CHAPTER 6 MASTER PLAN ON OPTIMIZATION FOR PEAKING POWER SUPPLY

Chapter 6. Master Plan on Optimization for Peaking Power Supply

6.1 Preliminary Study of Optimization of Peaking Power Supply

6.1.1 Efficient Simulation Tool for Optimizing Peaking Power Supply

Vietnam terrain spreads 1,650km long from the North to the South, and electricity demand concentrates in Hanoi in the North and in Ho Chi Minh city in the South. Besides, primary energy resources are unevenly distributed such as coal in the North and gas in the South.

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

Since WASP can not simulate daily operations, too, it is impossible to build optimum peeking power supply plan taking into account daily adjustment capacity of every power source.

Accordingly, JICA study team decided to use PDPAT II developed by Tokyo Electric Power Co. (TEPCO) as a simulation tool for the peaking power supply optimization study. PDPAT II has long-time practical accomplishment in the power system development planning of TEPCO and can simulate some power systems interconnected and daily operations.

Table 6-1-1 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 hrs

6.1.2 Comparison of Generation Costs of Peaking Supply

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

In this examination, fixed costs consist of depreciation and O&M costs. Variable costs correspond to the fuel costs in 2020. Further, the difference in heat rates by capacity factor is considered. The efficiency of pumping for PSPP is 70%. The discount rate is 10%. Conditions for screening curve analysis are shown in Table 6-1-2.

Table 6-1-2 Conditions for Screening Curve Analysis

	Construction Cost	Life time	Annual O&M Cost Rate	Fuel cost	
PSPP	650US$/kW	40	1%	Hydro 0 ¢ /kWh	Coal 2.1 ¢ /kWh
GT	400US$/kW	20	5.5%	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%	9.0 ¢ /kWh	

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

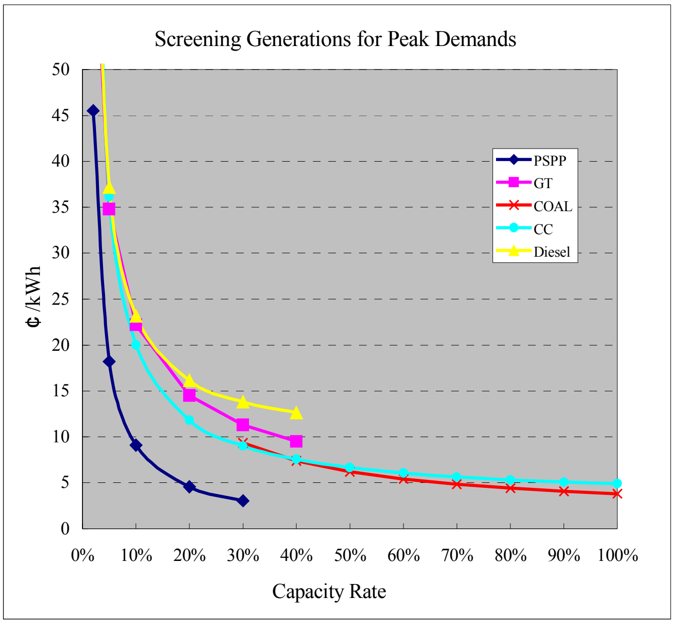

Figure 6-1-1 Generation Costs vs Capacity Rate in 2020
Pumping Energy; Coal case

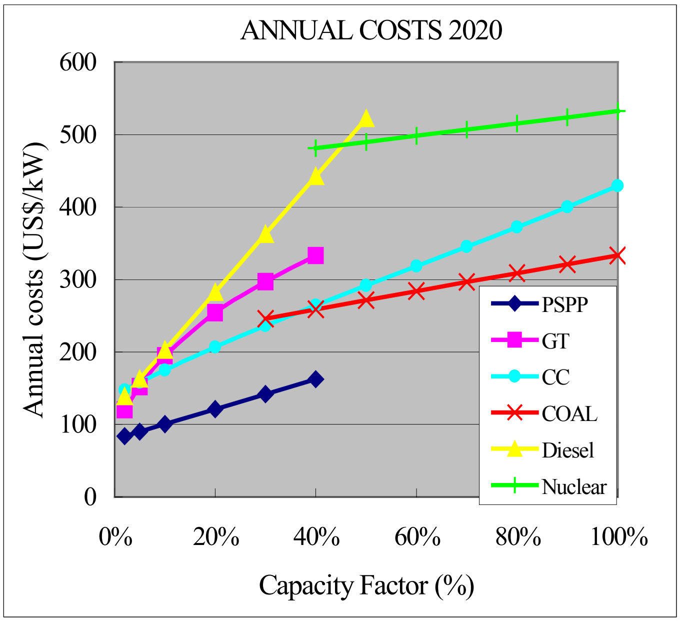

Figure 6-1-2 Annual Costs in 2020
Pumping Energy; Coal case

At the capacity factor of 5% or less, Pumped storage hydro power plant (PSPP) has an economic advantage as a peaking power source, followed by Gus turbine (GT) and Combined cycle power plant (CC).

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

Coal thermal and hydropower are considered for pumping energy. Even in Case1 that uses coal thermal for pumping, PSPP has an economic advantage over CC.

6.1.3 Current and Forecasted Peak Demand

(1) 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 peak demand day, Dec. 6th, 2002 (Figure 6-1-3), showed two peaks in the morning and evening. Their durations were 4-5 hours, and the amount of evening peak was 1,722MW between 6,552MW and 4,830MW. This is equivalent to 26% of the peak demand, which is similar to that of the average weekday load curve in 2002 (Figure 6-1-4).

The bottom demand of the evening peak was 4,830MW, corresponding to the 2,228th demand among 8,760 annual hourly records counted in descending order. Thus, it is assumed that the necessary amount of peaking power source is equal to 25% (2,228 / 8,760) of the total installed capacity (Figure 6-1-5).

In order to meet this peak demand, peak power sources with the plant factor of 15 – 20% are necessary. In actual operations, hydropower stations with large reservoirs (Hoa Bhin, Yaly and Trian: 3,040MW in total) supplied the peak demand in the dry season in 2002. In the rainy season, however, combined cycle generation units supplied peak demand since water level of reservoirs had to be lowered for preventing floods.

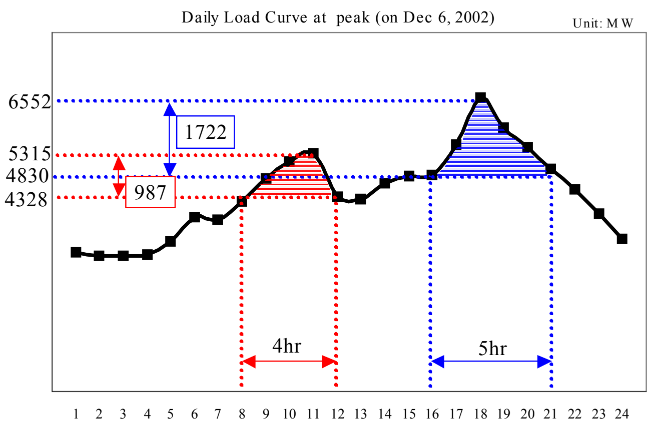

Figure 6-1-3 Daily Load Curve (peak demand day)

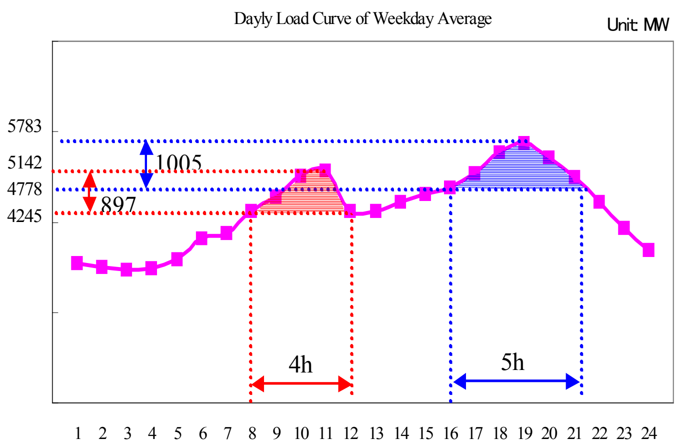

Figure 6-1-4 Daily Load Curve (weekday average)

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

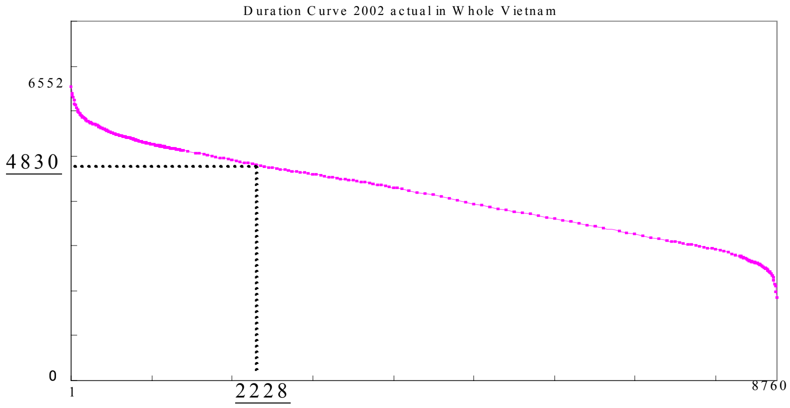


Figure 6-1-5 Duration Curve of Annual Demand

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% increasing from the actual record of 64%. Seasonal demand fluctuations in the Vietnam system are less remarkable compared with daily fluctuations. Thus, although an increase in load factor could raise daily bottom demand, its impacts on load profiles are limited. Therefore, the load curve in 2020 is assumed to be similar to the actual record in 2002 (Figure 6-1-6).

Accordingly, the necessary peaking power supply in 2020 is forecasted as 6,500MW, taking 20% of peak demand.

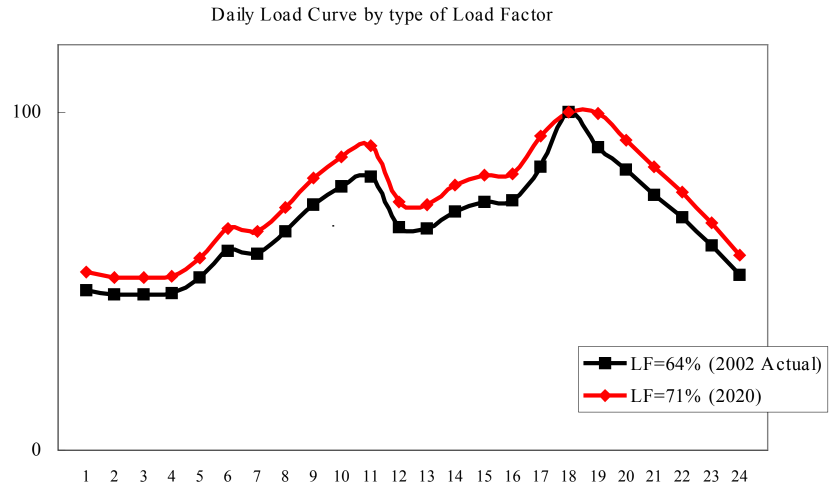


Figure 6-1-6 Estimation of Changing Load Profile

(Load Factor 64%vs.71%)

(2) Impacts of the Peak Shift from Nighttime to Daytime

Considering the peak shift from nighttime to daytime, necessary peaking 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, concentrating more in daytime as a result of the peak shift (Figure 6-1-7).

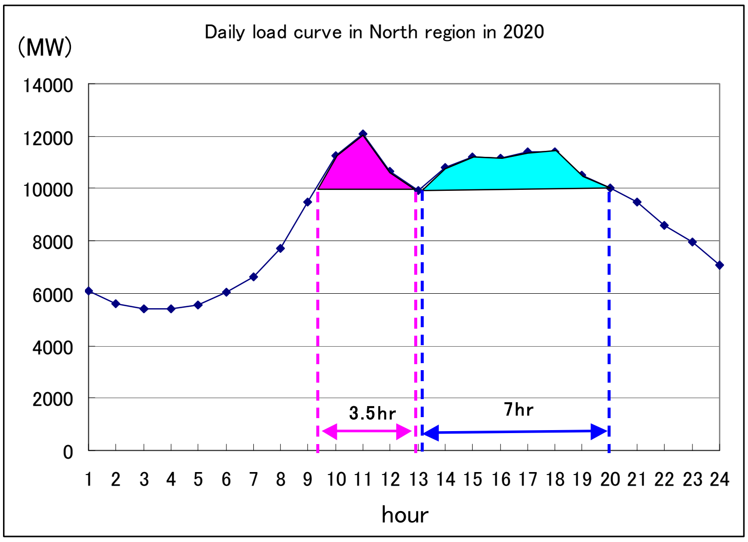


Figure 6-1-7 Daily Load Curve at Peak Demand in 2020 (in Peak shift demand)

The duration of peak demand is subject to the daily load curve. The daily load curve changes in line with the change of the structure of electricity consumption. The area of high demands over 80% of the daily maximum demand is analyzed as peak load. The peak duration time is defined as the equivalent hours of around 20% of the maximum demand peak as shown in Figure 6-1-8. In the case of 2015, the peak duration time is approximately 7 hours.

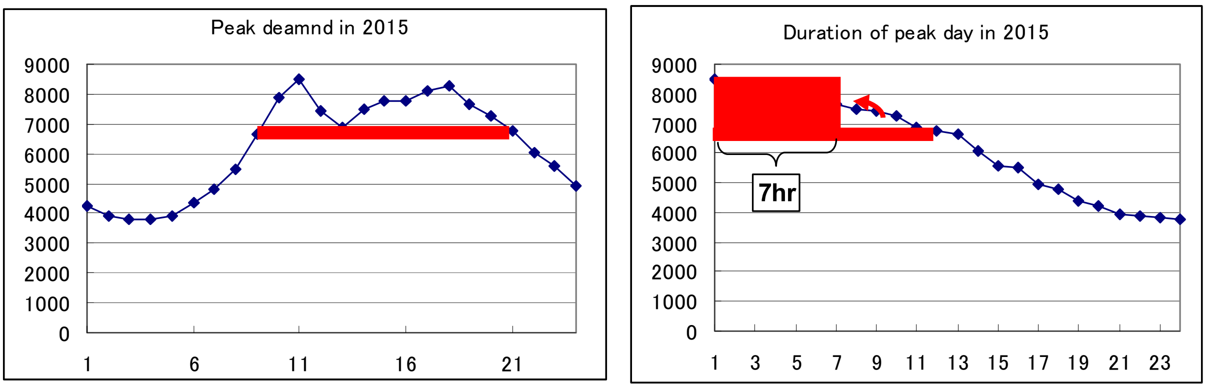


Figure 6-1-8 Peak Duration in 2015

6.1.4 Appropriate Reserve Margin based on System Reliability Criteria

In this section, the appropriate reserve margin for the simulation is examined. The relation between system reliability and reserve margin is analyzed in target years considering the capacity limitation of interconnection and the feature of each system. The appropriate reserve margin that meets the system reliability criteria (LOLE 24hours) is identified.

The relation between system reliability and reserve margin is analyzed by RETICS as the tool for analysis of system reliability based on the revised 5th master plan. In the divided system analysis, two (2) systems, the N system and C&S system, are analyzed. The almost all planned power plants in the central system supply the south system. The central system is combined by the south system from system operation aspects.

(1) System Reliability Condition in the Revised 5th Master Plan

The relation between system reliability and reserve margin is analyzed in 2020 with data from the revised 5th master plan and provided data such as water flow fluctuation, forced outage rates, and demand fluctuation. The results of analysis are shown as follows.

a. System Reliability of the Whole System

The relation between system reliability and reserve margin is analyzed in 2020 based on the revised 5th master plan (Figure 6-1-9). The 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.

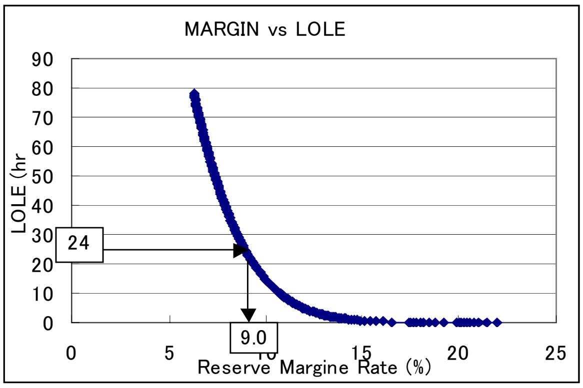


Figure 6-1-9 Relation of Reserve Margin vs. LOLE in 2020

b. System Reliability of the Divided System

The analysis of system reliability in the divided systems is conducted for the N system and the C&S system with PDPAT II in 2020. 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 N system, the 19% reserve margin, which is equivalent to 2,300MW, is necessary to satisfy the system reliability criteria (Fig. 6-1-10). The supply capacity of approximately 14,370MW is necessary to meet the system reliability criteria. In C&S system, the 9% reserve margin, which is equivalent to 1,850MW, is necessary to satisfy the system reliability criteria (Fig. 6-1-11). The approximately 22,410MW of supply capacity is necessary to meet the system reliability criteria.

Next, in the case of the interconnection capacity of 2,200MW, in N system, the 17% reserve margin, which is equivalent to 2,050MW, is necessary to satisfy the system reliability criteria. The supply capacity of approximately 14,120MW is necessary to meet the system reliability criteria. In C&S system, the 8% reserve margin, which is equivalent to 1,645MW, is necessary to satisfy the system reliability criteria. The approximately 22,210MW of supply capacity is necessary to meet the system reliability criteria. There is the difference of approximately 450MW of reduction in reserve margin between with and without the interconnection.

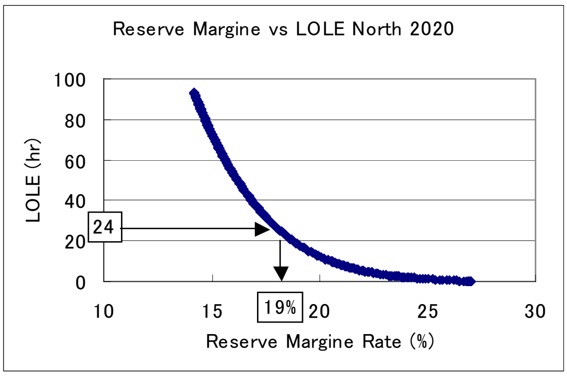


Fig. 6-1-10 Relation of Reserve Margin vs. LOLE in N System in 2020 without Interconnection

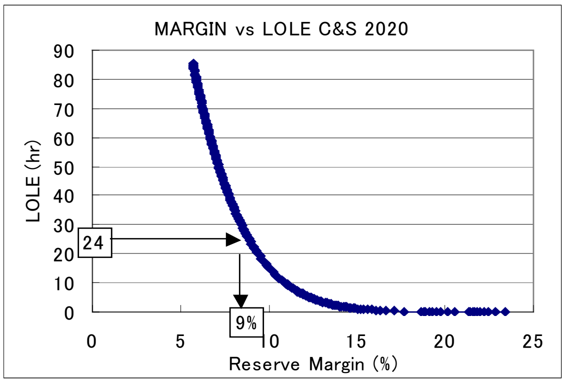


Fig. 6-1-11 Relation of Reserve Margin vs. LOLE in C&S System in 2020 without Interconnection

(2) Relation between Capacity of Interconnection and Reliability Improvement

The relation between amounts 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 generation utilization mutually. The amount of reduction from interconnection is calculated by RETICS as the tool of system reliability analysis (Figure 6-1-12). 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 from system reliability improvement. The most economic capacity of interconnection is necessary to be examined considering fuel savings by the economic operation through the interconnection with a simulation analysis of balance between demand-and-supply.

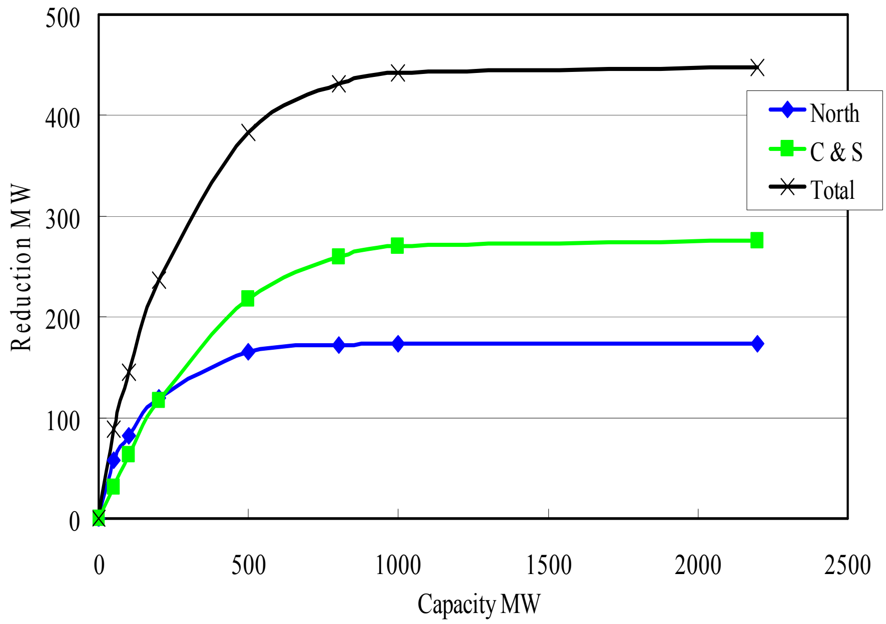


Figure 6-1-12 Relation between Amounts of Reduction in Power Development and Interconnection Capacity

[1] That Characteristic of a variety of electric loads whereby individual maximum demands usually occur at different times due to time deference and weather condition difference. When a system has 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.

(3) Annual Balance between Demand and Supply

The daily load curve in 2020 is estimated by the actual data in 2002. The peak demand is recorded in December, the end of rainy season. Since the present reserve margin is calculated based on the supply in the rainy season, it does not consider the reduction in supply in the dry season and the reduction in the water level in the flood season. Thus, the impact on a reserve margin resulted from the reduction of hydropower supply due to the dry season and a flood control of reservoirs is examined.

The balance between demand and supply of the N system and the C&S system is simulated. The balance between demand and supply is tight during June – September, the flood season, rather than the other months.

The indices on reliability applied for the demand and supply simulation should be identified considering the impacts on system reliability resulted from i) the decrease in supply capacity of hydropower plants in the flood season, and ii) severe demand and supply conditions observed when demand reaches its maximum level.

