4. STUDY FOR THE OPTIMAL POWER DEVELOPMENT SCENARIO

4.1. Supply and Demand of Primary Energy

Though it has been thought that abundant energy resources such as oil, the natural gas, and coal are reserved in Indonesia, they are also limited. As for oil, the production tends to decreases every year and the amount of import exceeded the amount of export in 2004. In around 2013, the amount of import is expected to exceed the production.

On the other hand, gas production has shown marginal changes since the 1990's and the supply to power plants where a large amount of gas is consumed is delayed in many occasions. This delay forced many PLTG/PLTGU that were constructed in order to meet the rapid growth of power demand since 2000 use HSD instead.

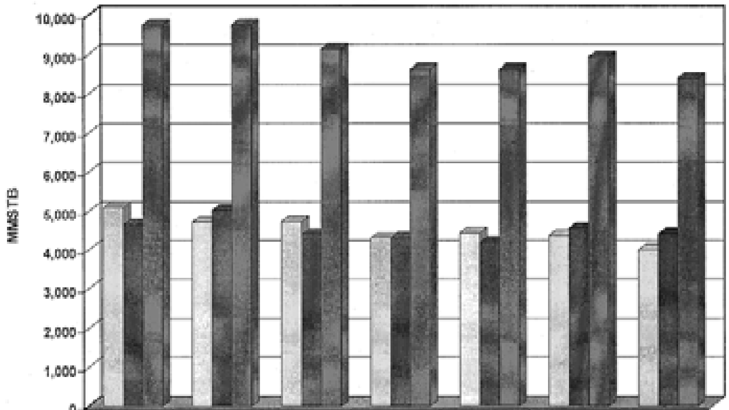
Based on the national policy, valuable and marketable high-quality coal is turned to export for the foreign currency earning, and low grade coal which has low calorific value and contains high moisture, is directed to domestic market. Recently, the government is promoting the use of LRC (Low Rank Coal) at power stations where a large amount of primary energy is consumed.

Meanwhile, as primary energy for power generation, geothermal, the potential of which in the country is the world's largest, run-of-river hydro, and other renewable energy such as wind and solar power, have also become candidates of important power resources.
The current state of primary energy is described below.

4.1.1 Crude Oil

(1) Reservoir and Area Map

Reserves of crude oil in Indonesia are shown in Fig.4.1-1. Total has been gradually decreasing while slight increase is seen in 2006 which is after the discovery of a new oil-field.
The proven reserve is 4 billion bbl, and total resources are 8.4 billion-bbl in 2007.
When keeping current production of 1 million bbl/day, the reservoir will deplete in 11 years, and even if potential is accounted for, in 23 years.

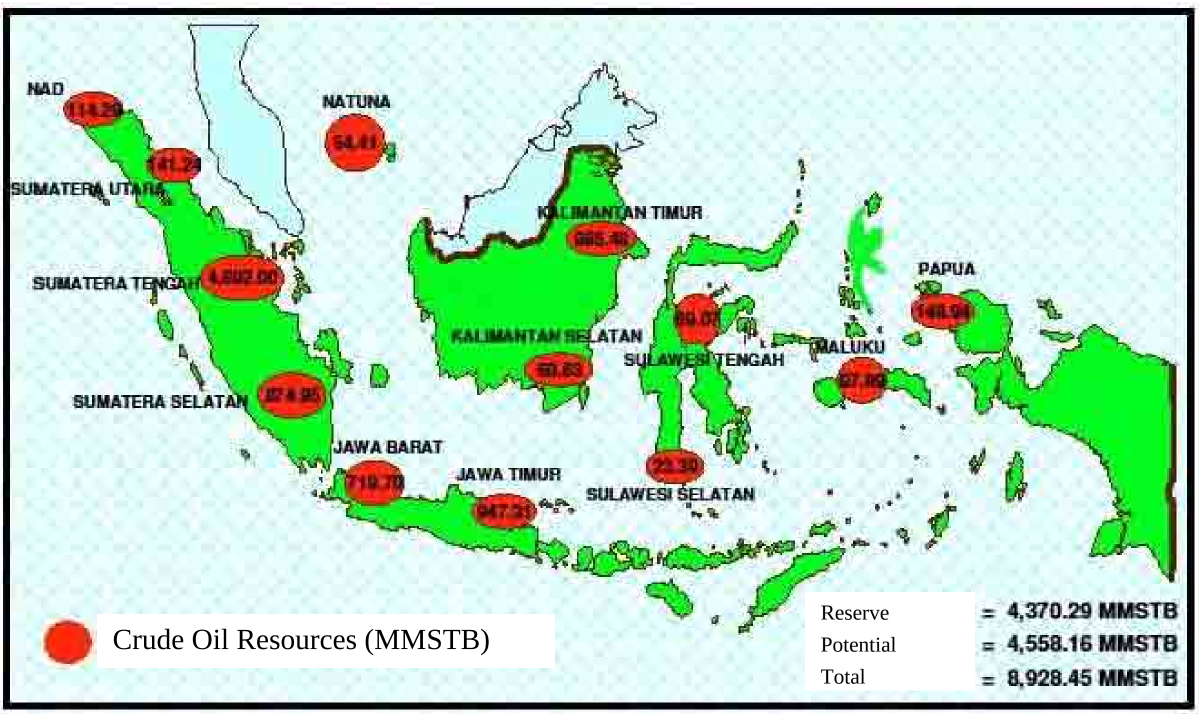


	2001	2002	2003	2004	2005	2006	2007
□ Terbukti	5,094.6	4,722.0	4,727.9	4,300.7	4,439.5	4,370.3	3,989.7
■ Potensial	4,658.9	5,025.0	4,403.5	4,312.2	4,187.5	4,558.2	4,414.6
■ Total	9,753.4	9,747.0	9,131.4	8,612.9	8,627.0	8,928.5	8,403.3

Note; MMSTB (Million Stock Tank Barrel) Source : MEMR MIGAS

Fig.4.1-1 Oil Resources in Indonesia

Fig.4.1-2 shows Resources and Area Map of Crude Oil.



Source : MEMR MIGAS

Fig.4.1-2 Area Map of Oil

(2) Oil Balance

Table 4.1-1 shows the transition of resources/reserves of oil and gas. Oil is in a trend to decrease gradually, and gas shows marginal changes in 2004 while it had been in increasing trend after 1990's.

Recently, the possibility of large-scale hydrocarbon source (in the magnitude of 100 billion-bbl) in Aceh Province southwest Simeulue-island was reported. There can be significant impact on the energy policy if the reserve confirmed.

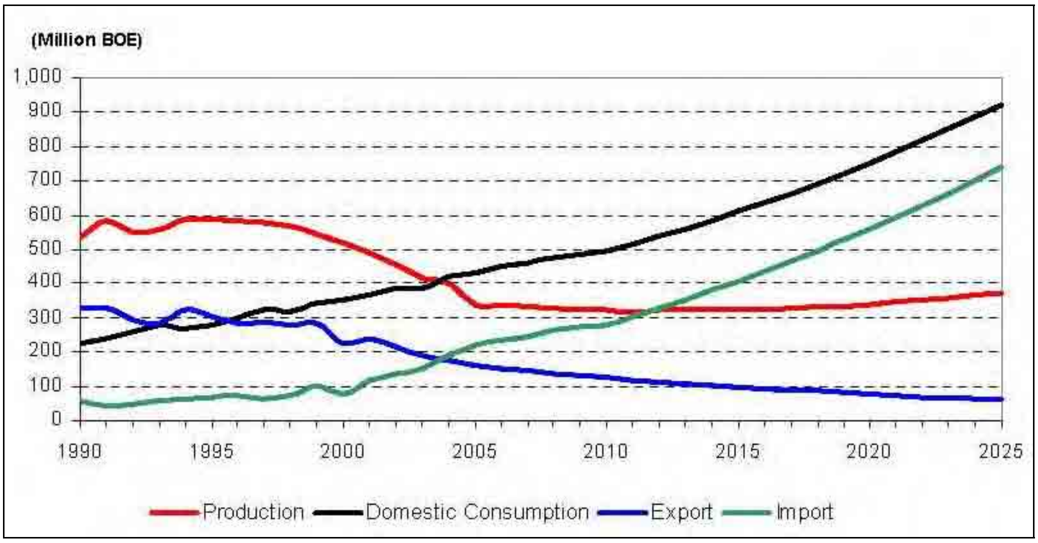
Table 4.1-1 Resources/Reserves of Oil and Gas

Year	Oil (Billion Barrel Oil)			Gas (Trillion Cubic Feet)		
	Proven	Potential	Total	Proven	Potential	Total
1995	4.98	4.12	9.10	72.26	51.31	123.57
1996	4.73	4.25	8.98	77.19	58.73	135.92
1997	4.87	4.22	9.09	76.17	61.62	137.79
1998	5.10	4.59	9.69	77.06	59.39	136.45
1999	5.20	4.62	9.82	92.48	65.78	158.26
2000	5.12	4.49	9.61	94.75	75.56	170.31
2001	5.10	4.66	9.75	92.10	76.05	168.15
2002	4.72	5.03	9.70	90.30	86.29	176.59
2003	4.73	4.40	9.13	91.17	86.96	178.13
2004	4.30	4.31	8.61	97.81	90.53	188.34
2005	4.19	4.44	8.63	97.26	88.54	185.80

Sources : - Data, Information Oil and Gas 6th Ed., 2002, (page 34), Directorate General of Oil and Gas, Ministry of Energy and Mineral Resources
- Oil and Gas Statistics of Indonesia 1999-2003, Directorate General of Oil and Gas, Ministry of Energy and Mineral Resources
- Oil and Gas Statistics of Indonesia 2000-2004, Directorate of Oil and Gas Ministry of Energy and Mineral Resources
- Directorate of Oil and Gas Ministry of Energy and Mineral Resources

Source : Energy Outlook & Statistics 2006

Fig.4.1-3 is the forecast of supply and demand balance of oil. Unless new resource is discovered, the amount of import exceeds production in around 2013.



Source : Energy Outlook & Statistics 2006

Fig.4.1-3 Crude Oil Balance

(3) Oil Consumption Reduction Plan in Power Generation

PLN advances the conversion of existing oil fired thermal power plants to gas fired, and the construction of coal fired thermal power plants as a reduction measures of oil consumption and estimates the fuel consumption in Java-Bali system as shown in Table 4.1-2.

Table 4.1-2 Fuel Consumption in Java-Bali Region (2008-2016)

Fuel Type	Unit	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
HSD	1000 kl	1924	2654	1297	157	140	139	140	194	192	270
MFO	1000 kl	1810	1889	1348	18	44	55	78	90	130	243
GAS	bcf	165	202	332	299	299	308	285	232	225	201
LNG	bcf	0	0	0	0	22	50	58	85	112	140
COAL	1000 ton	30864	30357	32441	41374	43566	45942	51220	57810	62213	67241

Source : RUPTL 2007

In this plan, oil consumption decreases after peaking in 2008, and it will decrease greatly to about 5% of 2007 level. This large decrease id made possible by coal-fired thermal power plants of Fast Track Program start operation in 2010.

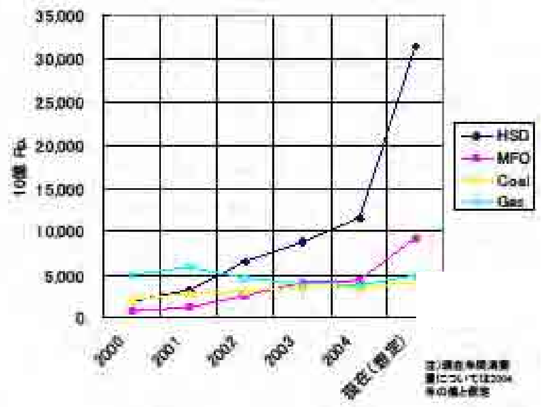
However, oil fired thermal power plant may still be in use, because of the tight balance of power supply and demand, the possibility of interruption of coal-fired plants due to fuel shortage by the weather and other incidents, and the possibility of delay of construction of new coal fired plants, etc. The realization of reduction of oil consumption can be delayed by various reasons.

(4) Oil Procurement of PLN

Apart from its high price, oil is a fuel with high availability compared with other types of fuel. As purchasing oil does require so-called "Take or Pay contract" like gas, it is possible to buy when and how much it is necessary and is easy to store.

Oil price is controlled by government in Indonesia. Large revision to oil price was made in 2005 because of the increase of subsidy due to soaring oil prices and demand increase by the growth of economy. Oil subsidy is applied only to private consumption, and for industrial use one has to purchase at international market price.

In PLN, fuel subsidy was scrapped a few years ago, while subsidy to electricity tariff is left untouched. The influence of fuel expenses on the management of PLN (Fig.4.1-4) is large, and the effort to reduce oil consumption and to lower purchasing price has become onerous more and more.

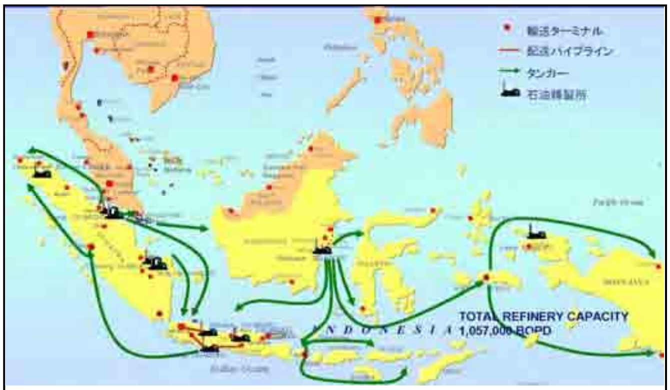


Source : JICA, Mr. Nagai

Fig.4.1-4 Fuel Cost of PLN

Oil (HSD and MFO) consumption of PLN is estimated 10 million kilo litter in 2008.
After monopoly of Pertamina was lifted in 2002, the Cabinet Council allows PLN to procure up to 10% of oil it uses every year in open market.

The current purchase price of HSD and MFO from Pertamina is MOPS + margin (commission and profit and others). Under the recent situation where oil price soars, as there is no rationality in that the margin increases in proportion to base price rise, the negotiation between PLN and Pertamina is underway. At the same time, PLN is negotiating with third parties as well, for the lowest total procurement cost including transportation, etc., to find a best deal available in the market. Fig.4.1-5 shows the infrastructure of oil.



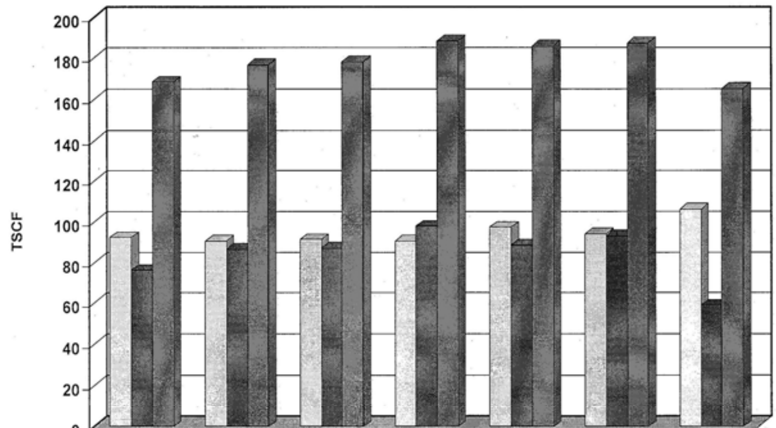
Source : Energy Management Blueprint

Fig.4.1-5 Infrastructure of Oil

4.1.2 Natural Gas

(1) Resources/Reserves of Natural Gas

Proven reserve of the natural gas in Indonesia shows gradual increase as shown in Fig.4.1-6. Proven reserve in 2006 is 94 TSCF, and the production may continue for another 31 years at current production rate, 3 TSCF/year. Because the discovery of new gas field can be expected as the result of the recent exploration, the proven reserves may increase.

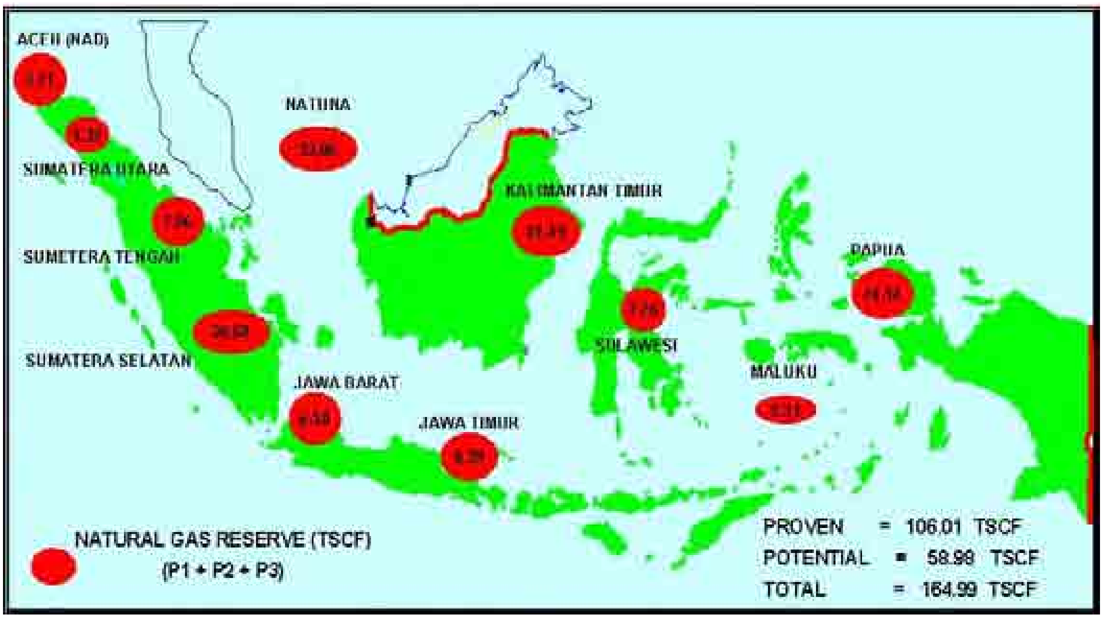


	2001	2002	2003	2004	2005	2006	2007
□ Terbukti	92.1	90.3	91.2	90.5	97.3	94.0	106.0
■ Potensial	76.1	86.3	87.0	97.8	88.5	93.1	59.0
■ Total	168.2	176.6	178.1	188.3	185.8	187.1	165.0

Source : MEMR MIGAS

Fig.4.1-6 Gas Resources in Indonesia

Fig.4.1-7 shows Resources and Area Map of Gas.



Source : MEMR MIGAS, Jan. 2007

Fig.4.1-7 Area Map of Gas

Moreover, the existence of CBM (Coal Bed Methane) of total reserve 453 TSCF was confirmed at the coal field in Sumatra and Kalimantan as shown in Fig.4.1-8, and the investigation on commercial development has just started.

Source : MEMR MIGAS

Fig.4.1-8 Area Map of Coal Bed Methane

(2) Supply and Demand of Gas

Tables 4.1-3 to 4.1-6 show the gas supply and demand schedules for power stations of PLN. The required gas quantity of PLN in West Java is 300 MMSCFD. The supply of 150 MMSCFD to the Muara Tawar Power Station through Sumatra-Java sub-sea pipeline (SSWJ-1) completed this year will be expected in mid. 2008. In East Java, the supply of gas from Kangean gas field to Gresik Power Station is currently under price negotiation. There are no further plans of gas supply to power stations excluding existing and new power stations that have already started construction.

Due to the recent crude oil price rise, gas price is rising in line with oil, which may put pressure on price negotiations of gas supply, then further delay of supply may result.
As for the pipeline gas, it is difficult to turn supply to end users other than the predetermined destinations of the pipeline. Therefore the supply will start soon after the completion of the gas pipeline and the gas price settlements.

LNG has been allocated for export, and there has been no domestic use up to now. The use of LNG in domestic market is now examined while existing for expiration of the existing long-term contracts for export.

Table 4.1-3 Supply and Demand Gas (Jakarta Region)

PEMBANGKIT	KAPASITAS (MW)	(mmscfd) 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
GAS DEMAND											
Existing Power Plant											
PLTGU M. Karang	508	70	70	70	70	70	70	70	70	70	70
PLTGU T. Priok	1180	145	145	145	145	145	145	145	145	145	145
PLTGU M. Tawar (Blok I)	660	90	90	90	90	90	90	90	90	90	90
PLTG M. Tawar (Blok 2)	290	60	60	60	60	60	60	60	60	60	60
PLTG M. Tawar (Blok 3 & 4)	858	180	180	180	180	180	180	180	180	180	180
Sub Total		***545***	***545***	***545***	***545***	***545***	***545***	***545***	***545***	***545***	***545***
New Power Plant											
PLTGU M. Tawar (Blok 5)	255			35	35	35	35	35	35	35	35
PLTGU M. Karang Repowering	720			125	125	125	125	125	125	125	125
PLTGU Priok Repowering	750			125	125	125	125	125	125	125	125
Sub Total		-	-	***285***	***285***	***285***	***285***	***285***	***285***	***285***	***285***
TOTAL OF DEMAND		**545**	**545**	**830**	**830**	**830**	**830**	**830**	**830**	**830**	**830**
GAS SUPPLY											
BP ONWJ *(GSA)*		135	100	100	100	100	100	100	100	100	100
PERTAMINA - P Tengah *(GSA)*		30	30								
Pipa Sumatera Selatan											
- PGN *(GSA)*		50	50	50	50	50					
- JOB Jambi Merang *(GSA)**				85	85	85	85	85	85	85	85
- MEDCO *(Proses Amandemen GSA)**				20	20	20	20				
- PGN - Tambahan, Firm *(GSA)*		150	150	150							
- PGN - Tambahan, Interruptible *(GSA)*		100	100	100							
TOTAL OF SUPPLY		**465**	**430**	**505**	**255**	**255**	**205**	**185**	**185**	**185**	**185**
DEFISIT / SURPLUS		**(80)**	**(115)**	**(325)**	**(575)**	**(575)**	**(625)**	**(645)**	**(645)**	**(645)**	**(645)**

* Diperlukan pembangunan Stasiun Booster Kompresor Gas di Pagardewa dan Terbanggi Besar

Source : PLN (Jun. 2008)

Table 4.1-4 Supply and Demand Gas (West Java)

PEMBANGKIT	KAPASITAS (MW)	(mmscfd)									
		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
GAS DEMAND											
PLTGU Cilegon	750	120	120	120	120	120	120	120	120	120	120
TOTAL OF DEMAND		120	120	120	120	120	120	120	120	120	120
GAS SUPPLY											
CNOOC *(GSA)*		80	80	80	80	80	80	80	80	80	80
Pipa Sumatera Selatan											
- MEDCO *(GSA)*			49	49	49	49	49	43	33	25	19
- PGN - Tambahan *(Proses GSA)*		30									
TOTAL OF SUPPLY		110	129	129	129	129	129	123	113	105	99
DEFISIT		(10)	9	9	9	9	9	3	(7)	(15)	(21)

Source : PLN (Jun. 2008)

Table 4.1-5 Supply and Demand Gas (Central Java)

POWER PLANT	CAPACITY (MW)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
GAS DEMAND												
Existing Power Plant												
- PLTGU Tambak Lorok		120	120	120	120	120	120	120	120	120	120	120
- PLTU Tambak Lorok		23	23	23	23	23	23	23	23	23	23	23
Sub Total		*143*	*143*	*143*	*143*	*143*	*143*	*143*	*143*	*143*	*143*	*143*
TOTAL OF DEMAND		143	143	143	143	143	143	143	143	143	143	143
GAS SUPPLY												
- Petronas (Approval GSA)						120	145	145	145	145	110	77
- SPP (Finalisasi GSA)					50	50	50	50	50	50	50	50
Sub Total		-	-	-	*50*	*170*	*195*	*195*	*195*	*195*	*160*	*127*
TOTAL OF SUPPLY		-	-	-	50	170	195	195	195	195	160	127
DEFISIT		(143)	(143)	(143)	(93)	27	52	52	52	52	17	(16)

Source : PLN (Jun. 2008)

Table 4.1-6 Supply and Demand Gas (East Java)

PEMBANGKIT	KAPASITAS (MW)	(mmscfd)									
		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
GAS DEMAND											
PLTGU Gresik	PLTGU : 3 x 525 PLTU : 3 x 200 2 x 100	280	280	280	280	280	280	280	280	280	280
PLTGU Grati	PLTGU : 1 x 460 PLTG : 3 x 100	110	110	110	110	110	110	110	110	110	110
Sub Total		*390*	*390*	*390*	*390*	*390*	*390*	*390*	*390*	*390*	*390*
TOTAL OF DEMAND		390	390	390	390	390	390	390	390	390	390
GAS SUPPLY											
Kodeco *(GSA)*		123	123	123	123	123	123				
Hess		100	100	100	100	100	91	77	64	54	45
Santos				60	60						
KEI *(GSA)*				100	100	100	30	30	30	30	30
MKS (GSA)		11	11	11	11	11	11				
WNE *(Proses GSA)*		20	20	20	17	12	12	12	4		
Sub Total		*254*	*254*	*414*	*411*	*346*	*267*	*119*	*98*	*84*	*75*
TOTAL OF SUPPLY		254	254	414	411	346	267	119	98	84	75
DEFISIT		(136)	(136)	24	21	(44)	(123)	(272)	(292)	(306)	(315)

Source : PLN (Jun. 2008)

(3) Infrastructure of Gas

In Indonesia, low-cost gas produced in middle- or small-scale gas fields is supplied to the domestic consumers through pipelines. The gas from large-scale gas fields in remote area or in deep-sea that require high production cost is turned to export through international pipelines or by means of LNG at higher international gas prices.

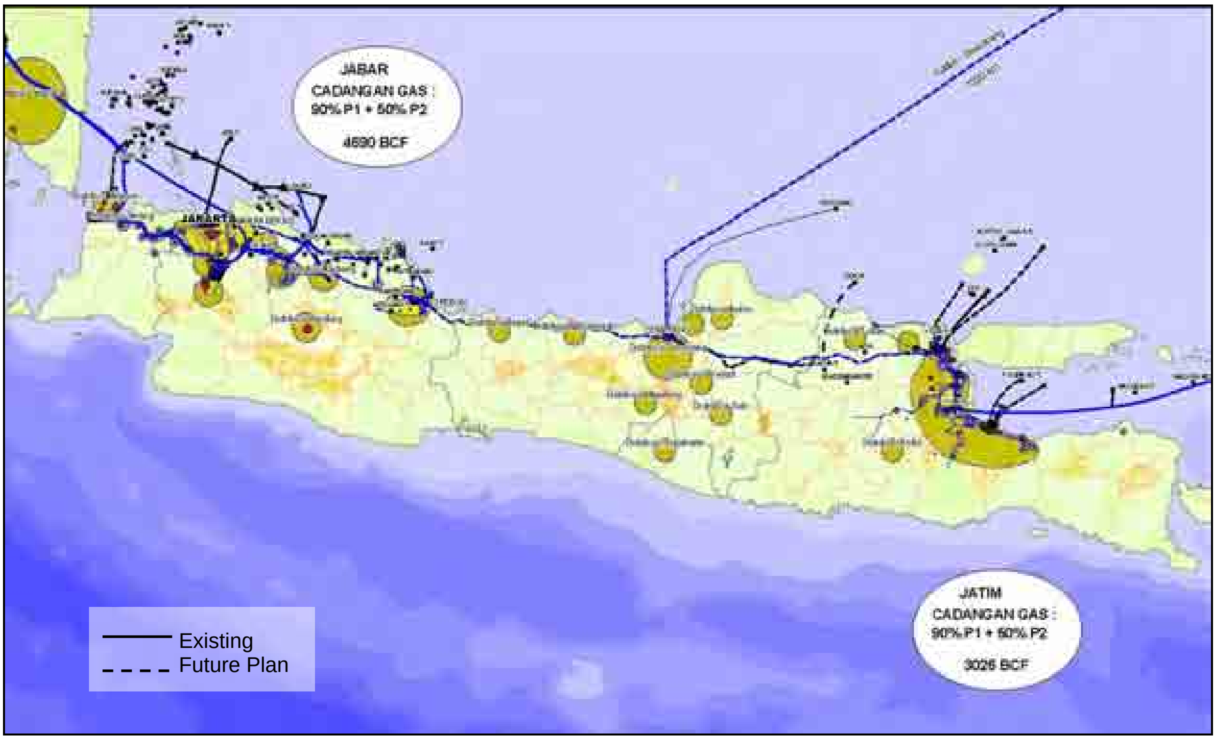
The gas fields also in West Java have also been developed from early time as they are located near the centers around Jakarta, and many gas pipelines from these gas fields to consumers have been constructed.

Many PLTG/PLTGU were constructed to meet the rapid increase of electricity demand around Jakarta in 1990's. However, for the reason that the cooperation between supply and demand sides was not sufficient, and gas production and construction of gas pipeline did not catch up with them, supply has not reached and HSD is burned in many plants instead. Previously, there was no problem in plants burning HSD because price difference between oil and gas was small. But now, by the recent rapid rise of oil price, power generating cost is considerably influenced.

The plan was made, as the oil price soared, to switch the fuel of PLTG/PLTGU from HSD to gas, which is an original designed fuel. However, in gas supply to power stations where a large amount of gas is consumed, there is often a limitation in the production capacity of gas fields in the surrounding area only, and it is necessary to construct long pipelines in order to supply gas from, say, Sumatra or remote islands where a gas reserve is more abundant (Fig.4.1-9). Construction of gas pipeline is extensive, and requires enormous capital for investment.
The pipeline SSWJ-1 (Sub-sea gas pipelines that connect Sumatra and Java with transportation capacity of 500 MMSCFD and constructed with JBIC fund) is completed in 2008, and SSWJ-2 (transportation capacity of 450 MMSCFD, with ADB fund) is scheduled to be completed by the end of 2008. The gas of 150 MMSCFD will be supplied from Sumatra to Muara Tawar Power Station through the SSWJ-1 pipeline in August 2008. As the gas production will be increased in the future, further supply to Tanjung Priok Power Station and Muara Karang Power Station around Jakarta is scheduled.

As for East Java, gas produced in the Kangean fields will be supplied through the East-Java pipeline in around 2011.

An incentive to the development of CEPU gas field in East Java that reserves 2.5 TCF is expected to be higher, as the fuel price soars.



Source : MEMR MIGAS

Fig.4.1-9 Gas Pipeline in Java

(4) LNG

Until 2005, Indonesia was the world's largest LNG exporting country. The contracted production, however, failed in 2004, and the position was handed over to Qatar. The LNG liquefaction terminals in Arun in northern Sumatra and Bontan in Kalimantan are operating now, and the case in Tangu in Papua under construction is scheduled to complete by the end of 2008. Production of Arun has already decreased, and the long-term contracts of Bontan with South Korea and Japan will expire sometime between this year and 2011. Dongi in Sulawesi (capacity of 2 million ton/year, start operation in 2015) and Masara in Timor (capacity of 3 million ton/year, start operation after 2015) are under development stage.

Although all LNG production has been turned to export before, the government is considering using LNG domestic in the future. LNG import terminal (gasification plant) is scheduled to be constructed in Bojanegara in West Java. This plant will be jointly operated by PGN, PLN and PERTAGAS. Gasification of LNG will amount to 1.5 million ton/year in 2011 and 3 million ton/year in 2014. It is planned that LNG will be supplied to domestic market from Bontan LNG liquefaction terminal operated by TOTAL Indonesia. The long-term contracts between South Korea and Japan will expire soon, the negotiations for new contracts will start. The preparation for the construction of the Bojanegara LNG import terminal is separately advanced, and construction will start as soon as the agreement among relevant parties is met.

For the Bontan LNG liquefaction terminal, production at the gas fields supplying the terminal has decreased, and the gas excavation in Musaka strait has become necessary for closing the gap. Moreover, there is no plan to own proprietary LNG vessels to transport from the liquefaction terminal to the import terminal.

Thus, the gas production at gas field and the LNG vessel arrangement are both likely to become a problem. LNG demand in Java is forecasted at 7 million ton/year (approximately 1 BCF per day) in 2016.

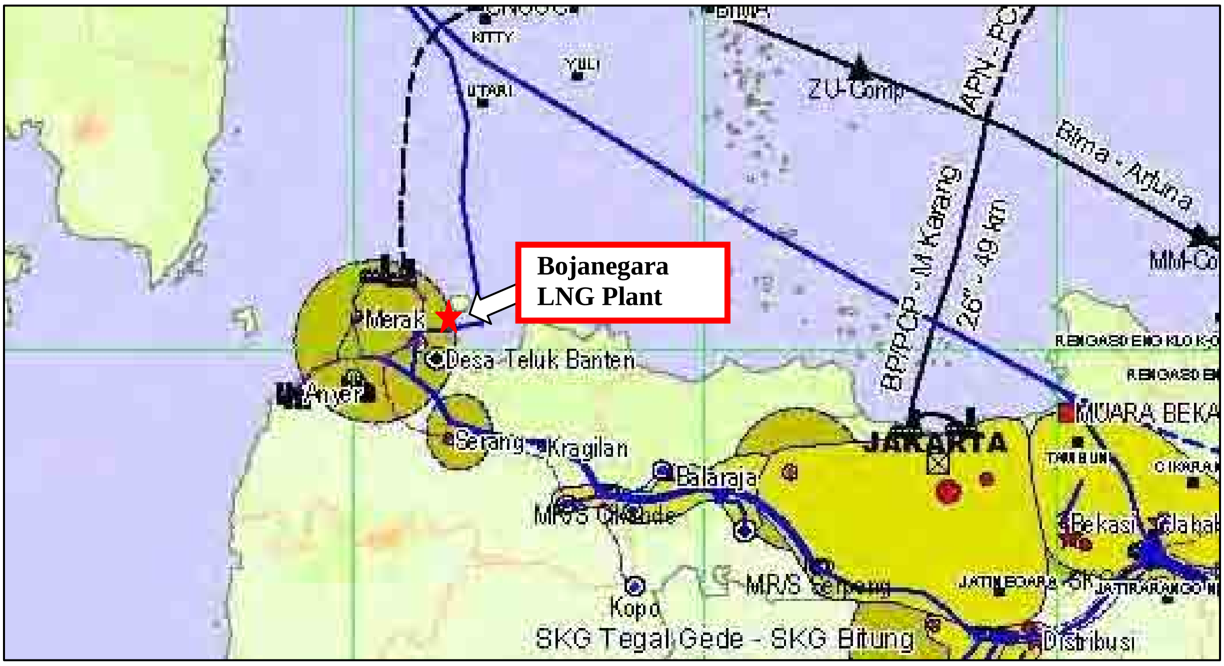


Fig.4.1-10 LNG Import Terminal in Java

(5) Gas Supply to Power Station

The PLTG/PLTGU that are supplied with gas through gas pipelines are usually operated for Base Load. A gas supply contract between supplier and consumer regularly imposes the obligation of fixed quantity gas supply, and is called “Take-or-Pay Contract”. This secures a stability of the operation on both sides by guaranteeing the continuation of gas production in gas fields and supply to the consumer.

It is preferable for the power generating systems to operate such power plants for Base Load, because the thermal efficiency can be maintained at higher level and more electricity can be generated per input. PLTGUs have been operated for Base Load, and they were competent with coal-fired PLTU when the difference of prices between gas and coal was small. Although the gas price was slightly higher than coal, the generation cost was not so different by compensating the fuel cost difference with their higher thermal efficiency.

After 2010, many coal-fired power stations with low-price fuel will be put in operation in the power generation systems in Indonesia. As these coal-fired plants will be operated for Base Load, Base Load operating PLTGUs may not be continued, because the generating cost of PLTGU has become very high due to the sudden rise of price of HSD and gas. The roles of

PLTG/PLTGU are shifted to Peak Load or Middle Load operation where the Start-Stop and load swing characteristics of PLTG/PLTGU can be effectively used.

Considering the best mix of energy and the possible environmental impacts, the fuel of PLTG/PLTGU should be shifted to gas, and HSD should be used only in emergency or generation in remote areas.

HSD can be stored easily and can be used as necessary, while there are many constraints for the gas use supplied by pipelines. The constant gas supply on "Take-or-Pay contract", the difficulty in change of gas production rate following the consumption rate at receiving end, the acceleration of deterioration of pipeline material due to pressure swing, the influence of supply gas pressure on other users connected, etc. are the factors related to this.

Two ideas discussed below are considered as a countermeasure that enables variable gas supply. Each power station's given role (Peak or Middle Load), the load swing rate, and the gas supply condition, etc., affect the applicability of these measures, and detailed examinations including the economy and reliability are necessary before actual application.

i) Application of LNG

LNG is a liquefied gas made by cooling the gas to -160°C. The volume becomes 1/600 of the gas, which enables the storage, although the manufacturing cost is expensive. This makes it possible to change the gas supply rate by adjusting the evaporation rate and to operate PLTG/PLTGUs for peak load or variable load.

Consideration between LNG import terminal (gasification plant) and power station is necessary in changing the gas supply rate.
In the design of LNG evaporation equipment, the examination as a whole system is required so that the evaporation equipment can meet the variability of demand of the power station.

ii) Application of CNG System

CNG system is a system that uses the gas compressed to 1/300 by volume at 30 MPa, and enables transportation and storage. Although the gas volume is twice as large as of LNG, the gas compressor system costs much less compared with LNG manufacturing facilities, and this system is developed as a convenient system for transportation for the short distance.

Gas is compressed at the gas production site, injected into a high-pressure tank loaded on a barge with several thousand-ton capacities, transported to the gas consumption site, and finally delivered to the consumer from the barge moored at the port. Fig.4.1-11 shows a general CNG supply system. With this system, management of the barges with high-pressure tanks is important, so that barges are available at both gas production site and gas-consuming site at any time. If no barge present is at gas production site, gas extracted from gas field is discharged into the atmosphere. If it is not present at gas-consuming site, the gas supply is interrupted. The possibility of interruption of the navigation of barges under foul weather is also considered. To avoid these problems, it is necessary to install high-pressure CNG storage tanks at both gas production and gas consuming sites.

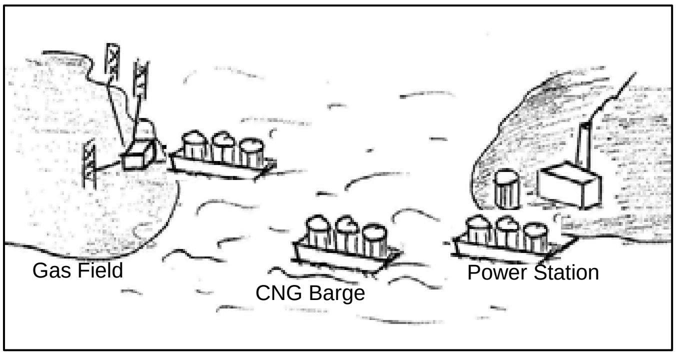


Fig.4.1-11 CNG System

If this system is applied to pipeline, as shown in Fig.4.1-12, consumer-side end of Peak Load operation may become possible.

This system consists of the followings.

-Branch of pipeline before power station
- Gas compressor
- CNG storage tank
- Pressure reducing valve
- Gas expander (turbine for recovering the energy of gas pressure, if necessary)

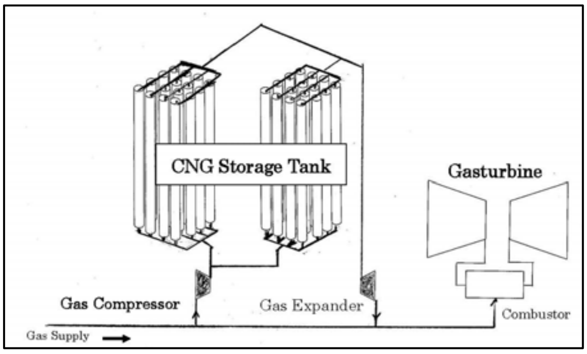


Fig.4.1-12 CNG Application to Pipeline Gas

Fig.4.1-13 shows the concept of operation. The surplus gas during low load operation of PLTG/PLTGU is stored in the tank as CNG. The pipeline gas and the gas from CNG tank are fed into the plant during Peak-Load operation. By applying this system, the gas supply to PLTG/PLTGU becomes variable and can follow the fluctuation of the electricity demand, while the gas supply through pipeline is constant.

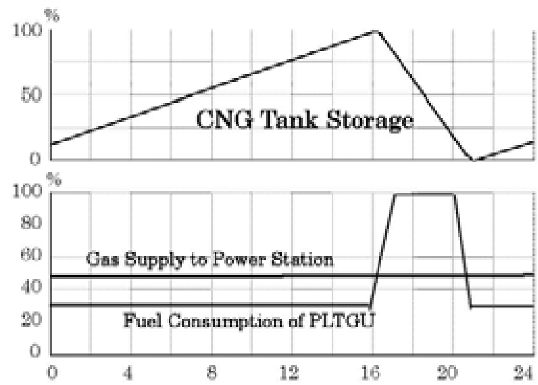


Fig.4.1-13 Operational Flexibility by CNG

There are a few power stations connected to small-scale gas fields by pipelines. These plants are operated for base load while other HSD-fired PLTG/PLTGU are operated for peak load. If this CNG system is applied, all PLTG/PLTGU can be operated Peak/Middle Load without burning the expensive HSD.

After 2010, new coal-fired PLTUs that are currently being constructed under the "Fast Track Program" will be coming into the power system, and the roles of PLTG/PLTGUs will be shifted to peak load or middle load operation.

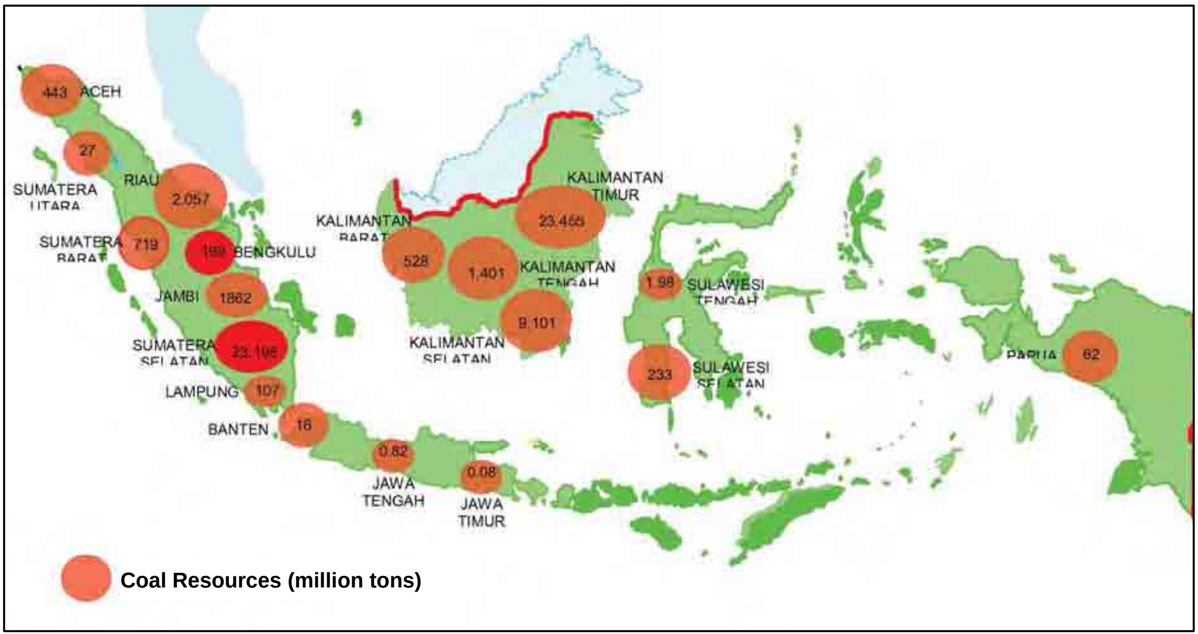
It is recommended that for each PLTG/PLTGU, taking into account the future role of the plant in the power generation system, the better use of fuel, LNG or CNG, should be studied.

4.1.3 Coal

(1) Resource and Coal Mine

Coal resources in Indonesia are about sixty-one billion tons, and mostly distributed in Sumatra (47%) and Kalimantan (52%), as shown in Fig.4.1-14. The production in 2006 was one hundred ninety million tons, and the reserve/production ratio is 36 years based on the proven reserve of six billion eight hundred million tons. When the calculation is made based on twelve billion four hundred million tons that includes the measured reserve, it becomes 101 years.

Among the production of one hundred ninety million tons per year, 70% is exported to Japan, Taiwan, Malaysia, Korea, etc. and the remaining 30% is within the country. 57% of domestic use is consumed for electric power generation.



Source : MEMR Coal & Geo

Fig. 4.1-14 Coal Resources in Indonesia

Table 4.1-7 is the reserves by the ranks of coal. About 80% of the proven reserves are the middle and low rank coal. The low rank coal has not been appreciated on a commercial base until now. Reserve/production ratio of only commercial base coal (middle, high and very high rank coal) is 20 years.

Table 4.1-7 Coal Resources/Reserves for Rank of Coal

Coal Rank	HHV (kcal/kg) Air Dried Base	Resources		Reserves	
		Billon ton	(%)	Billon ton	(%)
Low	<5100	14.95	(24.4)	2.98	(44.1)
Medium	5100-6100	37.65	(61.5)	2.44	(36.1)
High	6100-7100	7.97	(13.0)	1.22	(18.0)
Very High	>7100	0.67	(1.1)	0.12	(1.8)
Total		61.24	(100.0)	6.76	(100.0)

Source : MEMR Coal & Geo

If there is no more addition to proven reserves of the high rank coal, which has been turned to export the present exportation (about one hundred thirty million tons/year) of coal will deplete the reserve in 10 years.

Coal production is operated by PTBT (PT. Tambang Batubara Bulit Asam; State owned company), contractors (Contract of Works (KK), Coal Contract of Works (Pkp2B)), mining concessionaires (KP BUMN) and Village Joint Associations (KUD), and KK/PK2B (80%) and PTBT (20%) are the dominant groups. There are one state owned company, 63 domestic private companies and 18 foreign companies in operation in 2007. There are 17 shipping ports where the ships of 5,000 to 200,000 DWT call.

(2) Low Rank Coal (LRC)

In the coal fired thermal power station that will be built hereafter in Indonesia, low rank coal (LRC) with calorific value less than 5,100 kcal/kg (air dried base) and proven reserve of about three billion tons will be used. The estimated coal consumption in the power stations which are currently being constructed under “Fast Track Program” (total output 10,000 MW), is about 32 million tons/year. Only for these power stations the reserve/production ratio of low rank coal is 99 years. Even if a part of the low rank coal reserve is used in the existing power stations (As these plants were not designed to be fed with 100% LRC fuel, only mixed use with quality coal is acceptable) or in the power stations coming into the system with future, the LRC fuel reserve is sufficient to serve these plants.

Table 4.1-8 shows the typical specification of LRC, which is categorized in lignite or sub-bituminous. As LRC contains a large component of water (more than 30% in weight) and active oxidizing substances which will cause the natural-ignition, it is not suitable for storage/transport for long time.

