No.

STUDY OF THE COOPERATION POSSIBILITY ON POWER DEVELOPMENT PHASE 2 IN NORTH SUMATRA, INDONESIA

FINAL REPORT

November, 2010

JAPAN INTERNATIONAL COOPERATION AGENCY

Commissioned firm

TOKYO ELECTRIC POWER SERVICES CO.,LTD.

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STUDY OF THE COOPERATION POSSIBILITY ON POWER DEVELOPMENT PHASE 2 IN NORTH SUMATRA, INDONESIA FINAL REPORT

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Generating mode	No	Name of promissing development site
Thermal power generation	1	Kuara Tanjung
	2	Belawan
Geothermal power generation	3	Sarulla-2 (190MW)
Hydropower generation	4	Toru-1 (38.4MW)
	5	Simanggo-2 (59.0MW)
	6	Raisan-3,4 (80.0MW)

(Map source: http://commons.wikimedia.org/wiki/File:Map_of_Sumatra_Demis.png)

Map of the study target areas

List of abbreviations

Abbreviations	In English	In Indonesian
AMDAL	Environmental Impact Assessment	Analisa Mengenai Dampak Lingkungan
BAPPENAS	National Development Planning Agency	Perencanaan Pembangunan Nasional
BKPM	Investment Coordinating Board	Badan Koordinasi Penanaman Modal
CC	Combined Cycle	
CCOW	Coal Contract of Work	
CNG	Compressed Natural Gas	
CP	Captive Power	
CV	Calorific Value	
D/D	Detail Design	
DMO	Domestic Market Obligations	
EIA	Environmental Impact Analysis	
EPC	Engineering, Procurement and Construction	
F/S	Feasibility Study	
GHG	Green House Gas	
GWh	Giga Watt Hour (one billion watt hour)	
HRSD	Heat Recovery Steam Generator	
HSD	High Speed Diesel Oil	
INAGA	Indonesia Geothermal Association	
INALUM	PT. Indonesia Asahan Aluminum	
IPP	Independent Power Producer	
IRR	Internal Rates of Return	
IUP	Geothermal Energy Business Permit	Izin Usaha Pertambangan
JBIC	Japan Bank for International Cooperation	
JKT	Jakarta	
JICA	Japan International Cooperation Agency	
JV	Joint Venture	
KUD	Village Cooperation System	Koperasi Unit Desa
kV	Kilo volt	
LARAP	Land Acquisition and Resettlement Action Plan	
LIBOR	London Inter-Bank Offered Rate	
LNG	Liquefied Natural Gas	
MEMR	Ministry of Energy Mineral Resources	Menteri Energi dan Sumber Daya Mineral
MFO	Marine Fuel Oil	
MMbtu	Million British Thermal Unit	
MMscf	Million Standard Cubic Foot	

MMscfd	Million Standard Cubic Foot per Day	
M/P	Master Plan	
MW	Mega Watt (one million watt)	
NAD	Nangroe Aceh Darussalam province	Nangroe Aceh Darussalam
NEP	National Energy Policy	
NGAI	National Geological Agency of Indonesia	
ODA	Official Development Assistance	
OECD	Organization for Economic Cooperation and Development	
O/M	Operation and Maintenance	
ORMAT	Ormat Technologies Inc.	
PERTAMINA	State-owned oil and gas company	PT. Pertamina (Persero)
PGE	PT. Pertamina Geothermal Energy	PT. Pertamina Geothermal Energy
PGN	State-owned gas company	PT. Perusahaan Gas Negara (Persero)
PIKITRING	Power generation and network project office	Proyek Induk Pembankit dan Jaringan
PIUKU	Electricity Business License Holder	Pemberian Izin Usaha Ketenagalistrikan
PKUK	Electricity Business Authority	Pemegang Kuasa Usaha Ketenagalistrikan
PLN	State-owned electricity company	PT. PLN (Persero)
PLTA (HEP)	Hydro-electric power station	Pusat Listrik Tenaga Air
PLTD	Diesel power station	Pusat Listric Tenaga Diesel
PLTG	Gas-thermal power station	Pusat Listric Tenaga Gas
PLTGU	Combined cycle thermal power station	Pusat Listric Tenaga Gas dan Uap
PLTP	Geothermal power station	Pusat Listric Tenaga Panas Bumi
PLTU	Steam power station	Pusat Listric Tenaga Uap
PPP	Public-Private Partnership	
Pre-F/S	Pre Feasibility Study	
PTBA	State-owned coal mining company	PT. Bukit Asam (Persero) Tbk.
RES	Reservoir Type	
RKL	Environmental management plan	Rencana Kengelolaan Lingkungan
ROE	Return of Equity	
ROR	Run-of-River Type	
RPL	Environmental monitoring plan	Rencana Pemantauan Lingkungan
R/S	Reconnaissance Study	
RUKN	National electricity general plan	Rencana Umum Ketenagalistrikan Nasional
RUPTL	Power system development plan	Rencana Usaha Penyediaan Tenaga Listrik
SAIDI	System Average Interruption Duration Index	
SAIFI	System Average Interruption Frequency Index	
scf	Standard Cubic Foot	

SPC	Special Purpose Company	
STEP	Special Terms for Economic Partnership	
Tscf	Trillion Standard Cubic Foot	
UKL	Environment Management Efforts	Upaya Pengelolaan Lingkungan Hidup
UNSG	Unocal North Sumatra Geothermal Ltd.	
UPL	Environment Control Efforts	Upaya Pengelolaan Lingkungan Hidup
USD	US Dollar	
WACC	Weighted Average Capital Cost	
Wilayah	Region	Wilayah
WKP	Geothermal Working Area	Wilayah Kerja Panas Bumi
WTI	West Texas Intermediate	

Chapter 1 Objectives and Background of the Study

1.1 Objectives and Outline of the Study

This Study, intended to update the results of the JICA study (Phase 1) implemented between February-April 2009, has the objective of confirming the development potential of hydropower, coal, gas and geothermal power as additional energy sources for Asahan Aluminum and presenting a feasible draft plan for future development including the examination of the public use energy development for the demand increases which is excepted by the industrial development. The Study targets the North Sumatra Power Grid covering Aceh Province and North Sumatra Province.

In Phase 1, a preliminary study was conducted on numerous power resource options, and the various issues and problems were raised concerning the implementation setup, economic and financial feasibility and project risk, etc. The study also stressed the need to develop electric power for supply of additional power in line with extension of the Asahan Aluminum business beyond 2013 and supply of public power use to satisfy the additional demand expected in line with promotion of industrial investment from now on. Concerning power development in North Sumatra, it is necessary to narrow down numerous power supply options into promising options that are financially sound and viable in consideration of development risk, business risk and incentives, etc. on the Indonesian side upon carefully examining the economic feasibility of resource prices and considering social and environmental impacts, etc.

The main contents of the Study work are as follows:

- Confirmation of power demand and supply in North Sumatra
- Confirmation of the development potential in each power generation mode
- Confirmation of systems related to power resources development and power plant construction
- Indication of generating capacity and site options under each generating plan with development potential
- Examination of power supply options including investment and loans

1.2 Background of the Study

1.2.1 Current Conditions of Power Supply in North Sumatra

It is forecast that peak demand on the North Sumatra Grid in Indonesia will increase at an average rate of eight percent per year up to 2018. Meanwhile, the power supply backup rate until 2013 is expected to be less than 25 percent (result in the Phase 1 study) even when future development plans are taken into account. This grid is interconnected with Aceh Province, which is included in the supply range, however, since power plants in this province suffered extensive damage in the Indian Ocean earthquake of December 2004, it is forecast that the reconstruction effort will lead to further demand. Even taking into consideration the hydropower plants that were introduced under yen loans in fiscal 2005 and 2006 (Asahan No. 3: 154 MW and Pusangan No. 1 & 2: 86 MW), it is necessary to develop further power resources. As of September 2010, planned power interruptions are implemented two or three times per week in areas around Medan, the capital city of North Sumatra Province.

The demand for electric power in Indonesia temporarily declined following the Asian currency crisis of 1997, however, it has since displayed annual growth of around 7~8 percent thanks to the economic development of recent years. A similar trend can be seen in Sumatra: demand for power is expected to show solid growth in line with economic development; however, the supply setup is struggling to keep up and scheduled power interruptions are implemented across the province. Against such a background and in view of the rapid inflation in crude oil prices in recent years, the Government of Indonesia is aiming to reduce oil dependence in power supply. Towards this end it has compiled the First Crash Program, under which it is currently in the process of developing a total of 10,000 MW of new coal-fired thermal power including 600 MW within the North Sumatra Grid.

In the Phase 1 study, it was reported that the said program was originally planned for implementation until 2009 and that it would be completed by 2011 following some delays; however, as of October 2010, work on numerous power plants is behind schedule and it is forecast that operations at all facilities will start at least two or three years later than planned. Following on from the First Crash Program, the Indonesian government has compiled the Second Crash Program, in which it intends to commence the development of 10,000 MW of power sources based on coal, gas and new energies such as geothermal power and hydropower from 2010, although the start again is likely to be delayed due to the slow progress in the first program. Total development in the North Sumatra Grid is scheduled to be 1,124 MW.

However, in reality progress in the said program is well behind schedule; moreover, due to declining power generation efficiency arising from deterioration of existing generating facilities combined with the rapid increase in demand for power resulting from economic development, the electric power supply situation is in a critical state, so much so that the North Sumatra Grid has been designated as a power shortage area requiring urgent handling.

The electrification rate in North Sumatra grid is 78.7 percent in Aceh Province and 78.2 percent in North Sumatra Province (2008), thus indicating a relatively high electrification rate within Indonesia. The North Sumatra Grid was connected to the Riau Grid in 2007 with a 150 kV transmission network between Bagan Batu-Kota Pinang-Rantau Prapat, however, power supply shortages have not been resolved in either grid. Additionally, it is planned to connect with the South Sumatra Grid by means of a 275 kV transmission line in 2012, and the section between Payakumbuh and Padangsidempuan has already been completed. Furthermore, in 2018, it is scheduled to connect with the Java-Bali Grid by means of a 500 kV undersea transmission line across the Sunda Strait.

Figure 1.2-1 Map of Transmission Lines in the North Sumatra Grid

1.2.2 Asahan Aluminum Smelting Business

In view of its stable flow and high head, the basin of Asahan River, which originates in Lake Toba in North Sumatra Province, is an extremely promising location for water resource development. The Netherlands conducted a field survey geared to the construction of a power plant before World War II, and numerous surveys have subsequently been implemented by Russia and France, etc. At the start of the 1970s, a consortium of five Japanese aluminum smelting corporations and seven associated trading companies obtained support from the Government of Japan to execute the Asahan Aluminum Smelting Project (hereafter referred to as the Aluminum Project) as a state undertaking. For the Japanese side, the purpose of this project was the overseas development and import of aluminum, whereas for the Indonesian side it contributed to the national economic development goals of provincial economic development, expansion of employment and attraction of foreign currency revenue.

Under these circumstances, the Indonesian government and Japanese investors signed a master agreement concerning the development in 1975, and work was commenced on the Asahan Aluminum Smelting Project with the goals of constructing three dams and two power plants (with total capacity of 513 MW) on Asahan River as well as an aluminum smelting plant and incidental facilities, etc. on the coast facing the Malacca Straits roughly 80 km south of Medan. Following construction, production of aluminum was started in 1982.

Under the said agreement, a Japanese-Indonesian joint local aluminum producing corporation, PT. Indonesia Asahan Aluminum (INALUM), was established and this has overseen the project construction and operation. Via INALUM, water use rights on Asahan River, various tax benefits and operating rights based on Indonesian foreign capital law have been granted for 30 years until October 2013. An important point pertaining to power development is that the operating rights can be extended on the premise of expanding the existing smelter providing that the Indonesian government and Japanese investors can reach an agreement. INALUM has plans to increase smelting plant capacity by 90,000 tons per year, and the securing of cheap and stable power supply is essential for this. Additional power supply of 200 MW is needed (150 MW at the receiving end plus assuming 50 MW of transmission losses) in order to boost aluminum production by 90,000 tons per year, however, since this would account for between 20~30 percent of the current capacity of the North Sumatra Grid, it will be necessary to carefully determine whether such a cheap and stable supply of electricity can be realized in the current demand and supply climate and future plans.

Against such a background, based on recognition of the supply and demand gap in the North Sumatra Grid, a study was implemented in order to confirm the timing and scale of increase in power demand arising from the large-scale development (INALUM expansion plan) and to determine the viability of conducting power resources development with a view to minimizing or eliminating impact on the supply and demand balance on the grid.

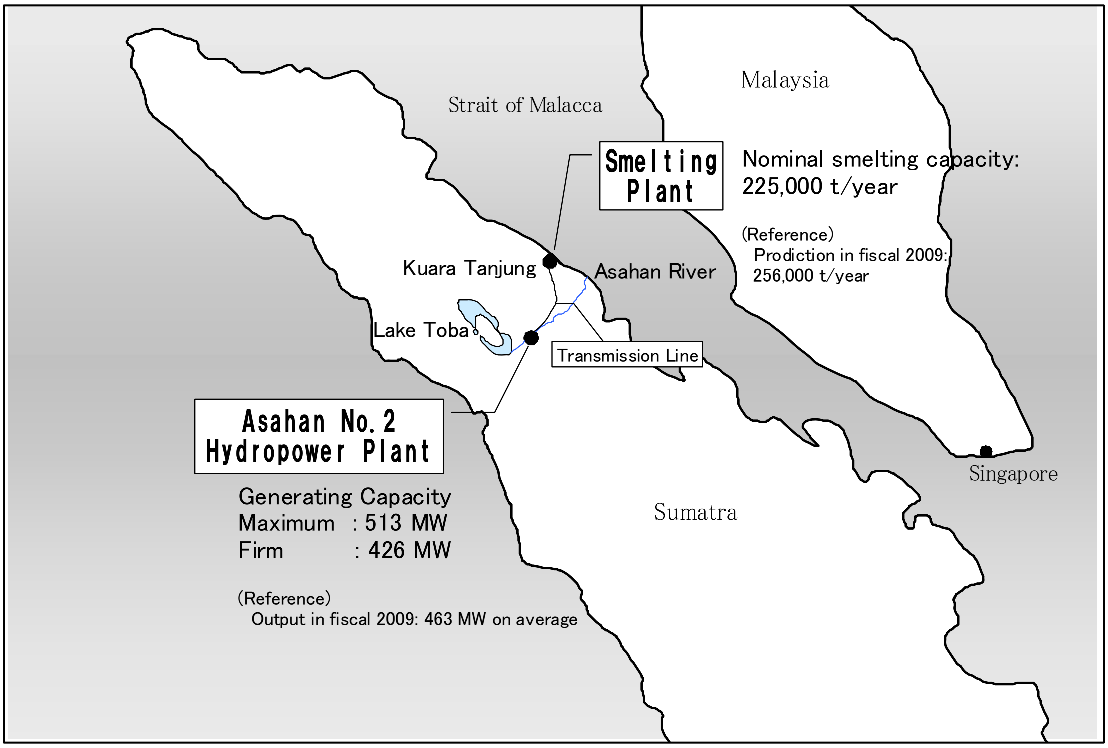


Figure 1.2-2 Project Location Map

Chapter 2　Outline of the Study

2.1 Study Target Areas

The Study targeted the North Sumatra Grid (North Sumatra Province and Aceh Province) where INALUM is located. And the information concerning coal and gas including data on resource marketing and past performance, etc. were obtained from all over Indonesia.

2.2 Related Agencies

Table 2.2-1 shows the related agencies in Japan and Indonesia where materials have been collected.

Table 2.2-1　Related Agencies in Japan and Indonesia and Collected Materials and Information

Related Agencies	Collected Materials and Information
(Japan)	
Nippon Asahan Aluminum (Co., Ltd.)	Expansion plans and future schedule for submission to the Indonesian government, i.e. the policy concerning business expansion (contents, scale and schedule of expansion) Intentions as an investor concerning business continuation Other information concerning the Asahan business
Japan International Cooperation Agency (JICA)	Intentions and trends of the Japanese government regarding the Asahan business Intentions as an investor Systems and procedures concerning investment and mobilization of the private sector Acquisition of information and collected materials (minutes of meetings, etc.) from the previous study
Nippon Koei (Co., Ltd.)	Acquisition of information and collected materials from Phase 1 Important points to consider during Study implementation
(Indonesia)	
Ministry of Energy and Mining Resources (MEMR)	Power resources development plans in the North Sumatra Grid
National Development Planning Agency (BAPPENAS)	Government policy concerning power resources development in North Sumatra
Power Public Corporation (PT. PLN)	Current conditions and progress of power resources and transmission development plans in the North Sumatra Grid area Intentions and implementation policy concerning power coordination

Related Agencies	Collected Materials and Information
	Latest information on hydropower, coal and gas development plans in the North Sumatra Grid area Latest information concerning power resources development plans by IPP Systems and procedures concerning power sale and purchase Systems, procedures, tariffs and preferential measures concerning consigned power transmission
Oil and Gas Corporation (PERTAMINA)	Information and systems concerning coal and gas supply Potential for supply as fuel for the expansion project Latest information concerning geothermal development plans in the North Sumatra Grid area Various data on potential areas
Pertamina Geothermal Energy (PGE)	Latest information concerning geothermal development plans in the North Sumatra Grid area Various data on potential areas
Ministry of Forestry	Confirmation of the distribution of nature protection zones in the North Sumatra Grid area
Itochu Corporation, Jakarta Office	Information collection concerning geothermal potential sites in the North Sumatra Grid area
Indonesia Investment Coordinating Board (BKPM)	Information collection concerning investment
Nippon Koei (Co., Ltd.), Jakarta Office	Information collection concerning Phase 1
JBIC Jakarta Office	Hearings on JBIC loans, JBIC syndicates and interest prospects

2.3 Work Methodology and Prepared Reports

The Study work was implemented according to the methods and processes prepared by the Study Team based on the proposals made in line with the TOR and the information subsequently obtained by the JICA officials, Nippon Asahan and the consultanting firm in Phase 1 of the preliminary study. The reports to be prepared in the Study in line with the contract comprise the Inception Report at the outset of the work, the (first) Intermediate Report compiled based on the materials collected in Japan prior to the field surveys, and the Field survey Report and Final Report (Draft and Final Reports) detailing the field surveys. In addition, distribution materials were prepared with the aim of informing the objectives and contents to related agencies in the field survey.

(1) First work in Japan

In Japan, materials and information were collated from materials provided by JICA and the materials independently acquired by the members of the Study Team. A list of questions was sent to the main related agencies in Indonesia via JICA, however, no responses were received during the work in Japan prior to the field survey. Accordingly, it was decided to wait until the field survey to collect all the necessary materials. The office of JKT TEPSCO also attempted to obtain materials from the Indonesian related agencies in advance, however, it was unable to acquire major items. Moreover, the interim report of the Master Plan Study for Hydropower Development in Indonesia currently being implemented by JICA Industrial Development Department was completed in July this year and it was thought that the findings of this could be used as core update materials in the hydropower planning component of the Study; however, since information cannot be disclosed from an undertaking currently under implementation, the latest information except for some hearing information is not reflected in the hydropower plans. Therefore, concerning hydropower planning in the North Sumatra Grid, it will be necessary to align information following completion of the said study.

<u>Inception Report</u>

The Inception Report was prepared and submitted at the outset of the Study. The contents of the report were basically based on the Work Policy and Method in the Study proposal, however, following submission of the proposal, new materials and information were obtained before the start of the Study and hearing information was acquired from interviews conducted with the consultanting firm in Phase and Nippon Asahan. Therefore, renewed examination was conducted on the materials that need to be collected in future, related agencies, the overall Study policy, methodology and work plan, etc. and the Inception Report was prepared based on the findings.

Interim Report

The Interim Report was prepared based on the information obtained prior to the field survey. Since it was difficult to update all the items reported in Phase 1 during the work in Japan, the Interim Report was compiled with the focus on the potential for electric power development based on geothermal energy, hydropower, coal and gas resources. The report stated the examination items and financial calculation conditions that are important points for implementing economic and financial analysis of the power supply options. It was decided to update the information concerning current conditions of power supply and demand, legal systems concerning power resource development and power supply options upon receiving the results of the field survey.

(2) Field survey

Interviews and discussions were held with officials and materials were collected from the National Development Agency (BAPENAS), the Ministry of Energy and Mineral Resources (MEMR), the state power corporation PLN and the geothermal energy corporation PGE, which is an affiliated company of the state oil corporation Pertamina, etc. Attempts were made to collect the materials necessary for the Study from these agencies, however, since the objective of the Study includes to develop power resources for a specific enterprise without requesting from Indonesian agencies and the contents are recognized as requiring 'careful handling,' the ability to collect information and obtain materials from state agencies in Indonesia apart from PGE and general companies has been extremely limited. At PLN Pikitring (Main Project Office for Power Generation and Transmission Line) in Medan, which was viewed as the most promising source of update materials, talks were held with related officials, however, discussions concerning the Study couldn't be held and no materials could be collected. In these circumstances, the experts made a committed effort to individually obtain materials from related agencies primarily with help from the JKT TEPSCO office during the field survey period. Accordingly, except for materials put into the public domain by PLN and other related agencies, care must be taken regarding the materials obtained in the Study. And the use of such materials in preparing the Final Report for the Study will be limited.

Field survey report

The Study schedule, contents of discussions held with the related agencies and officials, and materials collected during the field survey were compiled into the field survey report for submission (see the appendices). The Study Team immediately submitted this field survey report to JICA upon returning to Japan. Since parts of the report concerning power supply options and viability of each power generating mode were modified following discussions with JICA and other officials, there is some discrepancy with the contents of the final report.

(3) Second work in Japan

The materials obtained through the first survey in Japan and the field survey in Indonesia were organized, examined and analyzed before being compiled into the Draft Final Report.

Draft Final Report

The materials and information obtained through the survey work in Japan and the field survey in Indonesia were organized, and the Phase 1 study was updated and compiled into the Draft Final Report. Concerning the ‘Proposal of the Power Supply Options,’ which is the core component of the Study, out of the numerous options that were proposed in Phase1, the options found to be unfeasible based on the latest information were eliminated, while feasible supply options were examined upon adding new power resources (gas) and sites (hydropower). Furthermore, realistic power development within the business models and legal systems was examined, while supply options that entail difficulties and problems were omitted from the study. Although the objective of this Study was to update the findings of Phase 1, little progress has been made in the technical basis regarding the potential and actual development capacity of each power resource.

Final Report

The contents of the Draft Final Report were compiled upon making corrections and modifications to the contents following discussions with JICA, related agencies and related officials. In particular, concerning recommendations for the next phase study, the advice and recommendations given by JICA and other officials were reflected by specifically describing the future kind of work.

2.4 Study Work Schedule

The following tables show the schedule of the Study and the members of the Study Team.

Table 2.2-2 Study Work Schedule

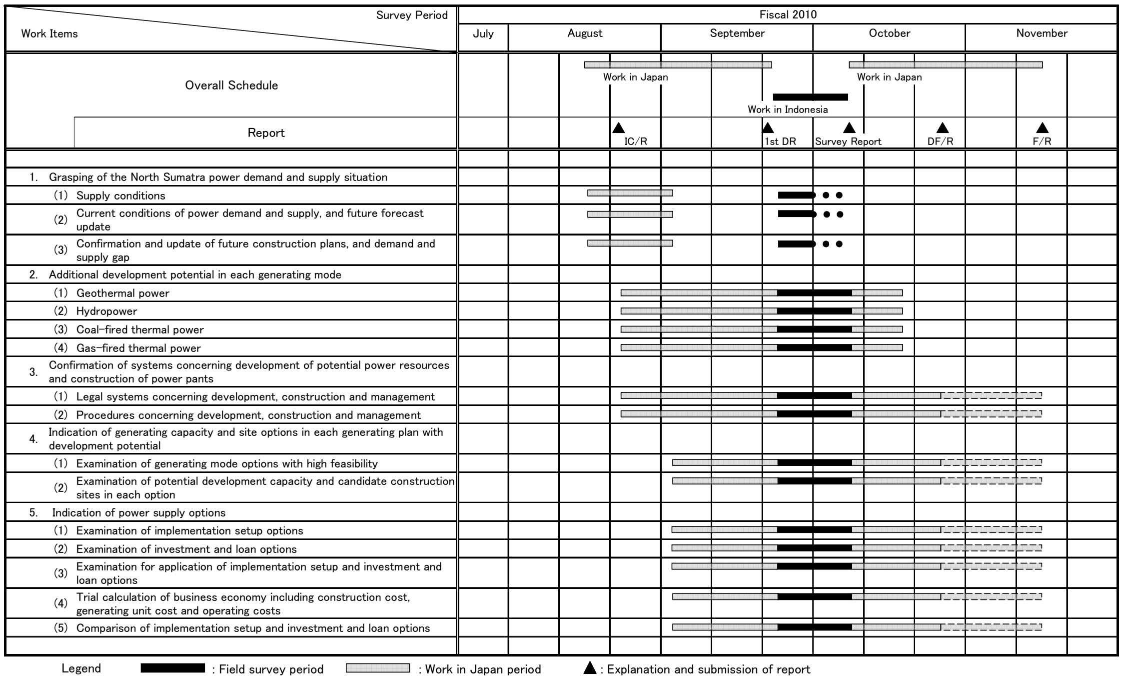


Table 2.2-3 Study Team Members

Responsible Area	Name	Affiliation
Team Leader / Power development planning	Keiichi Terao	TEPSCO Ltd. (International Development Center)
Geothermal energy development	Takehiro Kozeki	TEPSCO Ltd. (Mitsubishi Material Techno Co., Ltd.)
Coal and gas development	Sachio Kosaka	TEPSCO Ltd.
Hydropower development	Yukio Miyamoto	TEPSCO Ltd.
Power investment (economic and financial)	Tomoyuki Inoue	TEPSCO Ltd. (Techno Soft)
Legal systems	Mitsuru Shimizu	TEPSCO Ltd.

Chapter 3 Current Power Demand and Supply in North Sumatra

3.1 Power Demand and Supply and Existing Generation and Transmission Facilities

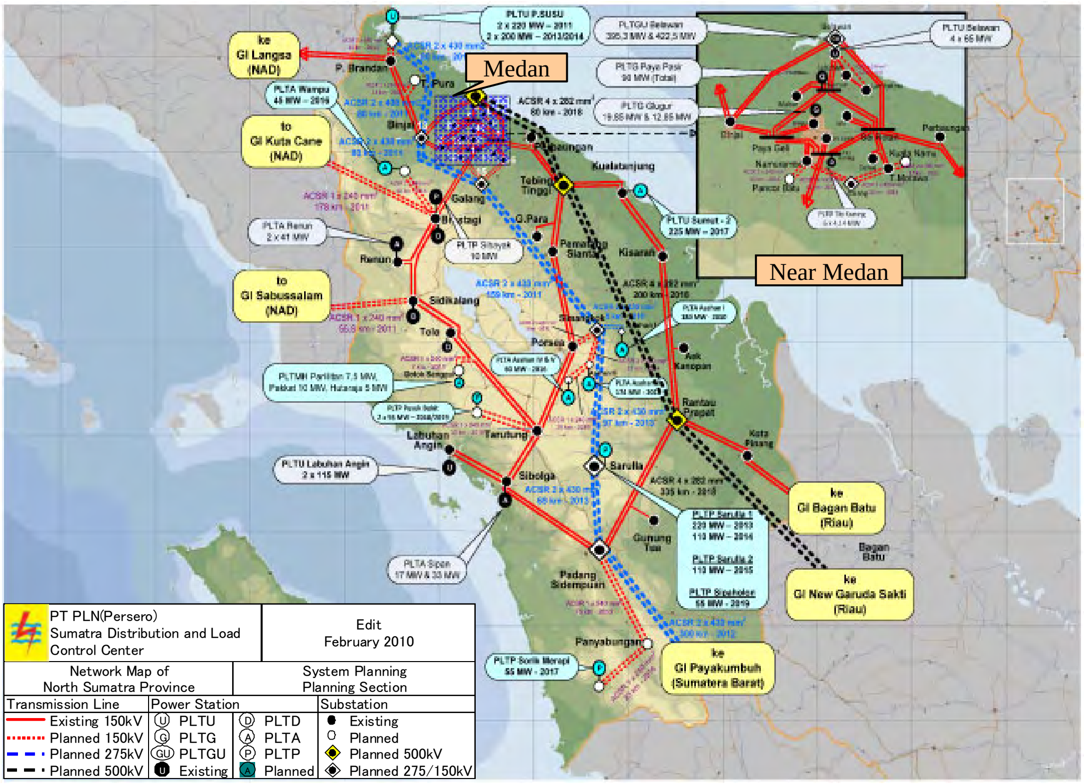
3.1.1 Power Supply

The power supply operator in North Sumatra is the state-owned power company PT. PLN, which owns and controls power supply facilities in all areas of generation, transmission, transformation and distribution. The North Sumatra Grid covers North Sumatra Province and Aceh Province and is linked by 150 kV transmission lines. PLN supplies power via the 150 kV North Sumatra Grid and other small independent power systems. These small independent power systems primarily supply power derived from diesel engine generation using relatively expensive fuel. On the other hand, the North Sumatra Grid supplies power from a diverse mix of hydropower, diesel power, steam power, gas turbines and combined cycle generation. Figure 3.1-1 and Figure 3.1-2 show the transmission systems in North Sumatra Province and Aceh Province as well as the locations of power plants and substations. These substations and transmission lines include both existing and planned facilities.

Source: RUPTL(2010-2019)

Figure 3.1-1 Transmission System in Aceh Province

The southwest coastal area and remote mountain areas of Aceh Province and the islands of Aceh Province and North Sumatra Province are not connected to the North Sumatra Grid, but rather they obtain power supply from small independent systems. However, there are plans to connect mountain areas to the North Sumatra Grid in future. In Aceh province, 70% of power is supplied from the North Sumatra Grid, while the remaining 30% comes from a 20 kV independent system (PLTD) using HSD as fuel. PLTD power supply via 20 kV systems based on HSD fuel is similarly conducted in limited parts of North Sumatra Province, however, this only accounts for 1% of overall grid capacity. Almost all power is obtained via the North Sumatra Grid. However, since the generating facilities currently connected to the grid do not possess adequate spare capacity, there is a constant risk that interference in the transmission network or problems in generating facilities with relatively large output will trigger major power interruptions. In order to avoid such situations, PLN Wilayah Sumatra Utara conducts rolling blackouts at times of peak power demand and limits newly connecting users in order to limit load growth. Moreover, at peak times, it directly receives power supply of 45-65 MW from INALUM PLTA via the 150 kV transmission network and supplies 15 MW to INALUM at off-peak times. PLN pays the differential on this based on its contract with INALUM.



Source: RUPTL(2010-2019)

Figure 3.1-2 Transmission Networks in North Sumatra Province

3.1.2 Existing Power Generation Facilities

Table 3.1-1 shows a list of power plants that are currently connected to the North Sumatra Grid.

Table 3.1-1 Power Generation Facilities in the North Sumatra Grid

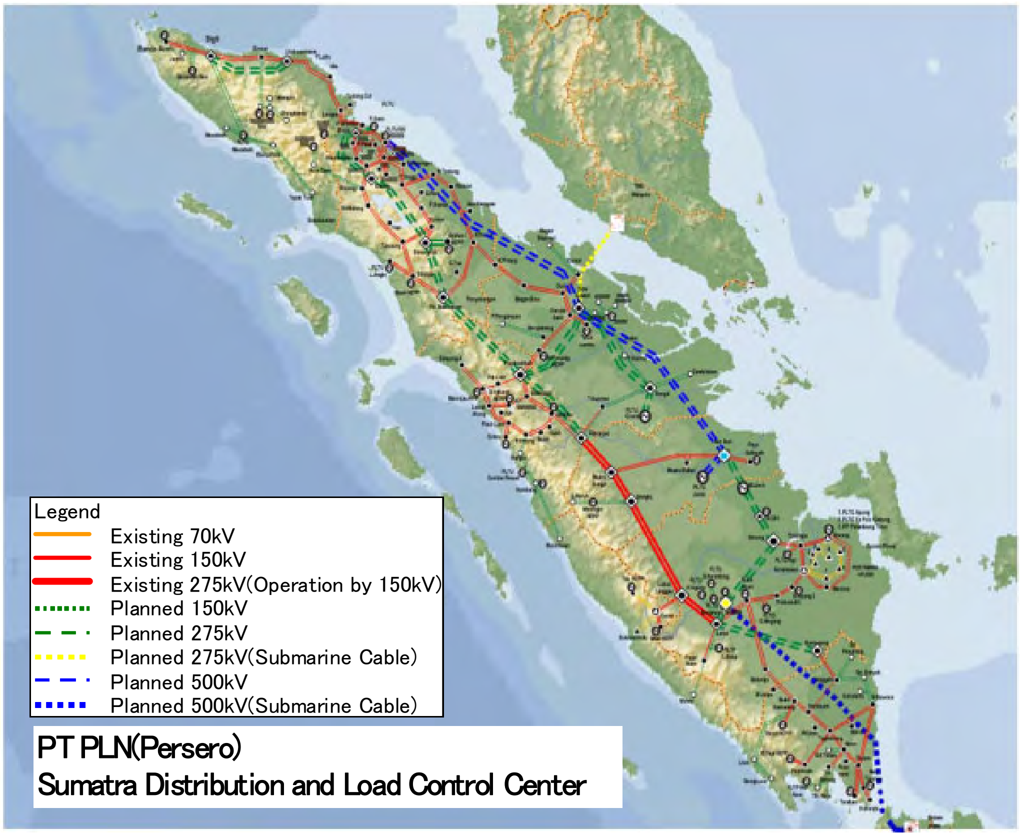
Name/Location	No.	Type	Fuel	Total Generation Capacity (MW) RUPTL 2010-2019						Year of operation start
				Installed					Available	
				PLTD	PLTG	PLTU	PLTGU	PLTA		
Lueng Bata/Ache (Rental)	1	PLTD	HSD	60.17					30.00	1978
	2	PLTD	HSD							1978
	3	PLTD	HSD							1981
	4	PLTD	HSD							1984
	5	PLTD	HSD							1985
	6	PLTD	HSD							1986
	7	PLTD	HSD							1986
	8	PLTD	HSD							1986
	9	PLTD	HSD							1986
	10	PLTD	HSD							1986
	11	PLTD	HSD							1988
	12	PLTD	HSD							–
	13	PLTD	HSD							–
	14	PLTD	HSD							–
Cot Trueng/Ache		PLTD	HSD	14.00					14.00	–
Pulo Pisang/Ache		PLTD	HSD	7.90					7.90	–
Glugur /North Sumatra	1	PLTG	HSD		44.51				11.00	1975
	2	PLTG	HSD							1967
Paya Pasir /North Sumatra	1	PLTG	HSD		111.94				47.00	1976
	2	PLTG	HSD							1976
	3	PLTG	HSD							1976
	4	PLTG	HSD							1978
	5	PLTG	HSD							1983
Belawan-1 /North Sumatra	1	PLTGU	GAS/HSD				817.88		741.00	1993
	2	PLTGU	GAS/HSD							1988
	3	PLTGU	GAS/HSD							1995
	4	PLTGU	GAS/HSD							1995
	5	PLTGU	GAS/HSD							1994
	6	PLTGU	GAS/HSD							1994
Belawan-2 /North Sumatra	1	PLTU	MFO			260.00			198.00	1984
	2	PLTU	MFO							1984
	3	PLTU	MFO/GAS							1989
	4	PLTU	MFO/GAS							1989
Titi kuning /North Sumatra	1	PLTD	HSD	24.85					14.00	1976
	2	PLTD	HSD							1976
	3	PLTD	HSD							1976
	4	PLTD	HSD							1976
	5	PLTD	HSD							1976
	6	PLTD	HSD							1976
Labuhan Angin /North Sumatra	1	PLTU	Coal			230.00			230.00	2008
	2	PLTU	Coal							2009
Sipansihaporas /North Sumatra	1	PLTA	Water					50.00	17.00	2002
	2	PLTA	Water							2003
Renun /North Sumatra	1	PLTA	Water					82.00	82.00	2005
	2	PLTA	Water							2006
Total Capacity of North Sumatra System				106.92	156.45	490.00	817.88	132.00		
						1,703.25			1,340.00	
Ratio of Generation Capacity				6.3%	9.2%	28.8%	48.0%	7.7%	78.7%	

Source: RUPTL(2010-2019)

The capacity of power generation facilities indicated in Table 3.1-1 amounts to approximately 1,700 MW, that is 80 MW in Aceh Province and 1,620 MW in North Sumatra Province. However, many of these power plants were constructed in the 1970s and 1980s and suffer from declining efficiency caused by deterioration, and they only have enough capacity to generate roughly 80% of rated capacity on average. This deterioration of power generation facilities, combined with the increasing demand for power, is one of the causes behind the critical power supply situation. In response to these conditions, PLN has designated the North Sumatra Grid as a 'critical area' (designated area of power shortage) requiring immediate countermeasures, and the rehabilitation and renewal of such deteriorated facilities is deemed to require urgent attention.

3.1.3 Existing Transmission Facilities

Figure 3.1-3 shows the transmission network in Sumatra including transmission lines still in the planning stage. The North Sumatra Grid and Sumatra Southern and Central Grid are already interconnected by a 150 kV transmission line, however, due to problems in terms of grid stability, the two systems are still electrically separated.



Source: RUPTL(2010-2019)

Figure 3.1-3 Map of Existing/Planned Transmission Systems in Sumatra

According to the Power Supply Business Plan (RUPTL) 2010-2019 compiled and published by PLN in 2010, it is scheduled for the Southwest Sumatra Grid and the 275 kV core transmission line in North Sumatra to link all transmission systems in Sumatra by 2012. When this system interconnection is realized, even though there is a concern about delay of project completion and transmission capacity will be constrained by the stability limit, power will come to be supplied to the North Sumatra Grid from systems in South Sumatra, where there are ample reserves of cheap and stable primary energy resources. When the transmission network on Sumatra Island is finished, the capacity of generating facilities will be approximately 6,200 MW, peak load will be approximately 4,500 MW and the network reserve margin will be around 38%. Furthermore, there are plans to connect the coal-fired thermal power plant intended for construction in Jambi Province via a 500 kV transmission line, and Sumatra will eventually be connected to the Java-Bali Grid via a 500 kV submarine transmission line under the Sunda Strait, thereby realizing even greater grid stability.