As an index of supply reliability, the reserve margin rate is determined to satisfy the system reliability criteria. Maintaining reserve margin rates, the differences in annual costs are compared through alternating planned thermal power development by peaking power sources. Accordingly, the optimal development capacity of peaking power sources is identified.

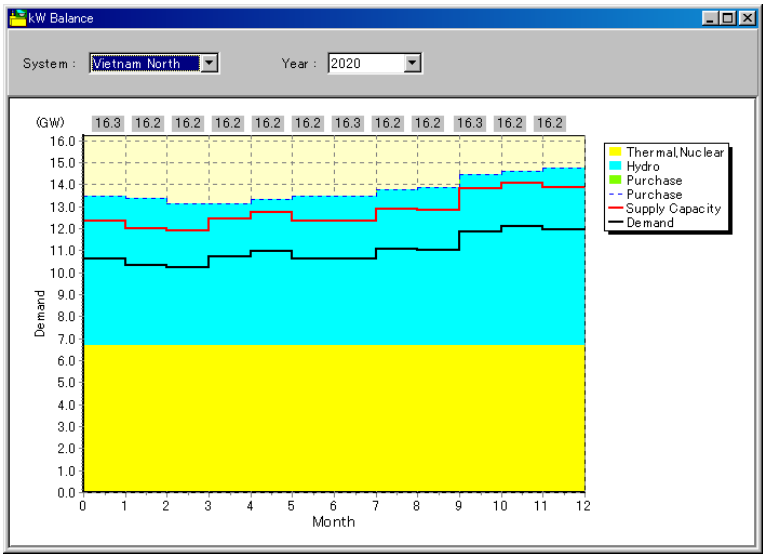


Figure 6-1-13 Balance Reserve Margin vs. Demand
North System in 2020

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

First, power development plans for the whole system of Vietnam that satisfy the LOLE 24 hours for system 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 the central & south, well 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 the central & 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.

6.2.1 Establishment of Power Development Plans for the Simulation

System reliability is evaluated by the supply and demand simulation for the Vietnam system as a mono system while making the 5th revised master plan. The Vietnam system is actually divided into two main systems for geographical and historical reasons. There are the limits for interconnection between the two systems, which cannot be addressed in the 5th revised master plan because of the mono system currently being planned. This is why that the balance between supply and demand in the north system becomes a severe condition, while the balance in the whole system is satisfied. Thus, the scenarios for the examination are established as the divided systems in this study. The limitation of interconnection capacity is up to 2,200MW depending on the transmission expansion plans of the 5th revised master plan. 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 purchasing 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 6-2-1 Scenarios of Power Development

	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.

(1) Basic Power Development Scenarios

a. Whole System Basic Scenario

The basic scenarios of power development for the whole system are arranged with the 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 reflects the interview with MOI, are excluded from the base case in order to conduct the sensitive analysis of peaking supply.

b. Divided Systems Basic Scenarios (the North System, the Central & South System)

The basic scenarios of power development for the divided systems are arranged in the same manner of the basic scenario of the whole system. The capacity of interconnection between the north system and the central & south system are selected three cases which are none, the capacity of simulating effects of improving system reliability around 1,300MW and the capacity of planned

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

in the 5^{th} revised master plan. The benefits of reduction in fuel consumption are reflected in the simulation of interconnection capacity varying in cases in addition to the benefits of improving system reliability.

(2) Varying in the Scenarios

a. Development of Son La Hydro Power Plant

The capacity of the Son La hydropower plant is 2,400MW. All units of Son La hydropower plant will be commissioned in 2015. In this study, the effects of development of Son La hydropower plant are examined in 2015 along with a discussion with their counterparts. We proposed two varying scenarios for Son La's construction as a fully operation case and a none-operation unit case.

b. Gas Fired Thermal Power Plants Installation

Sufficient gas reserves have not been discovered in the north area. The case of installation on GT and CC in the north system is excluded in this study. The case of installation of CC and GT in the south system simulates gas development limitations. The escalation of fuel prices is same condition as the 5^{th} revised master plan. The double price cases are simulated so as to make an impact on soaring fuel prices.

(3) Conditions

a. System Reliability Criteria

The LOLE 24 hour is adapted to the examination as system reliability criteria, which are used for the 5^{th} revised master plan. The power development plan adjusts supply capacity to the system reliability criteria.

b. Power Development Plan

The power development plans for the simulations are based on the 5^{th} revised master plan. The future thermal plants in the power development plan should be arranged to meet the reliability criteria. The development plans of hydropower and nuclear plants are not arranged due to their policy reasons.

c. Demand Forecast

Demand forecasts of peak demand and electric energy demand for the simulations are based on the 5^{th} revised master plan. The demand forecasts which are forecasted by the JICA study team are also examined, which considered the peak shift because of changing a structure of electric energy consumption. (Table 6-2-2)

Table 6-2-2 Features of Demand Forecasts

(Unit:MW,GWh)

		The 5th revised master plan			Considering a peak shift		
		Whole system	North system	C&S system	Whole system	North system	C&S system
Peak demand	2015	23,370	8,843	14,552	22,657	8,529	14,172
	2020	32,606	12,074	20,564	32,486	12,074	20,564
Electric energy demand	2015	141,260	51,282	89,201	142,172	51,743	90,429
	2020	201,367	72,557	127,590	202,364	73,207	129,156
Load factor	2015	69.0%	66.2%	70.0%	71.6%	69.3%	72.8%
	2020	70.5%	68.6%	70.8%	71.1%	69.2%	71.7%
Time of peak	2015	21p.m.	18p.m.	18p.m.	11a.m.	11a.m.	11a.m.
	2020	21p.m.	18p.m.	18p.m.	11a.m.	11a.m.	11a.m.

d. Supply Capacity

The supply capacity is calculated based on data from the 5th master plan. The conditions are assumed for the simulation on a daily operation of supply and demand.

1) Hydropower

a) Pondage Hydropower

The conditions of poundage hydro operation after installation of a peak supply are assumed to be:

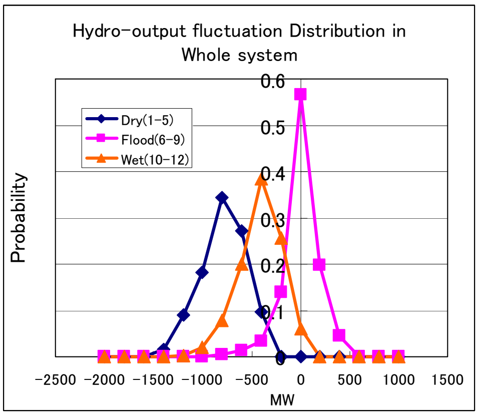
- Monthly maximum output: utilizing 90% probability output
- Monthly minimum output:

  Dry season (Jan.-May, Dec.): 1/3 of the monthly maximum output

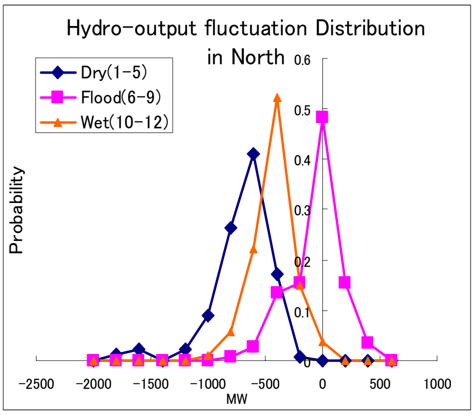
  Rainy season (Jun.-Nov.): 9/20 of the monthly maximum output
- Monthly available generating energy: 50% probability of energy generating

b) Water Flow Fluctuation

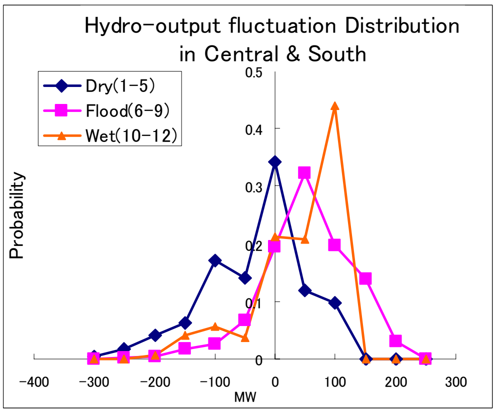
Distribution of water flow fluctuation is calculated using the data of the output from hydropower stations, at monthly peak demands from 1996 to 2001. Distribution of water flow fluctuation is shown in Fig. 6-2-1. The probability of securing planned output is low during the dry season in the north system.



Distribution in the Whole System



Distribution in the North System



Distribution in the C&S System

Fig. 6-2-1 Distribution of Water Flow Fluctuation

2) Thermal Power

- Forced outage: 5-6%
- Heat rates: To estimate heat rates with multiple regression models by capacity factors

a) Gas (including GT, CC), Oil Thermal Power

- To consider Daily start and stop (DSS), Weekly start and stop (WSS)
- Capacity of AFC: 5-20%
- Minimum output: GT, CC: 10-15% of installed capacity,

  Steam turbine: 50% of installed capacity

b) Coal Thermal

- Not to consider Daily start and stop (DSS), Weekly start and stop (WSS)
- Capacity of AFC: 20%of installed capacity
- Minimum output: 70% of installed capacity

3) Maintenance

The amount of maintenance per type of power plant is shown in the table below.

Table 6-2-3 Annual Duration

Type of fuel	Number of days
Nuclear	90
C/C	50
GT	30
S.T. (Gas)	30
S.T. (Oil)	30
S.T. (Coal)	60
Diesel	10

e. Fuel Costs

Fuel prices used for the simulation are based on the 5th revised master plan, which are shown below. The variable O&M costs are included in the fuel costs, in order to equilibrate with the 5th revised master plan. The cost for coal transportation from the north to south is 7US$/ton which includes prices of coal in the south system.

Table 6-2-4 Fuel Prices for Simulation

(Unit : ¢ ／10^3kcal)

	2000	2015	2020	%/Yr
Nuclear	0.24	0.36	0.40	2.56
Gas	1.11	1.73	1.91	2.73
FO	1.59	1.91	1.99	1.15
Coal	0.40	0.60	0.66	2.56
Coal (south)	0.47	0.67	0.73	2.00
Diesel	2.78	3.29	3.44	1.06

f. Fixed Costs

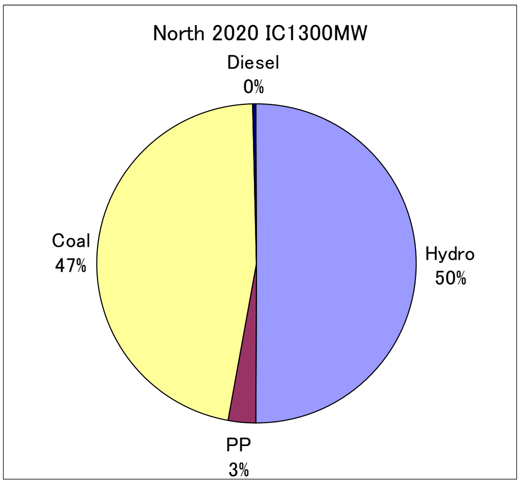
The conditions of fixed costs such as construction costs, interest, the lifetime and O&M are shown in the table below.

Table 6-2-5 Construction Costs and Related Data

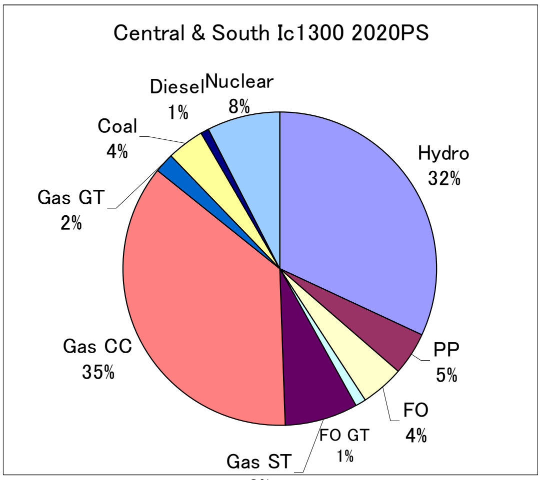
	Capacity	Construction Costs CENT/kW	Related data for fixed costs			
			Interest (%/yr)	Life time (yr)	Remaining value (%)	O&M (%)
Conventional hydro	>100MW	130,000	10	40	10	1.0
	>50MW	145,000	10	40	10	1.0
	<50MW	173,500	10	40	10	1.5
PSPP		65,000	10	40	10	1.0
Nuclear	600MW	220,000	10	40	10	3.0
C/C	600MW	60,000	10	25	10	4.5
GT	250MW	40,000	10	20	10	5.5
S.T.（Gas）	500MW	83,300	10	20	10	2.0
S.T.（Gas）	250MW	96,100	10	20	10	2.0
S.T.（Oil）	500MW	74,600	10	25	10	2.0
S.T.（Oil）	200MW	91,400	10	25	10	2.0
S.T.（Coal）	500MW	93,800	10	30	10	3.5
S.T.（Coal）	100MW	129,400	10	30	10	3.5

g. Composition of Power Generations

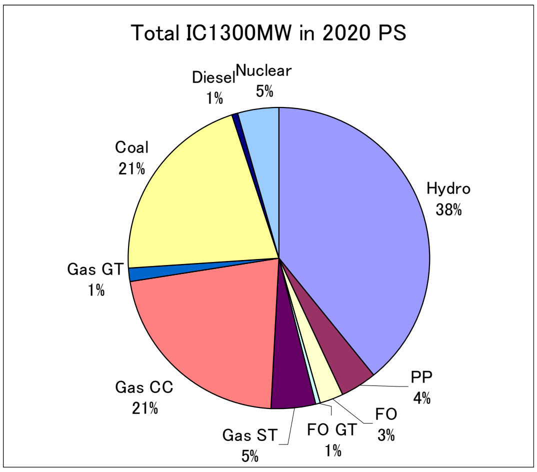
The actual system in Vietnam has limitations of interconnection capacity between the north and the south system. The composition of power generation of the divided systems is different from the whole system. The difference affects the system in an amount of reserve capacity to satisfy the daily operation and system reliability criteria. The composition in 2020 of the divided systems with the 1,300MW of interconnection capacity is shown in Fig. 6-2-2.



The North System



The Central & South System

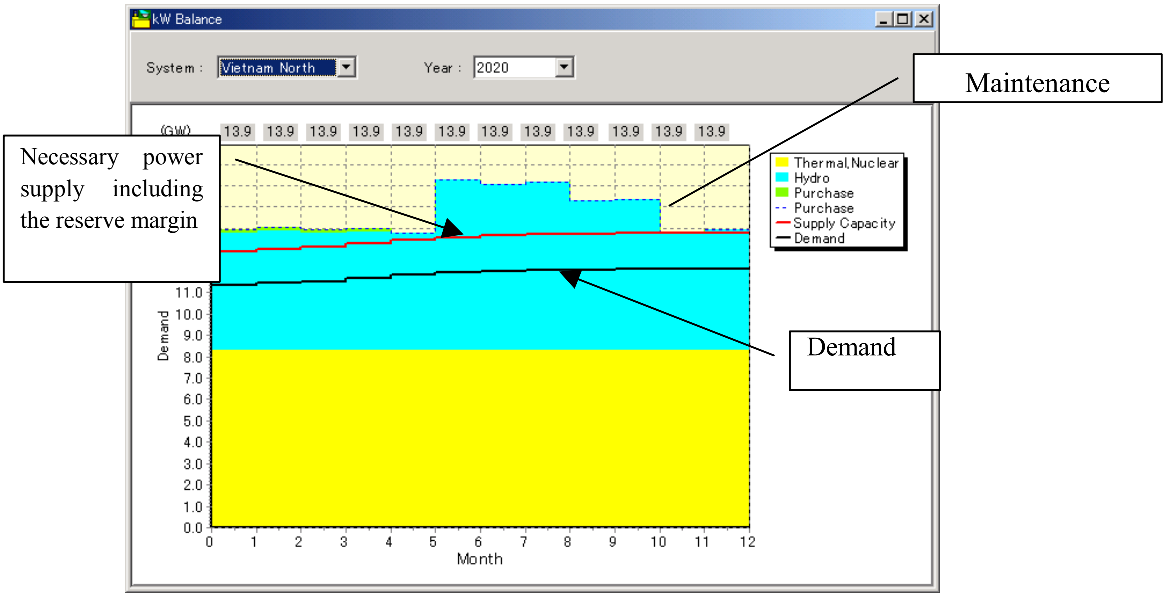


Total Capacity of Divided Systems

Fig. 6-2-2 Composition of Generation in Divided Systems in 2020

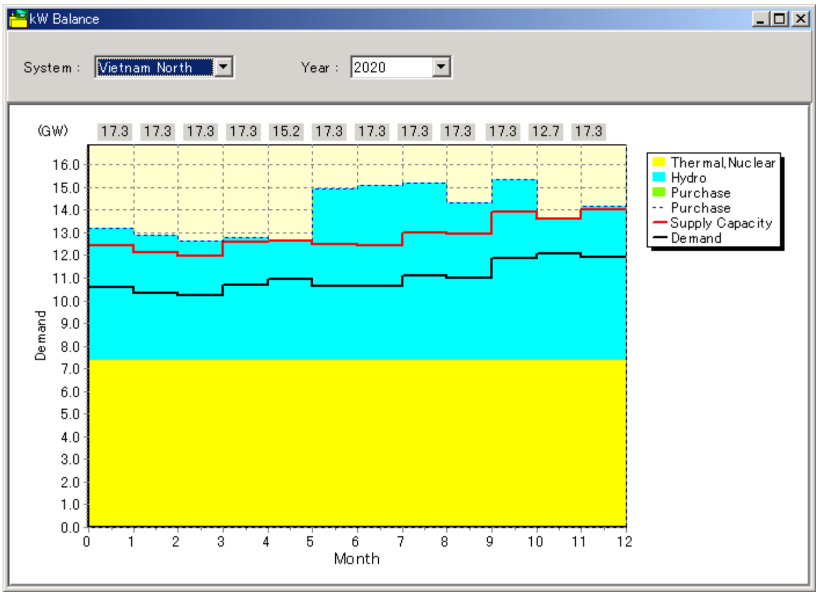
Thus, the composition of the Vietnamese system is different when the limitations of capacity of interconnection are considered. The composition of the north system consists of coal and hydropower. The characteristics of coal thermal power are that it operates as an economical base supply as mentioned in the screening section, and that it is difficult to flexibly operate due to fuel handling limitations. The types of hydropower are consisted to be the run-of-river type that operates by water from rivers, and the pondage type that can operate during peak hours with the storage of water via dams. These hydropower plants have the characteristics of reduced supply capacity during the dry season. These features affect system reliability and daily operation.

The monthly output of hydropower varies greatly between the dry season and the rainy season in Vietnam. The actual data of the monthly output of hydropower in the 2002 rainy season shows the reduction in supply capacity because of the lowered water head for flood control. The reduction in hydropower supply capacity in the rainy season causes the low monthly peak demand, because hydropower was over half the total supply capacity in 2002. Thermal power will be developed by 2020, and hydropower will be developed by 2020. The river system will be developed. The development river system brings an efficient operation of the river system. When the operation of the river system improves and the increasing capacity, it can reduce the effects from flooding control of hydropower output. Since MP demand forecasts are reflected in the records of 2002, the monthly peak demands are lower in the rainy season. The necessary amount of annual maintenance can be secured by using the surplus supply in the rainy season for maintenance. Monthly peak demands in forecasts consider a monthly peak increase. The surplus supply capacity in the rainy season is reduced due to an increased peak in monthly demand. Considering effects of a peak shift in demand forecasts, it is necessary to secure the same system reliability to develop additional power plants. The two cases of balance between supply and demand in 2020 with 1,300MW interconnection, is a consideration of peak shift effects and no consideration is shown below.



Balance between Supply and Demand in the North System

(Consideration of Peak Shift Effects)



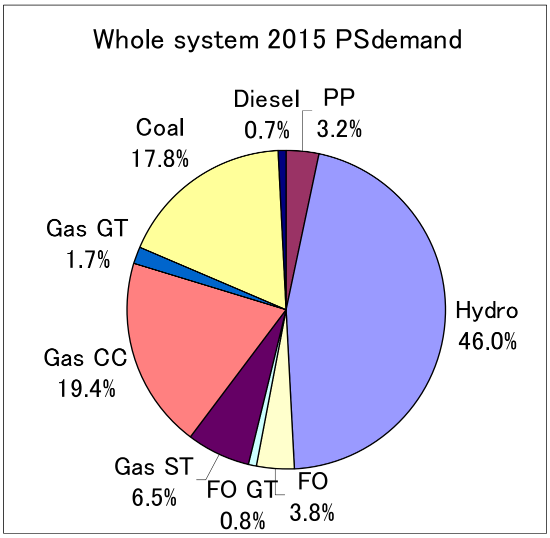
Balance between Supply and Demand in the North System

(No Consideration of Peak Shift Effects)

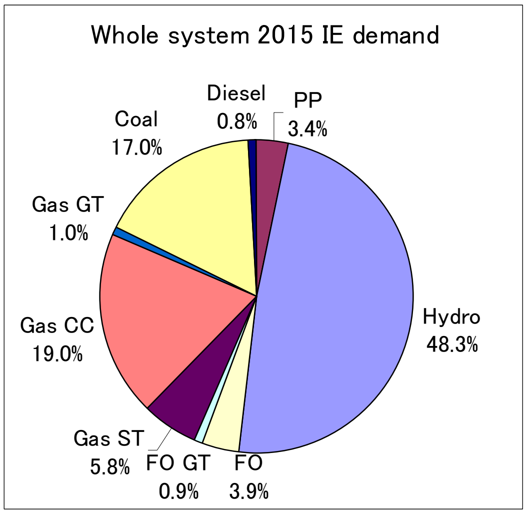
Fig. 6-2-3 Monthly Balances between Supply and Demand in 2020

The supply capacity is necessary for knowing demand forecasts considering peak shift effects which secure the system reliability criteria more so than MP demand forecasts. This is due to a monotonous increment of monthly peak demand. We consider not to be affected the difference of installed capacity which highly depends on demand forecasts to the generation composition.

