	330	200	170	450	126	500	1,000	210
PDP C&S total	680	570	740	1,080	1,200	748	1,550	856	1,220	1,240	1,310
C&S Peak Demand	9,843	10,587	11,388	12,249	13,175	14,172	15,244	16,397	17,637	18,971	20,406
C&S Supply	11,938	12,554	13,272	14,321	15,321	15,459	16,961	17,956	19,476	20,656	22,138
RM 7.8%	21.3%	18.6%	16.5%	16.9%	16.3%	9.1%	11.3%	9.5%	10.4%	8.9%	8.5%
PDP Total	2,080	1,340	1,645	2,080	1,800	1,898	2,100	1,906	2,500	2,740	1,810

FY	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Peak Demand	15,827	17,007	18,275	19,638	21,102	22,675	24,366	26,183	28,135	30,233	32,486
Supply Capacity	18,980	20,273	21,584	23,289	24,682	25,902	27,440	29,155	31,528	33,862	35,986
Reserve Margin	19.9%	19.2%	18.1%	18.6%	17.0%	14.2%	12.6%	11.4%	12.1%	12.0%	10.8%

LEGEND

: Hydropower	**: Coal**	**: Nuclear**
:PSPP	**: Gas**	**: Import**

6.3 Study of System Reliability

(1) Method of Study of System Reliability

The studies were carried out in the normal state of the system without any contingencies (the N-0 criterion) as well as in the state of the system where the N-1 criterion can be met. Power supply is still possible without any special influences on the system; even if a unit of facilities is dropped. The reason for selecting both criteria is that the existing 500 kV transmission lines of Vietnam consist of one circuit which the applied reliability criterion is the N-0 criterion. Acceptable levels of frequency-changes are to be set so as to prevent the expansion of outages that are caused by the dropping of cascade generator due to the extraordinary rise and fall of frequencies. 1 Hz is usually set as the criterion of frequency changes regarding system planning.

The north-south transmission lines have two circuits according to EVN's plan. If series capacitors were not used, there would be a few hundred MW of power transmission ability from the viewpoint of stability, which would be considered insufficient. Therefore, installation of series capacitors was expected among Nho Quang substation in the north and Phu Lam substation in the south. Because there is a possibility of stopping generators due to the shaft-twist vibration caused by series capacitors, it will be necessary for EVN to carry out interactive studies between series capacitors and generators, regarding generator-shafts, modeling, and a selection of tools for analysis and determine what to measure.

(2) Optimization Study of 500 kV System in 2020

a. Evaluation of the 500 kV System Planning in 2020 of EVN

The double-circuit line of the 500 kV network from north to south will be completed around 2010. A 500 kV power grid will be constructed northward from Nho Quang substation and southward from Di Linh and Phu Lam substation by 2020. It is thought that the power flow from the south to north in 2020 will be several hundreds of MW at most, from the viewpoint of balancing supply and demand, and there are no expected problems regarding power flow and stability.

On the other hand, power flow from the north and central area to the southern area tends to grow by an uneven distribution of hydropower and coal-fired power plants. Evaluations of the 500 kV system planned by EVN are summarized as shown in Table 6-9.

Table 6-9 Evaluation of the 500kV System in 2020 Planned by EVN

N-0 standard	When a large amount of power is produced in the central region, the power flow can increase to 1,300MW between the north and the central region.
N-1 standard	When a large amount of power is produced in the central region, power flow is not permitted from the north to the central region. (When a small amount of power is produced in the central region, the power flow can increase to about 1,400 - 1500 MW between the north and the central region.)

b. The Study of the Optimization of Reinforcements of 500 kV System in 2020

From the viewpoint of the supply and demand of power, there is a large economical effect on operation costs of thermal power plants by power transmission of hydropower stations in the north and the central region to the south. Therefore, we carried out brief studies of increasing the limit of power flow from the north to the south by putting further reinforcements on the 500 kV network in 2020 as planned by EVN.

The results of the study of the reinforcements of 500 kV system until 2020 in comparison with the construction costs and power flow limit are summarized in Table 6-10.