3.1.4 Power Supply Reliability

PLN publishes power statistics every year. According to the statistics PLN 2008 and statistics PLN 2009, the number of power outages and outage hours were as shown in table 3.1-2.

Table 3.1-2 Number of Outages/Outage Hours

Location	Number of Annual Outages per One Consumer（SAIFI）	Annual Outage Hours per One Consumer（SAIDI）
Aceh（NAD）	10.97/8.73	5.42/4.92
North Sumatra	59.59/53.13	143.99/126.49
Java-Bali system	9.99/7.10	103.73/9.61
Whole Indonesia[1]	13.33/10.78	80.90/16.70

Source: Statistik PLN 2008

All figures in the table are values per consumer. North Sumatra Province had more frequent power outages and longer outage time than the Java-Bali Grid and the national average. Though the primary cause for these outages was the shortage of power resources within North Sumatra Grid and this situation makes it urgently necessary to develop new power resources as mentioned in section 3.1.2, the power shortage was improved because two units of PLTU Labuhan Angin (2 x 115MW) commenced commercial operation consecutively in 2008/2009.

[1] Since Statistics PLN 2009 are not available yet, only the 2008 data are given for Aceh Province, North Sumatra Province and Java-Bali Grid. As for the whole of Indonesia, as the 2009 data are available, figures for 2008 and 2009 are given.

As the number of power outages and outage hours in North Sumatra Province remain to show large numbers, it is necessary to build up new power resources. However, it is thought that the situation in 2010 of power sector in North Sumatra has been improved, if PLTA Asahan-1 (180 MW) started commercial operation in October, 2010 as planned. And if new power sources will be installed in the North Sumatra Grid according to the plan mentioned in RUPTL 2010, it is expected that the above situation is improved and it afford sum of margin.

3.2 Power Demand and Demand Forecast

3.2.1 Power Demand

According to Statistics PLN 2009, the electrification rate in North Sumatra Province was 76.8% and in Aceh Province was 87.8%, meanwhile, since the electrification rate of over all Sumatra Island was 60.6% and over the whole of Indonesia was 63.8%, indicating a relatively high degree of electrification over the North Sumatra Grid. RUPTL 2010 aims to realize 100% electrification in North Sumatra Province by 2020 and in Aceh Province by 2015. According to RUPTL 2010, peak load on the North Sumatra Grid in 2009 was 1,507 MW, comprising 272 MW in Aceh Province and 1,235 MW in North Sumatra Province, but this had increased to 1,586 MW in 2010, comprising 293 MW in Aceh Province and 1,340 MW in North Sumatra Province. With respect to this demand, as was mentioned in section 3.1.2, the total capacity of installed power generating facilities is about 1,700 MW, meaning that the reserve margin is only 6.7%. Moreover, since the generating potential in reality is only around 1,340 MW, there is not enough capacity to respond to the peak load, meaning that rolling blackouts need to be conducted during peak load.

3.2.2 Demand Forecast

The demand for power increases in line with economic development and population growth, and it is necessary to forecast it as quickly and accurately as possible so that detailed plans for power generation and transformation facilities, transmission and distribution facilities and fuel procurement can be made. The Study will not conduct a power demand forecast, however, it will assess the power demand based on “Power Supply Business Plan (RUPTL: 2010-2019)’’ issued by PLN in July 2010 (hereinafter RUPTL 2010).

According to RUPTL 2010, the mean growth rate in net system energy demand over the five years between 2005-2009 was 6.1% over the whole of Indonesia, 5.4% on the Java-Bali Grid, and 8.7% in Sumatra. However, the rate of increase in power resource facilities in Sumatra is only 3.3%, and the gap resulting from such an imbalance is contributing to the chronic power shortages and making it necessary to curtail the net system energy demand. Generated electric energy on the Sumatra Grid is forecast to rise by 10.9% per year from 21,533 GWh in 2010 to 54,807 GWh in 2019. Of this increase, around 43% will be needed to satisfy demand in the North Sumatra Grid. It is forecast that peak demand on the Sumatra Grid will increase by 10.7% per year from 3,743 MW in 2010 to 9,355 MW in 2019.

Table 3.2-1 Demand Forecast Conditions

	Aceh (NAD)	North Sumatra
Economic Growth Rate	6.67%	5.95%
Population Growth Rate	1.2%	1.7%
Power Loss Rate	8.58%	7.26%
Elasticity Modulus for Electric Growth Rate respect to Economic Growth Rate	1.47%	1.49%
Year of 100% Electrification Rate	2015	2020

Meanwhile, in Aceh Province and North Sumatra Province, demand forecast was conducted based on the conditions shown in Table 3.2-1. According to this, in Aceh Province net system energy demand/ generated electric energy/ peak load will increase from 1,470 GWh/ 1,591 GWh/ 293 MW in 2010 to 3,541 GWh/ 3,893 GWh/ 684 MW in 2019, representing an annual increase of 10.4%/ 9.8%/ 9.7%. Meanwhile, in North Sumatra Province, the same items will increase from 6,782 GWh/ 7,474 GWh/ 1,293 MW in 2010 to 15,042 GWh/ 16,262 GWh/ 2,821 MW in 2019, representing an increase of 8.5%/ 8.3%/ 7.9% respectively. Compared to the situation in Sumatra as a whole, the growth rates for generated electric energy and peak load are slightly lower, however, these growth rates are still at a high level. Details are as indicated in the demand forecast in RUPTL 2010 shown in Table 3.2-2. These are the figures indicated under Power Demand: GWh and Peak Load: MW in the upper row RUPTL 2009-2018 (RUPTL2009) and lower row RUPTL 2010-2019 (RUPTL2010).

Table 3.2-2 Demand Forecast on North Sumatra Grid Based on RUPTL 2010

RUPTL (2010-2019)		Unit	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Aceh (NAD)												
Power Demand	2009	GWh	1,232	1,324	1,408	1,497	1,591	1,692	1,798	1,912	2,032	-
	2010		1,470	1,595	1,732	1,906	2,137	2,406	2,686	2,971	3,263	3,541
Growth Rate		%	-	8.5	8.6	10.0	12.1	12.6	11.6	10.6	9.8	8.5
Peak Load	2009	MW	270	285	301	317	334	353	371	394	413	-
	2010		293	315	340	372	416	466	518	572	625	684
Growth Rate		%	-	7.5	7.9	9.4	11.8	12.0	11.2	10.4	9.3	9.4
North Sumatra												
Power Demand	2009	GWh	6,826	7,470	8,180	8,963	9,822	10,773	11,761	12,849	14,042	-
	2010		6,782	7,411	8,093	8,835	9,638	10,502	11,489	12,568	13,749	15,042
Growth Rate		%	-	9.3	9.2	9.2	9.1	9.0	9.4	9.4	9.4	9.4
Peak Load	2009	MW	1,343	1,462	1,592	1,735	1,891	2,064	2,241	2,436	2,648	-
	2010		1,293	1,433	1,567	1,713	1,859	2,012	2,189	2,382	2,593	2,821
Growth Rate		%	-	10.8	9.4	9.3	8.5	8.2	8.8	8.8	8.9	8.8
Total of North Sumatra System												
Power Demand		GWh	8,252	9,006	9,825	10,741	11,775	12,908	14,175	15,539	17,012	18,583
Growth Rate		%	-	9.1	9.1	9.3	9.6	9.6	9.8	9.6	9.5	9.2
Peak Load		MW	1,586	1,748	1,907	2,085	2,275	2,478	2,707	2,954	3,218	3,505
Growth Rate		%	-	10.2	9.1	9.3	9.1	8.9	9.2	9.1	8.9	8.9

In Aceh Province, RUPTL 2010 indicates higher figures than RUPTL 2009 for both power demand and peak load. A major factor for this is that recovery in Aceh following the Indian Ocean earthquake and tsunami disaster of 2004 has picked up, the economy is recovering and civil order has improved. On the other hand, in North Sumatra Province, the 2009 version shows higher figures, and 2011 is expected to show a far bigger growth rate than subsequent years. As was mentioned previously, this reflects the fact that peak load has been held back through limiting the number of new contract holders in order to deal with routine power shortages, whereas from 2011 onwards new power plants will be commissioned and there will be a sudden jump in new contracts and peak load. For reference purposes, Table 3.2-3 shows the demand forecast for North Sumatra Grid according to RUPTL 2010; Figure 3.2-1 shows the demand forecast curves for North Sumatra Grid according to RUKN/ RUPTL2009/ RUPTL2010; and Figure 3.2-2 shows the peak load forecast curves for North Sumatra Grid according to RUKN/ RUPTL2009/ RUPTL2010.

Table 3.2-3 Demand Forecast Based on RUKN (2008-2027)

RUKN	Unit	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Power Demand Forecast											
Ache(NAD)	GWh	1,378	1,546	1,773	1,942	2,176	2,435	2,717	3,030	3,378	3,763
North Sumatra	GWh	7,008	7,543	8,124	8,756	9,441	10,183	11,020	11,939	12,945	14,044
Total of North Sumatra System	GWh	8,386	9,089	9,897	10,698	11,617	12,618	13,737	14,969	16,323	17,807
Growth Rate	%	8.0	8.4	8.9	8.1	8.6	8.6	8.9	9.0	9.0	9.1
Power Loss Rate	%	13.3	13.2	13.1	13.0	12.9	12.8	12.7	12.6	12.5	12.4
Load Factor	%	62.0	62.0	62.0	62.0	62.0	62.0	62.0	62.0	62.0	63.0
Peak Load	MW	1,781	1,928	2,097	2,264	2,456	2,664	2,897	3,153	3,435	3,683
Growth Rate	%	7.9	8.3	8.8	8.0	8.5	8.5	8.7	8.8	8.9	7.2

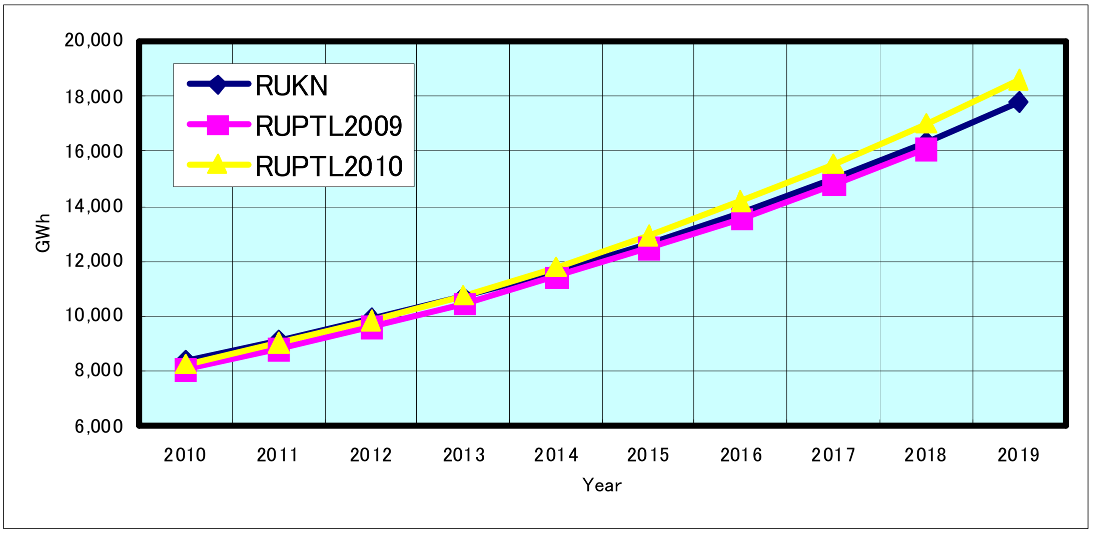


Figure 3.2-1 Demand Forecast Curves for North Sumatra Grid

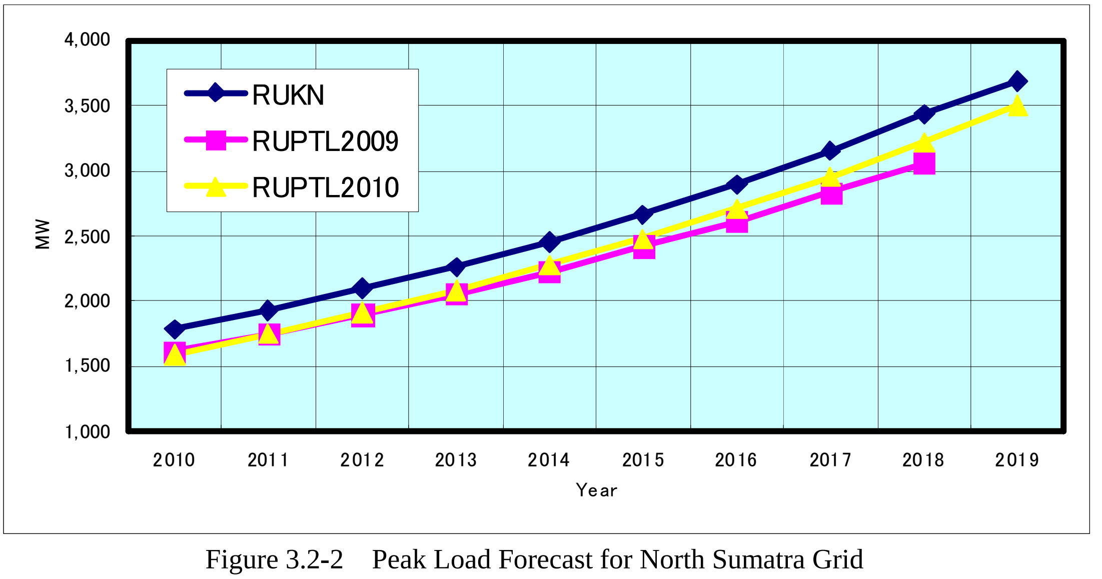


Figure 3.2-2 Peak Load Forecast for North Sumatra Grid

3.3 Power Supply Plan

3.3.1 Power Supply Operation Plan (RUPTL:2010-2019)

Based on Electric Power Law No.30/2009 Articles 28 and 29, as the holder of the public power supply utility license, PLN has the obligation to continuously supply an ample quantity of good quality and reliable power. Accordingly, in order to meet the current and future demand for power, PLN annually conducts a 10-year power demand forecast and compiles a power supply operation plan (RUPTL). The latest RUPTL (2010-2019) contains plans to introduce new power resources in order to meet the rapidly growing demand for power. As is also mentioned in the Phase 1 study (2009), responding to the depletion of petroleum resources and rapid inflation of petroleum prices, the Indonesian Government and PLN in 2006 compiled the Non-petroleum Power Resources Development Promotion Plan (commonly known as the First Crash Program or Fast Track Program) geared to developing 10,000 MW of coal-fired thermal power, thereby diversifying the energy mix based mainly on coal. Under this program, within the North Sumatra Grid, it is planned to commission Pangkaran Susu (1 & 2 PLTU 2 x 200 MW, North Sumatra Province) and Meulaboh (PLTU 2 x 100 MW, Aceh Province), however, work on both projects is behind schedule and they are expected to finish in 2012 according to RUPTL 2010. Moreover, in the Second Crash Program, the following projects are planned:

- PLTU: Pangkalang Susu Baru (3 & 4) /2x200MW /2013/2014
- PLTA: Asahan-3 /174MW /2013
- PLTP: Seulawah /55MW /2014
  Sarulla-1 /220MW/110MW /2013/2014
  Sarulla-2 /110MW /2014
  Sorik Merap /55MW /2014

Table 3.3-1 shows the details of power resource introduction plans including the crash programs on the North Sumatra Grid. Looking to other power grids apart from North Sumatra, since existing power generation facilities are showing reduced output due to deterioration, while IPP projects tend to be unreliable, RUPTL 2010 sets the reserve margin in systems other than the Java-Bali Grid at around 40% upon considering the risk of not being able to secure the necessary power resources. If currently planned projects are finished and introduced to the North Sumatra Grid on schedule, it will be possible to secure a reserve margin of 43.3%, higher than the target figure of 40%, by 2014.

Table 3.3-1 Power Resources Introduction Plan on the North Sumatra Grid

Item	Unit	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1 Summary											
Demand	GWh	8,252	9,006	9,825	10,741	11,775	12,908	14,175	15,539	17,012	18,583
Peak Load	MW	1,586	1,748	1,907	2,085	2,275	2,478	2,707	2,954	3,218	3,505
Load Factor	%	59.4%	58.8%	58.8%	58.8%	59.1%	59.5%	59.8%	60.0%	60.3%	60.5%
Reserve Margin	%	3.9%	6.9%	21.0%	43.3%	54.6%	42.0%	43.4%	46.9%	36.5%	28.5%
2 Supply	Unit	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Capacity of Power Supply (PLN)	MW	1,703	1,923	2,363	3,043	3,573	3,573	3,938	4,393	4,448	4,558
Type											
Diesel/PLTD	MW	107	107	107	107	107	107	107	107	107	107
Gas Turbine/ PLTG	MW	156	156	156	156	156	156	156	156	156	156
Combined Cycle/ PLTGU	MW	818	818	818	818	818	818	818	818	818	818
Steam Turbine/ PLTU	MW	490	710	1,150	1,350	1,550	1,550	1,750	2,175	2,175	2,175
Hydro/PLTA	MW	132	132	132	392	392	392	557	587	587	587
Geothermal/ PLTP	MW	0	0	0	220	550	550	550	550	605	715
3 Developing plan		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
3.1 On-Going Project Name/Type/Location		180	220	440	0	0	0	0	0	0	0
① PLN											
Meulaboh (FTP1)/ PLTU/Ache		→	→	220							
Pangkalan Susu (FTP1)/ PLTU/North Sumatra		→	220	220							
② IPP											
Asahan I/ PLTA/North Sumatra		180									
3.2 Planed Project		0	0	0	680	530	0	365	455	55	110
① PLN											
Peusangan 1-2/ PLTA/Ache				→	86						
Asahan III (FTP2)/ PLTA/North Sumatra				→	174						
Pangkalan Susu Baru (FTP2)/ PLTU/North Sumatra					200	200					
Meulaboh/ PLTU/Ache								200	200		
② IPP											
Sumut-2/ PLTU/North Sumatra									225		
Seulawah (FTP2)/ PLTP/Ache				→	→	55					
Sarulla I (FTP2)/ PLTP/North Sumatra			→	→	220	110					
Sarulla II (FTP2)/ PLTP/North Sumatra						110					
Pusuk Bukit/ PLTP/North Sumatra										55	55

Since the power resources introduction plans in Table 3.3-1 are based on the assumption that existing generating facilities will generate power at rated output, a slight reserve margin is secured even for 2010. However, in reality, because the generating facilities that were introduced in the 1970s and 1980s have not undergone appropriate maintenance, they suffer from seriously impaired output due to deterioration over time. When the potential generating output of facilities on the North Sumatra Grid in Table 3.1-1 is applied to the power resources introduction plan shown in Table 3.3-1, as is shown in Table 3.3-2 and Figure 3.3-1, the potential generating output is less than demand in recent years. Accordingly, PLN is now responding to this power supply shortfall by conducting rolling blackouts and so on. Having said that, the situation is expected to improve with the commissioning of PLTA Asahan-1 (180 MW).

Table 3.3-2 Power Resources Introduction Plan considering Existing Power Resources on North Sumatra Grid

Item	Unit	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Available Generation Capacity	MW	1,392	1,612	2,052	2,732	3,262	3,262	3,627	4,082	4,137	4,247
Type											
Diesel/PLTD	MW	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9
Gas Turbine/ PLTG	MW	58	58	58	58	58	58	58	58	58	58
Combined Cycle/PLTGU	MW	741	741	741	741	741	741	741	741	741	741
Steam Turbine/ PLTU	MW	428	648	1088	1288	1488	1488	1688	2113	2113	2113
Hydro/PLTA	MW	99	99	99	359	359	359	524	554	554	554
Geothermal/ PLTP	MW	0	0	0	220	550	550	550	550	605	715
Reserve Margin respect to Peak Load	%	-12.2%	-7.8%	7.6%	31.0%	43.4%	31.6%	34.0%	38.2%	28.6%	21.2%
Available Capacity Rate	%	84.5%	86.3%	88.9%	91.4%	92.7%	92.7%	93.4%	94.1%	94.2%	94.3%

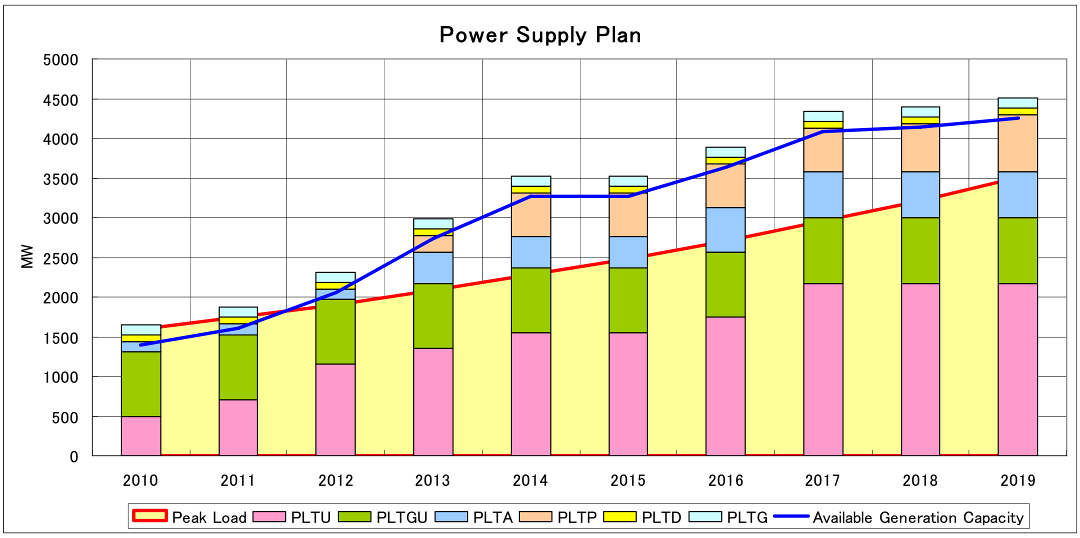


Figure 3.3-1 Power Supply Plans on the North Sumatra Grid

Concerning development of thermal power plants, the PLN plant Labuhan Angin (PLTU 2 x 115 MW), which wasn't included in the Crash Program, was completed in 2009 and is now supplying electricity, however, Pangkaran Susu 1 & 2 (2 x 220 MW) and Meulaboh (220 MW), which have combined output of 660 MW and were included in the Crash Program, have been delayed until 2012. Moreover, in the Second Crash Program, Pangkalang Susu Baru 3 & 4 (2 x 200 MW) has been postponed by around a year compared to RUPTL 2009. The reasons for these delays are problems in fundraising and management of subcontractors, difficulties in acquiring land in coal production areas and environmental issues. Out of the above IPP projects, PLTU only states location addresses rather than specific site names. This is to enable PLN to offer IPP projects to developers in the competitive tender process. PLTU Sumut-2 on the North Sumatra Grid, which is stated as an IPP thermal power plant in RUPTL 2010, refers to PLTU Kuala Tanjung.

Regarding geothermal energy development, in the Second Crash Program it is planned to develop 3,967 MW by 2014, while in RUPTL 2010 it is planned to develop 6,100 MW by 2019. Projects due to finish in 2014 are those for the expansion of existing geothermal power plants and a few selected sites. Meanwhile, development sites are selected based on the Geothermal Master Plan Study (2007), according to which it is planned to develop Sarulla-1 (330 MW), Sarulla-2 (110MW) and Sorik Merapi (55MW) by 2014 and Sipaholon (55 MW) by 2019. There are numerous candidates for PLTP geothermal projects in Sumatra, and in the event where all PLTP projects are implemented according to schedule in tandem with the coal-based PLTU, the capacity factor of PLTU base power plants will decline. However, since the implementation of many PLTP projects is still uncertain (development potential has not yet been verified by drilling on many sites) and IPP projects entail great uncertainty, Sumatra could fall into a critical state if the PLTP doesn't progress according to schedule. Sarulla-1 (currently being implemented) is already one year behind the schedule given in RUPTL 2010, and this will cause delays in the subsequent Sarulla-2 project, which will take a few years to get through the study stage and development stage.

Concerning hydropower development, Asahan No. 1 commenced operation in August 2010, however, Asahan No. 3, which is scheduled to start operating in 2013, is expected to be two or three years behind schedule judging from the present situation. Similarly, in Aceh Province, Pusangan 1 and 2, which have entered the implementation stage, are expected to be at least two or three years behind the intended commissioning target of 2013 due to various issues that need to be resolved by the start of construction. Concerning Wampu, which is an IPP project scheduled to commence operation in 2016, almost 20 years have passed since the JICA F/S was implemented in 1992 and it will be necessary to implement a renewed study in order to proceed to the implementation stage. Since the initial plans for Wampu entailed the power plant and transmission line route encroaching on a national park, it is necessary to redo the F/S and also review the basic plan. Accordingly, taking into account the new study, design and construction works processes, the project is expected to be delayed by two or three years. Incidentally, the above projected delays are based on information obtained from relevant sources, but not on information from the implementing party, PLN. Accordingly, because the Study Team couldn't acquire information and data based on concrete facts from PLN, it has been unable to independently review the supply plans contained in RUPTL 2010-19 (which was issued in July 2010) or analyze and confirm the actual demand and supply gap in this Study.

3.3.2 Power Supply Business Plan in Case of INALUM Plant Expansion

Assuming that the INALUM plant expansion increased aluminum production by 90,000 tons per year and that approximately 15 kWh of power is needed to produce one ton, it will be necessary to introduce generating facilities with the capacity to supply approximately 1,350 GWh of power per year (90,000 t/year x 15 kWh/ton). If it is intended to supply this via a 200 MW generating facility, since 200 MW x 24 hr x 365 x 77% = 1,349 GWh, it will be necessary to secure a high plant utilization factor of 77%, however, adequate power supply capacity will be available. Such a power resource is not included in RUPTL 2010, however, out of the new power resources stated in RUPTL 2010 (Table 3.3-1), if completion of the PLN project at Meulaboh (PLTU: 2 x 200 MW, 2016/2017) is brought forward to 2015 and this can be incorporated into the North Sumatra Grid, it will not be necessary to construct a new power plant. Table 3.3-3 shows the demand forecast assuming this plan revision and start of operation in 2015 in the RUPTL 2010 power supply plan.

Table 3.3-3 Demand Forecast in Case of Supplying Power for INALUM Plant Expansion through Revising RUPTL 2010

Item	Unit	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1 Summary											
Demand	GWh	8,252	9,006	9,825	10,741	11,775	14,257	15,524	16,888	18,361	19,932
Peak Load	MW	1,586	1,748	1,907	2,085	2,275	2,678	2,907	3,154	3,418	3,705
Load Factor	%	59.4%	58.8%	58.8%	58.8%	59.1%	60.8%	61.0%	61.1%	61.3%	61.4%
Reserve Margin	%	7.4%	10.0%	23.9%	46.0%	57.1%	40.9%	42.4%	39.3%	30.1%	23.0%
2 Supply	Unit										
Capacity of Power Supply (PLN)	MW	1,703	1,923	2,363	3,043	3,573	3,773	4,138	4,393	4,448	4,558

As a result of incorporating introduction of the 200 MW power resource and demand for the new aluminum smelting plant (1,349 GWh) in 2015, it is projected that a reserve margin of 40.9%, slightly higher than the 40% aimed for by PLN, can be secured. However, if there are no new power resource development plans after that, the problem of low reserve margin will resurface and once again hinder stability on the North Sumatra Grid in 2017. Moreover, since new power resource introduction plans are sometimes delayed but never accelerated, rather than responding to needs by revising power plant plans in RUPTL 2010, it is desirable to obtain power supply from new power resources not contained in RUPTL 2010. In consideration of the above points, assuming that a new power resource not mentioned in RUPTL 2010 and the new aluminum smelting plant commence operation in 2015, Table 3.3-4 shows the demand forecast that incorporates these contents into the RUPTL 2010 supply plan. Since it is scheduled to introduce large power resources by 2017, the reserve margin exceeds the target 40%, however, since only medium-scale geothermal power plants are planned for introduction from 2018 onwards, the burgeoning demand for power will push the reserve margin below 40% in 2018 and beyond. In either case, it will be necessary either to secure the reserve margin upon remaking the new power resources introduction plans for 2018 onwards, or to secure grid stability through certainly interconnecting the South and North Sumatra Grids as planned via 275 kV and 500 kV transmission lines. If the South and North Sumatra Grids can be interconnected in this way, the capacity of power resources over the entire system will be increased and stability will be achieved.

Table 3.3-4 Demand Forecast Assuming a New Power Resource for INALUM Plant Expansion

Item	Unit	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1 Summary											
Demand	GWh	8,252	9,006	9,825	10,741	11,775	14,257	15,524	16,888	18,361	19,932
Peak Load	MW	1,586	1,748	1,907	2,085	2,275	2,678	2,907	3,154	3,418	3,705
Load Factor	%	59.4%	58.8%	58.8%	58.8%	59.1%	60.8%	61.0%	61.1%	61.3%	61.4%
Reserve Margin	%	7.4%	10.0%	23.9%	46.0%	57.1%	40.9%	42.4%	45.6%	36.0%	28.4%
2 Supply	Unit										
Capacity of Power Supply (PLN)	MW	1,703	1,923	2,363	3,043	3,573	3,773	4,138	4,593	4,648	4,758

3.3.3 Transmission Line Construction Plan

In RUPTL2010, construction of the transmission line network is planned in tandem with the development of new power resources. The transmission system in Sumatra is currently interconnected between Aceh Province and Lampung Province, however, there are numerous areas where it is necessary to install many additional transmission lines in order to feed new substations and strengthen the existing system. In order to reduce voltage drop /power losses caused by long-distance medium voltage overhead transmission lines and to improve system reliability, it is necessary to install 2,360 km of new transmission lines by 2019. Moreover, as a measure to support existing substations that are already saturated, it is necessary to develop transmission lines (maximum 3 x 60 MW) between new substations. Table 3.3-5 shows the transmission network construction plans indicated in RUPTL 2010.

The selected power generation facilities in each generating mode will need to be connected to the INALUM transmission system or PLN North Sumatra Grid; however, considering the special character of the INALUM power for an aluminum smelting plant, it is better to adopt an independent transmission system, while it is desirable to connect civilian power resources to transmission lines of North Sumatra Grid over short distances.

Table 3.3-5 Transmission Line Construction Plan

No.	From	To	Voltage	Conductor	Distance (km)	Cost (M USD)	COD
Aceh							
1	Sidikalang	Sabulussalam	150kV	2cct, 1HAWK	111	6.2	2011
2	Brastagi	Kuta Can	150kV	2cct, 1HAWK	356	19.7	2011
3	Sigli	Meulaboh	150kV	2cct, 2Zebra	333	75	2011
4	Meulaboh	PLTU Meulaboh	150kV	2cct, 1HAWK	60	3.3	2011
5	PLTA Peusangan-1	Takengon	150kV	2cct, 2HAWK	22	171.7	2011
6	PLTA Peusangan-1	PLTA Peusangan-2	150kV	2cct, 2HAWK	14	1.1	2011
7	Bireun	PLTA Peusangan-2	150kV	2cct, 2HAWK	114	8.7	2011
8	Jantho	Incomer (Sigli-BandaAceh)	150kV	2cct, 1HAWK	1	0.1	2012
9	Panton Labu	Incomer (Idi-Lhokseumawe)	150kV	2cct, 1HAWK	1	0.1	2012
10	Meulaboh	Blang Pidie	150kV	2cct, 1HAWK	190	10.5	2012
11	Blang Pidie	Tapak Tuan	150kV	2cct, 1HAWK	130	7.2	2012
12	Cot Trueng	Incomer (Bireun-Lhokseumawe)	150kV	2cct, 1HAWK	6	0.3	2012
13	Samalanga	Incomer (Bireun-Sigli)	150kV	2cct, 1HAWK	4	0.2	2013
14	BandaAceh	Krueng Raya	150kV	2cct, 1HAWK	90	5	2014
15	PLTA Peusangan-2	Blang Kjeren	150kV	2cct, 1HAWK	174	9.6	2014
16	PLTP Seulawah (FTP2)	2 Pi Incomer (Sigli-Banda Aceh)	150kV	2cct, 1HAWK	16	0.9	2014
17	Kuta Cane	Lawemamas	150kV	2cct, 1HAWK	50	2.8	2016
North Sumatra							
1	Porsea	Simangkok	150kV	2cct, 2HAWK	10	0.8	2010
2	Tanjung Marowa	Kuala Namu	150kV	2cct, 2HAWK	34	2.6	2011
3	Dolok Sanggul	Incomer (Tele-Tarutung)	150kV	2cct, 1HAWK	14	0.8	2011
4	Galang	Namurambe	150kV	2cct, 2Zebra	80	7.9	2011
5	Galang	Tanjung Marowa	150kV	2cct, 2Zebra	20	2	2011
6	Padang Sidempuan	Panyabungan	150kV	2cct, 1HAWK	140	7.8	2013
7	Namurambe	Pancor Batu	150kV	2cct, 1HAWK	30	1.7	2013
8	Simangkok	PLTA Asahan-3 (FTP2)	150kV	2cct, 2HAWK	22	1.7	2013
9	Pangkalan Susu 3&4 (FTP2)	Pangkalan Brandan	150kV	2cct, 2HAWK	22	1.7	2013

No.	From	To	Voltage	Conductor	Distance (km)	Cost (M USD)	COD
10	Lamhotma	Belawan	150kV	12ndcct, 1HAWK	6	0.5	2013
11	Tanjung Pura	Incomer (P.Brandan-Binjai)	150kV	2cct, 1HAWK	30	1.7	2015
12	PLTA Wampu	Brastagi	150kV	2cct, 1HAWK	80	4.4	2016
13	Teluk Dalam	Gunung Sitoli	70kV	2cct, 1HAWK	220	12.2	2012
14	Panyabunganyg	PLTP Sorik Merapi (FTP2)	150kV	2cct, 1HAWK	46	2.5	2014
15	Tarutung	PLTP Pusuk Bukit	150kV	2cct, 2HAWK	60	3.3	2018
16	PLTA Asahan1	Simangkok	275kV	2cct ,2Zebra	16	3.6	2010
17	Tele	Pangururan	150kV	2cct, 1HAWK	50	3.8	2012
18	Simangkok	Galang	275kV	2cct, 2Zebra	318	71.6	2011
19	Galang	Binjai	275kV	2cct, 2Zebra	160	36	2011
20	Pangkalan Susu	Binjai	275kV	2cct , 2Zebra	160	36	2011
21	PLTP Sarulla (FTP2)	Simangkok	275kV	2cct, 2Zebra	194	43.7	2013
22	Padang Sidempuam	PLTP Sarulla (FTP2)	275kV	2cct, 2Zebra	138	31.1	2013
23	Rantau Prapat	Tebing Tinggi	500kV	2cct, 4Dove	400	123.6	2018
24	Tebing Tinggi	Belawan	500kV	2cct, 4Dove	160	49.4	2018

Chapter 4 Confirmation of Power Development Potential for Each Generating Mode

4.1 Coal-fired and Gas-fired Thermal Power

According to RUKN 2008-2027 issued by the Ministry of Energy and Mineral Resources in November 2008, as prescribed in Government Ordinance No.26/2006, the policy for escaping from dependence on petroleum consists of accelerating the diversification of energy resources, expanding the share of coal and natural gas, expanding the share of renewable energies and thereby constructing the most appropriate and economical energy mix. In addition to the policies of RUKN, responding to the depletion of domestic petroleum resources and rapid inflation of petroleum prices, PLN in 2006 compiled the Non-petroleum Power Resources Development Promotion Plan (commonly known as the First Crash Program or Fast Track Program) geared to advancing the construction of coal-fired thermal power plants all over the country and suspending use of old generating facilities that use petroleum-based fuels and have poor thermal efficiency.

However, although the First Crash Program was scheduled to finish in 2011, it has since been delayed until 2013 due to difficulties in raising the necessary funds and acquiring land in work areas and environmental problems, etc. Meanwhile, the Second Crash Program, which was compiled in January 2010, places emphasis on the development of renewable energy, while planning to obtain approximately 40% of generating output from coal-fired and gas-fired thermal power plants. Table 4.1-1 shows a list of the coal-fired thermal power plants on the North Sumatra Grid that are included in RUPTL 2010-2019. These comprise existing plants or plants in the planning stage geared to supplying power mainly for civilian purposes.

Table 4.1-1 Coal-Fired Thermal Power Plants (Existing and Planned) on the North Sumatra Grid

Developer	Name of Power Station	Crush Program (FTP)	Location	Capacity (MW) Number	Completion Year	
					Initial Plan	Current Plan
PLN	Meulaboh	1 (First)	Ache	220 (110 x 2)	2010	2012
	Pangkaran Susu	1 (First)	North Sumatra	440 (220 x 2)	2010	2011/12
	Pangkaran Susu Baru	2 (Second)	North Sumatra	400 (200 x 2)	2012	2013/14
	Labuhan Angin	-	North Sumatra	230 (115 x 2)	Existing	2009 completion
IPP	Sumat-2	-	North Sumatra	225 (225 x 1)	-	2017

Source: RUPTL (2010-2019)

When considering the development potential for new coal-fired and gas-fired thermal power generation, since fuel procurement is the most important factor, plans will be formulated while focusing on the fuel procurement method as shown below.

♦ Case where coal-fired thermal power generation is introduced on the North Sumatra Grid:

1) Construction of power plant at the mine (site of buried coal reserves), direct supply of coal to the plant, power generation and supply to consumer areas by long-distance transmission
2) Construction of power plant in an ideal location close to consumer areas, transportation of coal from the mine to the plant, power generation and supply to the consumer area

The above two options are available. As in the Phase 1 study (2009), this Study examines the amount of underground coal reserves, production volume and sales performance, the situation regarding transport infrastructure development, feasibility of supply to the North Sumatra Grid and environmental problems with a view to confirming the potential for additional development of coal-fired thermal power.