＜Composition of Generation 2015＞

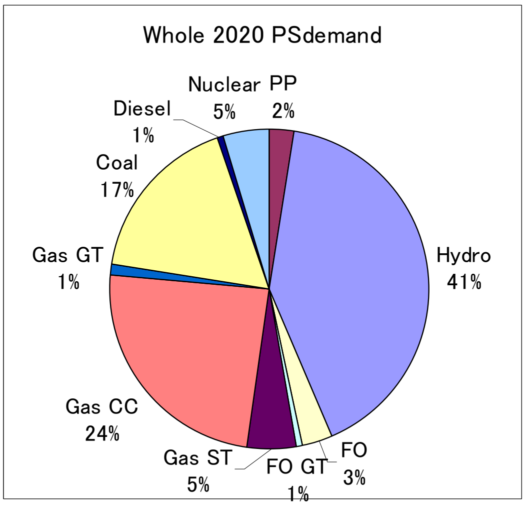


Consideration of Peak Shift Effects

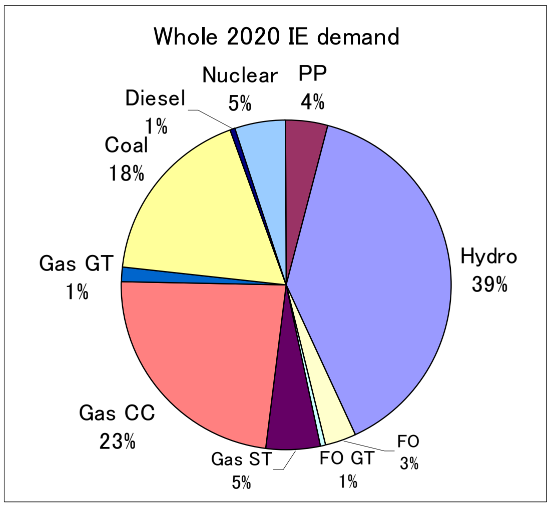


No Peak Shift Effects

＜Composition of Generation in 2020＞



Consideration of Peak Shift Effects



No Peak Shift Effects

Fig. 6-2-4 Composition of Generation Depending on Peak Shift Effects in 2015, 2020

6.2.2 Necessary Supply Capacity to Secure the System Reliability Criteria

(1) Balance between Supply and Demand in the 5th Revised Master Plan

First, 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 are LOLE = 0.08hr. The reserve margin is 19.3%. (Refer to Fig. 6-2-5, Fig. 6-2-6) The system reliability criteria is satisfied when the Vietnam system is treated as a mono system.

In case of no limitation to the Vietnam system, the supply capacity is enough to secure the system reliability criteria.

Aforementioned, there are differences such as the composition of generation, the scale of the system and the daily load profile divided between systems and whole system. This causes differences in the required capacity for LOLE=24hr between the divided systems and whole system. (Shown in Table 6-2-6)

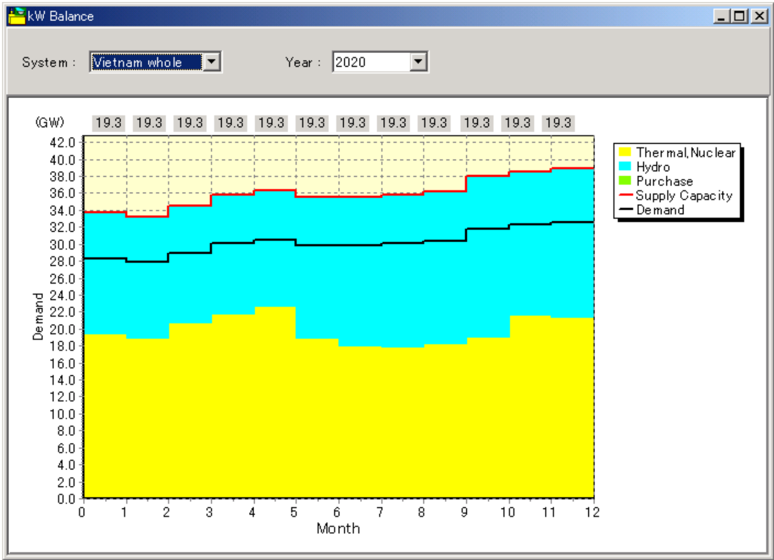


Fig. 6-2-5

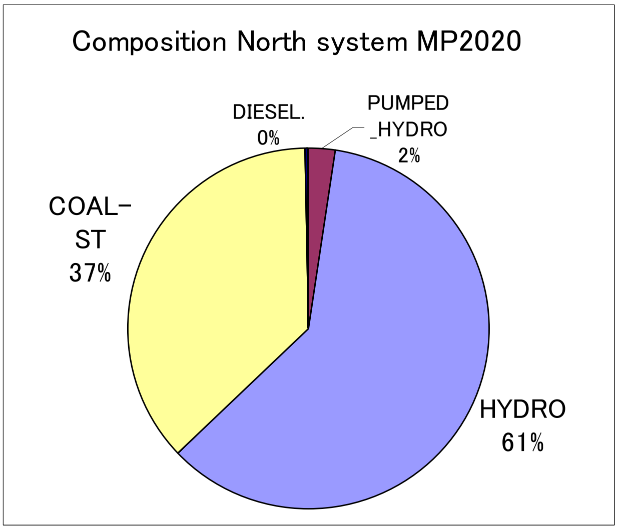
2020 Balance between Supply and Demand in the 5th Revised Master Plan

Table 6-2-6 Installed Capacity for the 5th Revised Master Plan in 2020

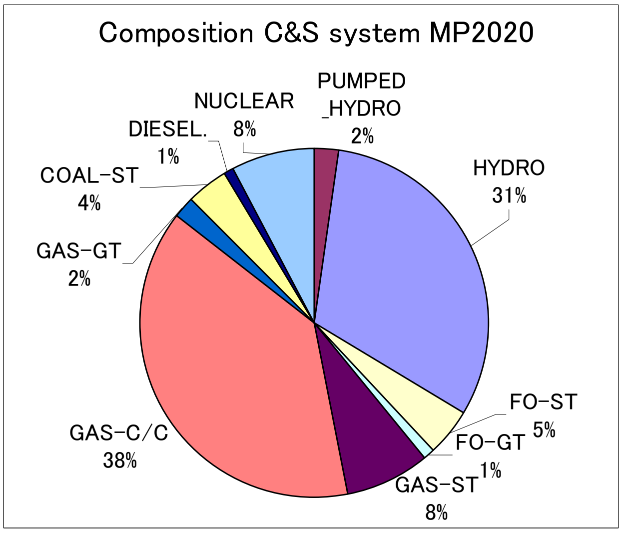
(Unit: MW)

	Installed capacity	Reserve margin rate	LOLE	Annual costs (US$ mil/Yr)
Whole system	42,162	19.3%	0.08	9,515
Divided North	16,290	10.9%	86.46	2,925
C&S	25,872	20.2%	0.03	6,699
Total	42,162		Annual costs total	9,624

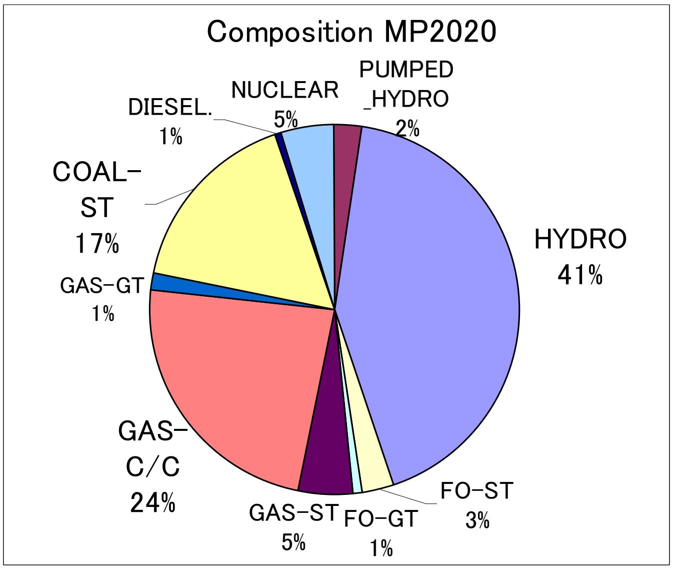
North System



C&S System



Total



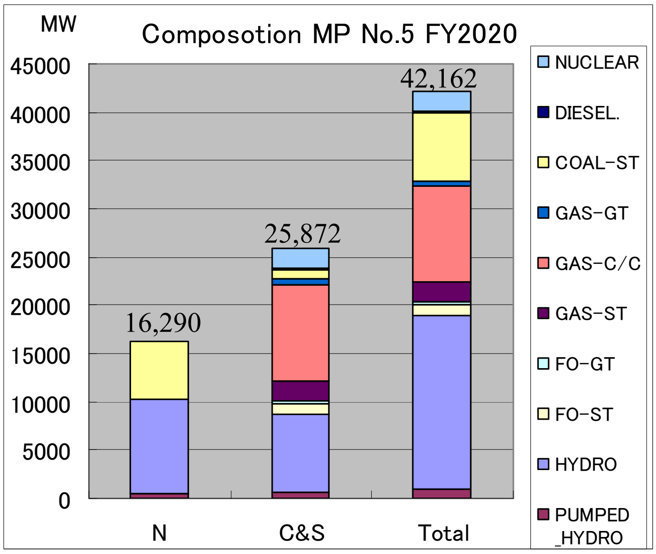


Fig. 6-2-6 Composition of Generation of the 5th Revised Master Plan in 2020

The 5th master plan has sufficient supply capacity to meet the system reliability criteria for the whole system. The capacity of the north system is insufficient when considering the limitations of interconnection capacity between the north and south system. The generation composition of the north system is occupied by hydropower supply. Hydropower supply is varied by the volume of water flowing in the rivers. During dry season, the output from hydropower decreases due to the reduction in water flowing in the rivers. The reduction in hydropower causes slumps in system reliability. Therefore, the supply capacity should be arranged to secure the system reliability as LOLE=24hr by revising the power development plan.

(2) Appropriate Installed Capacity to Secure System Reliability Criteria

The installed capacity to secure the system reliability is shown in Table 6-2-7.

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 & 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 & south system and an additional 65MW in the north system are necessary for the divided system to secure the system reliability criteria.

Table 6-2-7 Appropriate Installed Capacity to Secure the System Reliability Criteria

（Unit: MW, US$ mil/Yr）

	Installed capacity (MW)	Reserve margin rate	LOLE	Annual costs
①Whole system	39,793	9.7%	24.6	9,400
②Divided system (North)	16,225	14.2%	23.4	3,083
(Central & south)	24,538	7.9%	23.3	6,555
Total	40,763		Annual costs total	9,638

In the case of interconnection of 1,300MW, the installed capacity of the north system is 1%, of the central & south system is 3% and whole system is 4% less than the none interconnection case one. The reductions in installed capacity are caused by the utilization of reserve capacity through the interconnection.

Table 6-2-8 Appropriate Installed Capacity to Secure the System Reliability Criteria with the Interconnection of 1,300MW

（Unit: MW, US$ mil/Yr）

Interconnection 1,300MW	Installed capacity(MW)	Reserve margin rate	LOLE	Annual costs
③Divided systems (North)	16,032	12.3%	23.7	3,029
(Central & south)	23,824	6.8%	24.5	6,201
Total	38,857		Annual costs total	9,624

(3) Effects from Interconnection and Demand Forecast to Appropriate Installed Capacity

The appropriate installed capacity scenarios are examined for the study on the appropriate composition of peak supply. In this study, the case that includes the power purchase from Laos excluding Cambodia and China is set as the base case. The power purchase is assumed hydropower. The potential hydropower will be developed by 2020 in the 5th revised master plan. The capacity and schedule of hydropower development is same as the 5th revised master plan. The arrangement of appropriate capacity is conducted by thermal power development. This arrangement affects the composition in 2020 by about 3%. This effect does not make a significant change to the composition in 2020 for the simulation. The appropriate capacity of the scenarios is shown in Table 6-2-9.

Table 6-2-9 Appropriate Capacity of the Scenarios

(Unit: MW)

		MP demand forecast		Peak shift demand		Comparison with 5th revised MP	
		Installed capa.	RMR	Installed capa.	RMR	IE /MP	PS/MP
Whole system		39,793	9.7%	41,703	9.4%	-5.6%	-1.1%
Interconnection 0MW	North	16,225	14.2%	17,325	15.6%	0.4%	6.3%
	C&S	24,538	7.9%	25,528	9.5%	-5.1%	-1.3%
Interconnection 800MW	North	16,045	12.8%	17,095	14.3%	-1.5%	4.9%
	C&S	24,188	6.3%	25,178	7.8%	-6.5%	-2.7%
Interconnection 1,300MW	North	16,045	12.7%	17,025	13.9%	-1.5%	4.5%
	C&S	24,163	6.3%	25,188	7.8%	-6.6%	-2.6%
Interconnection 2,200MW	North	16,045	12.7%	17,025	13.9%	-1.5%	4.5%
	C&S	24,163	6.3%	25,188	7.6%	-6.6%	-2.6%

C&S: The central and south system, RMR: reserve margin rate

The appropriate installed capacity will see a reduction in the north system of the MP demand forecast. The condition of related power purchasing from neighboring countries of the base case will only be from Laos. The condition cases show reduction in hydropower supply in the north system. The reduction in hydropower brings a reduction in water flow fluctuation in the north system, which results in a decrease in necessary reserve capacity.

The duration of daily peak demand is longer than the MP demand forecast, when considering peak shift effects. The duration makes the latent supply capacity of hydropower, which results in the additional supply capacity for the cases of peak shift demand.

(4) Effects of Power Purchases from Neighboring Countries and Limitations of Interconnection

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 MP demand forecast, thermal power development of the central & 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 the system reliability. 2% of thermal power development can be reduced in the central & south system.

In terms of the MP 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.

6.2.3 Study on Peak Supplies in 2015

The daily operation considering the conditions of actual systems is simulated with the scenarios. After analysis of the simulation results, it is clear that the risks of interconnection capacity limitations and effects of peak shifting affect the composition of peak supply.

(1) Results of Simulation of Balance of Supply and Demand

The results of the balance of supply and demand simulation are shown in Table 6-2-10.[1]

Two cases related to demand forecasts are the MP demand forecast and the forecast considering peak shift effects. The capacity of interconnection is treated in four (4) cases such as zero (0) MW, 800MW, 1,300MW and 2,200MW. Under these conditions, 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 & south system. The gas turbine is installed in the central & south system. The gas turbine installed in the north system is not simulated because the gas potential is not in the north region.

Table 6-2-10 Appropriate Composition and Annual Costs

（Unit: %, US$ mil/Yr）

Scenario		PSPP in N		PSPP in S		GT in S	
Demand	Interconnection capacity	%	US$ mil/Yr	%	US$ mil/Yr	%	US$ mil/Yr
Peak shift	Whole system	1.6%	6546	1.6%	6546	0%	6582
	0MW	2.3%	6903	0%	6944	3.1%	6640
	800MW	1.8%	6644	0%	6692	4.2%	6368
	1300MW	1.8%	6609	0%	6626	4.2%	6241
	2200MW	0.6%	6586	0.6%	6587	4.1%	6245
MP demand	Whole system	3.4%	6320	3.4%	6320	5.1%	6314
	0MW	1.0%	6679	1.0%	6667	1.7%	6912
	800MW	0%	6489	2.1%	6457	3.6%	6606
	1300MW	0%	6336	0%	6336	2.3%	6564
	2200MW	0%	6328	0%	6328	2.4%	6532

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

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 MP demand forecast. The duration of daily peak demand in the peak shift demand forecast is longer than the duration in the MP 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

[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.

hydropower. Additional peak power supply will be needed to compensate for the latent 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.

The annual costs of simulated cases are shown in Table 6-2-11.

In the case of no interconnection, of capacity of 0MW, the annual costs of the divided system are 5% higher than the whole system. The annual costs of peak shift demand are 4% larger than the MP demand forecast one. The investment recovery costs are large because the peak shift demand cases request more capacity than in MP demand cases.

The effects of capacity of interconnection are shown in below. The cases have no capacity because of transmission line reliability as N-1 and 2,200MW that is obtained by another transmission line in addition to the existing plan.

Table 6-2-11 Annual costs vs. Interconnection Capacity in 2015

(Unit: US$ mil/Yr)

Type of demand forecast	Interconnection capacity 0MW	Interconnection capacity 2,200MW	Difference of annual costs
Peak shift	6,679	6,328	▲ 161
MP demand	6,903	6,586	▲ 317

(2) Effects of Son La's Construction

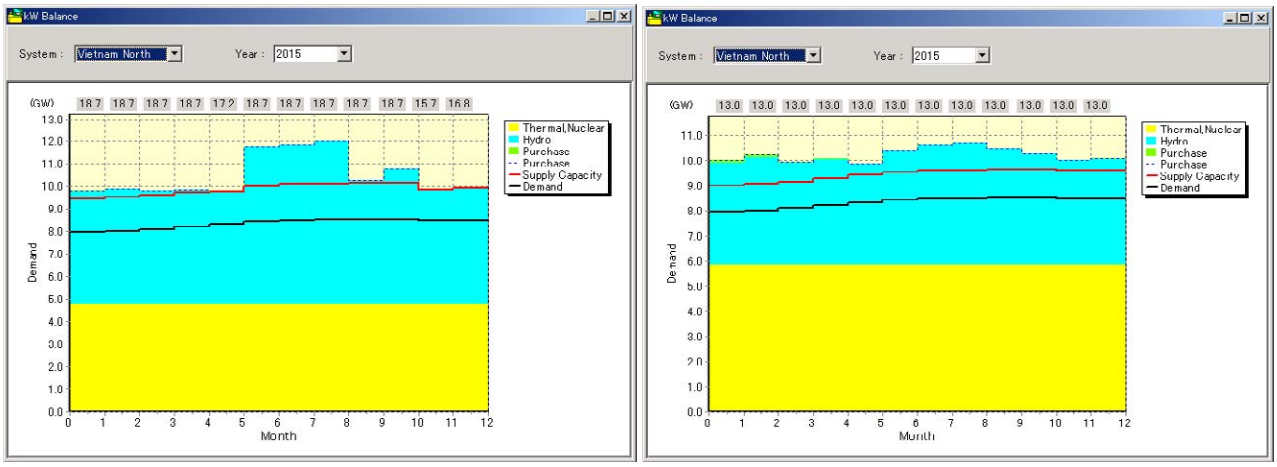
The effects of the development of Son La, with a 2,400MW capacity, are examined by the simulation of the balance of supply and demand in 2015. The development does not affect the composition of peak supply. In the case of peak shift demand with 1,300MW interconnection, the PSPP installation shows significant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

Table 6-2-12 Effects of Son La's Construction

<table>
<tr><th rowspan="2">Demand forecast</th><th rowspan="2">Interconnection</th><th colspan="2">PSPP in N</th><th colspan="2">PSPP in S</th></tr>
<tr><th>Installation rate</th><th>Annual costs US$ mil/Yr</th><th>Installation rate</th><th>Annual costs US$ mil/Yr</th></tr>
<tr><td rowspan="3">Peak shift</td><td>Whole system</td><td>0%</td><td>6,607</td><td>-</td><td>-</td></tr>
<tr><td>1,300MW</td><td>1.2%</td><td>6,538</td><td>0%</td><td>6,542</td></tr>
<tr><td>2,200MW</td><td>0%</td><td>6,538</td><td>0%</td><td>6,538</td></tr>
<tr><td rowspan="2">MP demand</td><td>Whole system</td><td>0%</td><td>6,475</td><td>-</td><td>-</td></tr>
<tr><td>1,300MW</td><td>0%</td><td>6,285</td><td>0%</td><td>6,542</td></tr>
</table>

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.

The North System



Son La (2400MW)（PSPP1.8%（750MW））　　　　Son La (0MW) (PSPP1.2%（500MW））

Fig. 6-2-7　Effects of Son La’s Construction to Balance Supply and Demand

Peak shift demand with Interconnection of 1,300MW

The operation of Hoa Binh reservoir will be different from before and after the development of Son La. Based on the data from IE, Hoa Binh reservoir can raise the water level and increase the monthly water volume in the rainy season after Son La’s construction. This is why the supply capacity in the rainy season increases 2GW after Son La’s construction, shown in Fig. 6-2-7.

(3) Scenarios of Gas Turbine Installation

The gas turbine installation reduces annual costs in 2015, based on the results of the simulation. 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 alternatives. 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.

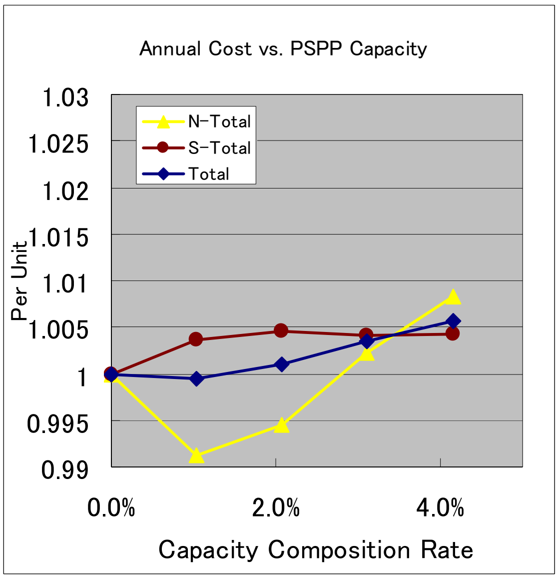
The gas turbine installation does not affect the annual costs reduction in 2020. When the gas turbine installation is decided immediately, benefits are obtained considering the lifetime of 20 years. It is difficult to change the planned thermal power to the gas turbine, because the contracts for gas supply will not be set for a few more years.

(4) Effects of Power Purchase from Neighboring Countries

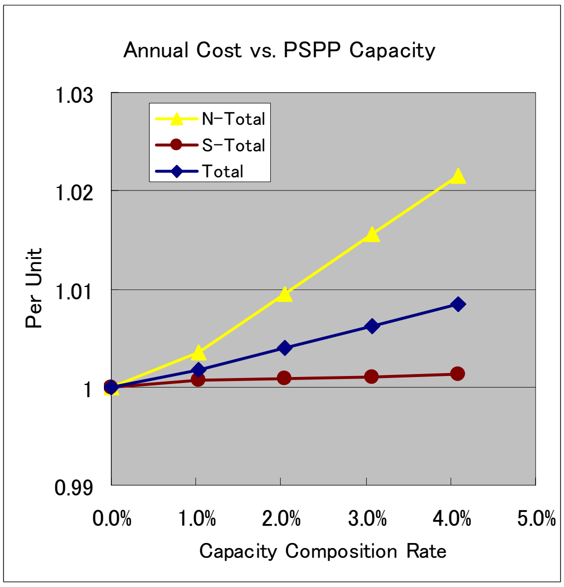
The power purchase of hydropower is planned for 1,900MW from Laos and Cambodia by 2015. In the simulation, these hydropower purchases are the same as Vietnam hydropower. Under the conditions, the effects of the power purchase are examined. The results of simulation are shown in Fig. 6-2-8.