Table 6-10 Summary of the Results of the Reinforcement Scenarios Study up to 2020

	Case with 500kV system reinforcement until 2020	Increment construction cost from base case (mil US$)	Limit power flow between north and central region in case of N-0 criterion (MW)	Limit power flow between north and central region in case of N-1 criterion (MW)
1	EVN 2020 year's plan (base case) With 2 circuits of north – central region and 2 circuits of central – south	-	1,300	0
2	With 2 circuits of north – central region and 3 circuits of central – south	82	1,600	1,100
3	With 3 circuits of north – central and 3 circuits of central – south	350	2,200	1,100
4	With 3 circuits of north – central region and 4 circuits of central – south and another circuit in the north system	467	2,200	2,200

If the N-0 criterion is applied, power transmission ability of 1,300MW will result between the north and the central region in 2020 according to the plan by EVN. This ability is considered to be economical in regards to the capital investment control side, because the power supply effect from the north to the south on saving investments in power stations is full with about 1,000MW. However, the effect of saving fuel costs is estimated to be about 10 million US$ a year when the power transmission ability increases from 1,300MW to 1,600 MW.

Because an increase in the investment of the transmission lines is 82 million US$ in the case of Case 2 “with 2 circuits of north - central and 3 circuits of central – south”, it can be converted to about 10 million US$ a year. Therefore, the addition of transmission lines between Plei Ku and Nha Trang in the 2020 plan of EVN, and the result of saving fuel costs is estimated to be almost same as the effect in terms of an increase in the investment of transmission lines. Furthermore, the connection of Nha Trang to Plei Ku will result in all connections of respective 500 kV substations to neighboring substations being able to connect both ends of the power supply. System reliability of the transmission lines from the center region to the south region can be improved. On the other hand, in case of Case 3 "with 3 circuits of north - central and 3 circuits of central – south", the effect of economic operations on saving fuel costs is estimated to be about 20 million US$. The investment of the transmission lines is about 350 million US$, which is equivalent to about 50 million US$ a year, and significant economical merit cannot be expected.

Therefore, the superior case in this study is shown in Table 6-10, "2 circuits of north - central and 3 circuits of central – south". However, the economical merit could not be clearly estimated so as to conclude the implementation of this case. Therefore, it will be necessary for EVN to carry out a study of detailed estimation of the effect of economic operations on saving fuel costs, including the methods of power generators, and careful examination about the effect of improvement in system reliability.

(3) Methods of Power Transmission of PSPP in the North

The PSPP is located over 100 km from the center of demand. If 220 kV is applied for the voltage of the transmission lines to the center of demand, three to four lines are needed. Strong reinforcement of the existing 220kV system is also needed for the power transmission for both the generation and pumping operations, which is not economically feasible at the time. The voltage of the transmission lines is assumed to be 500kV. The influence of the PSPP on the 500 kV network system in 2020 was also studied.

There is no room for installation of new bays in Hoa Binh power station for the PSPP transmission lines. Therefore, the methods of T-off branches from the 500 kV network for the transmission lines of PSPP were examined.

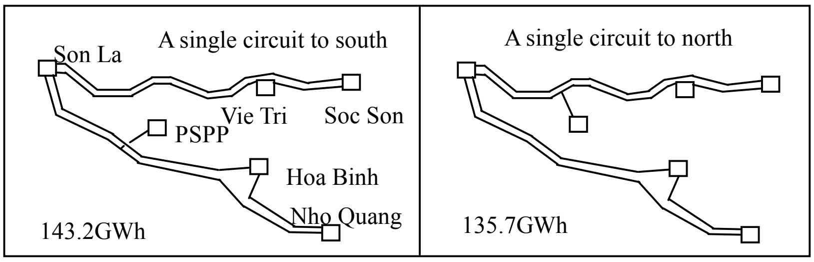
There are two routes of transmission lines passing near the PSPP sites. One is the northern route that will be constructed from Son La power station to Vie Tri substation and Soc Son substation with one circuit each. Another is the southern route that will be constructed from Son La power station to Hoa Binh substation and from Son La power station to Nho Quang substation by one circuit each.

It cannot be clearly determined whether a drop in 1,000 MW at an off-peak period is acceptable or not because a frequency change is expected to be 1 Hz when 1,000 MW is dropped. The cases of connection with one circuit and the cases of connection with double circuits were both studied. Remote generator shedding by a telecommunication system for the stability maintenance at a circuit fault is not allowed. When the power flow exceeds the thermal capacity of the remaining circuits in the case of a circuit fault, the power generation control of the pumped storage power plant is allowed.