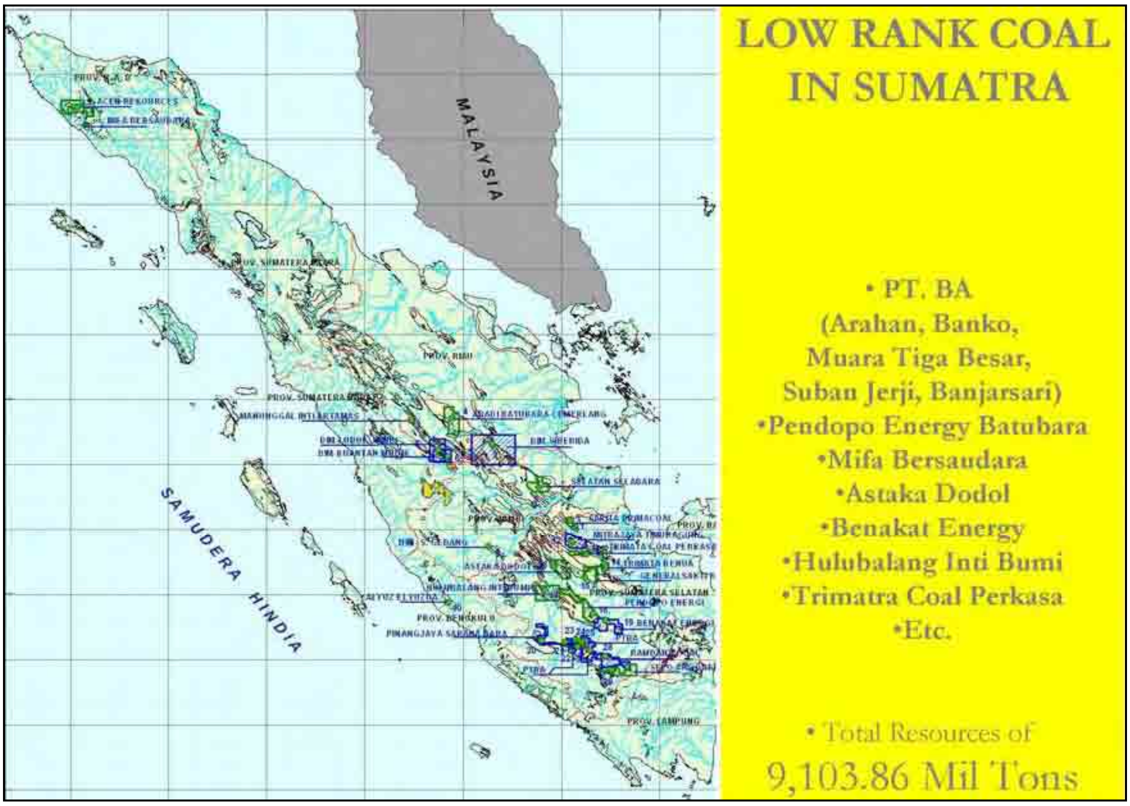
A special consideration is required in the design/operation of the boiler in which LRC with the characteristics of high water content and natural-ignition is burned. CO_2 emission is more lager than a bituminous coal fired boiler because the boiler efficiency is lower with LRC due to the higher water content. Meanwhile, LRC produced in Indonesia also has preferable properties, such as lower contents of ash and sulfur, which result in lower production of fly ash and SOx.

Table 4.1-8 Typical Specification of LRC

Description	Typical	Rejection
Gross Calorific Value Kcal/kg (AR*)	4200	<4000 or >4500
Hardgrove Grindebility Index	60	<45 or >65
Total Moisture % (AR)	30	>35
Ash Content % (AR)	5	>6
Sodium Content % (AR)	1.5	>4
Sulphur Content % (AR)	0.33	>0.35
Nitrogen % (AR)	Max. 1.2	>1.2
Slagging Fauling Index	Medium	>Medium
Grain Size through sieve 2.38 mm	Max. 20%	>20%
Grain Size through sieve 32 mm	Max. 80%	>80%
Grain Size through sieve 50 mm	Min. 95%	<95%
Grain Size through sieve 70 mm	100%	<98% (Max/ size 100 mm)
Ash Fusion Temperature (IDT) °C	1150	<1100

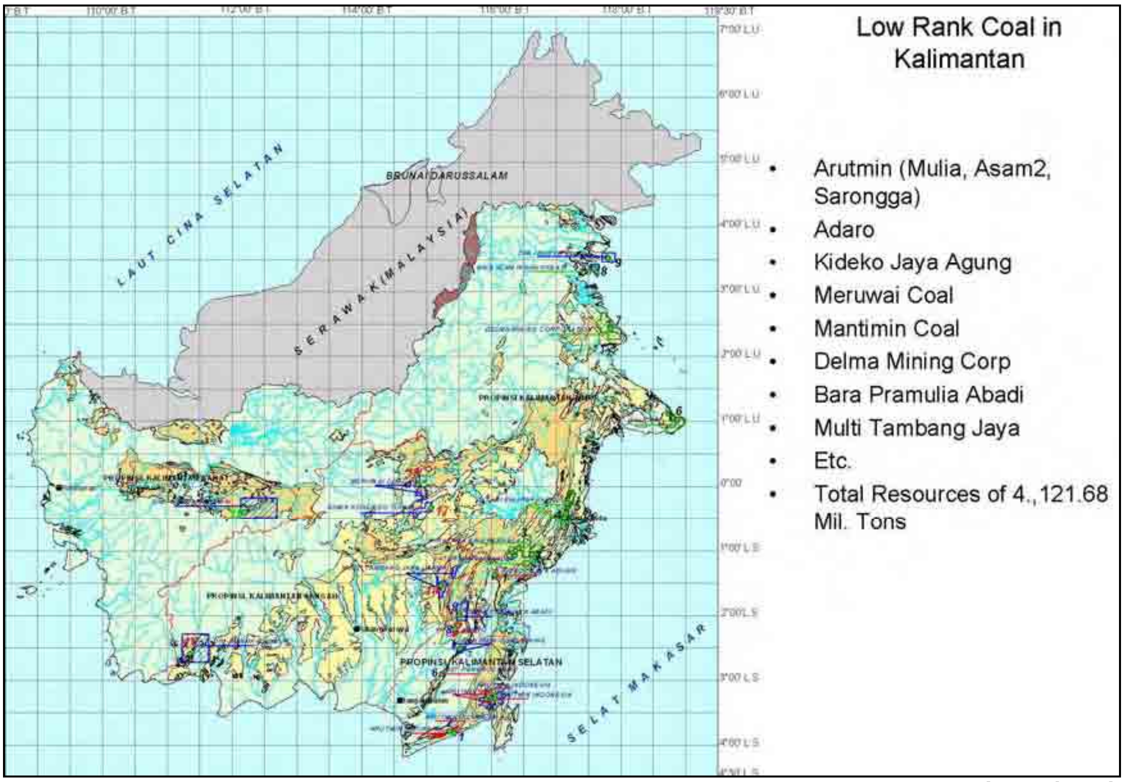
Note; AR = As Received Base Source : PLN (readiness of LRC)

Major mines of LRC are located in Sumatra and Kalimantan. The distribution of coal mines and mining company are shown in Figs.4.1-15 and 4.1-16.



Source : MEMR Coal &Geothermal

Fig.4.1-15 Mine and Company in Sumatra



Source : MEMR Coal &Geothermal

Fig.4.1-16 Mine and Company in Kalimantan

Mining authorization is not coal-type specific and each mining operator can produce various types of coal. LRC has been produced by PTBA, private companies of domestic capital and a private company of domestic/India joint capital. There are severed incoming companies as well.

LRC has not been circulated widely in the market, and is partially used in Suralaya Power Station. The prices of coal (CIF base, May 2008) are Rp. 420,000/ton (LRC, 4,500 kcal/kg as-received base), Rp. 540,000/ton (sub-bituminous coal, 5,100 kcal/kg), and LRC is about 10% cheaper than sub-bituminous for the same calorific value. As the mining and transportation costs for 1 ton-coal are not very different between LRC and sub-bituminous, coal mining companies and coal traders are inclined to deal in higher quality coal for export for more profitability. As the use of LRC by new power station is expected to explode in the next few years, it is crucial to increase the LRC production. However, there is no institutional incentive to induce investment at the moment, immediate actions must be taken.

When supply shortage of coal to power stations occurred in 2007, the international coal price was drastically increased and all the coal in Indonesia was turned to export market. Foul weather that disrupted sea transportation was also the reason for coal shortages in power stations. To avoid the recurrent of these accidents, the obligatory storage of one-month worth coal at every coal-fired power station and the supply to power stations were ordered by the cabinet. (The latter has not been in effect.) As LRC is not suitable for long-period storage,

storage period should be minimized. Extended storage causes many problems. It requires large coal yard capacity and precautions management to prevent self-ignition. As the distribution of LRC will be limited, there would be little influence of general coal market prices on is supply and demand. However the limited distribution means that infrastructure may not be suitably developed and it the development of transport infrastructure and production related facilities is an urgent matter. The contract should be long term basic due to the limited distribution. To secure the stable supply of LRC, the government support to LRC mining development including the arrangement of infrastructure and finances is highly desirable.

(3) Procurement of Low Rank Coal by PLN

As for the coal procurement for the existing power plants of PLN, PLN purchase the coal in open tendering. These coals are sub-bituminous coal produced in Sumatra, South Kalimantan, and South-east Kalimantan. The purchasing contract is on one year or a longer term basis. At the present condition where the steep rise of fuel price continues US$ 40/ton in 2006, US$ 60 this year, sellers do not prefer a longer term contract. A spot contract (e.g., for three months) is usually applied which is long enough to prepare for the possibility of disruption of transportation due to foul weather. There is no government subsidy applicable to PLN’s purchase of coal.

The coal that will be used in the new power plants currently under construction under the “Fast Track Program (total generation capacity 10,000 MW)” is LRC that is categorized as lignite, and is different from the coal used in existing power plants, which is categorized as sub-bituminous. LRC is not distributed in the market. PLN is negotiating with coal suppliers to purchase LRC of 31,900,000 tons/year. As of the end of April 2008, 28,490,000 tons/year which is approximately 90% of total demands has been secured with the contacts with eight suppliers, and the negotiation for the remaining 10% is underway. The contracts are on the long term of 20 years and CIF basis.

Table 4.1-9 shows eight companies that PLN has reached the contract agreements. Among them, three companies are located in Sumatra and five companies in Kalimantan. Those companies that are already on a production stage are four companies in Kalimantan.

Table 4.1-9 Coal Supplier for the Power Stations of Fast Track Program

No.	Name of Supplier	Status	Location	Production (ton/y)	Stage of Development
1	PT TITAN MINING ENERGY	PKP2B	Sumatra	3,205,000	Exploration
2	PT BARAMUTIARA PRIMA	PKP2B	Sumatra	2,328,000	Exploration
3	KONS. PT ARUTMIN INDONESIA	KP	Kalimatan	8,493,000	Production
4	KONS. PT KASIH INDUSTRI	KP	Kalimatan	3,810,000	Production
5	PT HANSON ENERGY	KP	Sumatra	4,372,000	Exploration
6	PT DWI GUNA LAKSANA	KP	Kalimatan	2,945,000	Production
7	KONS. OKTASAN BARUNA PERSADA	KP	Kalimatan	3,056,000	Production
8	KONS. MODAL INVESTASI MINERAL	KP	Kalimatan	279,000	Exploration
Total				**28,488,000**	

Source : PLN

Table 4.1-10 shows the present status of each company which PLN reached the contract agreement with. As most companies are not in the situation that they are able to secure stable production and supply even if they have started the production (* marked), some measures to expedite the development are urgently required.

Table 4.1-10 Present Status of Contracted Companies

PT. TITAN MINING ENERGY - No permanent infrastructure. - Use provincial road for transportation. - Barge transportation contract is not concluded
PT. BATUBARA PRIMA - No infrastructure. - The mining area is cramped. - There is thick sedimentation in Calik River. - Barge transportation contract is not concluded
KONS. PT. ARUTMIN INDONESIA(*) - Some infrastructure is available and under further development. - Transportation to the port by conveyer - Port is on lease from PT. Cenko and PT. BS, and a proprietary port ready in 2009 - 2 coal crasher plants exist and to be added with one plant every year. - Problems in Asam field; palm oil plantation in west Mulita region.
KONS. PT. KASIH INDUSTRY(*) - Coal will be supplied from KP in Muba region. - No Road nor Port now. - No detailed mining plan.

(4) Infrastructure for LRC

In Indonesia, the coal transportation from coal fields to power stations except for the case of mine-mouth power generation is organized usually with; land transportation from coal field to loading port (coal terminal), and marine transportation (ship or barge) from coal terminal to power station.
At present, railway transport is available only in part of South Sumatra. However this railway is a very old one built in Netherlands occupation era, and has undergone numerous rehabilitations. Its segment from Tanjung Enim to Tarakan is single-line, which restrict the capacity severely at about 8.2 million tons/year. PLN has experienced the power generation halted by a disruption of coal supply due to an accident of railway.

At several inland coal fields, inland water transport through river is used. This is common in Kalimantan where railway does not exist. As the production of coal grew sharply, transport capacity reached the limit. Recently coal transportation halted because low flow in a river during dry season made it un-navigable. At some coal loading port, the volume of coal handled exceeded capacity. Coal is transshipped offshore from barges to coal hauler ships. And the truck transport was interrupted by the flood which was attributable to the insufficient road upgrading/maintenance.

Under the present situation where the infrastructure of coal transportation is not quite developed the transportation of LRC, which is not widely distribute in market is extremely difficult to be enlarged, to prepare for the completion of power plants under "Fast Track Program".

As for the transaction of coal in Indonesia, the trade is made on CIF basis, and the transport is undertaken by the supplier. There are many private coal mining companies along the transport route, and they do not own any transport equipment. If the traded volume of coal exceeds the transportation capacity, the disruption may result.
Now we expect that the production of coal for domestic use increases by 50% in a short period, the overall infrastructure development and upgrading is required urgently, and must be coordinated with the development plans of coal fields.

i) Railway Development Plan

- There is a railway to Lampun (Coal Terminal of Tarahan Port) from the coal field in South Sumatra. Recently the construction of a new railway with the capacity of 20,000 tons per day (planned to be later upgraded to 60,000 tons per day) has just started. As there is an urban area on the route and land acquisition is not completed, which may delay the completion of the project.

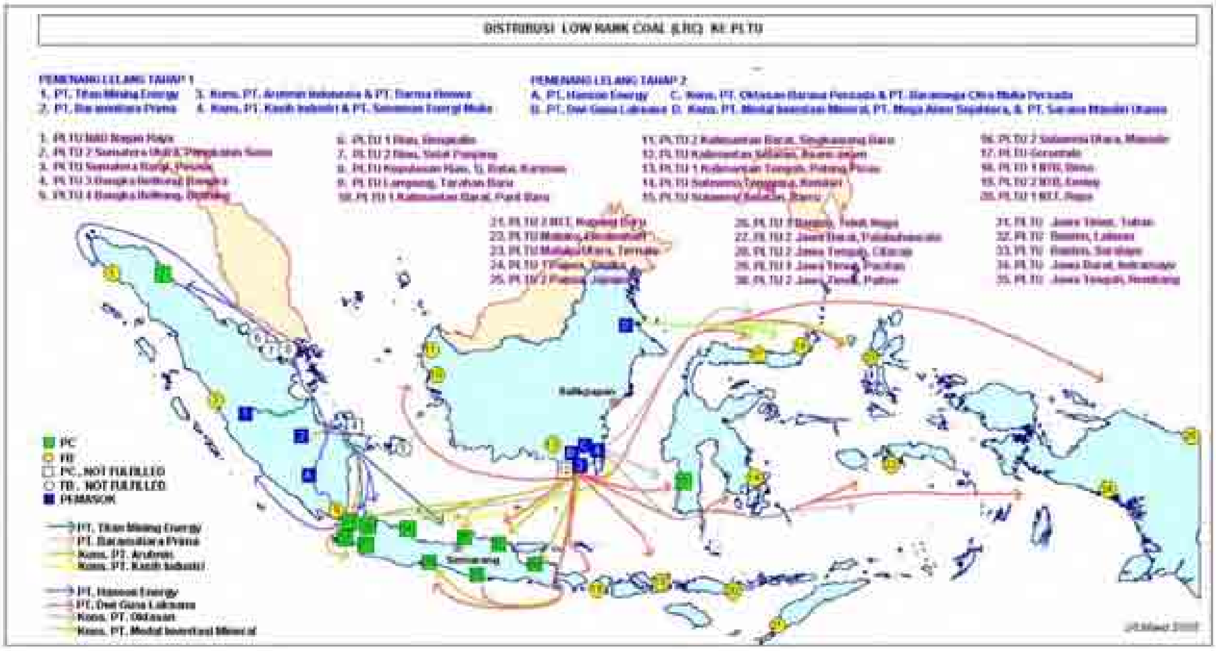
- Regarding the development of railway in Kalimantan which has the largest coal production, it is under negotiation between Ministry of Transportation and the local government. The railway development plans of Central Kalimantan (about 180 km long, connecting the mine - Barito River - South-Kalimantan Coal Terminal), and East Kalimantan (about 127 km long between the mine and coal terminal) are under the feasibility studies. At present, in this area, coal is transported to the port by trucks and loaded on barges. The road transport is sometimes interrupted by flood in rainy season, but also the river transport is interrupted by low flow (channel becomes un-navigable) during dry season.

ii) Marine Transportation

As shown in Fig.4.1-17, the transportation of coal to coal-fired thermal power station (except for mine-mouth power stations in Sumatra) of PLN depends on marine transportation from Sumatra or Kalimantan.
In Kalimantan, the coal for export is transported on barges along the river, and transshipped to larger coal hauler ships at the port near the river mouth. As for the coal for domestic supply, total lead time for transport is not so different between the direct deliver, by barge (5 days) and barge-ship combined delivery (1+1+2), but transportation cost is much lower with direct delivery. So the direct delivery will possibly be used commonly except for the delivery to very large power station.

Although an Indonesian enterprise is requested to use the ships of Indonesian flag, as of

2008, there are only 11 ships of PANAMAX size for coal transportation and 160 barges of 10,000 ton class. The domestic demands for them in 2010 will be estimated 21 ships and 340 barges. The ships and the barges will be in short supply and it is very difficult to build such large numbers of the ships and the barges in 2 years. In addition to the above, a large number of tag boats are also required to be built.



Source : PLN (readiness of LRC)

Fig. 4.1-17 Coal Transportation to the PowerStation of PLN

Although LRC do not rely on very much, there are coal terminals shown in Table 4.1-11 in Indonesia at the moment, and are scheduled to be reinforced in the future.

Table 4.1-11 Coal Terminal in Indonesia

No.	Name of Coal Port	Location	Max. Capacity (DW)	User
1	Tarahan	South Sumatera	55,000	PT BA
2	Tanjung Bara	East Kalimantan	180,000	Kaltim Prima Coal
3	Samarinda / ahakam	East Kalimantan	70,000	Umum
4	IBT / Pulau Laut	South Kalimantan	80,000	Adaro Indonesia
5	Kota Baru / Pulau Laut	South Kalimantan	150,000	Arutmin Indonesia
6	Bontang	East Kalimantan	90,000	Indominco Mandiri
7	Berau Offshore	East Kalimantan	180,000	Berau Coal
8	Banjarmasin / Taboneo	South Kalimantan	170,000	Adaro dan Terbuka Umum
9	Balikpapan	East Kalimantan	80,000	Terbuka Umum
10	Adang Bay	East Kalimantan	120,000	Kideco Jaya Agung

Source : PLN (readiness of LRC)

Regarding the port facilities in a power station, there are experiences of coal unloading interrupted by high tide due to seasonal wind. A jetty of the power station in Indonesia is facing open to the sea without the breakwater shielding it. It is recommended to consider breakwater, where necessary.

The accuracy of sea weather forecast is also important, because coal supply to power stations depends on marine transportation and it is unavoidable to hold ships under very foul weather.

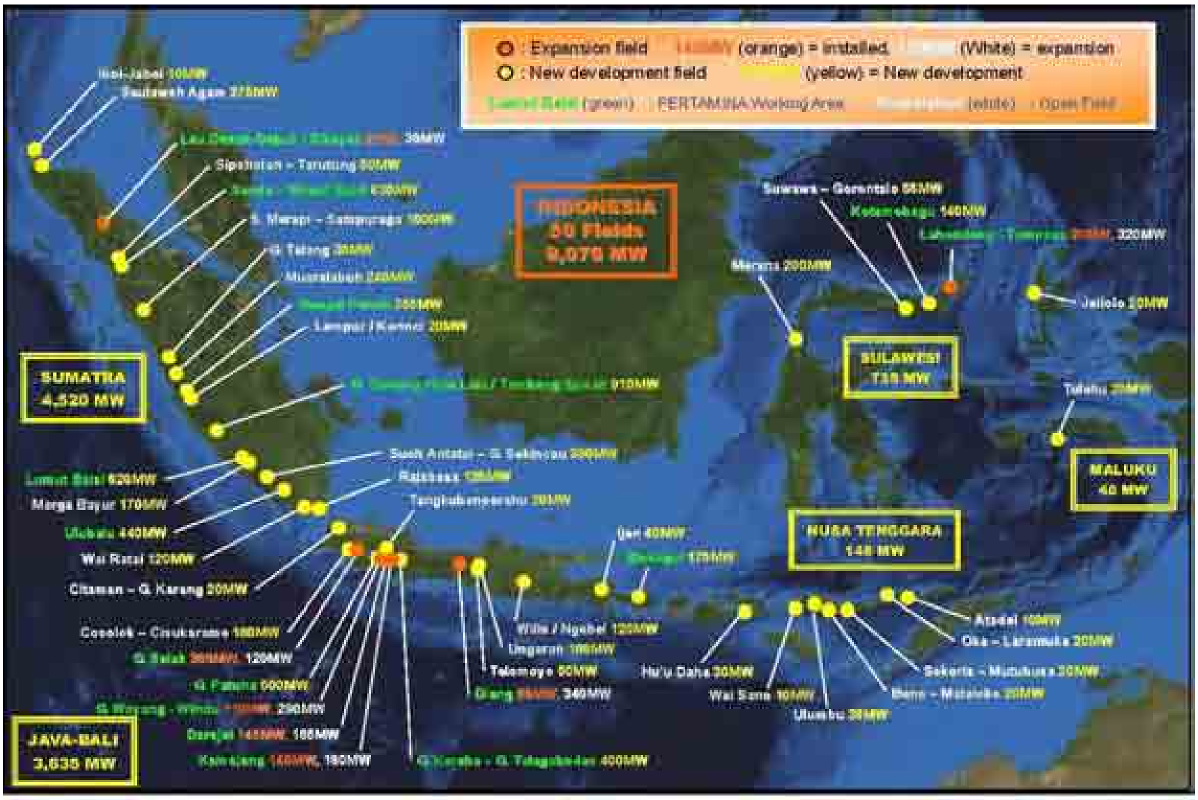
4.1.4 Geothermal

(1) Geothermal Resources

It is reported that Indonesia possesses the geothermal resources that will produce more than 27,000 MW of power, and accounts for 40% of the geothermal potential of the world. To use these resources effectively, the Indonesian government made the development road map and scheduled to develop 9,500 MW by 2025. In 2007, total 1,020 MW are operating.

According to the "Master Plan Study for Geothermal Power Development in the Republic of Indonesia" that JICA executed in 2007, the geothermal resource enough to feed power plants totaling 9,500 MW, which is the development goal, was confirmed.

Fig.4.1-18 is the distribution of geothermal resources of Indonesia, and Table 4.1-12 and Table 4.1-13 are the geothermal resources in Indonesia and Java Bali regions. The potential of large-scale development is concentrated in Sumatra and Java.



Source : JICA; M.P. Study for Geothermal Power Development 2007

Fig.4.1-18 Geothermal Resource in Indonesia

Table 4.1-12 Geothermal Resources in Indonesia

Region	Installed Capacity	Existing Plan	Possible New/ Additional Plan	Total Resource Potential
Sumatra	2	913	3,605	**4,520**
Java-Bali	835	785	2,015	**3,635**
Nusa Tenggara	0	9	138	**146**
Sulawesi	20	140	575	**735**
Maluku	0	0	40	**40**
Total (MW)	**857**	**1,847**	**6,373**	**9,076**

Source : JICA; M.P. Study for Geothermal Power Development 2007

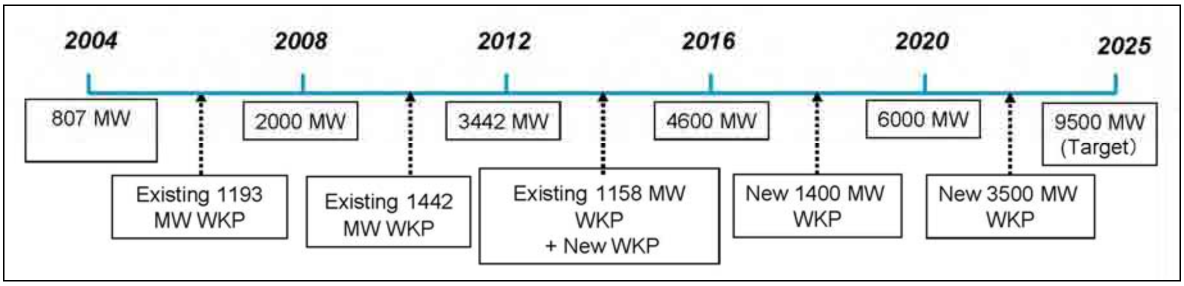
Table 4.1-13 Geothermal Resources in Java Bali Regions

Region	No	Names of the 70 fields in this Survey	Reservoir Volume (x 10^? m^3)			Temperature(°C)			Surface Water Type (Hot Spring)			Potential (MW)					Stage of Development
			Min.	Most Likely	Max.	Surface	Geotherm	Measured	pH	Major Anion	Cl max (ppm)	Spec.	Hypo.	Possible	Probable	Proven	
JavaBar	32	KAMOJANG	11.2	18.9	28	96		252	2.9-8.2	SO4, HCO3	17				73	227	OP
JavaBar	33	G. SALAK	22.1	33.15	44.2			280						115		485	OP
JavaBar	34	DARAJAT	13.3	19.95	28.6	77		245	3.0-5.0	SO4	14					362	OP
JavaBar	35	CISOLOK - CISUKARAME	50.4	75.6	100.8	99	>250		6.8-8.7	[illegible]	560			400			F1
JavaBar	36	G. PATUHA				89		245					65	247		170	F2
JavaBar	37	G. WAYANG - WINDU	25.4	63.675	119	50		270					75		135	250	OP
JavaBar	38	G. KARAHA	79.1	118.65	158.2	95			6.6	SO4	11		50	70	100	30	F2
JavaBar	39	G. TELAGABODAS				92							75	120	80		S2
JavaBar	40	TANGKUBANPERAHU	3.4	5.1	6.8	96	>170		2.5-7.4	[illegible]	1581			20			S2
Banten	41	BATUKUWUNG				52											S2
Banten	42	CITAMAN - G. KARANG	4	6	8	94	>180				(150)		50	25			F1
Banten	43	G. ENDUT				84											RE
JavaTen	44	DIENG	6.5	14.55	25.8	94		368					200	185	115	280	OP
JavaTen	45	MANGUNAN				46											S2
JavaTen	46	TELOMOYO	15.1	22.65	30.2	37	>190		7.6	HCO3/SO4 mixed well	180			90			S2
JavaTen	47	UNGARAN	24.5	36.75	49	86	180-320		6.0-8.0	HCO3, Cl-HCO3, Cl	5339			230			S2
JavaTen	48	G. SLAMET				51			7.9	HCO3	26						S2
JavaTim	49	G. ARJUNO - WELIRANG				70			6.7	HCO3	334						S1
JavaTim	50	WILIS / NGEBEL	20.8	31.2	41.6	93	190-250		6.6-7.0	Cl (Cl-HCO3 well)	4627			180			S2
JavaTim	51	IJEN	21.2	31.8	42.4	57			6.5-8.3	HCO3	152			130			S2
JavaTim	72	Iyang Agropuro				65			7.4	HCO3	26						S1
Bali	52	BEDUGUL				32		285					75	245		30	F2
Sub-Total in Java-Bali													590	2,057	503	1,834	

Source : JICA; M/P Study for Geothermal Power Development 2007

(2) Geothermal Master Plan

For the development of the geothermal resources, the road map is shown in National Energy Management Blueprint (2005-25) as reproduced in Fig.4.1-19, and development is scheduled to be advanced in Java-Bali region as shown in Table 4.1-14, according to the "Master Plan Study for Geothermal Power Development in the Republic of Indonesia" prepared by JICA.



Source : National Energy Management Blue Print 2005

Fig. 4.1-19 Roadmap of Geothermal Development

Table 4.1-14 Master Plan of Geothermal Development in Java Bali Regions

Source : JICA; M.P. Study for Geothermal Power Development 2007

(3) Incentive for Geothermal Development

Geothermal is the power generation system that will produce steam without the fuel, but it requires large investment capital accompanied by high exploration risks in development. As a result, power generating cost becomes more expensive than other power generating systems.

The government had once considered to make the electricity selling price index for geothermal energy at which PLN purchases. However it lacked the rationality for PLN to purchase geothermal energy at high cost while it owns many power plants with lower generation cost connected to the system.
Moreover, geothermal power plants are often located in mountainous areas, requiring vast site areas for excavation and digging wells to produce steam. Part of such large areas may fall onto the forest conservation areas.

For the abovementioned reasons, the development of geothermal tends to be delayed. However, the sudden rise of fossil fuel prices may lead to a certain advantage of geothermal which does not require any fuel to burn. Moreover, "Ministerial Regulation No.14/2008" that stipulates the cap of sales price of geothermal electricity is enacted in May 2008. It is 85% of the average power generation cost of the power system in that region for geothermal plant with capacity 10 to 55 MW, and 80% for geothermal larger than 55 MW. This may lead to a promotion of the development of geothermal in remote areas where power generation is currently depending on PLTD and the generating cost is high.

4.1.5 Renewable Energy

Besides oil, gas and coal, the primary energy that is available in Indonesia is hydro, mini-hydro, micro-hydro, solar, bio-diesel, bio-ethanol, wind and the waste. Hydro, mini-hydro, micro-hydro, solar and wind energy can be utilized for power generation. As shown in Table 4.1-15, the scales of these resources already exploited are small except hydro. These developments have been very limited as they are mostly located far away from demand centers, and face the problems of large investment cost and environmental protection, etc.

Table 4.1-15 Non-Fossil Energy in Indonesia

Non-Fossil Energy	Potential	Capacity
Hydro	75,670 MW	4,200 MW
Mini/Micro-hydro	459 MW	84 MW
Solar	4.8 kWh/m²/day (1203 TW)	8 MW
Wind	3 - 6m/s (9,290 MW)	0.5 MW

Source : Blue print

(1) Hydropower

A comprehensive investigation on the hydropower potential was executed by MEMR/ PLN in 1999. Table 4.1-16 shows the potential in Java-Bali region. However, the candidates PLN adopted in their development program, RUPTL, are only Rajamandala (run-of-river type), Jatigede (reserved type) and Upper Cisokan (pumped storage type). Other potential sites in Java-Bali region are sometimes accompanied by such problems as resettlement and existence of conservation areas, etc.

Table 4.1-16 Hydropower Potential in Java-Bali Region

Location	Project Name	Type	Installed capacity (MW)	Recommended Year of installation
Central Jawa	Manung	RES	360	2004
West Jawa	Cibuni-3	RES	172	2013
	Cipasang	RES	400	2006
	Cimandiri-3	RES	238	2006
	Upper Cisokan-PS	PST	1000	2006
	Cibuni-4	RES	71	2015
	Cijutang-PS-2	PST	1000	2008
Jawa-Bali	Sesayap-1	RES	949	2017
	Boh-2	RES	1120	2018
West Jawa	Cibuni-PS-1	PST	1000	2012
Central Jawa	Klegung-PS	PST	1000	2016
East Jawa	Grindulu-PS-3	PST	1000	2018
West Jawa	Rajamandala	ROR	55	—
	Jatigede	RES	175	—
	Citiman	RES	-	—
	Cikaso-3	RES	29.5	—
Central Jawa	Gintung	RES	19.2	—
	Rawato-1	ROR	0.64	—
East Jawa	Grindulu-2	RES	16.3	—
Note ; RES (Reserved), ROR(Run of River), PST(Pumped Storage)				

Source : Hydro Inventory Study 1999 by PLN

Meanwhile, there are only three potential sites of micro-hydro in Java-Bali region among those shown by the study as shown in Tables 4.1-17 and 4.1-18.

Table 4.1-17 Potential of Micro-hydro (Measured by PLN)

(kW)

No	Location	Province	Number of Units	Potential	Measuring Institution
1	Blangkeieren	Aceh	1	2,050	PLN Region I
2	Tangse	Aceh	2	1,250	PLN Region I
3	Sepakat	Aceh	2	1,750	PLN Region I
4	Arul Ralem	Aceh	1	378	PLN Region I
5	Sibundong-2	North Sumatera	2	2337	PLN Region II
6	Letter W	West Sumatera	1	5,000	PLN Region III
7	Hinas Kanan	South Sumatera	1	520	PLN Region IV
8	Lubuk Buntak	South Sumatera	2	2,210	PLN Region IV
9	Purui	South Sumatera	1	210	PLN Region IV
10	Merasap	West Kalimantan	1	1,160	PLN Region V
11	Muara Kedihin	South Kalimantan	1	500	PLN Region VI
12	Baras	East Kalimantan	1	200	PLN Region VI
13	Tamako/U-Peliang	North Sulawesi	1	1,090	PLN Region VII
14	Poigar	North Sulawesi	2	2,500	PLN Region VII
15	Lobong	North Sulawesi	2	1,500	PLN Region VII
16	Kolondom	North Sulawesi	2	2,000	PLN Region VII
17	Kembera	North Sulawesi	1	430	PLN Region VII
18	Toni	North Sulawesi	1	300	PLN Region VII
19	Tawaeli	North Sulawesi	1	1,270	PLN Region VII
20	Talise	North Sulawesi	1	1,200	PLN Region VII
21	Mongango	North Sulawesi	1	900	PLN Region VII
22	Wining	North Sulawesi	2	1,600	PLN Region VIII
23	Bambalo/Poso	Central Sulawesi	1	2,610	PLN Region VII
24	Kalumpang	Central Sulawesi	1	700	PLN Region VII
25	Hanga-hanga-2	Central Sulawesi	2	1,670	PLN Region VII
26	Rongi	Central Sulawesi	1	845	PLN Region VII
27	Mikuasi	Central Sulawesi	2	1,060	PLN Region VII
28	Enrekang/Lewaja	South Sulawesi	1	440	PLN Region VIII
29	Mamasa/Bala	South Sulawesi	1	340	PLN Region VIII
30	Palangka	South Sulawesi	1	1,500	PLN Region VIII
31	Bonelemo	South Sulawesi	1	1,340	PLN Region VIII
32	Cennae	South Sulawesi	1	590	PLN Region VIII
33	Usu Malili	South Sulawesi	2	3,750	PLN Region VIII
34	Batu Sitanduk	South Sulawesi	1	1,750	PLN Region VIII
35	Kadundung	South Sulawesi	2	1,443	PLN Region VIII
37	Rante Balla	South Sulawesi	1	612	PLN Region VIII
38	Hatu	Maluku	1	528	PLN Region IX
39	Teminabuan	Papua	1	150	PLN Region X
40	Wamena-3	Papua	2	1,000	PLN Region X
41	Werba	Papua	1	1,650	PLN Region X
42	Tatui	Papua	2	1,182	PLN Region X
43	Santong	East Nusa Tenggara	1	545	PLN Region XI
44	Roa/Ende	East Nusa Tenggara	1	700	PLN Region XI
45	Lokomboro/Waikabubak	East Nusa Tenggara	1	880	PLN Region XI
46	Banjar Cahyana	Central Java	1	1,490	PLN Region XI
47	Tapen	Central Java	1	730	PLN Region XI
			Total Potential	57,840	

Source :
Rencana Induk Pengembangan Energi Baru dan Terbarukan 1997, Directorate General of Electricity and Energy Development, Ministry of Energy and Mineral Resources

Source : ; Energy Outlook

Table 4.1-18 Potential of Micro-hydro (Except PLN)

(kW)

No	River	Location	Sub District	Regency	Province	Potential
1	Samalanga	Samalanga	Samalanga	North Aceh	Aceh	1,130.00
2	Kr. Inong	Jim-jim	Bandar Baru	Pidie	Aceh	458.40
3	Kr. Sabet	Sabet	Lamo	West Aceh	Aceh	1,274.00
4	Bt. Kumal	Padang Bulan	Pdg. Sidempuan	South Tapanuli	North Sumatera	684.00
5	Marpinggan	Siponggol	Pdg. Sidempuan	South Tapanuli	North Sumatera	340.00
6	Rantaupuran	Gunung Tua-2	Penyambungan	South Tapanuli	North Sumatera	809.60
7	Batang Gadis	Batang Gadis	Batang Toru	South Tapanuli	North Sumatera	900.00
8	A. Pasarean	Sipenggang	Batang Toru	South Tapanuli	North Sumatera	1,200.00
9	Hutapungkut	Alahan Kae	Kota Nopan	South Tapanuli	North Sumatera	1,248.00
10	I. Eho	I. Eho	Teluk Dalam	Nias	North Sumatera	712.30
11	I. Gomo	I. Gomo	Teluk Dalam	Nias	North Sumatera	457.30
12	Indano Moi	Indano Moi	Perw. kec. Moi	Nias	North Sumatera	672.00
13	Aek Raisan	Raisan-3	Pandan	North Tapanuli	North Sumatera	1,280.00
14	Aek Silang	Silang 2	Dolok Sanggul	North Tapanuli	North Sumatera	1,152.00
15	Sungai Putih	Sungai Putih	Bayang	Pesisir Selatan	West Sumatera	1,113.60
16	Ludang	Sawah Kerambil	Terusan	Pesisir Selatan	West Sumatera	411.80
17	Bayang Bungo	Koto Baharu	Bayang	Pesisir Selatan	West Sumatera	499.30
18	Muara sako	Muara Sako	Pancung Soal	Pesisir Selatan	West Sumatera	3,880.40
19	Bt. Bayang	Bayang Sani	Bayang	Pesisir Selatan	West Sumatera	644.00
20	Bt. Sumani	Sumani	Gunung Talang	Solok	West Sumatera	600.00
21	Bt. Gumanti	Pinti Kayu	Lembah Gumanti	Solok	West Sumatera	8,840.00
22	Bt. Balangir	Balangir	Sangir	Solok	West Sumatera	480.00
23	Bt. Sangir	Kubang Gajah	Sangir	Solok	West Sumatera	7,488.00
24	Bt. A. Guntung	Guntung	Palupuh	Agam	West Sumatera	624.00
25	Sikarbau	Sikarbau	Lembah Melati	Pasaman	West Sumatera	770.00
26	Patimah	Patimah	Bonjol	Pasaman	West Sumatera	860.00
27	~	Batu Hampar	Bonjol	Pasaman	West Sumatera	608.00
28	A. Tenang	Bedegung	Tanjung Agung	Muara Enim	South Sumatera	968.00
29	Selabung	Banding Agung 1	Banding Agung	Oku	South Sumatera	3,194.40
30	Selabung	Banding Agung 2	Banding Agung	Oku	South Sumatera	3,194.50
31	Selabung	Banding Agung 3	Banding Agung	Oku	South Sumatera	2,881.10
32	Campang	Mutar Alam	Sumber Jaya	North Lampung	Lampung	750.00
33	Rarem	Sinar Mulia	Bukit Kemuning	North Lampung	Lampung	1,044.00
34	Ilahan	Way Ilahan	Pulau Panggung	South Lampung	Lampung	1,700.00
35	Klingi	Klingi 1	P. Ulak Tanding	Rejang Lebong	Bengkulu	480.00
36	Klingi	Klingi 2	P. Ulak Tanding	Rejang Lebong	Bengkulu	998.00
37	Air Lang	Kepala Curup 2	P. Ulak Tanding	Rejang Lebong	Bengkulu	1,792.00
38	Blimbing	Cinta Mandi	Perw. Kb. Agung	Rejang Lebong	Bengkulu	1,850.00
39	Ketaun	Suka Negeri	Pw. R. Pengadang	Rejang Lebong	Bengkulu	2,306.00
40	Cawang Kiri	Bungin Tambun	Kaur Utara	South Bengkulu	Bengkulu	3,404.80
41	Padang Guci	Talang Genting	Kaur Utara	South Bengkulu	Bengkulu	1,489.60
42	Mana	Pulau Timun	Pino	South Bengkulu	Bengkulu	4,059.20
43	Seluma	Seluma	Manna	South Bengkulu	Bengkulu	358.40
44	Sindur	Talang Alai	Perw. Sukaraja	South Bengkulu	Bengkulu	777.60
45	Palik	Aur Gading	Kirkap	North Bengkulu	Bengkulu	1,854.00
46	Lais	Kuro Tidur	Lais	North Bengkulu	Bengkulu	1,315.20
47	Lubuk Banyau	Lubuk Banyau	Lais	North Bengkulu	Bengkulu	773.60
48	Merangin	Penetay	Sungai Manau	Sarko	Jambi	841.60
49	Bt. Air Batu	Perentak	Sungai Manau	Sarko	Jambi	518.40
50	Sampean	Sampean Baru	Prajekan	Bondowoso	East Java	2,486.90
					Total Potential	78,083.90

Source :
Rencana Induk Pengembangan Energi Baru dan Terbarukan 1997, Directorate General of Electricity and Energy Development, Ministry of Energy and Mineral Resources

Source : ; Energy Outlook

(2) Wind Power

The potential of wind power in western Indonesia is shown in Table 4.1-19. Development of wind power is part of the energy policy for the utilization of renewable energy, although there are difficulties in terms of the economy (More than 6m/s of wind velocity is necessary for large scale wind power from the economy) and the operation as the power generation is conditional on weather.

Because of the small potential and capacity wind power is not treated as specific power sources in the Electric Power Development Master Plan.

Table 4.1-19 Potential of Wind Power

No	Village/Sub District/Regency	Province	Year of Measurement	Average Velocity at Elevation of 24 m
1	Sabang	Aceh	1994	2.73
2	Meulaboh	Aceh	1994	3.33
3	Polonia Medan	North Sumatera	1994	3.68
4	Sei Dadap Kisaran	North Sumatera	1994	3.06
5	Binaka	North Sumatera	1994	3.06
6	Sicincin	West Sumatera	1994	3.86
7	KP. Laing	West Sumatera	1992	3.72
8	Depati Darbo	Jambi	1994	4.01
9	Simpang Tiga Pakanbaru	Riau	1994	3.97
10	Kijang	Riau	1994	4.22
11	Japura Rengat	Riau	1994	2.83
12	Ranai	Riau	1994	2.45
13	Pangkal Pinang	South Sumatera	1992	3.68
14	Buluh Tumbang Tanjung Pandan	South Sumatera	1995	5.56
15	Serang Banten	West Java	1992	3.01
16	Curug Tangerang	West Java	1994	2.70
17	Tanjung Priok	Jakarta	1993	4.45
18	Cengkareng	Jakarta	1994	3.55
19	Semarang Maritim	Central Java	1992	2.94
20	Kledung	Central Java	1994	4.08
21	Adi Sumarmo Surakarta	Central Java	1995	2.39
22	Iswahyudi Madiun	East Java	1994	5.57
23	Suranaya AURI	East Java	1994	4.65
24	Surabaya Perak	East Java	1994	2.61
25	Kalianget	East Java	1994	5.40
26	Sangkapura Bawean	East Java	1994	2.96
27	Surabaya Maritim	East Java	1994	3.37
28	Ploso	East Java	1991	2.39
29	Kp. Tiekung	East Java	1994	2.55
30	Denpasar	Bali	1992	2.39

- Small Scale : 2 – 3 (m/sec)
- Medium Scale : 3 – 4 (m/sec)
- Large Scale : > 4 (m/sec)

Source :
Rencana Induk Pengembangan Energi Baru dan Terbarukan 1997, Directorate General of Electricity and Energy Development, Ministry of Energy and Mineral Resources

(3) Solar Energy

The potential of solar energy is shown in Table 4.1-20. The development road map is indicated in Energy Management Blueprint 2005 as reproduced in Fig.4.1-20. The realization of this road map depends highly on efficiency improvement and production cost reduction of solar cells. Solar energy has a disadvantage of being able to generate power during daytime only. The development of solar energy is expected as a part of the policy for utilization of renewable energy.

Table 4.1-20 Potential of Solar Energy

No	Regency	Province	Year of Measurement	Average Radiation (kWh/m²)	Measured by
1	Banda Aceh	Aceh	1980	4.10	LSDE
2	Palembang	South Sumatera	1979-1981	4.95	BMG
3	Menggala	Lampung	1972-1979	5.23	DGEED/BMG
4	Rawasragi	Lampung	1965-1979	4.13	DGEED/BMG
5	Jakarta	Jakarta	1965-1981	4.19	DGEED/BMG
6	Bandung	West Java	1980	4.15	LSDE
7	Lembang	West Java	1980	5.15	LSDE
8	Citius, Tangerang	West Java	1980	4.32	LSDE
9	Darmaga, Bogor	West Java	1980	2.56	LSDE
10	Serpong, Tangerang	West Java	1991-1995	4.45	LSDE
11	Semarang	Central Java	1979-1981	5.49	BMG
12	Surabaya	East Java	1980	4.30	LSDE
13	Kenteng, Yogyakarta	Yogyakarta	1980	4.50	LSDE
14	Denpasar	Bali	1977-1979	5.26	DGEED/BMG
15	Pontianak	West Kalimantan	1991-1993	4.55	LSDE
16	Banjarbaru	South Kalimantan	1979-1981	4.80	BMG
17	Banjarmasin	South Kalimantan	1991-1995	4.57	LSDE
18	Samarinda	East Kalimantan	1991-1995	4.17	LSDE
19	Menado	North Sumatera	1991-1995	4.91	LSDE
20	Palu	South East Sulawesi	1991-1994	5.51	LSDE
21	Kupang	West Nusa Tenggara	1975-1978	5.12	DGEED/BMG
22	Waingapu, Sumba Timur	East Nusa Tenggara	1991-1995	5.75	LSDE
23	Maumere	East Nusa Tenggara	1992-1994	5.72	LSDE

Source :
Rencana Induk Pengembangan Energi Baru dan Terbarukan 1997, Directorate General of Electricity and Energy Development, Ministry of Energy and Mineral Resources

As micro-hydro, wind, and solar power are not cost-competent alternatives to large scale power generation such as PLTU, PLTGU, PLTA, etc. the suitable supports such as the preferential treatment (freedom from import duties of the equipment, reduction of various taxes, etc.) in taxation system, the arrangement for power sales (power purchasing obligation or subsidy), etc. are necessary from the political side to promote the development.