♦ Case where gas-fired thermal power generation is introduced on the North Sumatra Grid:

As was reported in the Phase 1 study (2009), production of natural gas in Aceh Province has been declining in recent years and it is increasingly difficult to procure gas locally. The following three options can be considered for constructing a gas-fired thermal power plant close to the consumer area of North Sumatra Province and procuring natural gas for that:

1) Procurement through supplying gas from other areas in Sumatra via pipeline
2) Procurement from other areas in Sumatra by LNG/CNG tank lorry
3) Procurement from off the island by LNG/CNG vessel

However, all of these options require expensive plant investment in order to build the necessary infrastructure. Moreover, since the natural gas produced in South Sumatra Province is supplied to Java as a priority destination and gas-fired thermal power development in other areas apart from Java is only planned when the natural gas supply has been secured, this reduces the possibility of conducting gas-fired thermal power development in North Sumatra. However, if it is possible to procure fuel gas from the offshore LNG loading point that is planned for completion in 2013 off the coast of Medan in North Sumatra Province, it will be possible to conduct thermal power generation based on the combined cycle approach.

4.1.1 Coal and Gas Underground Reserves

(1) Coal

According to the Indonesian Coal Book 2008/2009, Indonesia has approximately 70 billion tons of coal resources, of which 6.4 billion tons have been confirmed as economically feasible for mining and 5.5 billion tons have been confirmed as buried reserves (approximately 11.9 billion tons in total). Table 4.1-2 shows the amount of resources and estimated and confirmed reserves of coal in the three provinces of South Sumatra, East Kalimantan and South Kalimantan, which are possible supply bases for North Sumatra. Judging from these figures for the amount of resources and estimated and confirmed reserves, it can be seen that these three provinces will play a central role in Indonesia's coal production from now on. Each province has large amounts of medium rank quality coal resources and possesses ample potential as a domestic coal supply base. Coal from South Sumatra is mostly low rank quality and is supplied for domestic consumption. Meanwhile, coal from East Kalimantan contains a relatively high proportion of high rank quality coal with high calorific value, and this is used for international export. Concerning provinces in the north of Sumatra, Riau Province is thought to have minor reserves of coal as shown in Table 4.1-3, however, unlike the aforementioned three provinces, it does not have the potential to provide a stable supply of coal into the future.

In view of the above points, there is little possibility of building a mine-mouth power plant in North Sumatra, and it is more appropriate to plan a power plant assuming transportation of coal from either South Sumatra Province, East Kalimantan Province or South Kalimantan Province. Figure 4.1-1 shows a map of coal resources and reserves in each coal producing province. In the case where a coal-fired thermal power plant is constructed, depending on the conditions of steam generated in the boiler, either a subcritical, supercritical or ultra-supercritical boiler is selected. Based on experience in Japan, thermal power plants equipped with supercritical or ultra-supercritical boilers, which have excellent thermal efficiency, have minimum unit capacity of around 400 MW. However, since the North Sumatra Grid overall has generating capacity of roughly 1,700 MW as of 2010, such a plant would account for approximately 23% of the grid capacity, and this is far in excess of the 4% share recommended for single unit capacity of new power resources. Even if the power plants planned in the crash programs are completed and start generating power, thereby increasing grid capacity to approximately 3,500 MW by 2015, since a 400 MW plant would still account for 11% of grid capacity, it would be necessary to conduct grid power flow analysis to examine its impact on the grid.

Table 4.1-2 Data on Coal Resources and Reserves in South Sumatra Province, East Kalimantan Province and South Kalimantan Province

(Unit: 100million ton)

Province	Quality	CV(kcal/kg)	Resources	Reserves	
				Probable	Proven
South Sumatra	Low	<5,100	11,851	2,426	0
	Medium	5,100-6,100	11,338	0	186
	High	6,100-7,100	479	0	67
	Sub-Total		23,669 (33.8%)	2,426 (38.0%)	253 (4.6%)
South Kalimantan	Low	<5,100	1,015	214	536
	Medium	5,100-6,100	10,253	1,422	1,217
	High	6,100-7,100	798	90	45
	Very High	>7,100	30	0	0
	Sub-Total		12,096 (17.3%)	1,725 (27.0%)	1,798 (32.9%)
East Kalimantan	Low	<5,100	912	0	0
	Medium	5,100-6,100	15,838	407	1,486
	High	6,100-7,100	9,288	390	1,178
	Very High	>7,100	220	73	31
	Sub-Total		26,258 (37.5%)	870 (13.6%)	2,695 (49.3%)
Total			62,023 (88.6%)	5,022 (78.6%)	4,746 (86.9%)

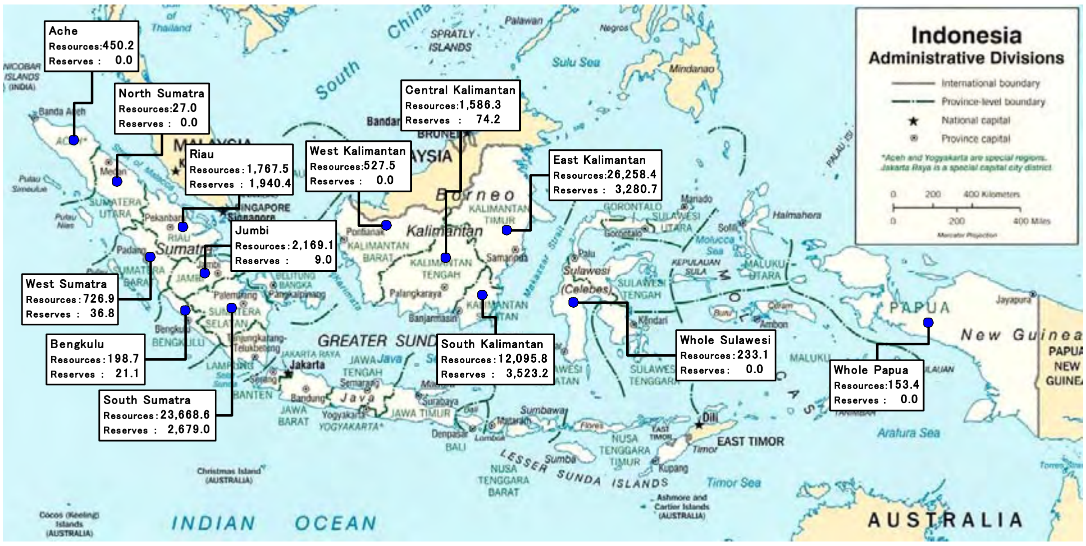
Source: Indonesian Coal Book 2008/2009

Table 4.1-3 Data on Coal Resources and Reserves in Northern Parts of Sumatra

(Unit: 100million ton)

Province	Quality	CV(kcal/kg)	Resources	Reserves	
				Probable	Proven
Aceh	Low	<5,100	91.8	0.0	0.0
	Medium	5,100-6,100	358.4	0.0	0.0
	Sub-Total		450.2	0.0	0.0
North Sumatra	Low	<5,100	20.0	0.0	0.0
	Medium	5,100-6,100	7.0	0.0	0.0
	Sub-Total		27.0	0.0	0.0
Riau	Low	<5,100	1,613.8	1,340.6	569.1
	Medium	5,100-6,100	103.3	14.1	0.0
	High	6,100-7,100	50.5	0.0	16.5
	Sub-Total		1,767.5	1,354.8	585.6
West Sumatra	Medium	5,100-6,100	369.2	0.0	2.8
	High	6,100-7,100	316.7	0.7	19.2
	Very High	>7,100	41.0	0.0	14.0
	Sub-Total		726.9	0.7	36.1
Total			2,972 (4.2%)	1,355 (21.2%)	622 (11.4%)

Source: Indonesian Coal Book 2008/2009



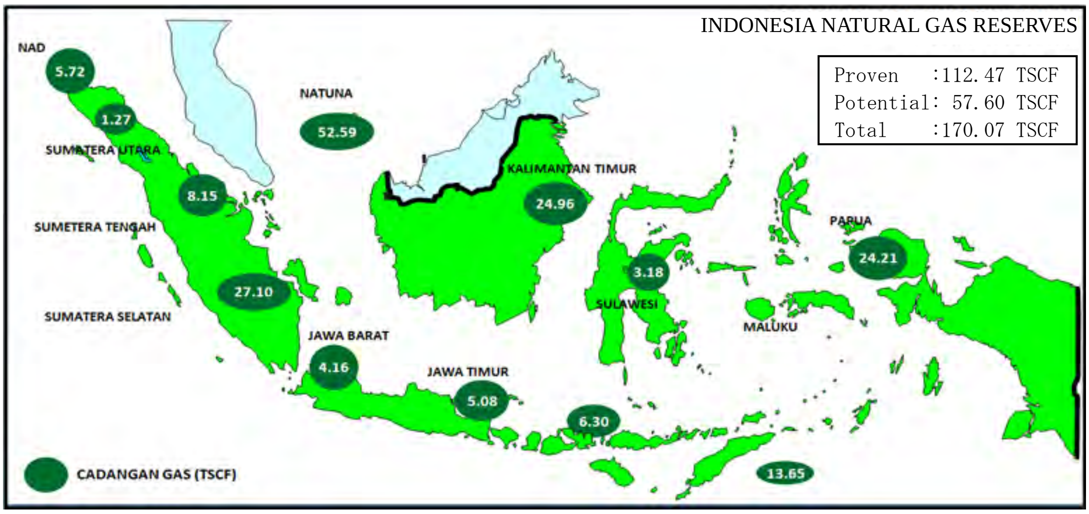
Source: Map data from the University of Texas Libraries, combined with data from the Indonesian Coal Book 2008/2009

(Unit: 100million tons)

Figure 4.1-1 Coal Resources and Reserves in Indonesia

(2) Gas

According to data in the data warehouse on the MEMR homepage, Indonesia has natural gas resources of 170.07 Tscf, of which confirmed reserves account for 112.47 Tscf and latent reserves for 57.60 Tscf. As is indicated in Figure 4.1-2, reserves of natural gas have been confirmed throughout Indonesia.



Source: MEMR, Data Warehouse

Figure 4.1-2 Natural Gas Reserves in Indonesia (Unit: Tscf)

The areas having the greatest potential are Natuna, South Sumatra Province, East Kalimantan Province and West Papua Province, and the gas fields around Natuna account for 31% of total reserves in Indonesia. This is followed by 16% in South Sumatra, 15% in East Kalimantan and 14% in West Papua. It is hoped to obtain gas supply from the gas fields around Natuna, which have the largest reserves and are located close to North Sumatra, however, these reserves have CO_2 content of 70% and their feasibility cannot be judged from the amount of reserves alone.

Sumatra also has the Arun gas field in Aceh Province. This has supplied LNG for export to Japan since 1977, however, production levels have been falling in recent years and there is concern that the field will dry up. Meanwhile, approximately 40 MMscfd of natural gas is supplied via PGN (state-owned gas company) pipeline from a small gas field in North Sumatra Province to the existing Belawan thermal power plant; however, this field only has minor development potential because reserves here are limited and production has been declining in recent years. Concerning natural gas produced in South Sumatra, since priority is given to supply to Java and it would be necessary to transport it more than 1,000 km by tank lorry, it is not feasible to use this. Moreover, concerning natural gas procurement via pipeline, a pipeline has been installed and is being used between Grissiki in South Sumatra Province and Duri in Riau Province, however, since the remaining section of more than 500 km to Medan is only in the planning stage and so far no specific construction schedule has been set, no date has been set for supply via this route. Accordingly, the remaining options are to procure natural gas from East Kalimantan Province or West Papua Province.

Source: PGN, Presentation to the investors

Figure 4.1-3 Existing and Planned LNG Facilities

The available options in this case are transportation of LNG or CNG. As is shown in Figure 4.1-3, since a new company financed by PGN is planning to construct a marine LNG receiving base with capacity of 60 mmscfd off the coast of Medan, it is more feasible to procure LNG. At the current point, it is not decided where the LNG will come from, however, procurement from East Kalimantan Province or West Papua Province is considered appropriate, and this is a promising source of fuel for thermal power generation. However, in this case, since LNG storage and vaporization equipment will be required, the fuel cost will be expensive. Even if a high efficiency gas turbine, heat recovery steam generator (HRSG) and steam turbine are used in a combined cycle (CC) system, the unit rate of generation will be expensive.

4.1.2 Required Supply of Coal and Gas for Power Generation

(1) Coal

In the Phase 1 study (2009) report, it is estimated that approximately 1.2 million tons of coal per year will be required for the INALUM plant expansion. This is the annual coal requirement in the case where a 450 MW generating facility is constructed and is based on the conditions of 70% annual utilization factor of the power plant, 39% generating thermal efficiency and medium quality coal with calorific value of 5,00 kcal/kg. According to this calculation, more than 270,000 tons of coal is required to produce output of 100 MW. Meanwhile, the PLN power plants shown in table 4.1-1 (total output 1,290 MW) require approximately 3.5 million tons of coal per year. Since this doesn't include the coal needed for INALUM plant expansion, the total required coal supply in this case will actually be around 4.7 million tons/year. Judging from the amount of coal resources and underground reserves in South Sumatra Province, South Kalimantan and East Kalimantan, the above quantity is deemed to be procurable, however, in order to supply a sufficient quantity of coal to North Sumatra Province, in addition to increasing mined quantities of coal it will also be necessary to increase transport capacity through reinforcing the transport infrastructure.

(2) Gas

Since natural gas is a mixture of flammable gases comprising mostly methane that vaporize in atmospheric pressure, reserves are expressed in scf (standard cubic feet), which is the international unit for gases. Handled quantities are also usually expressed in scf and this unit is used in the Study, although Btu (British Thermal Unit) is sometimes used to express calorific value. As for LNG, since this is a liquid, reserves are expressed in cubic meters (m^3) or tons.

When considering thermal power generation based on natural gas, rather than the conventional coal-fired generating method based on boiler and turbine, it is more appropriate to adopt the CC generating method. In North Sumatra, consideration will be given to introducing E-class CC power generation, which has been amply applied in Japan and in which the gas turbine combustion temperature is 1,100℃. Thermal efficiency in E-class CC generation is around 45%, and in the case where the annual utilization factor is set at 70% (the same as in coal-fired generation), if natural gas with a calorific value of 9,800 kcal/Nm3 is used as fuel, 12 million Nm^3 is required to generate 100 MW. Assuming supply of 200 MW for the INALUM plant expansion, it will be necessary to have 24 million Nm^3 of natural gas per year. In terms of scf (standard cubic feet), which is the unit used to express the amount of reserves, it is necessary to secure annual gas supply of approximately 8,400 MMscf or a daily supply of approximately 23 MMscf on average.

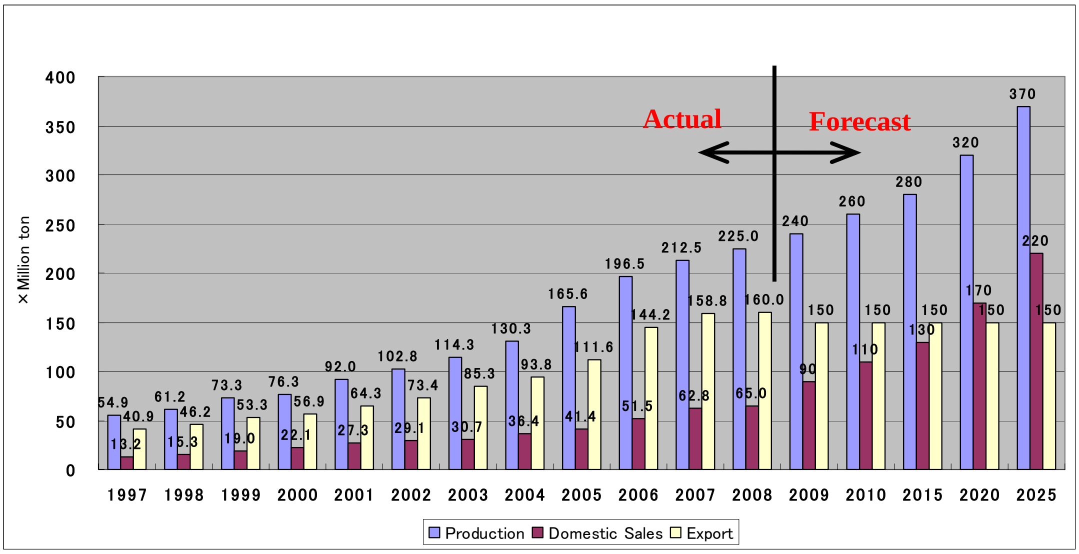
The offshore LNG loading point is planned to handle 60 MMscfd of gas, of which 23 MMscfd or almost 40% will be used in CC power generation. Considering supply to the manufacturing sector and other industries, it will be necessary to plan for expansion of the LNG loading point and to conduct detailed examination to ensure that an adequate flow of gas can be supplied to new power resources. If gas is supplied via pipeline, the schedule for construction of the section between Duri and Medan is currently undecided, however, the gas transmission capacity is planned as 420 MMscfd (approximately 5.5%) and it is likely that enough natural gas for supply to both CC power generation and other industries will be secured.

4.1.3 Production Quantity and Sales Record

(1) Coal

Coal production in Indonesia is carried out by the state-owned coal mining company (PTBA), coal contract of work operators (CCOW), small-scale mining concession holders (KP) and rural cooperative associations (KUD). In terms of production volume, PTBA accounts for approximately 4% and CCOW for approximately 80%, and production is increasing every year. According to the Indonesian Coal Book 2008/2009, coal production in 2007 was approximately 212.5 million tons, of which approximately 158.8 million tons (roughly two-thirds) was used for export and 62.8 million tons was supplied to the domestic market. However, the national coal policy intends to increase domestic use while holding or reducing exports, and it is eventually planned for domestic supply to outstrip exports. Figure 4.1-4 shows past and future projected figures for production, export, and domestic sale of coal. Since these data comprise actual figures up to 2007 and forecast values from 2008 onwards, the data for 2008 and 2009 can be revised to actual values if the latest data can be obtained. High rank quality coal with high calorific value tends to be used for export, while low rank quality coal with low calorific value is largely used for domestic supply. In 2007, out of approximately 62.8 million tons of domestic coal consumption, approximately 31.5 million tons (roughly 50%) was used in the power sector, and although there are yearly fluctuations, the power sector is the largest consumer of coal in the country.

Domestic coal sales in Indonesia in 2007 amounted to approximately 62.8 million tons, of which 27.67 million tons of 44% was consumed in South Kalimantan Province, 26.1 million tons or 41.5% was consumed in East Kalimantan Province, and 6.74 million tons or 10.7% was consumed in South Sumatra Province. This means that these three provinces accounted for approximately 96.3% of sales. Moreover, CCOW mines that are based on coal mining contracts with the government are the most common type of mining operation. Regarding the feasibility of coal supply to coal-fired thermal power plants in North Sumatra, the Phase 1 study (2009) only assessed mining companies in South Kalimantan Province and East Kalimantan Province, but it didn’t mention coal from South Sumatra Province, which is closer. However, South Sumatra Province is home to Tanjung Enim mine operated by PT. Tambang Batubara Bukit Asam (a PTBA), and since this produced approximately 10.8 million tons of coal in 2009, it shall be assessed as a candidate site for coal supply in this Study. It is considered appropriate to purchase coal from major mining enterprises such as PT. Adaro Indonesia and PT. Arutmin Indonesia in South Kalimantan Province, and PT. Kaltim Prima Coal, PT. Kideco JayaAgung PT. Berau Coal and PT. Indominco Mandiri (PT.Gunung Bayan Pratama Coal and PT. Jembayan Muarabara) in East Kalimantan Province.



Source: Indonesian Coal Book 2008/2009

Figure 4.1-4 Past and Future Sales Destinations of Indonesian Coal

Table 4.1-4 shows the coal resources and reserves of each coal mining company as well as production quantities for the past five years. The companies in South Kalimantan Province and East Kalimantan Province are CCOW mines that started production in the 1990s. Since these companies have signed contracts for 30 years and ample reserves exist in relation to the size of the working areas and annual production levels, stable operations can be anticipated for the immediate future.

Table 4.1-4 Coal Production Levels by Mining Companies in Each Province

(Unit:100miliion ton)

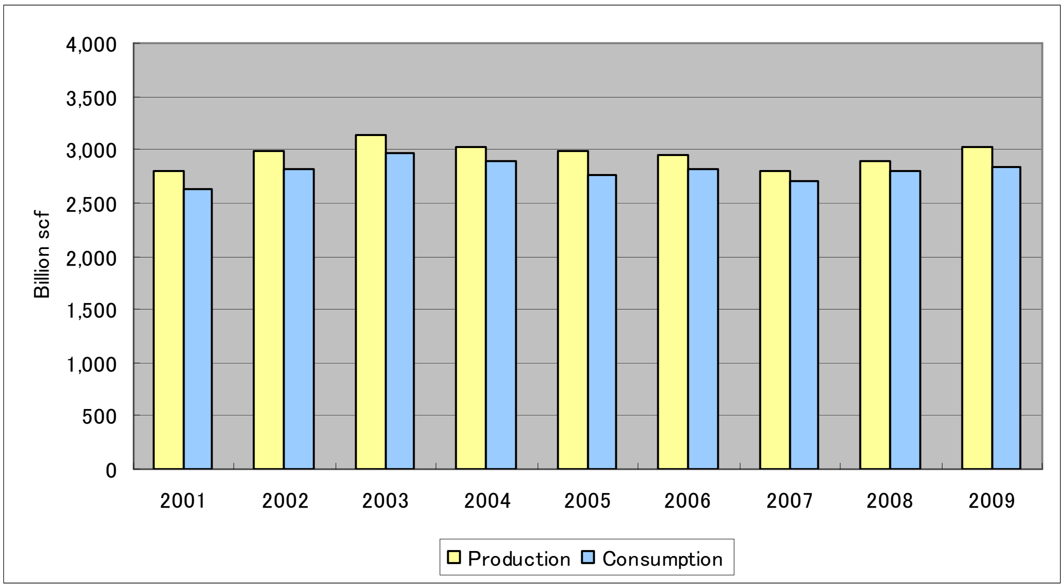
Company/Location	Year of Production Start	Resources	Reserves	Production				
				2005	2006	2007	2008	2009
PT. Tambang Batubara Bukit Asam /South Sumatra	1991	7,500	1,200	9.1	9.2	9.3	10.8	11.6
PT. Adaro Indonesia / South Kalimantan	1992	2,803	987	26.6	34.4	36.1	38.5	40.6
PT. Arutmin Indonesia / South Kalimantan	1990	2,422	540	16.8	15.3	17.3	15.4	19.3
PT. Berau Coal / East Kalimantan	1994	2,512		9.2	10.6	11.8		
PT. Indominco Mandiri / East Kalimantan	1999	609	93	7.7	10.3	11.5	12	13.8
PT. Kaltim Prima Coal / East Kalimantan	1991	4,333	903	27.6	35.3	36.3	37.5	40.3
PT. Kideco Jaya Agung / East Kalimantan	1993	2,857	915	18	19	20.5	22	24.7

Source: Indonesian Coal Book 2008/2009 or each company's annual report

As was also reported in the Phase 1 study (2009), Indonesian coal generally has low calorific value, however, it is internationally recognized as steam coal suited to low ash and low sulfur environments. Moreover, since roughly half of the coal consumed in Indonesia is used in the electric power sector, there is thought to be no problem regarding use as power generation fuel in North Sumatra Province.

(2) Gas

Natural gas is currently produced in gas fields at Arun in Aceh Province, Pagardewa and Corridor in South Sumatra Province, Bontang in East Kalimantan Province, and Tangguh in West Papua Province, etc. Gas from the two gas fields in South Sumatra Province is supplied to West Java via pipeline, however, because the other gas fields are remote from consumer areas, the gas is often liquefied and transported to consumer areas by LNG vessel. Moreover, as is shown in Figure 4.1-5, natural gas production and consumption levels in recent years have fluctuated between 2.5 and 3.0 trillion cubic feet, and the largest consumer is the electric power sector with a share of almost 40%. It is expected that production and consumption levels will continue to grow in line with economic development in the future.



Source: MEMR, Data Warehouse

Figure 4.1-5 Movements in Natural Gas Production and Consumption

Concerning the fuel gas used for thermal power generation, gas suppliers purchase natural gas produced mainly by foreign affiliated corporations such as Exxon Mobil as shown in Table 4.1-5 and supply it through pipelines. Alternatively, they transfer LNG by LNG carrier from the gas liquefaction plant to storage facilities, where they vaporize it and procure gas according to demand.

Table 4.1-5 Production Performance of Major Natural Gas Producers

(unit: billion scf)

Company	2001	2002	2003	2004	2005	2006	2007	2008	2009
Vico Indonesia	464.0	399.0	391.7	329.5	231.4	208.5	184.7	176.9	169.7
Exxon Mobil Oil Indonesia Inc.	268.1	508.2	602.1	507.1	379.1	322.4	280.7	231.5	178.6
ConocoPhillips (Grissik) Ltd	118.4	172.4	128.4	157.3	194.6	209.8	225.9	247.4	331.1
Conoco Phillips Natuna Ltd	41.4	68.9	116.0	127.3	145.3	132.9	164.5	166.9	190.3
Chevron Indonesia Company	159.3	138.5	138.8	102.9	84.7	76.1	74.7	81.3	66.7
BP Indonesia	181.9	169.3	191.8	138.8	123.7	139.3	118.9	117.6	91.4
Total E&P Indonesie	880.2	759.6	872.6	909.9	1067.2	1088.5	1016.1	1010.0	999.6

Source: MEMR, Data Warehouse

Since there is concern over the exhaustion of gas fields in North Sumatra Province, the option of direct supply from the gas field has been omitted in this Study; rather, the option of procuring LNG and transferring it to the offshore LNG loading point near Medan will be examined. In this case, the best option would be to procure LNG from the LNG plants in either Bontang in East Kalimantan Province or Tangguh in West Papua Province. The gas used for making LNG can be procured from Vico Indonesia, Total E&P Indonesia or BP Indonesia as shown in Table 4.1-5, while LNG can be produced from natural gas by PT. Badak or BP Indonesia. These plants produce 22.59 million tons and 7.6 million tons of LNG per year respectively and they purchase natural gas from gas producers according to the level of LNG production. Currently an ample amount of natural gas supply is available, however, since it is possible reserves will dry up in the future, it may be necessary to develop new gas fields in order to ensure the long-term supply of natural gas.

4.1.4 Conditions of Transport Infrastructure Development

(1) Coal

In Indonesia, barges are used more frequently than railways to carry coal. Coal is usually transported by truck or railway from the mine mouth to the nearest river container loading point, where it is stored and sometimes graded before being shipped on barges. Coal is usually directly transported by such barges to consumers in Indonesia and in nearby countries. In cases of long distance export to Japan and other countries further afield, the coal is either discharged at an outer harbor loading point or is directly shipped to an offshore ocean vessel.

Although barges have slow navigation speed, because they are cheap to build, can dock in ports with low draft and can be loaded and unloaded with basic equipment, they are widely used for transporting coal in Indonesia. Most of the CCOW mines, which bind business contracts with the government and account for the large proportion of coal production in Indonesia, transfer coal by truck or barge to shipping ports or offshore loading points for transfer to barges. These enterprises construct infrastructure for transporting to rivers and ports and they also build and operate independent loading ports on rivers or the coast. Coal is reloaded from barges to coal carriers (geared vessels) at offshore anchorage points or by floating cranes, etc. Figure 4.1-6 shows common models of coal transportation.

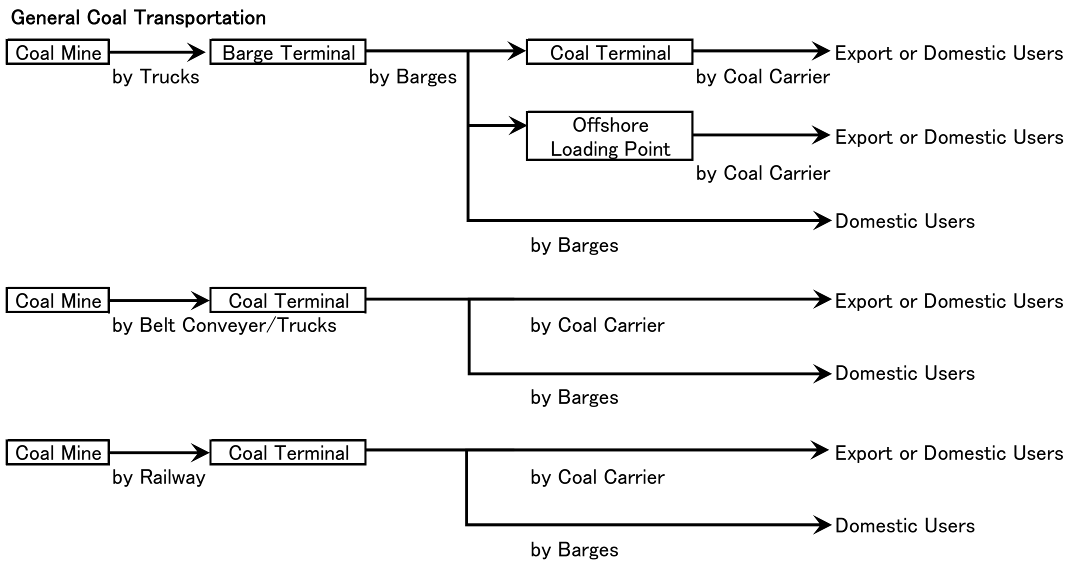


Figure 4.1-6 General Models of Coal Transportation

If a coal-fired thermal power plant is constructed in North Sumatra Province, it will be necessary to increase the number of barges used for transporting coal, however, since the barge transportation system is already well established in Indonesia, it will be possible to respond to the increased demand. Much of the coal that is produced at Tanjung Enim in South Sumatra Province is transported by rail to the loading ports, i.e. Kertapati Terminal (river port) in Palembang or Tarahan Terminal (ocean port) in lampung Province. From these terminals, the coal is transported by barge or Panamax ocean vessel to Java and overseas destinations.

Because the amount of coal handled at Kertapati Terminal has almost reached the upper limit and all coal from here is transported to Java and other destinations outside of North Sumatra, there is little chance of it supplying coal to North Sumatra. However, initial plans to build a railway from the outskirts of Palembang to Tanjung Api-Api Port on the South China Sea side in order to boost coal transportation capacity were changed to the construction of a 270 km direct rail line from Tanjung Enim to Tanjung Api-Api Port, and the contract for this project was signed in August 2009. If this project is realized, it will become possible to handle 35 tons of coal per year at Tanjung Api-Api Port, and if coal is purchased from PT. Tambang Batubara Bukit Asam, there is a strong likelihood that the transportation distance can be reduced to half the distance from Kalimantan.

(2) Gas

When building gas-fired thermal power plants in North Sumatra Province, it is realistic to either obtain gas via pipeline from gas fields in South Sumatra or to obtain vaporized LNG from the offshore LNG loading point near Medan. However, as was described in section 4.1.1 (Coal and Gas Reserves), since supply via pipeline is currently an unreliable option, the best option is to secure supply from the offshore LNG loading point. In this case, it will be necessary to obtain LNG carriers for transporting the LNG and build an LNG plant at the gas field, and also to have the LNG production company and gas supply company construct the necessary facilities at the offshore LNG loading point. Moreover, depending on the location of the power plant, in the case where the power plant is constructed close to Kuala Tanjung, it will be necessary to examine whether the gas supplier or consumers should invest in a pipeline leading from the existing pipeline network around Medan to the power plant.

4.1.5 Environmental Measures

（1）Coal

When coal is used as fuel at thermal power plants, the following environmental impacts can be expected: fly-off of particulate during transportation and handling mainly around the coal storage yard, wastewater from the coal yard and the starting and stopping of power generating equipment, emission of atmospheric pollutants such as nitrogen oxides and carbon dioxide contained in the exhaust gases of combustion, and so on. Measures concerning particulates, wastewater treatment and denitrification and desulfurization of exhaust gases need to be examined according to properties of the used coal, however, since these technologies are already well established, it should be possible to construct and operate coal-fired thermal power plants while incorporating appropriate environmental measures in Indonesia. However, although direct environmental impacts may be small, ample prior examination will need to be performed on the method for treating coal ash discharged after coal combustion.

(2) Gas

In the case where natural gas or gas obtained by vaporizing LNG is used as fuel, the recent mainstream trend is to adopt a high-efficiency combined cycle system comprising gas turbine generator + waste heat collection boiler + steam turbine generator. In this case, emissions of atmospheric pollutants such as nitrogen oxides contained in combustion exhaust gases can be expected, however, since gas turbines are equipped with Low-NOx combustors, which are now an established technology, it should be possible to construct and operate power generating facilities that incorporate appropriate environmental measures.

4.2 Geothermal Power Generation

4.2.1 Outline of Geothermal Resources in North Sumatra

(1) Outline of Geothermal Resource in Indonesia

Indonesia has the world largest class potential of geothermal energy and a total potential estimated by NGAI (National Geological Agency of Indonesia) account for about 27,000 MW. According to the INAGA (Indonesia Geothermal Association) and NGAI, there are 256 geothermal potential areas and among these 29 areas (2,795 MW) are prospective geothermal areas and development for operation is planned to start for 18 areas (1,205 MW). Geothermal power plants are currently in operation in seven areas and they have combined generating capacity of 1,196 MW (Surya Darama et al., 2010).

Indonesia's targets for geothermal energy development were set out in the Geothermal Road Map in 2003, which aims to achieve 9,500 MW power generations by geothermal energy by 2025. Moreover, the JICA Geothermal Power Development Master Plan Study of 2007 (hereafter Geothermal Master Plan (2007)) indicated that this development target was technically feasible. Furthermore, under the Second Crash Program for power development based on new energy (total 10,153 MW), it is planned to develop 3,977 MW of geothermal energy.

(2) Geothermal Areas in North Sumatra

On the island of Sumatra, numerous geothermal prospects are distributed along the northwest-southeast trending Great Sumatran Fault, and the North Sumatra is estimated to have 3,626 MW of geothermal resource potential. As shown in Table 4.2-1, 10 geothermal areas are distributed in North Sumatra (Note; the Sarulla mentioned in Phase 1 Study (2009) is given as Sarulla-1, while Sarulla/Sibual Buali in Phase 1 Study (2009) is given as Sarulla-2 in this study).

In Sibayak, a 12 MW geothermal power plant is in operation, while in Sarulla-1, the Power Purchase Agreement for 330 MW was signed between PLN and IPP in April 2010. In Merapi and Sipaholon, tender is being hold for development areas. In the area of Sinabung, located close to Sibayak, PGE is currently conducting surface investigation, however, the work is currently being suspended due to the eruption of Mt. Sinabung. Other areas are designated as

Green Field (non-surveyed areas), but surface investigations have been commenced in almost all of them. In the Geothermal Master Plan (2007), the areas of Sibayak, Sarulla, Merapi and Sipaholon were considered to be potential area for geothermal resources. In terms of development priority ranking, A rank is given to Sibayak and Sarulla, and B rank is given to Merapi. In the Phase 1 Study (2009), geothermal resources were examined in Areas 1~4, 7 and 8. Almost all of these geothermal potential areas are situated along the Great Sumatran Fault and are close to volcanoes (Figure 4.2-1).

Table 4.2-1 List of Geothermal Development Areas in North Sumatra

No.	Field name	Total Potential[1)] (MW)	Development Priority[2)]	Current Situation
1	Lau Debuk-Debuk/ Sibayak	40	A	Operation
2	Sarulla-1 Sarulla-2	630	A	Development
3	Sorik-Merapi	100	B	Tender
4	Sipaholon	50	L	Tender
5	Sinabung	ND (40)[3)]	N	Exploration
6	Dolok Marawa	-	-	Green Field (API NEWS, 2010)
7	Pusuk Bukit-Danau Toba	ND	N	
8	Simbolon-Samosir	ND	N	
9	Pagaran	-	-	
10	Sibubuhan	-	-	

1) Total Potential: Geothermal Master Plan (2007)
2) Development Priority: after Geothermal Master Plan (2007)
A: Existence of power plant or expansion/ development plan is scheduled
B: High possibility of existing geothermal reservoir
L: Low possibility of existing geothermal reservoir
N: Not enough data for evaluation
3) Estimated reserves by PGE

1: Lau Debuk-Debuk/ Sibayak, 2: Sarulla-1/ Sarulla-2, 3: S. Merapi, 4: Sipaholon, 5: Sinabung, 6: Dolok Marawa, 7: Pusuk Bukit-Danau Toba, 8: Simbolon-Samosir, 9: Pagaran, 10: Sibubuhan

Figure 4.2-1 Geothermal Potential Areas

(3) Geological Survey of North Sumatra

Sumatra is one of islands of an island arc system connecting Java, Bali and Flores situated in an area where the Indo-Australian Plate collides with and sinks beneath the Sunda Plate. As this plate is shifting toward the north-northeast direction, the right lateral fault of Great Sumatran Fault occurs near the west coast of Sumatra Island. The pull-apart basin formed by the Great Sumatran Fault has a structure suitable for storage of geothermal resources, and geothermal reservoirs in Sumatra are situated on the foot of volcanoes or in pull-apart basins. Due to the existence of the pull-apart basins, Sumatra has generally more geothermal reservoirs than normal volcanic zones (Muraoka et al, 2007). Distributions of the Great Sumatran Fault and pull-apart basins of the area are shown in Figures 4.2-2 and 4.2-3.