(4) Optimum Method of the Connection

The above studies are narrowed down the cases in comparison of power losses that have possible connections from the viewpoint of system reliability and that have the same branch point.

The following figure shows the system configurations of the respective cases. Power losses in the Figures represent the losses produced in the case of full outputs of generators in the north area and the generating/pumping operation of PSPP.



Cases of a drop in generating/pumping power of 1,000 MW is allowed in the case of a single line fault
[Transmission line with a single circuit]

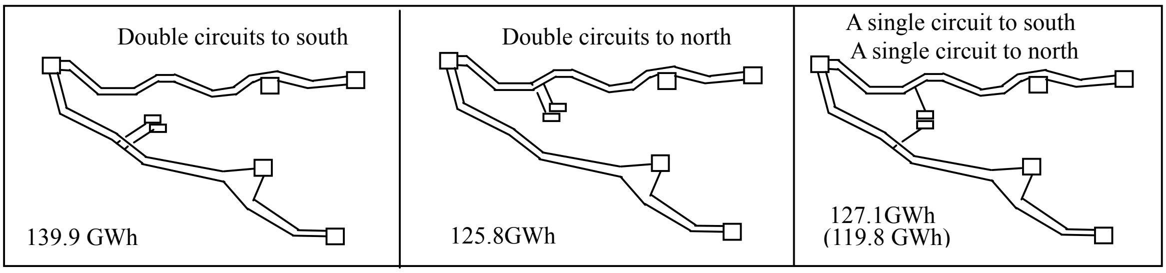


Figure 6-14 Cases of PSPP Connections

In order to seek the optimum case, comparison of the cost of power loss and construction costs between the cases of respective patterns of the connections is needed. However, construction costs of the transmission lines and the passes of the northern and southern route and operation patterns of other generators largely affect power losses. Therefore, it is difficult to determine the optimum connection at the present time for the following reasons.

- The case producing the least amount of loss depends on the patterns of operation of generators in the off-peak period.
- The difference of the cost of lost power between the case of connection to the south route and the case of connection to the north route is less than the cost of a 10 km transmission line. Because of undetailed information of the transmission line route, it is impossible to say which case is superior, the case of connection to south route or the case of the north route.

Therefore, more detailed studies are needed for implementation of the transmission lines of PSPP in comparison of:

- Cost of power losses
- Construction cost of the transmission lines among the five cases

in consideration with:

- A permissible drop in generators or pumping power of PSPP in case of a single circuit fault (The permissible range of variations in system frequency within 1 Hz)
- The direction of the transmission lines from Son La
- The patterns of operations of generators in the northern grid.

Chapter 7. Financial Evaluation

7.1 Past Financial Situation

(1) Past Financial Statements

EVN's past financial situation is analyzed below based on EVN's consolidated financial statements until the year ended December 31, 2002 prepared in accordance to the international accounting standards, and annual report for the year ended December 31, 2001.

Table 7-1 EVN Consolidated Income Statement

(Unit: Billion VND)

	1997	1998	1999	2000	2001	2002
Revenue	11,221	13,472	14,121	16,510	19,209	23,565
Cost of Goods Sold	-8,719	-10,913	-10,929	-13,574	-15,958	-19,067
Gross Income	2,502	2,559	3,191	2,936	3,250	4,497
Selling Expense	-177	-204	-253	-335	-405	-476
Administration Expense	-1,131	-577	-644	-673	-904	-1,092
Operating Income	1,193	1,776	2,293	1,926	1,941	2,928
Non-Operating Income	-11	-217	-559	-529	-400	-580
Net Income before Tax	1,181	1,558	1,733	1,397	1,540	2,347
Tax Expense	-670	-535	-644	-514	-541	-676
Net Income	510	1,023	1,088	882	999	1,671

Gross Profit Rate	22.3%	19.0%	22.6%	17.8%	16.9%	19.1%
Operating Profit Rate	10.6%	13.2%	16.2%	11.7%	10.1%	12.4%
Net Profit Rate	4.5%	7.6%	7.7%	5.3%	5.2%	7.1%