The effects of power purchases are examined in comparison with the scenario of a zero power purchase of PSPP. This would be installed in the north system in the case obtaining the benefits from PSPP installation in 2015. The zero power purchase case shows the benefits from reduction in fuel consumption due to PSPP installation in the north system. The benefits from reduction in fuel costs in the north system are cancelled by the increase of fuel consumption due to reductions in power exchange from the north system after PSPP installation. The results of the simulation of zero power purchase case indicate the effects of daily operation and no effects of peak supply installation.

The power purchase is treated in the same manner as a power plant in Vietnam. They however are not owned by Vietnam. Actually, their operation is not flexible as Vietnamese-owned plants. From that viewpoint, the power purchase does not affect the peak supply capacity.



Zero Power Purchasing



Power Purchasing from Laos, Cambodia

Fig. 6-2-8 PSPP installation vs. Annual Costs （Interconnection 1,300MW in 2015）

(5) Effects of Soaring Fuel Prices

Simulations are conducted by using fuel prices double those of normal cases in order to be clear regarding the effects of soaring fuel prices. The results show the effects of annual fuel costs, but it does not affect the peak supply installation.

Table 6-2-13 Annual Costs in Soaring Fuel Prices（in 2015）

Demand	Interconnection	PSPP in N	
		Peak installation	US$ mil/Yr
Peak shift	1,300MW	1.2%	6,609
		1.2%	8,668
		Diff.	2,059(+31%)
MP demand	1,300MW	0%	6,336
		0%	8,234
		Diff.	1,898(+30%)

The cases of oil and gas prices soaring to double the amount of normal prices affect the increasing 30% of annual costs.

Table 6-2-14 Soaring Fuel Prices in 2015

（Unit: ¢/10^3 kcal）

	Soaring fuel prices	Normal case
Gas	3.45	1.73
FO	3.82	1.91
Coal	0.60	0.60
Diesel	6.59	3.29

6.2.4 Study on Peak Supplies in 2020

The appropriate compositions of peak supplies in 2020 are examined by the simulation between supply and demand. The results of the simulation indicate that the peak shift effects and limits of interconnection affect the appropriate compositions of peak supply installations.

(1) Results of Simulation between Supply and Demand

The results of the simulation of balance between supply and demand are shown in Table 6-2-15.[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 MP demand forecast.

The other types of peak supply do not show the benefits of peak supply installation.

The benefits from this installation decrease when the utilization of peak supplies increases through the interconnection when the capacity of the interconnection is increased.

Table 6-2-15 Relation between Appropriate Composition and Annual Costs in 2020

(Unit: %,US$ mil/Yr)

Scenario		PSPP in N		PSPP in S		GT in S	
Demand	Interconnection	%	US$ mil/Yr	%	US$ mil/Yr	%	US$ mil/Yr
Peak shift	Whole system	0	9,621	0	9,621	0	9,621
	0MW	3.5	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
MP	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

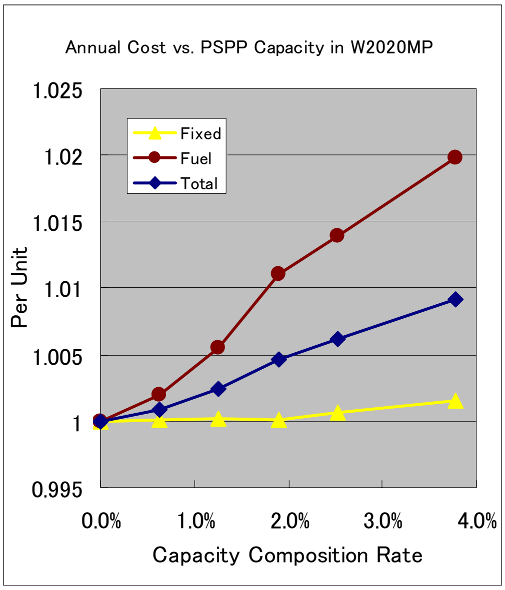
Notes) PSPP in N: Case of PSPP installation in the north system
PSPP in S: Case of PSPP installation in the central and south system
GT in S: Case of GT installation in the central and south system

The annual costs of divided system increase by 2% of the whole system's annual costs, when the capacity of interconnection is 0MW. The annual costs of peak shift demand cases are around 3% higher than the annual costs of the MP demand forecast. The increment is caused by the requirement of more supply capacity for the peak shift demand cases rather than MP demand cases.

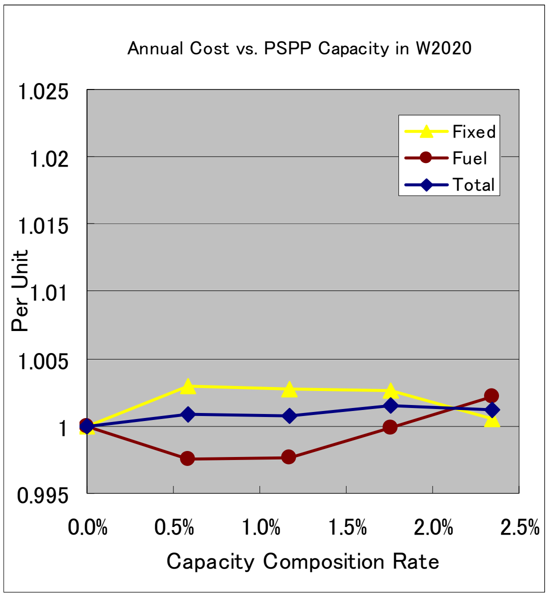
[1] The results are in the cases of installation of peak supplies respectively. They do not describe the cases of complex installation of peak supplies.

(2) Appropriate Compositions of Whole System

Hydropower supply is occupied in half of the composition of power supply in 2020. Furthermore, thermal power as the middle and base supply is around 40% of the composition of power supply in 2020. Though they can send supply to a peak demand, the benefits from the additional peak supply installation are few. (See Fig. 6-2-9)



MP Demand in 2020



Peak Shift Demand in 2020

Fig. 6-2-9 Relation between Annual Costs and Peak Supply for Whole System in 2020

(3) Appropriate Composition of Peak Demand in Divided System

a. Appropriate Composition of Peak Demand in Divided System in 2020

The results of the simulation between supply and demand in 2020 indicate the benefits from the PSPP installation in the north system. The appropriate composition of peak supply is affected by demand profiles. In the peak shift to daytime demand, the appropriate compositions are 3 – 4 %. While the MP demand is based on the actual peak, in which there are 2 – 4 peaking hours per day, the appropriate composition is 1%. The details of the simulation results are described in the sections below.

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.

In the case of interconnection capacity of 1,300MW, annual costs will fall to 49US$ mil/Yr. In this case, the fixed costs increase 2US$ mil/Yr but the fuel costs decrease 51US$ mil/Yr. The benefits of PSPP installation in the north system are continued until at 5.9% (2,500MW) of installed capacity. (See Fig. 6-2-10)

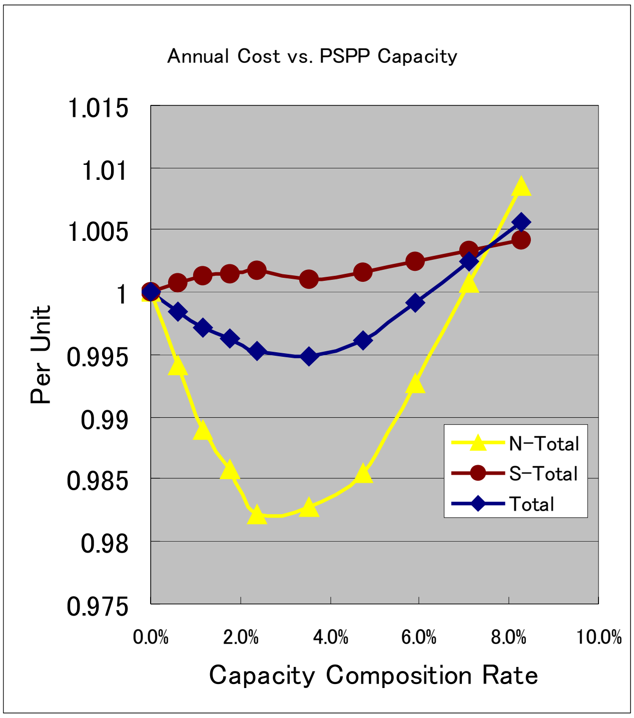


Fig. 6-2-10

Relation between PSPP installed Capacity (North) and Annual Costs in 2020

(Peak Shift Demand with Interconnection of 1,300MW)

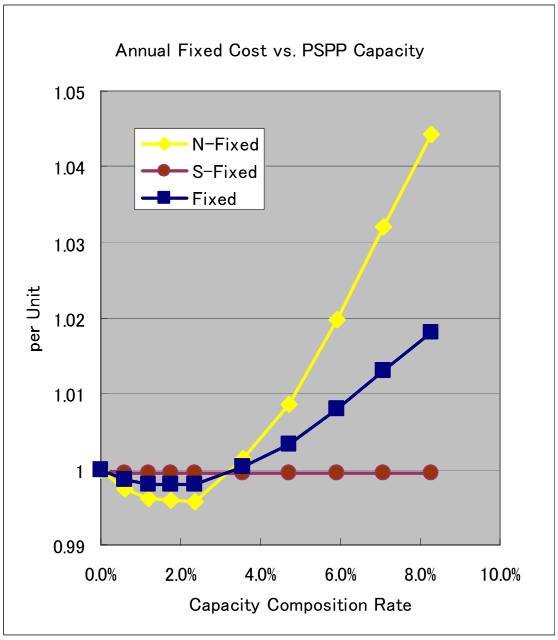


Fig. 6-2-11 PSPP Installed Capacity vs. Fixed Costs

Interconnection 1,300MW

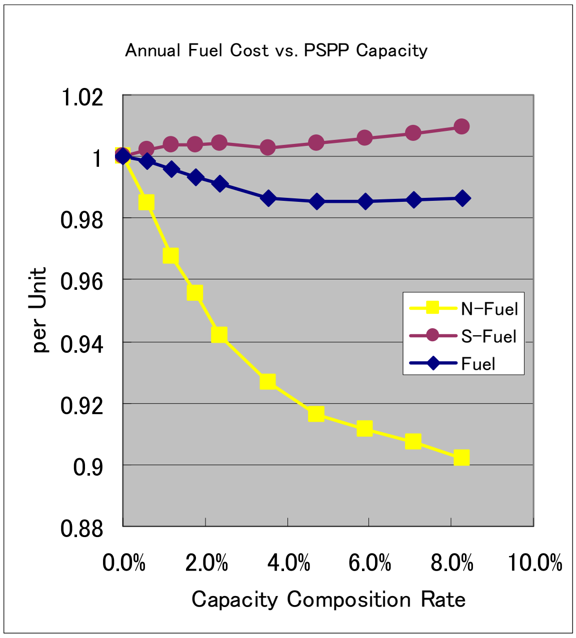


Fig. 6-2-12 PSPP Installed Capacity vs. Fuel Costs

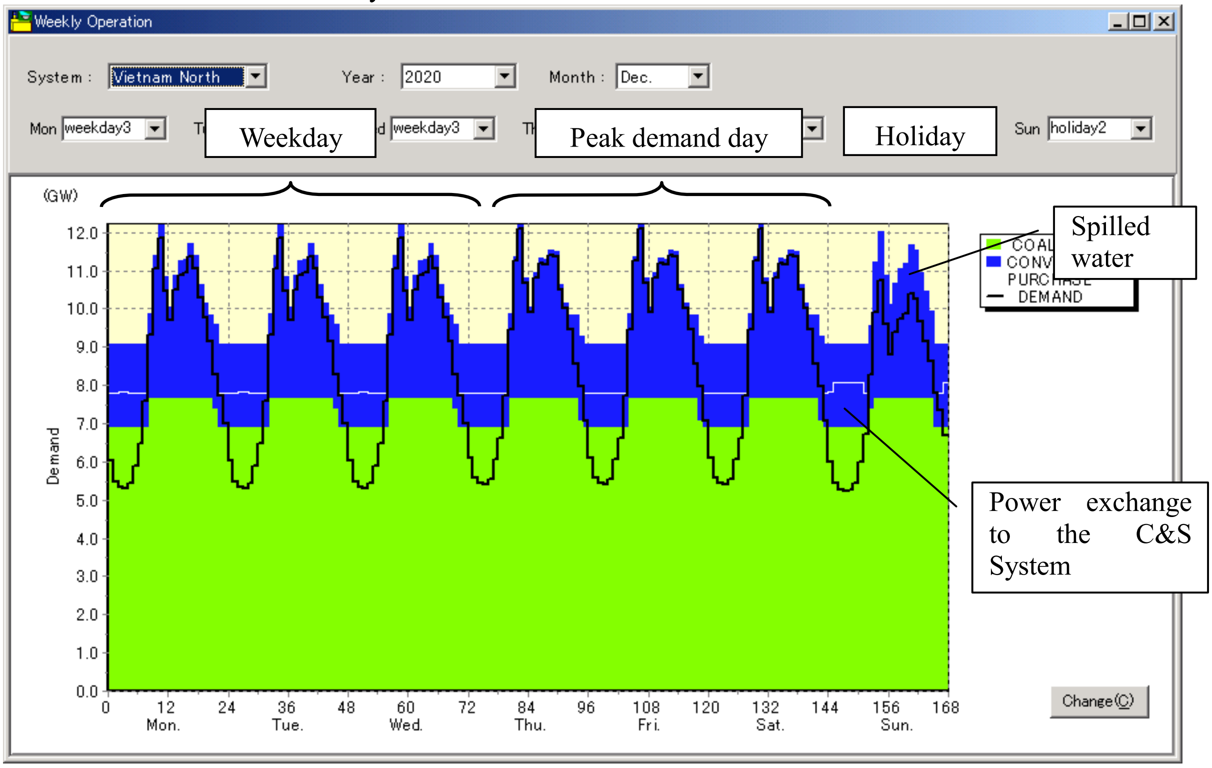
Interconnection 1,300MW

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 pump 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 central & south system after installing PSPP in the north system. (See Fig. 6-2-11, Fig.6-2-12)

The results of simulations before and after the PSPP installation in Dec. 2020 are shown in Fig. 6-2-13, Fig. 6-2-14. The PSPP installed in the north system can use the off-peak surplus capacity as pumping energy. The utilization of the off-peak surplus power for pumping energy brings about a reduction in power exchange to the central & 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.

(Dec. 2020 in the North System)



(Dec. 2020 in the C&S System)

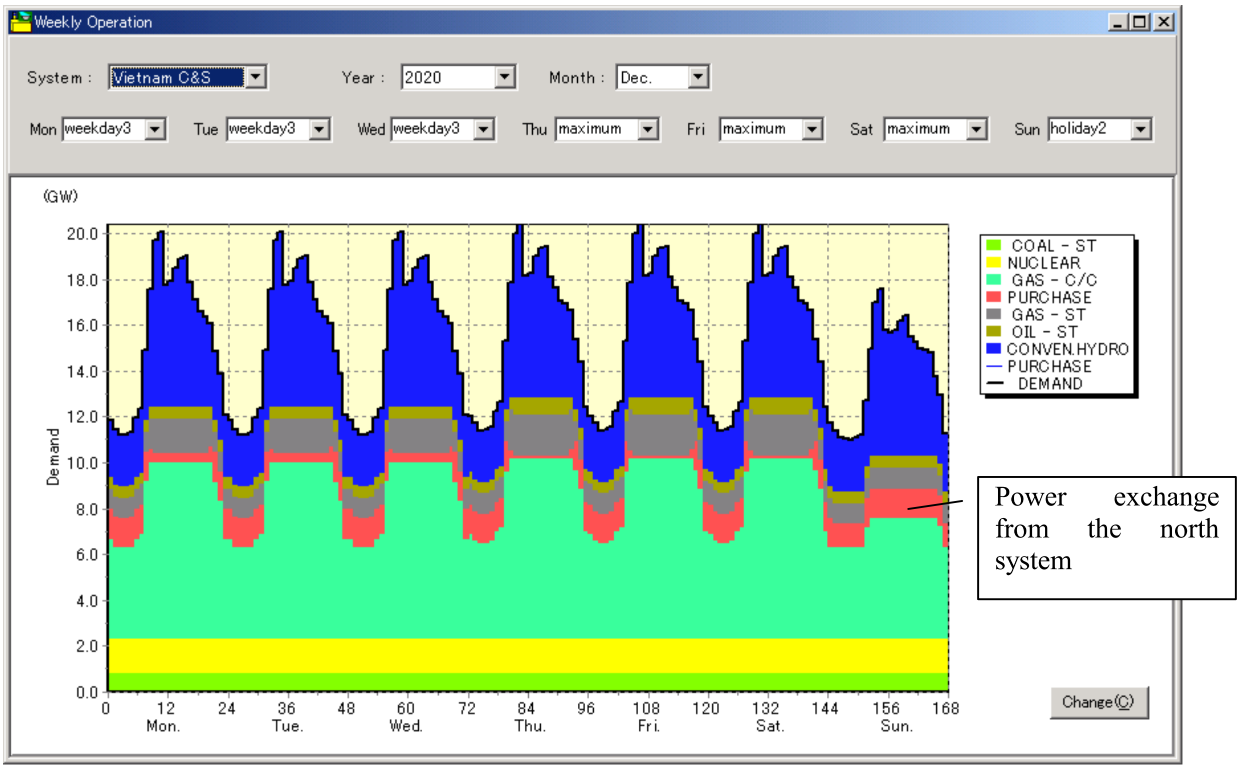
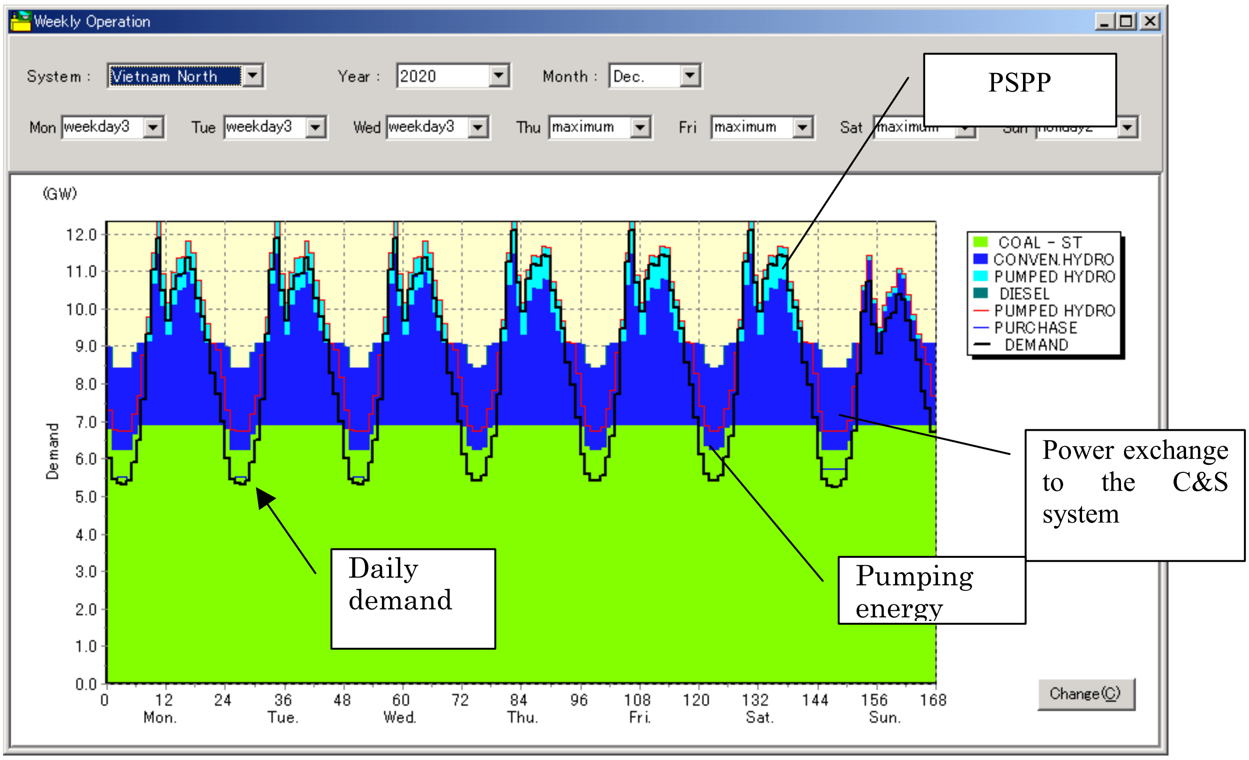


Fig. 6-2-13 Results of Daily Operation Simulation (Before Installation PSPP)

(Dec. 2020 in the North System)



(Dec. 2020 in the C&S system)

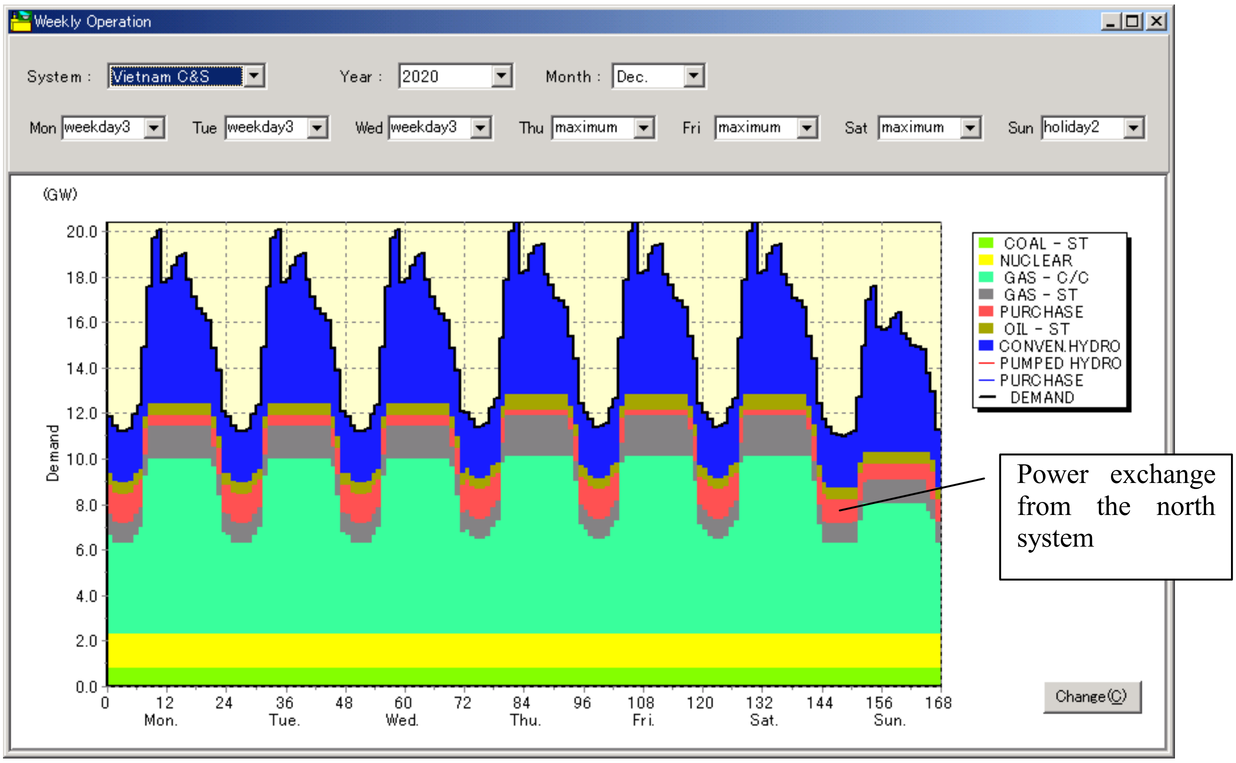


Fig. 6-2-14 Results of Daily Operation Simulation (after Installation PSPP)

(PSPP 3.5%, or 1,500MW in the North System)

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

In the case of PSPP installation in the central & 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 the latent capacity of PSPP.