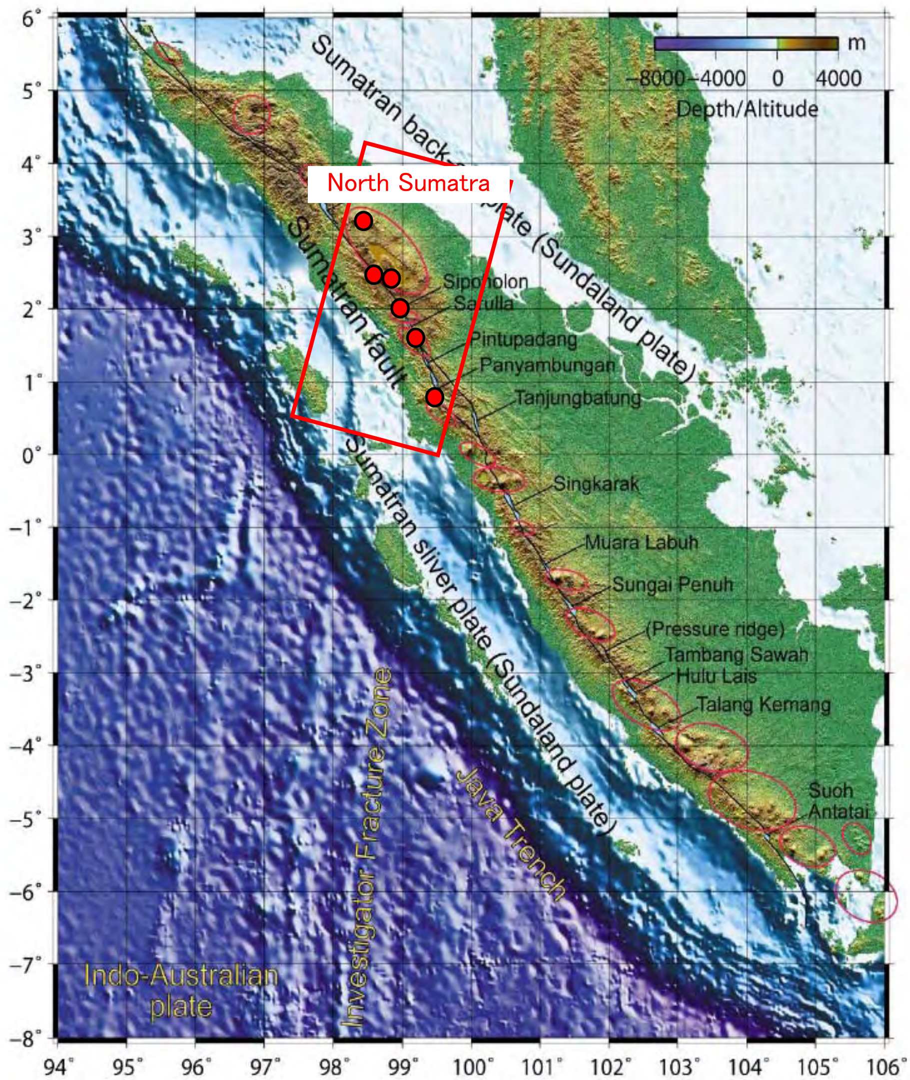


Figure 4.2-2 Distribution of Pull-Apart Basins, etc. along the Great Sumatran Fault

(Muraoka et al, 2010)

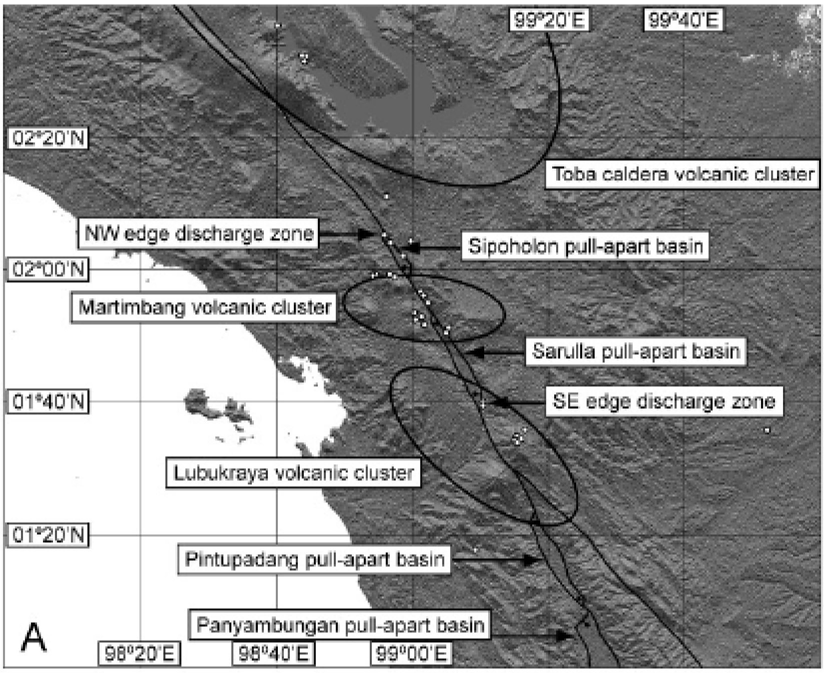


Figure 4.2-3 Distribution of Pull-Apart Basins around Sarulla

(Muraoka et al, 2010)

Pull-apart basins of Sinpoholon and Sarulla are situated along the Great Sumatran Fault in the southwest of North Sumatra. To the north of these areas lies the Toba caldera. This caldera, thought to have been formed 74,000 years ago, covers an extensive area of 100 km x 35 km. The Sibayak and Sinabung geothermal areas are situated at the northern tip of the Toba caldera.

(4) Outline of Geothermal Areas

(a) Sibayak (Lau Debuk-Debuk / Sibayak)

The area lies inside of the Singit caldera approximately 50 km southwest of Medan. Three volcanoes, namely Mt. Sibayak (2,090m), Mt. Pintau (2,212m) and Mt. Pratektekan (1,844m) occur in the Singit caldera. The caldera structure is elongated to northwest-southeast direction and the faults run trending in the northwest-southeast and northeast-southwest directions. The volcanoes inside the caldera are intersected by the northeast-southwest structure. Indications of geothermal activities are observed up to high altitude areas of both of Mt. Sibayak and Mt. Pratektekan, suggesting existence of an active up-flow zone in this area. The site for development of geothermal energy is located on the southern side of Mt. Sibayak (Figure4.2-4).

Development of geothermal resources of this area was started in 1991, and the operation of a 2 MW geothermal power plant was started in 1996. This was subsequently expanded to 12 MW with the addition of two 5 MW units. Ten wells have been drilled from three well bases and it was considered that there is sufficient steam supply of geothermal energy capable of generating 40 MW power. The outputs of investigation wells and production wells were estimated to be 2~6 MW/well (Supriyanto et al., 2005). The development plan aims at expanding capacity to 7.5 MW by 2012 and 19.5 MW by 2014, and investigation of the adjoining Sinabung geothermal prospect is planned for future expansion (Surya Darama et al., 2010). In this area, it is scheduled to drill production wells for expansion in.2011. Development plan is not found in RUPTL 2010.

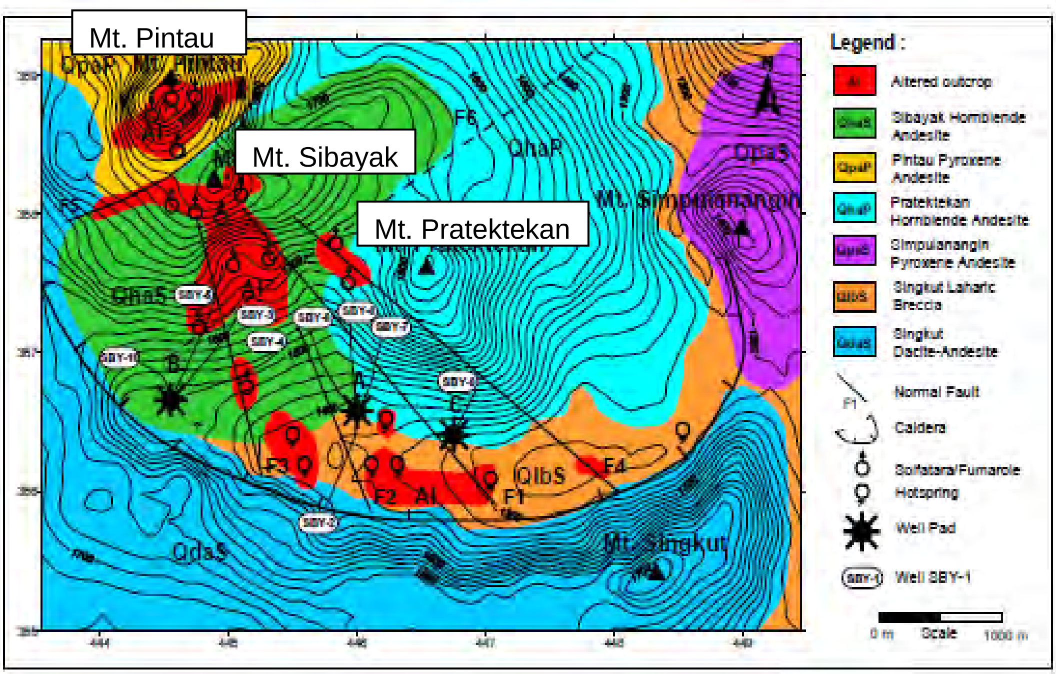


Figure 4.2-4 Geology, Alteration Distribution and Well Base in Sibayak Area
(Daud et al, 2001)

(b) Sarulla (Sarulla-1 / Sarulla-2)

1) Outlines of the area

Sarulla geothermal area is situated in the Sarulla rift valley of 60km long and 15 km wide, extending toward southeast direction from the point 10km southeast of Tarutung, Sarulla rift valley is a pull-apart basin formed by the Great Sumatran Fault and is divided into four prospect areas. Geothermal development surveys were carried out in three of these areas (Namora-I-Langit, Silangkitang and Sibualbuali) (Figure 4.2-5, Figure 4.2-6).

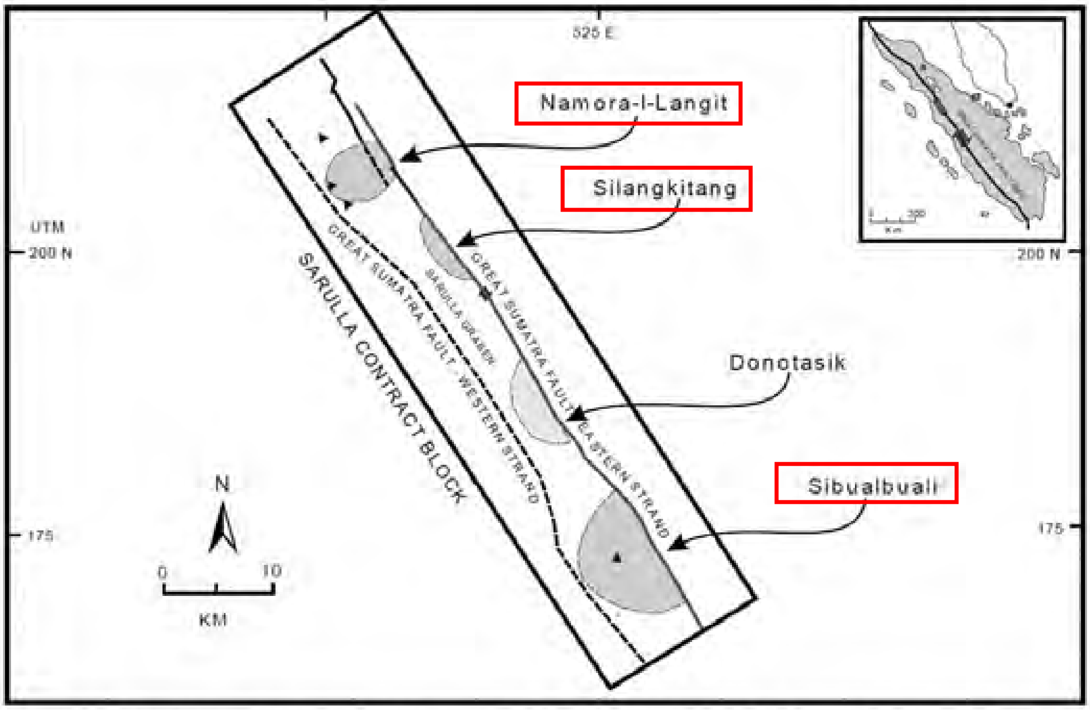


Figure 4.2-5 Map of Geothermal Energy Development Locations in Sarulla

(Gunderson, 2000)

2) History of development

In a period between 1993 and 1997, the UNSG (Unocal North Sumatra Geothermal Ltd.) drilled 13 wells in three prospects (Figure 4.2-7). The project was suspended due to the economic crisis in 1998, and UNSG withdrew and assigned the work to PLN in 2004. Currently, the project is taken over by a consortium consisting of Medco Power (37.25%), Itochu Corporation (25%), Kyushu Electric Power (25%) and ORMAT (12.75%).

In the Phase 1 Study (2009), it was said to be under discussion because it would not be worth developing at the power sale price of 4.642 ¢ /kWh; however, the consortium signed a contract with PLN at sale price of 6.79 ¢ /kWh at the meeting of WGC 2010 (World Geothermal Congress; April 25, 2010). Since the development concession area includes all four areas, if development is further continued following the development of 330 MW at Sarulla-1, it is scheduled to sell power to PLN.

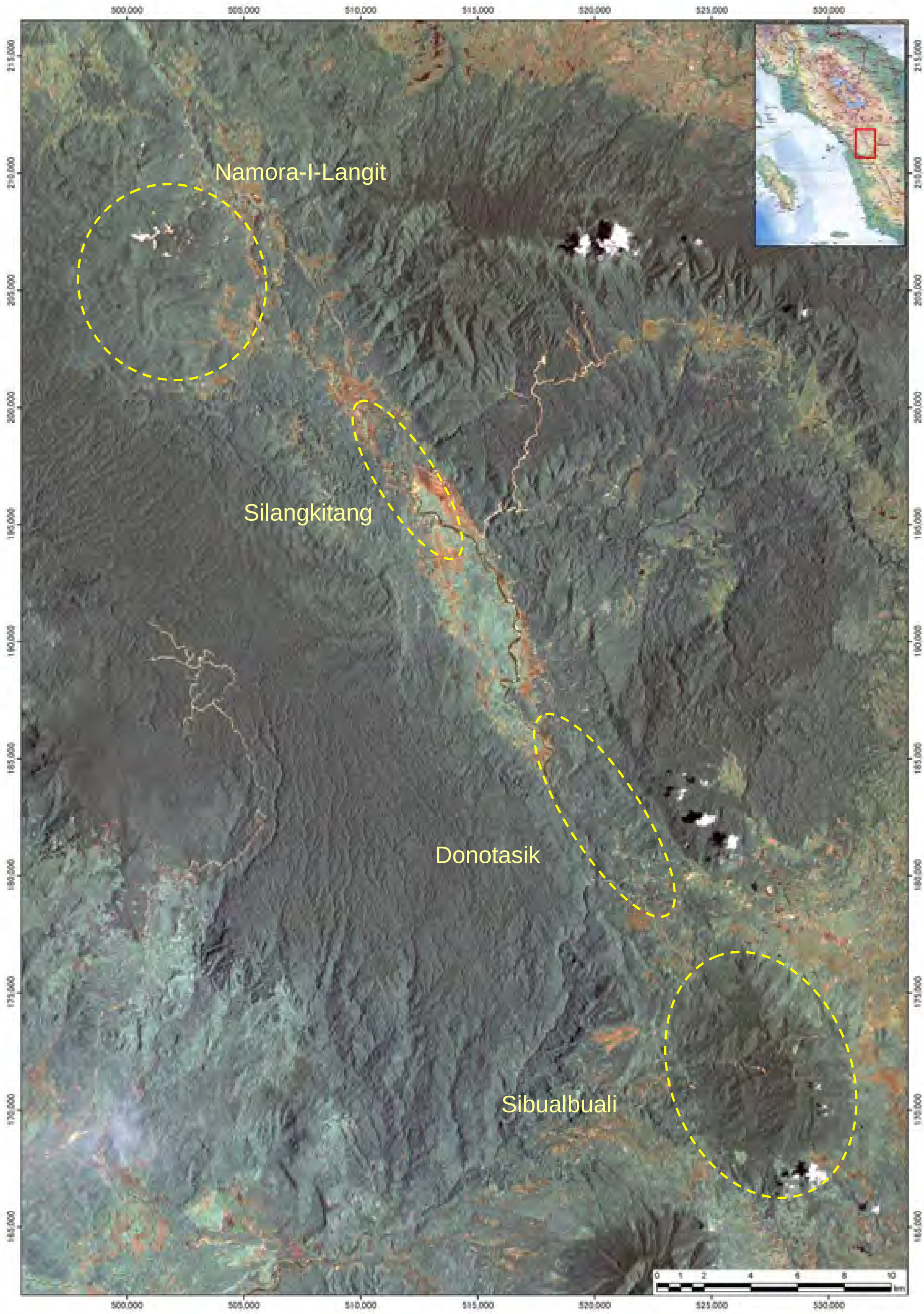
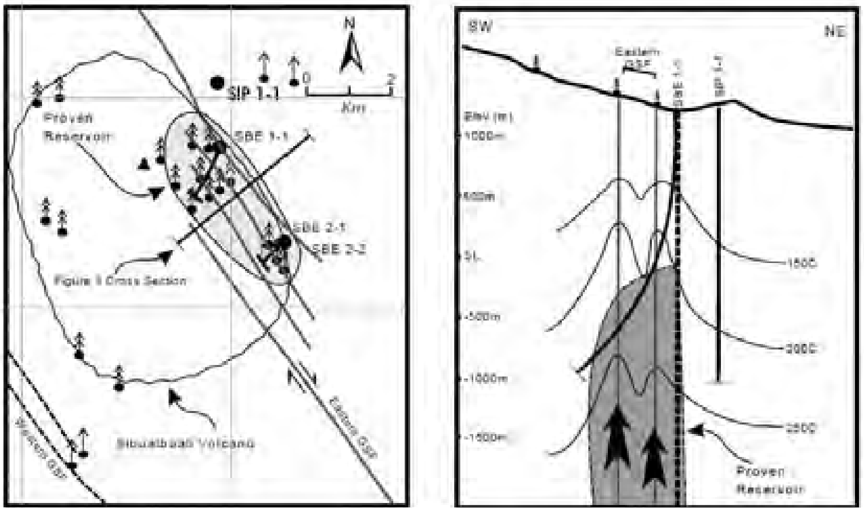
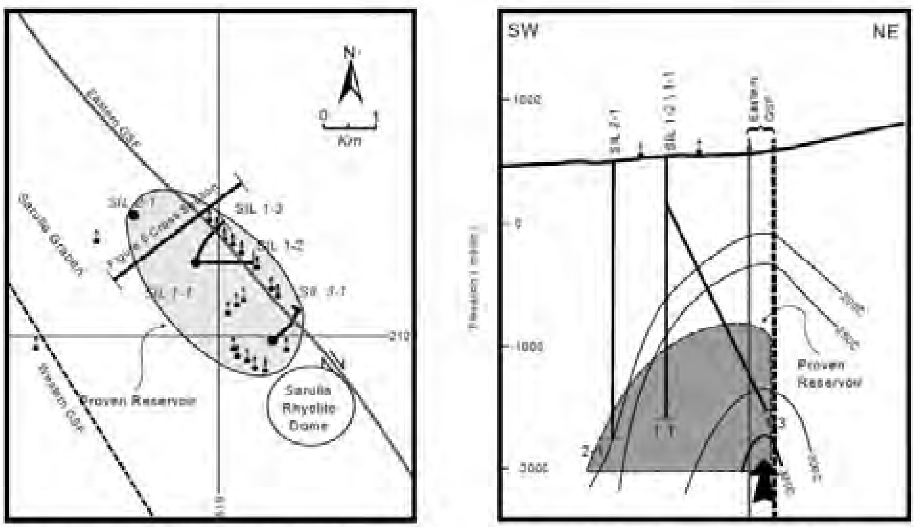


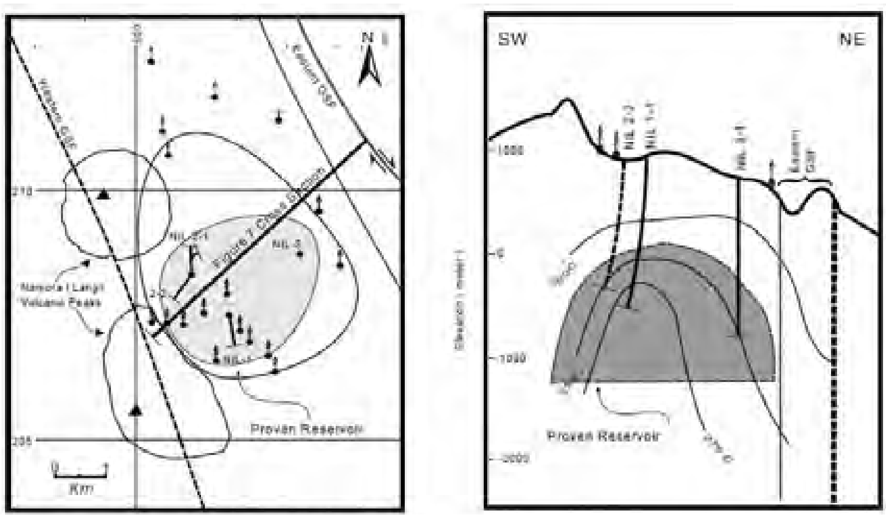
Figure 4.2-6 Landsat Image of Sarulla



A: Sibualbuali (plan, profile section)



B: Silangkitang (plan, profile section)



C: Namora-I-Laungit (plan, profile section)

Figure 4.2-7 Geothermal Structure of Sarulla (Gunderson, 2000)

3) Situation of Development

According to Surya Darama et al (2010), 13 geothermal wells have been drilled till present. The F/S has been conducted and the initial 330 MW development program for Silangkitang and NIL has been planed. According to the Geothermal Master Plan (2007), the potential of available geothermal resource in this area was estimated to be 630 MW. The total steam currently being obtained corresponds to energy potential of 126 MW, comprising 46 MW in NIL and 80 MW in Silangkitang (Table 4.2-2). In Silangkitang, a well (SIL 1-3) with steam production of 50 MW has been reported, however, it will be necessary to drill many more wells in order to achieve the target of development capacity in future.

In Sarulla-1, development of 330 MW power generation is being planned in NIL and Silangkitang located in northern part of Sarulla-1. Following Sarulla-1, development of Sarulla-2 will be proceeded step by step by carefully confirming situations, and development beyond 330 MW power generation will be planned from now on. In RUPTL 2010, it is planned to develop 330 MW at Sarulla-1 and 110 MW at Sarulla-2 by 2014, however, it is likely that development will be delayed if the current rate of progress is maintained.

Table 4.2-2 Outline of Assessment of Geothermal Resource in Sarulla

Sarulla		Name*	Remark	Depth	Temp.	Generating Capacity (MW)	Resouce Potential (MW)	Restriced by National Park & Power Demand. (MW)	Steam Available (MW)	Proven Reserve (MW)	Potential (MW)
1	Namora-I-Langit	NIL1-1 (P)		1333-1722m	>260℃, max. 276℃	210	660	630	46	210	965
		NIL2-1 (P)	WHP: 5MPa								
		NIL2-2 (P)									
		NIL3-1 (I)									
2	Silangkitang	SIL1-1 (I)		2031-2330m	max. 310℃	80			80	100	395
		SIL1-2 (P)									
		SIL1-3 (P)	50MW								
		SIL2-1 (I)									
		SIL3-1 (I)									
3	Sibualbuali	SIP1-1		1266-2439m	218-248℃, max. 267℃	40			-	20	90
		SBE1-1									
		SBE2-1									
		SBE2-2									
	Total					330	660	630	126	330	1450
Reference		1					2		3		

Name *) P: Production well, I: Injection well

Reference
1) JICA(2009) Phase1 Report & Gunderson et al. (2000)
2) JICA(2007) MP Report
3) Surya Darama et al. (2010)

(c) Merapi (Sorik-Merapi)

This area, located at the southern tip of North Sumatra Province, is distributed over the eastern to northern foothill area of the volcano S-Merapi on the Great Sumatran Fault. According to the Geothermal Master Plan (2007), a detailed surface investigation has been carried out in this area and the high temperature for deep geothermal reservoir was estimated by geochemical temperature, but a deep exploration well has not been drilled yet. It is estimated that there is an extensive geothermal reservoir in this area and it has geothermal energy development potential of 500 MW; however because of regulations imposed due to its location within a national park, an available potential of geothermal energy is decreased to 100 MW. Tender for the geothermal development concession is currently being conducted and the developer is likely to be decided in near future.

(d) Sipaholon (Sipaholon-Tarutung)

This area, located approximately 40 km southeast of Lake Toba, is situated in a pull-apart basin on the northwest edge of Tarutung rift valley running along the Great Sumatran Fault (Figure 4.2-8). This basin is located on the north side of the Sarulla area and thermal water and steam discharges occur along the fault trending northwest-southeast directions. According to the Geothermal Master Plan (2007), the temperature of geothermal reservoir is estimated to be 170℃, higher than the geochemical temperature, although no detailed investigation has been conducted. The estimated geothermal energy development potential is 50 MW. This area only includes minimal protected forests and there is no designated area as a national park. Tender for the geothermal development concession is currently being conducted.

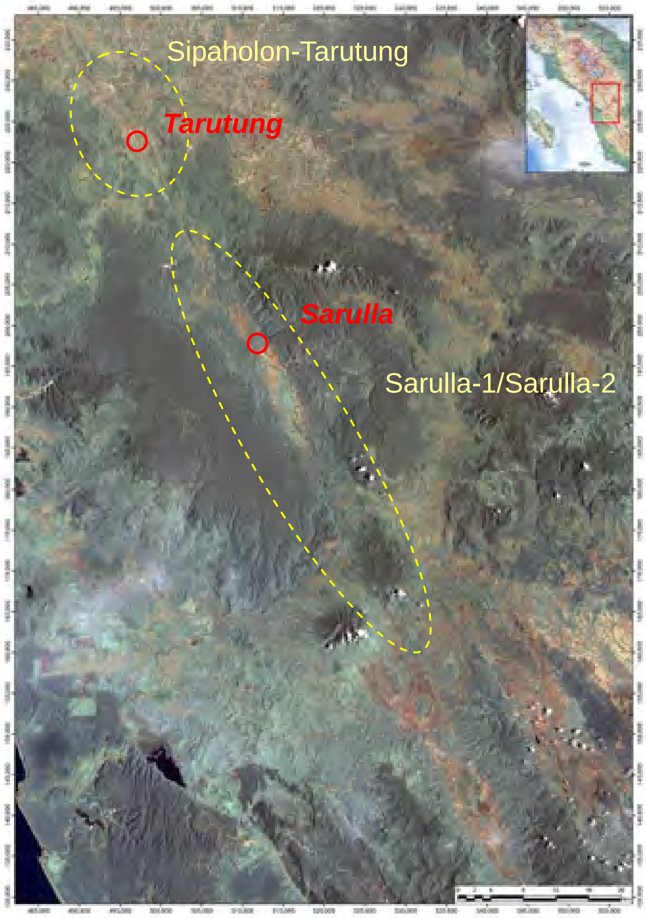


Figure 4.2-8 Landsat Image of Sarulla – Sipaholon

(e) Sinabung

This area, located to the west of Sibayak, includes the volcano Mt. Sinabung, which erupted in August 2010. PGE is conducting geothermal investigation in the area, but the work has been suspended due to the eruption. Both Sibayak and Sinabung correspond to the outer rim of the Toba caldera (Figure 4.2-9). Mt. Sinabung is a stratavolcano with an altitude of 2,460 m. Development of this area is paned to start in future along with the expansion plan of Sibayak in future, and there are plans to conduct detailed geological survey, geochemical survey and geophysical survey (electromagnetic investigation) in future. According to PGE, this area has geothermal resource potential of around 40 MW, which is similar value to Sinabung.

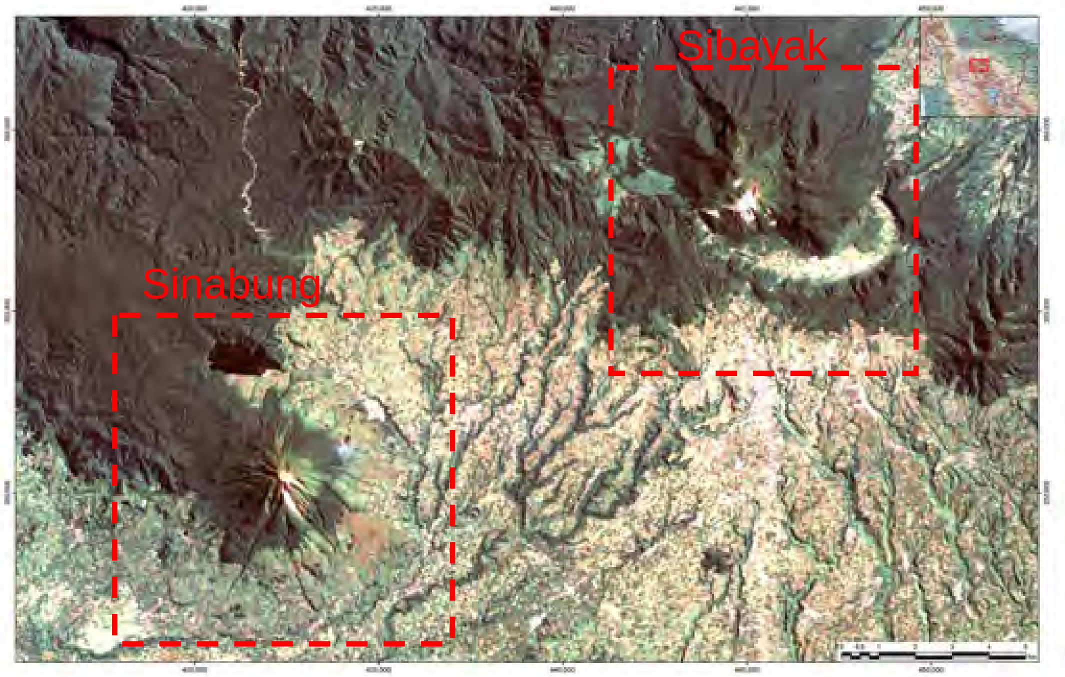


Figure 4.2-9 Landsat Image of Sibayak - Sinabung

(f) Other Areas

Concerning other areas, Dolok Marawa, Pusk Bukit-Danau Toba, Simbolon-Samosir Pagaran and Sibubuhan were designated as Green Field areas in API NEWS (2010), however, preliminary surface investigations have already started in almost all of these locations.

4.2.2 Geothermal Resource Potential in North Sumatra

(1) Geothermal Resource Potential

In the Geothermal Master Plan (2007), assessment of geothermal resources was conducted for 73 areas in Indonesia. In North Sumatra, this assessment survey was conducted in six areas, namely Sibayak, Sarulla, Merapi, Sipaholon, Pusuk Bukit-Danau Toba and Simbolon-Samosir. In the Phase 1 Study (2009), data from the Geothermal Master Plan (2007) was used regarding geothermal energy potential, and following Phase 1 Study (2009), these data are also used in this Study.

In the Geothermal Master Plan (2007), the overall quantity of geothermal resource was assessed based on volume and temperature of the geothermal reservoir, etc. Table 4.2-3 shows the geothermal resources potential of North Sumatra. Concerning the situation of investigation and development in each geothermal area, a geothermal power plant is already in operation and there are plans for expansion in Sibayak. The Sarulla-1 (Sarulla) is at development stage after completing the drilling of wells and F/S. In Sarulla-2 (Sarulla/Sibual Buali), Pre-F/S has been finished, while surface surveys are being conducted in other areas. In Merapi and Sipaholon, tender of concessions for development is being hold. Regarding underground temperature, high temperatures exceeding 300℃ have been confirmed at Sibayak and Sarulla-1, while Merapi seem to be promising area for geothermal development because the high temperature was estimated for deep geothermal reservoir by geochemical method. Even though it is at survey stage, the development plans suggests 20 MW in Sibayak (including already developed wells) and 330 MW in Sarulla-1. In the Geothermal Master Plan (2007), geothermal potential has been estimated in four areas, specifically 160 MW in Sibayak, 660 MW in Sarulla-1/ Sarulla-2, 500 MW in Merapi and 50 MW in Sipaholon. Moreover, PGE estimated potential of 40 MW in Sinabung.

Table 4.2-3 Geothermal Resource Potential of North Sumatra

	Field Name	Develop. Status*	Temperature(℃)			Reservoir Existance Possibility **	Installed Capacity (MW)	Existing Develop. Plan (MW)	Possible Additional /New Capa.	Total Potential (MW)
			Surface Max.	Geot./ Reserv.	Measured @well					
1	Lau Debuk-Debuk/ Sibayak	OP	116	–	302	1	12	7.5	140	160
2	Sarulla-1	F2	101	–	310	1	0	330	330	660
	Sarulla-2	F1	72	–	267	1				
3	Sorik-Merapi	S2	119	<290	–	2	0	0	500	500
4	Sipaholon	S2	65	>170	–	Low	0	0	50	50
5	Sinabung	S1	65	–	–	NE	0	0	–	(40)***
6	Dolok Marawa	S1	–	–	–	–	0	0	–	–
7	Pusuk Bukit-Danau Toba	S1	90	<290	–	NE	0	0	–	–
8	Simbolon-Samosir	S1	91	<290	–	NE	0	0	–	–
9	Pagaran	S1	–	–	–	–	0	0	–	–
10	Sibubuhan	S1	–	–	–	–	0	0	–	–

*Development Status
OP: Power plant in operation
F2: Feasibility syudies done
F1: Pre-feasibility studies done
S2: Detailed surface exploration done
S1: Local surface exploration done

**Reservoir Existance Possibility
1: Confirmed by well
2: Infered mainly by geothermometer
Low: Low possibility or low temp.
NE: Not enough data for evaluation

*** Sinabung
Estimated by PGE

(2) Natural Park Controls

In Indonesia, geothermal energy development is not permitted inside national parks. Accordingly, the development potential of geothermal reservoirs located inside promising areas is estimated based on the ratio of land area covered by national parks. Taking into consideration of controls imposed by national parks and protected forest, geothermal energy potentials based on the Geothermal Master Plan Study (2007) are shown in Table 4.2-4. In the study area, Sibayak is subject to park controls and has geothermal energy potential of 40 MW, while Sarulla has potential of 630 MW and Merapi, the most regulated area, has potential of 100 MW. In Sipaholon, almost without any controls, the potential is 50 MW.

Table 4.2-4 Geothermal Resource Potential considering Park Controls

	Field Name	Develop. Status*	Installed Capacity (MW)	Existing Develop. Plan (MW)	Possible Additional /New Capa.	National Park in Possible Reservoir Area		Percentage of Protected Forest in Possible Reservoir Area (%)	Limit by National Park (MW)	
						Percentage in the Area (%)	Note/ Name of National Park		Possible Add./ New Capacity	Total Potential
1	Lau Debuk-Debuk/ Sibayak	OP	12	7.5	150	100	THR. Bukit Barisan	none	28	40
2	Sarulla-1	F2	0	330	330	25	westen and southern part/ CA. Sibolga, CA. Sibual Bual, etc.	20	330	630
	Sarulla-2	F1								
3	Sorik-Merapi	S2	0	0	500	80	southwestern part/ SM. Batang Gadis	none	100	100
4	Sipaholon	S1	0	0	50	none	-	3	50	50
5	Sinabung	S1	0	0	(40)***	-	-	-	-	(40)***
6	Dolok Marawa	S1	0	0	-	-	-	-	-	-
7	Pusuk Bukit-Danau Toba	S1	0	0	-	none	-	75	-	-
8	Simbolon-Samosir	S1	0	0	-	none	-	10	-	-
9	Pagaran	S1	0	0	-	-	-	-	-	-
10	Sibubuhan	S1	0	0	-	-	-	-	-	-

*Development Status
OP: Power plant in operation
F2: Feasibility syudies done
F1: Pre-feasibility studies done
S2: Detailed surface exploration done
S1: Local surface exploration done

**Reservoir Existance Possibility
1: Confirmed by well
2: Infered mainly by geothermometer
Low: Low possibility or low temp.
NE: Not enough data for evaluation

*** Sinabun
Estimated by PGE

(3) Geothermal Resource Potential Assessment

Table 4.2-5 shows the geothermal energy potential assessment for North Sumatra based on the Geothermal Master Plan (2007). This assessment takes into consideration of economic feasibility in each area based on the premise of the investigated geothermal resource potential (development potential capacity). In terms of profitability, the following order of priority is obtained: Sarulla: E1>Sibayak, Merapi: E3>Sipaholon: E4, while in terms of comprehensive order of priority for development, A rank is given to Sarulla and Sibayak, B rank to Merapi, and L rank to Sipaholon. Further, according to the Phase 1 Study (2009), the order of priority was deemed to be as follows: 1st: Sarulla-2, 2nd: Merapi, and 3rd: Sibayak.

Table 4.2-5 Geothermal Potential Assessment in North Sumatra

	Field Name	Develop. Status 1)	Reservoir Existance Possibility 2)	Economy 3)	T/L Length (km)	Installed Capacity (MW)	Existing Develop. Plan (MW)	Possible Additional /New Capa. 4)	Total Potential (MW)	Development Priority 5)
1	Lau Debuk-Debuk/ Sibayak	OP	1	E3	6	12	7.5	28	40	A
2	Sarulla-1	F2	1	E1	21	0	330	300	630	A
	Sarulla-2	F1								
3	Sorik-Merapi	S2	2	E3	23	0	0	100	100	B
4	Sipaholon	S2	Low	E4	19	0	0	50	50	L
5	Sinabung	S1	–	–	–	0	0	(40) 6)	(40) 6)	–
6	Dolok Marawa	S1	–	–	–	0	0	–	–	–
7	Pusuk Bukit-Danau Toba	S1	NE	–	–	0	0	–	–	N
8	Simbolon-Samosir	S1	NE	–	–	0	0	–	–	N
9	Pagaran	S1	–	–	–	0	0	–	–	–
10	Sibubuhan	S1	–	–	–	0	0	–	–	–

1) Development Status
OP: Power plant in operation
F2: Feasibility syudies done
F1: Pre-feasibility studies done
S2: Detailed surface exploration done
S1: Local surface exploration done

2) Reservoir Existance Possibility
1: Confirmed by well
2: Infered mainly by geothermometer
Low: Low possibility or low temp.
NE: Not enough data for evaluation

3) Economy
Classification of Project IRR: E1>E2>E3>E4

4) Possible Additional/ New Capacity: Limited by National Park

5) Development Priority
A: Exisying Power Plant or Existing Expansion/ Development Plan
B: High Possibility of Existing Geothermal resourvoir
L: Low Possibillity of Existing Geothermal Reservoir
N: Not Enough Data for Evaluation

6) Sinabung
Estimated by PGE

4.3 Hydropower Generation

4.3.1 Outline of Hydropower Resources in North Sumatra

The identification of promising hydropower development sites in the Phase 1 Study 2009 was conducted based on the Hydro Inventory and Pre-Feasibility Study implemented by PT. PLN in 1999. In this Hydro Inventory and Pre-Feasibility Study, a three-stage screening process was conducted on hydropower potential sites all over the country, and 17 sites were identified in the area covered by North Sumatra Grid. Leaving aside two sites where the construction of power facilities has already been completed, out of the remaining 15 sites, four promising sites were selected based on consideration of the natural and social environment, generating unit cost and development capacity. In this Study, the hydropower potential of these sites was confirmed upon adding new data to materials in the Hydro Inventory and Pre-Feasibility Study and considering information and data obtained through further field surveys.