Table 7-2 EVN Consolidated Cash Flow Statement

(Unit: Billion VND)

	1997	1998	1999	2000	2001	2002
Cash Flow from Operating Activities	4,040	-2,808	5,882	7,311	6,739	8,413
Cash Flow from Investing Activities	-4,218	-4,539	-11,666	-13,696	-9,206	-9,915
Cash Flow from Financing Activities	1,242	7,008	7,004	7,772	3,426	4,640
Net Cash Flow	1,064	-339	1,221	1,387	959	3,138

Table 7-3 EVN Consolidated Balance Sheet

(Unit: Billion VND)

	1997	1998	1999	2000	2001	2002
Non Current Assets						
Fixed Assets	20,066	18,213	18,747	23,716	30,914	45,082
Construction in Progress	7,475	10,738	17,807	20,971	15,926	9,069
Others		42	122	4,157	4,364	4,534
Sub Total	27,541	28,995	36,676	48,844	51,204	58,687
Current Assets						
Cash and Cash Equivalents	4,424	4,085	5,306	6,693	7,653	10,791
Receivables	10,583	5,467	3,919	2,619	2,665	4,075
Inventories	3,076	3,952	5,123	1,374	1,731	2,298
Others	540	709	513	503	670	463
Sub Total	18,625	14,214	14,863	11,191	12,720	17,629
Total Assets	46,167	43,209	51,539	60,035	63,924	76,316
Equity						
Capital	24,143	25,182	26,902	27,834	28,681	33,896
Retained Earnings	319	17	187	62	65	279
Sub Total	24,462	25,199	27,090	27,897	28,747	34,175
Long-term Liabilities (LTL)	5,339	12,824	19,064	25,565	26,601	32,644
Current Liabilities						
Payables	15,572	4,544	4,290	5,217	6,843	7,717
Short-term Liabilities	143	44	43	68	112	136
Current Portion of LTL		10	494	1,287	1,620	1,641
Others	648	585	556			
Sub Total	16,365	5,185	5,385	6,572	8,576	9,495
Total Equity and Liabilities	46,167	43,209	51,539	60,035	63,924	76,316

Current Ratio	113.8%	274.1%	276.0%	170.3%	148.3%	185.7%
Equity Ratio	53.0%	58.3%	52.6%	46.5%	45.0%	44.8%

(2) Analysis Results

The financial analysis results based on past financial statements (for past six years) are summarized below.

- Profitability and financial stability are in relatively good condition. Financial indicators for the year 2002 show improvement due to a good business environment.
- The cash flow structure changed from year 2001. One capital investment cycle may have ended, or it could be said that capital investment was intentionally constrained to prevent borrowings from increasing. Overall, cash flow has improved in the past two years by reduced net increase in borrowings and increase in cash flow from operating activities.

7.2 EVN Financial Projection

(1) EVN Prospective Financial Statements

The EVN financial projection analyzed in this study is the most recent projection as obtained in December 2003. This financial projection is most reliable as it is the underlying data for when EVN requested a revision of the tariff to the government starting from April 2004.

Table 7-4 EVN Consolidated Prospective Income Statement

INCOME STATEMENT (EVN Planned) (Unit: Million US$)

	2003	2004	2005	2006	2007	2008
Average Power Price (US cents/kWh)	5.6	5.8	6.4	6.9	7.0	7.0
At the End of Last Year	5.6	5.6	5.9	6.5	7.0	7.0
Revised tariff in the Year	5.6	5.9	6.5	7.0	7.0	7.0
Time of Adjustment			Apr./04	Apr./05	Apr./06	
Net Average Price (excluding VAT)	4.96	5.30	5.77	6.25	6.36	6.36
Net Revenue	1,712	2,091	2,602	3,139	3,623	4,067
- Average Tariff (US cents/kWh)	4.96	5.30	5.77	6.25	6.36	6.36
- Sales Volume (Gwh)	34,510	39,454	45,093	50,228	56,964	63,953
Unusual Income						
1. Total Revenue	1,712	2,091	2,602	3,139	3,623	4,067
2. Total Cost	-1,481	-1,847	-2,259	-2,621	-3,019	-3,517
3. Net Profit from J/V						20
4. Income before Tax	231	244	343	518	604	570
5. Income Tax	-38	-35	-39	-43	-47	-52
6. Net Income	193	209	304	475	557	518
(Profit Rate)	11.3%	10.0%	11.7%	15.1%	15.4%	12.7%