In order to promote the development and the use of these resources, official support by the government, for example, preferential treatment on tax (import tax exemption on equipment, reduction of other taxes), subsidies, purchase obligation from small- to middle-scale power production using renewable resources, seem to be necessary.

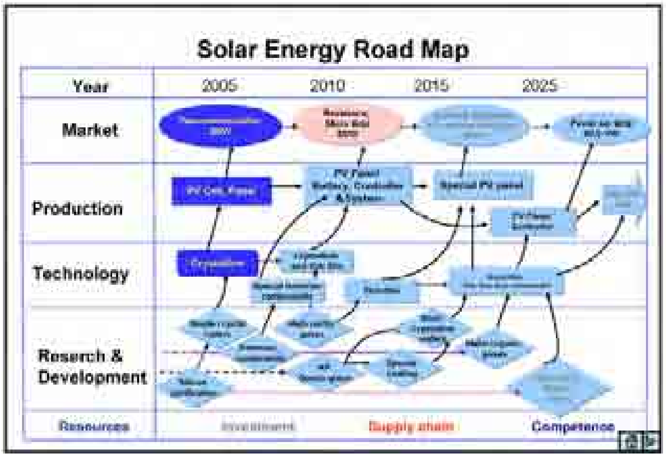


Fig.4.1-20 Roadmap of Solar Energy Development

4.2 Optimal Power Development Scenario

4.2.1 Potential Power Development

Table 4.2-1 shows main characteristics of the existing and planned power plants in Jamali System for the fuel price, fuel supply, environmental performance, and developmental benefit. Some of them are described in the previous Sections.
Constraints on the alternative power development scenarios are as described below.

(1) Requirements of Large-Scale Power Plants

1) According to RUPTL for 2006 to 2026, peak load of about 53,000 MW is forecasted for 2026, and this is about 3.3 times higher than 16,000 MW in 2007. Considering the rapid growth of peak load, large-scale power plants, such as a nuclear power plant with a 1,000 MW unit and a coal-fired power plant with a 1,000 MW/600 MW unit, must play a main role in future power supply.

2) For air quality, nuclear power plants are superior to coal-fired power plants since they do not emit SOx, NOx or CO_2.

(2) Requirement of Reliable Operation of Power Plants supported by Stable Fuel Supply

1) As for the reliable operation supported by stable fuel supply, nuclear power plants and geothermal power plants are advantageous.

2) For a nuclear power plant, once its nuclear fuel supply agreement is successfully concluded, frequency of periodical fuel supply is far less than those for coal-fired power plants and LNG-fired PLTG/PLTGU.

3) For geothermal power plants, fuel supply from external suppliers is not required.

4) HSD-fired and MOF-fired power plants (PLTG/PLTGU) are the most reliable power plants for their fuel supply, since HSD and MOF supplied by Pertamina, a state-owned company.

5) Gas-fired power plants (PLTG/PLTGU) are likely to face risks of delay and shortage of gas supply which PLN can not control.

(3) Requirement of Flexible Operation of Power Plants

1) Under the high crude oil price of 100 US$/bbl ~ 130 US$/bbl observed in 2008, capacity factors of HSD-fired PLTG/PLTGU, which burden the middle and/or peak loads at the present, will be intentionally reduced or retired fuel cost saving.

2) Power plants to replace the current HSD-fired PLTG/PLTGU for the middle and/or peak load are required. LNG-fired PLTG/PLTGU and pumped storage power plants are promising.

3) Reservoir type hydropower plants are also promising due to their flexible operation and quick responses to load fluctuations. However, potential sites for hydropower plants in Jamali have not been investigated in detail.

(4) Requirement of Low-Cost Operation of Power Plants

1) Considering the current high crude oil price and its volatility worldwide, power plants of contributing to low operation cost shall be introduced for the financial management of PLN.

2) However, not only the fuel oil prices (HSD and MFO) but also coal[1], gas and LNG prices have remarkably increased in recent years, especially in 2007 to 2008 under the influence of high crude oil prices. Operation of thermal power plants will be more costly in future unless market speculation on crude oil is terminated.

3) Nuclear power plants and coal-fired power plants, especially LRC-fired power plants, seem to be less affected by crude oil price than the other thermal power plants.

(5) Power Generation from Renewable Sources

Power generation from renewable sources, such as geothermal power generation, solar power generation, wind power generation, and run-of-river type hydroelectric power generation contributes to utilization of purely domestic primary energy and the environmental protection. Unfortunately, these power generations cannot play the same role as coal-fired power generation and nuclear power generation due to their relatively small unit capacity.

(6) Potential Power Development

Based on the above discussions, power plants shown in Table 4.2-2 seem to represent potential power plants for future power generation.

Table 4.2-2 Power Plants for Future Power Generation

Power Plants	Unit Capacity	Operation Pattern		
		Base Load	Middle Load	Peak Load
Nuclear Power Plants	1,000 MW	↔		
Geothermal Power Plants	55 MW	↔		
Coal-fired Power Plants	1,000/600 MW	↔	↔	
LNG-fired PLTG/PLTGU	150/600 MW		↔	↔
Pumped Storage Power Plants	500 MW			↔

[1] Such as medium rank coal

Table 4.2-1 Salient Features of the Existing and Planned Power Resources

	Power Plant	Type	Fuel prices in Medium Scenario		Reserve / Trade	Fuel Transportation System	Advantage of development	Environmental Issues	Role in Development / Comments	Candidate
1	Coal-fired power plant - Low Rank Coal	PLTU	1,509 Cents/M.kcal	80 $/ton	Abundant reserve of low rank coal (< 5,100 kcal/kg) but limited in domestic market	Reinforcement of transportation system by huge investment	(1) Effective utilization of low rank coal (2) Contribution to less generation cost	(1) CO_2 emission (887 g-CO_2/kWh) *4) (2) NOx and SOx and SPM (Suspended Particular Matter) emission (3) Thermal effluent	Supplemental development to make up the shortage of power supply provided by other power resources.	The most promising candidate
2	Combined Cycle Power plant -Gas	PLTGU	1,984 Cents/M.kcal	5.0 $/MMBTU	Decrease of Gas production after the year 2010 is forecasted. *1)	Always accompanying uncertainty of gas supply due to multiple gas suppliers	Flexible operation from base load to partial peak load	(1) Less air quality impacts than coal-fired , CO_2 emission (408 g-CO_2/kWh) (2) Thermal effluent	IG makes efforts to accelerate gas exploitation and production by introduction of incentive measures. Gas production might be restored in the future.	Not candidate at the moment
3	Gas Turbine - HSD	PLTG	9,222 Cents/M.kcal	133 $/barrel	Indonesia is a crude oil import country and IG announced that IG would quit OPEC in 2009. *2)	Stable supply from PERTAMINA and other suppliers at MOPS + α	Quick response to load fluctuation	CO_2 emission (478 g-CO_2/kWh)	(1) HSD-fired gas turbine is not considered as a candidate under the recent crude oil price level (100 ~ 130 US$/barrel). (2) Conversion of existing HSD-fired PLTG to PLTGU is recommended from the viewpoint of fuel saving.	Not candidate
4	Geothermal	PLTP	6,430 Cents/M.kcal	5.53 cents/kWh	Proven reserve in Jamali is 1,727 MW. *3) Exploration of steam well has to be done by developers.	No requiremet of fuel transportation system	(1) Pure domestic energy (2) Stable operation as base load due to no requirement of periodic fuel supply	(1) No SOx/NOx/SPM and limited CO_2 emission but H2S emission (2) Arsenic (As) and mercury (Hg) discharges	PLTP development will be promoted for outside of Jamali due to a new ministerial decree which allows PLTP (55 MW) developers can sell electricity to PLN at max. 85 % of generation cost in the region, where PLTD is a main power resource as base load.	Candidate
5	Diesel Plant -HSD	PLTD	9,222 Cents/M.kcal	133 $/barrel	HSD is imported to make up the shortage of domestic production.	Stable supply from PERTAMINA and other suppliers at MOPS + α	(1) Lowest forced outage rate (2) Quick response to load fluctuation	CO_2 emission (704 g-CO_2/kWh)	HSD-fired PLTD development might be still useful measures for blackout for outside of Jamali from the short term viewpoint due to its shortest implementation period, lowest Forced Outage Rate and easier operation	Not candidate
6	Hydropower	PLTA	No fuel		Potential sites are very few, especially for reservoir type development	No requiremet of fuel transportation system	(1) Minimum operation cost among the all power plants (2) Quick response to load fluctuation (3) Contribution to frequency regulation for the system	(1) Resettlement (2) Possible emission of methane from reservoir	If crude oil price continues to increase, an economically feasible site may come to one of candidates.	Not candidate at the moment
7	Pumped Storage	PLTA	About 30 % higher than the generation cost to be used for pumping energy		Some potential sites for pure water and sea water pumped storage power plants	No requiremet of fuel transportation system	(1) Quick response to load fluctuation (2) Contribution to frequency regulation for the system	(1) Resettlement (2) Impacts by saline water for sea-water P/S	In accordance with the development of PLTN, a capacity factor of a pumped storage power plant will be increased due to surplus energy in the mid night.	Candidate
8	PLTG/GU-LNG	PTG PLTGU	3,968 Cents/M.kcal	10.0 $/MMBTU	All LNG production is allocated to export, such as Japan, Korea etc.	Requirement of new LNG carriers for domestic use	Flexible operation from base load to peak load	(1) Less air quality impacts than coal-fired (CO_2 emission-PLTG 443 g-CO_2/kWh) (2) No SOx emission (3) Thermal effluent (PLTGU)	PLTG/GU-LNG will play a role of current HSD-fired PLTG/GU with less operation cost	Candidate
9	Nuclear	PLTN	250 Cents/M.kcal	-	Nuclear fuel is to be procured from overseas market.	No requiremet of fuel transportation system	(1) More compact space than coal-fired due to no coal stock yard. (2) Contribution to less generation cost	(1) No CO_2 emission (2) Thermal effluent	Earliest development is desirable to reduce the numbers of PLTU (coal) development from the reinforcement of coal distribution system and environmental viewpoint.	The 2nd promising candidate

Source : *1) BPMIGAS Website, *2) Jakarta Post May 29, *3) Master Plan Study for Geothermal Power Plant Development in the Republic of Indonesia (Summary Report), page 11", September, 2007, JICA
*4) Japan Atomic Energy Relations Organization (JAERO)

4.2.2 Basic Condition for Power Source Development Plan

(1) Common Assumption

Common assumptions used in the power source development plan are shown in Table 4.2-3.

Table 4.2-3 Common Assumptions

Items	Conditions	Remarks
Study Period	20 years	20 years from 2009 to 2028
Demand Forecast	Base Case	6.5 % of average power growth rate
Load Duration Curve	Typical Duration Curve as shown in Fig.4.2-1	Developed with annual operation data for the year 2006 provided by P3B (Constant for 20 years[2])
Minimum Reserve Margin	30 %	Minimum Reserve Margin = Supply Capacity / Peak Load ≧ 130 %
Loss of Load Probability	≤ 0.274 %	Less or equal to one (1) day / pear
Hydro Condition	1 condition	
Periods per year	2 periods	Wet season (6 months) and Dry season (6 months)
Peak Load ratio		Rainy season : Dry Season = 1: 0.971 Based on 2006 operation data
Cost of the energy not served	None	Due to the uncertainty of kWh cost of the energy not served because of none actual payment up to now.

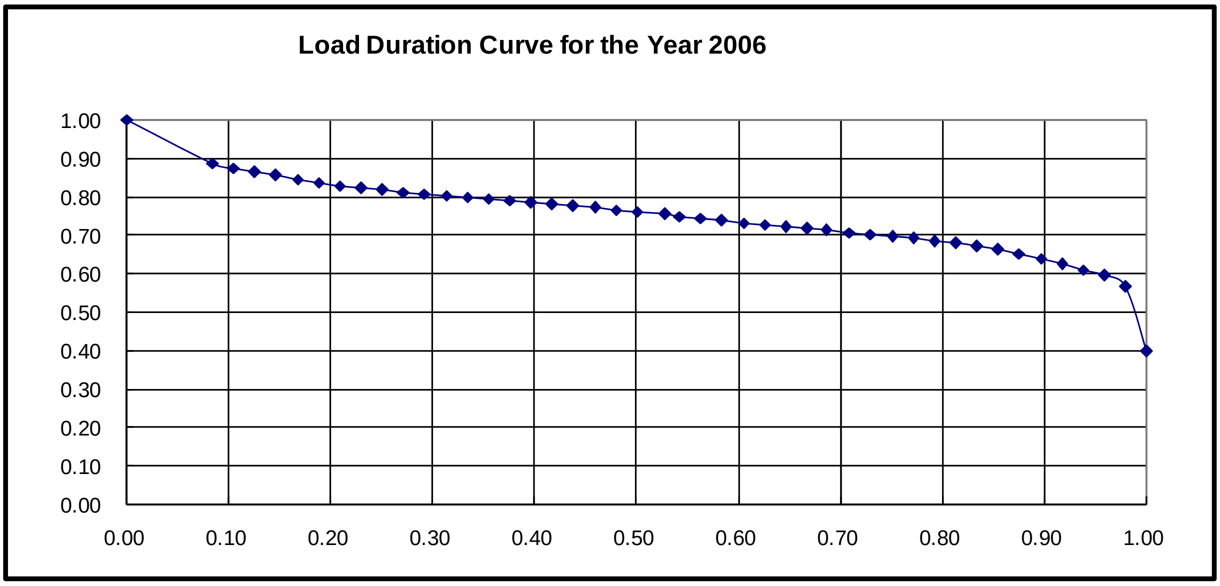


Fig.4.2-1 Load Duration Curve for Power Source Development Plan

[2] Using the typical load duration curve leads to 1.7 % more generated energy than that of demand forecast for 2028, which is the largest difference for the planning period, and for most of years the difference is within 1.0 % margin. Therefore, typical duration curve well represents the generated energy obtained in the demand forecast for Jamali Region.

<u>Reserve Margin</u>

The average reserve margin of ten (10) power utility companies in Japan from 1995 to 2005 has been fluctuating between 9.3 % (minimum in 2001) and 16.6 %[3] (maximum in 1999). The target reserve margin of thirty (30) % for Jamali is high in comparison with that in Japan. This is because the target reserve margin of 30 % in Jamali includes the following uncertainties.

- Once malfunction and/or breakage of generation equipment occurs, the duration for restoration cannot be estimated and tends to take long time[4], because main parts and/or spare parts for power generation equipment have to be procured from abroad.
- Negotiations on conditions between PLN/MEMR and international financial institutions sometimes cause the delay[5] of project implementation.
- Since peak load always occurs in summer season (July or August) in Japan, periodical maintenance for generation facilities is planned to be conducted in other seasons. On the other hand, timing (month/dates) of peak load in Indonesia cannot be forecasted in advance like Japan. Therefore, there is a possibility that some power stations are under periodical maintenance when peak load occurs, which requires more reserve margin.
- Generation by hydropower fluctuates[6] remarkably between dry season and wet season.
- Derating of existing generation facilities[7], especially thermal power plants

Based on the above observation, the target reserve margin of 30 % is kept for the whole planning period at the moment, although PLN have intension to reduce the reserve margin from 2020 onwards keeping LOLP being less than 0.274 %.

(2) Existing Power Plants, On-going and Committed Projects

Table 4.2-4 shows the list of the existing power plants, on-going & committed projects and their salient features used in the power source development plan. Table 4.2-4 also includes expected year of commercial operation and retirement for each plant. These data are mostly provided by PLN.

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3 Source: “Electric Power Industry in Japan 2007”, Japan Electric Power Information Center
4 Suralaya unit No.5 stopped operation for 241 days in 2007 and still stopped when JICA team visited Suralaya thermal power station on June 3, 2008.
5 Commencements of Engineering Service for T.Priok, M.Tawar and M.Karang projects were delayed for more than one year due to delay of issuance of gas supply agreement which consist a part of conditionality.
6 Monthly average generation energies from 2003 to 2006 in wet season and in dry season are 166.5 GWh and 66.8 GWh respectively for Saguling Hydropower Station (Source: data provided by Indonesia Power)
7 As shown in Table 2.4-1, differences between installed capacity and rated capacity in 2007 are estimated about 2,000 MW.

Table 4.2-4 (1/3) Existing Power Plants, On-going and Committed Project

No.	Name	Type	Explanation	No. of Sets	Min. Load	Capacity	Heat Rates Kcal/kWh		Fuel Costs Cents/Million Kcal		Fuel Type	Spinning Reserveas	FOR	Days Scheduled Maintenance	Maintenance Class Size	O&M (FIX)	O&M (VAR)	Heat Value
					MW	MW	Base Load	Average Increment	Domestic	Foreign					MW	$/kWm	$/MWh	Kcal/kg
1	SRL1	PLTU	Suralaya #1-#4 400 MW	4	240	381	2,622	2,452	1,509	-	0	5	12	42	381	2.61	2.00	5,100
2	SRL2	PLTU	Suralaya #5-#7 600 MW	3	340	579	2,560	2,309	1,509	-	0	5	14	42	579	2.61	2.00	5,100
3	MKR1	PLTU	M. Karang #1~#3 100 MW	3	44	84	3,273	3,194	5,437	-	3	5	11	28	84	3.68	2.00	9,598
4	MKR2	PLTG	M. Karang #4~#5 200 MW	2	90	165	2,948	2,884	-	1,984	1	5	11	35	165	3.68	1.00	2,520
5	MKR3	PLTGU	M.Karang	1	300	465	2,433	2,018	-	1,984	1	7	10	42	465	1.60	1.00	2,520
6	MKRR	PLTGU	M.Karang Repowering 2011	-	500	750	2,433	2,018	-	1,984	1	7	10	42	750	1.60	1.00	2,520
7	PRK1	PLTU	T.Priok #3 & #4 50 MW	2	25	48	3,229	2,957	5,437	-	3	5	11	28	48	3.68	2.00	9,598
8	PRK2	PLTGU	T.Priok Block I & II	2	315	560	2,319	1,994	9,222	-	4	7	10	42	560	1.60	2.00	9,095
9	PRK3	PLTG	T.Priok #1 & #3 26 MW	2	10	20	4,711	3,930	9,222	-	4	10	7	20	20	1.11	2.00	9,095
10	PRKE	PLTGU	T.Priok Extension 2012	-	500	750	2,433	2,018	-	1,984	1	7	10	42	750	1.60	1.00	2,520
11	MTR1	PLTGU	M.Tawar Block I	1	315	605	2,555	2,246	9,222	-	4	7	10	42	605	1.60	2.00	9,095
12	MTR2	PLTG	M.Tawar #2.1 ~ #2.2 145 MW	2	72	138	3,376	3,204	9,222	-	4	10	7	28	138	0.97	2.00	9,095
13	MTR3	PLTG	M.Tawar #3.1~#4.3 153 MW	6	72	143	3,376	3,204	9,222	-	4	10	7	28	143	0.97	2.00	9,095
14	MTRR	PLTGU	M.Tawar Repowering 2011	-	150	225	2,433	2,018	-	1,984	1	7	10	42	225	1.60	1.00	2,520
15	SLK1	PLTP	Salak #1 ~ # 3 60 MW	3	52	52	1,000	1,000	6,430	-	5	-	5	28	52	2.50	1.00	7,308
16	SLK2	PLTP	IPP Salak #4 ~ #6 60 MW	3	52	52	1,000	1,000	6,430	-	5	-	5	28	52	2.50	1.00	7,308
17	CLND	PLTG	IPP Cikarang Listrindo 150 MW	1	50	150	4,465	3,200	-	1,984	1	10	7	28	150	0.97	1.00	2,520
18	CLGN	PLTGU	Cilegon 740 MW	1	240	740	2,175	1,800	-	1,984	1	7	10	42	740	1.60	1.00	2,520
19	SRL3	PLTU	Crash Program Suralaya 600 MW	-	340	600	2,560	2,309	1,509	-	0	5	14	42	579	2.61	2.00	4,200
20	LBHN	PLTU	C.P. Labuhan 300 MW x 2	-	150	300	2,622	2,452	1,509	-	0	5	11	35	300	2.61	2.00	4,200
21	TLNG	PLTU	C.P. Teluk Naga 300 MW x 3	-	150	300	2,622	2,452	1,509	-	0	5	11	35	300	2.61	2.00	4,200
22	KMJ1	PLTP	Kamojang #1 30MW	1	26	26	1,000	1,000	6,430	-	5	-	5	28	26	2.50	1.00	7,308
23	KMJ2	PLTP	Kamojang #2 & #3 55MW	2	47	47	1,000	1,000	6,430	-	5	-	5	28	47	2.50	1.00	7,308
24	KMJ3	PLTP	IPP Kamojang #4 60 MW x 1	1	60	60	1,000	1,000	6,430	-	5	-	5	28	60	2.50	1.00	7,308
25	DRJ1	PLTP	Darajat #1 55 MW	1	44	44	1,000	1,000	6,430	-	5	-	5	28	44	2.50	1.00	7,308
26	DRJ2	PLTP	IPP Darajat #2 95 MW	1	70	70	1,000	1,000	6,430	-	5	-	5	28	70	2.50	1.00	5,300
27	DRJ3	PLTP	IPP Darajat #3 110 MW x 1	1	110	110	1,000	1,000	6,430	-	5	-	5	28	100	2.50	1.00	7,308
28	WW1	PLTP	IPP Wyndu #1 110 MW	1	110	110	1,000	1,000	6,430	-	5	-	5	28	110	2.50	1.00	7,308
29	SRG1	PLTG	Sunyaragi #1 & #2 20.03 MW	2	8	18	4,700	4,084	-	1,984	1	10	7	21	20	1.11	1.00	2,520
30	SRG2	PLTG	Sunyaragi #3 & #4 20.10 MW	2	8	20	4,700	4,084	9,222	-	4	10	7	21	20	1.11	2.00	9,095
31	PTH1	PLTP	IPP Patuha #1~#3 60 MW x 3	-	60	60	1,000	1,000	6,430	-	5	-	5	28	60	2.50	1.00	7,308
32	JBSL	PLTU	C.P Pelabuhan Baru 300 MW x 3	-	150	300	2,590	2,115	1,509	-	0	5	11	35	300	2.61	2.00	4,200
33	JBUT	PLTU	C.P. Indramayu 300 MW x 3	-	150	300	2,590	2,115	1,509	-	0	5	11	35	300	2.61	2.00	4,200
34	CRBN	PLTU	IPP Cirebon 600 MW x 1	-	360	600	2,560	2,160	1,509	-	0	5	14	42	600	2.61	2.00	5,300
35	TBK1	PLTGU	Tambak Lorok Block I & II	2	297	496	2,632	2,015	9,222	-	4	7	10	42	496	1.60	2.00	9,095
36	TBK2	PLTU	Tambak Lorok #1 & #2 50 MW	2	25	41	3,229	3,127	5,437	-	3	5	11	21	41	3.68	2.00	9,598
37	TBK3	PLTU	Tambak Lorok #3 200 MW	1	125	192	3,229	3,127	5,437	-	3	5	11	28	192	3.68	2.00	9,598
38	CLC1	PLTG	Cilacap #1 & #2 29 & 26 MW	2	10	22	4,700	4,079	9,222	-	4	10	7	21	22	1.11	2.00	9,095
39	CLC2	PLTU	IPP Cilacap #1 & #2 300 MW	2	150	300	2,772	2,285	1,509	-	0	5	11	35	300	2.61	2.00	5,215
40	TJB1	PLTU	Tanjung Jati-B #1 & #2 660 MW	2	330	660	2,772	2,285	1,509	-	0	5	14	42	660	2.61	2.00	5,215
41	TJB2	PLTU	C.P T.Jati Baru/Cilacap 600 MW x 1	-	360	600	2,560	2,160	1,509	-	0	5	14	42	600	2.61	2.00	4,500
42	DIEN	PLTP	IPP Dieng #1 60MW	1	60	60	1,000	1,000	6,430	-	5	-	5	28	60	2.50	1.00	7,308
43	RMBG	PLTU	C.P Rembang 300 MW x 2	-	150	300	2,590	2,115	1,509	-	0	5	11	35	300	2.61	2.00	4,500
44	PTN1	PLTU	Paiton #1 & #2 400 MW	2	225	370	2,579	2,412	1,509	-	0	5	12	35	370	2.61	2.00	5,100
45	PTN2	PLTU	C.P Paiton 600 MW x 1	-	340	600	2,560	2,309	1,509	-	0	5	14	42	600	2.61	2.00	4,500
46	PEC	PLTU	IPP Paiton #7 & #8 645 MW	2	368	615	2,772	2,285	1,509	-	0	5	14	42	615	2.61	2.00	5,215
47	JPOW	PLTU	IPP Jawa Power #5 & #6 610 MW	2	355	610	2,700	2,310	1,509	-	0	5	14	42	610	2.61	2.00	5,500
48	GSK1	PLGU	Gresik Block I ~ III	3	250	480	2,318	1,990	-	1,984	1	7	10	42	480	1.60	1.00	2,520
49	GSK2	PLTG	Gresik #1 & #2 20.1 MW	2	5	16	4,456	4,284	-	1,984	1	10	7	21	16	1.11	1.00	2,520
50	GSK3	PLTU	Gresik #1 & #2 100 MW	2	43	85	2,882	2,709	-	1,984	1	5	11	28	85	3.68	1.00	2,520
51	GSK4	PLTU	Gresik #3 & #4 200 MW	2	90	175	2,826	2,601	-	1,984	1	5	11	35	175	3.68	1.00	2,520
52	PRAK	PLTU	Perak #1 & #2 50 MW	2	25	48	4,323	3,517	5,437	-	3	5	11	21	48	3.68	2.00	9,598
53	GRT1	PLTGU	Grati Block I	1	270	462	2,632	2,083	9,222	-	4	7	10	35	462	1.60	2.00	9,095
54	GRT2	PLTG	Grati #2.1~#2.3 100.75 MW	3	40	100	3,376	3,310	9,222	-	4	7	10	21	100	1.75	2.00	9,095
55	PMRN	PLTG	Pemaron #1 & #2 48.8 MW	2	12	48	4,439	4,035	9,222	-	4	10	7	21	48	1.11	2.00	9,095
56	GLMR	PLTG	Giltimur #1 & #2 20.1 MW	2	5	16	4,456	4,284	9,222	-	4	10	7	21	16	1.11	2.00	9,095
57	GLMK	PLTG	Gilimanuk #1 133.8 MW	1	56	133	4,439	4,035	9,222	-	4	10	7	21	133	0.97	2.00	9,095
58	BLI1	PLTG	Pesanggaran #1 ~ #4 20/42 MW	4	6	20	4,700	4,131	9,222	-	4	10	7	21	20	1.11	2.00	9,095
59	BLI2	PLTD	Pesanggaran #2 ~ #11 5~12MW	10	2	5	3,880	3,576	9,222	-	4	10	7	21	5	1.11	2.00	9,095
60	BLUT	PLTU	IPP Bali Utara 130 MW x 3	-	65	130	2,590	2,115	1,509	-	0	5	11	28	130	2.61	2.00	5,300
61	BDGL	PLTP	IPP Bedugul 10 MW x 1	-	10	10	1,000	1,000	6,430	-	5	-	5	28	10	2.50	1.00	7,308
62	TJAW	PLTU	C.P T Awar-awar 300 MW x 2	-	150	300	2,590	2,115	1,509	-	0	5	11	35	300	2.61	2.00	4,500
63	JTSL	PLTU	C.P J.Selatan/Pacitan 300 MW x 2	-	150	300	2,590	2,115	1,509	-	0	5	11	35	300	2.61	2.00	4,500
	CSLC	PLTP	IPP Cisolok - Cisukarame 45 MW x 1	-	45	45	1,000	1,000	6,430	-	5	-	5	28	45	2.50	1.00	7,308
	TGBP	PLTP	IPP Tangkuban Perahu 110 MW x 2	-	220	220	1,000	1,000	6,430	-	5	-	5	28	220	2.50	1.00	7,308
	TMPM	PLTP	IPP Tampomas 50 MW x 1	-	50	50	1,000	1,000	6,430	-	5	-	5	28	50	2.50	1.00	7,308
24*	KMJ4	PLTP	IPP Kamojang #5 60 MW x 1	-	60	60	1,000	1,000	6,430	-	5	-	5	28	60	2.50	1.00	7,308
42*	DIEN2	PLTP	IPP Dieng #2 & #3	-	60	60	1,000	1,000	6,430	-	5	-	5		60	2.50	1.00	7,308
28*	WW2	PLTP	IPP Wyndu #2 110 MW	-	110	110	1,000	1,000	6,430	-	5	-	5	28	110	2.50	1.00	7,308
A1	RJMD	PLTA	IPP Rajamandandala 47 MW x 1	-	0	47												
A2	JTGD	PLTA	PU Jatigede 55 MW x 2	-	0	110												

Table 4.2-4 (2/3) Existing Power Plants, On-going and Committed Project

No.	Name	No. of Sets	Available Capacity MW	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	SRL1	4	381																				
2	SRL2	3	579																				
3	MKR1	3	84		**-3**																		
4	MKR2	2	165									-1	-1										
5	MKR3	1	465																				
6	MKRR	-	750			1																	
7	PRK1	2	48		-2																		
8	PRK2	2	560									-2											
9	PRK3	2	20																				
10	PRKR	-	750				1																
11	MTR1	1	605														-1						
12	MTR2	2	138																				
13	MTR3	6	143																				
14	MTRR	-	225			1																	
15	SLK1	3	52																				
16	SLK2	3	52																				
17	CLND	1	150																				
18	CLGN	1	740																				
19	SRL3	-	600		**1**																		
20	LBHN	-	300	**2**																			
21	TLNG	-	300	**1**	**2**																		
22	KMJ1	1	26																				
23	KMJ2	2	47																				
24	KMJ3	1	60																				
25	DRJ1	1	44																				
26	DRJ2	1	70																				
27	DRJ3	1	110																				
28	WW1	1	110																				
29	SRG1	2	18									-2											
30	SRG2	2	20									-2											
31	PTH1	-	60		2	1																	
32	JBSL	-	300	**1**	**2**																		
33	JBUT	-	300	**2**	**1**																		
34	CRBN	-	600			1																	
35	TBK1	2	496										-1	-1									
36	TBK2	2	41			-2																	
37	TBK3	1	192									-1											
38	CLC1	2	22																				
39	CLC2	2	300																				
40	TJB1	2	660																				
41	TJB2	-	600		**1**																		
42	DIEN	1	60																				
43	RMBG	-	300	**2**																			
44	PTN1	2	370																				
45	PTN2	-	600		**1**																		
46	PEC	2	615																				
47	JPOW	2	610																				
48	GSK1	3	480																				
49	GSK2	2	16																				
50	GSK3	2	85																				
51	GSK4	2	175																				
52	PRAK	2	48		-2																		
53	GRT1	1	462											-1									
54	GRT2	3	100																				
55	PMRN	2	48																				
56	GLMR	2	16																				
57	GLMK	1	133																				
58	BLI1	4	20										-2	-2									
59	BLI2	10	5		-10																		
60	BLUT	-	130		2	1																	
61	BDGL	-	10		1																		
62	TJAW	-	300	**1**	**1**																		
63	JTSL	-	300	**1**	**1**																		
	CSLC	-	45																				
	TGBP	-	220																				
	TMPM	-	50																				
24*	KMJ4	-	60				1																
42*	DIEN2		60		**2**																		
28*	WW2	-	110				1																
A1	RJMD	-	47				1																
A2	JTGD	-	110							1													

Table 4.2-4 (3/3) Existing Power Plants, On-going and Committed Project

FIXSYS HYDRO

PLTA	Index	Installed Cap. [MW]	Energy Storage (GWh)	Inflow Energy				Min. Generation				Average Capacity			
				I(Wet) [GWh]	II(Dry) [GWh]	III [GWh]	IV [GWh]	I(Wet) [GWh]	II(Dry) [GWh]	III [GWh]	IV [GWh]	I(Wet) [MW]	II(Dry) [MW]	III [MW]	IV [MW]
Jatiluhur #	JTLH	180	842.6	315.8	376.9			204.3	298			180	180		
Saguling	SAGL	700.7	2,520.7	1291.5	680.8			999.2	400.6			701	701		
IP- Area I	IPA1	37.26	-	70.5	53.9			61.8	37.8			37	37		
IP- Area II	IPA2	59.38	-	143.1	78.9			112.3	56.7			59	59		
Sudirman	MRTC	180.9	489.8	356.9	79.7			277.3	18			181	181		
IP-Area III	APA3	125.54	-	264.1	199			235.8	166.3			126	126		
Sutami	STMI	105	451.1	263.2	155.5			164.6	127.5			105	105		
EP Non Su	EPNS	134.5	563.5	312.3	175.8			223	115.8			135	135		
Brantas No	BNEP	41.9	-	47.3	41.2			17.1	11.3			42	42		
Cirata	CRI2	1008	1,377.0	648.2	444.9			487.8	256			1008	1008		
Rajamanda	RJMD	47	90.0	82.0	61.8			70.0	52.5			47	47		
Jatigede	JTGD	110	620.0	216.8	72.3			184.3	61.4			110	110		

(3) Candidates for Future Power Source Development Plan

1) Candidates of thermal power plants

Table 4.2-5 shows the candidate thermal plants for the power source development plan. Java-Sumatra Interconnection and LNG-fired thermal are seemingly promising candidates to be put into the system in 2014 and 2015 respectively.

Table 4.2-5 Candidates of Thermal Power Plant

Power Resource	Abbreviation	Unit Capacity
PLTU-Coal	C6H	600 MW / unit
PLTU-Coal	C10H	1,000 MW/unit
LNG-fired PLTG/TGU	LNG	750 MW / unit
PLTP	GE55	55 MW / unit
PLTN	N10H	1,000 MW / unit
PLTG	G150	150 MW / unit
Java-Sumatra Interconnection	JS-IC	600 MW / unit, Max 5 units

2) Candidates of Hydropower Plants and Pumped Storage Power Plants

Under the current soaring oil-based fuel prices, a hydropower plant, especially a reservoir type, seems to be competent even though it requires rather large initial investment cost in comparison with thermal power plants. At the moment, only two (2) projects, Rajamandala (IPP, 47 MW) and Jatigede (PU, 110 MW) are ongoing.

According to “Hydro Inventory and Pre-feasibility Studies”, conducted by Nippon Koei CO., LTD. in June 1999, the following four (4) hydropower projects in Jamali are recommended to proceed to D/D stage or implementation stage. The recommended (4) hydropower projects are used as candidates of hydropower plant.

Table 4.2-6 Candidates of Hydropower Plant

Name	Location	Type	Total Cost (M.US$)	Installed Capacity (MW)	Unit Cost ($/kW)	Annual Energy (GWh)
Cibuni-3	W.J	RES	363.3	172.0	2112.2	568.0
Cipasang	W.J	RES	482.4	400.0	1205.0	751.1
Cimandiri-3	W.J	RES	350.6	238.0	1473.1	600.0
Maung	C.J	RES	511.6	360.0	1421.1	534.9

Source : “Hydro Inventory and Pre-feasibility Studies”, June 1999, Table 15.1.1(1) & (2)

Concerning the pumped storage hydro power plants, three (3) projects are recommended to proceed to Pre-F/S stage or F/S stage in the abovementioned 1999 report. Among the three (3) projects, only Upper Cisokan project are being advanced to construction. The remaining two (2) projects are used as candidates of pumped storage power plant. Considering the Fast Track Program (6,900 MW Coal-fired thermal plants in Jamali) expected to provide pumping energy with low cost, pumped storage projects will have advantage in the future.

Table 4.2-7 Candidates of Pumped Storage Power Plant

Name	Location	Type	Total Cost (M.US$)	Installed Capacity (MW)	Unit Cost ($/kW)	Annual Energy (GWh)
Matenggeng	W.J	PST	585	1,000	585	905.2
Gurindulu	E.J	PST	624	1,000	624	905.2

Source : "Hydro Inventory and Pre-feasibility Studies", June 1999, Table 15.1.1(3) &(4)

According to Table 4.1-16 "Hydro Potential in Java-Bali Region", the remaining hydro potential in Jamali except the ongoing projects and the above candidates seems to be around 2,200 MW.

(4) Construction Costs of Candidates

1) PLTU-Coal (1,000 MW)

Construction cost for PLTU-Coal (1,000 MW) is derived from IPP Paiton III Extension Project, of which PPA (Power Purchase Agreement) was signed in 2008 between PLN and the investor, and expected commencement of commercial operation is in 2012. Since Paiton III Extension Project will be constructed at BLOCK III & IV in the present Paiton Complex and the project can utilize common facilities in the complex (intake & discharge channels and road etc.), the unit construction cost may be lower than the cost of a greenfield project.

Table 4.2-8 Construction Cost of IPP Paiton III Extension Project

Name	Location	Type	Total Cost (B.US$)	Installed Capacity (MW)	Unit Cost ($/kW)	Operation (Year)
Paiton III	EJ	Super Critical	1.4	815	1,718	2012

Source : TEPCO HP (Press Release August 04, 2008)

2) Geothermal Power Plant

Construction cost of geothermal power plant is derived from "Master Plan Study for Geothermal Power Development in the Republic of Indonesia", September 2007 conducted by JICA.

Table 4.2-9 Construction Cost for Geothermal Power Plant

Name	Construction Cost (M.US$)	Installed Capacity (MW)	Unit Cost ($/kW)
55 MW Model		55	
Steam Field	42		
Power Plant	65		
Total Construction Cost	107	55	1,945

Source: "Master Plan Study for Geothermal Power Development in the Republic of Indonesia", September 2007

3) Java-Sumatra Interconnection

Construction cost for Java-Sumatra Interconnection consisting of 400 km overhead HVDC transmission line and 40 km offshore cable is provisionally derived from "Updated Feasibility Study Jawa - Sumatera Interconnection", September. 2007 conducted by PLN.

Table 4.2-10 Construction Cost for Java-Sumatra Interconnection

Name	Type	Total EPC Cost (M.US$)	Installed Capacity (MW)	Unit Cost ($/kW)	Operation (Year)
Java-Sumatra Interconnection	HVDC	1,530	3,000	510	2014 & 15
PLTU Sumatra	Coal-fired			1,481	
Total				1,991	

Source : "Updated Feasibility Study Jawa - Sumatera Interconnection", Sep. 2007

4) Hydropower Plant and Pumped Storage Power Plant

Construction costs of hydropower plants and pumped storage power plants, listed in Table 4.2-11 are those of the 1999 price level. These costs were updated to the 2007 price level by referring to the construction cost of Upper Cisokan, of which cost was estimated in 2007.

Table 4.2-11 Construction Costs for Hydropower and Pumped Storage Power Plant

Name	Unit cost as of 1999 (US$/kW)	Unit cost as of 2007 (US$/kW)	Unit cost as of 2007 (US$/kW)
Upper Cisokan	630	697	697
Cibuni-3	2,112	-	2,337
Cipasang	1,205	-	1,333
Cimandiri-3	1,437	-	1,630
Maung	1,421	-	1,572
Matenggeng	585	-	647
Grindulu	624		691

Note: 1999 prices are after "Hydro Inventory and Pre-feasibility Studies", June 1999

5) Nuclear Power Plant

Construction cost for nuclear power plant is taken from "World Nuclear Association Report 2005". The report discloses that EIA (2004) used a starting point of 2,083 US$ per kW for its estimates in its "2004 Annual Energy Outlook". The construction cost of 2,083 US$ per kW as of 2004 price was also updated to 2007 price level by using "Domestic Corporate Goods Price Index (Iron & Steel)" released by Bank of Japan as shown in Fig.4.2-2. According to Fig.4.2-2, iron and steel prices in Japan have increased by approximately 25 % from 2004 to 2007. Construction cost of nuclear power plant updated to 2007 price level is shown in Table 4.2-12.

Table 4.2-12 Construction Cost for Nuclear Power Plant

Name	Unit cost as of 2004 (US$/kW)	Price Increase from 2004 to 2007	Unit cost as of 2007 (US$/kW)
Nuclear Power Plant	2,083	25 %	2,604

6) Other Thermal Plant

Construction costs for other thermal power plants are set as shown in Table 4.2-13 provisionally assuming the same price hike as shown in Fig.4.2-2.

Table 4.2-13 Construction Cost for Other Thermal Power Plants

Name	Installed Capacity (MW/unit)	Unit cost as of 2007 (US$/kW)
PLTU-Coal	600	1,200
PLTG – HSD	150	500
LNG-fired	750	875

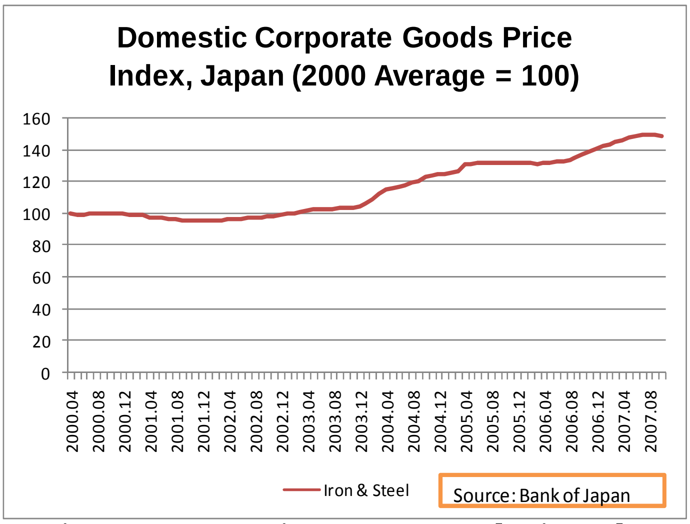


Fig. 4.2-2 Domestic Corporate Good Price Index

(5) Fuel Prices

In the course of the JICA Study, crude oil price recorded the high of 147 USD per barrel in early July 2008 and the Jakarta Post reported "Bukit Asam sold coal to the Tanjung Jati B power plant in Java at 80$ a ton, its record price for the domestic market (JKT Post, 2008.08.12)".

Not only oil-based fuel prices but also coal and gas prices have been increased in the recent years. Under the current marked fluctuation of fuel

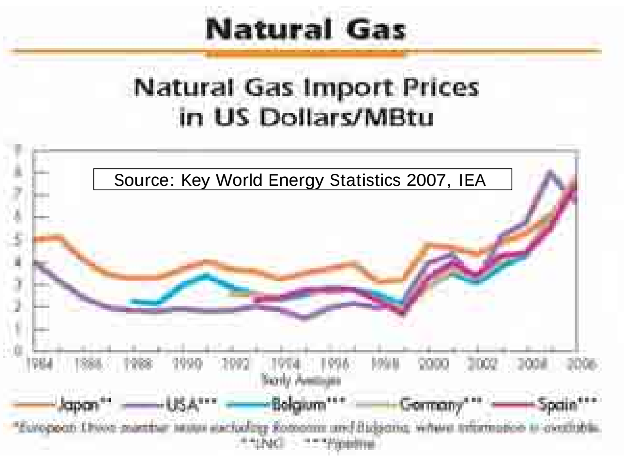


Fig. 4.2-3 Gas and LNG Prices

prices, it is very difficult to set the fuel prices to be used in the power source development plan. However, the fuel prices may not go down to 2006 price level due to further increase of fuel demand by economic growth in BRICs[8] in the future.

Considering the above circumstances, the fuel prices to be used in the power source development plan are set as shown in Table 4.2-14 provisionally. Table 4.2 -15 shows the relationship between crude oil price at MOPS and HSD & MFO and Fig.4.2-3 shows the Gas and LNG prices.

Table 4.2-14 Fuel Prices for Power Source Development Plan

Kind of Fuel	Price			Heat Content	
	USD		Cents/mKcal		
Coal	80.0	per Ton	1,509	5,300	Kcal/kg
LNG	10.0	per MMBTU	3,968	252,000	Kcal/mmbtu
Gas	5.0	per MMBTU	1,984	252,000	Kcal/mmbtu
HSD	133.0	per Barrel	9,222	9,070	Kcal/l
MFO	81.0	per Barrel	5,437	9,370	Kcal/l
Geothermal	0.0553	per kWh	6,430		
Nuclear			250		

Table 4.2-15 Relationship between Crude Oil Price and HSD/MFO Price

MOPS (2008/03/31 ~ 2008/04/04)	$/barrel
High Speed Diesel Oil (0.05%)	132.02
Kerosene	128.36
Crude Oil	**104.30**

Note: HSD and Kerosene are FOB at Singapore
MOPS means Mean of Platts Singapore
Source://www.gu-goon.com/

PERTAMINA Price	$/barrel	Price Index (IP)
HSD	**145.93**	**1.40**
MFO	**89.14**	**0.85**
Crude Oil	**104.30**	**1.00**

Note : 1 barrel = 159 liter

New Fuel Prices for Industry in April 2008 released by PERTAMINA on March 31, 2008

Fuel Type	Economical Selling Fuel Price - Non Tax (Base Price)					
	Region 1		Region 2		Region 3	
	Rp/KL	US$/KL	Rp/KL	US$/KL	Rp/KL	US$/KL
Gasoline	7080.13	768.17	7352.107	797.68	7508.057	814.60
Kerosene	8532.07	925.76	8718.104	945.94	8903.029	966.01
High Speed Diesel	8458.78	**917.77**	8819.464	956.91	9006.539	977.20
Marine Diesel Fuel	8284.08	898.88	8464.705	918.48	8644.250	937.97
Marine Fuel Oil	5166.53	**560.60**	5278.949	572.80	5390.924	584.95
Pertamina DEX	8757.37	950.14	-	-	-	-

Source: www.pertamina.com/
Note : Fuel prices released by PERTAMINA depend on MOPS.

(6) Salient Features of Candidates

Table 4.2-16 shows the summary of salient features of candidates based on the above studies.