Figure 4.3-1 shows the locations of the potential hydropower sites, and the following sections briefly describe the hydropower development plans at each location. The main materials used in this Study are as follows.

- ♦ Feasibility Study for Cooperation Possibility in Electric Power Development in North Sumatra (JICA, September 2009):
  This is the Phase 1 study that was implemented in the previous year 2009 to this Study.

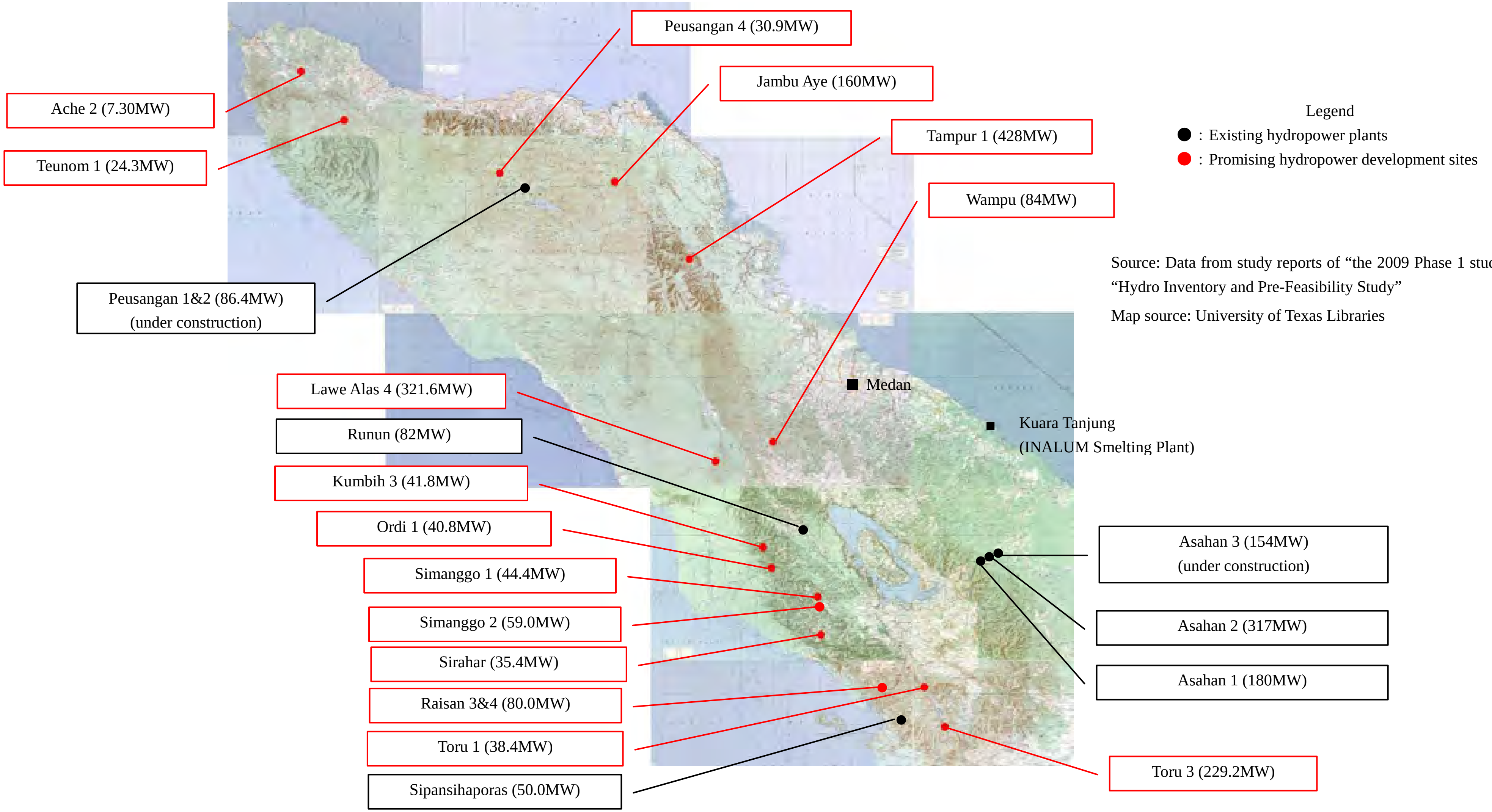
- ♦ Working group materials of the JICA Advisory Committee on Environmental and Social Consideration:
  These are the materials used for preparing draft advice regarding environmental and social consideration by JICA in July 2010 with respect to eight projects identified in the Master Plan Study of Hydropower Development in Indonesia currently being implemented by JICA. These materials are disclosed on the JICA homepage.

- ♦ Report of the Hydro Inventory and Pre-Feasibility Study:
  This is the report of the Hydro Inventory and Pre-Feasibility Study, which was implemented by PT. PLN over the entire area of Indonesia under support from the World Bank in 1999. In this Study, the Interim Report compiling the findings of the inventory study issued in 1997 and the Executive Summary of the final report issued in 1999 have been used.

- Rencana Usaha Penyediaan Tenaga Listrik 2010-2019 (RUPTL):
  PT. PLN compiles development plans for the coming decade into the Rencana Usaha Penyediaan Tenaga Listrik each year. The present RUPTL was issued in July 2010 and contains the power demand and supply plans and power resources and transmission network development plans for each PT. PLN branch office (Wilayah) in Indonesia from 2010 to 2019.

- Raisan No. 3 & 4 Hydroelectric Power Development Project in North Sumatra (June 2004):
  This site is located in the south of North Sumatra Province. TEPSCO implemented the Reconnaissance Study for this in 2004 under cooperation from PT. PLN.

- Feasibility Study on Wampu Hydroelectric Power Development Project (December 1992):
  This site is located southeast of Medan, the capital city of North Sumatra Province. JICA implemented the F/S for the project in 1992.



Source: Data from study reports of “the 2009 Phase 1 study” and “Hydro Inventory and Pre-Feasibility Study”

Map source: University of Texas Libraries

Figure 4.3-1 Hydropower Potential and Promising Sites in Ache and North Sumatra Provinces

(1) Asahan-1

This site is located on Asahan River, which flows northeast from Lake Toba in the middle of North Sumatra Province. It is a run-of-river power plant planned upstream of the Asahan-2 Power Plant (Tanga and Siguragura), which was constructed in 1983. Asahan River is the only river to flow out of Lake Toba, which is situated at an altitude of approximately 900 m, and it is a prime river for hydropower development having the lake as a natural reservoir. Through utilizing the mean river flow of 107.5 m^3/s and head of approximately 170 m, this power plant has the potential to generate peak output of 180 MW and 1,360 GWh of electricity per year. The Indonesian IPP PT. Bajradaya Nusantara started work on the plant in June 2006 with China Gezhouba Group Corporation as the main contractor, and the completion ceremony was conducted and power generation commenced on August 30, 2010.

Table 4.3-1 General Features of Asahan-1 Project

Location	North Sumatra Province
Generation Type	Run-of-River
Maximum Output	180 MW
Annual Generated Energy	1,360 GWh
Plant Factor	86.3%
Construction Cost	263.0 million USD

Source: Hydro Inventory Study

(2) Asahan-3

As is the case with Asahan-1, Asahan-3 is situated on Asahan River, downstream of Asahan-2. Through utilizing a peak water intake of 100 m^3/s and effective head of approximately 181.1 m, this power plant has the potential to generate peak output of 154 MW and 1,286 GWh of electricity per year. Since the catchment area at the intake point is 3,840 km^2, mean precipitation over the catchment area is 1,700 mm and annual mean flow at the intake point is 98.8 m^3/s, it should be possible to acquire stable electricity supply at this power plant The intake dam will be a relatively small gravity type dam with a dam height of 6.6 m and crest length of 55.0 m. From here water will pass through the mountains on the left bank of Asahan River via a 0.3 km box culvert, 3.1 km of open channel and 6.4 km of headrace tunnel (inner diameter 6.4 m) to the surge tank adjacent to the power plant, and from there it will be conveyed to the above-ground power plant via a buried penstock of 388.5 m. It is estimated that the total cost will be 404.4 million USD and that the unit cost will be 2,623 USD per kW.
The detailed design (D/D) for this plan was implemented in 1987 assuming a reservoir type power plant with a dam height of 129 m and output of 400 MW, however, the plan was suspended due to difficulties in raising the necessary construction cost of 866 million USD and problems over the relocation of residents in and around the reservoir. After that, PLN changed the plan to a run-of-river type power plant and implemented the F/S for the new plan in 2004. Subsequently, the Government of North Sumatra Province approved the construction plan in June 2010 and the work is due to start under funding from a yen loan.

Table 4.3-2 General Features of Asahan-3 Project

Power Generation Outline		
Location	Province	North Sumatra
	River / River Basin	Aek Asahan / Aek Asahan
Hydrology	Catchment Area	3,840 km^2
	Mean Annual Discharge	98.80 m^3/s
	Annual Rainfall	1,700 mm
Power Generation	Generation Type	Run-of-River
	Installed Capacity	154.0 MW
	Maximum Discharge	100.0 m^3/s
	Gross Head	193.70 m
	Effective Head	181.10 m
	Annual Generated Energy	1,286 GWh
	Plant Factor	95.3%
Plant Facilities Outline		
Dam / Weir	Full Supply Level	EL. 266.6 m
	Minimum Operation Level	EL. 260.45 m
	Type	Concrete Gravity
	Height	6.60 m
	Crest Length	55.00 m
	Design Flood	1,500 m^3/s
Headrace	Type and Length	Box Culvert: 305.0 m Open Channel: 3,068.2 m Pressure Tunnel: 6,409.4 m
	Inside Diameter	Pressure Tunnel: 6.4 m
Surge Tank/ Head Tank	Type	Restricted Orifice Tank
	Height	74.0 m
	Inside Diameter	14.0 m
Penstock	Type	Underground Type
	Length	388.5 m
	Inside Diameter	Average 5.4 m
Tailrace	Type	Flee Flow
	Tail Water Level	72.9 m
Power House	Type	—
Turbine	Type	Vertical Shaft Francis
	No. of Unit	2
Transmission Line	Voltage	150 kV
	Length	143.0 km
Economical Aspect		
Construction Cost		404.4 million USD
Cost per kW		2,623 USD/kW
Cost per kWh		—
Study Level		F/S in 1982 D/D in 1987 F/S Review in 2004

Source: "Feasibility Study for Reviewed Design" Asahan No.3 Hydroelectric Power Project in North Sumatra Province, July 2004, PT.PLN

—: No data

(3) Tampur-1

This site is located in the central mountainous area of Aceh Province, where annual rainfall is relatively high at 2,580 mm. Tampur River, where the dam is planned, has an adequate catchment area of 2,030 km^2 and the mean flow rate here is 108 m^3/s, which means that there is ample water flow and the site is suitable for hydropower development. Construction of the dam will create an effective head of 160.6 m and reservoir capacity of 697.4 million m^3, thereby creating the potential to generate peak output of 428.0 MW and 1,214.3 GWh of electricity per year. Out of this annual output, primary power will account for 927.6 GWh and secondary power for 286.7 GWh, meaning that primary power will account for three quarters of the total. The power plant will have peak water use of approximately 330.0 m^3/s and will be able to conduct peak operation for a few hours. The dam will be a rock fill dam with height of 173.5 m and crest length of 472.0 m. Waterways will consist of a headrace of 650.0 m (inner diameter 6.7 m) and penstock of 380.0 m (inner diameter 3.4 ~ 5.6 m) leading to an above-ground power plant. It is estimated that the total construction cost will be 704.5 million USD and that the unit cost will be 1,646 USD per kW.

This is certainly a promising development site with abundant water flow, however, since the reservoir would be approximately 41 km^2 that would entail the relocation of more than 200 residents and submergence of natural forests, project implementation would have a huge social and environmental impact. Accordingly, the ADB implemented an environmental impact assessment and F/S review in 1993 and revised the plans. Specifically, it lowered the maximum water level in the reservoir by 20 m so that the submergence area would be reduced, and it changed the plant output to 330 MW. In future, it is desirable to implement a detailed natural and social environmental study on project feasibility according to this plan.

Table 4.3-3 General Features of Tampur-1 Project

Power Generation Outline		
Location	Province	Nanggroe Aceh Darussalam
	River / River Basin	Sei Taming/ Sie Tampur
Hydrology	Catchment Area	2,030 km^2
	Mean Annual Discharge	108.00 m^3/s
	Annual Rainfall	2,580.0 mm
Power Generation	Generation Type	Reservoir
	Installed Capacity	428.0 MW
	Maximum Discharge	329.6 m^3/s
	Gross Head	169.80 m
	Effective Head	160.60 m
	Annual Generated Energy	1,214.3 GWh
	Primary Energy	927.6 GWh
	Secondary Energy	286.7 GWh
	Plant Factor	32.4%
Plant Facilities Outline		
Reservoir	Full Supply Level	EL. 280.0 m
	Minimum Operation Level	EL. 261.5 m
	Reservoir Surface Area	40.9 km^2
	Gross Storage	2,759.1×10^6 m^3
	Effective Storage	697.4×10^6 m^3
Dam / Weir	Type	Rockfill with Inclined Core
	Height	173.50 m
	Crest Length	472.00 m
	Design Flood	4,308.0 m^3/s
Headrace	Type	Pressure Flow
	Length	650.0 m
	Inside Diameter	6.70 m
Surge Tank / Head Tank	Type	Restricted Orifice Tank
	Height	48.70 m
	Inside Diameter	13.00 m
Penstock	Type	Steel Lined, Underground
	Length	380.0 m
Tailrace	Type	Open Air
	Tail Water Level	108.95 m
Power House	Type	Open Air
Turbine	Type	Vertical Shaft Francis
	No. of Units	4
Transmission Line	Voltage	150 kV
	Length	167.0 km
Economical Aspect		
Construction Cost		704.5 million USD
Cost per kW		1,646 USD/kW
Cost per kWh		0.580 USD/kWh
Study Level		F/S in 1984

Source: The outlines of power generation and plant facilities are referred from Y2009 report. The economic aspect is estimated based on the construction cost referred from “Hydro Inventory Study and Pre-Feasibility Studies” in 1999

－: No data

(4) Wampu

This site is located on Wampu River to the northwest of Lake Toba, and the plan entails construction of a run-of-river hydropower plant. An intake dam will be installed in the furthest upstream area of Wampu River; 35.0 m^3/s of river water will be taken in, led through a headrace tunnel and penstock with effective head of 276.4 m for use in generating power, after which the water will be discharged to the river. Peak output will be 84.0 MW and annual generated power will be 475.3 GWh. The generated power will be supplied to the North Sumatra Grid along a transmission line of 61 km.

Since the catchment area at the intake point is 959 km^2, mean precipitation over the catchment area is 1,500 mm and annual mean flow at the intake point is 30.5 m^3/s, it should be possible to acquire relatively large electricity supply at this power plant The intake dam will be a concrete dam with a dam height of 14.5 m and crest length of 68.0 m. From here, water will pass through the mountains on the right bank of Wampu River via a 17.8 km headrace tunnel (inner diameter 4.2 m) to a headtank, from where it will be conveyed to a semi-underground power plant via an above-ground penstock of 555 m. It is estimated that the total cost will be 127.2 million USD and that the unit cost will be 1,514 USD per kW.

Since this plan entails a run-of-river power plant that won’t require a large reservoir, it will not have a major impact on the natural and social environment. However, due to the possibility that the access road and transmission line with partially pass through Gunung Leuser National Park, the plan is currently suspended. In order to expedite the development, it is desirable to implement a detailed natural and social environmental study and to review the development plan.

Table 4.3-4 General Features of Wampu Project

Power Generation Outline		
Location	Province	North Sumatra
	River / River Basin	Sei Wampu/ Sie Wampu
Hydrology	Catchment Area	959 km^2
	Mean Annual Discharge	30.50 m^3/s
	Annual Rainfall	1,500.0 mm
Power Generation	Generation Type	Run-of-River
	Installed Capacity	84.0 MW
	Maximum Discharge	35.0 m^3/s
	Gross Head	303.50 m
	Effective Head	276.40 m
	Annual Generated Energy	475.3 GWh
	Primary Energy	232.5 GWh
	Secondary Energy	242.8 GWh
	Plant Factor	64.6%
Plant Facilities Outline		
Dam / Weir	Full Supply Level	EL. 528.0 m
	Minimum Operation Level	EL. 514.5 m
	Type	Concrete Gravity
	Height	14.50 m
	Crest Length	68.00 m
	Design Flood	940.0 m^3/s
Headrace	Type	Free Flow
	Length	17,760.0 m
	Inside Diameter	4.20 m
Surge Tank / Head Tank	Type	Head Tank
	Height	50.00 m
	Inside Diameter	15.00 m
Penstock	Type	Steel Pipeline, Open Air
	Length	555.0 m
	Inside Diameter	2.6 m to 3.8 m
Tailrace	Type	Free Flow
	Tail Water Level	219.00 m
Power House	Type	Semi-Underground
Turbine	Type	Vertical Shaft Francis
	No. of Units	2
Transmission Line	Voltage	150 kV
	Length	61.0 km
Economical Aspect		
Construction Cost		127.2 million USD
Cost per kW		1,514 USD/kW
Cost per kWh		0.268 USD/kWh
Study Level		F/S in 1992

Source: The outlines of power generation and plant facilities are referred from Y2009 report. The economic aspect is estimated based on the construction cost referred from “Hydro Inventory Study and Pre-Feasibility Studies” in 1999

－: No data

(5) Lawe Alas-4

This site is located in the south of Aceh Province on the border with North Sumatra Province, and the plan entails a reservoir type power plant in the middle reaches of Lawe Alas River in the Krueng Singkel River system that flows southeast through the southwest of Aceh Province. Since the catchment area at the intake point is 5,705 km^2, mean precipitation over the catchment area is 2,270 mm and annual mean flow at the intake point is 270 m^3/s, conditions are ideal for hydropower development. On the other hand, because the reservoir area is likely to exceed 20 km^2 and will be located within Gunung Leuser National Park, it will be necessary to display social and natural environmental consideration and to review the plans.

The dam is a rock-fill dam with a height of 110 m and crest length of 180 m, and the maximum plant discharge will be 369.8 m^3/s. The plant discharge will be conveyed downstream through a 750 m penstock (inner diameter 7.3 m) and 350 m pipeline (inner diameter 6.3 m) to the above-ground power plant. By utilizing the effective head of 105.7 m, it is planned to generate peak output of 321.6 MW and annual output of 1,549.1 GWh. It is estimated that the total construction cost will be 473.3 million USD and that the unit cost will be 1,472 USD per kW.

Table 4.3-5 General Features of Lawe Alas-4 Project

Power Generation Outline		
Location	Province	Nanggroe Aceh Darussalam
	River / River Basin	Krueng Singkil / Lawe Alas
Hydrology	Catchment Area	5,705 km^2
	Mean Annual Discharge	270.00 m^3/s
	Annual Rainfall	2,270.0 mm
Power Generation	Generation Type	Reservoir
	Installed Capacity	321.6 MW
	Maximum Discharge	369.8 m^3/s
	Gross Head	—
	Effective Head	105.70 m
	Annual Generated Energy	1,549.1 GWh
	Primary Energy	1,408.7 GWh
	Secondary Energy	140.4 GWh
	Plant Factor	55.0%
Plant Facilities Outline		
Reservoir	Full Supply Level	EL. 150.00 m
	Minimum Operation Level	EL. 122..51 m
	Reservoir Surface Area	—
	Gross Storage	1,360.0×10^6 m^3
	Effective Storage	586.51×10^6 m^3
Dam / Weir	Type	Rockfill
	Height	110.00 m
	Crest Length	180.00 m
	Design Flood	5,100.0 m^3/s
Headrace	Type	Pressure Flow
	Length	750.0 m
	Inside Diameter	7.32 m
Surge Tank / Head Tank	Type	Restricted Orifice Tank
	Height	—
	Inside Diameter	—
Penstock	Type	Steel Lined, Underground
	Length	350.0 m
	Inside Diameter	6.32 m
Tailrace	Type	Free Flow
	Tail Water Level	32.63 m
Power House	Type	Open Air
Turbine	Type	Vertical Shaft Francis
	No. of Units	4
Transmission Line	Voltage	150 kV
	Length	75.0 km
Economical Aspect		
Construction Cost		473.3 million USD
Cost per kW		1,472 USD/kW
Cost per kWh		0.306 USD/kWh
Study Level		Pre-F/S in 1987

Source: The outlines of power generation and plant facilities are referred from Y2009 report. The economic aspect is estimated based on the construction cost referred from “Hydro Inventory Study and Pre-Feasibility Studies” in 1999

—: No data

(6) Toru-1

The site is located in the middle reaches of Batang Toru River, which runs parallel to the Barisan Mountains that run through North Sumatra, and the plan is for a run-of-river type hydropower plant. Since the catchment area at the intake point is 1,013 km^2 and mean precipitation over the catchment area is 2,344.2 mm, it should be possible to obtain relatively abundant water flow. The intake dam is a relatively small-scale structure with a crest length of 34.0 m. From here, water will pass through a 3,465 m headrace tunnel and 950 m above-ground penstock to the power plant, where it is planned to generate peak output of 38.4 MW and annual output of 308.1 GWh. It is estimated that the total construction cost will be 63.2 million USD and that the unit cost will be 1,646 USD per kW.

Table 4.3-6 General Features of Toru-1 Project

Power Generation Outline		
Location	Province	North Sumatra
	River / River Basin	Batang Toru / Batang Toru
Hydrology	Catchment Area	1,013 km^2
	Mean Annual Discharge	—
	Annual Rainfall	2,344.2 mm
Power Generation	Generation Type	Run-of-River
	Installed Capacity	38.4 MW
	Maximum Discharge	—
	Gross Head	—
	Effective Head	—
	Annual Generated Energy	308.1 GWh
	Primary Energy	—
	Secondary Energy	—
	Plant Factor	91.6%
Plant Facilities Outline		
Dam / Weir	Full Supply Level	EL. 915.8 m
	Minimum Operation Level	EL. 915.8 m
	Type	Ungated Concrete Weir
	Height	—
	Crest Length	34.00 m
	Design Flood	—
Headrace	Type	Pressure Flow
	Length	3,465.0 m
	Inside Diameter	2.90 m
Surge Tank / Head Tank	Type	Restricted Orifice Tank
	Height	18.80 m
	Inside Diameter	10.0 m
Penstock	Type	Steel Pipe, Surface
	Length	950.0 m
	Inside Diameter	3.1 m
Tailrace	Type	—
	Tail Water Level	—
Power House	Type	Open Air
Turbine	Type	Vertical Shaft Francis
	No. of Units	2
Transmission Line	Voltage	150 kV
	Length	14.0 km
Economical Aspect		
Construction Cost		63.2 million USD
Cost per kW		1,646 USD/kW
Cost per kWh		0.205 USD/kWh
Study Level		Pre-F/S in 1995

Source: The outlines of power generation and plant facilities are referred from Y2009 report. The economic aspect is estimated based on the construction cost referred from “Hydro Inventory Study and Pre-Feasibility Studies” in 1999

—: No data

(7) Ordi-1

The site is located on Ordi River in the Krueng Singkel River system, which runs to the west of Lake Toba in North Sumatra Province, and the plan entails construction of a run-of-river power plant with intake dam and headrace. Since the catchment area at the intake point is 264 km^2, the maximum plant discharge is 22.30 m^3/s and the effective head is 221.6 m, the plan is to generate peak output of 40.8 MW and annual output of 263 GWh. It is estimated that the total construction cost will be 66.3 million USD and that the unit cost will be 1,625 USD per kW.

The intake dam is a gate type dam with height of 13 m and width of 200.6 m. From here, a peak flow of 22.30 m^3/s will be obtained, and this water will be conveyed along a 2,500 m headrace (inner diameter 3.3 m) and 1,500 m penstock (inner diameter 2.6 m) to the power plant. It is planned to supply the generated power along a 26.2 km transmission line to the North Sumatra Grid.

Table 4.3-7 General Features of Ordi-1 Project

Power Generation Outline		
Location	Province	North Sumatra
	River / River Basin	Krueng Singkel / Lae Ordi
Hydrology	Catchment Area	264 km^2
	Mean Annual Discharge	―
	Annual Rainfall	―
Power Generation	Generation Type	Run-of-River
	Installed Capacity	40.8 MW
	Maximum Discharge	22.3 m^3/s
	Gross Head	―
	Effective Head	221.6 m
	Annual Generated Energy	263.0 GWh
	Primary Energy	153.7 GWh
	Secondary Energy	109.3 GWh
	Plant Factor	73.6%
Plant Facilities Outline		
Dam / Weir	Full Supply Level	EL. 830.0 m
	Minimum Operation Level	EL. 824.3 m
	Type	Gated Weir
	Height	13.00 m
	Crest Length	200.60 m
	Design Flood	―
Headrace	Type	Pressure Flow
	Length	2,500.0 m
	Inside Diameter	3.30 m
Surge Tank / Head Tank	Type	Surge Tank
	Height	21.60 m
	Inside Diameter	13.3 m
Penstock	Type	Open Air
	Length	1,500.0 m
	Inside Diameter	2.6 m
Tailrace	Type	Open Channel
	Tail Water Level	EL. 590.0 m
Power House	Type	―
Turbine	Type	―
	No. of Units	1
Transmission Line	Voltage	150 kV
	Length	26.2 km
Economical Aspect		
Construction Cost		66.3 million USD
Cost per kW		1,625 USD/kW
Cost per kWh		0.252 USD/kWh
Study Level		Map Study

Source: The outlines of power generation and plant facilities are referred from Y2009 report. The economic aspect is estimated based on the construction cost referred from “Hydro Inventory Study and Pre-Feasibility Studies” in 1999

―: No data

(8) Peusangan-4

This site is located in the middle reaches of Peusangan River, which originates in the center of Aceh Province and flows into the Strait of Malacca, and the plan entails construction of a run-of-river power plant. Since the catchment area at the intake point is 945 km^2 and mean precipitation over the catchment area is 3,130 mm, it should be possible to obtain relatively abundant water flow. Out of the annual mean flow of 42.4 m^3/s at the intake point, a maximum of 30 m^3/s will be taken in, and the effective head of 128.4 m will be utilized to obtain peak output of 30.9 MW and generate 234.2 GWh of power per year.

The intake dam is a gravity type dam with height of 20 m and width of 66 m. From here, water will be conveyed along a 3,650 m headrace (inner diameter 3.8 m) and 150 m penstock (inner diameter 3.0 m) to an above-ground power plant located downstream. It is planned to supply the generated power along a 40 km transmission line to the grid. Also in the Peusangan River basin, PLN is conducting development of Peusangan-1 and Peusangan-2 (total output 86.4 MW) upstream of this site, and yen loans have already been arranged for this work.

Table 4.3-8 General Features of Peusangan-4 Project

Power Generation Outline		
Location	Province	Nanggroe Aceh Darussalam
	River / River Basin	Kr. Peusangan / Kr. Peusangan
Hydrology	Catchment Area	945 km^2
	Mean Annual Discharge	42.4 m^3/s
	Annual Rainfall	3,130.0 mm
Power Generation	Generation Type	Run-of-River
	Installed Capacity	30.9 MW
	Maximum Discharge	30.0 m^3/s
	Gross Head	—
	Effective Head	128.4 m
	Annual Generated Energy	234.2 GWh
	Primary Energy	118.7 GWh
	Secondary Energy	115.5 GWh
	Plant Factor	86.5%
Plant Facilities Outline		
Dam / Weir	Full Supply Level	EL. 545.74 m
	Minimum Operation Level	EL. 545.74 m
	Type	Concrete Gravity
	Height	20.00 m
	Crest Length	66.00 m
	Design Flood	1,600.0 m^3/s
Headrace	Type	Pressure Flow
	Length	3,650.0 m
	Inside Diameter	3.80 m
Surge Tank / Head Tank	Type	Restricted Orifice Tank
	Height	—
	Inside Diameter	—
Penstock	Type	Steel Lined, Underground
	Length	150.0 m
	Inside Diameter	3.0 m
Tailrace	Type	Free Flow
	Tail Water Level	EL. 412.81 m
Power House	Type	Open Air
Turbine	Type	Vertical Shaft Francis
	No. of Units	2
Transmission Line	Voltage	150 kV
	Length	40.0 km
Economical Aspect		
Construction Cost		55.7 million USD
Cost per kW		1,803 USD/kW
Cost per kWh		0.238 USD/kWh
Study Level		Pre-F/S in 1987

Source: The outlines of power generation and plant facilities are referred from Y2009 report. The economic aspect is estimated based on the construction cost referred from "Hydro Inventory Study and Pre-Feasibility Studies" in 1999

—: No data

(9) Sirahar

This site is located in North Sumatra Province and the plan entails utilizing Sirahar River in the Aek Batugarigis River system southwest of Lake Toba. The Simanngo-1 site is located close by. The catchment area at the intake point is 207 km^2, and a gate type diversion weir with height of 12.5 m and width of 64.1 m will be installed to obtain a maximum discharge of 16.7 m^3/s. From here, the water will be conveyed along a 2,990 m headrace tunnel (inner diameter 3.0 m) and 524 m penstock (inner diameter 2.3 m) to a run-of-river power plant, and the effective head of 256.3 m will be utilized to obtain peak output of 35.4 MW and generate 228.3 GWh of power per year. It is estimated that the total construction cost will be 58.9 million USD and that the unit cost will be 1,664 USD per kW. It is planned to supply the generated power along a 91.9 km transmission line to the North Sumatra Grid.

Table 4.3-9 General Features of Sirahar Project

Power Generation Outline		
Location	Province	North Sumatra
	River / River Basin	Aek Batugarigi / Aek Sirahar
Hydrology	Catchment Area	207 km^2
	Mean Annual Discharge	—
	Annual Rainfall	—
Power Generation	Generation Type	Run-of-River
	Installed Capacity	35.4 MW
	Maximum Discharge	16.7 m^3/s
	Gross Head	—
	Effective Head	256.3 m
	Annual Generated Energy	228.3 GWh
	Primary Energy	133.3 GWh
	Secondary Energy	95.0 GWh
	Plant Factor	73.6%
Plant Facilities Outline		
Dam / Weir	Full Supply Level	EL. 389.5 m
	Minimum Operation Level	EL. 384.0 m
	Type	Gated Weir
	Height	12.50 m
	Crest Length	64.10 m
	Design Flood	—
Headrace	Type	Pressure Flow
	Length	2,990.0 m
	Inside Diameter	3.00 m
Surge Tank / Head Tank	Type	Surge Tank
	Height	21.10 m
	Inside Diameter	12.0 m
Penstock	Type	Steel Lined, Underground
	Length	524.0 m
	Inside Diameter	2.3 m
Tailrace	Type	Open Channel
	Tail Water Level	EL. 120.0 m
Power House	Type	—
Turbine	Type	—
	No. of Units	1
Transmission Line	Voltage	150 kV
	Length	91.9 km
Economical Aspect		
Construction Cost		58.9 million USD
Cost per kW		1,664 USD/kW
Cost per kWh		0.258 USD/kWh
Study Level		Map Study

Source: The outlines of power generation and plant facilities are referred from Y2009 report. The economic aspect is estimated based on the construction cost referred from “Hydro Inventory Study and Pre-Feasibility Studies” in 1999

—: No data

TEPSCO

(10) Simanggo-1

This site is located adjacent to the Sirahar site southwest of Lake Toba in North Sumatra Province. The plan entails installing a gate type dam with height of 11.2 m an width of 129.7 m on Simmanggo River in the Krueng Singkel River system, and this will obtain a maximum discharge of 33.1 m^3/s. From here, water will be conveyed along a 2,000 m headrace tunnel (inner diameter 3.90 m) and 850 m penstock (inner diameter 3.10 m) to a run-of-river power plant, and the effective head of 162.4 m will be utilized to obtain peak output of 44.4 MW and generate 285.8 GWh of power per year. It is estimated that the total construction cost will be 77.8 million USD and that the unit cost will be 1,752 USD per kW.

Table 4.3-10 General Features of Simanggo-1 Project

Power Generation Outline		
Location	Province	North Sumatra
	River / River Basin	Krueng Singkel / Aek Simanggo
Hydrology	Catchment Area	436 km^2
	Mean Annual Discharge	—
	Annual Rainfall	—
Power Generation	Generation Type	Run-of-River
	Installed Capacity	44.4 MW
	Maximum Discharge	33.1 m^3/s
	Gross Head	—
	Effective Head	162.4 m
	Annual Generated Energy	285.8 GWh
	Primary Energy	167.3 GWh
	Secondary Energy	118.5 GWh
	Plant Factor	73.5%
Plant Facilities Outline		
Dam / Weir	Full Supply Level	EL. 683.2 m
	Minimum Operation Level	EL. 679.9 m
	Type	Gated Weir
	Height	11.20 m
	Crest Length	129.70 m
	Design Flood	—
Headrace	Type	Pressure Flow
	Length	2,000.0 m
	Inside Diameter	3.90 m
Surge Tank / Head Tank	Type	Surge Tank
	Height	19.70 m
	Inside Diameter	15.40 m
Penstock	Type	Steel Lined, Underground
	Length	850.0 m
	Inside Diameter	3.1 m
Tailrace	Type	Open Channel
	Tail Water Level	EL. 510.0 m
Power House	Type	—
Turbine	Type	—
	No. of Units	1
Transmission Line	Voltage	150 kV
	Length	94.5 km
Economical Aspect		
Construction Cost		77.8 million USD
Cost per kW		1,752 USD/kW
Cost per kWh		0.272 USD/kWh
Study Level		Map Study

Source: The outlines of power generation and plant facilities are referred from Y2009 report. The economic aspect is estimated based on the construction cost referred from “Hydro Inventory Study and Pre-Feasibility Studies” in 1999

—: No data

(11) Toru-3

This site is located in North Sumatra Province in the middle reaches of Batang Toru River flowing to the south of Lake Toba. The Toru-1 site is located in the upstream. The catchment area at the dam point is 2,320 km^2, and the plan entails utilizing effective head of 130.4 m to generate peak output of 229.2 MW and 519.7 GWh of power per year in a reservoir type power plant. The dam is a rock-fill dam with a height of 124.1 m and crest length of 405.6 m. Discharge will be conveyed immediately downstream through a 500 m penstock (inner diameter 5.0 m) and to the power plant. It is planned to supply the generated power along a 43 km transmission line to the North Sumatra Grid. It is estimated that the total construction cost will be 322.7 million USD and that the unit cost will be 1,408 USD per kW.

Table 4.3-11 General Features of Toru-3 Project

Power Generation Outline		
Location	Province	North Sumatra
	River / River Basin	Batang Toru / Batang Toru
Hydrology	Catchment Area	2,320 km^2
	Mean Annual Discharge	—
	Annual Rainfall	—
Power Generation	Generation Type	Reservoir
	Installed Capacity	229.2 MW
	Maximum Discharge	212.1 m^3/s
	Gross Head	—
	Effective Head	130.40 m
	Annual Generated Energy	519.7 GWh
	Primary Energy	498.4 GWh
	Secondary Energy	17.7 GWh
	Plant Factor	25.9%
Plant Facilities Outline		
Reservoir	Full Supply Level	EL. 433.1 m
	Minimum Operation Level	EL. 420.4 m
	Reservoir Surface Area	—
	Gross Storage	541.8×10^6 m^3
	Effective Storage	282.2×10^6 m^3
Dam / Weir	Type	Rockfill
	Height	124.10 m
	Crest Length	405.60 m
	Design Flood	5,019.0 m^3/s
Headrace	Type	—
	Length	—
	Inside Diameter	—
Surge Tank / Head Tank	Type	—
	Height	—
	Inside Diameter	—
Penstock	Type	Steel Lined, Underground
	Length	500.0 m
	Inside Diameter	5.0 m
Tailrace	Type	Open Channel
	Tail Water Level	295.0 m
Power House	Type	—
Turbine	Type	—
	No. of Units	1
Transmission Line	Voltage	150 kV
	Length	43.0 km
Economical Aspect		
Construction Cost		322.7 million USD
Cost per kW		1,408 USD/kW
Cost per kWh		0.621 USD/kWh
Study Level		Map Study

Source: The outlines of power generation and plant facilities are referred from Y2009 report. The economic aspect is estimated based on the construction cost referred from “Hydro Inventory Study and Pre-Feasibility Studies” in 1999

—: No data

(12) Kumbih-3

This site is located in North Sumatra Province in the middle reaches of Kumbih River in the Krueng Singkel River system flowing to the west of Lake Toba. The Ordi-1 site is located nearby. The catchment area at the intake point is 469.0 km^2, and a gate type dam with height of 11.8 m and width of 120.9 m will be installed to obtain water. From here, the water will be conveyed along a 3,790 m headrace tunnel (inner diameter 4.1 m) and 354.6 m penstock (inner diameter 3.3 m) to the run-of-river power plant, and the maximum flow of 37.9 m^3/s and effective head of 133.3 m will be utilized to generate 41.8 MW. It is planned to supply the generated power along a 42 km transmission line to the North Sumatra Grid. It is estimated that the total construction cost will be 78.6 million USD and that the unit cost will be 1,880 USD per kW.