Table 7-5 EVN Consolidated Prospective Cash Flow Statement

CASH FLOW STATEMENT (EVN Planned) (Unit: Million US$)

	2003	2004	2005	2006	2007	2008
a. Internal Source	339	380	447	332	310	119
1. Total Revenue	1,712	2,091	2,602	3,139	3,623	4,067
2. Changes in Working Capital	-21	61	93	-5	-38	-52
3. Total Cost (exc. Dep. and Interest)	-930	-1,234	-1,590	-1,917	-2,090	-2,453
4. Tax Payment	-38	-35	-39	-43	-47	-52
5. Contribution from Government						
6. All. to Funds (Use of Funds)	-23	-24	-27	-29	-31	-36
7. Principle Repayment and Interest	-361	-479	-592	-813	-1,107	-1,355
- Principle Repayment	-245	-325	-381	-525	-743	-919
- IDC	-38	-61	-111	-189	-230	-242
- Interest Expense	-78	-93	-100	-99	-134	-194
b. Application of Funds						
- Net Investment	-1,165	-1,291	-1,966	-2,012	-1,937	-1,944
c. a.-b.	-826	-911	-1,519	-1,680	-1,627	-1,825
d. Financing Activities	726	939	1,557	1,630	1,558	1,730
- Bond Issue						
- Borrowing	726	939	1,557	1,630	1,558	1,730
e. Net Cash flow	-100	28	38	-50	-69	-95
f. Beginning of Year	719	618	646	684	634	565
g. End of Year	618	646	684	634	565	471

(2) Analysis Results

The analysis results of EVN's financial projections are as follows.

- Steady profitability can be expected through the projected period as long as electricity demand increases and the tariff schedule proceeds as planned.
- Cash flow is expected to decrease although EVN continues to be profitable. It can be said that EVN is financially unbalanced as the planned capital investment is large for its profit size.
- EVN financial projection is based on the revised 5th Master Plan, but its electricity investment plan differs slightly from that of the Master Plan. Although the impact on profit due to the different investment plan is limited, the impact on cash flow is significant enough not to be overlooked. Therefore, financial projections based on the revised 5th Master Plan should also be considered.
- The fact that financial projections based on the revised 5th Master Plan have not been prepared casts doubt upon the feasibility of the Master Plan. Projections based on the Master Plan should also be prepared, with its results compared against EVN projections, and the results analyzed, as well as coordinating the interests of the concerned parties.

7.3 Financial Projection based on Long Term Investment Plan

(1) Long Term Investment Plan and Running Cost Projections

The JICA Team projected and calculated the investment by EVN and the running costs of EVN during 2003 – 2020 based on the revised 5th M/P and the optimum power system development plan proposed in Session 6.2. The calculation results are as follows.

a. Investment shown in Fig. 7-1 ; The investment based on the JICA Study is larger than that based on the revised 5th M/P in later years, because in the JICA Study the amount of coal TPPs development in the south is greater and the electricity imports from Cambodia and China are excluded.

b. O&M costs shown in Fig. 7-2 ; There is no significant difference.

c. Fuel costs shown in Fig. 7-3 ; The fuel costs after 2014 based on the JICA study amount to approx. 200 mln US$/yr less than that based on the revised 5th M/P, because in the JICA Study the coal TPPs development replaces Gas TPPs development in the south.

d. Power purchase costs shown in Fig. 7-4 ; The power purchase costs based on the JICA study is around 300 mln US$/yr less in 2020, due to exlusion of electricity imports from Cambodia and China.