8 Brazil, Russia, India and China

Table 4.2-16 Candidates and Their Salient Features

No.	Name	No. of Sets	Min. Load MW	Capacity MW	Heat Rates Kcal/kWh Base Load	Heat Rates Kcal/kWh Average Incremental	Fuel Costs Cents/Million Kcal Domestic	Fuel Costs Cents/Million Kcal Foreign	Fuel Type	Spinning Reserveas	FOR	Days Scheduled Maintenance Days	Maintenance Class Size MW	O&M (FIX) $/kWm	O&M (VAR) $/MWh	FLD HEAT RT KCAL/KWH	UNIT GENERATION COSTS ($/MWH) BASE DOM	BASE FRGN	FLD DOM	FLD FRGN	FLD TOT
1	C6H	0	300	600	2510	2389	1509	0	0	5	7	42	600	2.61	2.00	2450	39.9	0.0	39.0	0.0	39.0
2	C10H	0	500	1000	2510	2389	1509	0	0	5	7	42	1000	2.61	2.00	2450	39.9	0.0	39.0	0.0	39.0
3	LNG	0	375	750	1911	1741	0	3968	2	7	7	42	750	1.60	1.00	1826	1.0	75.8	1.0	72.5	73.5
4	N10H	0	1000	1000	2606	2606	0	250	6	0	7	28	1000	4.66	0.41	2606	0.4	6.5	0.4	6.5	6.9
5	GE55	0	44	55	1000	1000	6430	0	5	0	7	28	55	2.50	1.00	1000	65.3	0.0	65.3	0.0	65.3
6	G150	0	75	150	3150	2625	9222	0	4	10	7	28	150	0.97	2.00	2888	292.5	0.0	268.3	0.0	268.3
7	J-SIC	5	300	600	2510	2389	1509	0	7	5	8	45	600	2.64	2.00	2450	39.9	0.0	39.0	0.0	39.0

PUMP STORAGE
(Upper Cisokan)

PS1
Installed Capacity 500 MW
Efficiency 76 %
O&M (Fix) 0.55 $/kW-month
Available Year 2015

Period	Pump Cap. MW	Gen. Cap. MW	Max. Energy GWh
1	530	500	600
2	530	500	600

PS2
Installed Capacity 500 MW
Efficiency 76 %
O&M (Fix) 0.55 $/kW-month
Available Year 2016

Period	Pump Cap. MW	Gen. Cap. MW	Max. Energy GWh
1	530	500	600
2	530	500	600

Hydropower Project

		MANG (Maung)		CIB3 (Cibuni-3)		CPSG (Cipasang)		CMD3(Cimandiri-3)	
Construction Cost	$/kW	1872	Inc.IDC	2,865	Inc.IDC	1,636	Inc.IDC	1,998	Inc.IDC
Installed Caapcity	MW	360		172		400		238	
Reservoir Energy	GWh	535		568		751		600	
Inflow Energy wet	GWh	430		450		600		480	
dry	GWh	160		170		230		180	
Minimum Generation wet	GWh	320		340		450		360	
dry	GWh	80		90		110		90	
Average Capacity wet	MW	360		172		400		238	
dry	MW	360		172		400		238	
Construction Period	year	5		5		5		5	
	I.D.C (%)	22.6		22.6		22.6		22.6	

Source: Hydro Inventory and Pre-feasibility Studies, June 1999, Nippon Koei Co., Ltd.

PUMP STORAGE
(Matenggeng)

PS3
Installed Capacity 1000 MW
Efficiency 76 %
O&M (Fix) 0.55 $/kW-month
Available Year 2019

Period	Pump Cap. MW	Gen. Cap. MW	Max. Energy GWh
1	530	500	450
2	530	500	450

PUMP STORAGE
(Grindulu)

PS4
Installed Capacity 1000 MW
Efficiency 76 %
O&M (Fix) 0.55 $/kW-month
Available Year 2019

Period	Pump Cap MW	Gen. Cap MW	Max. Energy GWh
1	530	500	450
2	530	500	450

Construction Cost inc. IDC

PLANT	CAPITAL COSTS ($/kW) DEPRECIABLE PART DOMESTIC	DEPRECIABLE PART FOREIGN	NON-DEPRECIABLE PART DOMESTIC	NON-DEPRECIABLE PART FOREIGN	PLANT LIFE YEARS	D.R=12% I.D.C. (%)	CONSTR. TIME (YEARS)
C6H	444	1,037	0	0	30	18.46	4
C10H	611	1,425	0	0	30	18.46	4
LNG	300	699	0	0	25	14.13	3
N10H	659	2,637	0	0	40	26.6	6
G150	82	466	0	0	20	9.6	2
PS 1&2	271	584	0	0	50	22.6	5
PS 3	252	541	0	0	50	22.6	5
PS 4	268	579	0	0	50	22.6	5
GE55	444	1,776	0	0	30	14.13	3
J-SIC	308	2,051	0	0	30	18.46	4

Java - Sumatra Interconnection (HVDC)

1. Investment Cost for HVDC			Note
EPC Cost	1,370	M.US$	
Land Acquisition + ROW	160	M.US$	
Total Investment Cost	**1,530**	**M.US$**	
2. Construction Cost for HVDC	510	$/kW	Divided by 3000 MW
3. Construction Cost of C6H	1,481	$/kW	Referred to P3B Data
4. Total Investment Cost	**1,991**	**$/kW**	

Source: Updated Feasibility Study Jawa - Sumatera Interconnection, Sep. 2007

(7) Screening Curve

Based on the above investment costs, fuel costs and other related data listed in Table 4.2-16, the screening curve[9] for candidate thermal power plants is obtained as shown in Fig.4.2-4. The vertical-axis intercept represents the initial investment (fixed) cost and the slope represents the operation (variable) cost. For example, PLTN indicates the highest investment cost and the lowest operation cost. On the other hand, PLTG (HSD) indicates the lowest investment cost and the highest operation cost.

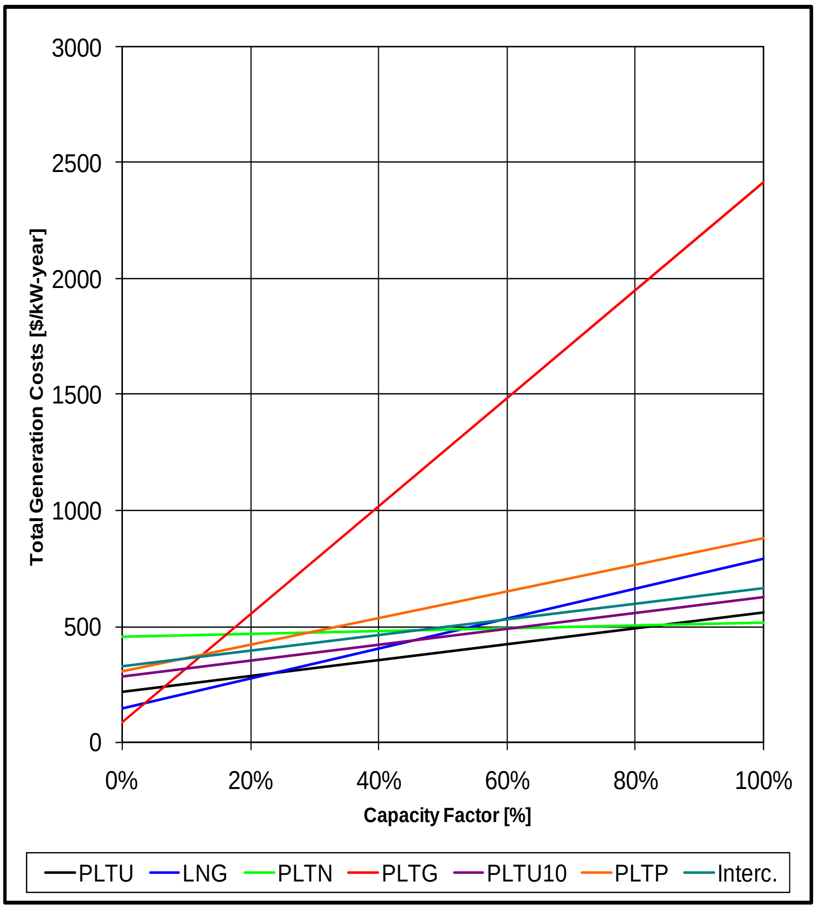


Fig. 4.2-4 Screening Curve for Candidates of Thermal Power Plant

[9] PLTU means PLTU-Coal 600 MW, LNG means LNG-fired, PLTN means Nuclear power plant, PLTG means PLTG-HSD 150 MW, PLTU10 means PLTU-Coal 1,000 MW, PLTP means Geothermal 55 MW and Interc. means Java-Sumatra Interconnection.

4.3. Evaluation of System Planning Method

The purpose of the study is to develop the integrated optimal power system development plan to secure the stable and sustainable electric power supply in the power sector. For this purpose, necessary evaluation of system planning method and basic condition of optimal system expansion plan in Indonesia were carried out.

4.3.1 System Planning Method in Indonesia

(1) System Planning Method

1) Target of power supply quality

The target of power supply quality in the development of system planning is as below, which is considered proper value judging from the requirement of the power consumers.

(a) Operating voltage
Permissive fluctuation range of operating system voltage should be designed within ±5% of the standard voltage (e.g. 500 kV system voltage → 475 kV ~ 525 kV)

(b) Frequency

Permissive fluctuation range of frequency should be designed at 50±0.2 Hz.

2) Criteria of System Planning

Generally the system planning shall be developed to ease overload condition in the whole of the system and maintain adequate system voltage under the normal and abnormal conditions.

Criteria of system planning are as shown below and they are considered proper in quality in consideration of the present requirement in Indonesia. However it is recommended to develop new criteria to cope with the severe accidents and system stability because the power supply requirement may become severer in the future.

(a) Power flow reliability criteria under normal and abnormal conditions
As a credible accident, a single accident is considered resulting in system shut down at one point of the system. A normal load is set at 60%, commencing the system expansion (reinforcement) when reached 80%.

- In case of normal condition;
  - System flow does not exceed the rated capacity of the system configuration.
  - System voltage is regulated within the reference value
  - Generators are to be operated safely.

- In case of abnormal condition (N-1 criteria);
  - Supply disorder in the limited area is basically permissible.
  - Limited impact to the power plant is permissible

(b) Three-phase short circuit capacity criteria
The value of three-phase short circuit capacity shall not exceed the circuit breaker capacity in each point of Jamali system.(normally the value is within 40 kA in the 500 kV system.)

3) Analysis Tool

In this study “PSSE* (refer to the explanation note in Appendix-8)” developed by Power Technologies Inc. and widely introduced in many countries including Indonesia, was used as the evaluation tool, to simulate the overload condition of power system components and system voltage condition based on the planning criteria by carrying out power flow analysis.

4) Others

A reactive power compensation plan, which is developed to keep an adequate system voltage, has not been developed in Indonesia till now.

(2) Evaluation of Java-Sumatra Interconnection Plan

Java-Sumatra Interconnection Plan is a large and influential project, so it was evaluated based on the collected information.

1) Project Outline

The project aims at to transmit the surplus power, which will be produced by IPP new coal fired power plants in the southern part of Sumatra Island where abundant coal reserve are expected, to Java Island by the 500 kV DC transmission lines to ease the stringency of power demand in both the Sumatra System and the Java System. This project includes construction of a 500 kV DC submarine cable and any technical issue on the DC system is not being found judging from the scale of the system. The project will also contribute for the stable power supply in Java Island to mitigate an intensive westward power flow in Jamali system.

This project is being planned to commission from 2012 to 2013, it seems, however, difficult to be completed as scheduled considering that the construction work has not commenced yet and it requires 4 to 5 years construction period.

500 kV DC/AC converter station of Java side will be located at Parung, south of Depok S/S, and the progress of land acquisition is not clear.

2) Realization of Project

PLN is carrying out the on-shore and off-shore route survey for the overhead transmission line & submarine cable, which is to be completed in the 1st quarter of 2009.

Although an overhead DC transmission line in Sumatra Island has long distance of about 400 km, the route survey has just started and land acquisition has not progressed yet. Furthermore it may take long time to develop a protection method for submarine cable because of the outcrop of sea bed rock. Regarding to the laying work of submarine cable, it may also take time for securing the special cable laying ship and laying work. Therefore the commissioning time will be anticipated to be postponed.

3) System Analysis

While a load condition of the related facilities is well analyzed in accordance with the existing system planning criteria in Java system, a frequency increase in Sumatra system in the case of shut-down on the interconnection line shall also be evaluated and those countermeasures will be examined. It is also recommended to check the system reliability of Java system as the westward power flow will be enlarged in Jamali system at a shut-down on the interconnection line.

4) Others

In addition to the above scheme, there is a conceptual design to transmit an additional power of 3,000 MW with another DC transmission line to be connected to Lengkong or Balaraja substations, of which transmission line route and commissioning time is not clear.

4.3.2 Basic Condition for Developing Optimal System Expansion Plan

Optimal system development plan shall be developed to meet the optimal power development plan for the purpose of securing a stable and flexible power supply in the variable condition of the power sector. Although a system planning shall be developed based on the above mentioned criteria, a stability analysis was also carried out for the representative years to prevent severe accidents. The following conditions were added in this study.

(1) Duration of Study

The objective time span of this study is from 2009 up to 2028.

The specified years for the system diagram and system analysis were selected to be years of 2010, 2015, 2020, 2025 and 2028.

(2) Criteria of System Planning

Additional criteria for this study are as follows:

1) In case of more severe criteria (N-2 criteria)

To study the case of more severe accident; fault on a certain T/L of 500 kV trunk loop system which may result in a large-scale block-out, N-2 criteria was adopted.

2) Transient Stability Criteria

No stability criterion is adopted with regard to the transient stability in Indonesia, however, a system stability was evaluated to prevent large-scale black-out under the severe accident condition (route accident) partially.

(a) Assumed accident

A stability of the 500 kV system is the most important issue in this study and the trunk power system shall be in a stable conditions even after the severe accidents.

The following parameters were adopted at the accident in the protected systems.

- Accident condition: three-phase short circuit accident and 1 circuit open
- Accident clearance time: 90 ms
- Load characteristic: an active power element is constant current characteristic, and a reactive power element is constant impedance

(b) Basic characteristics of generator

As for the generator constant, excitation and turbine governor characteristic, the following IEEE standard data was used for characteristics of AVR/GOV as shown in Table 4.3-1.

Table 4.3-1(1/2) Characteristics Data of Generator

Generator Constant		Excitation System		Turbine Governor	
Round rotor model (GENROU)		IEEE Type ST1A (SEXS)		IEEE Standard Governor (TGOV1)	
Item	Value	Item	Value	Item	Value
T'do	5.0	TA/TB	0.1	R	0.05
T"do	0.06	TB	10	T1	0.05
T'qo	0.2	K	100	VMAX	1.05
T"qo	0.06	TE	0.1	VMIN	0.3
Inertia H	3.0	EMIN	0.0	T2	1.0
D	0.0	EMAX	4.0	T3	1.0
Xd	1.6			Dt	0.0
Xq	1.55				
X'd	0.7				
X'q	0.85				
X"d = X"q	0.35				
X1	0.20				
S (1.0)	0.09				
S (1.2)	0.38				

Table 4.3-1(2/2) Characteristics Data of Hydro Generator

Generator Constant (GENSAL)		Excitation System IEEE Type ST1A (SCRX)		Turbine Governor IEEE Standard Governor (HYGOV)	
Item	Value	Item	Value	Item	Value
T'_{do}	5.0	T_A/T_B	0.1	R	0.05
T''_{do}	0.05	T_B	10	r	0.75
T'_{qo}	0.06	K	200	Tr	8
Inertia H	5.000	T_E	0.5	Tf	0.05
D	1.0	E_{MIN}	0.0	Tg	0.5
X_d	1.5	E_{MAX}	5.0	VELM	0.2
X_q	1.2	Cs	0	G_{MAX}	1
X'_d	0.4	rc/rfd	0	G_{MIN}	0
$X''_d = X''_q$	0.25			Tw	1.3
X_1	0.12			At	1.1
S (1.0)	0.03			D_t	0
S (1.2)	0.25			qNL_t	0.08

3) System to be simulated

Basically, power systems less than 500 kV shall be designed with radial structure based on a thermal conductor capacity, which is to be protected by the overcurrent relay. As the value of transformer and power line impedance are high, affect of the accidents less than 500 kV system to trunk power system is considered negligible in this study. Therefore, simulation was carried out only on the 500 kV system which is connected to the major power plants.

4.4. Strategic Environmental Assessment

4.4.1 Legal Status of Strategic Environmental Assessment

Indonesia has no legislation to require Strategic Environmental Assessment (SEA) at the moment. There is only the Environmental Management Law (Law No.23/1997) which provides for ordinary Environmental Impact Assessment (EIA) of individual projects. Article 15 of this Law requires projects with potential significant impacts on environment to conduct the Environmental Impact Assessment.

Indonesian Ministry of Environment is now planning to amend the Environmental Management Law to incorporate SEA into the framework of EIA. The Ministry is now drafting its amendment, and they will finalize it by early next year. Draft SEA Policy is under preparation now, and BAPPENAS, the Ministry of Environment, the Ministry of Public Work and the Ministry of Interior are involved in a committee to prepare it. A provision to require SEA will be incorporated to the Environmental Management Law through its amendment, and a Presidential Decree will be issued under the amended Law to require ministries and local governments to conduct SEA when they establish a policy, plan or program. Actual contents of SEA, or those to be assessed and how to assess them will be specified by a Minister of Environment Decree. Proposed amendment of the Environmental Management Law, proposed Presidential Decree and the proposed Minister of Environment Decree are now all under preparation, and they are expected to be issued at the same time.

According to the Ministry of Environment in Indonesia, eleven ‘SEAs’ have been conducted by local governments since 2000 for regional development plans under cooperation with universities. These ‘SEAs’, however, were conducted voluntarily, and they did not follow the AMDAL or formal EIA procedure.

4.4.2 Special Features of the Strategic Environmental Assessment for Study on the Optimal Power Development Scenario in Java-Madura-Bali Area

In power development scenarios, contribution by each type of power generation is proposed, but as for power stations to start operation after 2017, a candidate site for each power station is mostly not identified. Although it is apparent that these power stations will be allocated somewhere in Jamali area, sites for individual power stations are generally not proposed in the scenarios. On the other hand, construction sites for most of the power stations to start operation until 2016 are identified in the scenarios (“4.4.3 Avoidance of Siting in Protected Areas and Habitats of Endangered/Precious/Rare Species” describes whether these power stations are located within protected areas). But, alternative scenarios are identical up to 2016, and there is no difference between the scenarios in power stations to introduce. In the present Strategic Environmental Assessment, sites for most of the individual power stations are yet to be proposed in the scenarios after 2017 when each scenario introduce different power stations, and it is difficult to compare and assess the scenarios quantitatively for their potential impacts on natural and social environment. Power development scenarios are produced after qualitative considerations of their potential impacts on natural and social environment (see "4.4.5 Constraints on Power Development Scenarios by Environmental and Social Consideration").

Below summarizes environmental constraints and potential environmental impacts to be considered generally in Jamali area, together with potential concerns associated with environmental performance of each type of power generation and proposed measures against them. Environmental Impact Statements and Environmental Monitoring Reports for thermal power stations including coal-fired power stations under the Fast Track Program will be also reviewed, and recommendations will be made against potential concerns to be addressed for environmental protection in the power development in Indonesia.

4.4.3 Avoidance of Siting in Protected Areas and Habitats of Endangered/Precious/ Rare Species

When we identify potential sites for power stations or transmission lines, it is desirable to avoid protected areas designated under the relevant legislation and the habitats of protected/precious/ rare species. If siting within such area is essential due to engineering reasons, it should be determined whether the siting is acceptable or not, after feasible measures to avoid/reduce/ mitigate its potential impacts are considered, on the basis of appropriate predictions and evaluations of potential impacts by construction of a power station or transmission lines.

Java is rich in natural environment. As shown in Fig. 4.4-1, rich vegetation is observed at outskirts of the central mountain range and in coastal plains. In addition to various grasses, many species of trees, such as palms, bamboos, acacias, gum trees, and teaks are observed in the area lower than 500m. A quarter of the Island is covered with forests. Java also has rich fauna. Rhinoceroses, tigers, leopards and various monkeys occur on the Island. Fig.4.4-1 suggests that there is no noticeable mangrove forest in Jamali area.

Source: Ministry of Forestry

Fig.4.4-1 Vegetations in Jamali Area

There are many national parks and nature reserves in Jamali area. Among these, Ujungkulon National Park (see Fig.2.4-34(2/2)) in the western part of Java is registered as the World Heritage, and tropical plants are flourishing there. This National Park provides habitats for precious organisms, and critically endangered Javanese rhinoceroses occur there. Bangtens (wild oxen) and crab-eating monkeys are also observed in the National Park.

As shown in Fig.4.4-2, coral reefs are observed at many waters in Indonesia. Along the south coast of Java, however, there develop only fringing reefs at limited waters around Panaitan Island, Pangandaran, Pangumbahan and Parangtritis. The largest coral reefs are found at waters off Grajagan Coast and also along from Watu Ulo to Blambangan Peninsula in East Java Province. In contrast, fringing reefs develop only in Banten Bay and Jepara Bay along the north coast of Java.

Source：GCRMN Report on East Asian Water 2005
(http://www.coremoc.go.jp/report/ease2004/02_02indonesia_j.pdf)

Fig.4.4-2 Distributions of Coral Reefs in Indonesia

Protected areas in Jamali to avoid when we construct a power station or transmission line are shown in Table 2.4-34 and Fig.2.4-34. In Indonesia, protected areas are designated under Forestry Act (Law No.41/1999), and the Act requires a permit from the Minister of Forestry to conduct a development project within a protected area. However, an official responsible for protected areas in the Ministry has suggested that in reality, construction of a power station within a protected area has not been permitted except for exceptional cases such as construction of a geothermal power station. It is the basic policy of the Ministry of Forestry not to allow installation of an industrial facility within a protected area in principle. Because of this basic policy, there is no regulation to provide for specific review procedures to follow when an application is submitted for a development project within a protected area. There also is no legal time limit on the review period, and most of applications for development within a protected area have been left to be reviewed for a long time. Even applications for a permit to construct a geothermal power station within a protected area take a very long period to go through the review procedures, and they have not necessarily been granted a permit.

Bedugul Geothermal Power Station (10 MW) planned by IPP within Bali Barat National Park in Bali is expected to start its operation in 2010, but it is still waiting for a permit from the Ministry of Forestry. Kamojang Geothermal Power Station in West Java Province is located within a protected area. Although its Units #1 to #4 had been in operation before designation of the protected area, and they were allowed to continue their operation, its Units #5 and #6 made their applications for a construction permit after designation of the protected area, and their permits were not granted from the Ministry of Forestry and their construction was recently cancelled.

Location maps of the new power stations referred in RUPTL (National Power Development Plan in Indonesia) as those confirmed to be constructed are not detailed enough to assess their proximity to protected areas (For the coal-fired power stations to be constructed by PLN under the Fast Track Program, see "2.4.9 Environmental and Social Considerations"). Officials in PLN, however, have confirmed that Cirebon Coal-Fired Power Station (600 MW; expected to start operation in 2011), Bali Utara Coal- Fired Power Station (expected to start operation of 130 MW × 2 units in 2011 and 130 MW in 2012), Patuha Geothermal Power Station (expected to start operation of 60 MW in 2010 and 60 MW × 2 units in 2011), Dieng Geothermal Power Station (30 MW × 2 units; expected to start operation in 2010), and Windu Geothermal Power Station (110 MW; expected to start operation in 2012) are not located within protected areas. All of these power stations are proposed by IPPs.

As for reservoir-type hydroelectric power stations, Rajamandala Hydroelectric Power Station (47 MW; expected to start operation in 2012) proposed by IPP, and multi-purpose Jatigede Hydroelectric Power Station (55 MW × 2 units; expected to start operation in 2015) under construction by the Ministry of Public Works are already confirmed to operate. Officials in PLN also have confirmed that these are not sited within a protected area. Location map of Rajamandala Hydroelectric Power Station (in "HYDRO INVENTORY AND PRE-FEASIBILITY STUDIES – NIPPON KOEI CO., LTD. June 1999") confirms that this power station is not located within a protected area.

In the present study, Cimandiri Hydroelectric Power Station (238 MW), Muang Hydroelectric Power Station (360 MW), Cibuni-3 Hydroelectric Power Station (172 MW) and Cipasang Hydroelectric Power Station (400 MW) are also included in all of the power development scenarios as promising reservoir-type hydroelectric power stations to be introduced in 2020, although these are not included in RUPTL. For those other than Cipasang Hydroelectric Power Station, their location map (in "HYDRO INVENTORY AND PRE-FEASIBILITY STUDIES – NIPPON KOEI CO., LTD. June 1999") indicates that they are not located within a protected area.

Upper Cisokan Pumped-Storage Hydroelectric Power Station (expected to start operation of 500 MW unit in 2015 and another 500 MW unit in 2016), Matenngeng Pumped-Storage

Hydroelectric Power Station (1,000 MW; assumed to start operation in 2019), and Grindulu Pumped-Storage Hydroelectric Power Station (1,000 MW; assumed to start operation in 2019) are also included in all of the power development scenarios, although the latter two are not included in RUPTL. Their location map (in "HYDRO INVENTRY AND PRE-FEASIBILITY STUDIES – NIPPON KOEI CO., LTD. June 1999") confirms that they are not located within a protected area. Construction of Upper Cisokan Pumped-Storage Hydroelectric Power Station is already scheduled.

4.4.4 Potential Environmental Concerns of Various Power Generation Options and Transmissions (including the "Zero Option"), and Possible Measures against Them

Potential environmental concerns, with possible measures against them, of various power generation options and transmissions (including the "zero option") to be considered during the course of identification of alternative power generation scenarios are summarized below for each power generation option (except for potential siting in protected areas).

(1) Run-of-River Type Hydroelectric Power Plant

1) Potential Concerns

Construction of a run-of-river type hydroelectric power station, when its penstock and/or powerhouse are constructed on the ground, may require resettlement of local residents. However, even in this case, those to be resettled will be limited, compared to a reservoir type hydroelectric power station. Run-of-river type hydroelectric power generation creates a river section with reduced water flow, which is characteristic to this power generation option, and this may interfere with intakes of water there for irrigations/ domestic uses and also with local fishery to have impacts on life and livelihood of people in the area. A river section with reduced water flow could influence occurrences of endangered/precious/rare species and prevent migrations of anadromous and catadromous fish. A penstock and/or powerhouse may have impacts on cultural heritages, and they may influence a local landscape providing a resource for tourism.

Installations of a linear structure, such as a conduit/penstock, may restrict migrations of wild animals across it, to split their habitat. In addition, a conduit/penstock may provide an access to unexploited areas, to induce poaching/deforestation.

Run-of-river type hydroelectric power generation does not burn any fossil fuel, and it does not have a reservoir with a potential to release methane. It is a power generation option with minimal impacts on global warming. However, it may have impacts on the surrounding environment through air pollutions, noises and vibrations, and water contaminations during the construction period.

2) Measures against Potential Concerns

It is desirable not to site a run-of-river type hydroelectric power station at a location where local residents need to resettle for it. If engineering considerations make it inevitable to construct a run-of-river type hydroelectric power station there, necessity for its construction there shall be explained to those to be resettled, to obtain their consent, and appropriate compensation shall be conducted. Water uses and fishing activities in the river section likely to have reduced water flows shall be surveyed appropriately in advance, and the minimum water flows to maintain these shall be secured, to minimize their potential impacts on life and livelihood of the local people. Occurrences of endangered/precious/rare species, including anadromous and catadromous fish, in the river section with reduced water flows shall be also investigated properly in advance to avoid any significant potential impact on them. Potential distributions of cultural heritages at the proposed construction site for penstock/powerhouse, and potential importance of the power station construction area as a resource for tourism, shall be also properly investigated prior to the construction, so that there will be no significant impact on these.

As for endangered/precious/rare species in Jamali area, those occurring in some national parks and/or nature reserves have been surveyed only for particular species, and occurrences of endangered/precious/rare species in the areas other than protected areas have been seldom studied. Prior to construction of a power station, occurrences of wild animals around the proposed construction site shall be surveyed carefully, so that the installation of conduit/penstock does not prevent their migrations. Access to unexploited areas through the conduit/penstock route shall be restricted by establishing gates, and periodical patrols shall be conducted to prevent poaching/illegal logging.

Appropriate measures shall be taken against potential air pollutions, noises and vibrations, and water contaminations, during the construction period, so that relevant regulatory standards are satisfied.

(2) Reservoir Type Hydroelectric Power Plant (including Pumped-Storage Power Plant)

1) Potential Concerns

Construction of a reservoir, when many people are living in the proposed reservoir area, would require large-scale resettlement of local residents. During inundation of a reservoir, there may be impacts on water intakes in the downstream for irrigations/ domestic uses, local fishery, river traffics and ecosystems. Precious cultural heritages may go under water due to construction of a reservoir, and its emergence may have impacts on a local landscape providing a resource for tourism. On the other hand, a reservoir may attract tourists, and it may provide an opportunity for fishery. However, if water quality in a reservoir deteriorates, this may influence water intakes in the downstream for irrigations/domestic uses and also local fishery to have impacts on life and livelihood of people in the area.

Upper Cisokan Pumped-Storage Power Station (expected to start operation in 2015) will influence 987 households, and among these, 511 households will need to resettle. A total of 519 ha of lands (183 ha of paddy fields, 148 ha of vegetable fields and 189 ha of forests) will be lost for this power station.

Habitats of endangered/precious/rare species or precious ecosystems may go under water due to construction of a reservoir. Disconnection of a river by a dam would interrupt navigation of vessels and also migration of anadromous/catadromous fish. If water quality in a reservoir deteriorates, this may influence organisms in the downstream.

Construction of a reservoir type hydroelectric power station may have impacts on the surrounding environment through air pollutions, noises and vibrations, and water contaminations.

In the case of the seawater pumped-storage power generation, saline water may seep underground from a reservoir, and saline splashes may disperse to surrounding areas under the strong wind, to have significant impacts on local organisms without tolerance to salinity.

Influxes of nutrient salts to a reservoir may lead to eutrophication there, and deaths of phytoplankton and floating plants after their bloom could produce methane. Surveys on the present status of eutrophication within a reservoir of large-scale hydroelectric power stations in Jamali area indicate that growth of population and agricultural lands in the upstream to the reservoir of Saguling Hydroelectric Power Station in West Java Province has resulted in substantial influxes of nitrogen and phosphate and subsequent eutrophication and algal blooms (http://www.ilec.or.jp/database/asi/asi-39.html). Methane has 21 times more global warming effect than carbon dioxide. If greenhouse effect by the release of methane from a reservoir supersedes the suppression of global warming by hydroelectric power generation (through its replacement of thermal power generation), a reservoir type hydroelectric power station will be rather an emission source of greenhouse gas.

2) Measures against Potential Concerns

It is desirable not to site a reservoir type hydroelectric power station at a location where many people need to resettle for it. Necessity for its construction there shall be explained to those to be resettled, prior to the construction, to obtain their consent, and appropriate compensation shall be conducted. Water uses, fishing activities, river traffics and ecosystems in the downstream to its dam shall be surveyed appropriately in advance, to minimize its potential impacts on life and livelihood of the local people and the local ecosystems through reduced water flows in the downstream during inundation of its reservoir. Potential distributions of cultural heritages at the proposed construction site for its dam/reservoir/powerhouse, and potential importance of the power station construction area as a resource for tourism, shall be also properly investigated prior to its construction, so that there will be no significant impact on these. When crucial river traffics for the life of local people are interrupted by its dam, alternative means of transportation shall be provided to them.

As for endangered/precious/rare species in Jamali area, those occurring in some national parks and/or nature reserves have been surveyed only for particular species, and occurrences of endangered/precious/rare species in the areas other than protected areas have been seldom studied. Prior to construction of a power station, fauna, flora and ecosystems in the proposed construction area shall be surveyed carefully in advance, so that construction of the reservoir does not pose significant threats to endangered/precious/ rare species and precious ecosystems. When there occur anadromous/catadromous fish in the river, a fish passage shall be installed to the dam to allow their migration along the river.

Since degradation of water quality in the reservoir due to eutrophication would not only influence water uses and fishery in the downstream and organisms occurring there, but also may produce methane which is greenhouse gas, water quality of the reservoir shall be monitored so that actions, such as regulation of effluents in the surrounding area, can be taken as required. Indonesia is located in a tropical area where high water temperature tends to lead to degradation of water quality. There are not sufficient sewage treatment facilities in Indonesia, and substantial influxes of nutrient salts into a reservoir from its surrounding areas are likely to induce growth and subsequent decay of phytoplankton and waterweeds and eventually produce methane.

In the case of the seawater pumped-storage power generation, lining shall be established over the bottom and sides of the reservoir to prevent seepage of saline water underground, and measures shall be taken to suppress dispersions of saline splashes to the surrounding area under the strong wind, for protection of local vegetation from salinity.

Appropriate measures shall be taken against potential air pollutions, noises and vibrations, and water contaminations, during the construction period, so that relevant regulatory standards are satisfied.

(3) Geothermal Power Plant

1) Potential Concerns

Acquisition of a land for the proposed power station and steam well and the avoidance of potential impacts by H_2S emissions into the atmosphere may require small-scale resettlement. Release of H_2S from a geothermal power station may have impacts on life of the local residents through its offensive odor or metallic corrosions. Construction of a geothermal power station may have impacts on cultural heritages and local landscape providing a resource for tourism. Extraction of steam could lead to subsidence.

Release of H_2S from a geothermal power station may have impacts on local vegetations. Arsenic and mercury in discharges from geothermal power generation may also have impacts on aquatic organisms.

The present standard in Indonesia applicable to H_2S emissions to the atmosphere from geothermal power stations is shown below. When we operate a geothermal power station, we need to comply with an applicable standard at that time. Local governments have discretion to establish more stringent standards than national ones.

Table 4.4-1 Emission Standard of Geothermal Power Stations in Indonesia

	Hydrogen Sulfide (H_2S)
Standard (mg/m^3)	35

Source: Decree of the Minister of Environment KEP-13/MENLH/3/1995

Present standard in Indonesia applicable to Mercury and Arsenic in effluents from geothermal power stations is shown below.

Table 4.4-2 Effluent Standards of Geothermal Power Stations in Indonesia

	Mercury (Hg)	Arsenic (As)
Standards (mg/ℓ)	0.005	0.5

Source: Decree of the Minister of Environment No.4(2007)

Carbon dioxide would be released from geothermal power generation to the atmosphere as a part of steam, but its emissions would be much smaller compared to those from fossil fuel-fired power generation.

Construction of a geothermal power station may have impacts on the surrounding environment through noises and vibrations, and water contaminations.

2) Measures against Potential Concerns

It is desirable not to site a geothermal power station at a location where people need to resettle for it. If distributions of geothermal resources make it inevitable to construct a geothermal power station there, necessity for its construction there shall be explained to those to be resettled, prior to the construction, to obtain their consent, and appropriate compensation shall be conducted. Areas to suffer offensive odor of H_2S or its metallic corrosions shall be predicted to conduct resettlement as required. Potential distributions of cultural heritages at the proposed construction site for a geothermal power station, and potential importance of its construction area as a resource for tourism, shall be properly investigated prior to its construction, so that there will be no significant impact on these.

Since H_2S from a geothermal power station could have impacts on local residents and vegetations, steam for power generation shall be analyzed prior to its construction to confirm that it can operate under compliance with the emission standard for H_2S mentioned above. Arsenic and mercury in effluents from the use of geothermal resources could also influence aquatic organisms, and potential effluents shall be analyzed in advance to confirm that it can satisfy also effluent standards for these (see above). Removal of H_2S to make its emissions to the atmosphere below the applicable standard, and the removal of arsenic and mercury from the effluents to reduce their concentrations below the relevant effluent standards are not practical when their cost-effectiveness is considered. It is a common practice to identify a steam well which can extract steam while complying with these standards.

Appropriate measures shall be taken against potential noises and vibrations and water contaminations during the construction period, so that relevant regulatory standards are satisfied.

In Jamali area, Tampomas Geothermal Power Station (50 MW), Cisolok Sukarame Geothermal Power Station (45 MW) and Tangkuban Geothermal Power Station (220 MW) are now under construction by IPP in West Java Province and expected to start their operation in 2011.

(4) Coal-Fired Thermal Power Plant

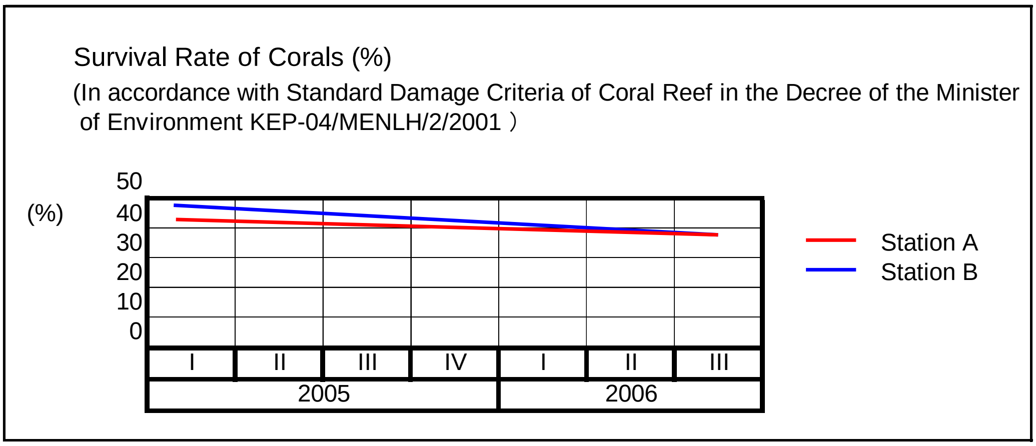
1) Potential Concerns

Construction of a coal-fired thermal power station may require resettlement of local residents to acquire a land for it. Its construction may have impacts on local cultural heritages. Habitats of endangered/precious/rare species and precious ecosystems may be lost for its construction, and it may have impacts on local landscape providing a resource for tourism.

Siting of a thermal or nuclear power station along a shoreline or large river, when it adopts an once-through cooling system, would lead to intakes of large amounts of cooling water, which may result in entrainments of larvae and juveniles of aquatic organisms and the impingements of adult fish against screens of water intakes, and may have impacts on occurrences of endangered/precious/rare species. Intakes of substantial amounts of cooling water may also influence the local fishery through their impacts on reproductions of commercial fish, and may eventually impact the life and livelihood of local fishermen. Discharges of substantial amounts of thermal effluents may further influence occurrences of aquatic organisms, such as endangered/precious/rare species, and they may also have impacts on reproductions of commercial fish, resulting in lower catches. As shown in

Fig.4.4-2, there are coral reefs off Jamali area, and discharges of thermal effluents may have impacts on them, if there occur corals in receiving water. If reclamations are required to create a land for a power station and/or associated port, there would be additional impacts on aquatic organisms.

One of the coal-fired power stations under the Fast Track Program, Suralaya Baru Power Station, is practically extension of existing Suralaya Power Station. For construction and operation of an additional unit, a separate Environmental Impact Assessment has been conducted for Suralaya Baru Power Station. Environmental Impact Statement (EIS) of Suralaya Baru Power Station provides results of the quarterly monitoring from February 2005 to August 2006 on survival of corals around existing Suralaya Power Station at two stations off Kelapa Tujuh Beach (see Fig.4.4-3). Survival rates of corals have been calculated in accordance with the Standard Damage Criteria of Coral Reef in the Decree of the Minister of Environment KEP-04/MENLH/2/2001.



Source: ANALISIS DAMPAK LINGKUNGAN (ANDAL) RENCANA PEMBANGUNAN PLTU I BANTEN DALAM RANGKA PEMGEMBENGAN PLTU SURALAYA – PT. INDONESIA POWER UNIT BISNIS PEMBANGKTAN SURALAYA

Fig.4.4-3 Survival Rates of Corals around Suralaya Power Station (at off Kelapa Tujuh Beach)

The EIS suggests that survival rates of corals occurring off Kelapa Tujuh Beach at about 1.5 km southeast to Suralaya Power Station have been decreasing gradually, and their survival rate as of August 2006 at Station A and Station B are 37.7% and 37.9%, respectively. It is supposed to be the increase of water temperature that has made the major contribution to the declines of survival rates of corals. When water temperature goes up more than 33°C, algae living symbiotically in corals will leave polyps to induce breaching of corals, and eventually corals will be destructed. As shown in Table 4.4-3 below, frequently recorded maximum temperature at Station A off Kelapa Tujuh Beach is 33°C, which is the tolerance limit for corals. Both at Station A and Station B, the maximum temperature is always no less than 30°C, which is more than temperature range of 23 to 30°C favorable for the growth of corals. Monitoring results of water temperature off Kelapa Tujuh Beach suggest that water temperature there is becoming not suitable for survival of corals.

Table 4.4-3 Monitoring Results of Water Temperature around Suralaya Power Station (off Kelapa Tujuh Beach)

Water Temp. (°C)	2005								2006					
	I		II		III		IV		I		II		III	
	A	B	A	B	A	B	A	B	A	B	A	B	A	B
Max. Temp.	33,0	30,0	33,0	31,0	33,0	32,0	32,0	31,0	31,5	32,0	31,0	32,0	33,5	30,0
Min. Temp.	21,0	28,5	28,0	28,0	28,0	28,5	28,5	28,0	28,0	28,0	28,0	28,5	28,0	23,5

A: Station A, B: Station B
Source: ANALISIS DAMPAK LINGKUNGAN (ANDAL) RENCANA PEMBANGUNAN PLTU I BANTEN DALAM RANGKA PEMGEMBENGAN PLTU SURALAYA – PT. INDONESIA POWER UNIT BISNIS PEMBANGKTAN SURALAYA

Decreasing survival rates of corals and the high water temperature mentioned above indicate that further increase of water temperature due to additional thermal effluents from a new thermal power station in its surrounding water could lead to further decrease of survival rates of corals and that operation of Suralaya Baru Power Station is not desirable for protection of corals.

As shown in Fig.4.4-2, there are coral reefs in some waters off Jamali area. In selection of sites for thermal power stations, whether construction and operation of a thermal power station are acceptable there shall be decided after due consideration of potential impacts of the temperature increase on survival of corals by thermal effluents from that thermal power station, taking advantage of monitoring results on survival of corals and seawater temperature.

Coal-fired power generation emits the largest amount of CO_2 per kWh among various types of power generation. In Indonesia, high-quality coal is for export, while low-quality coal is for domestic power generation. More CO_2 will be emitted from coal-fired power stations in Indonesia. Emissions of SO_2, NOx and suspended particulate matters (SPM) from a coal-fired power station may lead to air pollution. Dispersions of coal dusts and the seepages of leachate from coal storages may also create local environmental pollution. When coal ashes, such as bottom ashes and fly ashes, are piled in an open yard, they may disperse to the surroundings and deteriorate air quality there. Noises and vibrations from a power station may also pose threats to the well-being of local residents.

The present ambient air quality standards and emission standards applicable to coal-fired power stations in Indonesia are shown below. Local governments have discretion to establish more stringent standards than national ones.

Table 4.4-4 Ambient Air Quality Standards in Indonesia

Standard ($\mu g/m^3$)	Sulfur Dioxides (SO_2)	Nitrogen Oxides (NOx)	Suspended Particulate Matters
1-Hour Average	900	400	—
24-Hour Average	365	150	230
Annual Average	60	100	90

Source: Regulation Lampiran Peraturan Pemerintah Republik Indonesia Nomor 41 Tahun 1999

Table 4.4-5 Emission Standards of Coal-Fired Power Stations in Indonesia

	Sulfur Dioxides (SO_2)	Nitrogen Oxides (NOx)	Suspended Particulate Matters
Standard (mg/m^3)	750	850	150

* If 95% of normal operations during 3 months emit no more than the above standards, it is regarded to be in compliance with the standards.

Source: Decree of the Minister of Environment KEP-13/MENLH/3/1995

Below are monitoring results of the concentrations of suspended particulate matters in emissions from coal-fired Suralaya Power Station of Indonesian Power. The above-mentioned emission standard was exceeded in Units #1 and #2 at the second quarter of 2005, and in Unit #3 at the third quarter of 2005. Emission standards need to be satisfied. According to the monitoring report of this power station, maintenance work of its electrostatic precipitator was conducted to fix a glitch with it upon exceedance of the emission standard for suspended particulate matters.

Table 4.4.-6 Monitoring Results of the Concentrations of Suspended Particulate Matters in Emissions from Suralaya Power Station

	Standard	Unit	2005				2006				2007
			Quarter				Quarter				
			I	II	III	IV	I	II	III	IV	I
Unit 1	150	mg/Nm^3	130.00	197.00	148.00	115.00	130.10	99.95	118.97	123.17	126.24
Unit 2	150	mg/Nm^3	149.00	164.00	71.00	57.00	73.99	129.68	107.92	108.87	41.04
Unit 3	150	mg/Nm^3	52.00	32.00	154.00	77.00	132.97	117.38	123.86	116.48	50.38
Unit 4	150	mg/Nm^3	27.00	14.00	87.00	58.00	83.12	94.24	61.76	103.83	134.51
Unit 5	150	mg/Nm^3	44.00	80.00	109.00	143.00	102.57	119.91	143.67	132.44	78.83
Unit 6	150	mg/Nm^3	45.00	110.00	140.00	139.00	64.18	109.83	138.21	138.98	86.88
Unit 7	150	mg/Nm^3	58.00	147.00	149.00	116.00	146.65	126.93		104.15	122.51

Source: PEMANTAUAN PELAKSANAAN RKL DAN RPL PLTU SURALAYA UNIT 1-8 SEMESTER I TAHUN 2007 – PT. INDONESIA POWER UNIT BISNIS PEMBANGKTAN SURALAYA

Below are monitoring results of the ambient concentrations of suspended particulate matters in the atmosphere around Suralaya Power Station. Above-mentioned ambient air quality standard (24-hour average) was exceeded at Tapak UBP Suralaya Station at the first quarter of 2006. Although we can not conclude that the high concentration of suspended particulate matters is attributed to emissions from Suralaya Power Station, it is desirable to operate this power station in a manner to contribute to compliance with the ambient air quality standards.

Table 4.4.-7 Monitoring Results of the Ambient Concentrations of Suspended Particulate Matters in around Suralaya Power Station

Monitoring Station	Standard	Unit	2005				2006				2007
			Quarter				Quarter				
			I	II	III	IV	I	II	III	IV	I
LebakGede	230	μg/Nm^3	109.00	107.00	58.00	32.00	71.52	72.21	192.95	138.69	48.93
CipalaDua	230	μg/Nm^3	65.00	73.00	69.00	27.00	74.77	107.62	107.62	165.13	31.47
Brigil	230	μg/Nm^3	84.00	94.00	49.00	92.00	119.46	38.67	86.33	109	26.34
Gunug Gede	230	μg/Nm^3	54.00	74.00	65.00	85.00	22.69	103.97	115.89	84.54	70.45
Salira Indah	230	μg/Nm^3	50.00	89.00	146.00	74.00	16.28	54.15	113.34	109	10.95
Sumuranja	230	μg/Nm^3	70.00	90.00	125.00	30.00	117.09	72.31	113.44	128.14	37.58
Perumahan UBP Suralaya	230	μg/Nm^3	47.00	62.00	60.00	60.00	143.92	196.27	104.01	159.31	78.2
Tapak UBP Suralaya	230	μg/Nm^3	76.00	82.00	90.00	47.00	244.44	147.17	78.72	125.08	95.98

Source PEMANTAUAN PELAKSANAAN RKL DAN RPL PLTU SURALAYA UNIT 1-8 SEMESTER I TAHUN 2007 – PT.INDONESIA POWER UNIT BISNIS PEMBANGKTAN SURALAYA

Under the Fast Track Program, an additional unit is under construction next to the existing Suralaya Power Station. As mentioned above, exceedances of the emission standard have been already reported for this power station, and an exceedance of the ambient air quality standard has been recognized in its surrounding. If frequent exceedances of the ambient air quality standards occur after the new unit under the Fast Track Program comes into operation, it shall be considered whether the present electrostatic precipitators need to be upgraded to more efficient ones or additional bag filters need to be installed after the existing electrostatic precipitators.