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

It is shown in Fig. 6-2-16 and Fig. 6-2-17 that the results of simulations of PSPP installation 0.6% (250MW) and 4.7% (2,000MW) cases are both in the central & south system in Dec. 2020 with interconnection of 1300MW.

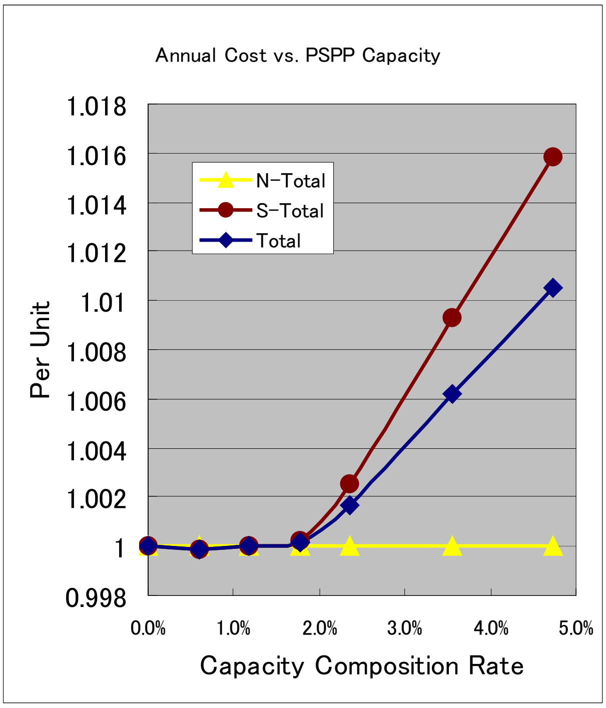


Fig. 6-2-15

PSPP Installation (in C&S System) Capacity vs. Annual Costs, Peak Shift Demand, Interconnection 1,300MW, in 2020

In the case of the 0.6% PSPP installation, the reduction in fuel consumption is caused by power exchange through the interconnection. In the case of the 4.7% PSPP installation, the pumping energy is insufficient for the power from the north system. Thus, thermal power increases in the south system. The PSPP generation costs are exceeding the gas thermal generation costs. This is why that the annual costs increase after PSPP installing in the central & south system.

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

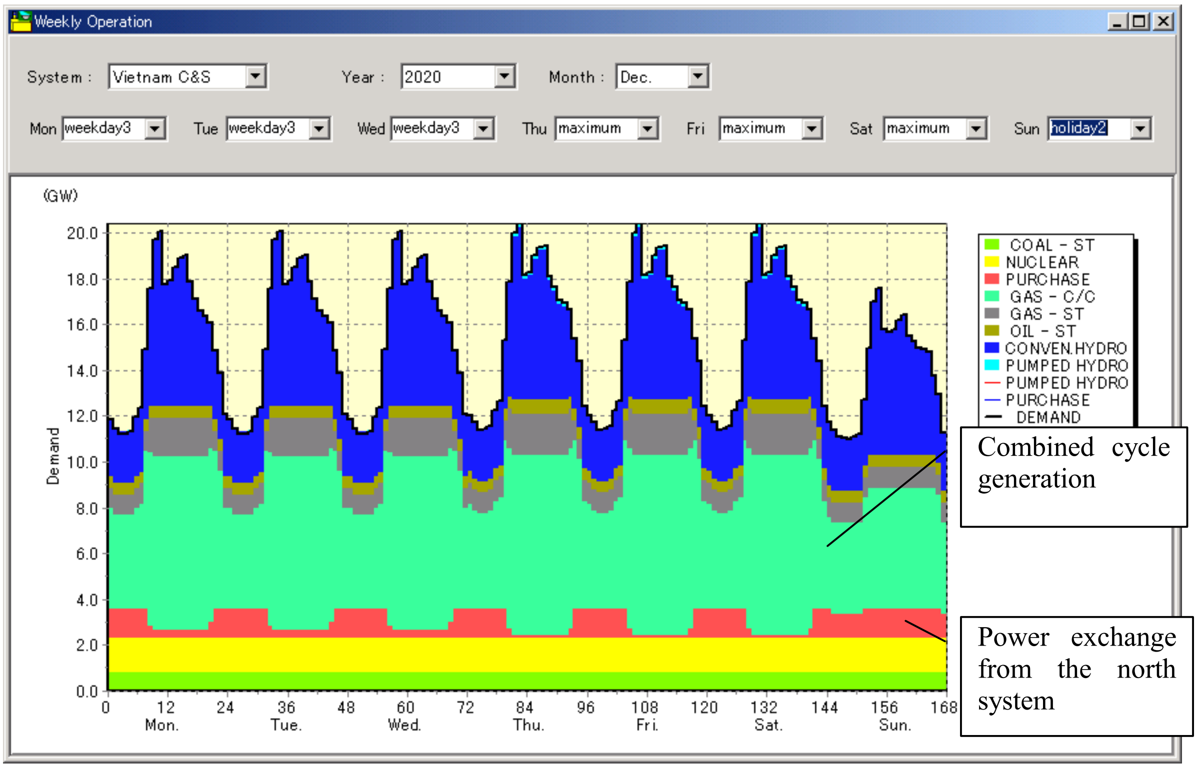


Fig. 6-2-16 Results of simulation in Dec. 2020, PSPP installation 0.6% in the C&S system in peak shift demand

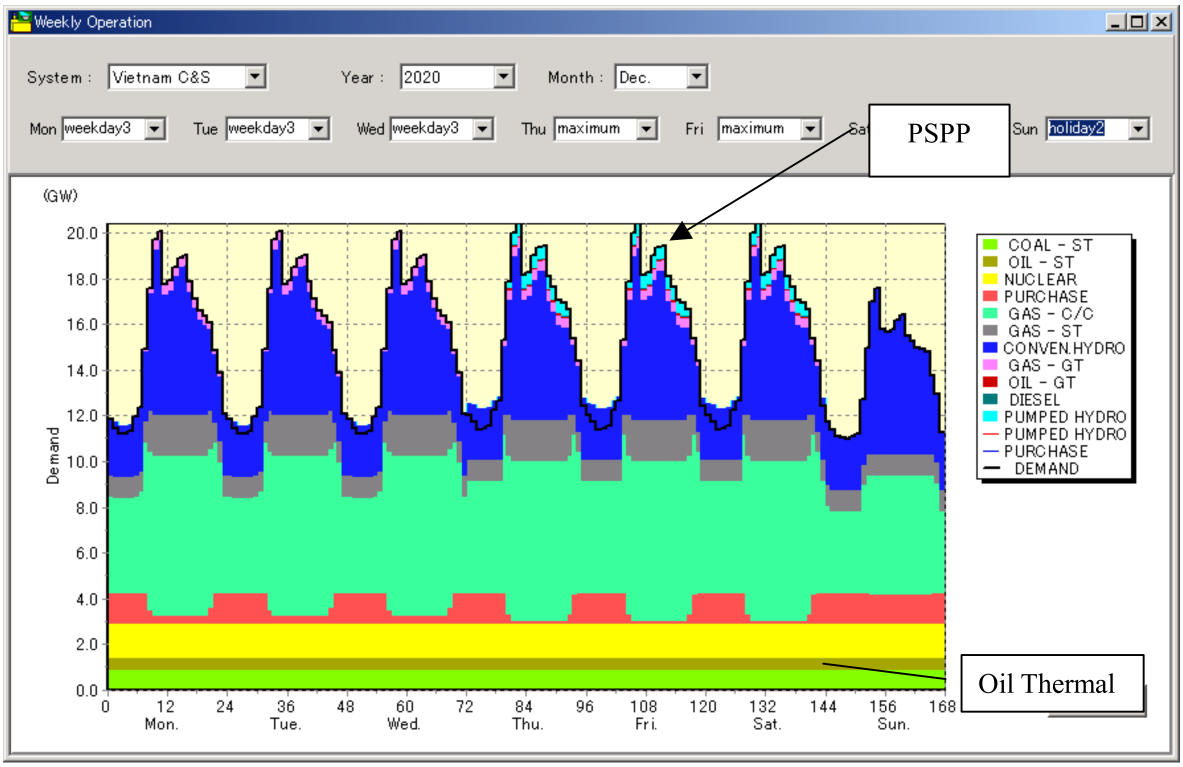


Fig. 6-2-17 Results of simulation in Dec. 2020, PSPP installation 4.7% in the C&S system in peak shift demand

3) Effects of GT Installation in the Peak Shift Demand

In the of peak shift demand in 2020, the benefit is not obtained from any cases of GT installation of the central & south system. (Fig. 6-2-18 to 20)

In the central & south system in 2020, Hydropower has the capability of arranging its supplies to meet the peak demand. The results of simulation indicate that GT is operated in May in the dry season but it is not operated in Dec. when the peak demand occurs. (See Fig. 6-2-21) In Dec. when the weather transitions from the dry season to the rainy season, hydropower has enough water in the reservoirs to supply the peak demand. (Fig. 6-2-22)

Total annual costs increase after the GT installation, because the increase of fuel costs exceeds the reduction in fixed costs due to the lowers heat rate of GT than alternatives of combined cycle.

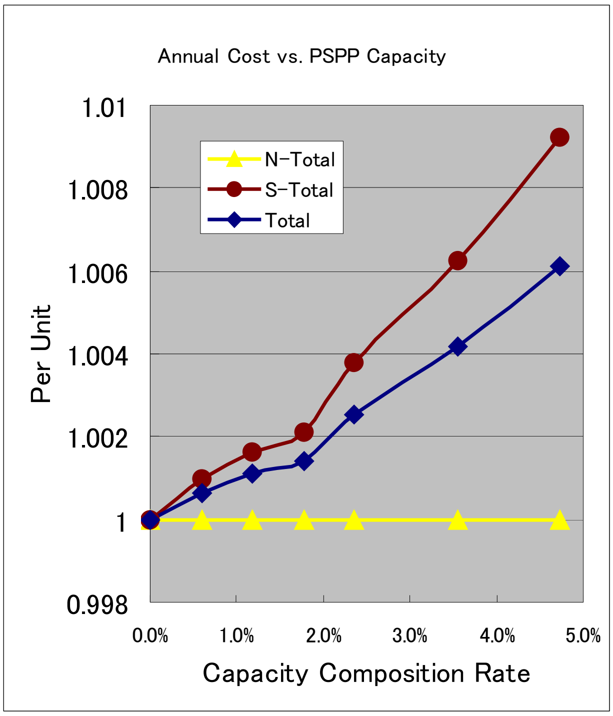


Fig. 6-2-18 GT Installation in C&S System vs. Annual costs

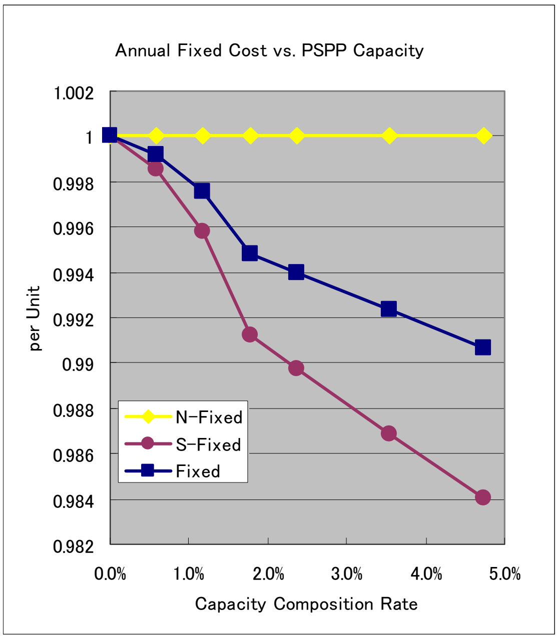


Fig. 6-2-19 GT Installed Capacity vs. Fixed Costs

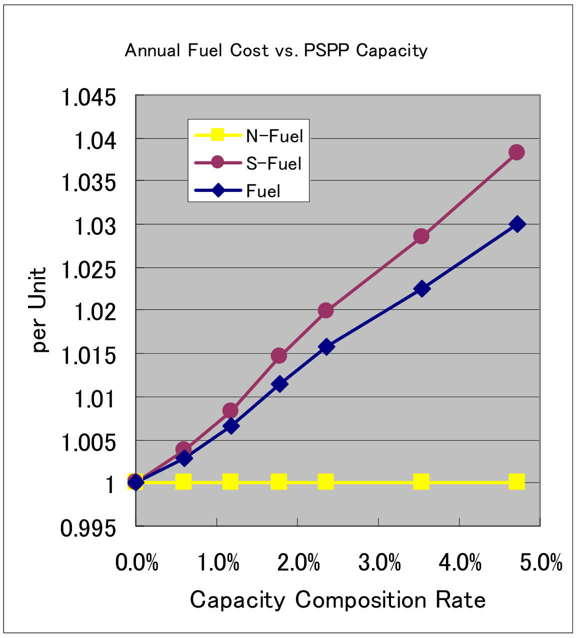


Fig. 6-2-20 GT installed capacity vs Fuel Costs

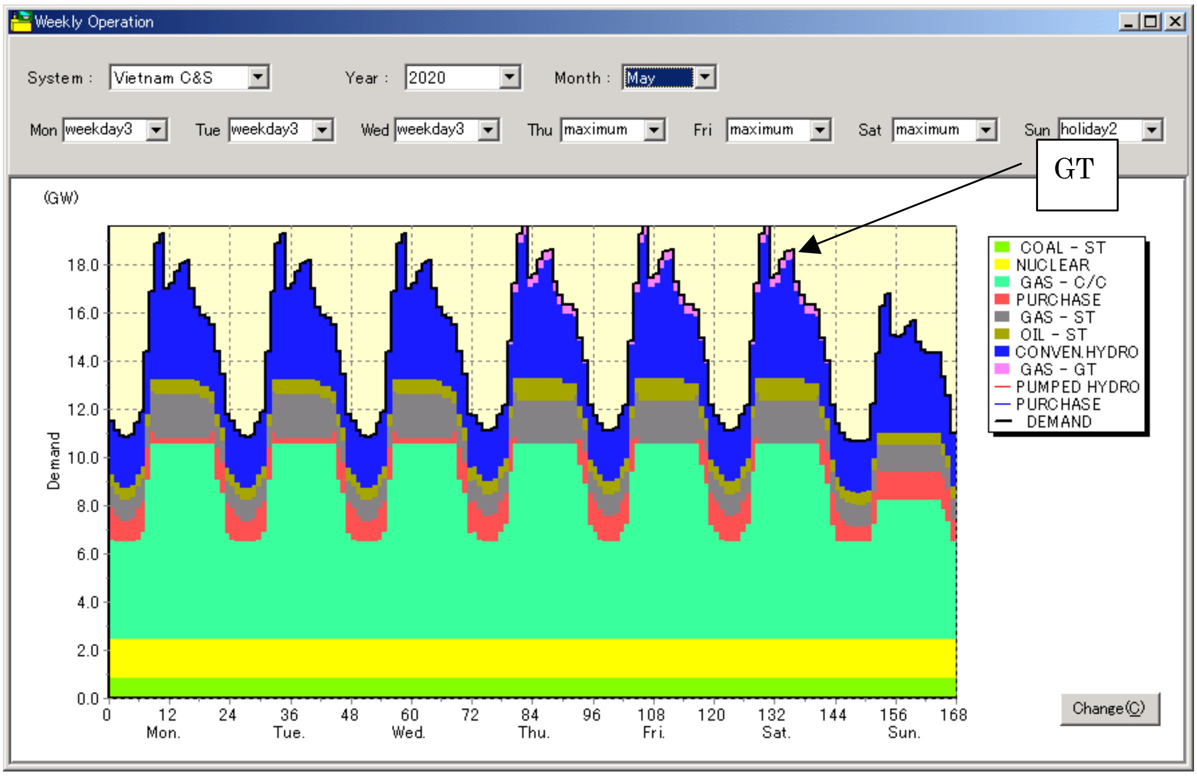


Fig. 6-2-21 Results of Simulation in May 2020, GT Installation 3.5% in the C&S System, Interconnection 1300MW

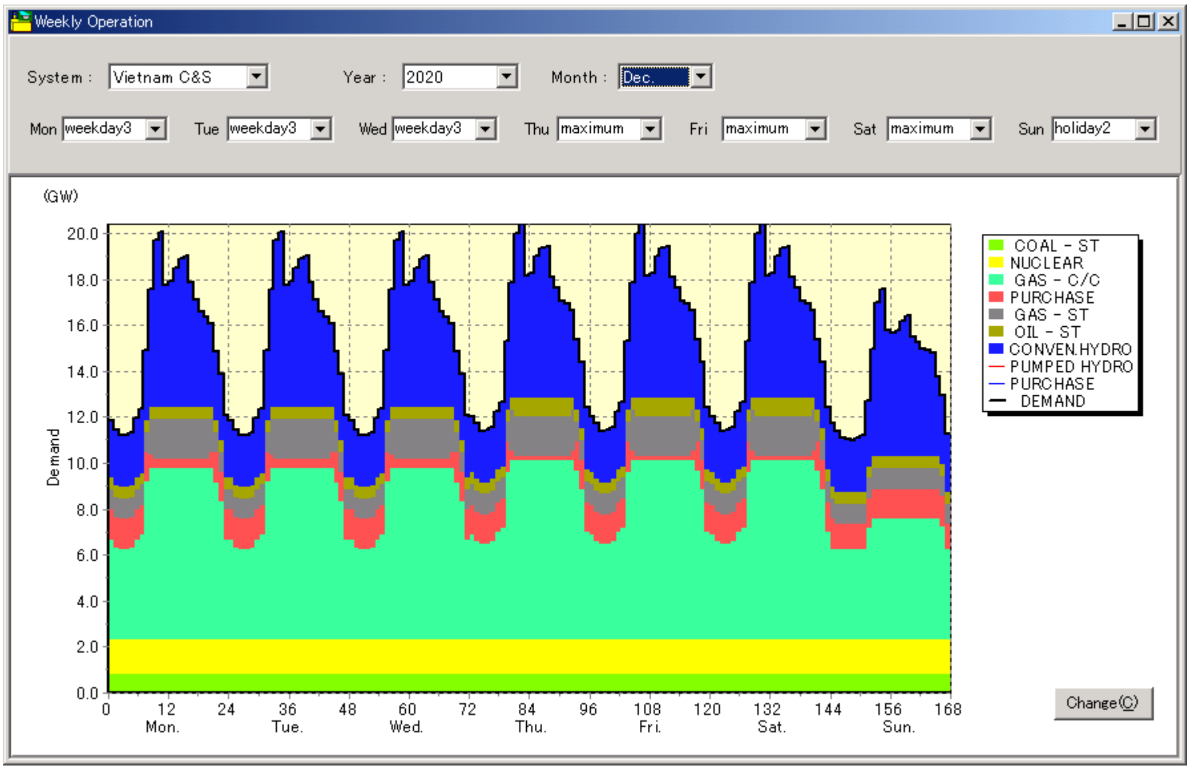


Fig. 6-2-22 Results of Simulation in Dec. 2020, GT Installation 3.5% in the C&S System, Interconnection 1,300MW

c. MP Demand Forecast Cases

1) Cases of PSPP Installation in the North System

The most economical case is the 1.2% (500MW) of PSPP installation in the north system in the MP demand with the interconnection capacity 0MW to 1,300MW. (Fig.6-2-23) The benefits of PSPP installation are not obtained in the interconnection capacity of 2,200MW.

The reduction in annual costs is 16US$ mil/Yr when the interconnection capacity is 1,300MW. The reduction is equivalent to 0.2% of the total annual costs. The reduction in fixed costs is 23US$ mil/Yr with the installation of PSPP. The fuel costs increase to 7US$ mil/Yr because of decreasing power exchange in the central & south system. (Fig. 6-2-24, Fig. 6-2-25)

In the interconnection capacity of 1,300MW, the annual costs are reduced by 1.9% (750MW) with the PSPP installation. The annual costs increase by 2.5% (1,000MW) with PSPP installation.