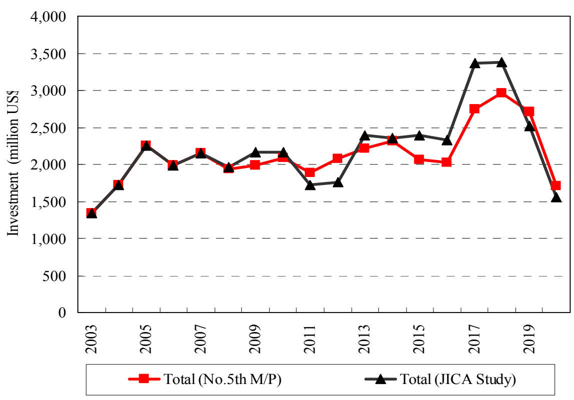


Fig. 7-1 Investments by EVN

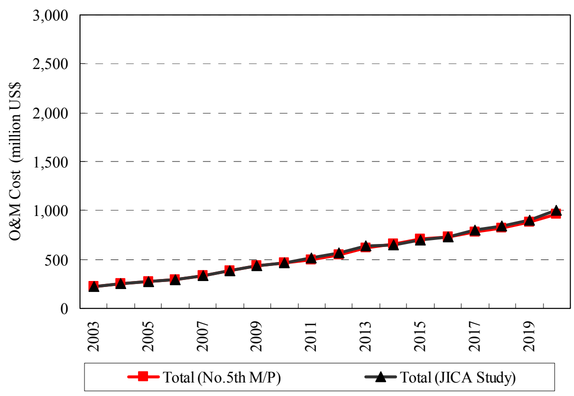


Fig. 7-2 O&M Costs of EVN

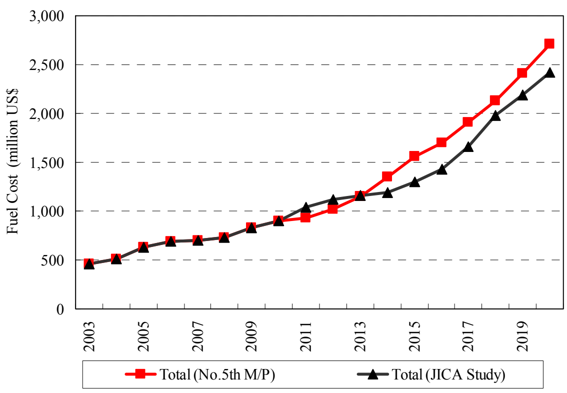


Fig. 7-3 Fuel Costs of EVN

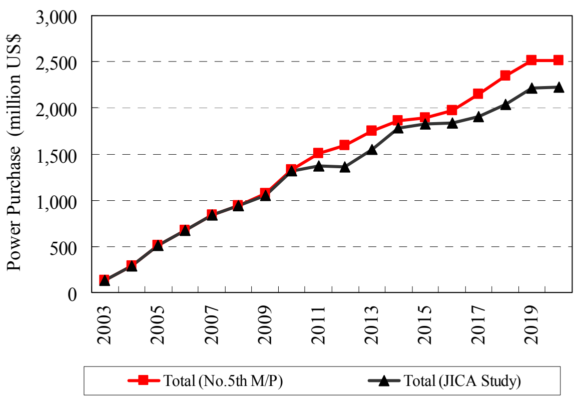


Fig. 7-4 Power Purchase Costs of EVN

(2) Study Projections

Two cases are assumed for financial projections based on the long-term investment plan of the study.

a. Case 1 (with EVN Financing Conditions)

1) Prospective Financial Statements

The same financing conditions used in EVN's financial projections are applied in preparing the projections.

Table 7-6 Prospective Income Statement

INCOME STATEMENT (CASE 1)

(Unit: Million US$)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Average Power Price (Uscents/k.Wh)	5.6	5.8	6.4	6.9	7.0	7.0	7.0	7.0	7.0	7.0
At the End of Last Year	5.6	5.6	5.9	6.5	7.0	7.0	7.0	7.0	7.0	7.0
Revised Tariff in the Year	5.6	5.9	6.5	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Time of Adjustment		Apr./04	Apr./05	Apr./06						
Net Average Price(Except VAT)	4.96	5.30	5.77	6.25	6.36	6.36	6.36	6.36	6.36	6.36
1.Net Revenue	1,712	2,091	2,602	3,139	3,623	4,067	4,543	5,119	5,581	6,086
-Average Tariff	4.96	5.30	5.77	6.25	6.36	6.36	6.36	6.36	6.36	6.36
-Sales Volume	34,510	39,454	45,093	50,228	56,964	63,953	71,426	80,486	87,754	95,694
2.Unusual Income										
Total Revenue (1.+2.)	1,712	2,091	2,602	3,139	3,623	4,067	4,543	5,119	5,581	6,086
3.Total Cost	-1,557	-1,942	-2,462	-2,927	-3,451	-3,984	-4,501	-5,169	-5,748	-6,149
4.Income before Tax	155	149	140	213	172	83	42	-50	-167	-63
5.Income Tax	-37	-35	-39	-43	-48	-23	-12	0	0	0
6.Net Profit from J/V						20	20	20	20	20
7.Net Income	118	114	101	170	124	80	50	-30	-147	-43
(Proft Rate)	6.9%	5.4%	3.9%	5.4%	3.4%	2.0%	1.1%	-0.6%	-2.6%	-0.7%