Exceedances of the ambient air quality standard have been reported also for the existing Paiton Power Station of PT. PEMBANGKITAN JAWA BALI (PJB). Ambient air quality standards established by East Java Provincial Government (Decree of Governor of KDH Tk. I Jatim No.129/1996) are applicable to this power station, but as shown in the table below, ambient concentrations of NOx greatly exceeded its East Javanese quality standard at the meteorological station in May 2005 and also at the guesthouse in February 2006.

Under the Fast Track Program, an additional unit will be constructed next to the existing Paiton Power Station. If frequent exceedances of the ambient air quality standards occur after this new unit comes into operation, countermeasures such as retrofit of a denitrification facility shall be considered.

An internal document in PLN entitled "Summary of EIA of Rembang Power Station" (NOTA DINAS No.062/121/PD Y5/2008) suggests that this coal-fired power station under the Fast Track Program is designed to emit following concentrations of air pollutants.

Table 4.4.-8 Monitoring Results of Ambient Air Quality around Paiton Power Station

Date of Monitoring	Monitoring Station					
	Guesthouse			Meteorological Station		
	SO_2	NOx	SPM	SO_2	NOx	SPM
	Ambient Air Quality Standards of East Java Province (Decree of Governor of KDH Tk. I Jatim No.129/1996)					
	0.1ppm	0.05ppm	0.26mg/m^3	0.1ppm	0.05ppm	0.26mg/m^3
2004						
February		0.0237	0.0387		0.0190	0.0480
May		0.0149	0.0430		0.0280	0.0770
August		0.0170	0.0870		0.0310	0.1190
October	0.0033	0.0126	0.2030	0.0022	0.0118	0.1175
2005						
February	0.0091	0.0150	0.0534	0.0079	0.0171	0.0691
May	0.0474	0.0119	0.0834	0.0004	0.2775	0.1228
August	0.0077	0.0137	0.0862	0.0013	0.0154	0.0824
2006						
February	<0.0001	0.1025	0.0854	<0.0001	0.0238	0.0796
May	0.0020	0.0178	0.0543	0.0003	0.0299	0.0077

Source: ANALISIS DAMPAK LINGKUNGAN (ANDAL) PEMBANGUNAN PEMBANGKIT LISTRIK TENAGA UAP (PLTU) 2 JAWA TIMUR KAPASITAS 1 X (600-700) MW DI KABUPATEN PROBOLINGGO – PT. PEMBANGKITAN JAWA BALI (PJB)

Table 4.4-9 Designed Emission Concentrations of Air Pollutants from Rembang Coal-Fired Power Station

Pollutant	Designed Emission Conc.	Emission Standard*
SO_2	175 mg/m^3	750 mg/m^3
NO_2	1,005 mg/m^3	850 mg/m^3
Suspended Particulate Matters	139 mg/m^3	150 mg/m^3

* Central Javanese standards (Keputusan Gubermur Jawa Tengah No.10 tahun 2000)

Source: PLN internal document (NOTA DINAS No.062/121/PD Y5/2008)

The internal document in PLN admits that the designed emission concentration of NO_2 (1,005 mg/m^3) exceeds the emission standard of Central Java Province, but it predicts and evaluates that even under emissions of 1,005 mg/m^3, ambient concentrations of NO_2 in the air around the power station will remain below the applicable standard, and justify the construction of Rembang Power Station. The EIS of this power station has been already approved by the Environmental Management Division (BAPEDALDA) of Central Java Province, and its construction has been permitted. In its EIS, however, designed emission concentration of NO_2 is not mentioned. According to the environmental officer in PLN, a low-NOx burner was already in place in the original design of Rembang Power Station.

Construction of a power station with emissions of air pollutants in concentrations more than applicable emission standards will aggravate the air quality of the area, and compliance with applicable emission standards is very much required. Upon notification by the JICA Study Team, Sub-Directorate of Electricity Environmental Protection, Directorate of Electric Power Engineering & Environment, Directorate General of Electricity and Energy Use, the Ministry of Energy and Mineral Resources will issue an administrative guidance to PLN to require its compliance with applicable emission standards. The above environmental officer in PLN confirms that electricity output of

Rembang Power Station has been changed from its original 2 x 400MW to 2 x 315MW to reduce its NOx emissions from 1,005 mg/m^3 to below 756.48 mg/m^3 so that its NOx emissions can meet the relevant emission standard for NOx of 850 mg/m^3.

Baseline concentrations, or ambient concentrations prior to construction of a power station, of air pollutants at and around the proposed site for Rembang Power Station are also described in the internal document of PLN (NOTA DINAS No.062/121/PD Y5/2008).

Table 4.4-10 Baseline Concentrations of Air Pollutants at and around Proposed Rembang Power Station

Air Pollutant	Unit	Station				Standard*
		1	2	3	4	
SO_2	μg/m^3	2.44	16.75	12.15	13.75	365
NOx	μg/m^3	2.93	16.28	12.84	14.23	150
Suspended Particulate Matters	μg/m^3	253.00	319.15	138.30	776.59	230

Station 1：Proposed Rembang Power Station site
Station 2：Trahan Village (Pemukiman Desa Trahan)
Station 3：Leran Village (Pemukiman Desa Leran)
Station 4：Raya Pantura Street (Jalan Raya Pantura)
* Regulation Lampiran Peraturan Pemerintah Republik Indonesia Nomor 41 Tahun 1999

As is clearly shown in the table above, at the proposed construction site for Rembang Power Station and also at two stations around it (Trahan Village and Raya Pantura Street), ambient concentrations of suspended particulate matters are already above the applicable standard, even before construction of the power station. These suggest that further increase of ambient concentrations of suspended particulate matters due to operation of Rembang Power Station is not acceptable.

Monitoring results of existing Suralaya Power Station and Paiton Power Station and the internal document on proposed Rembang Power Station indicate that environmental controls such as the ambient air quality standards and emission standards are not respected enough in these power stations to contribute to the protection of air quality. Compliance with relevant environmental regulations is very much required for the construction and operation of power stations.

Construction of a coal-fired power station may have impacts on the surrounding environment through noises and vibrations, and water contaminations.

2) Measures against Potential Concerns

It is desirable not to site a coal-fired power station at a location where many people need to resettle for it. If engineering considerations make it inevitable to construct a coal-fired power station there, necessity for its construction there shall be explained to those to be resettled, to obtain their consent, and appropriate compensation shall be conducted. If impacts on the local fishery are expected by intakes of substantial amounts of cooling water and the discharges of significant amounts of thermal effluents, necessity to construct a power station shall be explained to local fishermen to obtain their consent, and appropriate compensation shall be conducted. Potential distributions of cultural heritages at its proposed construction site, and potential importance of its construction area as a resource for tourism, shall be also properly investigated prior to its construction, so that there will be no significant impact on these.

As for endangered/precious/rare species in Jamali area, those occurring in some national parks and/or nature reserves have been surveyed only for particular species, and occurrences of endangered/precious/rare species in the areas other than protected areas have been seldom studied. In order to confirm that the loss of habitats of wildlife due to preparation of a land for the proposed power station, as well as the intakes of substantial amounts of cooling water and the discharges of substantial amounts of thermal effluents, will not have significant impacts on endangered/precious/rare species and precious ecosystems, it is necessary to conduct sufficient field surveys around the proposed power station site prior to its construction, and to predict and evaluate potential impacts on these species and ecosystems by the construction and operation of the proposed power station. It is required to arrange locations of a power station, water intake and water discharge, so that they will not pose unacceptable impacts on endangered/precious/rare species and precious ecosystems. Other than the once-through cooling system, there is a cooling-tower cooling system, which circulates and recycles cooling water. In a cooling-tower cooling system, intakes of cooling water and discharges of thermal effluents are greatly decreased and their impacts are substantially reduced.

Emissions of CO_2 from coal-fired power generation can be reduced either by less uses of fuel or recovery of CO_2. Less consumptions of fuel require higher power generation efficiencies. Integrated Gasification Combined Cycle (IGCC), when put into practical use, will be an option. Technologies to capture CO_2 produced from industrial facilities and to store CO_2 underground or in ocean are already in practical use. Sequestrations of CO_2 once emitted to the atmosphere, by afforestations through photosynthesis are indirect recoveries of CO_2. If Kyoto Mechanisms continue to be available in future, financing these CO_2 emission reductions and recoveries through Clean Development Mechanism (CDM) may be worth considerations. The Government of Indonesian so far approved 65 CDM projects, but only 15 of them have been registered to the United Nations.

As for emissions of SO_2, NOx and suspended particulate matters (SPM) from a coal-fired thermal power station, their diffusions to the surrounding areas shall be predicted by simulations on the basis of their concentrations in the flue gas, emission rates of the flue gas, and meteorological and topographical data, to confirm that air quality in the surrounding areas will still comply with applicable air quality standards even after a coal-fired thermal power station comes into operation. If any of them is predicted to exceed the applicable standard, installation of a desulfurization (deSOx) /denitrification (deNOx) facility or electrostatic precipitator (ESP) shall be considered. It is also required to prevent dispersions of coal dusts and seepages of leachate from coal storages and the dispersions of coal ashes from coal disposals.

In addition to measures to prevent/reduce/mitigate potential air pollution, noises and vibrations, and water contaminations during operations of a power station, appropriate measures shall be taken against potential air pollution, noises and vibrations, and water contaminations during the construction period, so that relevant regulatory standards are satisfied.

(5) Oil-Fired Thermal Power Plant

1) Potential Concerns

As for potential resettlement for construction of thermal power stations and their potential impacts on cultural heritages, endangered/precious/rare species and precious ecosystems and landscapes, and potential impacts by intakes of cooling water and discharges of thermal effluents on the environment, see “(4) Coal-Fired Thermal Power Generation”.

According to PLN, proposed modification of HSD-fired Pemaron Power Station in Bali to a combined-cycle power station was withdrawn to protect dolphins off the island from substantial increase of thermal effluents, under guidance from the Provincial Government of Bali.

Oil-fired power generation emits the second largest amount of CO_2 per kWh, next to the coal-fired power generation. Emissions of SO_2, NOx and suspended particulate matters (SPM) from an oil-fired power station may lead to air pollution. If proper measures have not been taken against potential oil spills from oil tanks, they may lead to contaminations of the surrounding areas. Noises and vibrations from a power station may also pose threats to the well-being of local residents.

The present emission standards in Indonesia applicable to oil-fired power stations are shown below. When we construct an oil-fired power station, we need to comply with applicable standards at that time. Local governments have discretion to establish more stringent standards than national ones.

Table 4.4-11 Emission Standards of Oil-Fired Power Stations in Indonesia

	Sulfur Dioxides (SO_2)	Nitrogen Oxides (NOx)	Suspended Particulate Matters
Standard (mg/m^3)	800	1000	350

Source: Decree of the Minister of Environment KEP-13/MENLH/3/1995

As for potential impacts during construction, see “(4) Coal-Fired Thermal Power Generation”.

2) Measures against Potential Concerns

As for measures against potential resettlement, potential impacts on local fishery by intakes of cooling water and discharges of thermal effluents, potential impacts on cultural heritages, landscapes, and endangered/precious/rare species and precious ecosystems, see “(4) Coal-Fired Thermal Power Generation”.

There are two major actions to reduce CO_2 emissions from oil-fired power generation; 1) reduction of fuel use, and 2) recovery of CO_2. Generation efficiencies need to be improved to reduce the fuel use. Technologies to capture CO_2 produced from industrial facilities and to store CO_2 underground or in ocean are already in practical use. Sequestrations of CO_2 once emitted to the atmosphere, by afforestations through photosynthesis are indirect recoveries of CO_2. If Kyoto Mechanisms continue to be available in future, financing these CO_2 emission reductions and recoveries through Clean Development Mechanism (CDM) may be worth considerations.

As for measures against emissions of SO_2, NOx and suspended particulate matters (SPM) from oil-fired power stations, see “(4) Coal-Fired Thermal Power Generation”. It is also required to take appropriate measures against potential oil spills from oil tanks, so that accidental oil spills do not contaminate the surrounding environment.

As for measures against potential impacts during construction, see “(4) Coal-Fired Thermal Power Generation”.

(6) Natural Gas-Fired Thermal Power Plant (including Combined-Cycle Power Plant)

1) Potential Concerns

As for potential resettlement for construction of thermal power stations and their potential impacts on cultural heritages, endangered/precious/rare species and precious ecosystems and landscapes, and potential impacts by intakes of cooling water and discharges of thermal effluents on the environment, see “(4) Coal-Fired Thermal Power Generation”.

Natural gas-fired power generation emits the third largest amount of CO_2 per kWh, next to the coal-fired and oil-fired power generations. Emissions of NOx from a natural gas-fired power station may lead to air pollution. Noises and vibrations from a power station may also pose threats to the well-being of local residents.

The present emission standards in Indonesia applicable to natural gas-fired power stations are shown below. When we construct a natural gas-fired power station, we need to comply with applicable standards at that time. Local governments have discretion to establish more stringent standards than national ones.

Table 4.4-12 Emission Standards of Natural Gas-Fired Power Stations in Indonesia

	Sulfur Dioxides (SO_2)	Nitrogen Oxides (NOx)	Suspended Particulate Matters
Standard (mg/m^3)	800	1000	350

Source: Decree of the Minister of Environment KEP-13/MENLH/3/1995

As for potential impacts during construction, see “(4) Coal-Fired Thermal Power Generation”.

2) Measures against Potential Concerns

As for measures against potential resettlement, potential impacts on local fishery by intakes of cooling water and discharges of thermal effluents, potential impacts on cultural heritages, landscapes, and endangered/precious/rare species and precious ecosystems, see “(4) Coal-Fired Thermal Power Generation”.

As for reduction of CO_2 emissions from natural gas-fired power generation, see “(5) Oil-Fired Thermal Power Generation”.

As for NOx emissions from a natural gas-fired power station, its diffusions to the surrounding areas shall be predicted by simulations on the basis of its concentrations in the flue gas, emission rates of the flue gas, and meteorological and topographical data, to confirm that air quality in the surrounding areas will still comply with applicable air quality standards even after a natural gas-fired thermal power station comes into operation. If NOx emissions are predicted to exceed the applicable standard, installation of a denitrification (deNOx) facility shall be considered.

As for measures against potential impacts during construction, see “(4) Coal-Fired Thermal Power Generation”.

(7) Gas-Turbine Power Plant

1) Potential Concerns

Construction of a gas-turbine power station may require resettlement of local residents to acquire a land for it. However, even if resettlement is required, those to be resettled would be limited. Due to its relatively small scale, its impacts on fauna and flora, ecosystems, cultural heritages, and the local landscape would be also limited. Its impacts on the surrounding environment during its construction and operation would not likely to be extensive.

Gas-turbine power generation emits more CO_2 per kWh than natural gas-fired power generation (including combined-cycle power generation). However, gas-turbine power stations are mostly small in scale, and they emit less CO_2 per unit.

2) Measures against Potential Concerns

Although large-scale resettlement is not expected, it is desirable not to site a gas-turbine power station at a location where local people need to resettle. If engineering considerations make it inevitable to construct a gas-turbine power station there, necessity for its construction there shall be explained to those to be resettled, to obtain their consent, and appropriate compensation shall be conducted. Potential distributions of cultural heritages at its proposed construction site, and potential importance of its construction area as a resource for tourism, shall be properly investigated prior to its construction, so that there will be no significant impact on these.

Limited habitats of wildlife would be lost for construction of a gas-turbine power station, but fauna, flora and ecosystems in its proposed construction site shall be properly surveyed to confirm that there will be no impact on endangered/precious/rare species and precious ecosystems.

(8) Nuclear Power Plant

1) Potential Concerns

Construction of a nuclear power station, when many people are living in a vast area for it, may require large-scale resettlement of local residents. Its construction may have impacts on local cultural heritages. Habitats of endangered/precious/rare species and precious ecosystems may be lost for its construction, and it may have impacts on local landscape providing a resource for tourism.

As for potential impacts of intakes of cooling water and discharges of thermal effluents from nuclear power stations, see “(4) Coal-Fired Thermal Power Generation”. Fossil fuels are not combusted in nuclear power generation, so its power generation process itself does not emit CO_2 to make it a power generation method with the maximum effect to suppress global warming.

Noises and vibrations from operations of a nuclear power station may pose threats to the well-being of local residents. Its construction may also have impacts on the surrounding environment through air pollutions, noises and vibrations, and water contaminations.

Accidents in a nuclear power station and the troubles during transportations of nuclear fuel and spent fuel could leak radiation to contaminate the environment.

2) Measures against Potential Concerns

It is desirable not to site a nuclear power station at a location where many people need to resettle for it. Necessity for its construction shall be explained to those to be resettled, to obtain their consent, and appropriate compensation shall be conducted. Potential distributions of cultural heritages at its proposed construction site, and potential importance of its construction area as a resource for tourism, shall be also properly investigated prior to its construction, so that there will be no significant impact on these.

As for measures against potential impacts on endangered/precious/rare species and precious ecosystems, see "(4) Coal-Fired Thermal Power Generation".
As for measures against potential impacts during construction, see "(4) Coal-Fired Thermal Power Generation".

Radiation leaks at accidents in a nuclear power station would have significant impacts on the local residents and environment, so measures to prevent possible accidents shall be taken, and actions against radiation leaks shall be determined in advance. According to the environmental officers of the Ministry of Energy and Natural Resources and PLN, there is no safety standard for nuclear power stations in Indonesia at the moment.

In Indonesia, construction of a nuclear power station is proposed at Muria Peninsula of Java, and it is expected to be in operation in 2018. There are four protected areas, such as Gunung Celering Strict Nature Reserve, Keling IA/B/C Strict Nature Reserve, Keling I/II Strict Nature Reserve, and Kembang Strict Nature Reserve in Muria Peninsula, but the proposed site is far from these protected areas.

(9) Wind Power Plant

1) Potential Concerns

As for potential resettlement for construction of wind power stations, their potential impacts on fauna and flora, ecosystems and cultural heritages, and potential impacts during construction, see "(7) Gas-Turbine Power Generation".

Radio interference by their towers, noises of the wind roaring by their blades, collisions of birds against their rotating blades, and impacts on local landscape are among environmental impacts specific to the wind power generation.

Wind power generation does not produce CO_2, and it is effective to suppress global warming. Its power output, however, depends on local wind conditions, and its introduction into a grid, when introduced in a large number, could hinder stable supply of electricity.

2) Measures against Potential Concerns

Although large-scale resettlement is not expected, it is desirable not to site a wind park at a location where local people need to resettle. If wind conditions and/or engineering considerations make it inevitable to construct a wind park there, necessity for its construction there shall be explained to those to be resettled, to obtain their consent. Those who may suffer from radio interference by wind towers and/or the noises of wind roaring by blades shall be predicted, and actions against them, such as establishment of a community antenna, or appropriate compensations shall be conducted. Potential distributions of cultural heritages at its proposed construction site, and potential importance of its construction area as a resource for tourism, shall be properly investigated prior to its construction, so that there will be no significant impact on these.

It shall be confirmed in advance that the proposed wind park is not located on the aviation route of endangered/precious/rare species of birds so that their potential collisions against rotating blades do not pose significant impacts on their occurrences.

(10) Solar Power Plant

1) Potential Concerns

As for potential resettlement for construction of solar power stations, their potential impacts on fauna and flora, ecosystems and cultural heritages, and potential impacts during construction, see “(7) Gas-Turbine Power Generation”.

Solar power generation does not produce CO_2, and it is effective to suppress global warming. Its power output, however, depends on local insolation conditions, and its introduction into a grid, when introduced in a large number, could hinder stable supply of electricity.

2) Measures against Potential Concerns

Although large-scale resettlement is not expected, it is desirable not to site a solar power station at a location where local people need to resettle. If insolation conditions and/or engineering considerations make it inevitable to construct a solar power station there, necessity for its construction there shall be explained to those to be resettled, to obtain their consent. Potential distributions of endangered/precious/rare species and cultural heritages at its proposed construction site, and potential importance of its construction area as a resource for tourism, shall be properly investigated prior to its construction, so that there will be no significant impact on these.

(11) Biomass-Fired Power Plant

1) Potential Concerns

As for potential resettlement for construction of thermal power stations and their potential impacts on cultural heritages, endangered/precious/rare species and precious ecosystems and landscapes, and potential impacts by intakes of cooling water and discharges of thermal effluents on the environment, see “(4) Coal-Fired Thermal Power Generation”.

In biomass-fired power generation, organic matters produced by plants through their sequestration of CO_2 from the atmosphere are combusted to generate electricity, and this is regarded as “carbon neutral” and assumed to emit no CO_2. On the other hand, biomass-fired power generation releases SO_2, NOx and suspended particulate matters

(SPM) in its flue gas to be a potential source of air pollution. When ashes are piled in an open yard, they may disperse to the surroundings and deteriorate air quality there. Noises and vibrations from a power station may also pose threats to the well-being of local residents.

Construction of a biomass-fired power station may have impacts on the surrounding environment through air pollution, noises and vibrations, and water contaminations.

2) Measures against Potential Concerns

Although large-scale resettlement is not expected, it is desirable not to site a biomass-fired power station at a location where local people need to resettle for it. If engineering considerations make it inevitable to construct a biomass-fired power station there, necessity for its construction there shall be explained to those to be resettled, to obtain their consent. Potential distributions of cultural heritages at its proposed construction site, and potential importance of its construction area as a resource for tourism, shall be also properly investigated prior to its construction, so that there will be no significant impact on these.

As for measures against potential impacts on endangered/precious/rare species and precious ecosystems, see "(4) Coal-Fired Thermal Power Generation".

Biomass-fired power generation is regarded as "carbon neutral" and assumed not to emit CO_2 from its power generation process. Transportations of biomasses to a power station by trains, trucks and vessels, however, require fossil fuels such as gasoline, diesel oil and heavy oil, and they emit CO_2. If biomasses are collected from wider areas and transported for long distances for power generation, "leakage", or CO_2 emissions by their transportations, may offset suppression of global warming by biomass-fired power generation through its replacement of fossil-fired power generation, and disqualify it as power generation friendly to global environment. Special attentions are required to this.

As for measures against emissions of SO_2, NOx and suspended particulate matters (SPM) from a biomass-fired power station, see "(4) Coal-Fired Thermal Power Generation". It is also required to prevent dispersions of ashes from ash disposals and to consider their utilizations.

As for measures against potential impacts during construction, see "(4) Coal-Fired Thermal Power Generation".

Biomass-fired power generation may use edible parts of agricultural products, such as corns, or phytogenic wastes, such as bagasse, rice husks and matchwoods, which are already utilized, to generate electricity. In these cases, there may occur conflicts with consumption of agricultural products as food or utilizations of phytogenic wastes by other industries. Special attentions shall be made when biomass is used for power generation.

Recently in Central Java Province, Sumitomo Forestry Co., Ltd. proposed a CDM project to reduce CO_2 emissions from diesel power generation, by replacing it with biomass-fired power generation. Woody biomass-fired power generator of 4 W would be introduced to a particle board factory. This project was registered to the United Nations as a CDM project on May 23, 2008.

(12) High-Voltage Transmission Lines (500 V)

1) Potential Concerns

Construction of transmission towers, when a transmission line goes through a populated area, may require resettlement of some local residents. However, those to be resettled would be limited. On the other hand, a transmission line may have impacts on local landscape providing a resource for tourism, and it could cause local radio interference.

A long strip of open land without tall trees along a transmission line could restrict migrations across its ROW of arboreal monkeys and the small animals, such as rodents, vulnerable to attacks by accipitral birds, and split their habitats. In addition, a transmission line may provide an access to an unexploited area, to induce poaching/ deforestation.

Construction of transmission towers and the wiring of transmission cables would produce noises and vibrations with potential impacts on local residents, but they are only temporal and a limited area would be impacted. Operations of transmission lines do not emit greenhouse gas.

2) Measures against Potential Concerns

It is desirable not to site a transmission tower at a location where people need to resettle for it. If engineering considerations make it inevitable to construct a transmission tower there, necessity for its construction there shall be explained to those to be resettled, to obtain their consent, and appropriate compensation shall be conducted. Potential importance of the area along the proposed transmission line as a resource for tourism shall be properly investigated prior to its construction, so that there will be no significant impact on it. When there occurs local radio interference, actions against it, such as the installation of a community antenna, shall be taken.

Occurrences of wild animals along the proposed transmission route shall be surveyed carefully, so that the installation of a transmission line does not prevent their migrations across its ROW. Access to unexploited areas through its ROW shall be restricted by establishing gates, and periodical patrols shall be conducted to prevent poaching/illegal logging.

(13) Zero Option

In Zero Option, or No Action Alternative, no new power station or transmission line will be constructed. Although power shortages will not be solved, no resettlement of people will be required, and there will be no impact on cultural heritages/landscape. There also will be no impact on fauna and flora and the ecosystems. No greenhouse gas will be released.

Environmental performances of the major types of power generation discussed above are summarized in the table below. Environmental impacts completely subject to the location of power stations are not included in this table.

Table 4.4-13 Environmental Performances of Major Types of Power Generation

	Coal-Fired	Oil-Fired	Gas-Fired	Geothermal	Hydro	Nuclear
Air Pollution	SO_2, NOx, SPM	SO_2, NOx, SPM	NOx	H_2S	-	-
Water Pollution	From Coal Storage/ Ash Disposal	-	-	As, Hg	Water Quality Degradation in Reservoir	-
Greenhouse Gas Emission	CO_2	CO_2	CO_2	-	CH_4 from Reservoir	-
Thermal Effluent	Substantial Amount	Substantial Amount	Substantial Amount	Limited Amount	-	Substantial Amount
Involuntary Resettlement	Possible	Possible	Possible	-	May be Large-Scale	May be Large-Scale
River Water Use	-	-	-	-	Impacts Likely	-
Radiation Risk	-	-	-	-	-	Potential

4.4.5 Constraints on Power Development Scenarios by Environmental and Social Considerations

As mentioned in "4.4.3 Special Features of the Strategic Environmental Assessment for Study on the Optimal Power Development Scenario in Java-Madura-Bali Area", power stations to be introduced up to 2016 are completely identical in the Alternative Scenarios 0 to 3, and there is no difference between scenarios. On the other hand, power sources to be introduced after 2017 differ between scenarios, but sites for individual power stations are yet to be proposed.

In our identification of power development scenarios, we have considered potential impacts of individual types of power generation on natural and social environment as discussed above, and we have created scenarios so that particular environmental loads will not be produced excessively. For example, while thermal and nuclear power generation may have impacts on marine organisms and local fishery through thermal effluents, hydroelectric power generation may require large-scale resettlement of local residents. In the present study, we have created scenarios without too much reliance on a particular type of power generation, in order to exclude repeated occurrences of a particular environmental impact and to achieve "diversification of risk".

4.5. Power Development Scenario

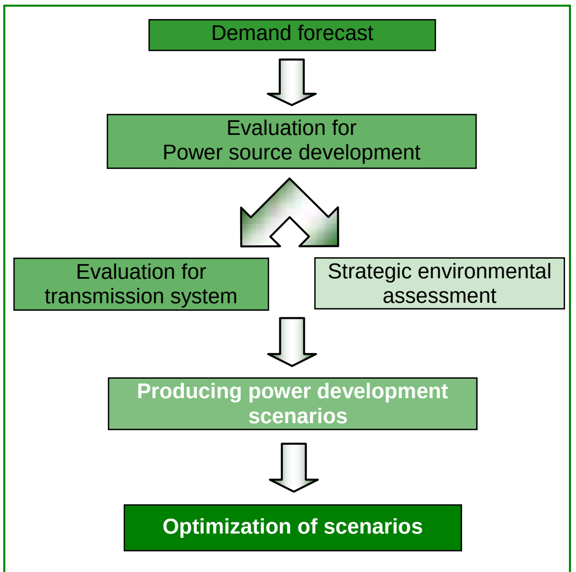
4.5.1 Concept of Power Development Scenario

(1) Framework of Planning

To determine the optimum power development plan, firstly we need to identify the most important factors in a power development plan, such as economy, stability and reliability of power supply and environment, in defining the optimality of power mix. Then we need to examine methods of evaluation for these factors, giving consideration to such issues that are not included in the available power development optimization applications and/or systematic planning software. Further, it is also necessary to consider the target values of energy mix stipulated in the existing policies, KEN, RUKN, etc.

Indonesian energy policy is at the moment focusing on reducing oil consumption in the power sector by large proportion. While base load power sources are to be rapidly increased by ongoing coal thermal power projects under the FTP, it is urgently necessary now to augment power sources for middle and the peak load. It is understood that gas-fired thermal plants and reservoir type hydro including pumped storage hydro are the strong candidates for these places. Among these candidates, gas-fired thermal becomes effective for the middle and/or peak load plant only if gas supply is available, which is not the case so far. Making gas supply available requires studies on the possibility of changing terms and conditions of a contract between supplier and offtaker, or providing a facility that absorbs temporal supply-demand difference, such as gas storage tank, placed between the pipeline end and power plant's receiving end valve.

The flowchart of alternative power development scenario and its optimization is shown in the figure on the right hand side.



Optimization Flowchart

The optimal power development scenario is examined to make overall power supply economical, stable and reliable, and environmentally friendly. The recent skyrocketing oil price has already put a huge pressure on the finance of the government and PLN. The higher market price of oil tends to divert more oil product to exporting, which makes securing oil for home consumption more difficult. This situation gives an extremely large adverse effect on energy and power policy and management of power production/sales in Indonesia. Decrease of oil usage in power production is the first priority in power development scenarios.

Various policies have been released by the government on energy and electric power. Power plant development in massive scale to attempt reducing oil consumption is in progress. Aside from the cases where small-scale diesel engine plants are being used in remote areas and gas turbine or combined cycle plants are using oil unwillingly due to the shortage of natural gas supply, oil fuel usage is to be reduced as much as possible by these policies.

On the other hand, it is difficult to secure sufficient power sources substituting for oil-burning plants. Gas supply is very slow to materialize and hydropower development has not even started yet. Therefore, large-scale coal-fired power plant development and pumped storage hydro development are being advanced. Negative social and environmental impacts due to exhaust and thermal water discharge may result when several coal thermal power plants are developed on a limited stretch of land. These phenomena are perceived as the downside of substituting coal for oil. Existing policies, economy and positive/negative impacts of power generation should be evaluated as a whole to make scenarios. First, the policy oriented scenario shall be drafted on the basis of current situations, ongoing projects, and the state development plans and policies. Next, alternative scenarios shall be drafted one by one, by shifting priority to generation cost, stability and reliability of power supply, and impacts on global environment, respectively.

Each scenario is given a long-term objective in the first place, and developed into a specific plan. Configuration of power generation and transmission systems that meets effectively the maximum power demand and energy in 2028 is the long-term goal of each scenario.

The electric power demand is forecasted for three cases: the base case with 6.5% per annum demand growth, the high case, and the low case. The power development plan is to satisfy the base case. In the plan, reserve margin is kept at 30%, which is the present rate and judged to be adequate in consideration of various factors like derating of plant output, occurrences of unscheduled outage (assumed from the record), LOLP (less than a day a year is the regulation in Indonesia), and probable variability of river discharge affecting hydropower output (assumed from the record).

Installed capacity in Jamali system is 22.3 GW (PLN 18.4 GW and IPP 3.9 GW), and the produced energy is 104.8 TWh (PLN 79.9 TWh and IPP 24.9 TWh) in 2006. In the base case of demand forecast, annual growth of 6.5% is expected for both maximum power and energy in Jamali region which means they will double in 11 years. Produced energy is 406.6 TWh and the maximum power demand reaches 62.5 GW in 2028. In the power development plan, when the reserve margin of 30% is set, installed capacity must be 81.2 GW in 2028 against the maximum power demand. Suppose Java-Sumatra system provides 3 GW of power to Jamali, additional capacity of 78.2 GW should be developed in Jamali system. IPPs must and will complement the capacity increase of PLN. In IPP projects, coal and the geothermal plants are main means of generation so far.

(2) Development Plan for Power Generation and Transmission

As for current power sources, coal, geothermal and small-hydro are used to meet the base load and oil, gas, and reservoir type hydro to middle to peak load. Coal, geothermal, and nuclear will be main candidates for base load generators under the demand increase in the future. Natural gas including LNG, and reservoir type hydro and pumped storage hydro are main candidate power for peak load. Small hydro, wind, solar, and biomass (bio-fuel), etc. are expected as renewable sources, too. Moreover, there is a plan to transmit power generated on Sumatra and Kalimantan Islands to Java Island via submarine cables. The candidate power sources and the transmission system in the future are considered as follows.

Coal-fired thermal will be the main substitution for oil thermal in the future. The FTP is now in progress over the country. Capacity of 10,000 MW in total, and 6,900 MW in Jamali region, is scheduled to be developed by 2010/11. The power plant constructions are steadily being advanced although the delay for a year or two has already been observed. Procurement of low rank coal produced in Sumatra and Kalimantan is still not all certain. Coal-fired plant sites tend to be located adjacent to existing plants as an extension taking advantage of existing infrastructure such as piers, belt conveyers, coal-storage yard, and flyash disposal site, etc. But such an extension aggravates the environmental impact to the surrounding area in the form of more exhaust and thermal water discharge. This is the rationale of building new coal-fired thermal power plants on other islands than on densely populated Java Island. Electricity generated at such power plants will be transmitted via submarine cables to Jamali system.

All the three gas-fired power plant projects financed by JBIC (Muara Karang: 694 MW, Muara Tawar: 241 MW, Tanjung Priok: 743 MW, and 1,678 MW in total) currently under construction are scheduled to commence commercial operation by 2010[10]. Considering the capacity of the gas pipelines, there is no possibility of building gas-fired power plants in addition to these on-going projects. LNG, which can be stored, enables flexible and variable gas use and can be fed to power plants operated for middle to peak load. Bojanegara CC with LNG (4@750 MW = 3,000 MW, to be put into the system from 2015 to 2018) is planned. However, LNG fuel is export oriented, and is difficult to supply domestic consumers unless long-term procurement system (policy support and contract, etc.) for the domestic consumption is established. Moreover, it is necessary to advance funding arrangements and developments of infrastructure such as LNG sea vessels and gasification bases which are very costly.

Geothermal power development is being advanced with a goal of the long-term energy ratio of 5%, following the policy of promoting renewable energy set out in the road map (852 MW in 2006, 4,600 MW in 2016, and 9,500 MW in 2025 in whole Indonesia) although the construction cost is expensive. The capacity of 835 MW has already been developed in Jamali region. The aggregate capacity of priority sites is 785 MW, and the feasible capacity 2,015

[10] PLN Report, NERACA DAYA SISTEM JAWA-BALI 2008/2009－2018, 2008 April

MW. All combined, 3,635 MW may be developed by 2025[11]. Therefore, attaining capacity ratio of 5% in 2025 is a possibility.

After the expansion of 500 MW at Cirata hydropower plant was completed in 1998, no reservoir type hydro has been constructed for ten years in Jamali system. PLN became seemingly reluctant to take on a hydropower development after the Asian economic crisis in 1997-1998 even though the potential of reservoir type and run-of-river type hydro development had been studied and identified before the crisis. The government has been preoccupied to decrease large debts of the nation and PLN and restore financial balances after the crisis. As a hydropower requires larger initial investment than power plants of other types, its development has been avoided so as not to increase the debts. Moreover, after the Suharto regime collapsed in May 1998, decentralization and democratization gradually unfolded, and the government refrains from land expropriation and involuntary resettlement. This situation does not necessarily provide better opportunity for hydropower development. However, hydropower being free from fuel price risk does make economic sense today, and its development policy should be reviewed again in the light of lower operation cost and supply stability. After such review, hydropower development should be resumed from those projects with better prospects.

Pumped storage hydro is expected to supply peak power in the future. The ratio of generation capacity to required reservoir areas for a pumped storage power plant is smaller than that of reservoir type, hence natural and social environmental impacts are smaller, in general. Therefore, it is thought that pumped storage plant is more desirable with respect to land acquisition and involuntary resettlement. There is an energy loss of about 25% by the cycle of pumping and power generation but it is less significant under the situation where the price difference between coal and oil is getting wider. The system that is economical and responsive to peak load can be achieved by combining pumped storage hydro and coal thermal. Pumped storage development investigation has been executed for several sites. Among them Upper Cisokan PS is expected to be available at the earliest date because a detailed design was already done, and it is ready to be advanced to the implementation stage. However, other pumped storage projects also should be studied further as their studies are still at below F/S level.

If nuclear power is developed at the Muria Peninsula, starting its commercial operation by 2018 is still a possibility. Accumulation of experience of safety operation and confirmation of operator education is necessary, which requires development of power station in several steps, minimum two-year interval between installations of 1,000 MW units, possibly reaching 4,000 MW or 5,000 MW in total in 2028. The delay from the road map is already identified as described earlier, and further delay is anticipated. When nuclear power development is delayed, it will be a coal thermal power that will take its place as base load source. Therefore, the risk

[11] JICA Report, Master Plan Study for Geothermal Power Development in the Republic of Indonesia, 2007

of planning nuclear is high, and this risk should be a factor considered in the scenarios.

Biomass or bio-fuel does not contribute to power generation now. Meanwhile, the government plans to develop bio-fuel like bio-ethanol from palm oil or sugar cane, etc., to become 5% of the primary energy in national energy usage by 2025. Although the use in power generation is possible as a substitution for diesel oil, biomass fuel is expected to be used chiefly for transportation. To decrease the global environmental effect of fossil fuel use, promotion of biomass use is desirable.

Renewable energy development of small hydropower, solar power, and wind power, etc. are expected over the globe. CO_2 emission is effectively reduced by renewable energy, which helps mitigate global warming. Indonesian government states the target of renewable energy use should be 3% in 2025 on primary energy basis (nuclear power 2% is deducted from the total renewable energy 5%). Although nuclear power plants have disadvantage of high initial cost, nuclear will be promoted by the policy. As for solar power, its manufacturing cost is expected to decrease in the future, which will give solar power a competitive edge.

Japan has been a leader of solar power sector in the world. Japanese manufactures kept the largest production volume of solar (photovoltaic) cells in the world and accumulated installed capacity in Japan had been also largest by 2004 but became next to Germany in 2005. The accumulated capacity reached 1,421 MW in Japan and 1,429 MW in Germany in 2005. Japanese government forecast the accumulated capacity of about 100 GW as of 2030[12]. The energy production of 100 GW by solar cells will cover about 10 % of total energy demand in Japan. Cost reduction and promotion strategies are key elements to meet the target. Same methodology will be also effective for Indonesia.

Power generation cost of solar is expected to be reduced in large proportion in the future. The present cost, Yen 46 per kWh is two times of power tariff, Yen 23 per kWh, for household users in Japan. Present unit cost to install 4 kW system to a household is about Yen 230 million on average. But the generation cost is expected to be down to Yen 14 per kWh in 2020 and Yen 7 per kWh in 2030. Technology advancement of solar cells and related systems will bring competitiveness with other power sources. Besides cost reduction, the power system improvement is necessary to accept solar power in a large scale. The existing power system should be adapted to allow reverse flow from solar battery to existing distribution lines.

With regard to the spatial distribution of power plants, it is preferable to develop power plants in West Java region where demand is high on the system. There is a large current from East Java to West Java now. If the candidate site of nuclear power is relocated or its development is delayed, the overall transmission system plan may have to be revised. Moreover, Java - Sumatra interconnection is planned along with mine-mouth coal thermal power development in

[12] NEW ENERGY AND INDUSTRIAL TECHNOLOGY DEVELOPMENT ORGANIZATION, Overview of “PV Roadmap Toward 2030” (PV2030), June 2004

the southern Sumatra. This may eventually lead to the Indochina power system interconnection plan. There are also plans to develop hydropower, coal thermal power, and nuclear power outside Java Island, in order to stimulate economic development on outer islands or to alleviate environmental degradation on Java Island. Construction and operation of large-scale power plant like mine-mouth thermal power etc. will accelerate industrialization of regional economies of Sumatra and Kalimantan. Besides, Java Island is already densely populated, and it is becoming more and more difficult to secure sites for future power plant.

4.5.2 Alternative Scenarios

(1) Priority Set in Each Scenario

Some alternative scenarios are drawn out first and optimization process is undertaken by comparison of scenarios. In Indonesia the target of primary energy mix for the power sector is set up in RUKN or RUPTL. One scenario can be drawn to follow up this target. Other alternative scenarios give priority to one of the following three themes in power development planning:

a. Lower generation cost (priority to coal),
b. Reliable and stable power supply system,
c. Less global environmental impact.

In the first option with the priority given to low generation cost, oil use is given up at the earliest possible stage and coal power will be introduced instead. In the second option with the priority on reliable and stable power supply system, primary energy mix is diversified more, and LNG for peak power is developed additionally. In the third option of mitigating global environmental impact, CO_2 emission is to be reduced as much as possible. Each scenario follows the plant expansion plan until 2016 indicated in RUPTL 2007/16 in a short term. It is assumed in each option that some power is supplied (about 3,000 MW) from Sumatra via submarine cable[13].

(2) Policy Oriented Scenario (Scenario 0)

The policy oriented scenario meets the target of primary energy policy or power generation development plan that Indonesian government or PLN has announced. The target values of the policy and the plan are indicated in Table 4.5-1.

Oil fuel use is to be held down as much as possible in current policies and plans. Further, it seems that gas use ratio is smaller in RUKN than in others because power generation using LNG will not be in time by 2010.

The long-term target values for primary energy mix in the policy oriented scenario were set up on the basis of these policies and plans as shown in Table 4.5-1. The scenario is to be an

[13] 500 kV submarine cable is planned to connect Java to Sumatera with some political priority.

electric power development plan that satisfies the target shown in the table. Besides, in the case where power is transmitted from mine-mouth coal thermal plants in Sumatra to Jamali system, produced energy by coal thermal in Jamali must be reduced by the transmitted energy (Modification in policy oriented scenario).

Table 4.5-1 Target of Primary Energy Consumption for Power Sector

Description Target year	RUKN 2010	RUPTL 2016	Energy Outlook[14] 2025	Estimation in Policy oriented scenario 2028	Modification in Policy oriented scenario 2028
Oil	2	0.2	3.1	0.2－3	0.2－3
Coal	71	72.1	64.9	65－72	62－70
Gas	12	18.6	18.8	12－19	12－19
Geothermal	7	9.1	13.1	5－7	5－7
Hydro	8			4－8	4－8
Others (Nuclear, etc)	0	0		4－9	4－9
Transmit from Sumatera	0	0	0	0	2－3
Total (%)	100	100	100	100	100

Note: Primary energy consumption is estimated for overall Indonesia.
The longest term target year is different among policies or plans.
Capacity balance in 2021 in RUPTL shows that Coal 59%, Gas 16 %, Oil 7 %, Hydro 6 %, Geothermal 2 % and Nuclear 10 %. But the plan for energy consumption is only up to 2010 in RUPTL.

Geothermal, nuclear power, and coal are the main sources for base load and LNG, reservoir type hydro, and pumped storage are the main candidate sources to meet peak load. Except these, small hydropower, wind power, solar power, and biomass fuel, etc. are considered in aggregate as “other candidates”. The energy consumption by fuel in 2006 and 2028 are shown in Fig.4.5-1.

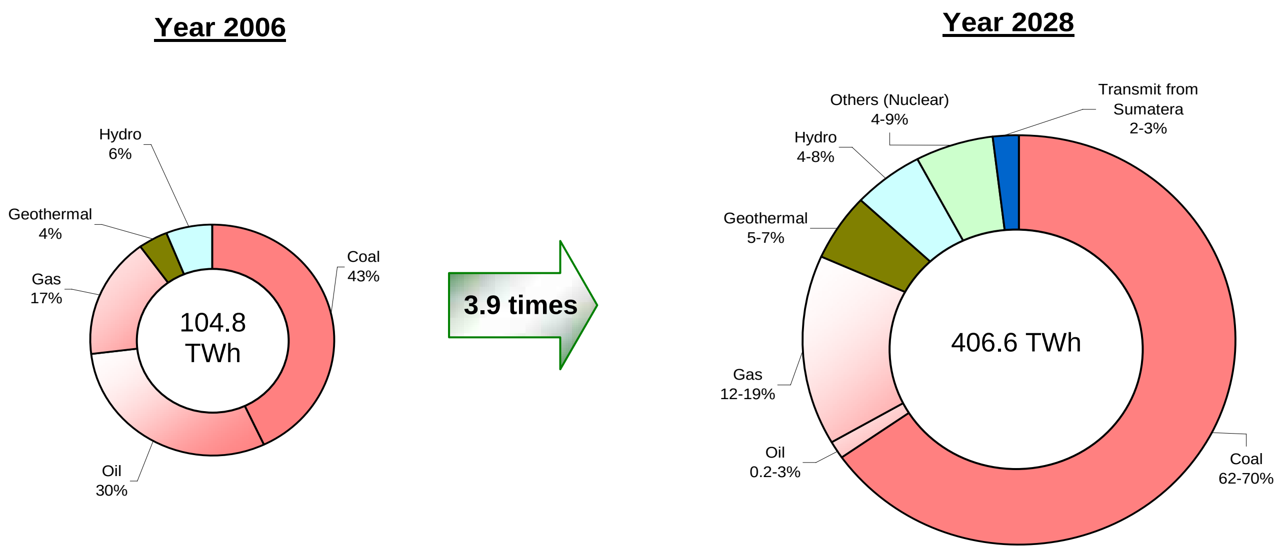


Fig.4.5-1 Change of Primary Energy Consumption by Fuel (Policy oriented scenario)

[14] Pengkajian energi universitas Indonesia, Indonesia energy outlook & statistics 2006

The short-term power development plan in RUPTL 2007/2016 recommends that geothermal and coal as domestically produced primary energy are planned to be developed. For those ongoing projects whose actual project schedules are delayed, such as those in the FTP and hydropower (Upper Cisokan and Rajamandala, etc.), the delays are considered in the scenario. Where gas supply program is uncertain, only certain gas projects are taken into the policy oriented scenario, as so done in RUPTL.

In the mid or long-term, LNG, pumped storage, and nuclear power which are likely to be implemented are taken into the scenario. The power supply from Sumatra is considered. Capacity ratio of gas plants, 12% (target in 2010 in RUKN's short-term development plan), is assumed to be maintained. Among renewable energy sources, geothermal is given a certain place for its potential and environmental benefit. Geothermal can be developed further, and the long-term target of geothermal is decided to be 5% on primary energy basis, considering the promotion policy and its potential. Hydropower development has been received with antipathy especially for the past ten years due to possible negative social and natural environmental impacts. But hydropower potential is still large in Jamali region. Hydro is assumed to be developed up to 4-8% of total capacity, following the policy. Nuclear power is assumed to be developed up to 4-5 GW by 2028. It is further assumed that biomass fuel, wind power, and solar power are negligible. The total energy balance will be covered by coal development (produced energy of 62 ~ 70%). On the basis of the above assumptions and conditions, WASP, the least cost power development analysis software, is applied to calculate the power plant scheduling and energy production.