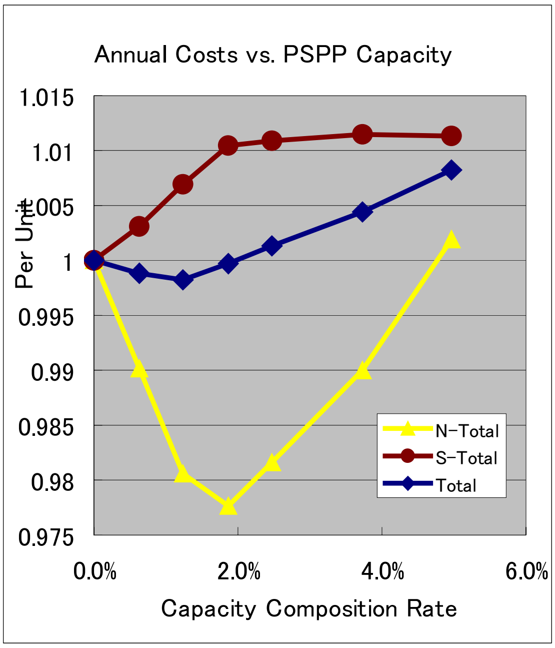
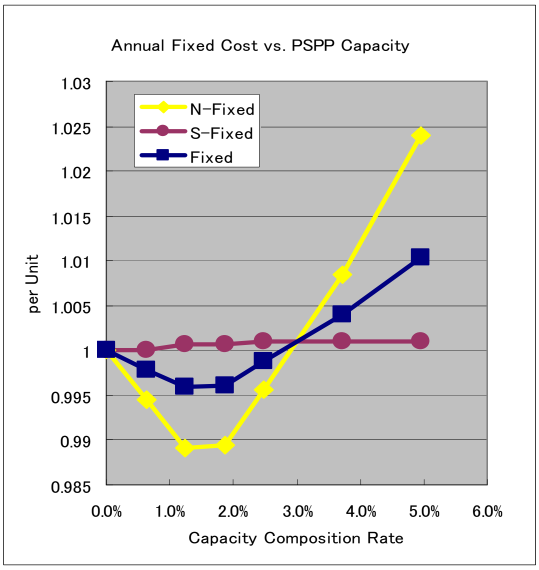


Fig. 6-2-23

PSPP Installed Capacity vs. Annual Costs,

MP Demand, Interconnection 1,300MW in 2020



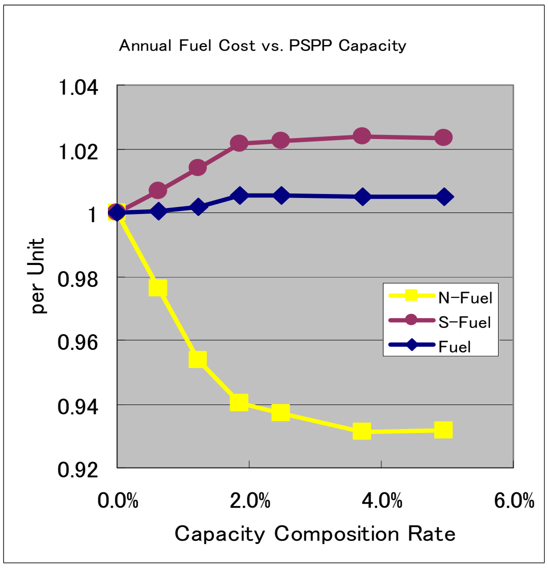


Fig. 6-2-24 PSPP Installed Capacity vs. Fixed Costs Fig. 6-2-25 PSPP Installed Capacity vs. Fuel Costs

Interconnection 1,300MW Interconnection 1,300MW

2) Case of PSPP Installation in the C&S System

The benefits from PSPP installation in the central & south system are not obtained for MP demand in 2020. (Fig. 6-2-26)

In the central & south system in 2020, hydropower has the capability of arranging its supplies to meet the peak demand in the same manner as the peak shift demand. Furthermore, the off-peak supply is comprised of gas-combined cycles, which are the same as the daytime supply in the central & south system. This causes the PSPP generation costs to be uncompetitive in the central & south system.

The results of simulation are shown in Fig. 6-2-27. Hydropower can supply almost all peak demand and the rest can be supplied by thermal power.

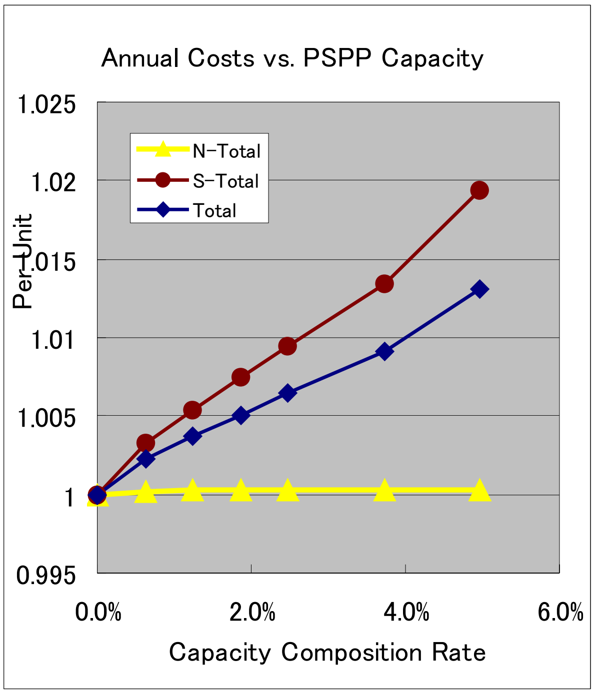


Fig. 6-2-26
PSPP Installed Capacity vs. Annual Costs
MP Demand, Interconnection 1,300MW, in 2020

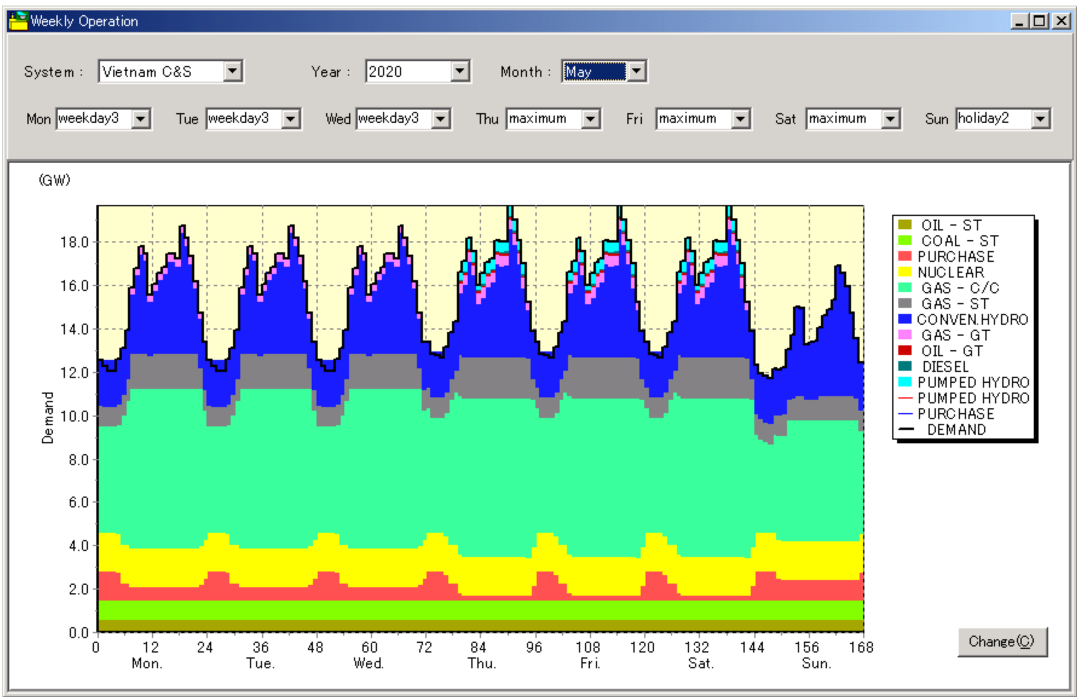


Fig. 6-2-27 Results of Simulation in May 2020 in the C&S System
PSPP Installation 1.2% (500MW) in the C&S System

3) Effects of GT Installation in the MP Demand

Regarding MP demand in 2020, benefits are unobtainable from GT installation in the central & south system (Fig. 6-2-28).

In the central & south system in 2020, the hydropower has capability of arranging its supplies to meet the peak demand. The results of the GT installation simulation of 2.5% (1,000MW) indicate that GT is operated shortly in Dec. when the peak demand occurs. (See Fig. 6-2-29) Total annual costs increase after GT installation, because the increase in fuel costs exceeds the reduction of fixed costs due to the lower heat rate of GT, rather than the alternatives of combined cycle.

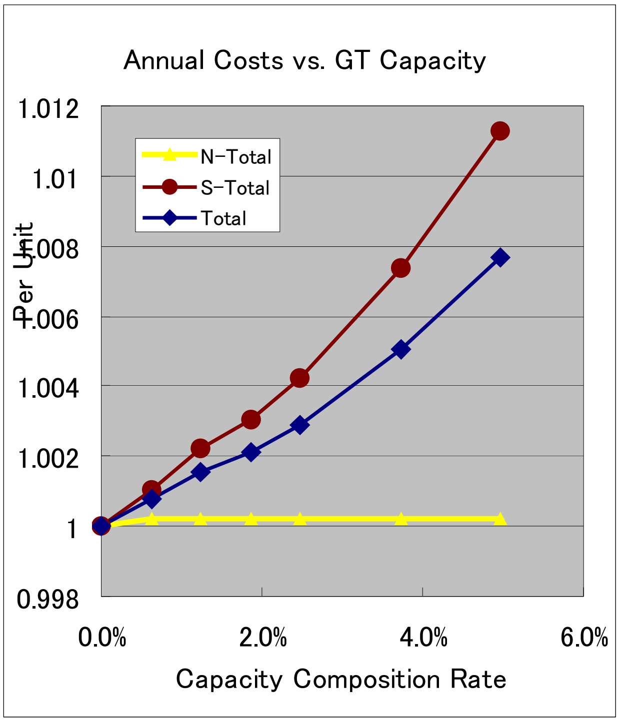


Fig. 6-2-28
PSPP Installed Capacity vs. Annual Costs
MP Demand, Interconnection 1,300MW in 2020

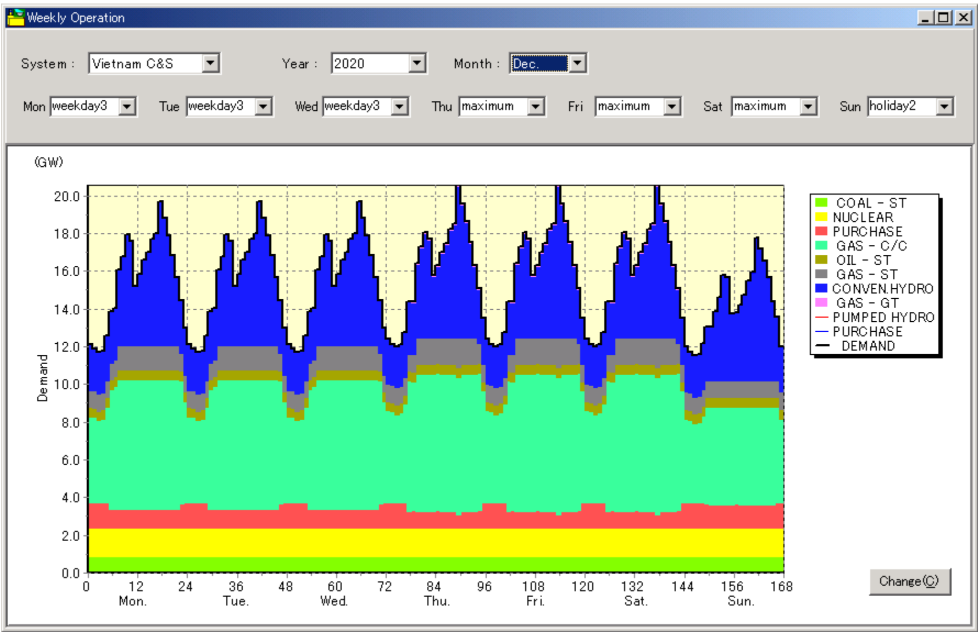


Fig. 6-2-29 Results of GT Simulation in Dec. 2020 in MP Demand
GT Installation 2.5% (1,000MW) in the C&S System

d. Effects of Soaring Fuel Prices

The simulations are conducted by using fuel prices that are twice the normal cases (see Table 6-2-16), in order to be sure of the effects of soaring fuel prices. The simulations are conducted in the cases of PSPP installation in the north system, which show greater benefits than others are. The results of the simulation are shown in Table 6-2-17.

Table 6-2-16 Fuel Prices

(Unit: ¢ /10^3 kcal)

	Soaring prices in 2020	Normal prices in 2020
Gas	3.81	1.91
FO	3.99	1.99
Coal	0.66	0.66
Diesel	6.88	3.44

The results show the effects of annual fuel costs, but do not affect the peak supply installation. The cases of high oil and gas prices, which double the normal cases prices, cause an increase of 28 - 29% in annual costs.

Table 6-2-17 Annual Costs of Fuel Prices Twice of Normal Cases in 2020

Demand	Interconnection	PSPP in N	
		Installed rate	Annual costs US$ mil/Yr
Peak Shift	1,300MW	3.5%	9,618
		3.5%	12,356
		Diff.	2,738 (+28%)
MP	1,300MW	1.2%	11,936
		1.2%	11,936
		Diff.	2,676 (+29%)

e. Effects of Limiting fuel Consumption

The appropriate composition of peak supply is examined and confirmed by the aforementioned discussions. The 2% (250MW) installation of PSPP in the north system is the appropriate scenario of the peak shift demand in 2015. The 3-4% (1,500MW) installation of PSPP in the north system is the appropriate scenario for the peak shift demand in 2020. Furthermore, the 1-2% (250MW) of PSPP installation in the north system is the appropriate scenario composition for the MP demand in 2020.

The gas and oil potential in the north system is insufficient for electric power generation. The hydropower potential is sufficient in the north system. Thus, the hydropower development has a priority to be established economically in the north system. The gas thermal power development has a priority in the south system, which has been indicated as the limitations. 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 coal thermal power development is planned for 1,000MW until 2020 under the 5th revised master plan. 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 thermal power is increasing in popularity and is taking the place of the gas thermal power. The annual costs are decreasing for every case in the system. The reduction in fuel costs exceeds the increase of fixed costs from higher coal thermal plant construction costs and the gas thermal.

1 Data from the interview with Vinacoal

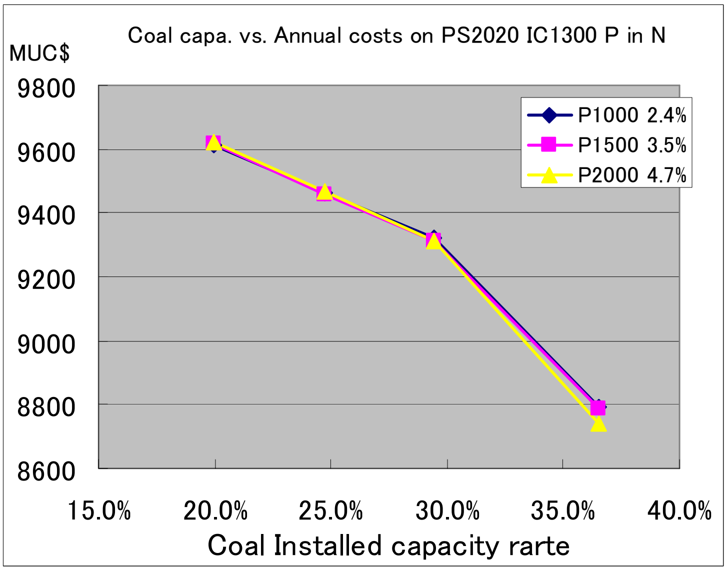


Fig. 6-2-30 Annual Costs vs. Coal and PSPP installed Capacity in the Peak Shift Demand in 2020

The relations between annual costs and coal thermal installed capacity of simulation in the case of a 3.5% PSPP installation is shown in Fig. 6-2-31 and Fig. 6-2-32. The fixed costs increase as the coal thermal plant is installed. The fuel costs decrease in relation to the increasing fixed costs.

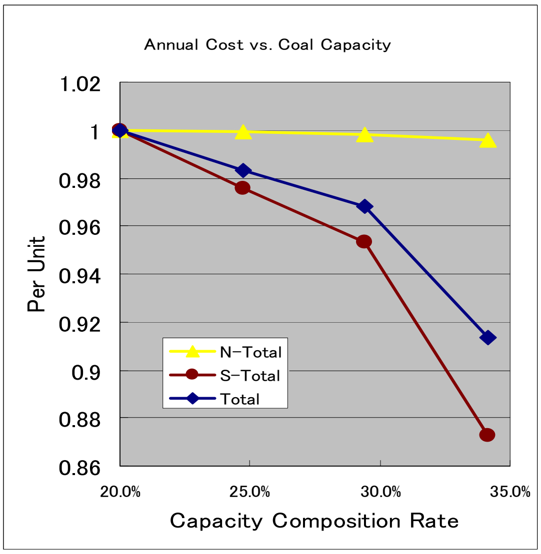


Fig. 6-2-31 Coal installed Capacity vs. Annual Costs

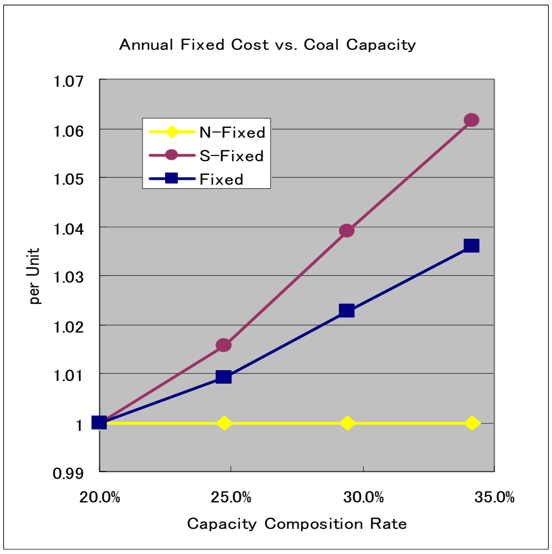


Fig. 6-2-32 Coal installed Capacity vs. Annual Costs

There is a limitation of coal consumption in 2020. The coal consumption is simulated by installation rates. The results of the simulation are shown in Fig. 6-2-33.

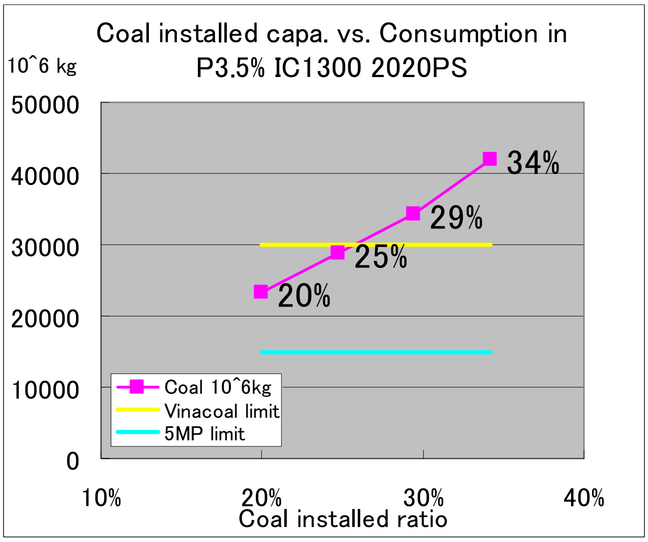


Fig. 6-2-33 Coal Consumption vs. Coal Installed Capacity in 2020 In Peak Shift Demand, PSPP 3.5% installed in the North System, Interconnection 1,300MW

When the coal installation rate is greater than 25%, and the total coal capacity of 10,000MW includes the capacity of 3000MW in the south, the coal consumption exceeds the limit. Thus, the appropriate coal installation capacity in 2020 is the 7000MW installed in the north system and 3000MW installed in the south system. This results in a total of 10,000MW. The gas consumption for the appropriate coal installation is shown in Fig. 6-2-34.

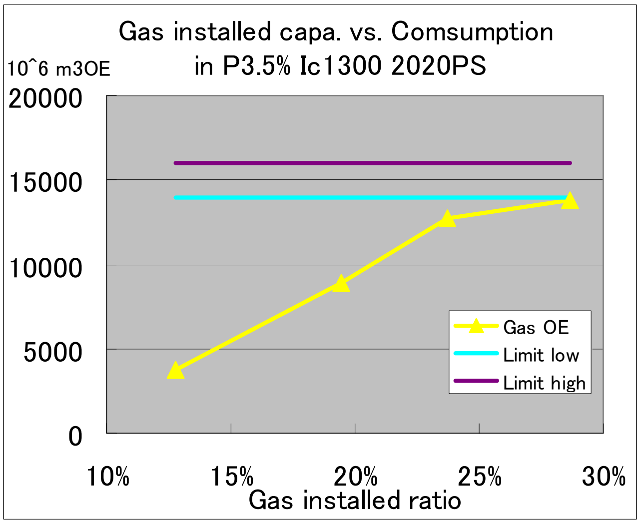


Fig. 6-2-34 Gas Thermal Installed Capacity vs. Gas Consumption in 2020 in Peak Shift Demand, PSPP installed 3.5%, interconnection 1,300MW

The gas consumption of every case does not exceed the limitation. The gas consumption is in the relation to the coal consumption. The minimum installation of coal is the maximum installation of gas, which is same scenario as the 5th revised master plan. The appropriate coal thermal installed capacity scenario has a 25% coal installation rate and a 24% gas installation rate (10,000MW).

c) Results of Appropriate Composition in 2020

The case of adding 2,000MW of coal thermal power in the south system is the most economical case for 2020. The results of simulation considering fuel limitations in 2020 are shown in Table 6-2-18.

Table 6-2-18 Least Cost Power Composition in 2020

		Peak shift demand	MP demand
Interconnection		1,300MW	
Type of peak supply		PSPP	PSPP
		3.5%（1,500MW）	1.2%（500MW）
		Installed in the north system	Installed in the north system
Annual costs	Fixed costs	5,923 US$ mil/Yr	5,699 US$ mil/Yr
	Fuel costs	3,535 US$ mil/Yr	3,397 US$ mil/Yr
	Total	9,458 US$ mil/Yr	9,096 US$ mil/Yr
The 5th revised MP		9,624 US$ mil/Yr	
Difference		▲166 US$ mil/Yr	▲528 US$ mil/Yr

6.2.5 Appropriate Duration of PSPP Operating Times

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 of the maximum output of PSPP is examined considering the situation of the Vietnam system. (See Fig. 6-2-35)

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. (Fig. 6-2-36) When the PSPP operating hour is over 8 hours, the pumping hour cannot 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.