Table 7-7 Prospective Cash Flow Statement

CASH FLOW STATEMENT (CASE 1)

(Unit: Million US$)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
a. Internal Sources	317	152	-21	-131	-359	-590	-799	-922	-1,053	-676
1.Total Revenue	1,712	2,091	2,602	3,139	3,623	4,067	4,543	5,119	5,581	6,086
2.Total Cost(exc. Dep. and Interest)	-955	-1,227	-1,603	-1,867	-2,110	-2,321	-2,613	-3,020	-3,308	-3,458
3.Tax Payment	-37	-35	-39	-43	-48	-23	-12	0	0	0
4.All. to Funds (Use of Fund)	-24	-26	-31	-34	-39	-12	0	0	0	0
5.Principle Repayment and Interest	-379	-651	-951	-1,326	-1,785	-2,302	-2,717	-3,021	-3,327	-3,304
-Principle Repayment	-237	-410	-591	-840	-1,186	-1,606	-1,938	-2,185	-2,489	-2,499
-IDC	-51	-113	-202	-277	-308	-304	-337	-344	-287	-244
-Interest Charge	-91	-128	-158	-208	-291	-393	-442	-492	-551	-562
b. Application Fund										
-Net Investment	-1,505	-1,764	-2,499	-2,428	-2,609	-2,393	-2,741	-2,419	-1,919	-1,990
c. a.-b.	-1,188	-1,612	-2,520	-2,559	-2,968	-2,983	-3,540	-3,341	-2,972	-2,666
d. Financing Activities										
-Borrowing	1,505	1,764	2,499	2,428	2,609	2,393	2,741	2,419	1,919	1,990
e. Net Cashflow	317	152	-21	-131	-359	-590	-799	-922	-1,053	-676
f. Beg. of Year	719	1,036	1,187	1,166	1,035	676	86	-713	-1,635	-2,689
g. End of Year	1,036	1,187	1,166	1,035	676	86	-713	-1,635	-2,689	-3,365

2) Analysis Results

The analysis results are as follows.

- Steady profit is expected to continue until 2006. However, the positive effect of raising the tariff to 7 cents starts diminishing from 2007.
- Cash flow balance turns negative in 2009, and therefore, the investment plan of the project

cannot likely be implemented with the same borrowing conditions as assumed in EVN's financial projections.

- The major reason for the cash shortage is the substantial amount of annual repayments of borrowings.

b. Case 2 (with Revised Financing Conditions)

Based on the results of Case 1, the financing conditions are revised so that the investment plan of the study may be sufficiently implemented.

1) Revision of Financing Conditions

- Extended repayment period on network related borrowings to 20 years from 15 years.
- Extended repayment period for an additional five years on projects, which EVN plans to conduct with ODA loans.
- Changed fund source from commercial borrowings to ODA loans for those projects, which EVN preferred to conduct using ODA loans but did not reflect in their projections, as it has not yet been decided.
- Based on the results shown in Case 1, relatively ample internal source funds are used for investment in the first half of the projected period.
- Changed fund source from commercial borrowings to ODA loans for 110kV transmission and distribution line projects are planned for the second half of the projected period, when the amount of ODA loans decreases.