Table 4.3-12 General Features of Kumbih-3 Project

Power Generation Outline		
Location	Province	North Sumatra
	River / River Basin	Krueng Singkel / Lae Kumbih
Hydrology	Catchment Area	469 km^2
	Mean Annual Discharge	－
	Annual Rainfall	－
Power Generation	Generation Type	Run-of-River
	Installed Capacity	41.8 MW
	Maximum Discharge	37.9 m^3/s
	Gross Head	－
	Effective Head	133.3 m
	Annual Generated Energy	269.6 GWh
	Primary Energy	157.5 GWh
	Secondary Energy	112.1 GWh
	Plant Factor	73.6%
Plant Facilities Outline		
Dam / Weir	Full Supply Level	EL. 263.8 m
	Minimum Operation Level	EL. 260.1 m
	Type	Gated Weir
	Height	11.80 m
	Crest Length	120.90 m
	Design Flood	－
Headrace	Type	Pressure Flow
	Length	3,700.0 m
	Inside Diameter	4.10 m
Surge Tank / Head Tank	Type	Surge Tank
	Height	25.30 m
	Inside Diameter	16.20 m
Penstock	Type	Steel Lined, Underground
	Length	354.6 m
	Inside Diameter	3.3 m
Tailrace	Type	Open Channel
	Tail Water Level	EL. 120.0 m
Power House	Type	－
Turbine	Type	－
	No. of Units	1
Transmission Line	Voltage	150 kV
	Length	42.0 km
Economical Aspect		
Construction Cost		78.6 million USD
Cost per kW		1,880 USD/kW
Cost per kWh		0.292 USD/kWh
Study Level		Map Study

Source: The outlines of power generation and plant facilities are referred from Y2009 report. The economic aspect is estimated based on the construction cost referred from "Hydro Inventory Study and Pre-Feasibility Studies" in 1999

－: No data

(13) Jambu Aye

The plan here is for a multipurpose earth-fill dam that includes electricity generation on Jambu Aye River in Aceh Province. Since the catchment area at the intake point is 3,890 km^2, mean precipitation over the catchment area is 1,812 mm and annual mean flow at the intake point is 149 m^3/s, conditions are ideal for hydropower development. On the other hand, since the reservoir will cover an area of 115 km^2, there are concerns over the social and natural environmental impacts. The Ministry of Public Works is currently conducting an F/S review for the multipurpose plan, and this should reveal that extent of the environmental impact. The earth-fill dam will have a height of 66 m and crest length of 3,200 m, and a penstock of 130 m in length and 4.70 m inner diameter will convey water from here to the reservoir type power plant immediately downstream. Utilizing the maximum flow of 86.0 m^3/s and effective head of 54.0 m, the plant will have maximum output of 160 MW and generate 650 GWh of power per year. It is estimated that the total construction cost will be 443.1 million USD, however, it will be necessary to confirm the economic feasibility of the power generation utility upon clarifying the cost burden for power generation of the multipurpose dam operator.

Table 4.3-13 General Features of Jambu Aye Project

Power Generation Outline		
Location	Province	Nanggroe Aceh Darussalam
	River / River Basin	Kr. Jambu Aye / Kr. Jambu Aye
Hydrology	Catchment Area	3,890 km^2
	Mean Annual Discharge	149.00 m^3/s
	Annual Rainfall	1,812.0 mm
Power Generation	Generation Type	Reservoir
	Installed Capacity	160.0 MW
	Maximum Discharge	86.0 m^3/s
	Gross Head	60.5 m
	Effective Head	54.0 m
	Annual Generated Energy	650.0 GWh
	Primary Energy	―
	Secondary Energy	―
	Plant Factor	46.4%
Plant Facilities Outline		
Reservoir	Full Supply Level	EL. 84.0 m
	Minimum Operation Level	EL. 74.0 m
	Reservoir Surface Area	115.0 km^2
	Gross Storage	$4{,}170.0\times10^6\ m^3$
	Effective Storage	$1{,}050.0\times10^6\ m^3$
Dam / Weir	Type	Zoned Earthfill
	Height	66.00 m
	Crest Length	3,200.00 m
	Design Flood	3,850.0 m^3/s
Headrace	Type	―
	Length	―
	Inside Diameter	―
Surge Tank / Head Tank	Type	―
	Height	―
	Inside Diameter	―
Penstock	Type	Steel Pipeline with Concrete Lining
	Length	130.0 m
	Inside Diameter	4.7 m
Tailrace	Type	Free Flow
	Tail Water Level	26.00 m
Power House	Type	Open Air
Turbine	Type	Vertical Shaft Francis
	No. of Units	4
Transmission Line	Voltage	150 kV
	Length	64.0 km
Economical Aspect		
Construction Cost		433.1 million USD
Cost per kW		2,707 USD/kW
Cost per kWh		0.666 USD/kWh
Study Level		F/S in 1985

Source: The outlines of power generation and plant facilities are referred from Y2009 report. The economic aspect is estimated based on the construction cost referred from "Hydro Inventory Study and Pre-Feasibility Studies" in 1999

―: No data

(14) Teunom-1

This site is located in the middle reaches of Teunom River in the northwest of Aceh Province and the plan entails building a reservoir type power plant. With a catchment area of 900 km^2 at the intake point and mean precipitation over the catchment area of 3,140 mm, annual mean flow at the intake point is estimated at 55.60 m^3/s. A rock-fill dam with height of 96 m and crest width of 240 m will be installed to obtain a maximum intake of 214.0 m^3/s. From here, water will be conveyed along a 450 m headrace tunnel (inner diameter 3.85 m) and 250 m penstock (inner diameter 3.23 m) to the power plant, and the effective head of 213.8 m will be utilized to obtain peak output of 24.3 MW and generate 212.4 GWh of power per year. It is estimated that the total construction cost will be 99.7 million USD and that the unit cost will be 4,103 USD per kW. It is planned to supply the generated power along a 65 km transmission line to the North Sumatra Grid.

Table 4.3-14 General Features of Teunom-1 Project

Power Generation Outline		
Location	Province	Nanggroe Aceh Darussalam
	River / River Basin	Kr. Teunom / Kr. Teunom
Hydrology	Catchment Area	900 km^2
	Mean Annual Discharge	55.60 m^3/s
	Annual Rainfall	3,140.0 mm
Power Generation	Generation Type	Reservoir
	Installed Capacity	24.3 MW
	Maximum Discharge	214.0 m^3/s
	Gross Head	231.0 m
	Effective Head	213.8 m
	Annual Generated Energy	212.4 GWh
	Primary Energy	—
	Secondary Energy	—
	Plant Factor	99.8%
Plant Facilities Outline		
Reservoir	Full Supply Level	EL. 309.34 m
	Minimum Operation Level	EL. 296.74 m
	Reservoir Surface Area	—
	Gross Storage	—
	Effective Storage	—
Dam / Weir	Type	Rockfill
	Height	96.00 m
	Crest Length	240.00 m
	Design Flood	3,370.0 m^3/s
Headrace	Type	Pressure Flow
	Length	450.0 m
	Inside Diameter	3.85 m
Surge Tank / Head Tank	Type	Restricted Orifice Tank
	Height	—
Penstock	Type	Steel Lined, Underground
	Length	250.0 m
	Inside Diameter	3.23 m
Tailrace	Type	Free Flow
	Tail Water Level	215.56m
Power House	Type	Open Air
Turbine	Type	Vertical Shaft Francis
	No. of Units	2
Transmission Line	Voltage	150 kV
	Length	65.0 km
Economical Aspect		
Construction Cost		99.7 million USD
Cost per kW		4,103 USD/kW
Cost per kWh		0.469 USD/kWh
Study Level		Pre-F/S in 1987

Source: The outlines of power generation and plant facilities are referred from Y2009 report. The economic aspect is estimated based on the construction cost referred from “Hydro Inventory Study and Pre-Feasibility Studies” in 1999

—: No data

(15) Aceh-2

This is the site of the planned reservoir type power plant on Aceh River on the outskirts of Banda Aceh in Aceh Province. Although this is a reservoir type power generation plan, the reservoir will only cover an area of 0.6 km^2 and the environmental impact will be minimal. With a catchment area of 323.0 km^2 at the intake point and mean precipitation over the catchment area of 2,170 mm, annual mean flow at the intake point is 13.20 m^3/s. A rock-fill dam with height of 72 m and crest width of 260 m will be installed to obtain a maximum intake of 80.0 m^3/s. From here, water will be conveyed along a 2,700 m headrace tunnel (inner diameter 2.28 m) and 500 m penstock (inner diameter 1.80 m) to the power plant, and the effective head of 111.40 m will be utilized to obtain peak output of 7.3 MW and generate 64.30 GWh of power per year. It is planned to supply the generated power along a 59 km transmission line to Banda Aceh.

It is estimated that the total construction cost will be 56.3 million USD and that the unit cost will be 7,712 USD per kW. Since this plan was initially compiled with the primary purpose of supplying electricity to Banda Aceh, it will be necessary to re-examine the contents with a view to ensuring supply to the North Sumatra Grid.

Table 4.3-15 General Features of Aceh-2 Project

Power Generation Outline		
Location	Province	Nanggroe Aceh Darussalam
	River / River Basin	Krueng Aceh / Krueng Aceh
Hydrology	Catchment Area	323 km^2
	Mean Annual Discharge	13.20 m^3/s
	Annual Rainfall	2,170.0 mm
Power Generation	Generation Type	Reservoir
	Installed Capacity	7.30 MW
	Maximum Discharge	80.0 m^3/s
	Gross Head	—
	Effective Head	111.40 m
	Annual Generated Energy	64.30 GWh
	Primary Energy	32.10 GWh
	Secondary Energy	32.10 GWh
	Plant Factor	—
Plant Facilities Outline		
Reservoir	Full Supply Level	EL. 231.21 m
	Minimum Operation Level	EL. 225.32 m
	Reservoir Surface Area	—
	Gross Storage	19.20×10^6 m^3
	Effective Storage	4.23×10^6 m^3
Dam / Weir	Type	Rockfill
	Height	72.00 m
	Crest Length	260.00 m
	Design Flood	1,760.0 m^3/s
Headrace	Type	Pressure Flow
	Length	2,700.0 m
	Inside Diameter	2.28 m
Surge Tank / Head Tank	Type	Restricted Orifice Tank
	Height	—
	Inside Diameter	—
Penstock	Type	Steel Lined, Underground
	Length	500.0 m
	Inside Diameter	1.80 m
Tailrace	Type	Free Flow
	Tail Water Level	110.08m
Power House	Type	Open Air
Turbine	Type	Vertical Shaft Francis
	No. of Units	2
Transmission Line	Voltage	150 kV
	Length	59.0 km
Economical Aspect		
Construction Cost		56.3 million USD
Cost per kW		7,712 USD/kW
Cost per kWh		0.876 USD/kWh
Study Level		Pre-F/S in 1987

Source: The outlines of power generation and plant facilities are referred from Y2009 report. The economic aspect is estimated based on the construction cost referred from “Hydro Inventory Study and Pre-Feasibility Studies” in 1999

—: No data

(16) Raisan-3 & 4

This site is located on the mainstream of Raisan River, which flows from the south of North Sumatra Province to Sibolga and empties into the Indian Ocean. The plan entails building a small-scale regulating reservoir in the upstream and constructing hydropower plants at Raisan-3, which will conduct daily adjustment operation, and Raisan-4, which is a run-of-river plant further downstream. Raisan-1 & 2 (total output 750 kW), which are run-of-river power plants owned by PT. PLN, are currently operating upstream of Raisan-3, and the intake point for Raisan-3 will be 3~4 km downstream from here.

The intake dam for Raisan-3 will be a gravity dam of 40 m in height and plant discharge of 40 m^3/s. From here, water will be conveyed through the mountains via a 3.7 km pressure tunnel, surge tank and penstock, and the effective head of 106.0 m will be utilized to obtain the output of 37.0 MW. Moreover, immediately downstream of Raisan-3, the intake dam of Raisan-4 (height 15.0 m) will also secure discharge of 40 m^3/s, and this water will be conveyed via a 4.0 km non-pressurized headrace tunnel, forebay and penstock to a power plant, where the effective head of 122.0 m will be utilized to generate output of 43.0 MW. With a catchment area of 204 km^2 at the Raisan-3 intake point, mean annual precipitation of 4,000~4,500 mm and mean river flow of 19.0 m^3/s, the regulating pondage will be a small structure, and the combined energy of both sites will be 295.0 GWh. The generated power will be transmitted to the existing Tarutung substation, from where it will be connected to the North Sumatra Grid. This plan will entail the creation of a small regulating pondage upstream of the intake point for Raisan-3 power plant, however, since the submerged area will be small and there will be no need for relocation of residents (according to the field survey), the natural and social environmental impacts will be minimal.

Table 4.3-16 General Features of Raisan-3 & 4

Project Name		Raisan-3	Raisan-4
Power Generation Outline			
Location	Province	North Sumatra	
	River / River Basin	Aek Raisan	
Hydrology	Catchment Area	204 km^2	259 km^2
	Mean Annual Discharge	19.00 m^3/s	24.00 m^3/s
	Annual Rainfall	4,000 – 4,500 mm	
Power Generation	Generation Type	Regulating Reservoir	Run-of-River
	Installed Capacity	37.0 MW	43.0 MW
	Maximum Discharge	40.0 m^3/s	40.0 m^3/s
	Gross Head	113 m	129 m
	Effective Head	106 m	122 m
	Annual Generated Energy	135.0 GWh	160.0 GWh
	Primary Energy	―-	―
	Secondary Energy	―	―
	Plant Factor	41.7%	42.5%
Plant Facilities Outline			
Reservoir	Full Supply Level	EL. 345 m	EL. 229 m
	Minimum Operation Level	EL. 342 m	EL. 229 m
Dam / Weir	Type	Concrete Gravity	
	Height	40.00 m	15.00 m
Headrace	Type	Pressure Flow	Free Flow
	Length	3,700 m	4,000 m
	Inside Diameter	4.5 m	4.5 m
Surge Tank / Head Tank	Type	Surge Tank	Head Tank
Penstock	Type	Ground	
Power House	Type	Ground	
Economical Aspect			
Construction Cost		14.0 million USD	
Cost per kW		1,750 USD/kW	
Cost per kWh		0.475 USD/kWh	
Study Level		Reconnaissance Study	

Source: ” RAISAN NO.3 & 4 HYDROELECTRIC POWER DEVELOPMENT PROJECT IN NORTH SUMATRA (June 2004)”

(17) Simanggo-2

It is scheduled to implement a pre-feasibility study on this potential site that was selected in the Hydropower Master Plan. This site is located downstream of the previously mentioned Simanggo-1 site; it passed third-stage screening in the Hydro Inventory and Pre-Feasibility Study, and it is scheduled to undergo development from 2018 onwards. The detailed project particulars cannot be disclosed because they are still undergoing investigation. The plan outline according to the Working group materials of the JICA Advisory Committee on Environmental and Social Consideration are shown below and indicate no major change from the Hydro Inventory and Pre-Feasibility Study.

Table 4.3-17 General Features of Simanggo-2

Power Generation Outline		
Location	Province	North Sumatra
	River / River Basin	Krueng Singkel / Aek Simanggo
Power Generation	Generation Type	Run-of-River
	Installed Capacity	59.0 MW
	Annual Generated Energy	367.0 GWh
Economical Aspect		
Construction Cost		118.0 million USD
Cost per kW		2,000 USD/kW
Cost per kWh		0.322 USD/kWh
Study Level		Under processing pre-feasibility study

Source: Working group materials of the JICA Advisory Committee on Environmental and Social Consideration

4.3.2 Comparison of Construction Costs

In the Phase 1 Study 2009, estimation of construction cost was carried out on the promising sites identified in the Hydro Inventory and Pre-Feasibility Study based on 2008 prices taking into account inflation and exchange rate (see pages 6~9, Phase 1 Study 2009). The following table gives a comparison of construction costs, scale of development and generated electric energy in each plan between the Phase 1 Study 2009 and the Hydro Inventory and Pre-Feasibility Study.

Table 4.3-18 Comparison of the Phase 1 Study and Hydro Inventory and Pre-Feasibility Study

No.	Project	Type	Province	Phase 1 Study 2009			Hydro Inventory and Pre-Feasibility Study 1999				Conversion Factor of Construction Cost	Remarks
				Capacity	Energy	Cost	Capacity	Energy	Cost	Category		
				MW	GWh	M USD	MW	GWh	M USD		%	
1	Asahan-1	ROR	N. Sumatra	180.0	1,360.0	263.0	180.0	1,360.0	263.0	A-1	100.0	under construction
2	Asahan-3	ROR	N. Sumatra	174.0	1,477.0	326.7	400.0	1,930.0	689.6	A-1	47.4	Commence of the construction, review of development scale
3	Tampur-1	RES	Aceh	330.0	1,067.0	559.4	428.0	1,214.3	704.5	A-2	79.4	Review of the development scale due to the environment issue
4	Wampu	ROR	N. Sumatra	84.0	475.3	123.5	84.0	475.3	127.2	A-2	97.1	
5	Lawe Alas-4	RES	Aceh	321.6	1,549.1	459.7	321.6	1,549.1	473.3	A-2	97.1	
6	Toru-1	ROR	N. Sumatra	38.4	308.1	61.4	38.4	308.1	63.2	A-2	97.2	
7	Ordi-1	ROR	N. Sumatra	40.8	263.0	64.4	40.8	263.0	66.3	A-3	97.1	
8	Peusangan-4	ROR	Aceh	30.9	331.7	71.6	30.9	234.2	55.7	A-3	128.5	Review of the generated energy
9	Sirahar	ROR	N. Sumatra	35.4	228.3	57.2	35.4	228.3	58.9	A-4	97.1	
10	Simanggo-1	ROR	N. Sumatra	44.4	285.8	75.6	44.4	285.8	77.8	A-4	97.2	
11	Toru-3	RES	N. Sumatra	229.2	519.7	313.4	229.2	519.7	322.7	A-4	97.1	
12	Kumbih-3	ROR	N. Sumatra	41.8	269.6	76.3	41.8	269.6	78.6	A-4	97.1	
13	Jambu Aye	RES	Aceh	160.0	650.0	350.4	160.0	650.0	433.1	B-1	80.9	Review of the construction cost
14	Teunom-1	RES	Aceh	24.3	212.4	96.8	24.3	212.4	99.7	B-1	97.1	
15	Aceh-2	RES	Aceh	7.3	64.3	54.7	7.3	64.3	56.3	B-1	97.2	

Source: Prepared from the Phase 1 study 2009 and Hydro Inventory and Pre-Feasibility Study
* ROR: run-of-river type generation, RES: reservoir type generation

According to this, apart from revisions to construction cost arising from changes to plans for some of the promising sites, the price conversion factor used for correcting the construction cost in promising projects is estimated to be around 97.1%.

Similarly, the following table shows a comparison of construction costs between the Master Plan data and the Hydro Inventory and Pre-Feasibility Study.

Table 4.3-19 Comparison of the Master Plan and Hydro Inventory and Pre-Feasibility Study

No.	Project	Type	Province	Hydro Master Plan 2010			Hydro Inventory and Pre-Feasibility Study 1999				Conversion Factor of Construction Cost	Remarks
				Capacity	Energy	Cost	Capacity	Energy	Cost	Category		
				MW	GWh	M USD	MW	GWh	M USD		%	
1	Sirahar	ROR	N. Sumatra	18.0	114.0	71.0	35.4	228.3	58.9	A-4	120.5	Review of the development scale
2	Simanggo-2	ROR	N. Sumatra	59.0	367.0	118.0	59.0	366.9	108.1	B-2	109.2	
3	Gumanti-1	ROR	W. Sumatra	16.0	85.0	54.0	15.8	85.4	32.2	B-2	167.7	
4	Anai-1	ROR	W. Sumatra	19.0	109.0	57.0	19.1	109.2	39.4	B-2	144.7	
5	Endikat-2	ROR	S. Sumatra	22.0	154.0	69.0	22.0	179.8	65.7	B-2	105.0	Review of the generated energy
6	Cibareno-1	ROR	Banten	18.0	117.0	61.0	17.5	117.0	48.8	B-2	125.0	
7	Cimandiri-1	ROR	W. Jawa	24.0	168.0	111.0	24.4	167.5	77.3	B-2	143.6	
8	Masang-2	ROR	W. Sumatra	40.0	256.0	111.0	39.6	256.1	91.5	B-2	121.3	

Source: Prepared from the Hydro Master Plan data and Hydro Inventory and Pre-Feasibility Study

According to this, although some corrections can be seen with respect to the scale of development and amount of generated electric energy, construction cost in the Master Plan data increases by between 5% and 67% compared to the Hydro Inventory and Pre-Feasibility Study and the average level of increase is around 30%.

The detailed methods of calculation in both these approaches are unclear, however, on viewing Indonesia's economic development since 1999, it is clear that there has been price inflation and, when this is taken into account with fluctuation in the exchange rate, an increase of around 30% in construction cost between 1999 and 2010 may be appropriate. Therefore, in this Study, it shall be assumed that the rate of increase in construction cost from the Hydro Inventory and Pre-Feasibility Study to the present has been 30%.

The following table shows the construction cost and generating unit cost for potential hydropower sites deemed to be promising in the Hydro Inventory and Pre-Feasibility Study excluding Asahan-1 and Asahan-3, where construction has been completed or commenced. In the Phase 1 Study 2009, Tampur-1 and Jambu Aye were deemed to be promising and to have a generating unit cost of 0.053 USD/kWh and 0.054 USD/kWh respectively, however, these figures rise to 0.076 USD/kWh and 0.087 USD/kWh in the following table, indicating an increase of between 30% and 60%. Concerning Tampur-1, since the results of the review by the ADB are unclear, the power generation particulars in the table below have been based on the results of the Hydro Inventory and Pre-Feasibility Study.

Table 4.3-20 Hydropower Potential Sites and Construction Cost

No.	Project	Type	Province	Capacity	Energy	Cost	Cost/kW	Cost/kWh	Generation Unit Cost
				MW	GWh	M USD	USD/kW	USD/kWh	USD/kWh
3	Tampur-1	RES	Aceh	428.0	1,214.3	915.9	2,140	0.754	0.076
4	Wampu	ROR	N. Sumatra	84.0	475.3	165.4	1,969	0.348	0.035
5	Lawe Alas-4	RES	Aceh	321.6	1,549.1	615.3	1,913	0.397	0.040
6	Toru-1	ROR	N. Sumatra	38.4	308.1	82.2	2,140	0.267	0.027
7	Ordi-1	ROR	N. Sumatra	40.8	263.0	86.2	2,113	0.328	0.033
8	Peusangan-4	ROR	Aceh	30.9	234.2	72.4	2,343	0.309	0.031
9	Sirahar	ROR	N. Sumatra	35.4	228.3	76.6	2,163	0.335	0.034
10	Simanggo-1	ROR	N. Sumatra	44.4	285.8	101.1	2,278	0.354	0.036
11	Toru-3	RES	N. Sumatra	229.2	519.7	419.5	1,830	0.807	0.082
12	Kumbih-3	ROR	N. Sumatra	41.8	269.6	102.2	2,444	0.379	0.038
13	Jambu Aye	RES	Aceh	160.0	650.0	563.0	3,519	0.866	0.087
14	Teunom-1	RES	Aceh	24.3	212.4	129.6	5,334	0.610	0.062
15	Aceh-2	RES	Aceh	7.3	64.3	73.2	10,026	1.138	0.115

Source: Prepared from the Hydro Inventory and Pre-Feasibility Study
* As in the Phase 1 Study, the generation unit cost was calculated using the following expression:
Power generation unit cost = (construction cost)/Annual cost factor 10.1%)/ Annual generated electric power

4.3.3 Outline of the Hydropower Master Plan

JICA has been implementing the Master Plan Study on Hydropower Development in Indonesia since fiscal 2009. Since 10 years have already passed since PLN implemented the Hydro Inventory and Pre-Feasibility Study in 1999 and the natural and social environment at each potential site has changed, the Hydropower Master Plan Study aims to reassess the sites with emphasis on social and natural environmental conditions and to conduct pre-feasibility study at two sites upon examining economic indicators.

The Hydropower Master Plan Study has recently witnessed completion of the interim report, and potential sites are now being selected for implementation of the pre-feasibility study. Thought was given to obtaining information from the Hydropower Master Plan and examining the selection of further potential sites in this Study, however, since the interim report in the aforementioned study has only just been finished, there is still a possibility that the study findings will be changed. The following table shows the planning particulars of promising sites that have so far been identified in the Hydropower Master Plan; out of these, Sirahar and Simanggo-2 are located in the North Sumatran Grid. In addition, it is scheduled to implement a pre-feasibility study at Simanggo-2 as a promising site.

Table 4.3-21 Promising Hydropower Sites according to the Hydropower Master Plan

No	Project Name	Type	Province	Capacity (MW)	Energy (GWh/yr)	Cost (M. USD)
1	Sirahar	RoR*	N. Sumatra	35	228	71
2	Simanggo-2	RoR	N. Sumatra	59	367	118
3	Gumanti-1	RoR	W. Sumatra	16	85	54
4	Anai-1	RoR	W. Sumatra	19	109	57
5	Endikat-2	RoR	S. Sumatra	22	180	69
6	Cibareno-1	RoR	Banten	18	117	61
7	Cimandiri-1	RoR	W. Jawa	24	168	111
8	Masang-2	RoR	W. Sumatra	40	256	111

Source: JICA homepage, Working group of the JICA Advisory Committee on Environmental and Social Consideration

* RoR: Run-of-river type power generation

4.3.4 Outline of Hydropower Sites in RUPTL

The current RUPTL was issued in July 2010, and the hydropower development plans contained in this are as indicated below. All the plans for 2016 onwards are intended for implementation by IPPs.

Table 4.3-22 Hydropower Development Sites planned in RUPTL 2010-2019

Site	Developer	Scale of Development	Year of Introduction	Province
Asahan-1	IPP	180MW	2010	North Sumatra
Asahan-3	PT.PLN	174MW	2013	North Sumatra
Peusangan-1 & 2	PT.PLN	86MW	2013	Aceh
Wampu	IPP	45MW	2016	North Sumatra
Lawe Mamas	IPP	90MW	2016-2017	Aceh
Asahan-4 & 5	IPP	60MW	2016	North Sumatra

Asahan-1 power plant started operation in August 2010, while construction on Ashan-3 and Peusangan-1&2 is scheduled to commence under ODA funding in the near future. All the power resources stated in RUPTL are scheduled to be developed as civilian power resources with PT. PLN as the main operator; however, even in cases where development is conducted by an IPP, it is assumed that power will be supplied to PT. PLN and used as civilian power.

Meanwhile, local governments possess the authority to confer hydropower development concessions to developers. According to information collected by PT. PLN, there are cases where even though PT. PLN implements F/S on a specific hydropower site, the local government grants the development concession to an IPP after the F/S is finished. This means that PT. PLN is unable to vigorously promote development. Accordingly, IPPs are developing all the sites scheduled for construction in the current RUPTL, except for Asahan-3 and Peusangan-1 & 2, where plans have been finalized.

Concerning the site at Wampu, where development has been delayed due to environmental impacts since the F/S of 1992, the plan has been included in RUPTL with an operation start year of 2016 and maximum output of 45 MW. In the field survey, we couldn’t obtain information from PT. PLN concerning the revised plan, however, we assume that environmental impacts have been avoided. Also, concerning Asahan-4 & 5, according to PT. PLN, since plans appear to overlap with plans for Asahan-3 further upstream, it may be difficult to realize plans depending on the outcome at Asahan-3.

Chapter 5 Promising Development Sites for Each Generating Mode

5.1 Coal-fired and Gas-fired Thermal Power Generation

Usually when selecting sites for thermal power stations, providing that enough space to install major equipment, water treatment facilities and fuel storage facilities (depending on the fuel type) is available, and it is possible to acquire the essential water for plant operation and cooling water for steam, unlike geothermal and hydropower facilities, there are no restrictions on candidate sites. In the case of coal-fired thermal power plants, since it is necessary to install the regular boilers, turbines, generators, auxiliary units and attached equipment and to provide a yard or silo for storing coal, it is necessary to secure a large area for the plant site. Meanwhile, in the case of gas-fired thermal power plants, since the fuel gas is stored as LNG in the facilities of a separate company, there is no need to install the fuel storage facilities inside the plant complex.

Coal-fired and gas-fired thermal power plants are often installed at sites that are close to consumer areas so that transmission distances can be reduced; however, coal-fired thermal power plants are sometimes constructed at the mine mouth in order to shorten the coal transportation distance, although the transmission distance becomes long in such cases. Plant construction candidate sites are narrowed down upon examining which option is more appropriate in economical and technical terms. However, even assuming that the South and North Sumatra grids are interconnected, considering that there is more than 1,000 km of transmission distance between mines in South Sumatra Province and consumer areas in North Sumatra, it is better to construct power plants close to the demand centers.

As was mentioned in Chapter 4, it is difficult to secure ample coal or natural gas from Aceh province and North Sumatra Province to justify construction of thermal power plants in those provinces. Accordingly, there will be a choice between 1) using the newly constructed railway, etc. to transport coal from mines in South Sumatra Province that possess ample reserves to Tanjung-Api-Api Port facing the South China Sea, and from there transporting to North Sumatra, or 2) in the case of gas, installing a pipeline from the LNG loading point that is planned for completion off the coast of Medan in 2013 to candidate power plant sites in order to secure a supply of gas as fuel[1].

[1]It was originally intended to examine supply via a gas pipeline from South Sumatra (according to the JICA report on the Approaches to Comprehensive Technical Cooperation to the Energy Sector in Indonesia (project research)). However, although the section to Duri in Riau Province was completed in 1998, the 500 km section from there to Medan is only in the planning stage (according to PLN personnel) and there is no concrete schedule for construction. Therefore, this option has been omitted from the Study.

5.1.1 Power Plant Development Sites

Since the coal-fired thermal power plant will obtain coal supply from outside of North Sumatra, it is desirable to construct it on the coast, where it is possible to build coal unloading facilities suitable for coal transportation, in a site where the freshwater essential for plant operation and seawater necessary for cooling can be obtained. A site near Kuala Tanjung where the INALUM aluminum smelting plant is located is a candidate because the distance of the dedicated transmission line can be shortened. Since RUPTL 2010 also includes plans to construct an IPP power plant near Kuala Tanjung, this satisfies the above conditions.

In the case of a gas-fired thermal power plant, construction is conditional on the gas supply company installing the necessary gas pipeline. In this case, the options are to either 1) construct the power plant on the outskirts of Medan in order to minimize the length of pipeline and to install a dedicated overhead transmission line to the smelting plant, or 2) have a pipeline installed to the same location as in the coal-fired case and shorten the distance of the dedicated transmission line. In either case, it is assumed that gas will be supplied from the offshore LNG loading point scheduled for completion in 2013, and since the supply capacity from the loading point is planned as roughly 40 mmcfd, it will be necessary to conduct detailed examination into whether or not a sufficient quantity of gas can be supplied to the new power resource in line with the LNG loading point expansion plans. Moreover, in the case of gas-fired thermal power, another option is to rehabilitate the existing Belawan thermal power plant owned by PLN, however, in this case it would be necessary for the aluminum smelting plant to receive power supply from the existing PLN grid via a dedicated transmission line.

Belawan thermal power plant is currently installed with a conventional steam PLTU generating system and combined cycle PLTGU system, however, the steam facilities in particular suffer from extreme deterioration: even though the four units (65 MW each) possess intended capacity of 260 MW, they are only generating around 200 MW at present. It may be possible to increase generating capacity to 780 MW through boosting output to 520 MW by replacing these boilers with four 130 MW gas turbines and heat recovery steam generators (HRSG). In this case, although there are no problems concerning land acquisition and water supply, the gas field in North Sumatra that supplies natural gas to PLTGU is at risk of becoming exhausted and the issue of securing a fuel supply still remains as in the above cases.

5.1.2 Scale of Power Resources Development

In the case of coal-fired or gas-fired thermal power, generating capacity can be set relatively freely so long as the necessary coal or gas supply can be secured. Here, examination is conducted on the following generating capacity scenarios:

- 200 MW for INALUM plant expansion
- 400 MW comprising 200 MW for INALUM plant expansion + 200 MW for public use
- 600 MW comprising 200 MW for INALUM plant expansion + 400 MW for public use

Meanwhile, the following combinations are targeted for coal-fired or gas-fired thermal power

Coal-fired thermal power	Steam generating system	
	Subcritical pressure	(Ultra) Supercritical pressure
200 MW	200 MW x 1 unit	Not applicable
400 MW	200 MW x 2 units 400 MW x 1 unit	400 MW x 1 unit
600 MW	200 MW x 3 units 600 MW x 1 unit	600 MW x 1 unit

Gas-fired thermal power	Combined cycle generating system
200 MW	200 MW x 1 unit
400 MW	200 MW x 2 units
600 MW	200 MW x 3 units

In the case of coal-fired thermal power, it is likely that provision of Japanese ODA will be conditional on the adoption of supercritical pressure or ultra supercritical pressure. Judging from past installation experience in Japan, it is technically feasible to construct facilities with unit capacity of 400 MW or 600 MW in either the supercritical pressure or ultra supercritical pressure case. However, assuming that the power resource for INALUM plant expansion will be introduced in 2015 following interconnection between the South and North Sumatra grids in 2012, according to RUPTL, load of 200 MW will be added to the peak load of 6,200 MW in 2015, meaning that peak load on the grid will rise to 6,400 MW.

If a facility with unit capacity of 400 MW or 600 MW is introduced in this situation, such facilities will account for approximately 6.3% and 9.4% of grid capacity respectively, figures which are higher than the recommended 4% or less for a single generating unit. Accordingly, in the event where the facility needs to be suddenly closed down due to equipment troubles, there is risk that this could destabilize the grid. Accordingly, it will be necessary to conduct system flow analysis in order to investigate the impact on the grid in detail. Incidentally, in the case of generating equipment with unit capacity of 200 MW, the share of grid capacity will be approximately 3.1% and, if this is installed after the South and North Sumatra grids are interconnected, the impact imparted on the grid will be mitigated.

In the event where a coal-fired thermal power plant with unit capacity of 400 MW or 600 MW is introduced, if a permanent civilian power supply of 200 MW or 400 MW can be supplied from coal-fired thermal power, it will be possible to use this as base power and conduct efficient operation in the high load zone irrespective of the system type; however, if this becomes the peak power supply, the system will only operate at partial load for supplying power to the INALUM aluminum smelting plant outside of peak times, meaning that plant operating efficiency will decline and the cost of power will become expensive. Since such a trend is accentuated in supercritical or ultra-supercritical generating systems that require large initial investment, examination must be conducted on operating methods in combination with other power resources. Meanwhile, in the event where multiple generating units with 200 MW capacity are introduced, the above issue will be alleviated, however, in the case of a coal-fired system, since starting loss increases and it takes longer time to start and stop the system thus reducing load follow-up performance, it is better to adopt a combined cycle system, which has better starting characteristics and load follow-up performance, as the peak power resource.

Moreover, in the event where 200 MW is secured solely for the INALUM plant expansion, either a subcritical steam generating system or a combined cycle system can be introduced. However, because there would be no independent backup system in this case, it would be necessary to connect to the PLN grid and have power diverted from PLN during emergencies, and it would be necessary to examine the cost of this in advance. In this case, fixed power charges will arise irrespective of the said power coordination with PLN, while the specific charge will be levied according to the amount of power consumption. In either case, the tariff will be higher than conventional charges.

5.1.3 Thermal Power Plant Construction and Operating Cost

In order to operate a coal-fired or gas-fired thermal power plant and conduct stable power supply, it is necessary to have a constant and ample supply of fuel. Considering that fuel prices have a major impact on earnings when operating a thermal power plant, fuel prices have been estimated while referring to other study reports and hearings. In the case of coal, the price was set assuming that low rank quality coal (4,500 kcal/ton) will be transported by railway or barge from mines in South Sumatra Province and discharged in the vicinity of Kuala Tanjung. Meanwhile, in the case of natural gas, price was set assuming that gas will be transported by LNG carrier from Kalimantan and Papua, consolidated at the LNG loading point off the coast of Medan and supplied via a pipeline constructed by the gas supply company.

The other major factor that impacts operating returns following the start of operation is the construction cost, which will be covered by loans. In the case of a coal-fired steam generating system based on subcritical pressure boilers, enterprises capable of building such systems exist in all countries, and the construction unit cost has been set at 800 USD/kWh, which is the mean value given to coal-fired thermal power in the Crash Program. In the case of a coal-fired steam generating system based on supercritical pressure boilers, since materials are more expensive than in the subcritical case and only limited enterprises have the capability to build such systems, the construction unit cost has been set at 1,300 USD/kWh. In the case of a gas-fired combined cycle system, based on recent projects in Indonesia, the construction unit cost has been set at 1,000 USD/kWh. This case assumes construction of a new combined cycle facility, however, the scenario of supercritical generating equipment is omitted because this would require the rehabilitation of Belawan thermal power plant and removal of existing facilities

Table 5.1-1 Estimates of Construction Cost and Operating Conditions of Thermal Power

Capacity	Fuel	Type	Construction Cost (M USD)	O&M Cost/Year (M USD)	Fuel Cost	Thermal Efficiency	Load Factor
200MW	Coal	Subcritical	160	9.6	45 USD/t	39%	70%
400MW	Coal	Subcritical	320	19.2	45 USD/t	39%	70%
600MW	Coal	Subcritical	480	28.8	45 USD/t	39%	70%
400MW	Coal	Supercritical	520	31.2	45 USD/t	41%	70%
600MW	Coal	Supercritical	780	46.8	45 USD/t	41%	70%
200MW	Gas	Combined Cycle	216	10.8	D7/MMbtu	45%	70%

As for other power plant operation and maintenance costs, the cost of maintaining a coal storage yard is assumed to be 6% of construction cost, while maintenance in the case of a gas-fired plant is assumed to be 5%. Concerning the thermal efficiency, general figures based on LHV disregarding the effects of water content in fuel have been adopted, while the equipment utilization rate has been set at a uniform level of 70%. Table 5.1-1 shows the base values for financial calculation according to unit capacity in each system type.

5.2 Geothermal Power Generation

5.2.1 Promising Area and Development Plans for Geothermal Power Generation in North Sumatra

Table 5.2-1 shows the geothermal power sites where study or operation is currently being implemented. Specifically, these are Sibayak, Sarulla, Merapi, Sipaholon and Sinabung, etc.