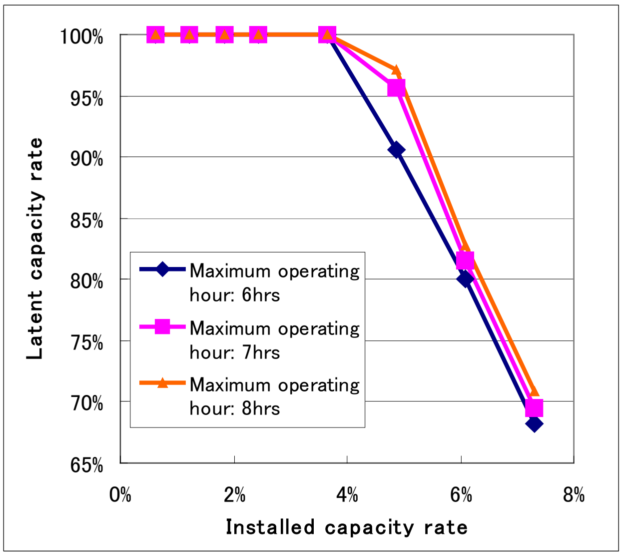


Fig. 6-2-35

Latent Capacity vs. PSPP installed Capacity in 2020

In Peak Shift Demand, Interconnection 1,300MW

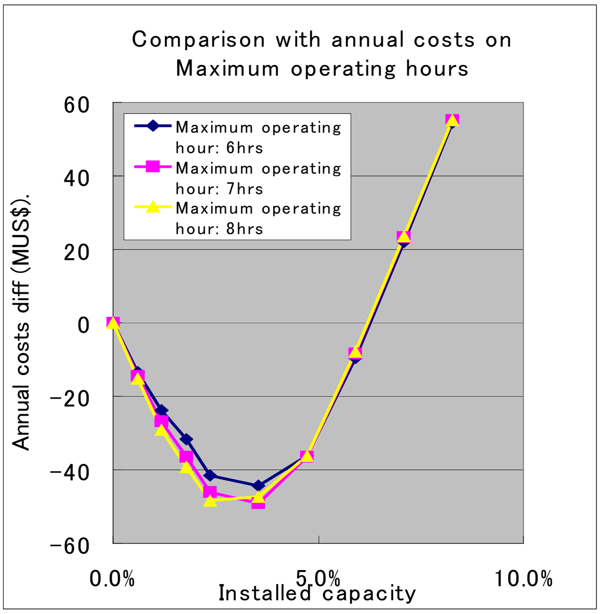


Fig. 6-2-36 PSPP Operating Hours vs. Annual Costs

6.2.6 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 & 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 of 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 approximately 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 the MP demand. The difference of interconnected capacity between 0MW and 2,200MW is US$50 mil/Yr in the peak shift demand

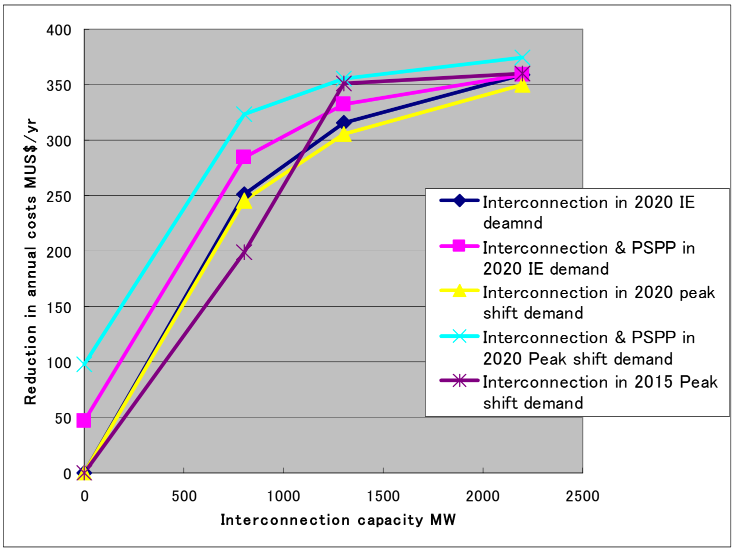


Fig. 6-2-37 Interconnection Capacity vs. Annual Cost

Table 6-2-19 Interconnection Capacity vs. Annual Costs (Unit: US$ mil/y)

Capacity of Interconnection (MW)	Interconnection MP demand in 2020	Including PSPP MP demand in 2020	Interconnection Peak shift demand in 2020	Including PSPP Peak shift demand in 2020	Interconnection Peak shift demand in 2015
0	0	46	0	98	0
800	251	284	246	323	198
1,300	316	331	306	355	350
2,200	359	359	350	375	359

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

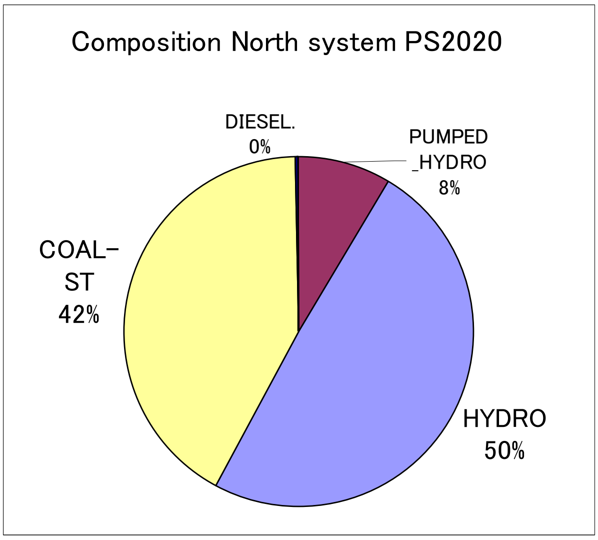
6.2.7 Appropriate Composition in 2020

(1) Appropriate Composition based on the Scenarios of Peak Supply

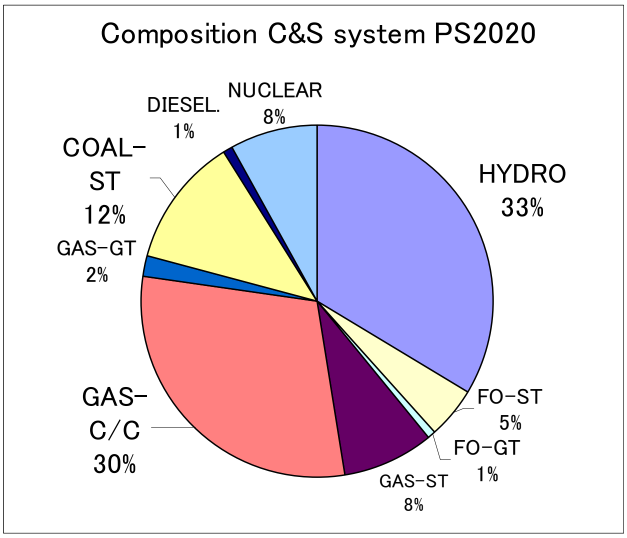
In the aforementioned discussion, the functions are clear as to effects of the composition of peak supply. They consist of the load profile considering a peak shift caused by variation in the demand structure and the interconnection constrained.

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. The other scenario is the scenario of 1 – 2% (500MW) of PSPP installation in the north system in 2020. (Fig. 6-2-38, Fig. 6-2-39)。

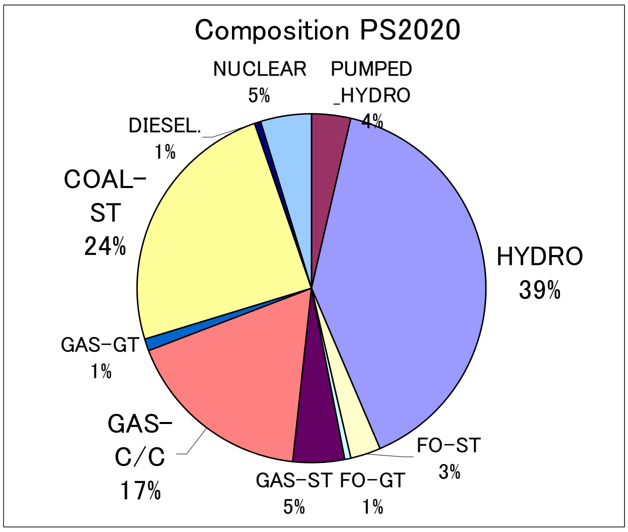
The North System



The Central & South System



Total



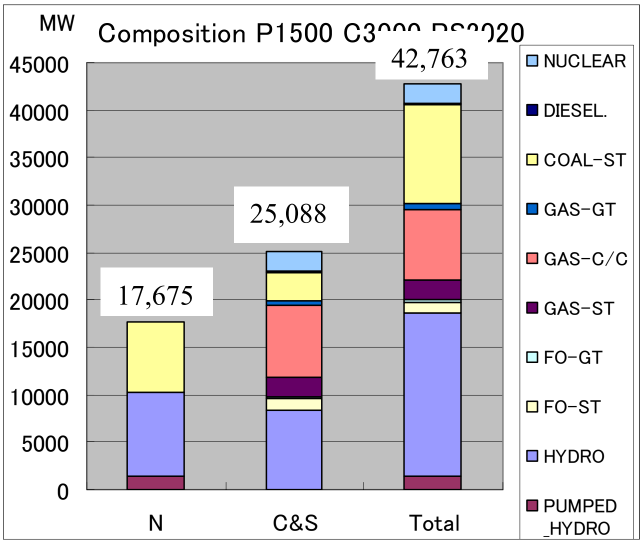


Fig. 6-2-38 The Appropriate Composition in the Peak Shift Demand

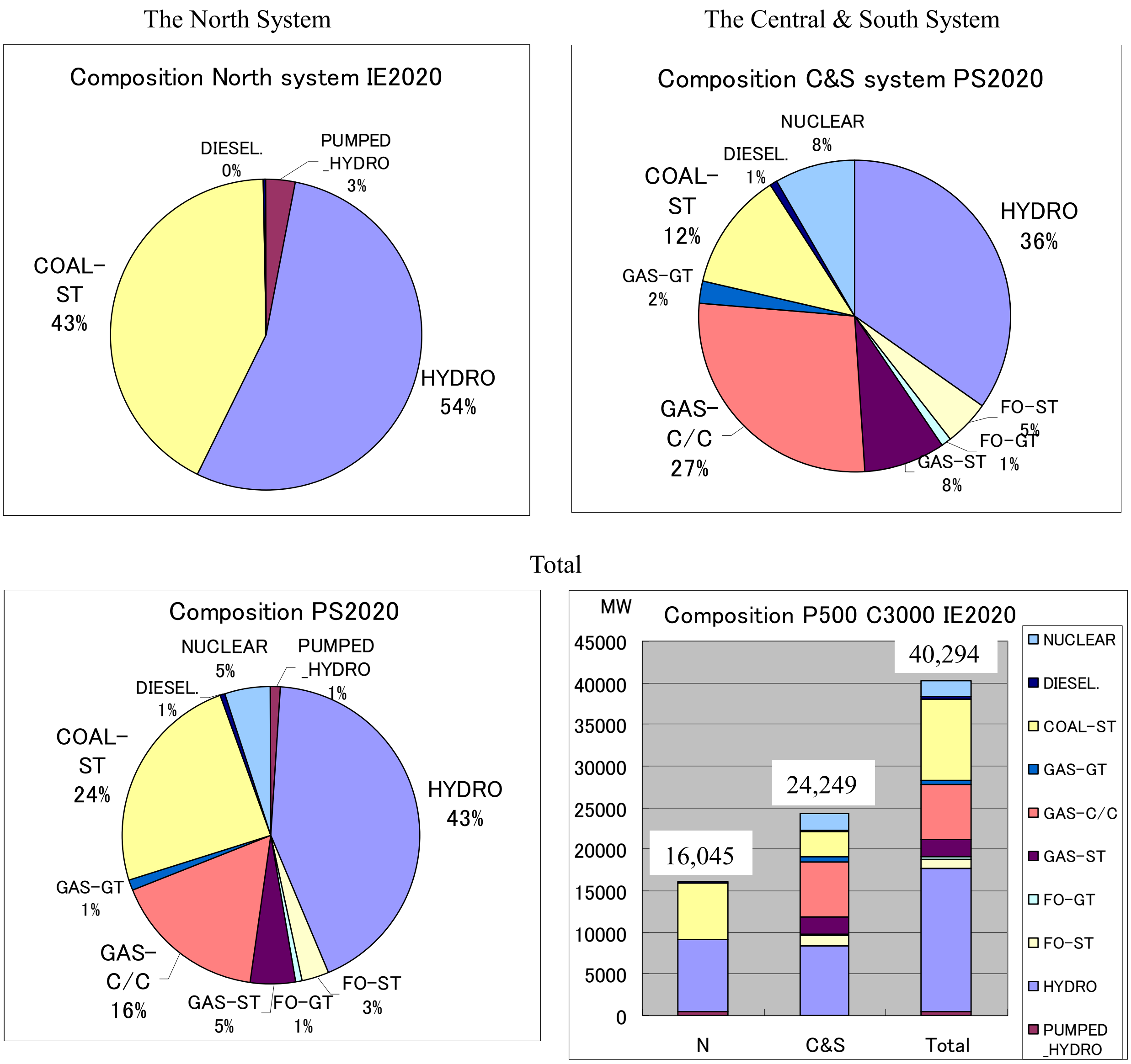


Fig. 6-2-39 Appropriate Composition of the Peak Supply in the IE Demand

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.

When the appropriate composition is compared with the 5th revised master plan, the PSPP installed capacity is changes 2% to 4%, and the coal thermal changes 17% to 24%, and the gas thermal power does not change in the case of peak shift demand. In MP demand, PSPP is the same as 1%, and the coal increases to 24% and the gas decreases to 22%.

(2) Development Schedule of Scenarios of Appropriate Peak Supply

The development schedule of the 5th revised master plan by 2010 has been committed by the Vietnamese Congress. Therefore, the development schedule from 2011 to 2020 will be examined in order to catch up the optimal generation compositions in 2020. The arrangement development schedule should be conducted to concentrate on securing the system reliability such as reserve margin rate. You must consider the risks such as a development delay, a fuel supply and varying demand situation. In this section, we will show some example of arrangements for power development.

a. Development Schedule of the 5th Revised Master Plan

The development plan of the IE draft is shown in Table 6-2-20, which is based on the data collected during the study.

b. Example of Development Scenarios of Peak Supply

The development schedules from 2011 to 2020 are set up based on the results of examinations and the 5th revised master plan. The coal thermal plan and gas thermal developments are the main points of the 5th revised master plan.

1) Example of Development Scenario of Peak Supply in the Peak Shift Demand

The sample development schedule of peak supply in peak shift demand is shown in Table 6-2-21. 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%, the central & south system: 8％

2) Example of Development Scenario in the MP demand

The sample development schedule of peak supply in the MP demand is shown in Table 6-2-22. The features of the scenario are as follows:

Interconnection capacity: 1,300MW

Installation capacity of PSPP in the north system: 1.2%（500MW）

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

Reserve margin in the north system: 13%, the central & south system: 7％

Table 6-2-20 Power Development Schedule (Revised 5th M/P)

MP2020 IE original (Unit: MW)

FY	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Power Development Plan			Quang Ninh 4 Coal								
			300								
			Hua Na								
			195								
		Quang Ninh 3 Coal	Nam Chien			Mong Duong1 Coal	PSPP1		PSPP3		
		300	140			500	200		200		
	Nghi Son 1 Coal	Nghi Son 2 Coal	Huoi Quang 2	Nam Thuen3(Laos)		Ban Uon	Mong Duong2 Coal		MaLuTang(China)		PSPP5
	300	300	270	400		250	500		465		200
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	Import (China)	Import (China)
	200	270	300	600	600	900	550	550	280	250	300
PDP N total	500	870	1,205	1,000	600	1,650	1,250	550	945	250	500
N Peak Demand	6,153	6,615	7,108	7,645	8,219	8,843	9,402	10,008	10,646	11,346	12,074
N Supply	6,780	7,283	8,264	8,716	9,167	10,712	11,714	12,050	12,671	12,762	13,031
RM 13.9%	10.2%	10.1%	16.3%	14.0%	11.5%	21.1%	24.6%	20.4%	19.0%	12.5%	7.9%
		O Mon2		NhonTrach4 STGas				New CCGT2			
		300		300				720			
	Dong Nai 3	O Mon3-1 Gas ST		Hon Dat 2 GT Gas	New CCGT1			Se Kong5(Laos)		PSPP4	New CCGT5
	240	300		250	720			250		200	720
	Upper Kon Tun	Upper Kon Tum	O Mon3-2 STGas	Hon Dat 1 GT Gas	Hon Dat3 ST Gas			PSPP2	New CCGT3	New Coal2	Dien nguyen tu 2
	110	110	300	250	250			200	720	500	1,000
	Song Con 2	Song Ba Ha	NhonTrach3 STGas	Ha Se San(Cambodia)	Prek Lieng(Cambodia)	Dong Nai 2	Quang Tri CCGT	Ha Se San&Srepoc	New Coal1	New CCGT4	Duc Xuyen1
	70	250	300	375	100	78	720	429	500	720	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	Sam Bor(Cambodia)	Dien nguyen tu 1	Dak My1
	260	210	240	330	200	170	450	126	165	1,000	210
PDP C&S total	680	1,170	840	1,505	1,270	248	1,170	1,725	1,385	2,420	2,030
C&S Peak Demand	9,666	10,485	11,370	12,340	13,396	14,552	15,572	16,694	17,885	19,195	20,564
C&S Supply	10,872	11,871	12,639	13,933	15,113	15,586	16,776	18,213	19,736	21,799	23,463
RM 7.8%	12.5%	13.2%	11.2%	12.9%	12.8%	7.1%	7.7%	9.1%	10.3%	13.6%	14.1%
PDP Total	1,180	2,040	2,045	2,505	1,870	1,898	2,420	2,275	2,330	2,670	2,530
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	17,652	19,154	20,903	22,649	24,280	26,298	28,490	30,263	32,407	34,561	36,494
Reserve Margin	11.5%	12.6%	14.4%	15.3%	15.1%	16.0%	16.9%	15.6%	15.2%	14.3%	12.3%

Table 6-2-21 Power Development Schedule (Peak Shift)

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	6,153	6,615	7,108	7,645	8,219	8,843	9,402	10,008	10,646	11,346	12,074
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%	14.4%	16.7%	16.9%	17.3%	13.9%	18.1%	11.5%	11.9%	13.2%	16.4%	14.7%
	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	1000	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	9,666	10,485	11,370	12,340	13,396	14,552	15,572	16,694	17,885	19,195	20,564
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%	23.5%	19.7%	16.7%	16.1%	14.4%	6.2%	8.9%	7.6%	8.9%	7.6%	7.7%
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%

Table 6-2-22 Power Development Schedule (IE; Base Case)

MP2020 P1.2% IC1300 (Unit: MW)

FY	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Power Development Plan											
			Hua Na								
			195								
			Nam Chien					Coal			
			140					500			
	Coal	Coal	Huoi Quang 2	Nam Thuen3(Laos)		Ban Uon		Coal	PSPP1	Coal	PSPP2
	600	300	270	400		250		300	250	500	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	Coal	Coal
	200	270	300	600	600	900	550	550	280	300	470
PDP N total	995	570	710	1,000	600	1,150	550	1,350	530	800	720
N Peak Demand	6,153	6,615	7,108	7,645	8,219	8,843	9,402	10,008	10,646	11,346	12,074
N Supply	7,080	7,583	8,264	8,717	9,468	10,223	10,567	11,701	12,010	12,719	13,581
RM 12.7%	15.1%	14.6%	16.3%	14.0%	15.2%	15.6%	12.4%	16.9%	12.8%	12.1%	12.5%
	Dong Nai 3										
	240										
	Upper Kon Tun	Upper Kon Tum		CCGT	CCGT	CCGT	Coal	CCGT	CCGT	CCGT	Dien nguyen tu 2
	110	110		500	250	300	500	720	300	300	1,000
	Song Con 2	Song Ba Ha	Coal	Coal	Coal	Dong Nai 2	CCGT	Se Kong5(Laos)	CCGT	Coal	Duc Xuyen1
	70	250	500	500	1,000	78	600	250	720	500	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	Coal	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	1,330	1,450	548	1,550	1,096	1,520	1,800	1,310
C&S Peak Demand	9,666	10,485	11,370	12,340	13,396	14,552	15,572	16,694	17,885	19,195	20,564
C&S Supply	10,572	11,413	12,366	13,557	15,070	15,670	16,699	17,779	19,760	21,060	22,060
RM 6.3%	9.4%	8.8%	8.8%	9.9%	12.5%	7.7%	7.2%	6.5%	10.5%	9.7%	7.3%
PDP Total	1,675	1,140	1,450	2,330	2,050	1,698	2,100	2,446	2,050	2,600	2,030
FY	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Peak Demand	15,728	17,019	18,403	19,923	21,562	23,370	24,943	26,674	28,497	30,512	32,606
Supply Capacity	17,652	18,996	20,630	22,274	24,538	25,893	27,266	29,480	31,770	33,779	35,641
Reserve Margin	12.2%	11.6%	12.1%	11.8%	13.8%	10.8%	9.3%	10.5%	11.5%	10.7%	9.3%

LEGEND

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

c. Limitation of Coal Supply

The development schedule for coal supply limitation case is considered based on the optimal composition in 2020. When the coal consumption in electrical power sector is limited up to 60% of Vinacoal present production plan in 2020, the difference between the Vinacoal' plan and the coal consumption in the revised 5th MP is 30,000 kt/Yr. The 2,000MW of coal plants can be installed under the coal supply limitation based on the simulation.