2) Prospective Financial Statements

Table 7-8 Prospective Income Statements

INCOME STATEMENT (CASE 2)

(Unit: Million US$)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Average Power Price (Uscents/k.Wh)	5.6	5.8	6.4	6.9	7.0	7.0	7.0	7.0	7.0	7.0
At the End of Last Year	5.6	5.6	5.9	6.5	7.0	7.0	7.0	7.0	7.0	7.0
Revised Tariff in the Year	5.6	5.9	6.5	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Time of Adjustment		Apr./04	Apr./05	Apr./06						
Net Average Price(Except VAT)	4.96	5.30	5.77	6.25	6.36	6.36	6.36	6.36	6.36	6.36
1.Net Revenue	1,712	2,091	2,602	3,139	3,623	4,067	4,543	5,119	5,581	6,086
-Average Tariff	4.96	5.30	5.77	6.25	6.36	6.36	6.36	6.36	6.36	6.36
-Sales Volume	34,510	39,454	45,093	50,228	56,964	63,953	71,426	80,486	87,754	95,694
2.Unusual Income										
Total Revenue(1.+2.)	1,712	2,091	2,602	3,139	3,623	4,067	4,543	5,119	5,581	6,086
3.Total Cost	-1,552	-1,926	-2,438	-2,894	-3,406	-3,928	-4,456	-5,125	-5,675	-6,098
4.Income before Tax	160	165	164	245	217	139	87	-7	-94	-12
5.Income Tax	-37	-35	-39	-43	-48	-39	-24	0	0	0
6.Net Profit from J/V						20	20	20	20	20
7.Net Income	123	130	125	202	169	120	83	13	-74	8
(Proft Rate)	7.2%	6.2%	4.8%	6.4%	4.7%	3.0%	1.8%	0.3%	-1.3%	0.1%

Table 7-9 Prospective Cash Flow Statements

CASH FLOW STATEMENT (CASE 2)

(Unit: Million US$)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
a. Internal Sources	331	261	207	209	97	−73	−123	−197	−255	53
1.Total Revenue	1,712	2,091	2,602	3,139	3,623	4,067	4,543	5,119	5,581	6,086
2.Total Cost(exc. Dep. and Interest)	−955	−1,227	−1,603	−1,867	−2,110	−2,321	−2,613	−3,020	−3,308	−3,458
3.Tax Payment	−37	−35	−39	−43	−48	−39	−24	0	0	0
4.All. to Funds (Use of Fund)	−24	−26	−30	−33	−39	−28	−11	0	0	0
5.Principle Repayment and Interest	−365	−542	−723	−987	−1,329	−1,753	−2,018	−2,296	−2,528	−2,575
−Principle Repayment	−235	−335	−417	−575	−816	−1,141	−1,325	−1,542	−1,753	−1,793
−IDC	−45	−93	−170	−232	−261	−264	−283	−292	−277	−250
−Interest Charge	−86	−113	−135	−180	−253	−347	−410	−462	−498	−532
b. Application Fund										
−Net Investment	−1,258	−1,506	−2,231	−2,103	−2,609	−2,393	−2,741	−2,419	−1,919	−1,990
−Investment from Internal Sources	−247	−258	−268	−325						
c. a.−b.	−1,174	−1,503	−2,292	−2,219	−2,512	−2,466	−2,864	−2,616	−2,174	−1,937
d. Financing Activities										
−Borrowing	1,258	1,506	2,231	2,103	2,609	2,393	2,741	2,419	1,919	1,990
e. Net Cashflow	84	3	−61	−116	97	−73	−123	−197	−255	53
f. Beg. of Year	719	803	806	745	629	726	653	530	334	79
g. End of Year	803	806	745	629	726	653	530	334	79	132

3) Analysis Results

The analysis results are as follows.

- Cash flow will improve by changing the financing conditions.
- Profitability will slightly improve, and interest expenses will be reduced by changing to ODA loans and using internal source funds for network investments from 2003 to 2007.
- However, consideration may also need to be given to raising the tariff after 2007, otherwise profit rate will remain low.
- A shortage of cash can be prevented by reducing the amount of annual repayments as opposed to CASE 1, by using ODA loans and extending the ODA repayment period for five years.

(3) Financing Recommendations

Based on the results above, the key for implementing the project investment plan would be to secure borrowings with not as tight of conditions, such as ODA loans.

For Case 1, the major fund source for network projects is borrowings from commercial banks. The amounts for network investment are substantial and also long-term, and therefore, it is important that soft loans be used.

Additionally, for Case 1, the repayment period of most ODA loans is set at fifteen years, which would probably cause cash shortage. Therefore, it is also recommended that the government extend subloan conditions for five years.