(1) Sibayak

As was described in section 4.2, existence of geothermal reservoir has been confirmed by exploration wells in this area. The geothermal resource potential here was estimated as 160 MW in the Geothermal Master Plan (2007), however, this is limited to 40 MW because of the site of its location in THR.Bukit Barisan National Park. The operation of 12 MW geothermal power plant was started in 2010, and it is estimated that a further 28 MW of development potential remains. Total expansion of the power plant until 2014 is planed to be 19.5 MW (Surya Darama et al., 2010). While, no development plans given in RUPTL 2010.

(2) Sarulla

Concerning Sarulla, a 330 MW development program has been formulated and the consortium signed a power purchase agreement with PLN in April 2010 for Sarulla-1 (Silangkitang, NIL). Currently steam equivalent to 126 MW is being obtained: 46 MW in NIL and 80 MW in Silangkitang (Surya Darama et al, 2010). The consortium has the development concession of four areas, and it is going to examine plans to develop 330 MW (Sarulla-2). According to RUPTL2010, Sarulla-1 is planed to be developed up to 330MW before 2014.

Concerning Sarulla-2, since 110 MW as IPP is already specified in RUPTL 2010, further the consortium intends to sell power to PLN from developments after Sarulla-1, the power of Sarulla-2 will be used as a power source for public use. However, considering that the Geothermal Master Plan (2007) estimated that Sarulla has total geothermal resource of 630 MW, this means that the area still has potential for the development of 190 MW not stated in RUPTL 2010. The actual development plans are more delayed than RUPTL 2010 and it is expected that development of Sarulla-1 (330 MW) will not take place until 2015 at the earliest and that development of Sarulla-2 will start after that. Moreover, since development of this area will be proceeded step by step, it is possible that the actual development will be even slower than this.

(3) Merapi

According to the Geothermal Master Plan (2007), detailed surface survey has been conducted in this area and high temperature for deep geothermal reservoir was estimated by geochemical temperature, however, so far no deep exploratory well has been drilled. A large geothermal reservoir with geothermal development potential of 500 MW was estimated for this area, however, the development potential is limited to be 100 MW because of its location within an area of national park. A tender for concession in geothermal development areas is currently being held in Merapi, and a development plan of 55 MW has been mentioned in RUPTL 2010. It will be difficult to commence operation by the planned date of 2014. Based on the Geothermal Master Plan (2007), this area has 45MW more development potential than that mentioned in RUPTL 2010.

(4) Sipaholon

According to the Geothermal Master Plan Study (2007), the geothermal resource potential is estimated to be 50 MW. Tenders for concession in geothermal development working areas are currently being conducted in Sipaholon. According to RUPTL 2010, a development plan for Sipaholon by 2019 is 55 MW

(5) Sinabung

This area, located next to Sibayak, is scheduled to be underwent development in the next phase. Surface investigation was being carried out, however, this was suspended due to volcanic eruption in the area. Detailed investigation and well investigation are planed in future. Judging from the surface survey, development potential here is estimated to be 40 MW, the same as in Sibayak. Development of this area is not mentioned in RUPTL 2010, and it will take time for a geothermal power plant to be actually constructed.

(6) Other Areas

In the other areas such as Dolok Marawa, Pusk Bukit-Danau Toba, Simbolon- Samosir, Pagaran and Sibubuhan, survey work has only just begun and it will take for a while before actual development can start.

Table 5.2-1 Geothermal Potential Sites

	Area Name	Developer	Geothermal Master Plan Study (2007) Total Capacity (MW)	Installed(2010) (MW)	RUPTL(2010-2019) (Operaion) (MW)	API NEWS(2010) Tender Status & Green Field List	Possible Additional Development (MW)
1	Sibayak	PGE	40	12	–	–	28
2	Sarulla-1	IPP	630	0	330 (2014)	–	–
	Sarulla-2	IPP		0	110 (2014)	–	190
3	Sorik-Merapi	IPP	100	0	55 (2014)	Tender	45
4	Sipaholon	IPP	50	0	55 (2019)	Tender	0
5	Sinabung	PGE	ND	0	–	–	(40)
6	Dolok Marawa	–	–	0	–	Green Field	–
7	Pusuk Bukit-Danau Toba	–	ND	0	–		–
8	Simbolon-Samosir	–	ND	0	–		–
9	Pagaran	–	–	0	–		–
10	Sibubuhan	–	–	0	–		–
	Total		820		550		273/(313)

5.2.2 Extraction of Promising Areas for Geothermal Development

(1) Promising areas for Geothermal Development

Promising areas for Geothermal development where operation or survey work is currently being undertaken are Sibayak, Sarulla, Merapi, Sipaholon and Sinabung, etc. Concerning development of Sarulla (330 MW), a power purchase agreement has been signed with PLN, and power from subsequent developments will also be sold to PLN. Since Sarulla-2 is already indicated as a 110 MW IPP power resource in RUPTL 2010, this will be utilized as a public use power resource. However, judging from the Geothermal Master Plan (2007), it is estimated that Sarulla still has potential for the development of 190 MW not stated in RUPTL. Plans not stated in RUPTL include expansion of Sibayak and Sinabung. Of these areas, the Sibayak expansion (28 MW) can be considered as a power resource for INALUM at present, while Sinabung is still at investigation stage. Surface survey is still being carried out at Sinabung and potential reserves are still only estimate values. From the above discussion, considering 100 MW level of power generation, Sarulla-2 (190 MW, public use) is selected as a promising area for geothermal development.

(2) Geothermal Power Plant Construction Cost

Among the promising development sites, rough cost for construction of the Sarulla-2 geothermal power plant (190 MW) estimated. For calculation, consideration was given to the cost of drilling the number of wells deemed necessary according to the geothermal reservoir characteristics estimated in the Geothermal Master Plan (2007) and Phase 1 Study (2009) and the cost of plant construction, while adding new information (Table 5.2-2). Moreover, as was pointed out in the Phase 1 Study (2009), construction cost is impacted by the capacity (output) of production wells. Accordingly, the construction cost was estimated while using the average production well capacity (8 MW/well). Details regarding calculation of construction costs are indicated in the appendix.

Table 5.2-2 Estimate of Construction Cost of a Promising Potential Site

No.	Development area	Generating capacity	Production well capacity	Drilling cost	Initial investment cost	Civil engineering cost	Transmission line	Total constraction cost	Annual generated energy
		(MW)	(MW)	(million USD)	(million USD)	(million USD)	(million USD)	(million USD)	(GWh)
1	Sarulla-2	190	8	275	553	28	6	586	1,332

5.3 Hydropower Generation

5.3.1 Conditions for Extraction of Promising Hydropower Potentials

Concerning the hydropower potential indicated in Chapter 4, the conditions for extracting promising development sites based on information gathered from related agencies in Indonesia were compiled as follows.

(1) Environmental impact of large-scale reservoirs

In plans such as those for Tampur-1 and Jambu Aye, which were identified as promising sites in the Phase 1 Study 2009 but which have large-scale reservoirs covering an area over several tens km^2, the impacts on the social and natural environment will be huge, and even PT. PLN believes that it will be difficult to resolve these problems and conduct development. Accordingly, sites such as these which have large-scale reservoirs will be omitted from the list of promising sites. (Concerning Tampur-1, PT. PLN thinks it will be difficult to achieve early development because the reservoir is situated in a conservation area, whereas in the case of Jambu Aye, since this project is a multipurpose dam, it will take time to coordinate and reach agreement with the related ministries and agencies).

(2) Political situation in Aceh

Aceh Province has been in conflict with the central government for many years and it is forecast that coordinating and reaching consensus over power development will be difficult. PT PLN also believes that development in Aceh will require time-consuming coordination due to the strong autonomy and political conflict in that province. Accordingly, potential sites in Aceh Province shall be omitted from the list of promising development sites.

(3) Run-of-river and pondage type power generation plans

Usually, development of hydropower plants begins with the development concept; the detailed development plan is compiled upon conducting a series of studies including feasibility study and detailed design; the construction contractor is decided by tender, and then the construction work begins. It is not unusual for this development process from the study phase to construction to take more than 20 years; particularly in cases of projects that have large-scale reservoirs, in addition to these phases, it is necessary to give consideration to the social and natural environment. Meanwhile, it will be necessary to develop the potential sites identified in this Study at the same time as or soon after the plant expansion works at INALUM. Accordingly, the Study will target potential sites where run-of-river or pondage type plants can be developed relatively quickly and where the map study has already been completed in the study stage. In such cases, since the power supply from the run-of-river or pondage type power plant will fluctuate according to the river flow, such systems are not suited to power supply for an aluminum smelting plant which requires a constant and uniform power supply. Accordingly, such potential hydropower cases will be considered as power resources for public use power supply.

5.3.2 Extraction of Promising Hydropower Sites

Out of the potential sites that were identified in Chapter 4, promising development sites were extracted based on the aforementioned conditions. The selected sites are as follows.

Table 5.3-1 Promising Hydropower Potential Sites

Site	Install capacity (MW)	Annual generated energy (GWh)	Plant factor (%)	Type of generation	Study level
Toru-1	38.4	308.1	91.6	Run-of-river	Pre-FS
Simanggo-2	59.0	367.0	71.0	Run-of-river	MP
Wampu	45.0	209.7	53.2	Run-of-river	FS
Raisan-3,4	80.0	295.0	42.1	Pondage	RS
Total	222.4	1,179.8			

And the sites that were omitted, and the reasons for their omission, are indicated in Table 5.3-2.

Table 5.3-2 Potential Hydropower Sites Omitted from Selection

Site	Reason for Omission			
	Large Reservoir*1	Location in Aceh Province	Not Developed up to Map Study	Other Reason
[Hydro Inventory and Pre-Feasibility Studies]				
Tampur-1*2	○ (40.9km²)	○		
Lawe Alas-4	○ (21km²)	○		
Ordi-1			○	
Peusangan-4		○		
Sirahar			○	
Simanggo-1			○	
Toru-3	○ (22km²)		○	
Kumbih-3			○	
Jambu Aye*3	○ (115.0km²)	○		
Teunom-1	(2km²)	○		
Aceh-2	(1km²)	○		
[RUPTL 2010]				
Lawe Mamas		○		
Asahan-4 & 5				○*4

*1: Figures in parentheses ( ) indicate the reservoir area. Figures for Lawe Alas-4, Toru-3, Teunom-1 and Aceh-2 are estimated from the project features.
*2: Concerning Tampur-1, development will also be difficult because it encroaches on a conservation area.
*3: Concerning Jambu Aye, since the plan targets a multipurpose dam and this will require long-term coordination with related ministries and agencies, early development will be impossible.
*4: Concerning Asahan-4 & 5, this has been omitted because the development potential will be influenced by the Asahan-3 plan currently being compiled.

5.3.3 Project Features of Promising Hydropower Sites

The project features (plant particulars, construction costs) for each promising development site are estimated as follows.

(1) Toru-1

The project features for this development site are taken from the Hydro Inventory and Pre-Feasibility Study implemented in 1999. Construction costs are as indicated in Chapter 4, and an escalation of 30% is added to the construction cost that was estimated in 1999.

(2) Simanggo-2

This site has been identified in the Master Plan Study for Hydropower Development in Indonesia that is currently being implemented by JICA, and it is scheduled to implement a Pre-F/S. Because surveys are still being implemented, it wasn't possible to obtain detailed information in this Study, however, the Working group materials of the JICA Advisory

Committee on Environmental and Social Consideration have been adopted. Moreover, it will be necessary to once more review the plans based on the study findings following completion of the Master Plan.

(3) Wampu

This site was the subject of a JICA feasibility study in 1992, when development potential of 84.0 MW was estimated. However, development was subsequently delayed when it was found that the transmission line and access road would encroach on a conservation forest. In RUPTL, the scale of development has been reduced to 45 MW and development is scheduled to begin by an IPP in 2016. In this Study, because the detailed plans are still unclear, plant particulars were compiled based on the 1992 F/S while assuming the plan for 45 MW development. As for the construction cost, based on reference to the escalation of 9% from the F/S report to the Hydro Inventory and Pre-Feasibility Study and the escalation of 30% from the Hydro Inventory and Pre-Feasibility Study to the Hydropower Master Plan, an increase of 40% has been assumed here.

(4) Raisan-3 & 4

The project features for this site have been adopted based on the Reconnaissance Study implemented in 2004. Concerning the construction cost, based on reference to the escalation of 30% from the Hydro Inventory and Pre-Feasibility Study to the Hydropower Master Plan, an increase of 15% has been assumed here.

The following table and figure summarizes the project features and locations of each hydropower site. Out of the four sites described, Wampu has been designated for start of operation from 2015 by an IPP in RUPTL 2010.

Table 5.3-3 Project Features and Cost Estimates of Promising Hydropower Potential Sites

	Site		Toru-1	Simanggo-2	Wampu	Raisan-3	Raisan-4
Power Generation Outline	Province		North Sumatra Province				
	River		Bantang Toru	Aek Simanggo	Sie Wampu	Raisan	
	Catchment area (km^2)		1,013	480	959	204	259
	Generation mode		Run-of-river	Run-of-river	Run-of-river	Pondage	Run-of-river
	Install capacity (MW)		38.4	59.0	45.0	37.0	43.0
	Plant discharge (m^3/s)		-	38.1	35.6	40.0	40.0
	Total head (m)		-	187.4	114.0	113.0	129.0
	Annual generated energy (GWh)		308.1	366.9	209.7	135.0	160.0
	Operating factor (%)		91.6	71.0	53.2	42.1	
Plant Facilities Outline	Dam	Dam type	Concrete	Gate weir	Concrete	Concrete	Concrete
		Dam height (m)	-	15.0	4.5	40.0	15.0
	Headrace	Type	Pressure tunnel	Non-pressure tunnel	Non-pressure tunnel	Pressure tunnel	Non-pressure tunnel
		Length (km)	3.47	4.75	8.0	3.70	4.00
		Inner diameter (m)	2.9	4.1	4.2	4.5	4.5
	Penstock	Type	Ground	Tunnel	Ground	Ground	
	Power house	Type	Ground	Ground	Ground	Ground	
Economy	Construction cost (million USD)		82.2	118.0	148.3	161.0	
	Cost per kW (USD/kW)		2,140	2,000	3,296	2,013	
	Cost per kWh (USD/kWh)		0.267	0.322	0.707	0.546	
	Study level		Pre-F/S	M/P	F/S	R/S	

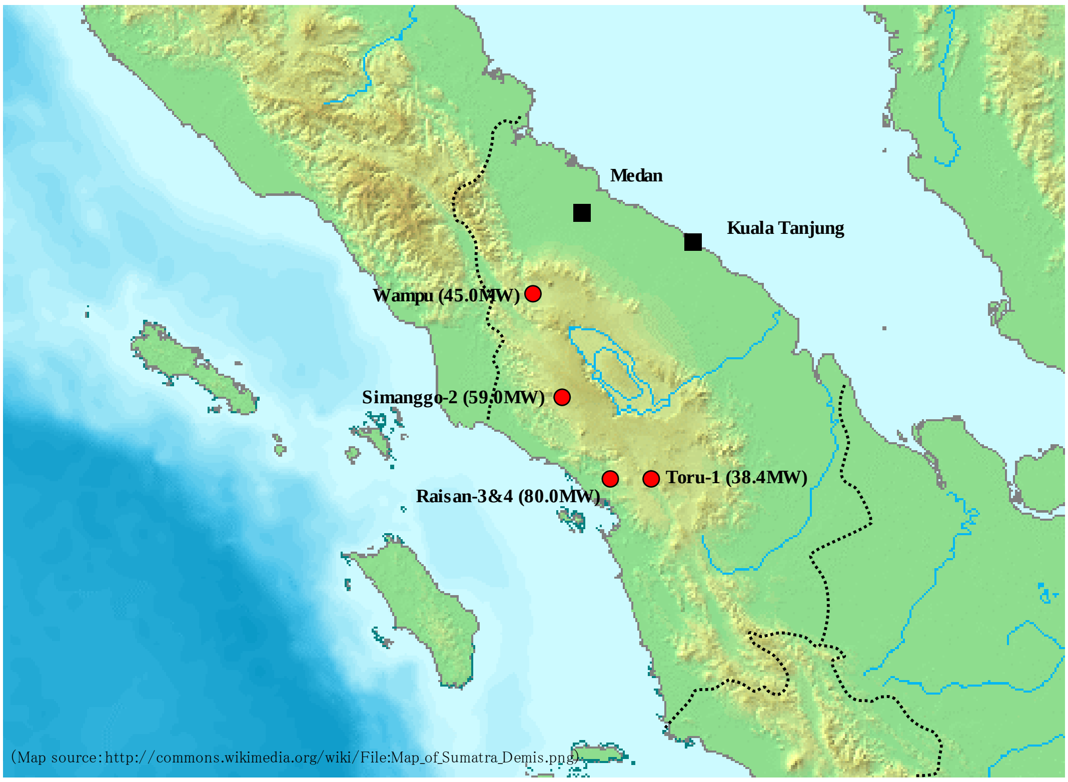


Figure 5.3-1 Location Map of Promising Hydropower Sites

5.4 Schedule for Start of Operation in Potential Development Options

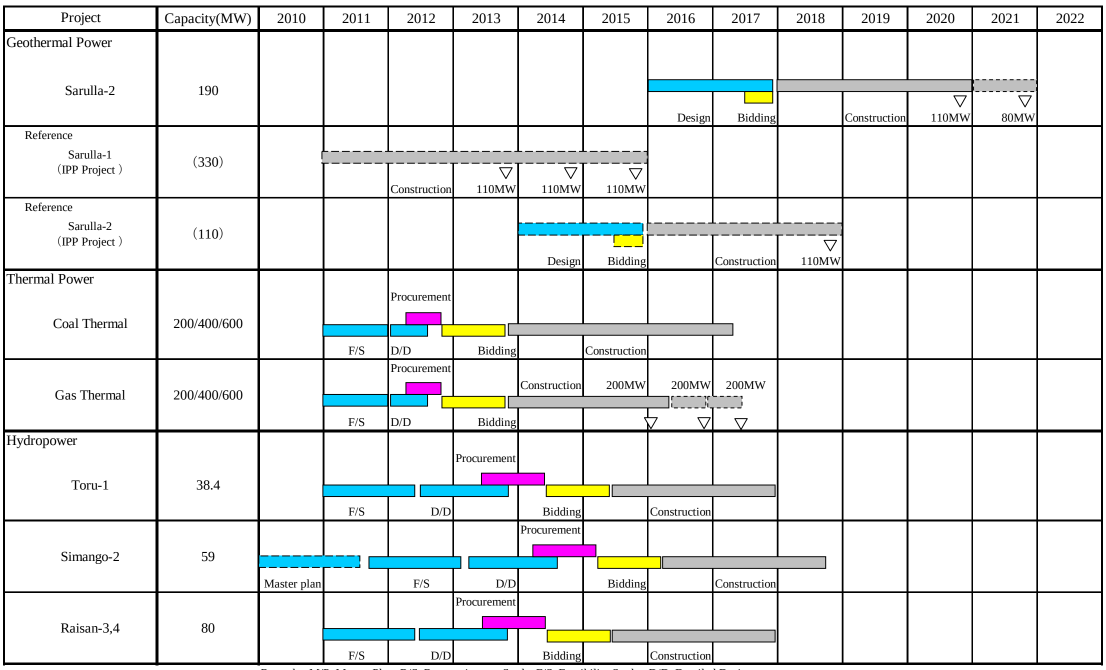
The schedule for the start of operation at each identified potential development site was examined. Until operation can start at each site, it will be necessary to decide the implementation concept of the plan, and then to conduct studies, design, fund procurement, tender and construction, and it was assumed that this series of processes will start from 2011 following completion of the Study. However, concerning hydropower generation site Simanggo-2, since the current JICA Hydropower Development Master Plan will finish in July 2011, it was assumed that the above processes will begin immediately after that. These processes differ according to the project implementation body, however, leaving aside Sarulla-2 geothermal site for which IPP development has been decided, it was assumed that the project implementation body will implement projects upon obtaining public funding. In addition, it was assumed that the required processes judging from the characteristics of each potential site would smoothly progress.

In cases where a site plan contains multiple generators, the start of operation is assumed to be the point at which the first generator goes into operation. Usually, in plans that entail multiple units, generators are installed and operation is started at successive intervals a few months apart. In the case of coal-fired thermal power generation utilizing supercritical or ultra-supercritical boilers, it is structurally more advantageous to adopt single units. Meanwhile, in the case of geothermal power generation, phased development is conducted while confirming the state of geothermal fluid reservoirs by means of well surveys, and the entire development may require a few years. Sarulla-2 (the target of this Study) is at the Pre-F/S stage of development, and the development stage won’t begin until the F/S including well investigation is finished. The F/S for Sarulla-2 (110 MW) will begin during construction of Sarulla-1, while the development study for Sarulla-2 (190 MW), which is targeted in the Study, will commence following completion of the F/S for Sarulla-2 (110 MW).

Taking these conditions into account, the following table indicates the years of operation commencement for each potential site in the event where all processes advance smoothly. According to this, gas-fired power generation, which entails relatively fast study, design and construction work, will commence in 2016, followed by coal-fired thermal power generation in 2017 and hydropower generation in 2017~2018. Meanwhile, geothermal power generation will commence in 2020, following the development of the already scheduled Sarulla-1 (330 MW) and Sarulla-2 (110 MW). However, this Study assumes the earliest possible operation start times in the case where all processes advance smoothly, and it is possible that schedules will change according to the type of project operator, incentives and adjustment policies concerning power resource development by the central government and local governments, and other factors.

Table 5.4-1 Start of Operation of Promising Potential Options

Plan		Capacity	Purpose of Use	Start of Operation
Geothermal	Sarulla-2	190MW	Civilian / (INALUM expansion)	2020
Coal-fired thermal	Kuala Tanjung outskirts	200/400/600 MW (subcritical)	INALUM expansion / Civilian	2016
	Kuala Tanjung outskirts	>450 MW (ultra / supercritical)	INALUM expansion / Civilian	2016
	New	200/400/600 MW (subcritical)	Civilian	2016
	New	>450 MW (ultra / supercritical)	Civilian	2016
Gas-fired thermal	Kuala Tanjung outskirts	200/400/600 MW	INALUM expansion / Civilian	2016
	Belawan Rehabilitation	520 MW	Civilian	2016
	New	200/400/600 MW	Civilian	2016
Hydro	Toru-1	38.4 MW	Civilian	2017
	Simanggo-2	59.0 MW	Civilian	2018
	Raisan-3 & 4	80.0 MW	Civilian	2017



Remarks: M/P: Master Plan, R/S: Reconnaissance Study, F/S: Feasibility Study, D/D: Detailed Design

Figure 5.4-1 Implementation and Construction Schedule of Promising Potential Sites

*Concerning geothermal development sites, IPP development has already been decided for Sarulla-1 (330 MW) and Sarulla-2 (110 MW) and they are not targeted by the Study, however, they are shown here for reference.

Table 5.4-2 Outline of Possible Development Options

Plan	Type	Location	Grid Interconnection
Sarulla-2	Geothermal	North Sumatra Province Tarutung outskirts	Connect to Sarulla S/S via a 275 kV T/L (new installation 16 km). Supply to the newly installed 275 kV transmission system.
Kuala Tanjung outskirts	Coal / Gas thermal	North Sumatra Province Kuala Tanjung outskirts	Connect to Kuala Tanjung S/S via a 150 kV T/L (new installation 10 km). Supply to the existing grid or the INALUM smelting plant.
Belawan Rehabilitation	Gas thermal	North Sumatra Province Belawan	Use the 150 kV T/L being used for Belawan thermal power plant.
Toru-1	Hydropower	North Sumatra Province Tarutung outskirts	Connect to Sarulla S/S via a 275 kV T/L (new installation 15 km). Supply to the newly installed 275 kV transmission system.
Simanggo-2	Hydropower	North Sumatra Province South of lake Toba	Connect to Tele S/S via a 150 kV T/L (new installation 35 km). Supply to the newly installed 150 kV transmission system.
Raisan-3 & 4	Hydropower	North Sumatra Province Sibolga outskirts	Connect to Sibolga S/S via a 150 kV T/L (new installation 10 km). Supply to the existing 150 kV transmission system.

Figure 5.4-2 Location Map of Potential Development Options

5.5 Environmental Study

5.5.1 Forest Protection Areas in Indonesia

Based on Forest Law No. 41/1999, the Ministry of Forestry classifies forests into the following three types according to functions, and it conducts protection and management of each type.

- Conservation forest
- Protection forest
- Production forest

Of these, land utilization is not permitted in conservation forest (see section 6.6 Environmental Legislation for details), and a lot of adjustment needs to be performed in order to develop power facilities. As a result, development in such areas is practically impossible. As for protection forests, development can be carried out upon implementing an EIA and obtaining authorization from the Ministry of Forestry.
Figure 5.5-1 and Figure 5.5-2 show the forest protection classifications in Aceh Province and North Sumatra Province as of 2009. The forest classifications contained in these figures are as follows; the purple areas indicate conservation forests.

: Natural Sanctuary and Natural Conservation Land	Conservation Forest
: Protection Forest	Protection Forest
: Limited Production Forest	Production Forest
: Production Forest	
: Convertible Production Forest	
: Other Use Area	

5.5.2 Location of Promising Sites

Upon projecting promising development sites on Figure 5.5-2, the following forest protection classifications are shown and it can be seen that conservation forests are avoided.

(1) Promising coal and gas development sites

When planning coal-fired and gas-fired thermal power plants along the coast close to the INALUM aluminum smelting plant, it should be noted that the coast around Kuara Tanjung is within the range of production forest.

(2) Promising geothermal development sites

- Sarulla : This is located within a production forest

(3) Promising hydropower development sites

- Toru-1 : This is located within a production forest
- Simanggo-2 : This is not designated within a forest protection area.
- Wampu : The F/S that was implemented in 1992 found that parts of the access road and transmission line encroached conservation forest, however, the plan has since been changed to affect a protection forest. It will be essential to implement an EIA before the project.
- Raisan-3 & 4 : Since these are situated in a protection forest, it will be essential to implement an EIA before the project.

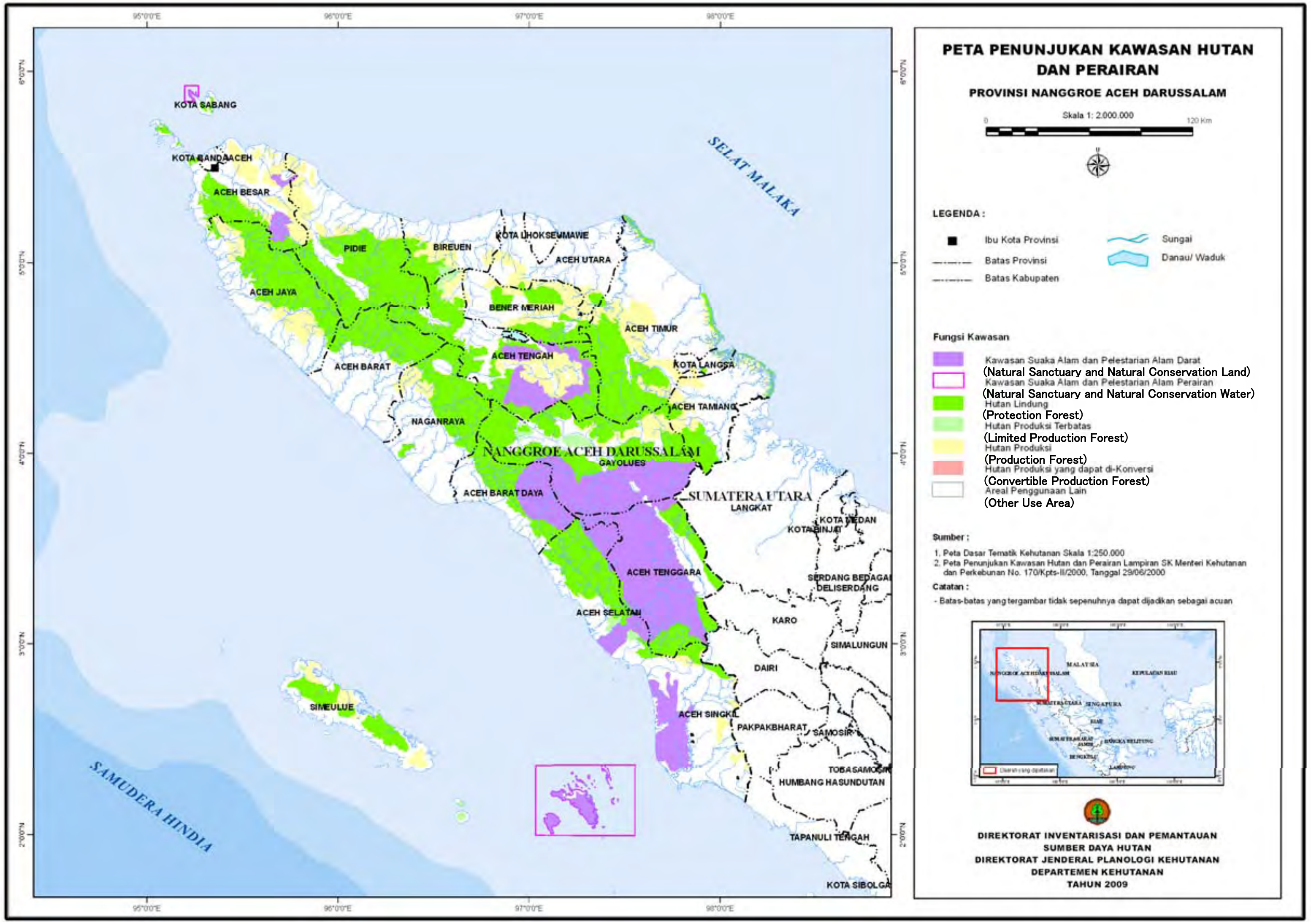


Figure 5.5-1 Map for forest protection classifications of Nangroe Aceh Darusalam Source: Ministry of Forestry

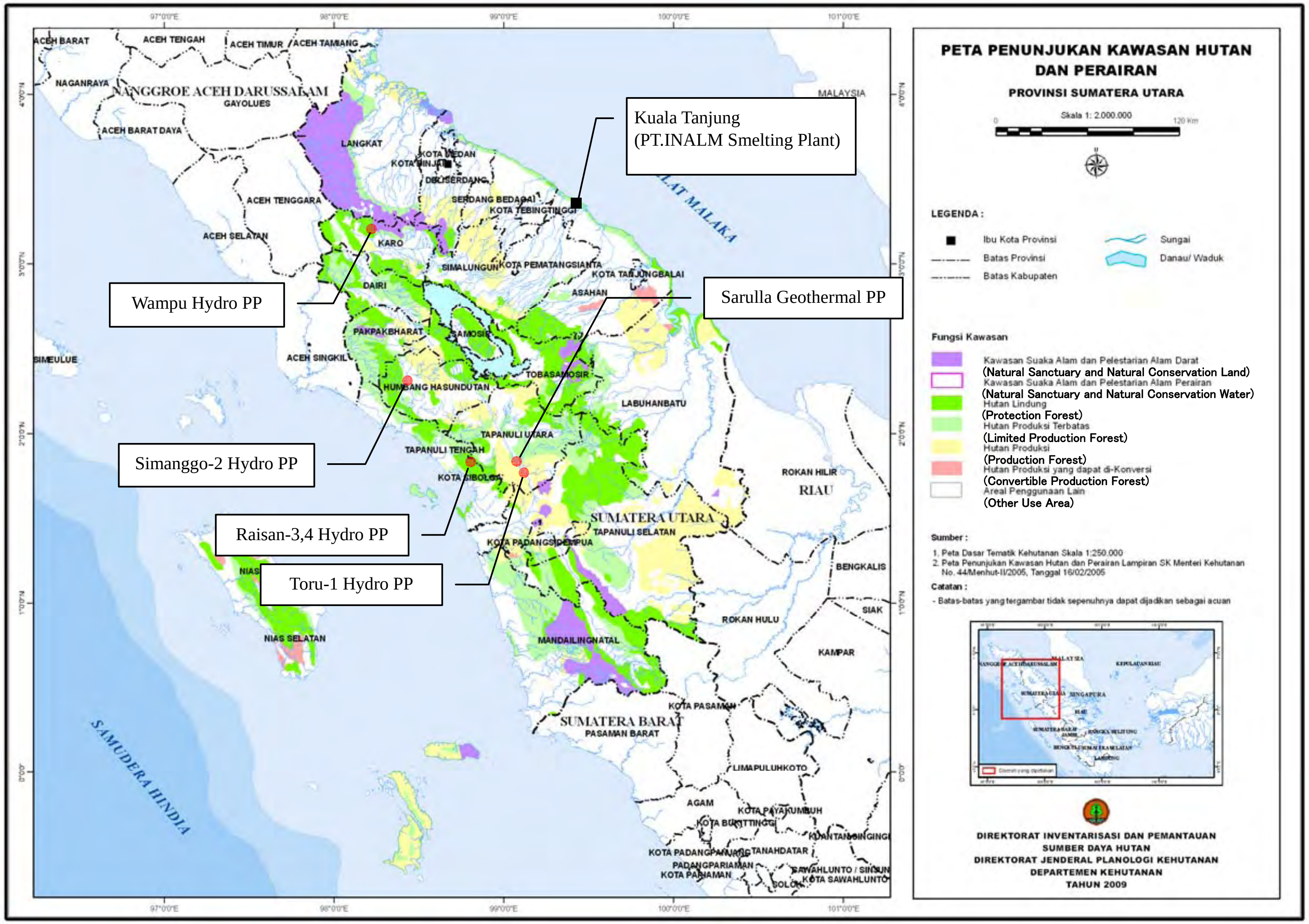


Figure 5.5-2 Map for forest protection classifications of North Sumatra Province

Source: Ministry of Forestry

Chapter 6 Confirmation of Systems concerning Power Resources Development and Power Plant Construction

6.1 Outline of the Legal Framework and Main Legal Systems in Power Resources Development

Legislation in Indonesia constitutes the following kind of hierarchy based on the Constitution and the Law concerning Legal Provisions (No.10/2004). The practical order of priority is as follows:
Law → Government Decree → Presidential Regulation/Presidential Decree → Presidential Instruction → Regional Regulation.

Table 6.1-1 Legal Framework in Indonesia

Order	Acts in English (Indonesian)
1	1945 Constitution (UUD1945)
2	People's Consultative Resolution (Ketetapan MPR)
3	Law (Undang Undang)
4	Government Regulation Substituting a Law (PP pengganiti UU/Perupu)
5	Government Regulation (Peraturan Pumerintah)
6	Presidential Regulation (Keputusan Presiden/Perpres) Presidential Decree (Keputusan Presiden/Inpres)
7	Presidential Instruction (Instruksi Presiden/Inpres)
8	Ministerial Decree (Keputusan Menteri/KepMen)
9	Regional Regulation (Peraturan Daerah/Perda)

Bearing in mind this hierarchy, Table 6.1-2 shows the system of legislation relating to power resources development.

Table 6.1-2 List of Legislation concerning Power Resources Development

Field	Name	Classification	Outline
Energy policy	Law No.5/2006	Presidential Regulation/ Presidential Decree	Presidential Decree on National Energy Policy The target primary energy mix in 2025 will be as follows: coal 33% or more, geothermal energy 5% or more, renewable energies comprising hydropower, biomass and nuclear power, etc. 5% or more.
	Law No.30/2007	Law	This was declared as the Energy Law. It prescribed about energy management based on energy policy.
Electricity	Law No.15/1985 (Former Electric Power Law)	Law	Law concerning Electric Power This electric power law was targeted by the government for revision in 2002, however, this was declared

Field	Name	Classification	Outline
			unconstitutional by a court of law in 2004. This law was annulled in line with enactment of the New Electric Power Law (Law No.30/2009).
	Law No.30/2009 (New Electric Power Law)	Law	This basically succeeds Law No.15 of 1989 but it also reflects decentralization policy. Revision of RUKN and electricity tariffs require Diet approval (provincial assemblies in the case of provincially settled tariffs). The detailed method for setting electricity tariffs is stipulated in government regulations (however, since no new government regulation is currently issued, the government regulations based on the old law remain effective). Table 6.2-1 shows a comparison between the old and new electric power laws.
	Government Regulation (No.10/1989)	Government Regulation	Power supply and use are implemented based on RUKN. The power supply utility is basically implemented by the state.
	Government Regulation (No.25/1999)	Government Regulation	This is the government regulation concerning the electric power support businesses.
	Government Regulation (No.53/2003)	Government Regulation	This is the law concerning establishment of the Electric Power Market Supervisory Board
	Government Regulation (No.3/2005)	Government Regulation	This is the government regulation pertaining to revision of the Government Regulation on Power Supply and Use (No.10/2009). <Revision contents> 1. Authority of the minister 2. Compilation of RUKN 3. Top priority of renewable energy 4. Roles of the central government and provincial governments 5. Organizations, etc. able to become holders of power business authorization for the public benefit 6. Use of transmission networks for the public good 7. General tender or direct designation for purchase of power and lease of transmission networks 8. Decision of power sale prices to customers
	Government Regulation (No.26/2006)	Government Regulation	This is the second revision to the Government Regulation on Power Supply and Use (No.10/2009). <Revision contents> Reduce electric power production costs through diversifying energy sources from petroleum fuel to

Field	Name	Classification	Outline
			non-petroleum fuel. 1.Procurement of electric power energy resources based on directly selected non-petroleum fuel, and purchase of electric power from additional power plant capacity in same areas based on direct designation 2.Use of rupiah or foreign currency in power sale prices
	2006 Law Nos.71, 72, 86	Presidential Regulation / Presidential Decree	Series of Presidential Decrees concerning PLN duties for accelerating the development of coal-fired power plants (Crash Program)
	Second Crash Program Presidential Decree (No. 4/2010)	Presidential Regulation / Presidential Decree	Program for improving the tight electric power demand and supply situation. The amount of power resources development is 10,000 MW, which is the same as in the First Crash Program. (For details, see Tables 6.2-3, 6.2-4).
	Ministerial Decree on Energy and Mining Resources (No.9/2005)	Ministerial Decree	Ministerial Decree on electric power purchasing and transmission network leasing Ministerial Decree on power purchasing in the power supply utility for the public benefit and/or the Ministerial Decree on Energy and Mining Resources concerning the transmission network leasing procedure
	Ministerial Decree on Energy and Mining Resources (No.10/2005)	Ministerial Decree	Ministerial Decree on authorization procedures for power utilities between provinces or in connection with the national transmission network
	Ministerial Decree on Energy and Mining Resources (No.1/2006)	Ministerial Decree	Ministerial Decree on electric power purchasing and transmission network leasing This clarifies No.9 of 2005 (03-04) and re-established the procedures for electric power purchasing and transmission network leasing
	Ministerial Decree on Energy and Mining Resources (No.4/2007)	Ministerial Decree	Revised Ministerial Decree on electric power purchasing and transmission network leasing Revision to No.1 of 2006 (03-07) (addition of ‘Direct selection’)
	Ministerial Decree on Energy and Mining Resources (No.7/2010)	Ministerial Decree	Ministerial Decree prescribing the basic electricity tariff
Coal	Regulations on the Directorate General of Electricity and Energy Utilization (No.751-12)		Regulations concerning the use of Indonesian products and services in construction of coal-fired thermal power generation with connected capacity of up to 8 MW per unit
	National Coal Policy		Enacted in January 2004, this aims to stabilize domestic coal supply, increase the added value of coal utilization and increase coal exports.