(3) Coal Power Development Scenario (Scenario 1)

This scenario aims at decreasing the total generation cost from the policy oriented scenario. The scenario points to more development of coal and nuclear power plants. Main power source of the system becomes coal thermal power for base load and both its capacity and energy produced will be increased in proportion.

Coal thermal power is to be developed more expansively if lowering generation cost is the first priority of the scheme. Coal fuel is domestically produced, and the reserve is large enough for the long time, and its price on calorie basis is extremely lower than oil. Gas price has soared following that of oil, and LNG price is almost equal to oil on calorie basis. Therefore, gas power generation is assumed to be developed only for ongoing projects. Gas-fired power plants take 17% (3.76 GW) of Jamali installed capacity today. JBIC-funded three (3) power plants, 1,678 MW in total capacity, are under construction. In addition, Bojanegara LNG, the capacity of 3,000 MW has been included in the existing power development plan. As a result, total installed capacity of gas-fired plants will be 81.2 GW, that is 10.4% of Jamali system as of 2028 (retirement of existing gas thermal power plants is ignored here).

Because power generation cost of geothermal is high, it is assumed that those candidate sites classified as “most feasible” only, 785 MW in aggregate, will be constructed and total capacity in 2028 will be 1,620 MW including currently running 835 MW, which will be 2% of the Jamali system. Reservoir type hydropower is not assumed to make any progress because the initial cost of reservoir type hydropower is high. On the other hand, pumped storage hydro is an economic option when combined with coal thermal power, and contributes to peak power supply. Its economy is evaluated with WASP and development possibility and desirable capacity are examined. As for nuclear power, the development road map shows that up to 5 GW is to be installed by 2028. This is taken as the target for the scenario. Renewable energy is negligible because of its high initial cost and small share in the system.

(4) Power Source Diversification Scenario (Scenario 2)

This scenario, which gives priority to reliable and stable power supply system, reflects the current situation that the prospect of primary energy supply and procurement in the future is quite uncertain everywhere in the world. Thus power sources shall be diversified.

In the policy oriented scenario or the lower generation cost scenario the proportion of coal becomes about 70% on primary energy basis. Excessive dependence on coal is not a good policy in avoiding the risk of coal supply. Therefore, nuclear, geothermal, and hydro should be developed more than in preceding scenarios. Renewable energy; solar power, wind power, and biomass fuel should be developed as well to diversify primary energy sources more. In this scheme, oil is retained to some degree, and gas is subject to LNG development.

LNG development as a substitution for oil has a large impact on power development planning. Recently, LNG price has soared to the level equivalent to oil. Bojanegara LNG, with four 750 MW units and total capacity of 3,000 MW, is scheduled to be put in operation by one unit a year from 2015. However, there is a possibility that LNG use in further power development may not be expanded after Bojanegara. PLN may find it more convenient to use oil than LNG due to the better availability of the former, if their prices are about the same. If LNG is made available to PLN in a reliable manner at other power stations, the advantage of LNG-fired power plants for peak load may persuade PLN to convert currently oil-fired steam (PLTU) and combined cycle (PLTGU) to LNG-fired plants. Following the government policy, the primary energy ratio target of natural gas is set at 19%.

For geothermal, feasible development potential of 3.6 GW (4.5% of required capacity in 2028) is set as a target. Hydropower including those with reservoirs should be developed as much as possible because it is domestically produced energy and there is no fuel cost involved. The target value is set at 4 - 8% in capacity following the government policy. A pumped storage hydro is an economic option when combined with coal thermal power, and contributes to peak power supply. Its economy is evaluated by WASP simulations and development possibility and desirable capacity are examined. As for nuclear power, the development road map shows that up to 5 GW is to be installed by 2028. This is taken as the target for the scenario. The development goal of renewable, solar power, wind power, and biomass, is set at 4%, about a half of the energy target of the government policy.

(5) Carbon Dioxide Emission Reduction Scenario (Scenario 3)

The scenario of less global environmental impact aims at reducing CO_2 emission as much as possible from the policy oriented scenario. Coal thermal power does more harm than other power sources in terms of air pollution and global warming. First of all, coal thermal generation accompanies larger emission of NOx, SOx and particulates. Desulfurization and denitrification equipment fitted to the plants can decrease the emission of NOx and SOx. Installation of electrostatic precipitation device is effective in preventing dispersion of particulates. Unless measurements of these substances exceed the maximum values stated in environmental standards, no regulatory restriction is imposed on development and/or operation of coal-fired power plant. Because CO_2 emission per kWh of energy generated by coal-fired plant is larger than that of other power sources, it is preferable to develop other type of plants for the purpose of mitigating global warming.

The FTP is in progress for the rapid development of coal thermal power, and 6.9 GW in total capacity is scheduled to begin operation after 2010 in Jamali region. Together with the present 8 GW of the coal thermal power capacity, 14.9 GW in total will be operating in a few years. This capacity is only 18% of the required total capacity of Jamali system in 2028. Without further development of coal-fired plant after the FTP, the system will not be able to meet the demand.

To minimize the coal-fired power development, the scenario requires LNG, hydropower, nuclear power, and renewable energy to be developed more to substitute for part of the coal-fired. LNG is a clean fuel from which SOx and particulate emission is negligible, and CO_2 emission is smaller when used at combined cycle plant (PLTGU). Therefore, the target of LNG development in Scenario 2 is applied to this scenario, too. The same idea applies to geothermal, but with a little higher target of 5%. Hydropower should be developed as much as possible provided that methane emission from reservoirs is not significant. Therefore, 8% in capacity should be developed with small and medium-sized hydro. As nuclear power free from CO_2 emission, it should be developed to the probable maximum of 5 GW by 2028. Further, following the government policy, wind power and solar power should be 5% and biomass fuel 2%, on energy basis by 2028. Proportion of generated energy by coal is minimized in this scheme.

Table 4.5-2 Power Development Scheme in Each Scenario (Target in 2028)

Scenario \ Source		Oil	Coal	Gas	geothermal	hydro	Pumped storage	nuclear	Renewable
Present 2006	Capacity ratio 2006 (%)	29	39	17	3.5	11.5	0	0	0
	Energy ratio 2006 (%)	30.4	43.2	16.8	3.7	5.9	0	0	0
Scenario 0 Policy oriented		Energy ratio 0.2% after PLN target	Energy ratio 62-70% after policy	Energy ratio 12% after policy and on-going projects	Energy ratio 5% after policy and feasible capacity	Energy ratio 4-8% after policy	Appropriate capacity developed for peak load, based on WASP results	Capacity ratio 5-7%, 4-5GW after roadmap	Negligible
Scenario 1 Coal power acceleration		Energy ratio 0.2% after PLN target	Energy ratio 73% due to inexpensive fuel. Intensify development	Capacity ratio 10% due to expensive fuel.	Capacity 1,620 MW, 2% after adding feasible 785 MW	Energy ratio down to 2% due to high initial cost impeding development.	Appropriate capacity developed for peak load, based on WASP results	Capacity up to 5 GW (7%) due to inexpensive generation cost	Negligible due to expensive production cost.
Scenario 2 Power source diversification		Energy ratio kept to 2-3% to sustain diversification	Just as much as to complement the deficit left by other sources	Energy ratio 19%, intensely developed using LNG	Available capacity 3.6 GW, 5%, intensely developed	Energy ratio 4-8%, reservoir type developed	Appropriate capacity developed for peak load, based on WASP results	Capacity 5 GW (7%) to diversify sources	Energy ratio 4%, solar , wind and biomass, to diversify sources
Scenario 3 CO_2 emission reduction		Energy ratio kept to 2-3% to sustain diversification	Just as much as to complement the deficit left by other sources	Energy ratio 19%, intensely developed using LNG	Available capacity 3.6 GW, 5%, intensely developed	Energy ratio 4-8%, run-of-river type developed	Appropriate capacity developed for peak load, based on WASP results	Capacity 5 GW (7%) to reduce CO_2 emission	Energy ratio 5% by solar and wind , and 2% by biomass

Note: Total capacity 22,126 MW and 104.8 TWh (PLN 79.9 TWh, IPP 24.9 TWh) in Jamali system in 2006.

The installed capacity by fuel for thermal power including IPP depends on RUPTL 2007-16. The total capacity of thermal power 18,825 MW (85 %) is divided into steam 10,370 MW (46.9 %), combined cycle 6,143 MW (27.8 %), gas turbine 2,236 MW (10.1 %) and diesel 76 MW (0.3%).

Power supply from Sumatra (Capacity 3 GW, ratio 3.7%) is common to all scenarios but not presented in the Table.

4.5.3 Comparison of Scenarios

The long term development targets of power sources in four scenarios are summarized in Table 4.5-2 (produced energy 406.6 TWh, maximum power 62.5 GW, and total installed capacity 81.2 GW in 2028). The capacity ratio of each power source in the table is an expected ratio of its capacity to the total installed capacity 81.2 GW, and the energy production ratio is an expected ratio of its generated energy to the total produced energy of 406.6 TWh. Both power and energy count on transmission from Sumatra in every scenario but they are not indicated in Table (capacity 3 GW, capacity ratio 3.7 % as of 2028).

Energy production (consumption) ratio by fuel as of 2028 was roughly estimated on the basis of the above-mentioned targeting. Fig.4.5-2 shows the result.

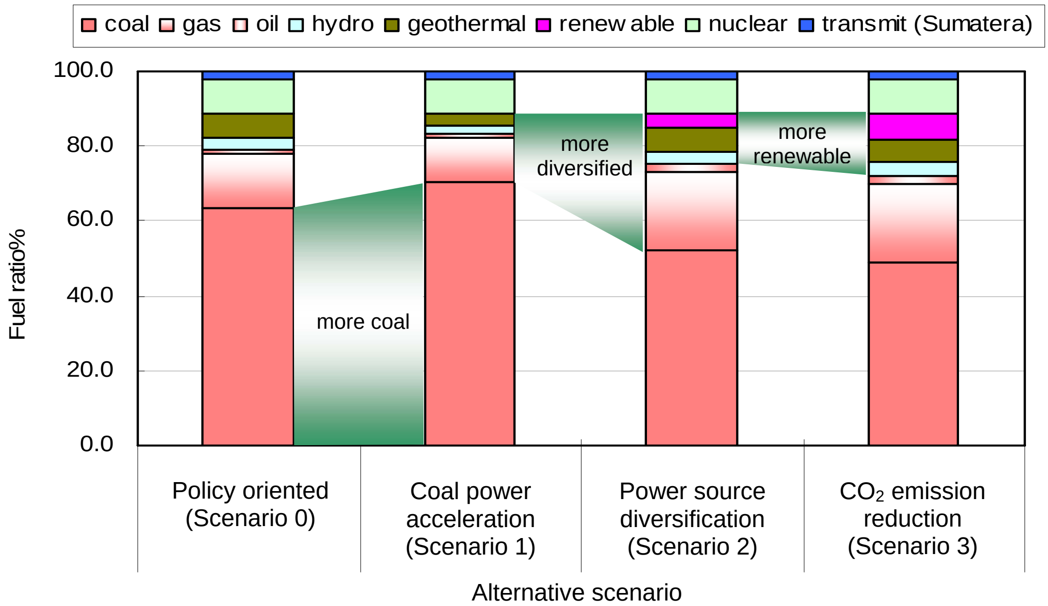


Fig.4.5-2 Energy Production Ratio by Fuel for Scenarios (Total 406.6 TWh, 2028)

4.6. Estimation of Financial Requirements

4.6.1 Power Source Development Plan

(1) Power Source Development Plan

1) Methodology for Translation of Each Scenario by WASP IV

Four alternative scenarios proposed in Section 4.5 are translated into the power source development plans by WASP IV. Since WASP IV is a generation expansion planning tool based on the total cost minimization algorithm and if coal fuel price of $ 80 per ton is used, the energy mix in four (4) scenarios cannot be reproduced due to the imbalance of fuel prices. Therefore, coal fuel price is set as a parameter to reproduce the target energy mix of four (4) scenarios. And after reproduction of the targets of four (4) scenarios, operation cost is adjusted by using coal fuel price of $ 80 per ton as shown in Fig.4.6 -1.

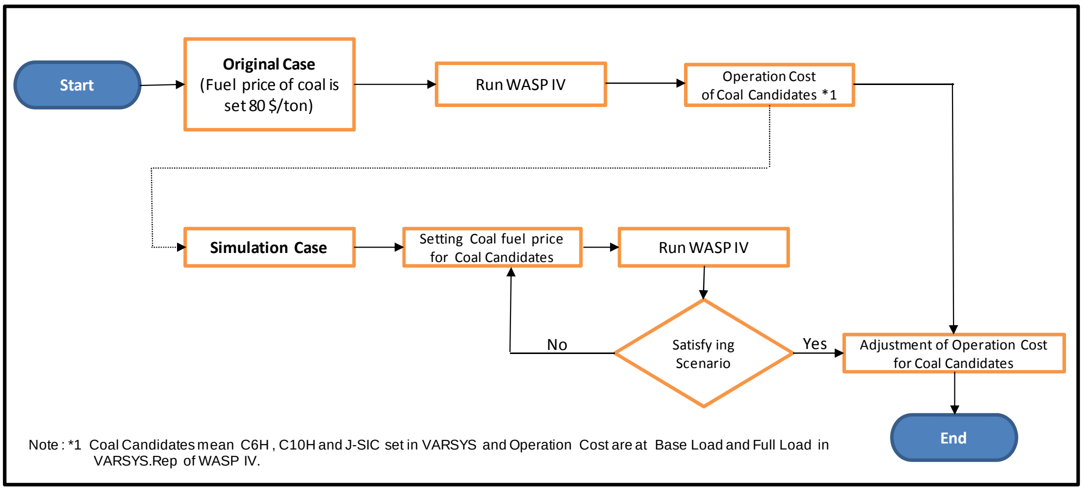


Fig.4.6-1 Methodology for Reproduction of Each Scenario by WASP IV

2) Development Stage

Power source development plan for the 20 years from 2009 to 2028 is divided into three (3) stages, (a) On-going and committed projects development stage, (b) Prospective projects development stage, and (c) Potential projects development stage as shown in Fig.4.6-2, which shows for Scenario 0.

(a) On-going and committed project development stage (2009 ~ 2015)
On-going and committed projects in RUPTL are to be developed in this stage.

(b) Prospective projects development stage (2016 ~ 2020)
Prospective projects mean the projects whose sites are identified specifically in the relevant studies. Pre-FS, FS and/or D/D including EIA are to be carried out for the

future implementation.

(c) Potential projects development stage (2021 ~ 2028)

Potential projects mean the projects whose sites have not yet been identified. Inventory list will be prepared and realization methods will be studied and prepared especially for renewable energy development.

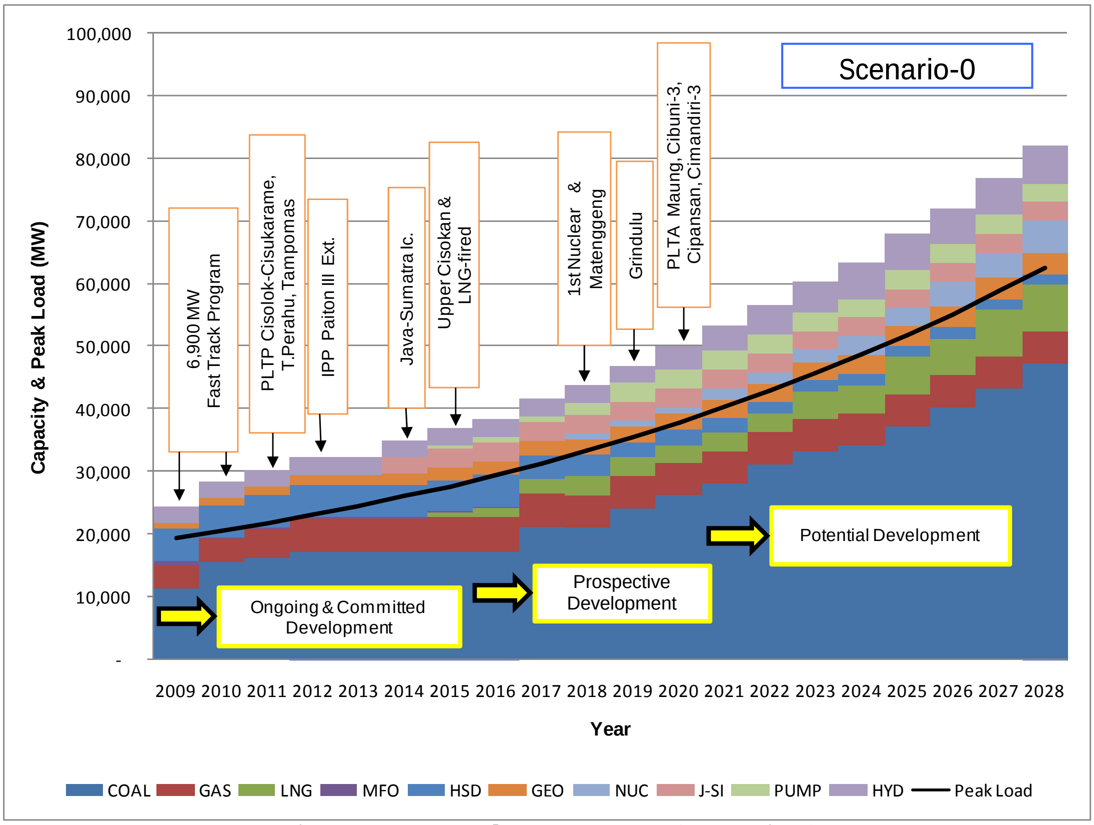


Fig.4.6-2 Development Stage (Scenario 0)

3) Scenario 0 (Policy oriented scenario)

Table 4.6 -1 shows the power source development plan for Scenario 0.

Table 4.6-1 Power Source Development Plan for Scenario 0

				2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
C6H	PLTU	600																					
C10H	PLTU	1000					1,000	1,000	1,000	1,000	1,000	5,000	5,000	8,000	10,000	12,000	15,000	17,000	18,000	21,000	24,000	27,000	31,000
LNG	PLTG	750								750	1,500	2,250	3,000	3,000	3,000	3,000	3,000	4,500	4,500	6,000	6,000	7,500	7,500
N10H	PLTN	1000											1,000	1,000	1,000	2,000	2,000	2,000	3,000	3,000	4,000	4,000	5,000
GE55	PLTP	55				330	330	330	550	660	770	880	990	1,100	1,210	1,320	1,430	1,540	1,650	1,760	1,870	1,980	2,090
G150	PLTG	150																					
PS	Pumped S.	500								500	1,000	1,000	2,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
CIB3	PLTA	172													172	172	172	172	172	172	172	172	172
CPSG	PLTA	400													400	400	400	400	400	400	400	400	400
CMD3	PLTA	238													238	238	238	238	238	238	238	238	238
MANG	PLTA	360													360	360	360	360	360	360	360	360	360
PLTA	PLTA	300															900	900	1,800	1,800	1,800	2,100	2,100
Java-Sumatera I.C.		600							2,400	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Total Additional Capacity				-	-	330	1,330	1,330	3,950	5,910	7,270	12,130	14,990	19,100	22,380	25,490	29,500	33,110	36,120	40,730	44,840	49,750	54,860
Total Supply Capacity at year end				24,389	28,305	30,318	32,285	32,285	34,905	36,975	38,335	41,642	43,801	46,913	50,193	53,303	56,708	60,318	63,328	67,938	72,048	76,958	82,068
Reserve Margin		%		26.2%	37.8%	39.0%	39.4%	31.4%	33.9%	33.7%	30.4%	32.9%	31.2%	31.9%	32.5%	32.1%	32.0%	31.8%	30.0%	31.1%	30.6%	31.1%	31.4%

4) Scenario 1 (Coal power acceleration scenario)

Table 4.6-2 shows the power source development plan for Scenario 1.

Table 4.6-2 Power Source Development Plan for Scenario 1

				2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
C6H	PLTU	600																					
C10H	PLTU	1000					1,000	1,000	1,000	1,000	2,000	5,000	6,000	9,000	10,000	13,000	17,000	19,000	22,000	26,000	30,000	34,000	38,000
LNG	PLTG	750								750	1,500	2,250	3,000	3,000	3,000	3,000	3,000	3,750	3,750	3,750	3,750	3,750	3,750
N10H	PLTN	1000											1,000	1,000	1,000	2,000	2,000	2,000	3,000	3,000	4,000	4,000	5,000
GE55	PLTP	55				330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330
G150	PLTG	150																					
PS	Pumped S.	500								500	1,000	1,000	2,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
CIB3	PLTA	172													172	172	172	172	172	172	172	172	172
CPSG	PLTA	400													400	400	400	400	400	400	400	400	400
CMD3	PLTA	238													238	238	238	238	238	238	238	238	238
MANG	PLTA	360													360	360	360	360	360	360	360	360	360
PLTA	PLTA	300																					
Java-Sumatera I.C.		600							2,400	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Total Additional Capacity				-	-	330	1,330	1,330	3,730	5,580	7,830	11,580	15,330	19,330	21,500	25,500	29,500	32,250	36,250	40,250	45,250	49,250	54,250
Total Supply Capacity at year end				24,389	28,305	30,318	32,285	32,285	34,685	36,645	38,895	41,092	44,141	47,143	49,313	53,313	56,708	59,458	63,458	67,458	72,458	76,458	81,458
Reserve Margin		%		26.2%	37.8%	39.0%	39.4%	31.4%	33.0%	32.5%	32.3%	31.1%	32.2%	32.5%	30.1%	32.1%	32.0%	30.0%	30.3%	30.1%	31.3%	30.2%	30.4%

5) Scenario 2 (Power source diversification scenario)

For the Scenario 2, generated energy in demand forecast was reduced by four (4) percents, which is the proportion of renewable energy (solar, wind power and biomass) and peak load reduced[15] consequently.

Table 4.6-3 shows the power source development plan for Scenario 2.

Table 4.6-3 Power Source Development Plan for Scenario 2

				2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
C6H	PLTU	600																					
C10H	PLTU	1000					1,000	1,000	1,000	1,000	1,000	5,000	5,000	7,000	7,000	9,000	10,000	13,000	13,000	16,000	17,000	20,000	24,000
LNG	PLTG	750								750	1,500	2,250	3,000	3,000	4,500	4,500	6,000	6,000	7,500	7,500	9,000	9,000	9,000
N10H	PLTN	1000											1,000	1,000	1,000	2,000	2,000	2,000	3,000	3,000	4,000	4,000	5,000
GE55	PLTP	55				330	330	330	550	660	770	880	990	1,100	1,210	1,320	1,430	1,540	1,650	1,760	1,870	1,980	2,090
G150	PLTG	150												450	600	600	900	900	1,200	1,200	1,500	1,800	1,800
PS	Pumped S.	500								500	1,000	1,000	2,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
CIB3	PLTA	172													172	172	172	172	172	172	172	172	172
CPSG	PLTA	400													400	400	400	400	400	400	400	400	400
CMD3	PLTA	238													238	238	238	238	238	238	238	238	238
MANG	PLTA	360													360	360	360	360	360	360	360	360	360
PLTA	PLTA	300															900	900	1,800	1,800	1,800	2,100	2,100
Java-Sumatera I.C.		600							2,400	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Total Additional Capacity				-	-	330	1,330	1,330	3,950	5,910	7,270	12,130	14,990	18,550	21,480	24,590	28,400	31,510	35,320	38,430	42,340	46,050	51,160
Total Supply Capacity at year end				24,389	28,305	30,318	32,285	32,285	34,905	36,975	38,335	41,642	43,801	46,363	49,293	52,403	55,608	58,718	62,528	65,638	69,548	73,258	78,368
Reserve Margin		%		26.2%	37.8%	39.0%	39.4%	31.4%	33.9%	33.7%	30.4%	32.9%	31.2%	30.3%	30.1%	31.2%	30.7%	31.0%	31.0%	30.5%	30.0%	30.0%	30.7%

6) Scenario 3 (CO_2 emission reduction scenario)

For the Scenario 3, generated energy in demand forecast is reduced by seven (7) percents, which is the proportion of renewable energy (solar, wind power and biomass) and peak load reduced consequently as in Scenario 2.

Table 4.6-4 shows the power source development plan for Scenario 3.

Table 4.6-4 Power Source Development Plan for Scenario 3

				2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
C6H	PLTU	600																					
C10H	PLTU	1000					1,000	1,000	1,000	1,000	1,000	5,000	5,000	7,000	7,000	9,000	10,000	12,000	12,000	15,000	16,000	18,000	21,000
LNG	PLTG	750								750	1,500	2,250	3,000	3,000	4,500	4,500	6,000	6,000	7,500	7,500	9,000	9,000	9,000
N10H	PLTN	1000											1,000	1,000	1,000	2,000	2,000	2,000	3,000	3,000	4,000	4,000	5,000
GE55	PLTP	55				330	330	330	550	660	770	880	990	1,100	1,210	1,320	1,430	1,540	1,650	1,760	1,870	1,980	2,090
G150	PLTG	150												450	600	600	900	900	1,200	1,200	1,500	1,800	1,800
PS	Pumped S.	500								500	1,000	1,000	2,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
CIB3	PLTA	172													172	172	172	172	172	172	172	172	172
CPSG	PLTA	400													400	400	400	400	400	400	400	400	400
CMD3	PLTA	238													238	238	238	238	238	238	238	238	238
MANG	PLTA	360													360	360	360	360	360	360	360	360	360
PLTA	PLTA	300															900	900	1,800	1,800	1,800	2,400	2,400
Java-Sumatera I.C.		600							2,400	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Total Additional Capacity				-	-	330	1,330	1,330	3,950	5,910	7,270	12,130	14,990	18,550	21,480	24,590	28,400	30,510	34,320	37,430	41,340	44,350	48,460
Total Supply Capacity at year end				24,389	28,305	30,318	32,285	32,285	34,905	36,975	38,335	41,642	43,801	46,363	49,293	52,403	55,608	57,718	61,528	64,638	68,548	71,558	75,668
Reserve Margin		%		26.2%	37.8%	39.0%	39.4%	31.4%	33.9%	33.7%	30.4%	32.9%	31.2%	30.3%	30.1%	31.2%	30.7%	30.1%	30.2%	31.3%	30.8%	31.1%	30.2%

[15] Peak load = (generation energy /load factor)

(2) Results of Power Source Development Plan

Main results of simulation by WASP IV are presented in Fig.4.6-4 to Fig.4.6-7 and detailed output is shown in **Appendix 6.**

1) Comparison of Target in Scenario and Result of WASP Simulation

The comparison between energy mix target in each scenario set in Section 4.5 and the results of WASP simulation are shown in Table 4.6-5.

Table 4.6-5 Comparison of Target in Scenario and Result of WASP Simulation

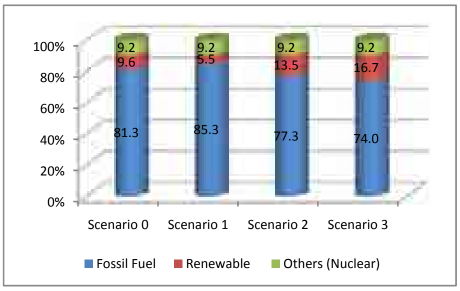
Scenario		Oil	Coal	Gas	Geothermal	Hydro	Pumped Storage	Nuclear	Other Renewable
Scenario 0	Target in 2028	Energy rate 0.2 %	Energy rate 56 ~ 66 %	Energy rate 12 %	Energy rate 5 %	Energy rate 4 ~ 8 %	Up to WASP IV economic development	Capacity rate 5 ~ 7 %, 4 ~ 5 GW	Negligible
	Simulation Results in 2028	Energy rate 1.1 %	Energy rate 65.7 %	Energy rate 14.5 %	Energy rate 9 %	Energy rate 3.3 %	Negligible	Capacity rate 6.1 %, 5 GW	None
Scenario 1	Target in 2028	Energy rate 0.2 %	Energy rate 70 %	Capacity rate 10 %	Capacity 1,620 MW	Energy rate 2 %	Up to WASP IV economic development	Capacity rate 7 %, 5 GW	Negligible
	Simulation Results in 2028	Energy rate 1.1 %	Energy rate 72.3 %	Capacity rate 10.8 %	Capacity 1,696 MW	Energy rate 2.2 %	Negligible	Capacity rate 6.1 %, 5 GW	None
Scenario 2	Target in 2028	Energy rate 2 ~ 3 %	Cover power shortage	Energy rate 19 %	Available capacity 3.6 GW, 5 %	Energy rate 4 ~ 8 %	Up to WASP IV economic development	Capacity rate 7 %, 5 GW	Energy rate 4 % by solar, wind and biomass
	Simulation Results in 2028	Energy rate 2.2 %	Energy rate 54.1 %	Energy rate 21.0 %	Available capacity 3.5 GW, 4.2 %	Energy rate 3.3 %	Negligible	Capacity rate 6.1 %, 5 GW	Energy rate 4 %
Scenario 3	Target in 2028	Energy rate 2 ~ 3 %	Cover power shortage, at least 18 % capacity after FTP	Energy rate 19 %	Available capacity 3.6 GW, 5 %	Energy rate 4 ~ 8 %	Up to WASP IV economic development	Capacity rate 7 %, 5 GW	Energy rate 5% by solar, wind and 2 % by biomass
	Simulation Results in 2028	Energy rate 2.2 %	Energy rate 51.0 %	Energy rate 20.8 %	Available capacity 3.5 GW, 4.2 %	Energy rate 3.5 %	Negligible	Capacity rate 6.1 %, 5 GW	Energy rate 7 %

As shown in the table above, most of targets except hydropower have been met by WASP IV simulation. Hydropower targets could not be met due to limited hydro potential in Jamali.

Fig.4.6-3 shows the generation shares by fuel origin and by operation pattern for the four (4) scenarios in 2028. More than 80% of generation energy will be produced by fossil fuels for Scenario 0 and Scenario 1, while those percentages for Scenario 2 and Scenario 3 will be less than 80%. Concerning the generation share by operation pattern, generation energy by middle to peak & peak operation plants will account for less than 20% for Scenario 0 and Scenario 1, while those percentages for Scenario 2 and Scenario 3 will be more than 25%. Four (4) scenarios can be divided into two (2) groups, such as Scenario 0 & Scenario 1, and Scenario 2 & Scenario 3 in terms of the above aspects.

Fuel Type	Power Sources	Generation Share (%) in 2028				Operation Pattern	Power Sources	Generation Share (%) in 2028			
		Scenario 0	Scenario 1	Scenario 2	Scenario 3			Scenario 0	Scenario 1	Scenario 2	Scenario 3
	Generation	407 Th.GWh	407 Th.GWh	407 Th.GWh	407 Th.GWh		Generation	407 Th.GWh	407 Th.GWh	407 Th.GWh	407 Th.GWh
Fossil Fuel (Coal)	Coal-fired Java-Sumatra In.	65.7	72.3	54.1	51.0	Base	Nuclear Geothermal	15.5	12.5	15.4	15.4
Fossil Fuel (Gas + LNG + MFO +HSD)	Gas, LNG, MFO, HSD	15.6	13.0	23.2	23.0	Base to Middle	Coal-fired Java-Sumatra In.	65.7	72.3	54.1	51.0
Renewable	Geothermal Hydropower	9.6	5.5	9.5	9.7	Middle to Peak	Gas-fired LNG-fired Hydropower	17.8	14.1	24.3	24.3
Other Renewable	Solar, Wind, Biomass	0.0	0.0	4.0	7.0	Peak	MFO & HSD-fired Pumped Storage	1.1	1.1	2.2	2.2
Others	Nuclear	9.2	9.2	9.2	9.2	Others	Solar, Wind & Biomass	0.0	0.0	4.0	7.0
Total		100.1	100.0	100.0	99.9	Total		100.1	100.0	100.0	99.9

	Scenario 0	Scenario 1	Scenario 2	Scenario 3		Scenario 0	Scenario 1	Scenario 2	Scenario 3
Fossil Fuel	81.3	85.3	77.3	74.0	Base & Base to Middle	81.2	84.8	69.5	66.4
Renewable	9.6	5.5	13.5	16.7	Middle to Peak & Peak	18.9	15.2	26.5	26.5
Others (Nuclear)	9.2	9.2	9.2	9.2	Others (Solar etc.)	0.0	0.0	4.0	7.0
Sum	100.1	100.0	100.0	99.9	Sum	100.1	100	100	99.9



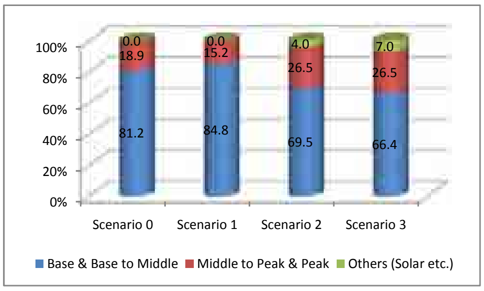


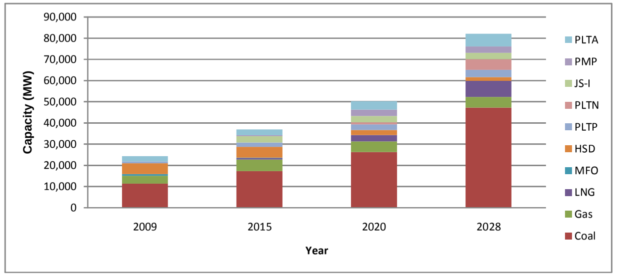
Fig. 4.6-3 Generation Share by Fuel and by Operation Pattern

Investment and operation costs in Fig. 4.6-4 to Fig. 4.6-7 are expressed in nominal value and the costs for Scenario 2 and Scenario 3 do not include those costs for renewable sources, such as solar, wind power and biomass. More detailed analyses of the costs are described in Section 4.6.2.

1 Base Scenario (Policy Oriented)

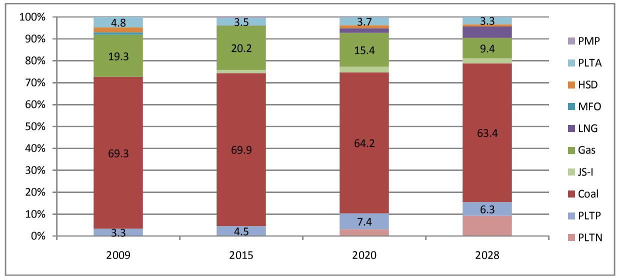
(1) Power Components (MW)

Year	Coal	Gas	LNG	MFO	HSD	PLTP	PLTN	JS-I	PMP	PLTA	SUM
2009	11,371	3,713	0	718	5,128	886	0	0	0	2,574	24,390
2015	17,261	5,438	750	192	5,078	2,026	0	3,000	500	2,731	36,976
2020	26,261	5,072	3,000	0	2,384	2,576	1,000	3,000	3,000	3,901	50,194
2028	47,261	5,072	7,500	0	1,779	3,456	5,000	3,000	3,000	6,001	82,069



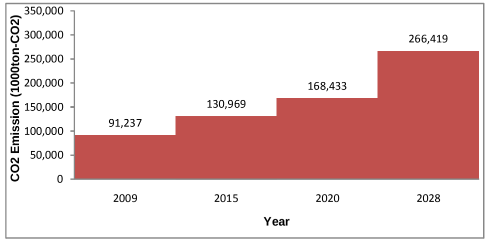
(4) Generation Energy (%)

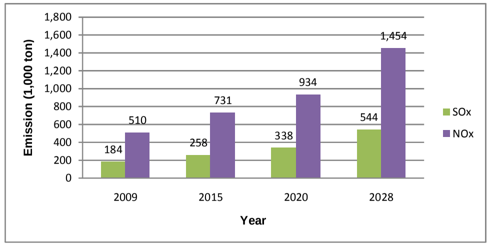
Year	Coal	Gas	LNG	MFO	HSD	PLTP	PLTN	JS-I	PMP	PLTA	SUM
2009	69.3	19.3	0.0	1.1	2.3	3.3	0.0	0.0	0.0	4.8	100
2015	69.9	20.2	0.0	0.0	0.1	4.5	0.0	1.4	0.4	3.5	100
2020	64.2	15.4	2.2	0.0	1.3	7.4	3.0	2.7	0.1	3.7	100
2028	63.4	9.4	5.1	0.0	1.1	6.3	9.2	2.3	0.0	3.3	100



(8) Annual Emission (1000 t)

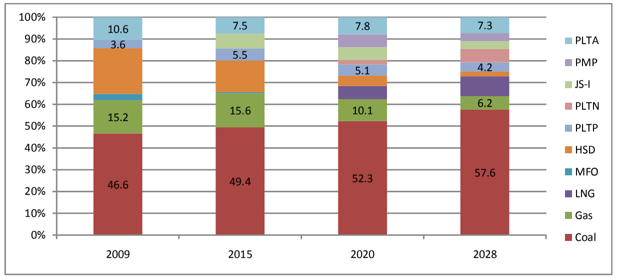
Year	CO2	SOx	NOx
2009	91,237	184	510
2015	130,969	258	731
2020	168,433	338	934
2028	266,419	544	1,454





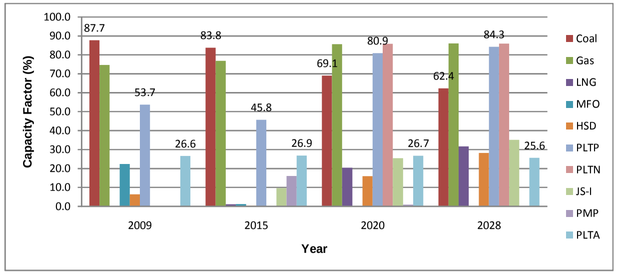
(2) Power Components (%)

Year	Coal	Gas	LNG	MFO	HSD	PLTP	PLTN	JS-I	PMP	PLTA	SUM
2009	46.6	15.2	0.0	2.9	21.0	3.6	0.0	0.0	0.0	10.6	100
2015	49.4	15.6	0.0	0.6	14.5	5.5	0.0	6.9	0.0	7.5	100
2020	52.3	10.1	6.0	0.0	4.7	5.1	2.0	6.0	6.0	7.8	100
2028	57.6	6.2	9.1	0.0	2.2	4.2	6.1	3.7	3.7	7.3	100



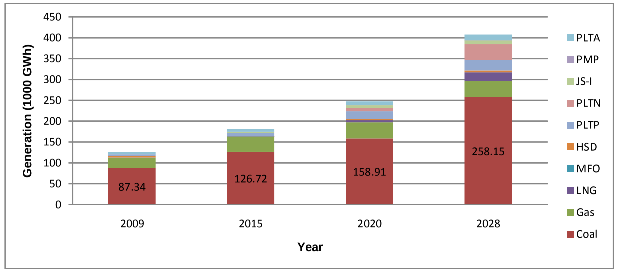
(5) Capacity Factor (%)

Year	Coal	Gas	LNG	MFO	HSD	PLTP	PLTN	JS-I	PMP	PLTA
2009	87.7	74.7	0.0	22.4	6.4	53.7	0.0	0.0	0.0	26.6
2015	83.8	76.8	1.1	1.2	0.3	45.8	0.0	9.6	16.0	26.9
2020	69.1	85.6	20.3	0.0	15.9	80.9	85.8	25.4	0.9	26.7
2028	62.4	86.1	31.6	0.0	28.2	84.3	85.9	35.1	0.1	25.6



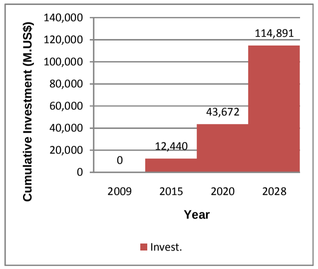
(3) Generation Energy (1000 GWh)

Year	Coal	Gas	LNG	MFO	HSD	PLTP	PLTN	JS-I	PMP	PLTA	SUM
2009	87.34	24.29	0.00	1.41	2.86	4.17	0.00	0.00	0.00	6.00	126.07
2015	126.72	36.58	0.07	0.02	0.13	8.12	0.00	2.51	0.70	6.43	181.28
2020	158.91	38.04	5.34	0.00	3.32	18.25	7.52	6.68	0.24	9.13	247.43
2028	258.15	38.25	20.79	0.00	4.40	25.52	37.62	9.23	0.02	13.47	407.45



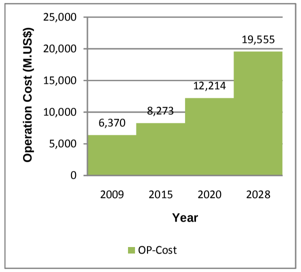
(6) Cumulative Investment Cost & Annual Operation Cost (M.US

Year	Invest.	OP-Cost
2009	0	6,370
2015	12,440	8,273
2020	43,672	12,214
2028	114,891	19,555



(7) Operation Cost (USc/kWh)

Year	OP-Cost	Gene.	OP-Cost
	M.US$	1000 GWh	c/kWh
2009	6,370	126.1	5.05
2015	8,273	181.3	4.56
2020	12,214	247.4	4.94
2028	19,555	407.5	4.80



(9) Annual Fuel Consumption

Year	Coal	Gas +LNG	MFO+HSD
	M.ton	M.mmbtu	M. KL
2009	44.1	221.1	1.20
2015	66.4	331.6	0.00
2020	83.2	381.4	1.10
2028	129.2	496.0	1.70

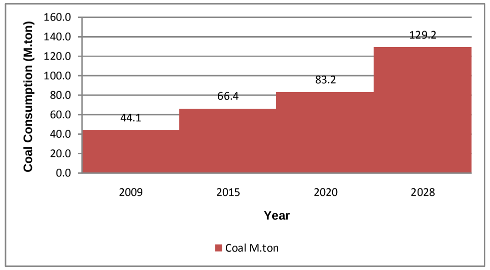
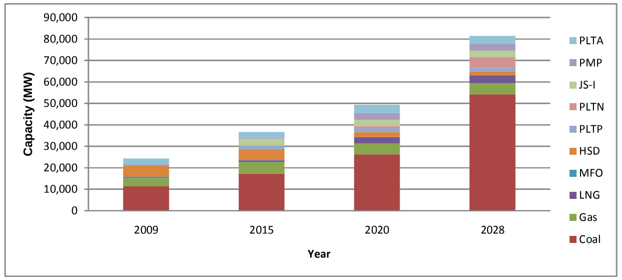


Fig. 4.6-4 Results of Simulation for Scenario 0

2 Scenario 1 (Coal Power Acceleration)

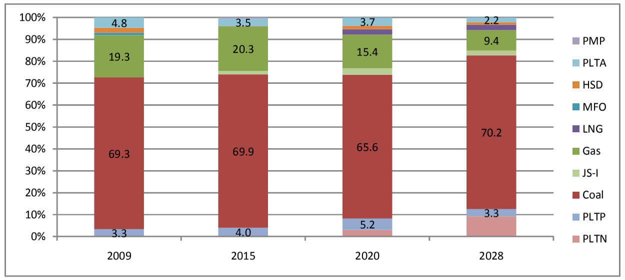
(1) Power Components (MW)

Year	Coal	Gas	LNG	MFO	HSD	PLTP	PLTN	JS-I	PMP	PLTA	SUM
2009	11,371	3,713	0	718	5,128	886	0	0	0	2,574	24,390
2015	17,261	5,438	750	192	5,078	1,696	0	3,000	500	2,731	36,646
2020	26,261	5,072	3,000	0	2,384	1,696	1,000	3,000	3,000	3,901	49,314
2028	54,261	5,072	3,750	0	1,779	1,696	5,000	3,000	3,000	3,901	81,459



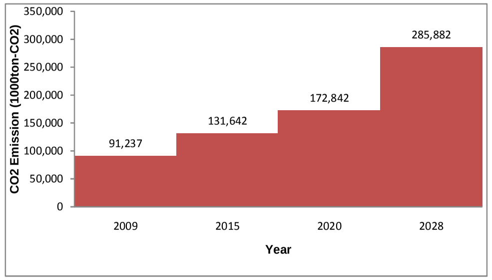
(4) Generation Energy (%)

Year	Coal	Gas	LNG	MFO	HSD	PLTP	PLTN	JS-I	PMP	PLTA	SUM
2009	69.3	19.3	0.0	1.1	2.3	3.3	0.0	0.0	0.0	4.8	100.0
2015	69.9	20.3	0.1	0.0	0.1	4.0	0.0	1.6	0.4	3.5	100.0
2020	65.6	15.4	2.4	0.0	1.6	5.2	3.0	3.0	0.1	3.7	100.0
2028	70.2	9.4	2.5	0.0	1.1	3.3	9.2	2.1	0.0	2.2	100.0



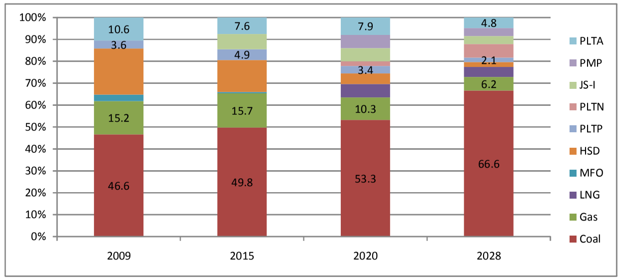
(8) Annual Emission (1000 t)

Year	CO2	SOx	NOx
2009	91,237	184	510
2015	131,642	260	735
2020	172,842	347	960
2028	285,882	598	1,528



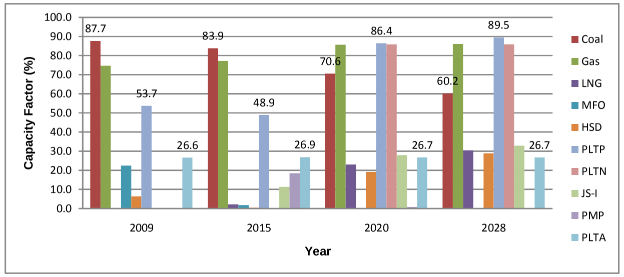
(2) Power Components (%)

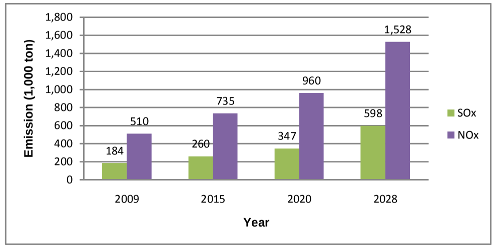
Year	Coal	Gas	LNG	MFO	HSD	PLTP	PLTN	JS-I	PMP	PLTA	SUM
2009	46.6	15.2	0.0	2.9	21.0	3.6	0.0	0.0	0.0	10.6	100.0
2015	49.8	15.7	0.0	0.6	14.6	4.9	0.0	6.9	0.0	7.6	100.0
2020	53.3	10.3	6.1	0.0	4.8	3.4	2.0	6.1	6.1	7.9	100.0
2028	66.6	6.2	4.6	0.0	2.2	2.1	6.1	3.7	3.7	4.8	100.0



(5) Capacity Factor (%)