The sample development schedule of peak supply in peak shift demand is shown in Table 6-2-23. 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: 2,000MW

Reserve margin in the north system: 14%, the central & south system: 8%

Table 6-2-23 Power Development Schedule (Peak Shift; Limitation of Coal supply)

PS2020 P3.5% IC1300 C2000 (Unit: MW)

FY	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Power Development Plan											
			Hua Na 195						Coal7 500		
	Coal1,2 600		Nam Chien 140						PSPP2 250	Coal8,9 1,000	
	Coal3,4 600	Coal5 500	Huoi Quang 2 270	Nam Thuen3(Laos) 400		Ban Uon 250		Coal6 500	PSPP1 250	PSPP4 250	PSPP6 250
PDP North	Ban Chat 200	Huoi Quang 1 270	Son La 1 300	Son La 2,3 600	Son La 4,5 600	Son La 6,7,8 900	Nam Nhun1,2 550	Nam Nhun3,4 550	Bac Me 280	PSPP3 250	PSPP5 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										CCGT 300
	Upper Kon Tun 110	Upper Kon Tum 110			Coal 500	Coal 500	CCGT 600	CCGT 300			Dien nguyen tu 2 1,000
	Song Con 2 70	Song Ba Ha 250	CCGT 500	CCGT 750	CCGT 500	Dong Nai 2 78	Coal 500	Se Kong5(Laos) 250	CCGT 720	CCGT 300	Duc Xuyen1 100
PDP C&S	Se Kaman(Laos) 260	Dak My4 210	Nam Kong(Laos) 240	Se San 4 330	Song Bung4 200	Dong Nai 5 170	Se Kong4(Laos) 450	Song Bung2 126	Coal 500	Dien nguyen tu 1 1,000	Dak My1 210
PDP C&S total	680	570	740	1,080	1,200	748	1,550	676	1,220	1,300	1,610
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	17,776	19,296	20,596	22,378
RM 7.8%	21.3%	18.6%	16.5%	16.9%	16.3%	9.1%	11.3%	8.4%	9.4%	8.6%	9.7%
PDP Total	2,080	1,340	1,645	2,080	1,800	1,898	2,100	1,726	2,500	2,800	2,110

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	28,975	31,348	33,802	36,226
Reserve Margin	19.9%	19.2%	18.1%	18.6%	17.0%	14.2%	12.6%	10.7%	11.4%	11.8%	11.5%

LEGEND

: Hydropower : Coal : Nuclear

:PSPP : Gas : Import

d. M/P demand forecast (High Case)

The development schedule is arranged to catch up the High demand Case of the M/P demand. The development schedule is shown in Table 6-2-24. The comparison with the base case is shown in Table 6-2-25.

Table 6-2-25 Comparison between Base and High cases in MP Demand

(Unit: MW, %)

		Peak demand in 2020	Diff.	Growth rate
Base case	North system	12,074	—	6.32%/Yr
	C&S system	20,564	—	7.10%/Yr
High case	North system	15,933	+3,859	8.39%/Yr
	C&S system	23,910	+3,346	8.27%/Yr

The high demand case has a 2%/Yr of growth rate difference. The peak demand of the north system is estimated 3,900MW larger than the base case. The central & south system is estimated to 3,300MW larger than the base case. The reserve margins are necessary for the north to add 4,400MW and for the central & south system to add 3,500MW. In the north system, the remaining fuel with the potential to be further developed is coal thermal, because all hydropower potential will be developed by 2020 in the base case.

The additional development of 4,000MW of coal thermal power is required in addition to 10Mt/Yr in 2020. The additional coal development will begin in 2017, which is four (4) years earlier than the base case. The additional development of 1,440MW of gas thermal is satisfied by the exceeding demand, because the arrangement of maintenance is produced approximately 2,000MW in the south system.

Table 6-2-22 Power Development Schedule (IE; Base Case)

MP2020 P1.2% IC1300 (Unit: MW)

FY	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Power Development Plan											
			Hua Na								
			195								
			Nam Chien					Coal			
			140					500			
	Coal	Coal	Huoi Quang 2	Nam Thuen3(Laos)		Ban Uon		Coal	PSPP1	Coal	PSPP2
	600	300	270	400		250		300	250	500	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	Coal	Coal
	200	270	300	600	600	900	550	550	280	300	470
PDP N total	995	570	710	1,000	600	1,150	550	1,350	530	800	720
N Peak Demand	6,153	6,615	7,108	7,645	8,219	8,843	9,402	10,008	10,646	11,346	12,074
N Supply	7,080	7,583	8,264	8,717	9,468	10,223	10,567	11,701	12,010	12,719	13,581
RM 12.7%	15.1%	14.6%	16.3%	14.0%	15.2%	15.6%	12.4%	16.9%	12.8%	12.1%	12.5%
	Dong Nai 3										
	240										
	Upper Kon Tun	Upper Kon Tum		CCGT	CCGT	CCGT	Coal	CCGT	CCGT	CCGT	Dien nguyen tu 2
	110	110		500	250	300	500	720	300	300	1,000
	Song Con 2	Song Ba Ha	Coal	Coal	Coal	Dong Nai 2	CCGT	Se Kong5(Laos)	CCGT	Coal	Duc Xuyen1
	70	250	500	500	1,000	78	600	250	720	500	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	Coal	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	1,330	1,450	548	1,550	1,096	1,520	1,800	1,310
C&S Peak Demand	9,666	10,485	11,370	12,340	13,396	14,552	15,572	16,694	17,885	19,195	20,564
C&S Supply	10,572	11,413	12,366	13,557	15,070	15,670	16,699	17,779	19,760	21,060	22,060
RM 6.3%	9.4%	8.8%	8.8%	9.9%	12.5%	7.7%	7.2%	6.5%	10.5%	9.7%	7.3%
PDP Total											
FY	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Peak Demand	15,728	17,019	18,403	19,923	21,562	23,370	24,943	26,674	28,497	30,512	32,606
Supply Capacity	17,652	18,996	20,630	22,274	24,538	25,893	27,266	29,480	31,770	33,779	35,641
Reserve Margin	12.2%	11.6%	12.1%	11.8%	13.8%	10.8%	9.3%	10.5%	11.5%	10.7%	9.3%

Table 6-2-24 Power Development Schedule (IE; High Case)

MP2020high (Unit: MW)

FY	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Power Development Plan											
			Hua Na						**New Coal5**	**PSPP3**	
			195						**500**	**250**	
	Coal	Coal	Nam Chien					**New Coal3**	**New Coal4**	PSPP2	**New Coal10**
	300	500	140					**500**	**500**	250	**500**
	Coal	Coal	Huoi Quang 2	Nam Thuen3(Laos)	Coal	Ban Uon	Coal	Coal	PSPP1	**New Coal7**	**New Coal9**
	600	300	270	400	500	250	500	500	250	**500**	**500**
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	**New Coal6**	**New Coal8**
	200	270	300	600	600	900	550	550	280	**500**	**500**
PDP N total	1,100	1,070	710	1,000	1,100	1,150	1,050	1,550	1,030	1,250	500
N Peak Demand	6,568	7,225	7,951	8,766	9,668	10,680	11,554	12,515	13,551	14,703	15,933
N Supply	7,380	8,383	9,064	9,516	10,467	11,512	12,360	13,698	15,011	16,293	17,702
RM 12.7%	12.4%	16.0%	14.0%	8.6%	8.3%	7.8%	7.0%	9.5%	10.8%	10.8%	11.1%
	Dong Nai 3					New Coal1					**New CCGT2**
	240					500					**720**
	Upper Kon Tun	Upper Kon Tum		CCGT	CCGT	**New CCGT1**		New Coal4		**New Coal9**	Dien nguyen tu 2
	110	220		720	600	**720**		500		**500**	1,000
	Song Con 2	Song Ba Ha	CCGT	CCGT	CCGT	Dong Nai 2	New Coal2,3	Se Kong5(Laos)	**New Coal7**	**New Coal8**	Duc Xuyen1
	70	250	750	300	600	78	1,000	250	**500**	**500**	100
PDP C&S	Se Kaman(Laos)	Dak My4	Nam Kong(Laos)	Se San 4	Song Bung4	Dong Nai 5	Se Kong4(Laos)	Song Bung2,4	New Coal5,6	Dien nguyen tu 1	Dak My1
	260	210	240	330	200	170	450	326	1,000	1,000	210
PDP C&S total	680	680	990	1,350	1,400	1,468	1,450	1,076	1,500	2,000	2,030
C&S Peak Demand	9,974	10,953	12,028	13,222	14,540	16,006	17,318	18,772	20,335	22,070	23,910
C&S Supply	11,739	12,283	13,225	14,509	15,869	17,287	18,647	20,108	22,008	24,008	25,976
RM 6.3%	17.7%	12.1%	10.0%	9.7%	9.1%	8.0%	7.7%	7.1%	8.2%	8.8%	8.6%
PDP Total											
FY	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Peak Demand	15,728	17,019	18,403	19,923	21,562	23,370	24,943	26,674	28,497	30,512	32,606
Supply Capacity	19,119	20,666	22,289	24,025	26,336	28,799	31,007	33,806	37,019	40,301	43,678
Reserve Margin	21.6%	21.4%	21.1%	20.6%	22.1%	23.2%	24.3%	26.7%	29.9%	32.1%	34.0%

LEGEND

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

6.2.8 Examination of Sustainability of the Appropriate Scenarios

(1) Appropriate Scenario Considering the Lifetime of Hydropower

The PSPP installation scenario shows the benefits, which are confirmed in long term considering the lifetime of hydropower. The peak shift demand in 2040 is selected to examine the benefits of sustainability for the scenarios considering the lifetime of hydropower.

a. Demand Forecasts in 2040

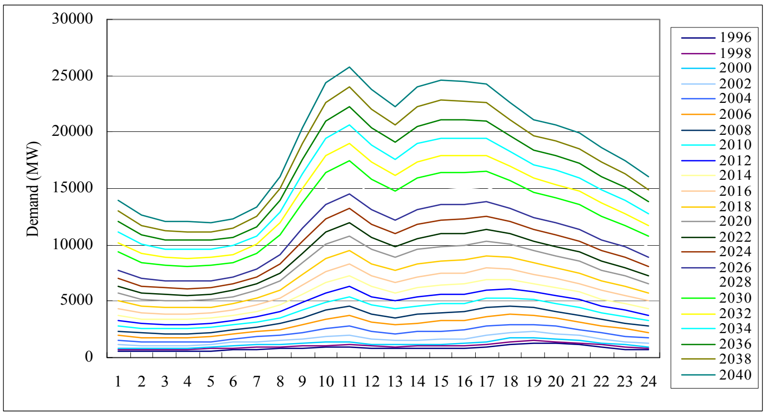
The study team estimated the peak demand in 2040 based on the conditions of the demand forecast in 2020, which is shown in Table 6-2-26 and Fig. 6-2-40.

The peak demand in the north system is twice the demand in 2020. The peak demand in the central & south system is three times the demand in 2020. The load factors are the same levels in 2020.

Table 6-2-26 Demand Forecast in 2040

	Peak demand（MW）	Electric energy（GWh）	Load factor（%）
North	28,829	169,363	67
C & S	68,210	434,307	72
Total	99,446	603,670	69

(The North System)



(The C&S System)

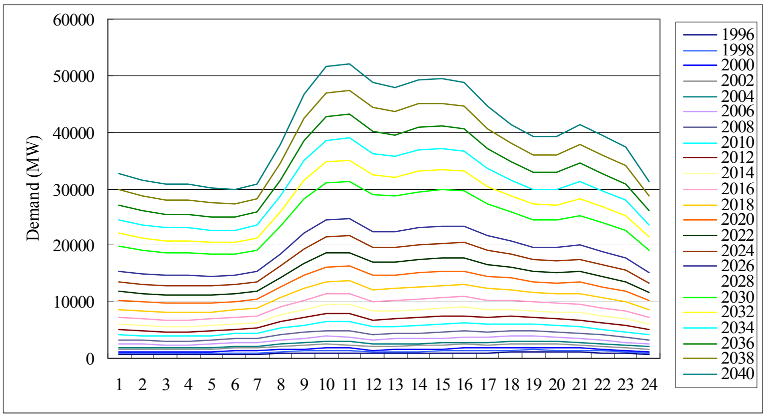


Fig. 6-2-40 Peaks Shift Demand in 2040

b. Arrangement of Generation

Additional generation will consist of thermal power in addition to the 2020 capacity.

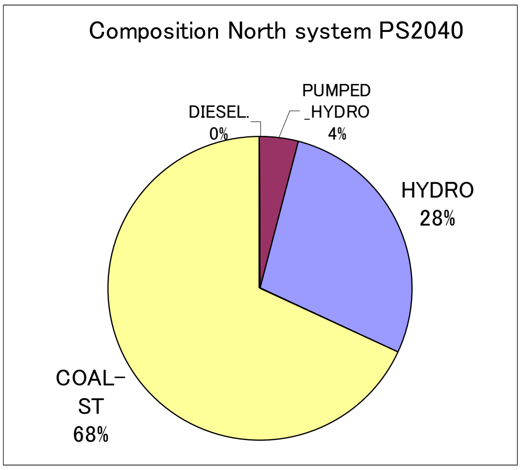
Because the hydropower potential will run out by 2020, thermal power is selected to be the additional supply.

(2) Appropriate Composition in 2040

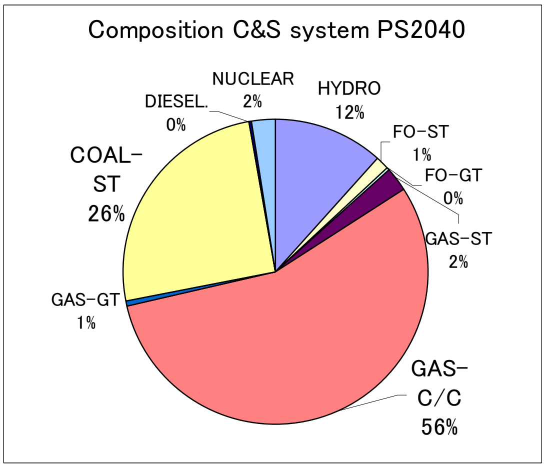
a. Composition of Generation

The additional generation for 2040 is thermal power in addition to the 2020 capacity, because the hydropower potential will run out by 2020. The peak demand in the central & south system is growing rapidly. Mainly gas and coal thermal power will developed for the capacity in 2040.

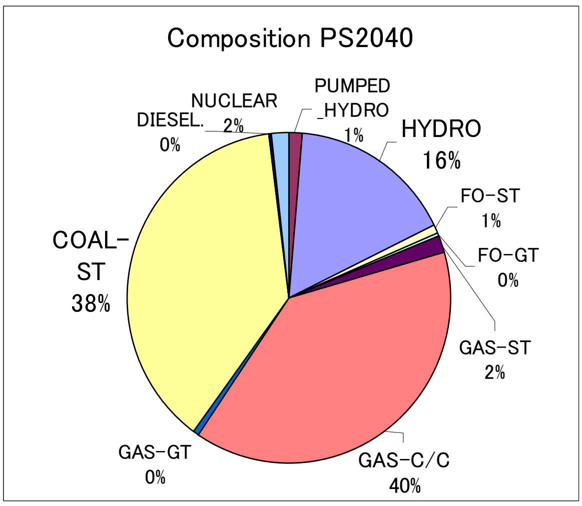
The North System



The Central & South System



Total



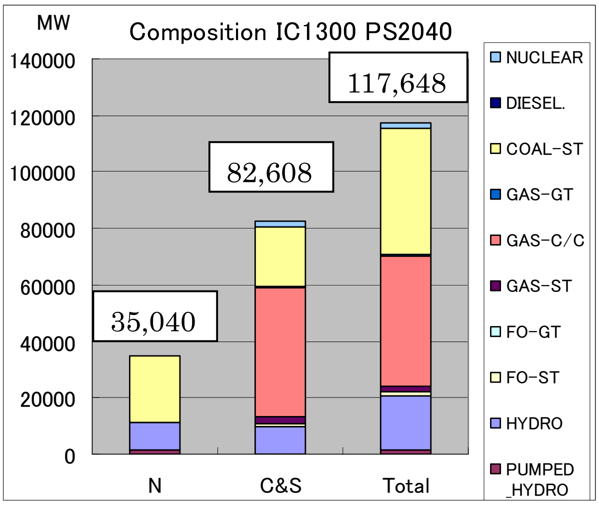


Fig. 6-2-41 Appropriate Composition in 2040

b. Confirmation of Sustainability of PSPP Installation Scenario

The benefits of PSPP installation in 2040 show the same benefits as the case in 2020. The benefits are continued for the 5,000MW of PSPP installation in the north system.

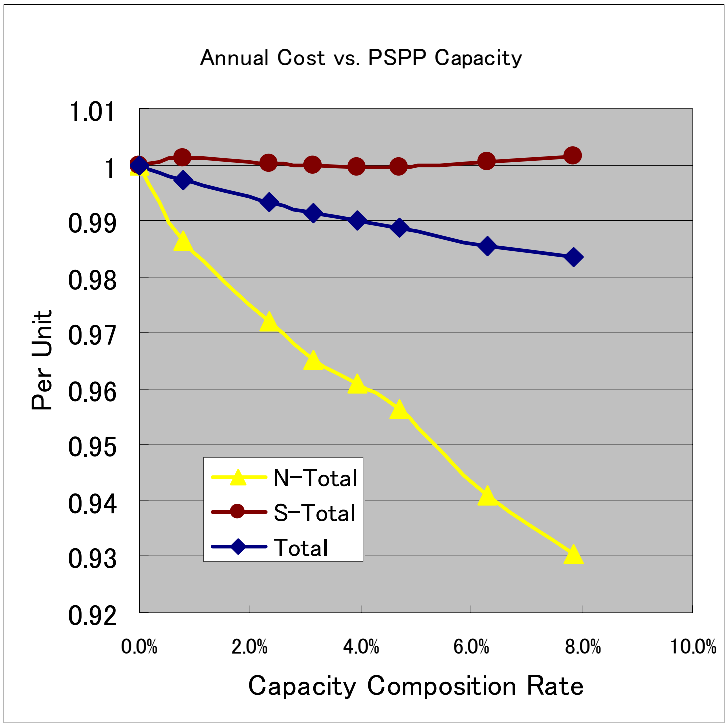
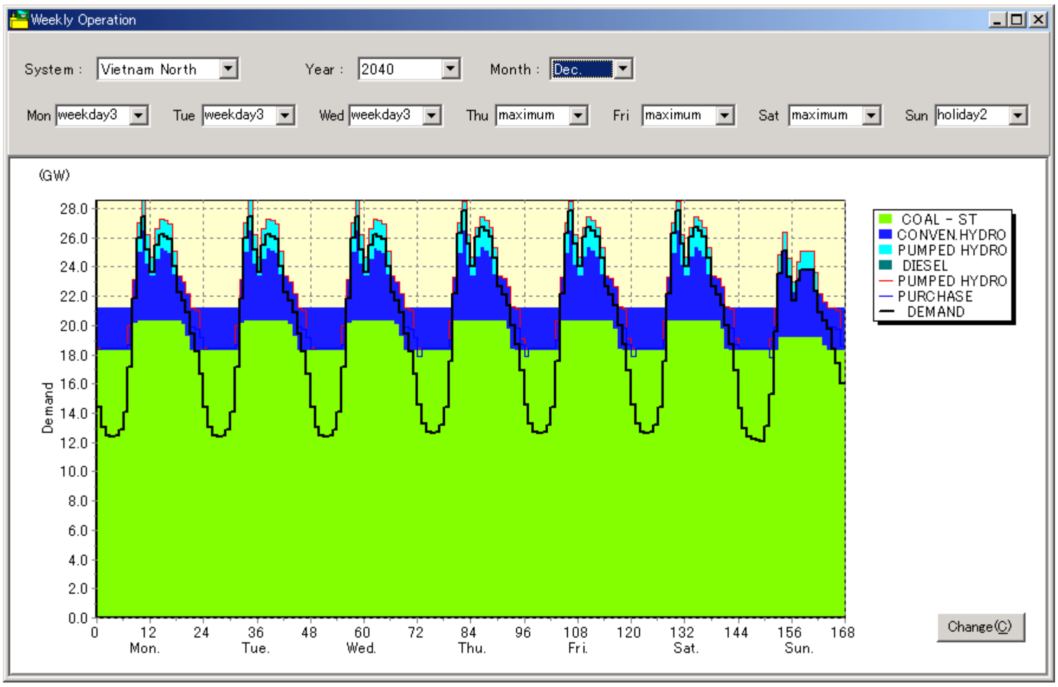


Fig. 6-2-42 PSPP Installation vs. Annual Costs in 2040

The results of simulation of the 5,000MW PSPP installation in the north system in 2040 are shown in Fig. 6-2-43. The benefits of PSPP installation are expanded; meaning the off-peak supply increases due to the increase in the coal thermal power supply. The share of hydropower supply is reduced, because of running out of potential new sites. The peak supply is necessary in 2040, because the peak demand cannot be supplied by hydropower. Generally, when the share of hydropower supply is under 20%, the benefits of peak supply show that the lesser fixed-cost are expanding.

(The North System)



(The Central & South System)

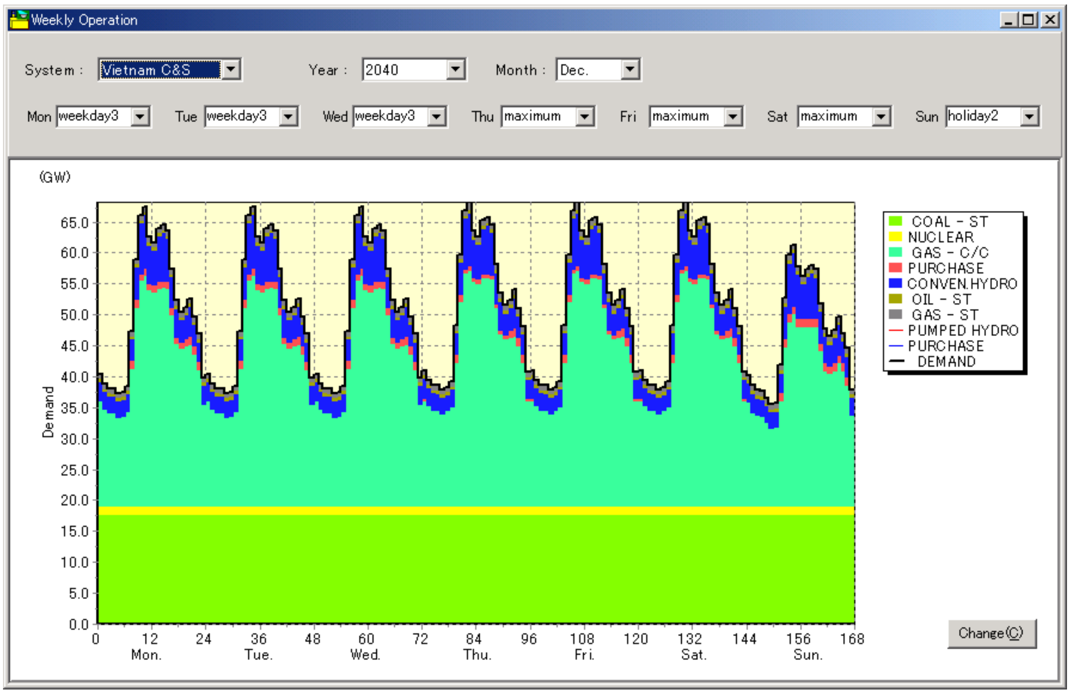


Fig. 6-2-43 Results of Simulation in Dec. 2040

(Interconnection 1,300MW, PSPP Installation 5,000MW in the North System)