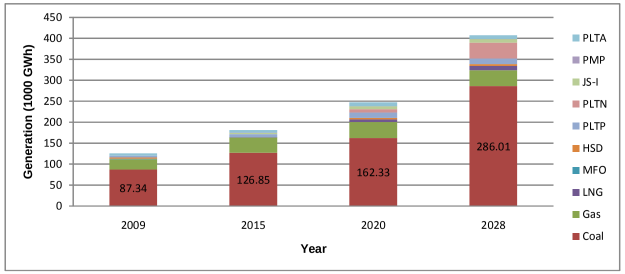
Year	Coal	Gas	LNG	MFO	HSD	PLTP	PLTN	JS-I	PMP	PLTA
2009	87.7	74.7	0.0	22.4	6.4	53.7	0.0	0.0	0.0	26.6
2015	83.9	77.2	2.1	1.8	0.4	48.9	0.0	11.3	18.5	26.9
2020	70.6	85.7	23.0	0.0	19.1	86.4	85.8	27.9	0.9	26.7
2028	60.2	86.0	30.4	0.0	28.8	89.5	85.9	32.9	0.0	26.7





(3) Generation Energy (1000 GWh)

Year	Coal	Gas	LNG	MFO	HSD	PLTP	PLTN	JS-I	PMP	PLTA	SUM
2009	87.34	24.29	0.00	1.41	2.86	4.17	0.00	0.00	0.00	6.00	126.07
2015	126.85	36.77	0.14	0.03	0.17	7.27	0.00	2.97	0.81	6.43	181.44
2020	162.33	38.07	6.05	0.00	3.99	12.84	7.52	7.33	0.24	9.13	247.50
2028	286.01	38.23	10.00	0.00	4.49	13.30	37.62	8.64	0.01	9.13	407.43

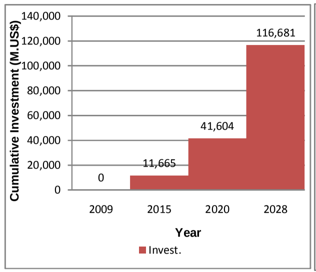


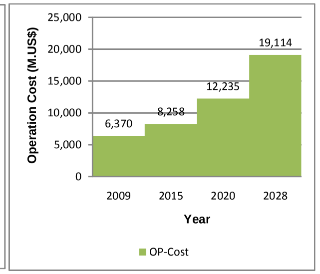
(6) Cumulative Investment Cost & Annual Operation Cost (M.US$)

Year	Invest.	OP-Cost
2009	0	6,370
2015	11,665	8,258
2020	41,604	12,235
2028	116,681	19,114

(7) Operation Cost (USc/kWh)

Year	OP-Cost	Gene.	OP-Cost
	M.US$	1000 GWh	c/kWh
2009	6,370	126.1	5.05
2015	8,258	181.4	4.55
2020	12,235	247.5	4.94
2028	19,114	407.4	4.69





(9) Annual Fuel Consumption

Year	Coal	Gas +LNG	MFO+HSD
	M.ton	M.mmbtu	M. KL
2009	44.1	221.1	1.20
2015	66.8	334.3	0.00
2020	85.0	386.9	1.40
2028	141.5	417.4	1.70

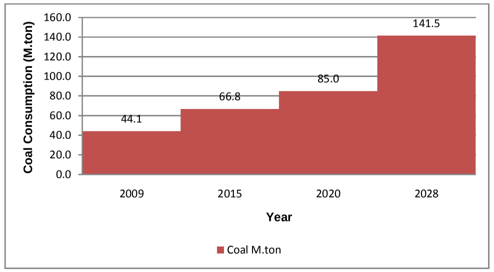
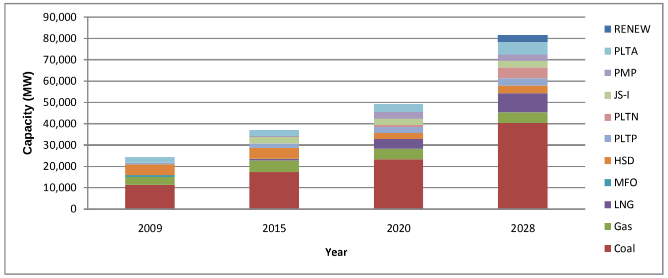


Fig. 4.6-5 Results of Simulation for Scenario 1

3 Scenario 2 (Power Source Diversification)

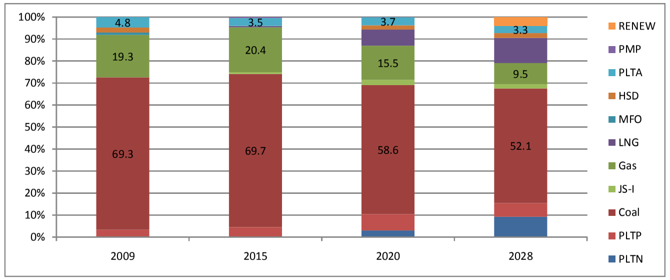
(1) Power Components (MW)

Year	Coal	Gas	LNG	MFO	HSD	PLTP	PLTN	JS-I	PMP	PLTA	RENEW	SUM
2009	11,371	3,713	0	718	5,128	886	0	0	0	2,574	0	24,390
2015	17,261	5,438	750	192	5,078	2,026	0	3,000	500	2,731	0	36,976
2020	23,261	5,072	4,500	0	2,984	2,576	1,000	3,000	3,000	3,901	0	49,294
2028	40,261	5,072	9,000	0	3,579	3,456	5,000	3,000	3,000	6,001	3,250	81,619



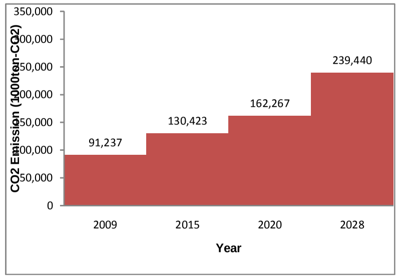
(4) Generation Energy (%)

Year	Coal	Gas	LNG	MFO	HSD	PLTP	PLTN	JS-I	PMP	PLTA	RENEW	SUM
2009	69.3	19.3	0.0	1.1	2.3	3.3	0.0	0.0	0.0	4.8	0.0	100.0
2015	69.7	20.4	0.6	0.0	0.1	4.5	0.0	0.8	0.5	3.5	0.0	100.0
2020	58.6	15.5	7.3	0.0	1.9	7.4	3.0	2.4	0.1	3.7	0.0	100.0
2028	52.1	9.5	11.5	0.0	2.2	6.2	9.2	2.0	0.0	3.3	4.0	100.0



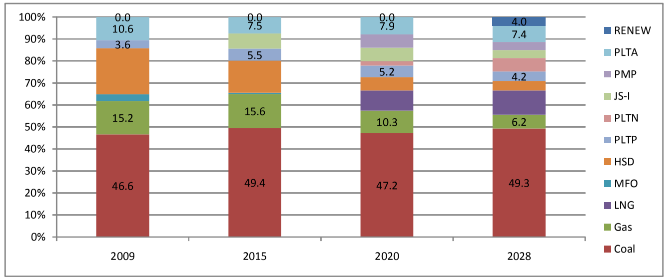
(8) Annual Emission (1000 t)

Year	CO2	SOx	NOx
2009	91,237	184	510
2015	130,423	256	731
2020	162,267	311	934
2028	239,440	458	1,384



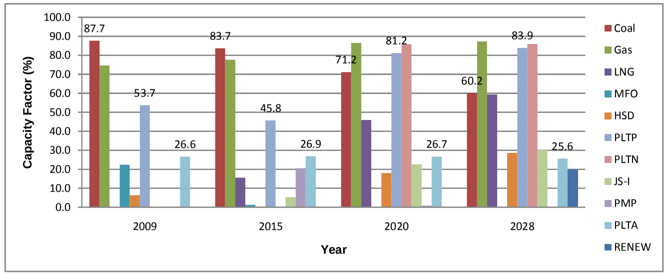
(2) Power Components (%)

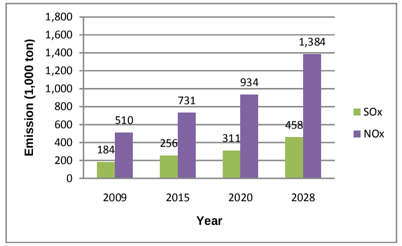
Year	Coal	Gas	LNG	MFO	HSD	PLTP	PLTN	JS-I	PMP	PLTA	RENEW	SUM
2009	46.6	15.2	0.0	2.9	21.0	3.6	0.0	0.0	0.0	10.6	0.0	100.0
2015	49.4	15.6	0.0	0.6	14.5	5.5	0.0	6.9	0.0	7.5	0.0	100.0
2020	47.2	10.3	9.1	0.0	6.1	5.2	2.0	6.1	6.1	7.9	0.0	100.0
2028	49.3	6.2	11.0	0.0	4.4	4.2	6.1	3.7	3.7	7.4	4.0	100.0



(5) Capacity Factor (%)

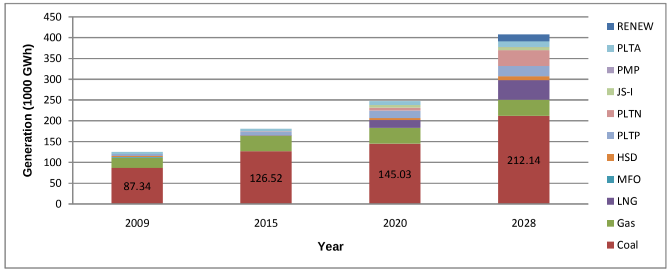
Year	Coal	Gas	LNG	MFO	HSD	PLTP	PLTN	JS-I	PMP	PLTA	RENEW
2009	87.7	74.7	0.0	22.4	6.4	53.7	0.0	0.0	0.0	26.6	0.0
2015	83.7	77.7	15.5	1.2	0.3	45.8	0.0	5.4	20.6	26.9	0.0
2020	71.2	86.5	45.9	0.0	18.0	81.2	85.8	22.6	0.9	26.7	0.0
2028	60.2	87.3	59.4	0.0	28.6	83.9	85.9	30.3	0.1	25.6	20.0





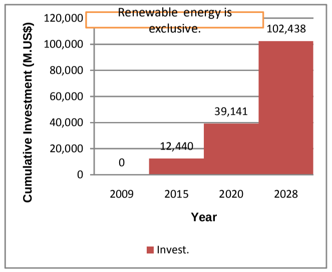
(3) Generation Energy (1000 GWh)

Year	Coal	Gas	LNG	MFO	HSD	PLTP	PLTN	JS-I	PMP	PLTA	RENEW	SUM
2009	87.34	24.29	0.00	1.41	2.86	4.17	0.00	0.00	0.00	6.00	0.00	126.07
2015	126.52	37.00	1.02	0.02	0.13	8.12	0.00	1.41	0.90	6.43	0.00	181.55
2020	145.03	38.45	18.11	0.00	4.70	18.32	7.52	5.93	0.24	9.13	0.00	247.43
2028	212.14	38.79	46.79	0.00	8.96	25.41	37.62	7.95	0.02	13.47	16.27	407.42



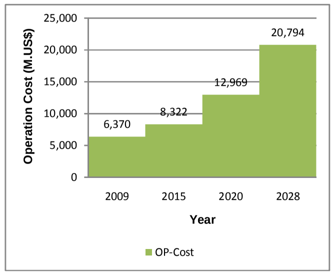
(6) Cumulative Investment Cost & Annual Operation Cost (M.US$)

Year	Invest.	OP-Cost
2009	0	6,370
2015	12,440	8,322
2020	39,141	12,969
2028	102,438	20,794



(7) Operation Cost (USc/kWh)

Year	OP-Cost	Gene.	OP-Cost
	M.US$	1000 GWh	c/kWh
2009	6,370	126.1	5.05
2015	8,322	181.6	4.58
2020	12,969	247.4	5.24
2028	20,794	407.4	5.10



(9) Annual Fuel Consumption

Year	Coal	Gas +LNG	MFO+HSD
	M.ton	M.mmbtu	M. KL
2009	44.1	221.1	1.20
2015	65.7	343.5	0.00
2020	76.5	479.8	1.60
2028	107.9	692.1	3.10

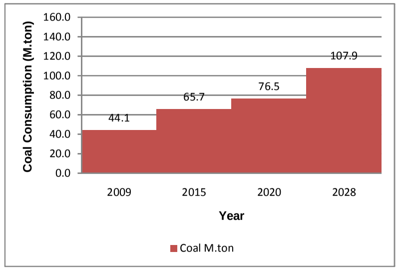
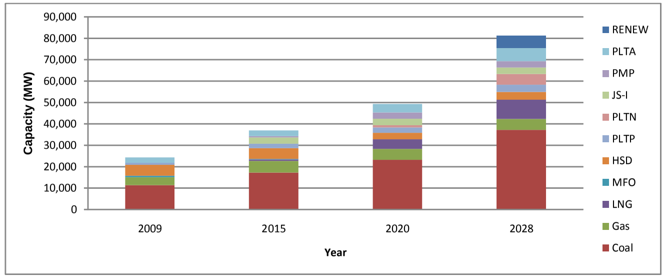


Fig. 4.6-6 Results of Simulation for Scenario 2

4 Scenario 3 (CO2 Emission Reduction)

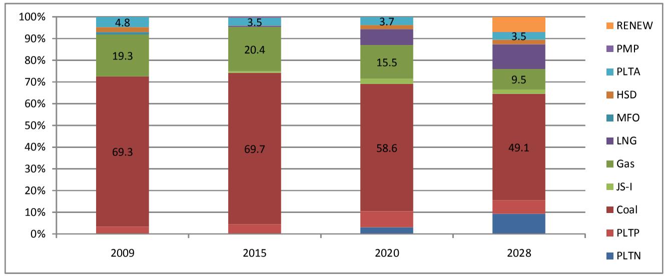
(1) Power Components (MW)

Year	Coal	Gas	LNG	MFO	HSD	PLTP	PLTN	JS-I	PMP	PLTA	RENEW	SUM
2009	11,371	3,713	0	718	5,128	886	0	0	0	2,574	0	24,390
2015	17,261	5,438	750	192	5,078	2,026	0	3,000	500	2,731	0	36,976
2020	23,261	5,072	4,500	0	2,984	2,576	1,000	3,000	3,000	3,901	0	49,294
2028	37,261	5,072	9,000	0	3,579	3,456	5,000	3,000	3,000	6,301	5,686	81,355



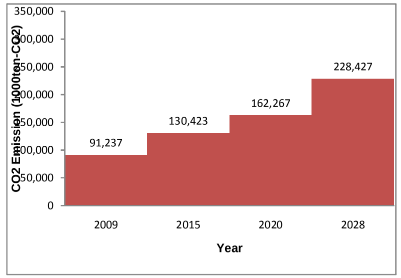
(4) Generation Energy (%)

Year	Coal	Gas	LNG	MFO	HSD	PLTP	PLTN	JS-I	PMP	PLTA	RENEW	SUM
2009	69.3	19.3	0.0	1.1	2.3	3.3	0.0	0.0	0.0	4.8	0.0	100.0
2015	69.7	20.4	0.6	0.0	0.1	4.5	0.0	0.8	0.5	3.5	0.0	100.0
2020	58.6	15.5	7.3	0.0	1.9	7.4	3.0	2.4	0.1	3.7	0.0	100.0
2028	49.1	9.5	11.3	0.0	2.2	6.2	9.2	1.9	0.0	3.5	7.0	100.0



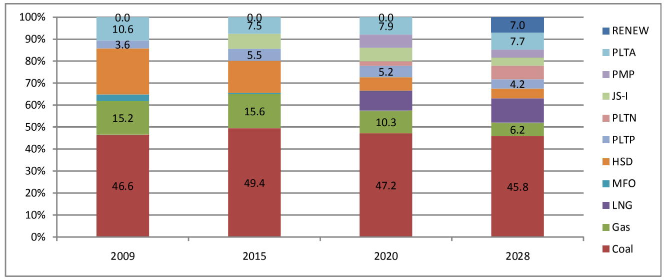
(8) Annual Emission (1000 t)

Year	CO2	SOx	NOx
2009	91,237	184	510
2015	130,423	256	731
2020	162,267	311	934
2028	228,427	434	1,329



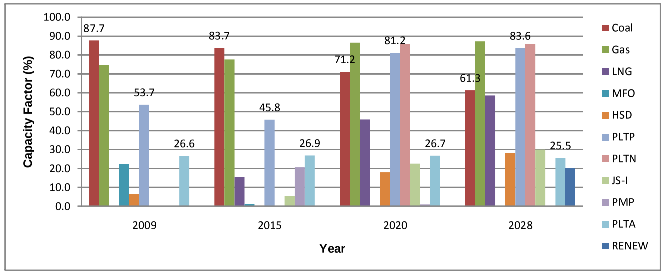
(2) Power Components (%)

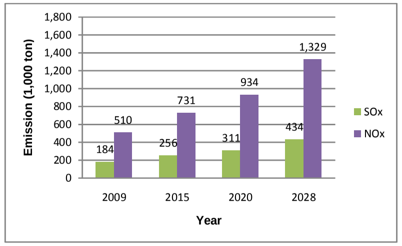
Year	Coal	Gas	LNG	MFO	HSD	PLTP	PLTN	JS-I	PMP	PLTA	RENEW	SUM
2009	46.6	15.2	0.0	2.9	21.0	3.6	0.0	0.0	0.0	10.6	0.0	100.0
2015	49.4	15.6	0.0	0.6	14.5	5.5	0.0	6.9	0.0	7.5	0.0	100.0
2020	47.2	10.3	9.1	0.0	6.1	5.2	2.0	6.1	6.1	7.9	0.0	100.0
2028	45.8	6.2	11.1	0.0	4.4	4.2	6.1	3.7	3.7	7.7	7.0	100.0



(5) Capacity Factor (%)

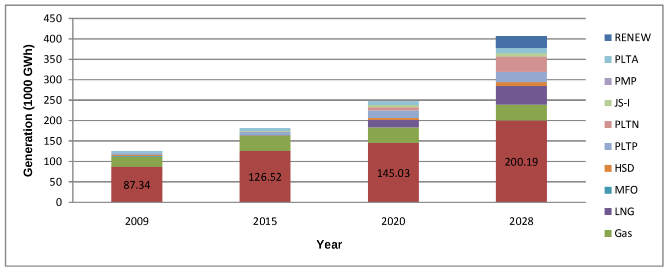
Year	Coal	Gas	LNG	MFO	HSD	PLTP	PLTN	JS-I	PMP	PLTA	RENEW
2009	87.7	74.7	0.0	22.4	6.4	53.7	0.0	0.0	0.0	26.6	0.0
2015	83.7	77.7	15.5	1.2	0.3	45.8	0.0	5.4	20.6	26.9	0.0
2020	71.2	86.5	45.9	0.0	18.0	81.2	85.8	22.6	0.9	26.7	0.0
2028	61.3	87.3	58.6	0.0	28.2	83.6	85.9	30.0	0.1	25.5	20.0





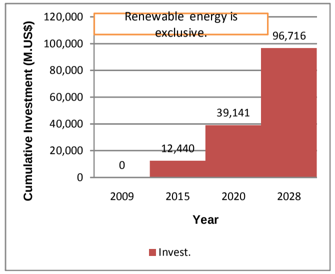
(3) Generation Energy (1000 GWh)

Year	Coal	Gas	LNG	MFO	HSD	PLTP	PLTN	JS-I	PMP	PLTA	RENEW	SUM
2009	87.34	24.29	0.00	1.41	2.86	4.17	0.00	0.00	0.00	6.00	0.00	126.07
2015	126.52	37.00	1.02	0.02	0.13	8.12	0.00	1.41	0.90	6.43	0.00	181.55
2020	145.03	38.45	18.11	0.00	4.70	18.32	7.52	5.93	0.24	9.13	0.00	247.43
2028	200.19	38.77	46.19	0.00	8.84	25.31	37.62	7.89	0.02	14.09	28.46	407.38



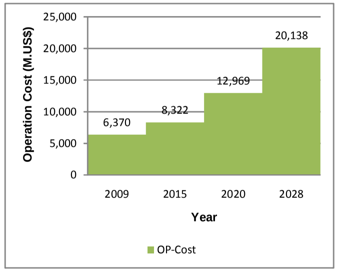
(6) Cumulative Investment Cost & Annual Operation Cost (M.US$)

Year	Invest.	OP-Cost
2009	0	6,370
2015	12,440	8,322
2020	39,141	12,969
2028	96,716	20,138



(7) Operation Cost (USc/kWh)

Year	OP-Cost	Gene.	OP-Cost
	M.US$	1000 GWh	c/kWh
2009	6,370	126.1	5.05
2015	8,322	181.6	4.58
2020	12,969	247.4	5.24
2028	20,138	407.4	4.94



(9) Annual Fuel Consumption

Year	Coal	Gas +LNG	MFO+HSD
	M.ton	M.mmbtu	M. KL
2009	44.1	221.1	1.20
2015	65.7	343.5	0.00
2020	76.5	479.8	1.60
2028	102.4	687.7	3.10

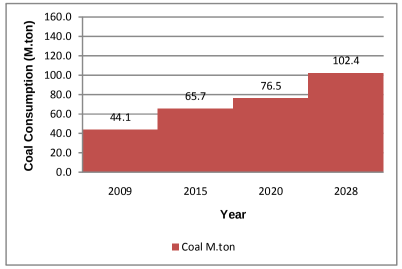


Fig. 4.6-7   Results of Simulation for Scenario 3

2) Study on results

(a) Coal consumption

Table 4.6-6 shows the estimate of coal consumption in 2028. Since the coal consumption of PLN for whole Indonesia in 2006 was 19.1 million ton[16], coal consumption will be increased by 5 to 7 times as large as that in 2006.

Coal production in 2006 was 190 million ton, of which about 70 % was exported and 30 % was for domestic use, which means 133 million ton was exported and 57 million ton was used in the country as described in Section 4.1.3. As coal consumption in Table 4.6-6 is less than the coal production in 2006, coal would not be in short supply. However, exportable amount will be remarkably decreased unless expansion of coal production is achieved.

Table 4.6-6 Estimate of Coal Consumption in 2028

Scenario	Scenario 0	Scenario 1	Scenario 2	Scenario 3
Coal (Million ton)	129.2	141.5	107.9	102.4

Note: Heat Content is 4,800 kcal/kg approximately and Heat Rate is 2,450 kcal/kWh at full load in average

(b) Oil consumption

Table 4.6-7 shows the estimate of oil consumption in 2028. According to Table 4.1-2 “Fuel Consumption in Java-Bali Region (2008 – 2016)”, oil consumption for MFO and HSD in 2007 is estimated 3.73 million kiloliter and 0.51 million kiloliter in 2016 respectively. Oil consumption of 1.7 million kiloliter for Scenario 0 and Scenario 1 is about 50 % of that in 2007 and 3.1 million kiloliter for Scenario 2 and Scenario 3 is almost at the same level as in 2007.

Table 4.6-7 Estimate of Oil Consumption in 2028

Scenario	Scenario 0	Scenario 1	Scenario 2	Scenario 3
Oil (Million Kilo Liter)	1.7	1.7	3.1	3.1

(c) Gas and LNG consumption

Table 4.6-8 shows the estimate of gas and LNG consumption in 2028. According to Table 4.1-2 “Fuel Consumption in Java-Bali Region (2008 - 2016)”, gas consumption in 2016 is estimated 341 billion cubic feet (bcf). Gas consumption resulted from WASP simulation is 22 % (Scenario 1) to 100 % (Scenario 2) higher than in the estimate for 2016. As the proven gas reserve in 2005 was 97.26 trillion cubic feet according to Table 4.1-1 “Resource/Reserve of Oil and Gas”, 692 bcf for Scenario 2 will account for 0.7 % of the proven gas reserve in 2005. Further acceleration of gas exploitation will be required considering the current shortage of gas supply to the exiting thermal power stations.

[16] Source: PLN Statistics 2006, Table 24

Table 4.6-8 Estimate of Gas and LNG Consumption in 2028

Scenario	Scenario 0	Scenario 1	Scenario 2	Scenario 3
Gas & LNG (Million mmbtu)	496	417	692	688
Gas & LNG (Billion Cubic Feet)	496	417	692	688

Note: 1000 Cubic Feet equal to about 1 mmbtu.

(d) Capacity Factor of Coal-fired Power Plants

Table 4.6-9 shows the estimate of capacity factor of coal-fired thermal plants in 2028. All scenarios bears capacity factor of 60 to 62 %. Capacity factor of PJB Paiton coal-fired thermal plant (400 MW × 2 units) was 75.4 % in 2005, 81.6 % in 2006 and 87.1 % in 2007 (See Appendix 5-1). The current capacity factor of PJB Paiton means that the plant is being operated as a base load power plant. Simulation results by WASP indicate that the position of coal-fired thermal plants will change from a base load plant to a base to middle load plant, if LNG & Gas-fired thermal plants, geothermal plants and nuclear power plants are full operation to meet the scenarios' targets as mentioned before.

Table 4.6-9 Capacity Factor of Coal-fired Power Plants in 2028

Scenario	Scenario 0	Scenario 1	Scenario 2	Scenario 3
Capacity Factor (%)	62.4	60.2	60.2	61.3

(e) Capacity Factor of Nuclear Power Plant

Table 4.6-10 shows the estimate of capacity factor of nuclear power plant in 2008. All scenarios indicate that nuclear power plants will be full operation, except the planned and forced outage period because of their lowest operation cost at the moment.

Table 4.6-10 Capacity Factor of Nuclear Power Plants in 2028

Scenario	Scenario 0	Scenario 1	Scenario 2	Scenario 3
Capacity Factor (%)	85.9	85.9	85.9	85.9

(f) Environmental issues

Environmental issues are discussed in Section 4.6.3.

3) Conclusion

(a) All scenarios indicate more than 50 % of generated energy will be provided by coal-fired thermal plants including Java-Sumatra Interconnection up to the year 2028. Coal-fired thermal plants will play an important role in the power source development plan.

(b) Maximum coal consumption in 2028 will be 75 % of domestic coal production of 190 million ton in 2006. Exportable volume will be remarkably decreased unless acceleration of coal production is achieved.

(c) The position of coal-fired thermal plants will be changed from a base load plant to a base to middle load plant.

(d) Despite its large initial investment cost, a nuclear power plant will be at full operation for all scenarios due to its lowest operation cost.

(e) Oil-fired power plants will account for 1 to 2% of generated energy in 2028 as a peak load plant.

(f) Gas and LNG-fired plants will account for 15 to 21% of generated energy in 2028 as peak load & middle load plants.

4.6.2 Capital Requirement and Generation Cost of Scenarios

(1) Assumptions for Calculation

For each power development scenario discussed in the previous Section 4.6.1, capital requirement for investment was estimated. The assumptions made for the estimation are as follows.

< Construction cost >

- All the values are in 2008 prices and no variations of prices nor inflation is considered.
- Investment costs are those used in 4.6.1. Adding IDC (interest during construction), investment cost is shown on the year in which the plant (the unit) is put in operation.
- IPP power plants are included along with those power plants owned by PLN, Indonesia Power and PJB.
- Jawa-Sumatra Interconnection project includes submarine cable and related transmission facilities, and development cost of power plants (coal-fired) on the sending end.
- Projects listed in RUPTL 2007-2016 are included but separately shown from those considered in generation expansion planning in 4.6.1 However, coal thermal plants related to Jawa-Sumatra Interconnection, pumped storage projects are shown outside of RUPTL group.
- Costs for Transmission Lines, Distribution Lines and Substations are not included in this section as there are no differences between scenarios. It will be discussed in the next chapter.
- As for renewables, it is assumed that the proportions of energy generated by solar (PV), wind power and biomass are 65%, 34.4% and 0.6%, respectively, of total renewable

energy and that the average capacity factors are 14%, 20% and 43%, respectively, to calculate the capacities to be developed. Unit costs of renewables are assumed as follows.

Table 4.6-11 Unit Costs of Renewable Energy

	Capital cost (US$/kW)	OM cost	Life time
Solar	5,000	US¢3/kWh	24.4
Wind	1,100	0.6% of capital cost	25
Biomass	1,700	3% of capital, US¢0.44/kWh	15

- It is assumed that solar generation is not done by PLN or other power generating companies but done at numerous number of individual houses and factories and office buildings, etc. The investment of solar generation equipment is therefore assumed to be done by individual households, private companies and organizations, etc., and is not included in capital requirement calculation.
- The investment cost of solar generation equipment is assumed to be recovered by selling the generated energy to the system. This sales is named, just for the convenience, "Green Energy Payment" and its unit rate is US¢ 30 per kWh, which is the cost just enough to recover all the cost incurred by those who invested in the equipment. The calculation of the unit cost is shown in the table below.

Table 4.6-12 Calculation of Unit Cost of Solar (Green Energy Payment)

	Cost per kW	Cost per kWh	Remark	
System Life (years)	24.4			
Total kWh (capacity factor)	30,535.66		14%	
Installed cost	$5,000.00	$0.16		
Reliability/Maintenance costs	$575.58	$0.02		
Maintenance contract				
Insurance	$226.47	$0.01		
Decommissioning	$46.95	$0.00		
Permitting	$30.95	$0.00		
Financial cost (Interest R, Yr)	$3,137.27	$0.10	10%	10
TOTAL Costs	$9,017.22	$0.30		
Rp Conversion(exchange rate)		IDR 2,716.77	9,200	

Source: "A REVIEW OF PV SYSTEM PERFORMANCE AND LIFE-CYCLE COSTS FOR THE SUNSMART SCHOOLS PROGRAM, "Proceedings of ISEC2006:ASME International Solar Energy Conference 2006, modified by JICA team.

The capacity factor of solar (PV) unit in the table above is set at 14%, which came from the actual records in the United States. In Indonesia, MEMR reported that 10 kW unit generated 32.62 kWh/day on average, which leads to just the same level of capacity factor.[17].

[17] MEMR internet home page news : SIARAN PERS NOMOR : 45/HUMAS DESDM/2008, Tanggal : 15 Juli 2008, Workshop "Peran Photovoltaic Dalam Penyediaan Energi Listrik di Indonesia"

< Fuel cost and O & M cost for generation cost estimation >

- All the values are in 2008 prices and no variations of prices nor inflation is considered.
- Depreciation and interest of current assets and debts are taken from PLN's annual report 2007, assumed to be constant for the planning period. Current assets and debts for Jamali region are assumed at 75%, approximately the proportion of installed capacity of Jamali, of PLN total.
- The costs related to construction of those power plants considered in each power development scenario are assumed to be secured by loans and repaid at constant amount to calculate interests. Depreciation of these plants is calculated by constant depreciation method for the life time of power plants with no residual values.
- Fuel costs are those used in 4.6.1. Fuel cost for geothermal is the payment to Pertamina for the use of steam.
- Costs related to transmission/distribution system is not included here.
- Head office markup of PLN is not included.

Calculation of interest payment for power plant development is done on the financial condition shown in the table below.

Table 4.6-13 Financial Conditions assumed for Interest Calculation

	RUPTL	LNG	NUC	GEO	COAL	J-SI	CC60	HYDRO	Renewable (wind, bio)	Solar*
Repayment years	10	20	30	20	15	20	20	30	15	10
Interest rate	8%	6%	6%	10%	8%	6%	8%	6%	6%	10%

* Investment costs for solar units are not included in capital requirement calculation.

(2) Capital Requirement

Investment schedule and capital requirement for each scenario is shown in Table 4.6-14 to 4.6-17. These are the reproduction of power development schedules shown in money terms. For Scenario 2 and 3, columns were added to the tables to show the capital requirements when the investment for solar units are explicitly taken into consideration.

Comparing with Scenario 0, LNG, geothermal and hydro are smaller in Scenario 1, compensated by increased coal thermal. In Scenario 2, LNG is slightly larger and large input of renewables lowers the investment in coal thermal than in Scenario 0. Total investment of Scenario 2 looks smaller than Scenario 0, only when the investment for solar equipment, which takes 65% of energy generated by renewables, is not included. If included, Scenario 2 exceeds Scenario 0 by US$ 20 billion for the 20 year total. In Scenario 3, more hydro and renewables are to be developed and if solar investment is included, total investment exceeds Scenario 0 by US$ 40 billion.

Table 4.6-14 Capital requirement for Power Plant Construction in Scenario 0

YEAR	RUPTL	LNG	N10H	GE55	C10H	J-SI	Hydro	PUMP	RENEW	Total
2009	3,893	-	-	-	-	-	-	-	-	3,893
2010	5,355	-	-	-	-	-	-	-	-	5,355
2011	1,807	-	-	733	-	-	-	-	-	2,539
2012	729	-	-	-	2,035	-	-	-	-	2,764
2013	-	-	-	-	-	-	-	-	-	-
2014	-	-	-	488	-	4,755	-	-	-	5,243
2015	275	749	-	244	-	1,189	-	416	-	2,873
2016	-	749	-	244	-	-	-	416	-	1,409
2017	-	749	-	244	8,141	-	-	-	-	9,134
2018	-	749	3,297	244	-	-	-	832	-	5,121
2019	-	-	-	244	6,105	-	-	832	-	7,181
2020	-	-	-	244	4,070	-	3,002	-	-	7,316
2021	-	-	3,297	244	4,070	-	-	-	-	7,611
2022	-	-	-	244	6,105	-	2,309	-	-	8,659
2023	-	1,498	-	244	4,070	-	-	-	-	5,812
2024	-	-	3,297	244	2,035	-	2,309	-	-	7,885
2025	-	1,498	-	244	6,105	-	-	-	-	7,848
2026	-	-	3,297	244	6,105	-	-	-	-	9,646
2027	-	1,498	-	244	6,105	-	770	-	-	8,617
2028	-	-	3,297	244	8,141	-	-	-	-	11,681
Total	12,058	7,490	16,483	4,639	63,089	5,944	8,390	2,495	-	120,589

Unit : US$ million

Table 4.6-15 Capital requirement for Power Plant Construction in Scenario 1

YEAR	RUPTL	LNG	N10H	GE55	C10H	J-SI	Hydro	PUMP	RENEW	Total
2009	3,893	-	-	-	-	-	-	-	-	3,893
2010	5,355	-	-	-	-	-	-	-	-	5,355
2011	1,807	-	-	733	-	-	-	-	-	2,539
2012	729	-	-	-	2,035	-	-	-	-	2,764
2013	-	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	4,755	-	-	-	4,755
2015	275	749	-	-	-	1,189	-	416	-	2,629
2016	-	749	-	-	2,035	-	-	416	-	3,200
2017	-	749	-	-	6,105	-	-	-	-	6,854
2018	-	749	3,297	-	2,035	-	-	832	-	6,912
2019	-	-	-	-	6,105	-	-	832	-	6,937
2020	-	-	-	-	2,035	-	3,002	-	-	5,037
2021	-	-	3,297	-	6,105	-	-	-	-	9,402
2022	-	-	-	-	8,141	-	-	-	-	8,141
2023	-	749	-	-	4,070	-	-	-	-	4,819
2024	-	-	3,297	-	6,105	-	-	-	-	9,402
2025	-	-	-	-	8,141	-	-	-	-	8,141
2026	-	-	3,297	-	8,141	-	-	-	-	11,437
2027	-	-	-	-	8,141	-	1,539	-	-	9,680
2028	-	-	3,297	-	8,141	-	-	-	-	11,437
Total	12,058	3,745	16,483	733	77,335	5,944	4,541	2,495	-	123,334

Unit : US$ million

Table 4.6-16 Capital Requirement for Power Plant Construction in Scenario 2

YEAR	RUPTL	LNG	N10H	GE55	C10H	J-SI	Hydro	PUMP	RENEW	(Solar)	Total	Total with Solar
2009	3,893	-	-	-	-	-	-	-	-	-	3,893	3,893
2010	5,355	-	-	-	-	-	-	-	-	-	5,355	5,355
2011	1,807	-	-	733	-	-	-	-	-	-	2,539	2,539
2012	729	-	-	-	2,035	-	-	-	-	-	2,764	2,764
2013	-	-	-	-	-	-	-	-	-	-	-	-
2014	-	-	-	488	-	4,755	-	-	-	-	5,243	5,243
2015	275	749	-	244	-	1,189	-	416	-	-	2,873	2,873
2016	-	749	-	244	-	-	-	416	-	-	1,409	1,409
2017	-	749	-	244	8,141	-	-	-	-	-	9,134	9,134
2018	-	749	3,297	244	-	-	-	832	-	-	5,121	5,121
2019	-	-	-	244	4,070	-	-	832	-	-	5,146	5,146
2020	-	1,498	-	244	-	-	3,002	-	-	-	4,744	4,744
2021	-	-	3,297	244	4,070	-	-	-	630	4,970	8,241	13,211
2022	-	1,498	-	244	2,035	-	2,309	-	38	300	6,124	6,424
2023	-	-	-	244	6,105	-	-	-	754	5,935	7,103	13,038
2024	-	1,498	3,297	244	-	-	2,309	-	87	685	7,435	8,120
2025	-	-	-	244	6,105	-	-	-	892	7,030	7,241	14,271
2026	-	1,498	3,297	244	2,035	-	-	-	148	1,170	7,222	8,392
2027	-	-	-	244	6,105	-	770	-	1,059	8,350	8,178	16,528
2028	-	-	3,297	244	8,141	-	-	-	220	1,740	11,902	13,642
total	12,058	8,988	16,483	4,639	48,843	5,944	8,390	2,495	3,828	30,180	111,668	141,848

Unit : US$ million

Table 4.6-17 Capital Requirement for Power Plant Construction in Scenario 3

YEAR	RUPTL	LNG	N10H	GE55	C10H	J-SI	Hydro	PUMP	RENEW	(Solar)	Total	Total with Solar
2009	3,893	-	-	-	-	-	-	-	-	-	3,893	3,893
2010	5,355	-	-	-	-	-	-	-	-	-	5,355	5,355
2011	1,807	-	-	733	-	-	-	-	-	-	2,539	2,539
2012	729	-	-	-	2,035	-	-	-	-	-	2,764	2,764
2013	-	-	-	-	-	-	-	-	-	-	-	-
2014	-	-	-	488	-	4,755	-	-	-	-	5,243	5,243
2015	275	749	-	244	-	1,189	-	416	-	-	2,873	2,873
2016	-	749	-	244	-	-	-	416	-	-	1,409	1,409
2017	-	749	-	244	8,141	-	-	-	-	-	9,134	9,134
2018	-	749	3,297	244	-	-	-	832	-	-	5,121	5,121
2019	-	-	-	244	4,070	-	-	832	-	-	5,146	5,146
2020	-	1,498	-	244	-	-	3,002	-	-	-	4,744	4,744
2021	-	-	3,297	244	4,070	-	-	-	630	4,970	8,241	13,211
2022	-	1,498	-	244	2,035	-	2,309	-	38	300	6,124	6,424
2023	-	-	-	244	4,070	-	-	-	1,462	11,520	5,776	17,296
2024	-	1,498	3,297	244	-	-	2,309	-	132	1,035	7,480	8,515
2025	-	-	-	244	6,105	-	-	-	1,741	13,730	8,090	21,820
2026	-	1,498	3,297	244	2,035	-	-	-	245	1,930	7,319	9,249
2027	-	-	-	244	4,070	-	1,539	-	2,063	16,265	7,917	24,182
2028	-	-	3,297	244	6,105	-	-	-	386	3,045	10,033	13,078
total	12,058	8,988	16,483	4,639	42,738	5,944	9,160	2,495	6,697	52,795	109,202	161,997

Unit : US$ million

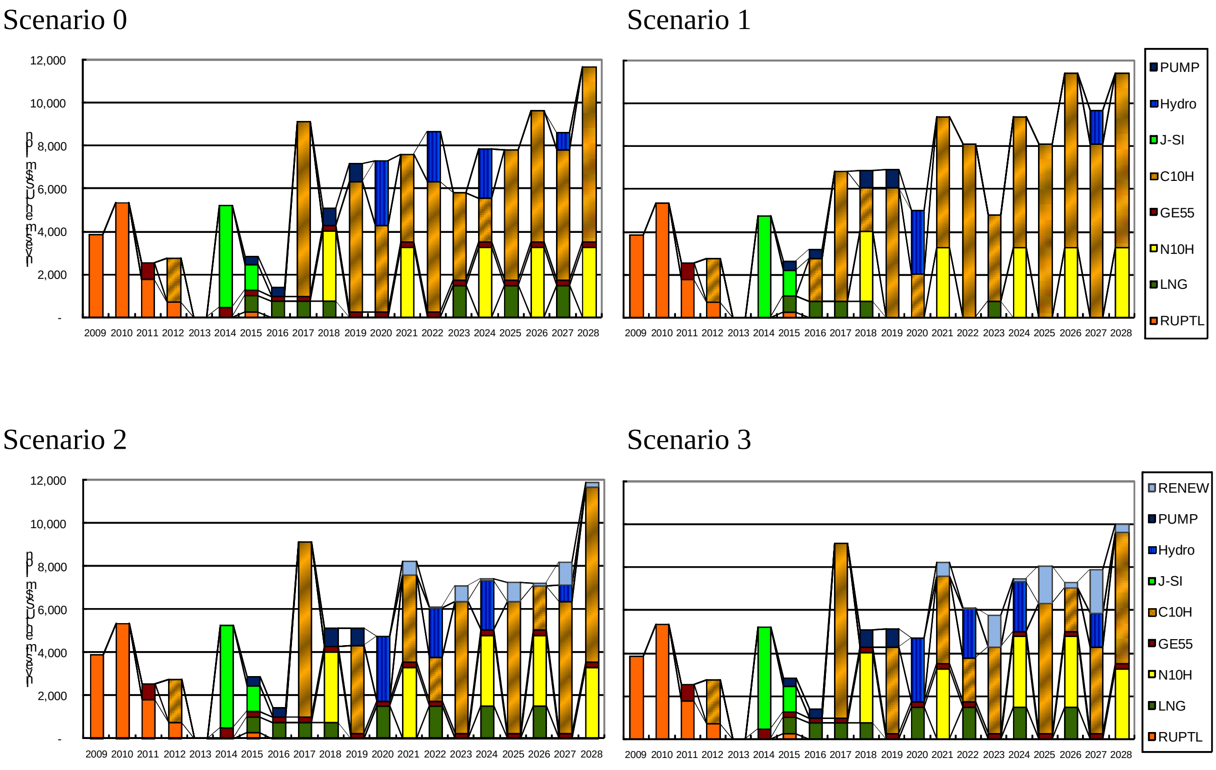


Fig. 4.6-8 Investment Schedule by Plant Type (shown in COD year, without Solar)

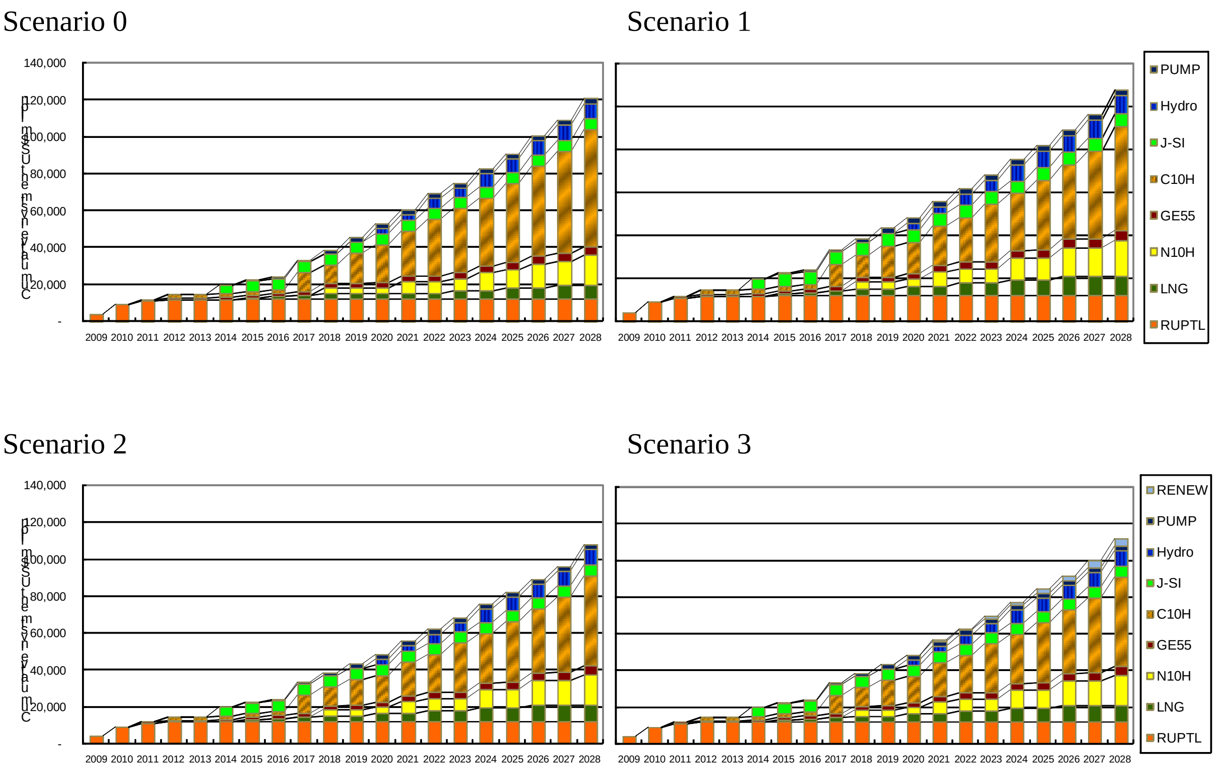


Fig. 4.6-9 Cumulative Investment Schedule by Plant Type (without Solar)

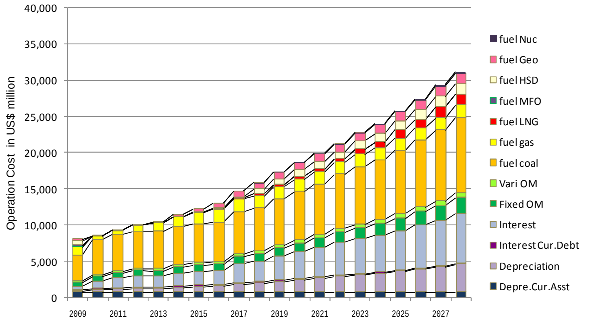
(3) Operation Cost and Unit Generation Cost

For each scenario, depreciation of assets, interests for loans, operation and maintenance costs, fuel costs are estimated to obtain unit generation cost at generating end. For the calculation of unit generation cost, own use of 4% is deducted from the generated energy.

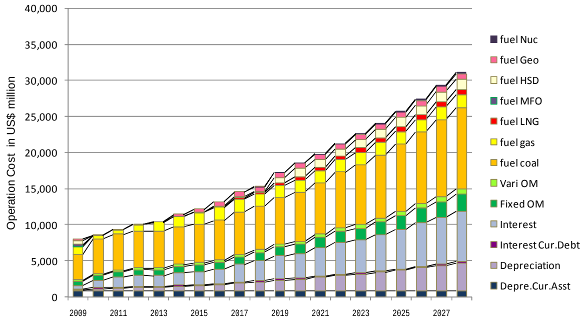
Fig. 4.6-10 shows the total generation cost for four power development scenarios. Compared to Scenario 0, fuel cost for LNG and geothermal are smaller in Scenario 1 which is balanced by the increase of coal fuel cost. Total generation costs in these two scenarios are almost the same. In Scenario 2, coal fuel cost is decreased, LNG fuel increased, and there is large portion of cost for "Green Energy Payment" after 2021. In Scenario 3, characteristics of Scenario 2 are more accentuated but there is no difference of LNG fuel cost between Scenario 2 and 3, as the capacity of LNG plants are fully used in these scenarios.

Figs. 4.6-11 to 4.6-14 show the component of generation cost at four points during the planning period, 2009, 2015, 2020 and 2028. In 2009 and in 2015, there are no differences recognized among four scenarios. This is because power plants to be constructed by these time points are mostly those in RUPTL. In 2020, Scenario 1 reveals a slight increase in coal fuel and a slight decrease in fuel and capital related costs (depreciation and interest payment) for geothermal, compared to Scenario 0. In Scenario 2 and 3, the decrease of coal fuel, increase of LNG, HSD and geothermal fuel, decrease in total capital related costs, compared to Scenario 0. In 2028, capital related costs and coal fuel cost are larger, and LNG fuel smaller, in Scenario 1 than in Scenario 0. The difference between Scenario 0 & 1 group and 2 & 3 group is very large in that the latter group has a large share of "Green Energy Payment" and smaller capital related costs. This is more marked in Scenario 3. As has been explained, these two scenarios cover the cost of solar generation equipment in the form of power purchase payment to large number of individual solar generators.

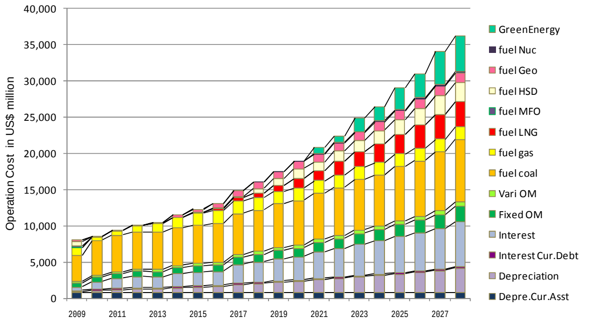
(a) Scenario 0



(b) Scenario 1



(c) Scenario 2



(d) Scenario 3

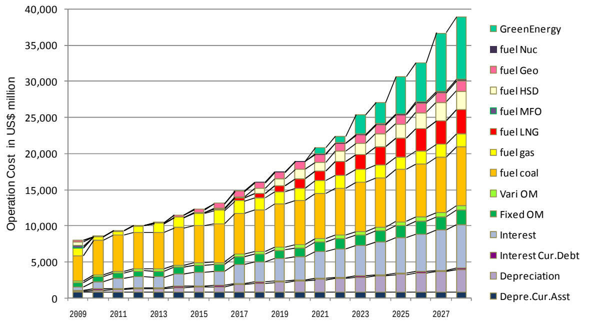
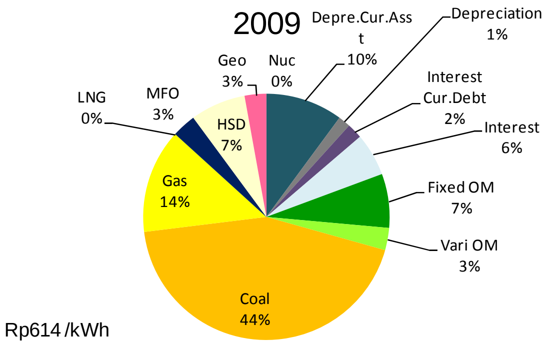
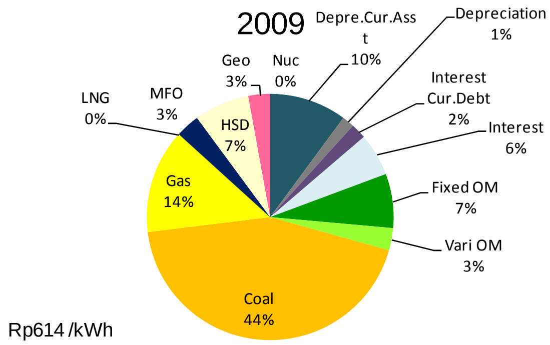


Fig. 4.6-10 Estimation of Total Generation Cost

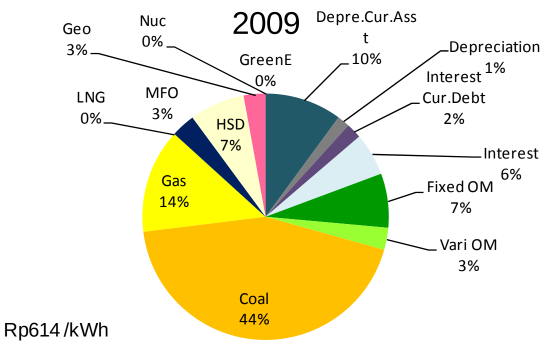
(a) Scenario 0



(b) Scenario 1



(c) Scenario 2



(d) Scenario 3

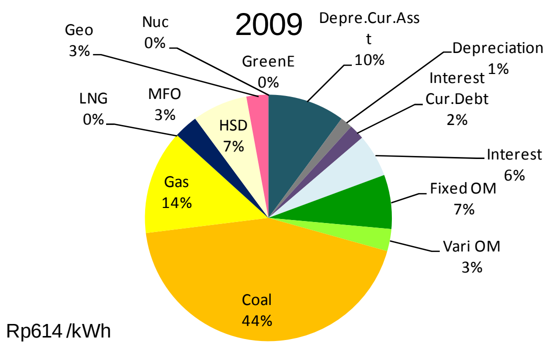


Fig. 4.6-11 Generation Cost Component in 2009

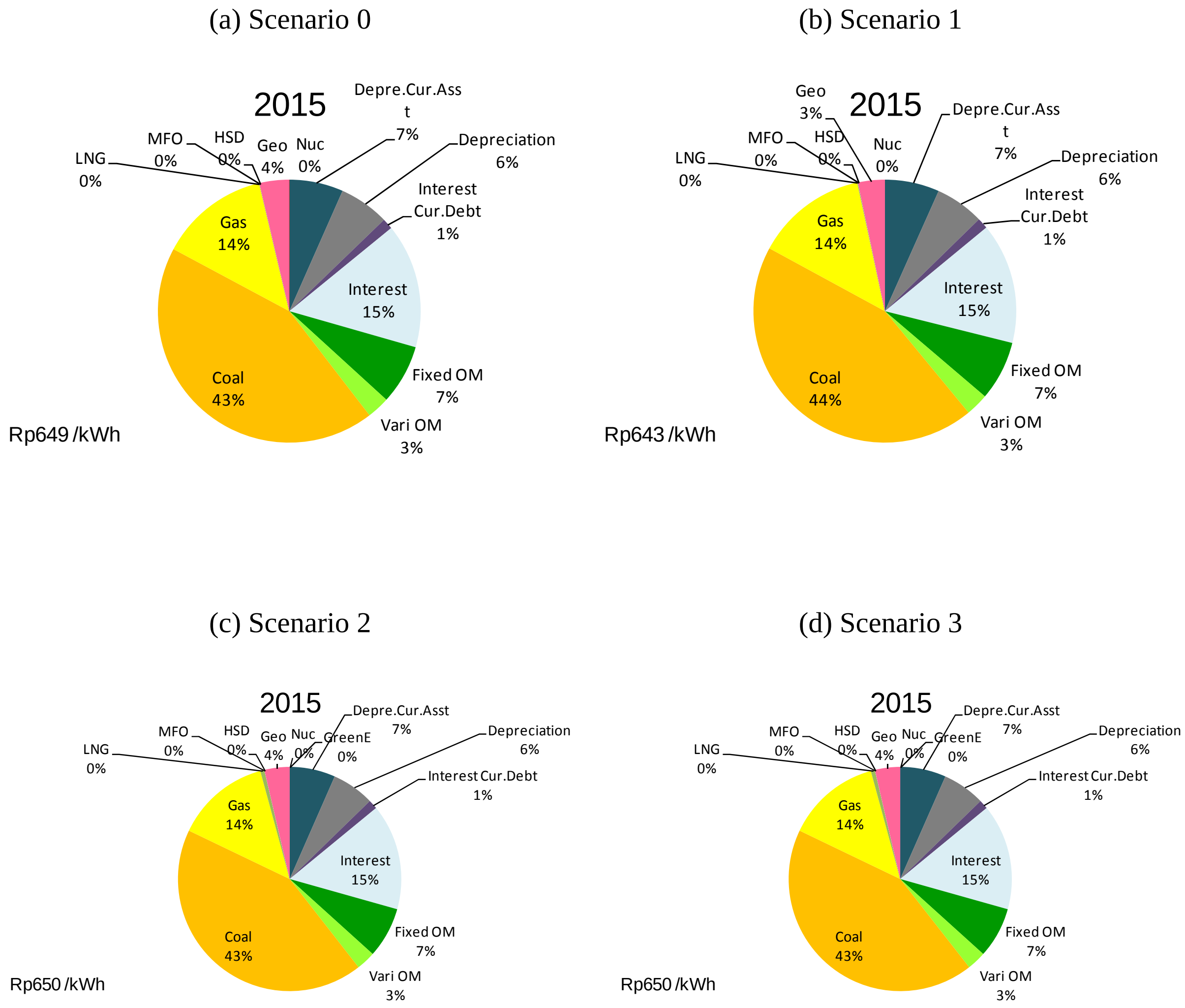


Fig. 4.6-12 Generation Cost Component in 2015

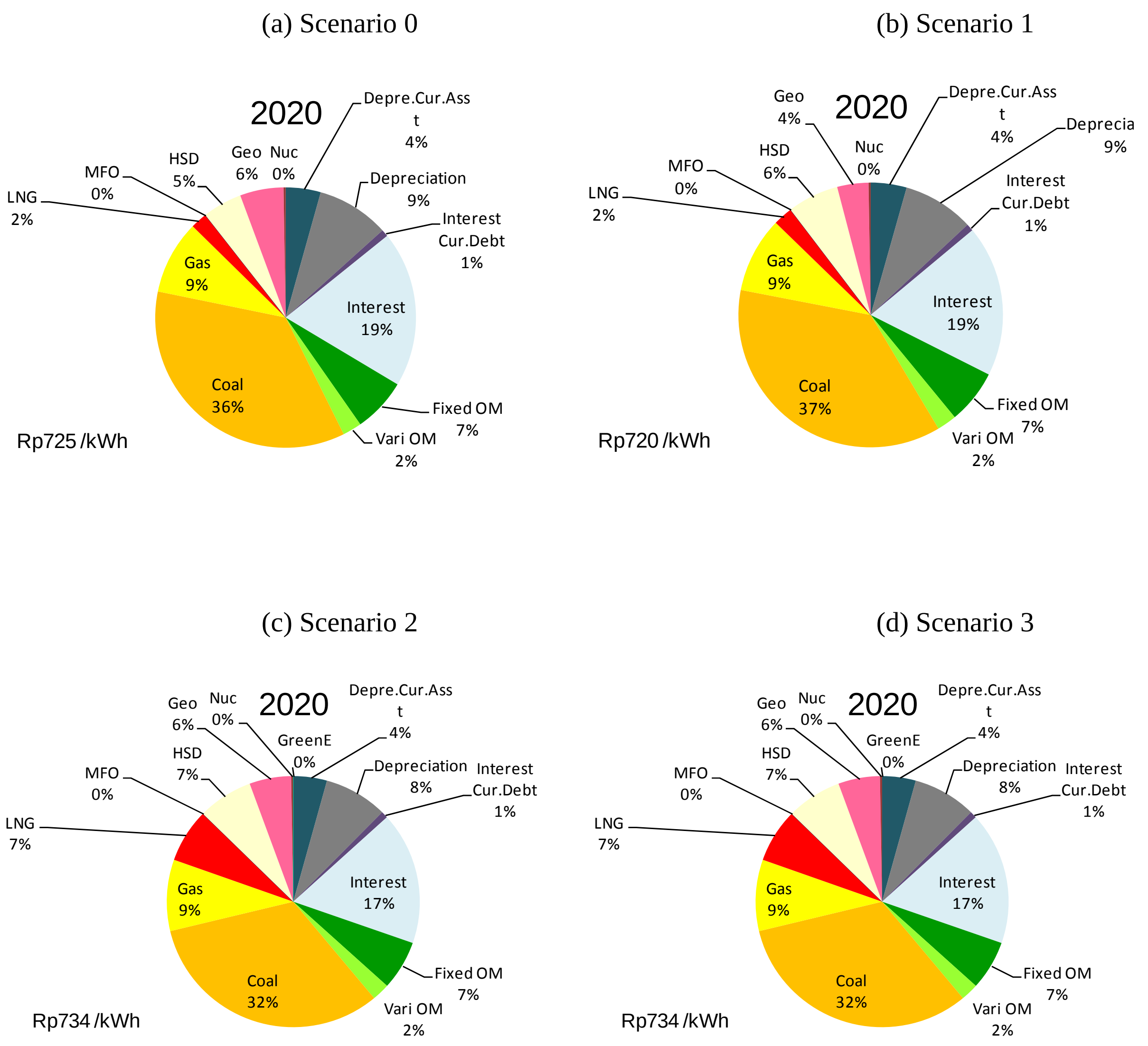


Fig. 4.6-13 Generation Cost Component in 2020

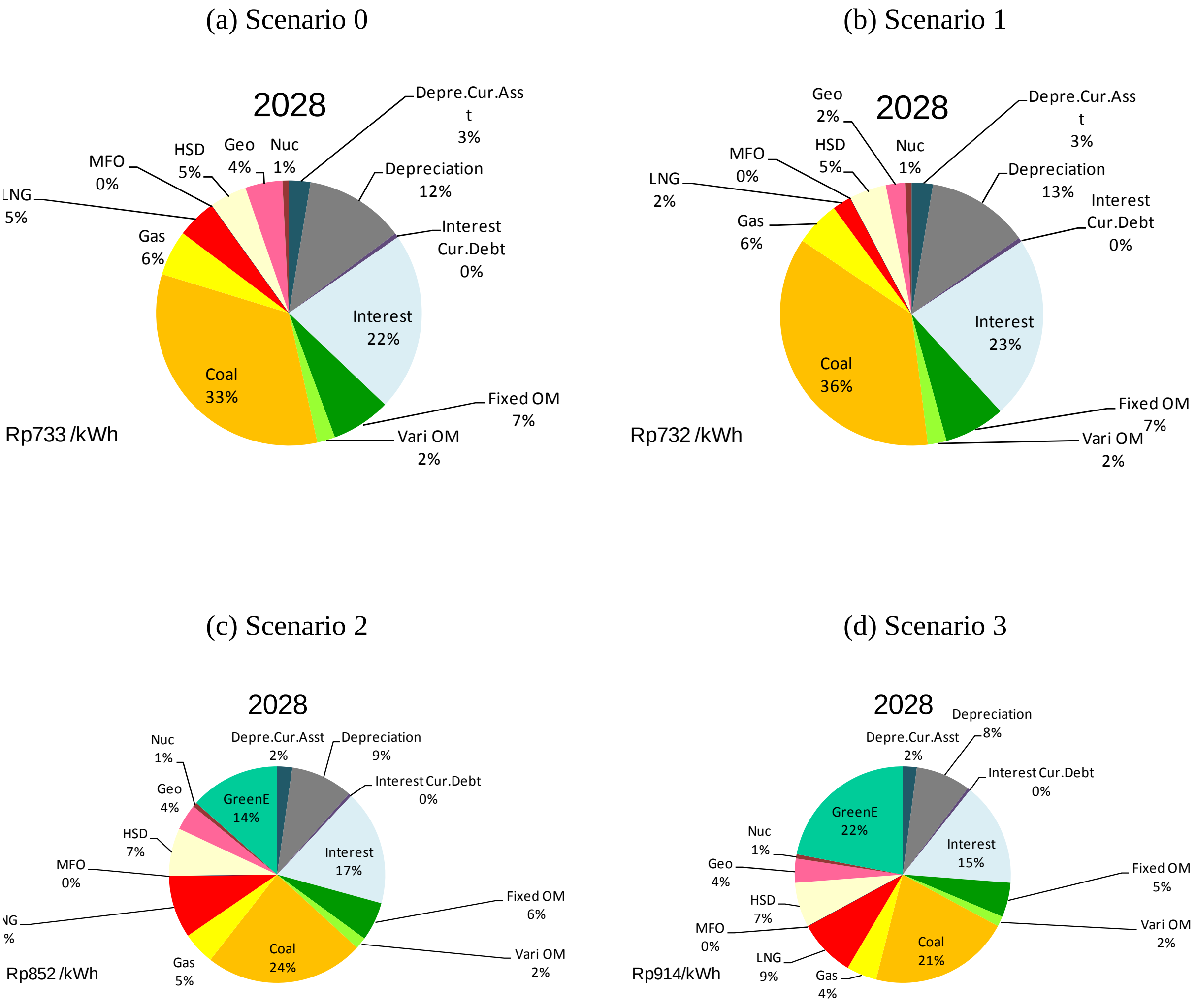


Fig. 4.6-14 Generation Cost Component in 2028

(4) Summary

For four power development scenarios, capital requirement and unit generation cost are summarized in Tables 4.6-18 and 4.6-19, respectively. Capital requirement is largest in Scenario 1 which will have more coal thermal plants than others, but the difference in total is only about 2% compared to Scenario 0. Total capital requirement becomes smaller in Scenario 2 and 3, when the capital for solar generation equipment is assumed to be born by many individuals and not included in the investment schedules. When included, however, these scenarios will be much more expensive than Scenario 0 and 1.

Table 4.6-18 Comparison of Capital Requirement in Four Scenarios

YEAR	Scenario 0	Scenario 1	Scenario 2	Scenario 2 with Solar	Scenario 3	Scenario 3 with Solar
2009	3,893	3,893	3,893	3,893	3,893	3,893
2010	5,355	5,355	5,355	5,355	5,355	5,355
2011	2,539	2,539	2,539	2,539	2,539	2,539
2012	2,764	2,764	2,764	2,764	2,764	2,764
2013	-	-	-	-	-	-
2014	5,243	4,755	5,243	5,243	5,243	5,243
2015	2,873	2,629	2,873	2,873	2,873	2,873
2016	1,409	3,200	1,409	1,409	1,409	1,409
2017	9,134	6,854	9,134	9,134	9,134	9,134
2018	5,121	6,912	5,121	5,121	5,121	5,121
2019	7,181	6,937	5,146	5,146	5,146	5,146
2020	7,316	5,037	4,744	4,744	4,744	4,744
2021	7,611	9,402	8,241	13,211	8,241	13,211
2022	8,659	8,141	6,124	6,424	6,124	6,424
2023	5,812	4,819	7,103	13,038	5,776	17,296
2024	7,885	9,402	7,435	8,120	7,480	8,515
2025	7,848	8,141	7,241	14,271	8,090	21,820
2026	9,646	11,437	7,222	8,392	7,319	9,249
2027	8,617	9,680	8,178	16,528	7,917	24,182
2028	11,681	11,437	11,902	13,642	10,033	13,078
Total	120,589	123,334	111,668	141,848	109,202	161,997

Unit : US$ million

Unit generation costs of Scenario 0 and 1 are almost the same, despite the difference in the proportions of power plant types. Scenarios 2 and 3 start deviating from Scenarios 0 and 1 around in and after 2015, because more LNG is used in these scenarios and also large amount is paid to individual solar generators at US cent 30 per kWh later in the planning period.

Table 4.6-19 Comparison of Unit Generation Cost in Four Scenarios

YEAR	Scenario 0	Scenario 1	Scenario 2	Scenario 3
2009	614	614	614	614
2015	649	643	650	650
2020	725	720	734	734
2028	733	732	852	914

Unit : Rp. per kWh

4.6.3 Environmental and Social Considerations

Future emissions of CO_2, SOx and NOx from power generation in Jamali area are presented separately for scenarios 0 to 3.

CO_2, emission factors for calculations are derived from the Federation of Electric Power Companies of Japan, and 887g-CO_2/kWh, 704 g-CO_2/kWh and 443 g-CO_2/kWh are assumed for coal-fired, oil-fired (regardless of fuel oil types) and natural gas-fired power generation, respectively. CO_2 emission factor for natural gas-fired power generation is the average of

478g-CO_2/kWh for single-cycle power generation and 408g-CO_2/kWh for combined-cycle power generation. in future emission factors are expected to go down in future, as generation efficiencies are improved in Jamali area. For geothermal, hydroelectric, nuclear and renewable power generation, CO_2 emissions are assumed to be zero. As for power from Sumatra to Jamali area through Java-Sumatra underwater transmission lines, emission factor of 887g-CO_2/kWh for coal-fired power generation has been applied to all of the supply, since it will be produced by coal-fired power generation.

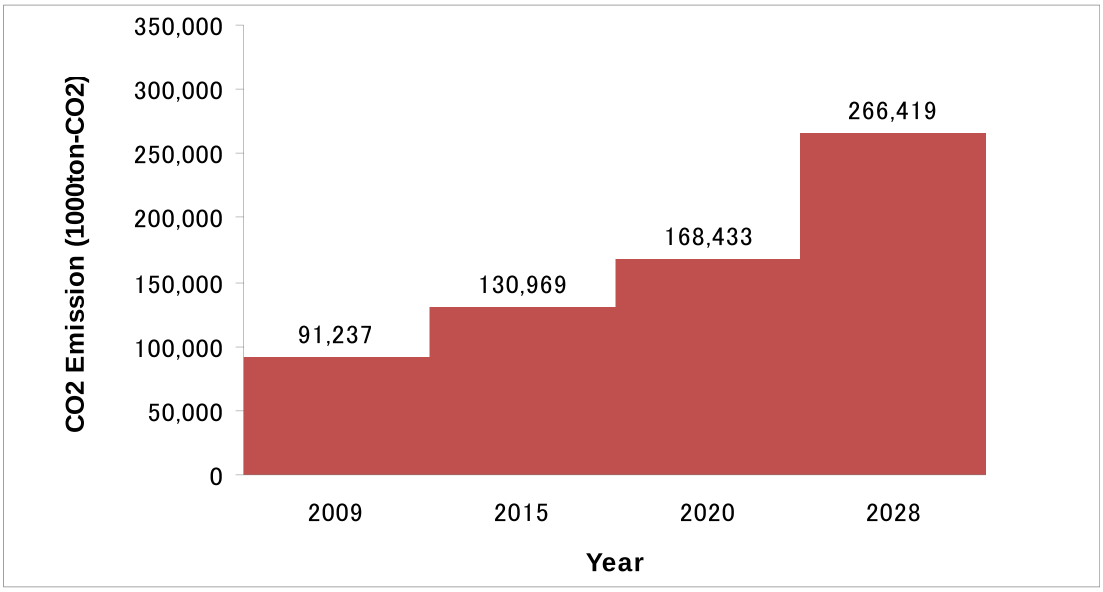
On the other hand, SOx emission factors for calculations are based on a report of J-Power and their averages for six OECD countries in 2001 have been used. SOx emission factor of 2.0g/kWh is assumed both for coal-fired and oil-fired power generation. SOx emissions from natural gas-fired, geothermal, hydroelectric, nuclear and renewable power generation are all regarded to be zero.

Only thermal power generation was assumed to emit NOx, with its NOx emission factor of 4.4g/kWh regardless whether it is coal-fired, oil-fired or natural gas-fired. As for electricity supplied through underwater transmission lines, it will be produced by coal-fired power generation, and NOx emission factor for coal-fired power generation (4.4g/kWh) was applied to all of the supply. Actual emissions of SOx and NOx to the atmosphere will be significantly reduced, when desulfurization/denitrification facilities become widely used in Jamali area.
Total emissions of CO_2, SOx and NOx estimated on the basis of the above assumptions are presented below, separately for each scenario.

Table 4.6-20 (1/4) CO_2, SOx and NOx emissions for Scenario 0

Scenario 0- Annual Emission (1,000 t)

Year	CO_2	SOx	NOx
2009	91,237	184	510
2015	130,969	258	731
2020	168,433	338	934
2028	266,419	544	1,454



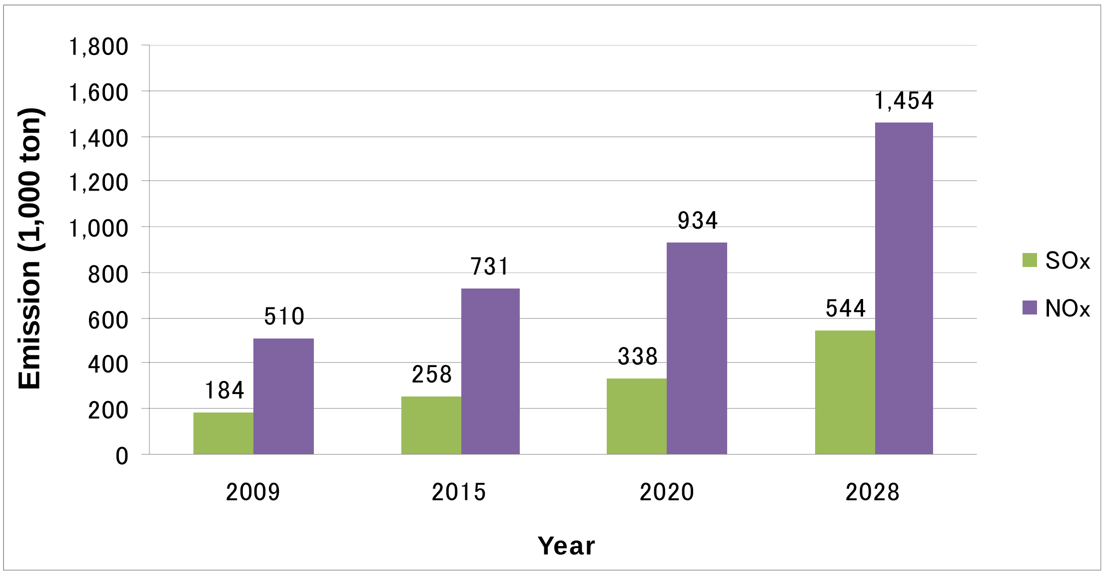
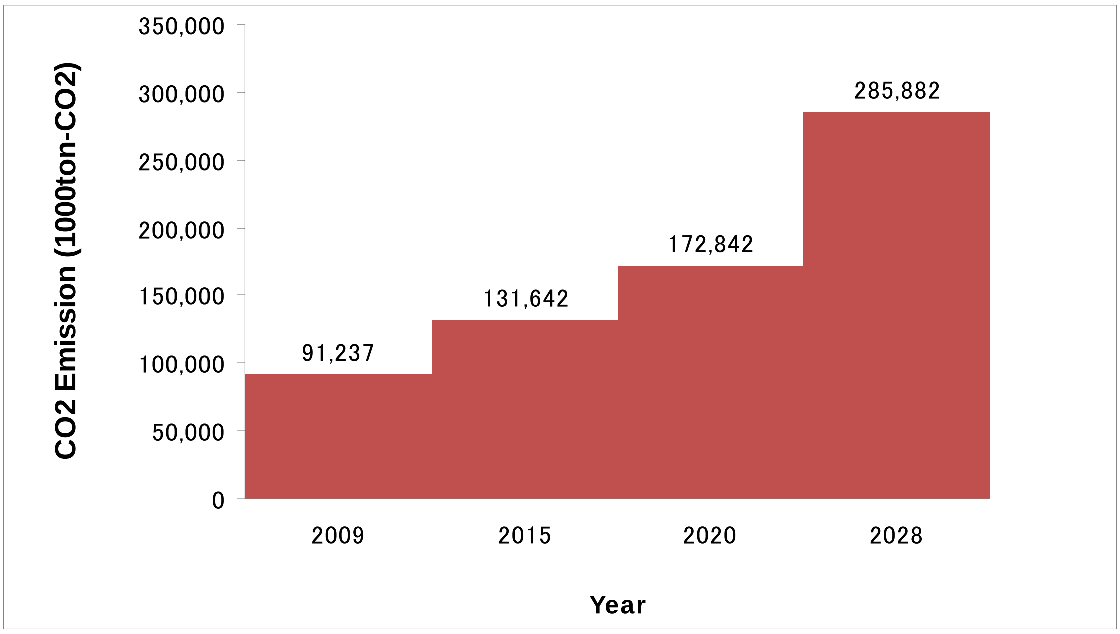


Table 4.6-20 (2/4) CO_2, SOx and NOx emissions for Scenario 1

Scenario 1- Annual Emission (1000 t)

Year	CO_2	SOx	NOx
2009	91,237	184	510
2015	131,642	260	735
2020	172,842	347	960
2028	285,882	598	1,528



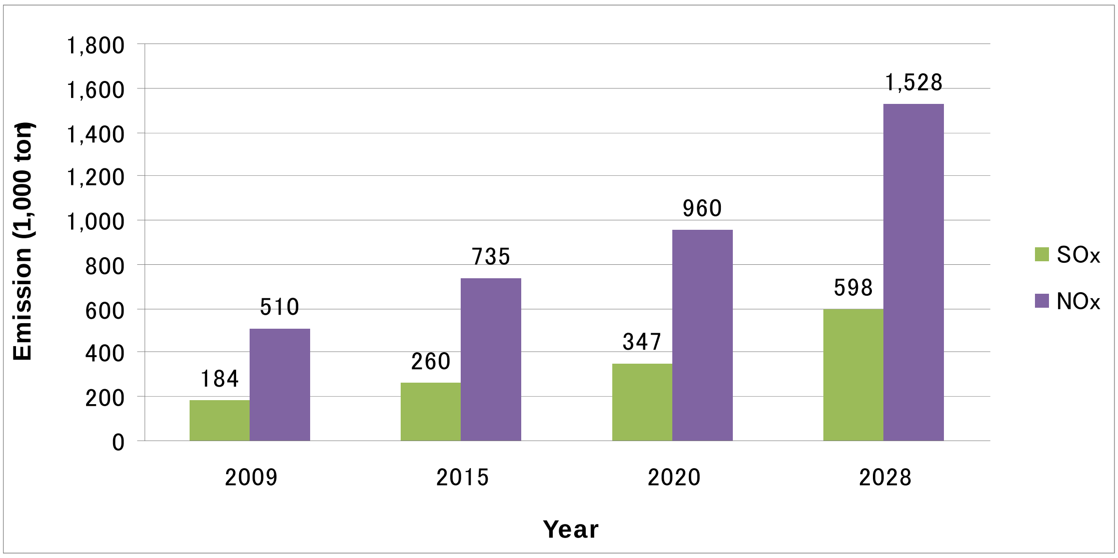
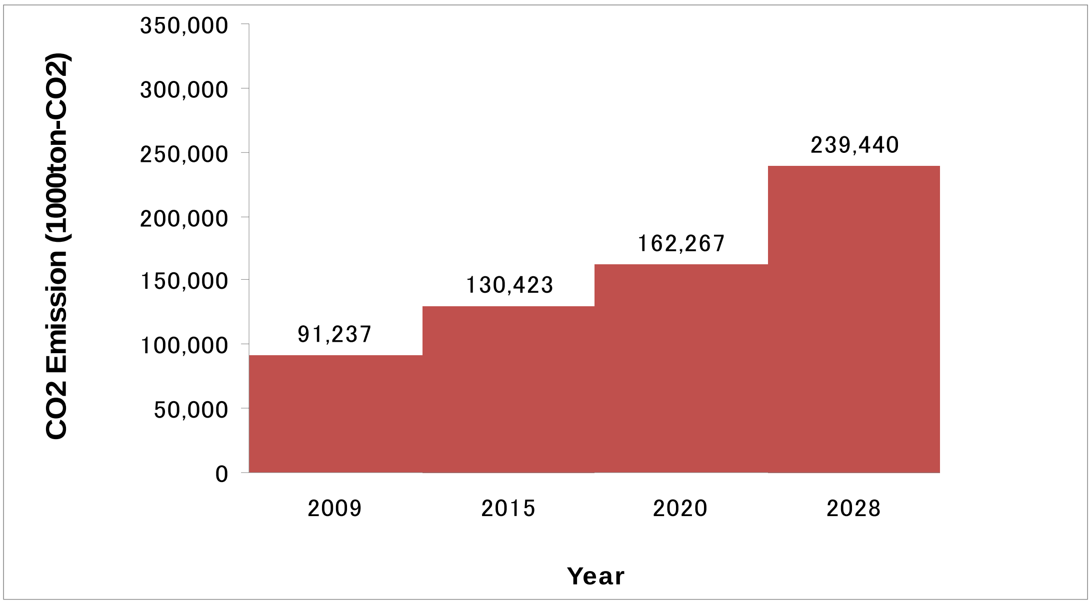


Table 4.6-20 (3/4) CO_2, SOx and NOx emissions for Scenario 2

Scenario 2 - Annual Emission (1,000 t)

Year	CO_2	SOx	NOx
2009	91,237	184	510
2015	130,423	256	731
2020	162,267	311	934
2028	239,440	458	1,384



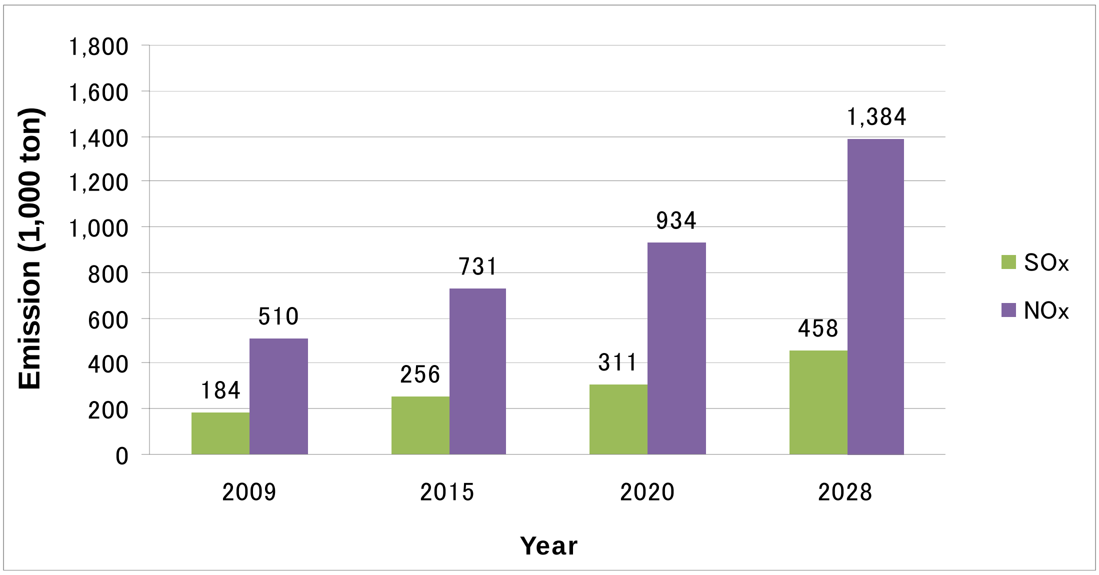
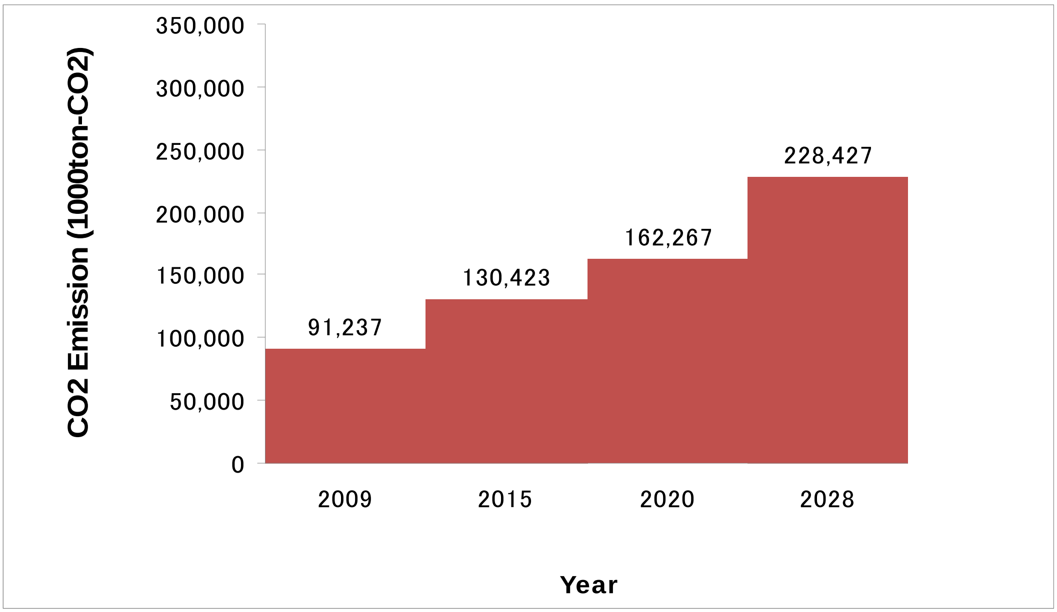
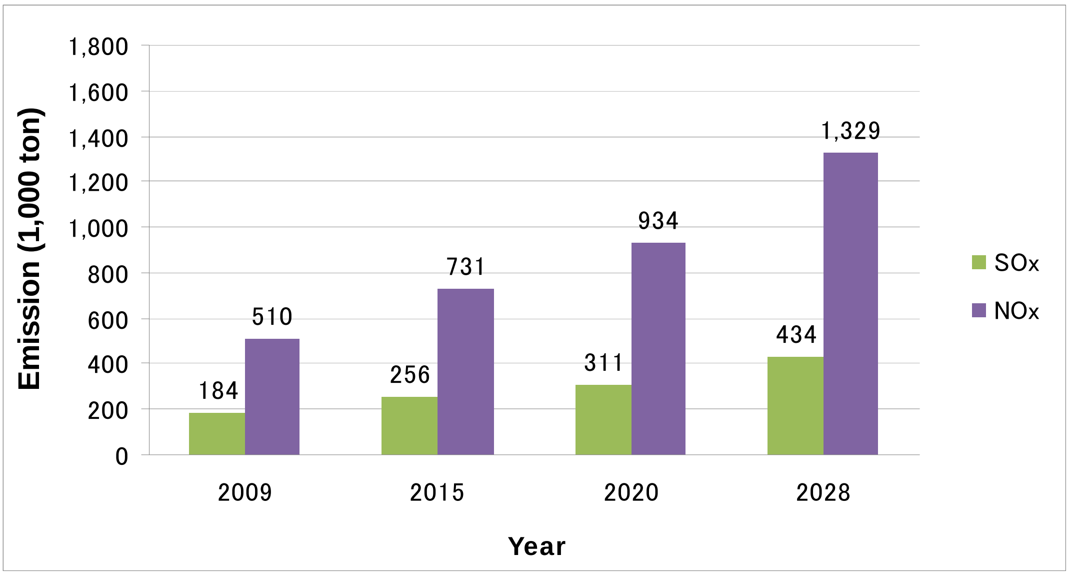


Table 4.6-20 (4/4) CO_2, SOx and NOx emissions for Scenario 3

Scenario 3 - Annual Emission (1,000 t)

Year	CO_2	SOx	NOx
2009	91,237	184	510
2015	130,423	256	731
2020	162,267	311	934
2028	228,427	434	1,329





Predicted emissions of CO_2, SOx and NOx in 2028 for these scenarios are summarized below.

Table 4.6-21 Predicted Annual Emissions of CO_2, SOx and NOx in 2028

(1,000 ton/year)

	CO_2	SOx	NOx
Scenario 0	266,419	544	1,454
Scenario 1	285,882	598	1,528
Scenario 2	239,440	458	1,384
Scenario 3	228,427	434	1,329

Table 4.6-21 indicates that Scenario 3 will have the least annual emissions for all of CO_2, SOx and NOx, followed by Scenario 2 and Scenario 0. Scenario 1 will emit the largest amounts for all of them.

Scenario 3 is most favorable against global warming and air pollution, and Scenario 2 is the second most favorable scenario. Most undesirable is Scenario 1.

4.6.4 Proposed Scenario

In the previous section the validity of the following scenarios was compared and evaluated in terms of power source development plan including power system, finance and environmental impact.

Scenario 0: Policy oriented scenario
Scenario 1: Coal power acceleration scenario
Scenario 2: Power source diversification scenario
Scenario 3: CO_2 emission reduction scenario

Main conclusion from the comparison of four scenarios is summarized in Table 4.6-22. The values forecasted or targeted as of 2028 are shown in the table.

Table 4.6-22 Main conclusion from comparison of scenarios

Description	Reliability		Cost	Environmental impact
	Power sources	System		
Scenario 0: Policy oriented scenario	Energy production ratio by fossil fuel 81% including coal 66%. No renewable energy	Energy production ratio by middle to peak power sources of oil, gas, reservoir hydro and pumped storage 19%	Generation cost 733Rp/kWh (100%).	Second largest emission of CO_2, NOx and SOx
Scenario 1: Coal power acceleration scenario	Energy production ratio by fossil fuel 85% including coal 72%. No renewable energy	Energy production ratio by middle to peak power sources 15%	Generation cost 732Rp/kWh (100%).	Largest emission of CO_2, NOx and SOx
Scenario 2: Power source diversification scenario	Energy production ratio by fossil fuel 77% including coal 54%. Renewable energy 4%, Capacity 3.3 GW.	Energy production ratio by middle to peak power sources 26%	Generation cost 852Rp/kWh (116%). Production cost by renewable energy is large.	Second least emission of CO_2, NOx and Sox Impact of coal is reduced.
Scenario 3: CO_2 emission reduction scenario	Energy production ratio by fossil fuel 74% including coal 51%. Renewable energy 7%, capacity 5.7 GW.	Energy production ratio by middle to peak power sources 26%	Generation cost 914Rp/kWh (125%). Production cost by renewable energy is large.	Least emission of CO_2, NOx and Sox Impact of coal is reduced.

The least cost development analysis by WASP etc. was applied and capacity of each power source to be developed and energy produced were computed. Every scenario indicates energy production from coal (including mine mouth coal plants in Sumatra), as the most important power source, accounts for more than a half. But energy from coal is 72% in Scenario 1 against 51% in Scenario 3 showing large difference of 21% between two scenarios. The second largest portion produced by gas and LNG accounts for 11 % in Scenario 1 against 21 % in Scenarios 2 and 3. Fossil fuel (total of oil, gas and coal) usage ratio in energy production was 90% in 2006 and is assumed to be lowered to 85% in Scenario 0, the largest among four scenarios, 81% in Scenario 0, 77% in Scenario 2 and 74% in Scenario 3.

Scenarios 2 and 3, reducing fossil fuel consumption, look well-balanced in terms of power supply reliability and environmental impact as well as cost. Difference between Scenarios 2 and 3 is observed in 3% more energy from coal in Scenario 2 (54%) than Scenario 3 (51%), and, on the other hand, 3 % less energy from the renewable (solar, wind and biomass) in Scenario 2 (4%) than Scenario 3 (7%). But it is noted that renewable capacity must be developed by 3.3 GW in Scenario 2 and 5.7 GW in Scenario 3. Development of the renewable energy should be the challenge for the government to reach 3 GW by 2028 from the present conditions of no production from renewable energy.

In the power system, plants for middle to peak load should be run to meet the load change and future peak load. In Scenarios 0 and 1, the ratio of energy production from base load plants such as coal, nuclear and geothermal exceeds 80% and the ratio of the middle to peak load plants such as oil, gas, reservoir hydro and pumped storage is only 15 to 19%. On the other hand, the proportion of middle to peak load plants reaches 26 % in Scenarios 2 and 3.

In the financial study, generation cost was estimated in consideration of construction cost of plants, fuel cost, and operation and maintenance cost every year from 2009 to 2028. The generation cost is estimated at 733 Rp/kWh (100%) in Scenario 0, 732 Rp/kWh (100%) in Scenario 1, 852 Rp/kWh (116%) in Scenario 2, and 914 Rp/kWh (125%) in Scenario 3. Cost difference is little between Scenario 0 and Scenario 1 but the cost is increased in Scenarios 2 and 3. Scenarios 2 and 3 have disadvantage of cost but the cost difference is variable due to fuel price change and cost down of solar power unit which will be realized by technological advancement.

As for the environmental impact, forecasted annual emission (CO_2, SOx and NOx) volume (2028) was compared among scenarios. The same inter-scenario differences are observed in emission of three gases. The emission is least in Scenario 3 and second-least in Scenario 2 and third-least in Scenario 0. Then Scenario 3 is preferred in terms of gas emission, Scenario 2 is next. Scenario 1 is not preferred most.

The positive and negative outcomes of four scenarios with respect to power source development, finance and environmental impact are varied. But Scenarios 2 and 3 are, as a whole, well balanced in consideration of fuel supply reliability and environmental impact as well as cost. Target of renewable energy development, however, should be examined in terms of possibility and potential.

Through discussion with counterparts, the following points were made.

1) Excessive dependence on coal should be avoided to maintain reliability of power supply.
2) Gas will be developed and used in the form of LNG to efficiently meet middle to peak load.
3) Government policy focuses on renewable energy development. Renewable energy will be able to be applied to outer islands. It is challenging how to promote the renewable in Jamali region.
4) Power source diversification scenario, Scenario 2 indicates to provide enough energy, totally more than 20%, produced by nuclear, geothermal, other renewable.
5) Cost difference is not very large between scenarios. The generation cost is estimated at 733 Rp/kWh (100%) in Scenario 0, 732 Rp/kWh (100%) in Scenario 1, 852 Rp/kWh (116%) in Scenario 2, and 914 Rp/kWh (125%) in Scenario 3.

Power utility company is conscious of generation cost and operation reliability, and in addition, the government demands less environmental impact in the local and the global scale. Scenario 3, CO_2 emission reduction scenario, seeks a lot of renewable energy development. The target energy ratio of 7% (5.7GW) was evaluated to be too risky to be accomplished. In conclusion, Scenario 2, power source diversification scenario, was selected as the optimal one because the scenario is best balanced in power supply reliability, production cost and environmental impact.

Scenario 2 aims at the target of renewable energy produced by solar, wind and biomass, 4 % of the total energy production. Adequate and effective policy measures should be studied and applied to promote renewable energy development. In Japan, three policies: subsidy, tax exemption and preferable financial arrangement, have been applied to promote the renewable energy development. Subsidy has the similar economic effect with tax exemption. Financial arrangement can be provided in the form of lower interest, more loan amount or longer repayment period. In Europe, there is a policy of setting fixed price for utilities to buy the renewable energy from producers. The policies adopted in Japan and Europe will be also effective in Indonesia.

In the next chapter, the optimal scenario of power source diversification is studied in detail to identify the issues and measures in terms of power source development, power system development, finance and private investment promotion, and environmental impact.