Field	Name	Classification	Outline
	Law No.17/2008	Law	Indonesian Maritime Law This stipulates coastal navigation rights and the principle of priority for Indonesian shipping.
	Law No.4/2009: Minerals and Coal Mining Law	Law	Since this received Presidential approval in January 2009, it is likely to go into effect from 2010. Transfer to a system of business authorization by local governments. Abolition of the CCOW (coal contract of work) scheme based on contracts with the central government within 1 year. Obligation to convert foreign currency into local capital in 5 years.
	(Draft) Government Regulation on the Domestic Coal Supply Obligation and Domestic Coal Price Policy		This made it compulsory for coal producers to supply a certain percentage of production to the domestic market, with prices determined in reference to various price indicators (this is current being refined as a government regulation).
Renewable energy including geothermal energy	Presidential Regulation / Presidential Decree No. 45/1991, No.49/1991	Presidential Regulation / Presidential Decree	This made it possible for private sector geothermal energy operators to take part in the utility and reduced the tax rate on geothermal energy development from 46% to 34%.
	Law No.27/2003	Law	This law on geothermal energy established provisions concerning geothermal energy development. Under this law, the tax rate of 34% was revised to comply with regular tax legislation prescribed by central authorities and the government.
	Ministerial Decree on Energy and Mining Resources (No.0002/2004)	Ministerial Decree	This is the Government Regulation on renewable energy. It covers development of new energies (biomass, geothermal energy, photovoltaic energy, hydropower, wind power, ocean energy, etc.) and energy conservation.
	Promulgated in June 2004		Following on from the Geothermal Energy Law, this proclaimed the 'Geothermal Roadmap' stipulating targets for geothermal development from 2004 to 2020.
	Ministerial Decree on Energy and Mining Resources No.2/2006	Ministerial Decree	This prescribes the sale price of electric power in medium-scale renewable energy generation utilities.
	Government Regulation on Geothermal Energy and Mining (No.59/2007)	Government Regulation	Government Regulation No.59 of 2007 – promulgated based on the Geothermal Energy Law of 2003
	Ministerial Decree on Energy and Mining Resources No.14, No. 269/2008	Ministerial Decree	This stipulates that the standard unit price for sale of geothermal energy should be 80~85% of the power generating cost in surrounding areas.
	Ministerial Decree on Energy and Mining Resources No.5/2009	Ministerial Decree	Under the above Ministerial Decree No.269/2008, the government decided the purchase price of power generated by operators based on the PLN supply

Field	Name	Classification	Outline
			cost (80~85% of the unit price), however, this was annulled under this Ministerial Decree, which gave PLN the authority to decide price without having to show the method of calculation.
Environment-related	Presidential Decree Nos. 36 and No.65/2005	Presidential Regulation / Presidential Decree	Presidential Decree concerning Land Acquisition and Resident Relocation
	Law No. 4/1982	Law	Enactment of the Basic Law on Environmental Management
	Government Regulation No.27/1999	Government Regulation	The Government Regulation concerning the environmental assessment system, this establishes stipulations on AMDAL.
	Environmental Ministerial Decree No.11/2000, No.17/2001	Ministerial Decree	This prescribes about the content and scale of activities for which submission of AMDAL is required, and about the competent ministries.
	Environmental Ministerial Decree No.86/2002	Ministerial Decree	This prescribes the environmental management activities that are required in business sectors where AMDAL implementation is not compulsory.
	Law No.41/1999	Law	The Forest Law, this prescribes forest classifications.
Investment and business operation-related	Government Regulation No.20/1994	Government Regulation	Government Regulation concerning joint ownership between foreign affiliated enterprises and Indonesian society.
	Law No.1/1995	Law	Law concerning company establishment
	Law No.22/1999	Law	This is the local government law, prescribing about decentralization and local government. It stipulates local authority concerning natural resources.
	Law No.25/1999	Law	This is the Central and Local Government Balanced Budget Law, prescribing fiscal apportionment between central and local governments. This was issued at the same time as the above Law No. 22.
	Law Nos.16~20/2000	Law	This stipulates about tax deductions on overseas investment.
	No.29/2004	Presidential Regulation / Presidential Decree	This implements a one-roof service for investment authorization.
	Government Regulation (No.1/2007)	Government Regulation	Enactment of ‘Preferential tax measures on investment.’ After this, the scope of sectors eligible for preferential measures was expanded to include geothermal energy generation under Government Regulation No.62 of 2008.
	Law No.25/2007	Law	The new Investment law, this summarized conventional legislation on domestic and foreign investment with a view to aiding national economic reconstruction based on promoting

Field	Name	Classification	Outline
			foreign investment.
	Government Regulation (No.36/2008)	Government Regulation	This lowered the maximum income tax rate to 25%.
	No.76 and No. 77/2007	Presidential Regulation / Presidential Decree	This stipulated that foreign investment in power generation, transmission and distribution could be increased to a maximum of 95%.
	No.41/2008	Industry Ministerial Decree	Procedures concerning licensing and expansion of all industrial enterprises with total assets of 200 million rupiah.
Petroleum and gas	New Petroleum and Gas Law (No.22/2001)	Law	Through separating the functions and liberating the petroleum and gas sectors, this dissolved the monopoly of Pertamina and introduced competition into these sectors. A reviewed bill is currently being prepared.
	Government Regulation (No.42/2002)	Government Regulation	Government Regulation concerning establishment of an executive agency in petroleum and gas upstream sectors.
	Government Regulation (No.67/2002)	Government Regulation	Government Regulation concerning establishment of an executive agency in petroleum and gas downstream sectors.
	Government Regulation (No.31/2003)	Government Regulation	Government Regulation concerning privatization of the State Oil and Natural Gas Company
	Government Regulation (No.35/2004)	Government Regulation	- Government Regulation concerning the petroleum and gas upstream sectors - This granted 10% of participation right profits to local public corporations. - It made it compulsory to supply 25% of production to domestic demand (Article 146).
	Government Regulation (No.36/2004)	Government Regulation	- Government Regulation concerning the petroleum and gas downstream sectors - The government will decide the price for supply to households and small-scale consumers. Other prices will be determined by the market competition mechanism.
	Ministerial Decree on Energy and Mining Resources No.1321K/20/MEM/2005	Ministerial Decree	National Gas Transmission and Distribution Network Master Plan

Presidential Decree No.5 of 2006 and its pursuant Law No.30 of 2007 (the so-called ‘Energy Law’) provide the supreme guidelines for energy policy. The Presidential Decree raised the following target primary energy mix in 2025 as the objective for stable domestic energy supply and sustainable development: coal 33% or more, geothermal energy 5% or more, and renewable energies comprising hydropower, biomass and nuclear power, etc. 5% or more. As the organization for implementing and managing this energy policy, the Energy Law stipulated establishment of the National Energy Council in charge of the National Energy Master Plan. Whereas national energy policy will be planned and compiled in the National Energy Council, local governments will be responsible for compiling local energy policies while referring to the National Energy Policy.

6.2 Legal Systems in the Electric Power Field

6.2.1 New Electricity Law

The electric utility in Indonesia was for many years regulated under the electricity law of 1985, according to which PLN basically gave exclusive responsibility for electricity supply to the power utility license holder (PKUK). However, realizing that public funding could only go so far in satisfying the growing demand for electricity, the Government enacted Presidential Decree No.37 of 1992, under which market entry by IPPs was recognized and private sector enterprises were allowed to become power supply license holders (PIUKU).

In order to encourage electric power policy with emphasis on market economic principles, a new electricity law promoting utility reforms was enacted in 2002; however, the Constitutional Court of Indonesia in 2004 declared this unconstitutional, stating that electricity supply should be operated and managed by the state as it directly impacts national welfare. In effect, this verdict revalidated the electricity law of 1985 (although contracts signed with the government based on the new law of 2002 remained effective). Responding to this situation, the Government issued Government Regulation No.3 in 2005, in which it aimed to avert confusion through stipulating the conditions regarding private sector participation in the power sector. Furthermore, in 2005, it passed Ministerial Decrees 9 and 10 concerning the purchase of electricity and leasing of transmission line systems.

In September 2009, the New Electricity Law was passed with the objective of averting confusion of the sort described above. Features of the New Electricity Law are described below, while Table 6.2-1 shows a comparison of the old and new Electricity Laws.

- The new law basically imitates the electricity law of 1985 (Law No.15/1985), although it also incorporates aspects of the 2002 electricity law (Law No.20/2002) concerning decentralization.
-
- It has become necessary to obtain diet approval (local assembly approval in the case of local decisions) concerning revisions to the General National Power Plan (RUKN) and electricity tariffs.

- The detailed method (and other items) concerning the setting of electricity tariffs will be prescribed in future government regulations.

Table 6.2-1 Comparison of the Old and New Electricity Laws

Category	Electricity Law (No.15/1985)	New Electricity Law (No.30/2009)
Power development planning	The central government compiles the General National Power Plan (RUKN)	The central government compiles RUKN (with approval by the national diet). Local governments compile local general power plans (RUKD).
Business responsibility	PLN is implemented under the management of the central government.	Division of responsibilities by the central government and local governments under jurisdiction of the central government
Business licensing	National government authorization	National government authorization However, authorization by local governments in cases where businesses do not span multiple provinces or regencies
Business implementation	Implementation by PLN, cooperative associations on some independent networks, etc.	PLN, public enterprises, private sector, cooperative associations, civic groups. However, priority is given to PLN utilities.
Electricity tariffs	Uniform rates across the country Presidential authorization	Central government (national diet approval is required). However, local governments establish local tariffs with local assembly approval in cases where businesses do not span multiple provinces or regencies.

6.2.2 Classification of Electric Utility Operators

Electric utility operators are classified as follows under the present legal system.

- Electric utility authorized operators assessment (PIUKU)
  This refers to operators prescribed by Government Regulation to conduct electric power business for the public benefit and specifically refers to PLN.

- Electric utility license holders (PKUK)
  License holders receive authorization to conduct general electricity supply business and to supply electricity for the public benefit. They include IPPs by public enterprises, cooperative associations and private enterprises.

- Specific supply electric utility license holders
  These are operators who acquire authorization to supply electricity to specific

consumers, and they supply to limited areas (in-fencing of industrial estates, etc: captive power).

- ♦ Privately generated power utility license holders
  These are operators who have acquired authorization concerning establishment of electric power facilities for private purposes.

6.2.3 Electricity Tariffs

When supply utilities span across provinces and regencies or cities (area of the PLN national transmission grid), electricity tariffs are fixed at a uniform level based on national diet approval. The current electricity tariff system was prescribed under MEMR Ministerial Decree No.7/2010 (revised in July 2010, when the average tariff was increased by approximately 15%). Out of the electricity tariff, the specific rate (consumption charge) is 605 Rp/kWh (approximately 7cent/kWh) for major consumers and high voltage consumers and is a uniform rate in areas covered by the national transmission grid. In the event where INALUM purchases power from PLN, it must abide by this tariff scheme. Table 6.2-2 shows the estimated tariffs in this case. Moreover, PLN received approximately 680 billion yen in subsidies from the national government in 2010 (according to the PLN management plan), and MEMR intends to continue revising tariffs with a view to reducing subsidies. Table 6.2-3 shows the planned electricity tariffs indicated in RUPTL 2010.

Table 6.2-2 Tariffs in the Case where Power for INALUM Plant Expansion Purchased from PLN

Item	Demand Charge	Consumption Charge	Remarks
Group I-4/TT	24,200 (Rp/kVA/Month)	605 (Rp/kWh)	The demand charge shows the case for industrial power supply.
Power for INALUM plant expansion	150,000 kVA	86,400,000 kWh/Month	Plant power factor: 1.0 Operating rate: 80%
Monthly electricity tariff (Rp/month)	24,200 x 150,000 = 3,630,000,000	86,400,000 x 605 = 52,272,000,000	
Monthly total (Rp/month)	55,902,000,000		
Monthly total (US$/month)	6,352,500		1 USD ＝ 8,800Rp
Mean unit rate of power purchase	647 (Rp/kWh)		= 55,902,000,000/86,400,000
	7.35 (¢/kWh)		= 6,352,500/86,400,000

Source: Basic Electricity Tariff 2010 based on MEMR Ministerial Decree No.07/2010

Table 6.2-3 Future Movements in Electricity Tariffs

Fiscal year		2010	2011	2012	2013	2014	2015
Government subsidies (trillion Rp)		68.0	52.1	43.3	40.3	40.2	44.7
Mean power tariff (Rp/kWh)		703	805	885	910	935	960
Inflation rate		100	115	126	129	133	137
Supply price (Rp/kWh)		1,187	1,145	1,111	1,088	1,078	1,103
Difference (Rp/kWh)	(Rp/kWh)	484	340	226	178	143	143
	(¢ /KWh)*	5.50	3.86	2.56	2.02	1.65	1.65

Source: RUPTL 2010 *:1US$=8,800Rp

6.2.4 Leasing of Transmission Lines

The New Electricity Law will remain valid until existing Government Regulations are revised; and concerning the leasing of transmission lines, Government Regulations 2005/3 and 2006/26 will apply. Article 11 in Government Regulations 2005/3 and 2006/26 stipulates the obligation to lease PLN transmission lines, however, it is currently almost practically impossible to lease transmission lines for the following reasons and there have been no such cases so far.

- The government is in charge of prescribing detailed provisions concerning leasing[1], however, no technical or economical examination has so far been implemented and the matter has been shelved with no immediate prospect of enactment.

- Concerning lease charges[2], since these are also included within the scope of the above detailed provisions, nothing has so far been decided. Even if an SPC develops a power plant as a power source for INALUM, in the absence of any detailed provisions concerning the leasing of transmission lines, it is not possible to lease PLN transmission lines. Accordingly, the only options would be to install dedicated transmission lines or to sell power to PLN and purchase according to the tariff scheme of that operator.

[1] These provisions are equivalent to the Japanese Ministry of Economy, Trade and Industry Ministerial Ordinance "General electric utility consigned supply stipulations, tariff calculation rules," issued December 1999, final revision March 2010 (59 pages in total)
[2] The consigned tariff of a certain power company in Japan is approximately 2.3 yen/kWh for special high voltage demand (7 MW or higher).

6.2.5 Crash Program

Based on Presidential Decree No.71 of 2006, development of coal-fired power plants with capacity of around 10,000 MW was consigned to PLN in order to improve the fuel mix and satisfy the nationwide demand for power (the First Crash Program). The First Crash Program is eight months behind schedule on average in Java-Bali, and the delays are even longer than this in other areas. The delays are mainly due to a lack of finance and difficulties in construction.

The Second Crash Program, which was officially announced with the enactment of Presidential Decree No.4 of 2010 on January 8, 2010, will entail consigning the acceleration of power resource development based on renewable energy, coal and gas to PLN. The Second Crash Program aims to make further use of renewable energy, especially geothermal energy. However, considering that the supply and demand balance and preparations for geothermal energy projects are not fully prepared yet, it is planned to develop 3,967 MW of geothermal energy by 2014 in the Second Crash Program. With this amount of geothermal energy development already planned, PLN has decided to postpone a number of coal-fired thermal power development projects that were planned under RUPTL in an effort to maintain the reserve margin at a reasonable level[3].

Except for a number of WKP[4] sites for which PLN manages the downstream side, IPP will generally conduct geothermal power generation projects as total undertakings (integrating steam and electricity into single projects). The projects that are scheduled to be completed by 2014 are those intended to expand existing WKP and a number of new sites selected by geothermal energy officials. The selection of geothermal energy development sites and decisions on promising sites were conducted based on the "Master Plan Study for Geothermal Energy Development in the Republic of Indonesia" implemented by JICA and the Directorate General of Mineral Coal and Geothermal in 2006-2007. The following table gives a comparison of the first and second crash programs.

[3] The reserve margin in Sumatra is planned as 40% or higher to correspond with PLTP projects.
[4] WKP= Mine working area

Table 6.2-4 Comparison of the First and Second Crash Programs

Category	First Crash Program	Second Crash Program
Development planning years	2006-2009	2010-2014
Development mode	100% PLN	PLN: 50.4% IPP: 49.6%
Amount of power resources development	Approximately 10 GW	Approximately 10 GW
Objectives (background)	Urgent power resource development (centering on Java-Bali) Policy to break away from oil dependence	Urgent power resource development Diversification of power resources Introduction of renewable energy
Types of power resources	Coal 100％	Renewable energy: 51% Fossil fuels (gas, coal): 49%
Legal basis	Presidential Regulation / Presidential Decree (No.71/2006)	Presidential Regulation / Presidential Decree (No.4/2010)
Required funds for development	Power resources: 8 billion USD	Power resources: 16 billion USD Transmission: 400 million USD

Table 6.2-5 Mix of Power Resources in the Second Crash Program

Category	PLN Related		IPP		Total
	Plant output (MW)	Required funds (million USD)	Plant output (MW)	Required funds (million USD)	Plant output (MW)
Hydropower	1,174 (174)	923 (261)	30 (0)	45 (0)	1,204 (174)
Combined	1,200	1,020	360	360	1,506
Geothermal energy	880 (0)	1,343 (0)	3,097 (550)	7,212 (1,254)	3,977 (550)
Steam	1,764 (400)	2,567 (520)	1,548 (0)	2,240 (0	3,312 (400)
Gas	100	50			100
Total	5,118	5,903	5,035	10,057	10,153

(Note) Figures in parentheses indicate planned values for the North Sumatra area alone.

6.3 Legislation related to Geothermal Power Generation

6.3.1 Related Laws and Regulations

Laws and systems concerning geothermal energy development date back to when geothermal utilization was stipulated as a national objective in the National Energy Policy of 2002. Following that, the Geothermal Energy Law of 2003 became the basic legislation, stipulating the methods for deciding geothermal power development targets, setting geothermal development areas and granting licenses, setting development periods and establishing the systems for determining unit rates for sale of power derived from geothermal energy.

(1) Geothermal Energy Law (Law No.27 of 2003)

The Geothermal Energy Law aims to vigorously utilize abundant reserves of renewable geothermal energy, and thereby to contribute to the sustainable development of society in Indonesia. The law covers the setting and limitation of working areas (WKP) based on open bidding, procedure concerning the Geothermal Energy Business Permit (IUP) and the determination of geothermal development areas based on tender.

- The national government (Ministry of Energy and Mining Resources) is responsible for setting geothermal development working areas (WKP).

- Contents regarding IUP include the setting of the development term as three years for exploration (with possible extension of two years), the feasibility study term as two years and the exploitation phase as 30 years (with possible extension). The law also includes obligatory relinquishment (in cases where exploitation is not commenced within two years from the end of exploration) and provisions concerning the development plan application system and revision orders by the supervisory government agency.

An important item within the law is in Article 10, paragraph 1, which classifies geothermal development activity into the five phases of preliminary survey, exploration, project feasibility study (FS), exploitation and utilization. Concerning the preliminary survey, paragraph 2 states that ‘the state and provincial governments must implement preliminary surveys according to their respective authorities.”

(2) Road Map (Road Map Development Planning of Geothermal Energy for 2004-2020)

In response to the National Energy Plan and Geothermal Energy Law, the Road Map Development Planning of Geothermal Energy for 2004-2020, which was compiled in June 2004, establishes a geothermal development target of 6,000 MW by 2020 and indicates the guidelines for achieving that target. By 2025, it is intended to achieve an even higher target of 9,500 MW of geothermal power.

(3) Government Regulation No.59 of 2007 concerning geothermal business activities based on the Geothermal Energy Law

This Government Regulation stipulates the detailed procedures concerning the setting, tender and development activity of geothermal development areas (denoted as Work Sites on the Japanese government side).

6.3.2 Problems confronting Geothermal Energy Development

The above legislation is intended to promote and secure the fairness of geothermal energy development, however, in reality development is stagnating due to the following kind of problems.

- In terms of the system, preliminary surveys can be implemented by the central and local governments, however, the private sector is expected to provide funding. As a result, survey work isn't necessarily connected to exploitation rights and income.

- When bidding for working areas, bidders must present steam or electricity sale prices, however, this entails great risk before exploration and F/S implementation.

- The IPU (Geothermal Energy Survey Permit) is not granted until after the bidding for working areas, however, drilling of exploratory wells cannot be performed without an IPU. Accordingly, bidders must tender for work areas based only on ground surveys, meaning that no technical basis for presenting power sale prices based only on ground survey can be obtained (an economic basis can be given but the resulting prices are extremely high).

6.4 Coal Development Legislation

The following legislation is currently the subject of the greatest attention concerning coal development: the new Minerals and Coal Mining Law (Law No.4 of 2009), the Government Regulation concerning domestic supply obligation and coal price policy, and the new Marine Transportation Law (Law No.17 of 2008). Since all these laws and regulations have only recently been enacted, Indonesia is currently in the process of shifting to the mining implementation setup; moreover, under the new Marine Transportation Law it is moving to a transportation system based on Indonesian vessels.

Under the New Minerals and Coal Mining Law, the conventional form of contract that was made by the government and mining companies for coal mining activities has been abolished and replaced with a permit/licensing system based on tenders for working districts. As a result, mining permits will now become available to state-owned enterprises, local public enterprises, private enterprises, cooperative associations and even individuals. The new law was enacted following approval in January 2009. The government is advancing a regime of government regulations geared to realizing its ‘self-sufficiency obligation and coal price policy’ with a view to securing coal supply from power plants to cement and pulp plants within Indonesia in order to give priority to domestic economic activities and welfare. Accordingly, coal supply to domestic coal-fired thermal power plants will be secured as a matter of policy.
The Mineral and Coal Mining Law (Law No.4/2009) clearly stipulates the obligation to conduct domestic supply. The provisions related to this principle are as follows.

- ♦ Chapter 2 Basic Principles and Objectives
  - ・ Article 3 c. Supply of minerals and coal shall be guaranteed as raw materials and energy resources for domestic demand

- ♦ Chapter 3 Utilization of Minerals and Coal
  - ・ Article 4 (1) The non-renewable natural resources that are minerals and coal are national assets that should be controlled by the state for the maximum well-being of citizens

  - ・ The state control of minerals and coal mentioned in paragraph (1) shall be executed by the central government or local governments

  - ・ Article 5 (1) For the national benefit, the government can compile policies that give top priority to the national benefit concerning minerals and coal upon holding discussions with the People's Consultative Assembly

- The national benefit described in item (2) paragraph (1) can be executed through control of production and exports

- In executing the control stated in item (2), the government shall possess the authority to decide annual production of each mineral type in each province

- Local governments must comply with the quotas stipulated by the government as described in (3)

- Details will be stipulated in separate government regulations.

Accordingly, the New Mineral and Coal Mining Law clearly stipulates domestic market obligations, while government regulations set out the details regarding implementation. Since the domestic market obligations target supply to all coal-fired power plants, cement plants and pulp plants, etc., this legislation provides a clear and definite basis for securing fuel supply in cases when considering the construction of new coal-fired power plants in Indonesia.

6.5 Natural Gas-related Legislation

Legislation pertaining to natural gas utilization comprises the new Petroleum and Natural Gas Law (Law No.22/2001). Through separating functions of the petroleum and natural gas sectors, the new law dissolved the monopoly of Pertamina and introduced competitive principles to the sectors. Gas drilling is carried out under government control, however, in addition to state-owned enterprises, business participation is open to local public enterprises, cooperative associations and private sector enterprises. Concerning gas utilization, priority is given to domestic use, however, it is also an important source of national revenue.

6.6 Environment-related Legal Systems

Whether development targets coal, geothermal or hydropower resources, it is necessary to implement surveys from the aspects of natural and social environment. The need for environmental impact assessment AMDAL was first raised in Government Regulation No.51/1993 and officially established under Government Regulation No.27/1999. According to this legislation, depending on the scope of business activities, supervision is carried out by cities or regencies, by provinces if activities span multiple cities and regencies, and by the central government if activities span multiple provinces. Concerning the sectors and scale of business activities targeted by AMDAL, Ministry of Environment Ministerial Ordinance No. 17/2001 prescribed 14 fields and 84 sectors requiring the preparation of environmental impact assessment (AMDAL), environmental management plan (RKL) and environmental monitoring plan (RPL). Moreover, even in sectors where AMDAL is not applicable, Government Regulation No.27/1999 requires submission of an environmental management activity UKL and environmental monitoring activity UPL. Tables 6.3-1 and 6.3-2 show the fields that are subject to AMDAL as well as the supervisory agencies relating to the Study work.

Table 6.6-1 Fields Subject to AMDAL

(Provided by Ministry Decree No.17/MENLH/02/2001)

No.	ACTIVITIES	SCALE/AREA
Ⅰ.MINING AND ENERGY SECTOR		
A.	General Mining	
1	License area	>= 5,000 ha and/or
	Open mining area	>= 100 ha(cumulative/year)* and/or
2	Production and exploitation phases	
	a. Coal	>= 1.200,000ton/year(ROM)
	*To prevent too wide land clearing	
	**Raw materials	
B.	Electricity	
1	Transmission	>= 150KV
2	PLTD/PITG/PLTU/PLTGU	>= 100MW
3	Electric hydro power with dam height/	>= 15m or
	Electric hydro power with puddle area	>= 200ha
4	Geothermal electricity generating stations	>= 55MW
D.	Environmental System Geology	
1	Groundwater exploitation (either shallow or deep soil well)	>= 50 lt./day (from 1 well / or from 5 wells in < 10 ha area for commercial purposes)
Ⅱ.COMMERCE AND INDUSTRIAL SECTOR		
7	Aluminum manufacture	All (Raw Material from Alumina)
Ⅸ.FORESTRY AND PLANTATION SECTOR		
1	Forest concession (HPH)	All
2	Sago forest concession	All
3	Bamboo forest concession	All
4	Industrial forest concession	>= 10,000 ha or with Areas of <= 10,000 ha located just next to the protected area
Ⅹ.PUBLIC WORK		
1	Dam construction	Height >= 15m, or
		Reservoir area >= 200ha
13	Water intake from lake, river, water spring or other water sources	Flow rate >= 500 l/second

Table 6.6-2 Target Facilities of Environmental Impact Assessment and Agencies with Jurisdiction (Ministry of Environment Ministerial DecreeNo.11/2000)

Target facilities	Scale	Agency with jurisdiction
Coal-fired thermal power plant	Output 100 MW or more	Regency or city of location (provinces if activities span multiple cities and regencies, and by the Ministry of Environment if activities span multiple provinces)
Geothermal power plant	Output 55 MW or more; however, if in a protected area, activities with output of less than 55 MW will also be targeted (*1)	Regency or city of location (provinces if activities span multiple cities and regencies, and by the Ministry of Environment if activities span multiple provinces)
Hydropower plant	Dam height 15 m or higher Reservoir area 200 ha or more Output 50 MW or more	Regency or city of location (provinces if activities span multiple cities and regencies, and by the Ministry of Environment if activities span multiple provinces)
Transmission line	Voltage greater than 150 kV	Regency or city of location (provinces if activities span multiple cities and regencies, and by the Ministry of Environment if activities span multiple provinces)

*1: Forest protection area, water resource area, coast, river bank, area around lake, marsh or reservoir, nature protection area, ocean and freshwater protection area, mangrove area, national park, recreation park, cultural site, scientific research area, and area where there is risk of natural disaster

Forest protection is not supervised by the Ministry of Environment, but the Ministry of Forests designates protected areas and manages forests. According to Forest Law No.41/1999, forests in Indonesia are classified into three types according to function, namely 1) conservation forest, 2) protection forest and 3) productive forest. Utilization of forests is permitted except in sanctuary forests and core zones of national parks.

(1) Conservation Forest

Conservation forests are special areas for preserving the diversity of flora and fauna and ecosystems, and they are further divided into the following sub-types. Uses of protection forests are prescribed in separate government regulations, however, use of sanctuary forests and core zones of national parks is not allowed.

(a) Sanctuary forest (natural reserve forest)

- Natural sanctuary forest
- Animal / wild life sanctuary forest

(b) Nature conservation forest

- National park (core zone, utilization zone, others)
- Grand forest park

- Nature tourism park
- Game hunting park

(2) Protection Forest

In terms of protecting the livelihoods and assets of residents, protection forests have the functions of hydrological activity, flood protection, erosion prevention, seawater reverse flow prevention and maintenance of soil fertility. Use of protection forests is limited to environmental services and extraction of non-timber products and is conditional on the acquisition of an operating license.

(3) Productive Forest

Productive forests are endowed with both production and service functions. Use of productive forests extends to environmental services and the extraction and production of timber and non-timber materials and is conditional on the acquisition of an operating license. An important issue in examining social environmental issues is responding to the relocation of residents. The legal system concerning land acquisition and resident relocation was promulgated in Presidential Decree No.36/2005 and No.65/2005. These regulations require that consent be obtained from residents and that compensation be paid in cases of relocation. The law also stipulates preparation of Land Acquisition Resettlement Action Plan (LARAP), which is an essential requirement in order to receive AMDAL approval and loans from international agencies including JBIC.

6.7 Legal System concerning Investment and Business Operation

Assuming the case of business activity based on IPM, the following paragraphs give a simple description of the legal system concerning investment and operation.

(1) New Investment Law

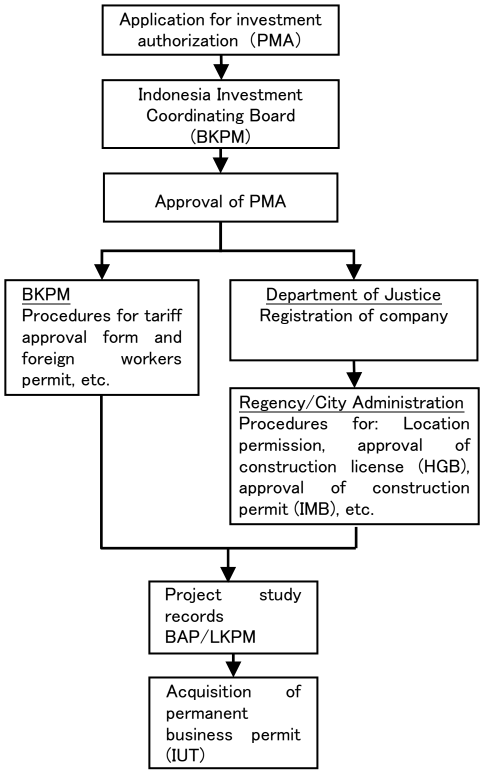
The Foreign Investment Law was enacted in 1967. According to this, enterprises with direct foreign investment were guaranteed operating rights for 30 years, while this guarantee period could be extended by a further 30 years if additional investment were conducted during the initial period. With a view to rebuilding state finances based on promotion of foreign investment, the foreign investment law of 1967, the revised foreign investment law of 1970, the domestic investment law of 1968 and the revised domestic investment law of 1970 were consolidated into the New Investment Law Bill that was approved by the national diet in 2007. Under this law, the period for authorization of investment by foreign enterprises was greatly shortened, and preferential tax measures and licensing procedures in central and local governments were consolidated. According to Presidential Decree No. 29/2004 and the New Investment Law, the Indonesia Investment Coordinating Board (BKPM) was placed in charge of implementing all investment authorization and convenience services. Foreign capital activity in Indonesia has so far almost entirely comprised establishment of local corporate persons based mainly on the procedure shown in the figure. The authorized investment period is 30 years, however, this can be extended by a further 30 years if additional investment is implemented.

(2) Tax Law

Taxation in Indonesia is broadly composed of national taxes, tariffs and local taxes. The main types of national tax are individual and corporate income tax and value added tax. Land and building tax is also a type of national tax. The existing tax system was established following a drastic reform of the system during the 1980s, and the basic principle is payment of taxes based on self declaration. According to Government Regulation No.36/2008, the corporate tax rate was set at three levels according to annual taxable income, i.e. 10% on income less than 50 million rupiah, 15% on income between 50~100 million rupiah, and 25% on income of more than 100 million rupiah. The allowance for depreciation was set at a maximum of 20 years on buildings and construction machinery. The value added tax rate is 10%.

Based on Government Regulation No. 62/2008, preferential tax measures were extended to additional sectors including geothermal power development. The contents of preferential tax measures are as follows.

- Deduction of 30% of the investment amount (5% per year over 6 years) from taxable income.
- Shortening of the depreciation period (1/2)
- Reduction of dividend tax from 20% to 10% for non-residents (is less than 10%, the existing level is retained).



6.8 Legal Issues in Securing Power Resources for INALUM Plant Expansion

The biggest legal obstacle to securing power resources for INALUM plant expansion is that no detailed regulations exist to enable the actual leasing of PLN transmission lines. Even if the power resource development and transmission line construction plans indicated in RUPTL 2010 proceed according to schedule, in reality it will be difficult to lease transmission lines because it is forecast that the North Sumatra Grid will continue to be unstable[5] until 2012. In this case, even if an SPC or IPP developed power resources for INALUM, so long as it used PLN transmission lines, it would have to comply with the electricity tariff regime prescribed by the state irrespective of the generating costs.

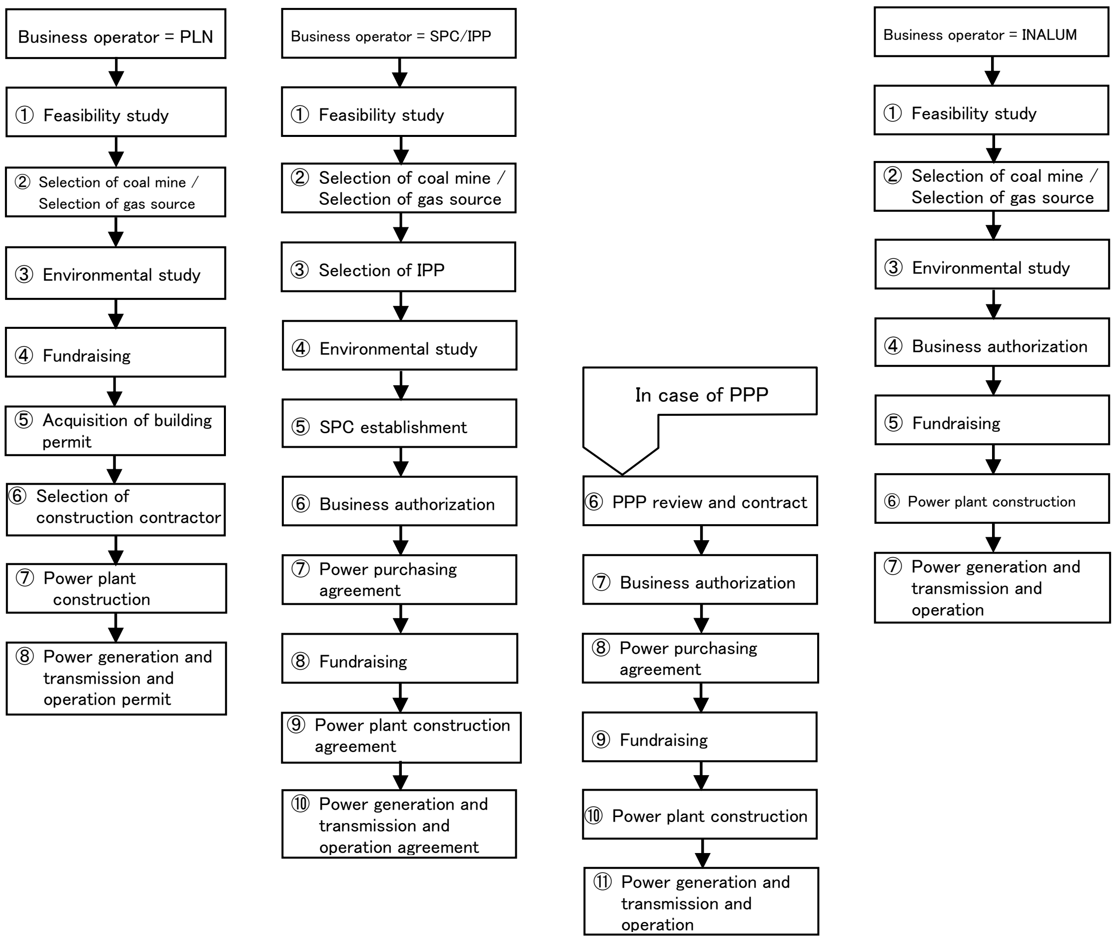
Accordingly, as business models for independently securing power resources for the INALUM plant expansion, options are limited to either having an SPC become a designated supply electric utility license holder (CP) so that it can secure a power resource close to the aluminum smelter and transmit power along dedicated transmission lines, or having INALUM secure power resources as a private generating electric utility license holder. In either case, it is possible to sell excess power to PLN[6], however, it will be necessary to receive backup power supply[7] from PLN in the event where operations at the dedicated plant are interrupted due to breakdown.

[5] Since RUPTL 2010 is expected to be delayed, this grid instability is likely to continue for longer.
[6] In the case of excess power, it is expected that the power price will only be enough to cover fuel expenses and personnel expenses, etc.
[7] In this case, it is necessary to pay the basic charge (routine tariff + additional charge) irrespective of use. Concerning the metered charge too, tariffs will be charged according to the actual power usage (including additional charge). There are no clear stipulations concerning additional charges.

6.9 Legal Procedures in Each Power Resource Mode

6.9.1 Case of Coal/Gas Development

The following figure schematically shows the coal/gas-fired thermal power development procedure and legal requirements according to three types of operator, i.e. PLN, private operator (special purpose company: SPC) or INALUM.



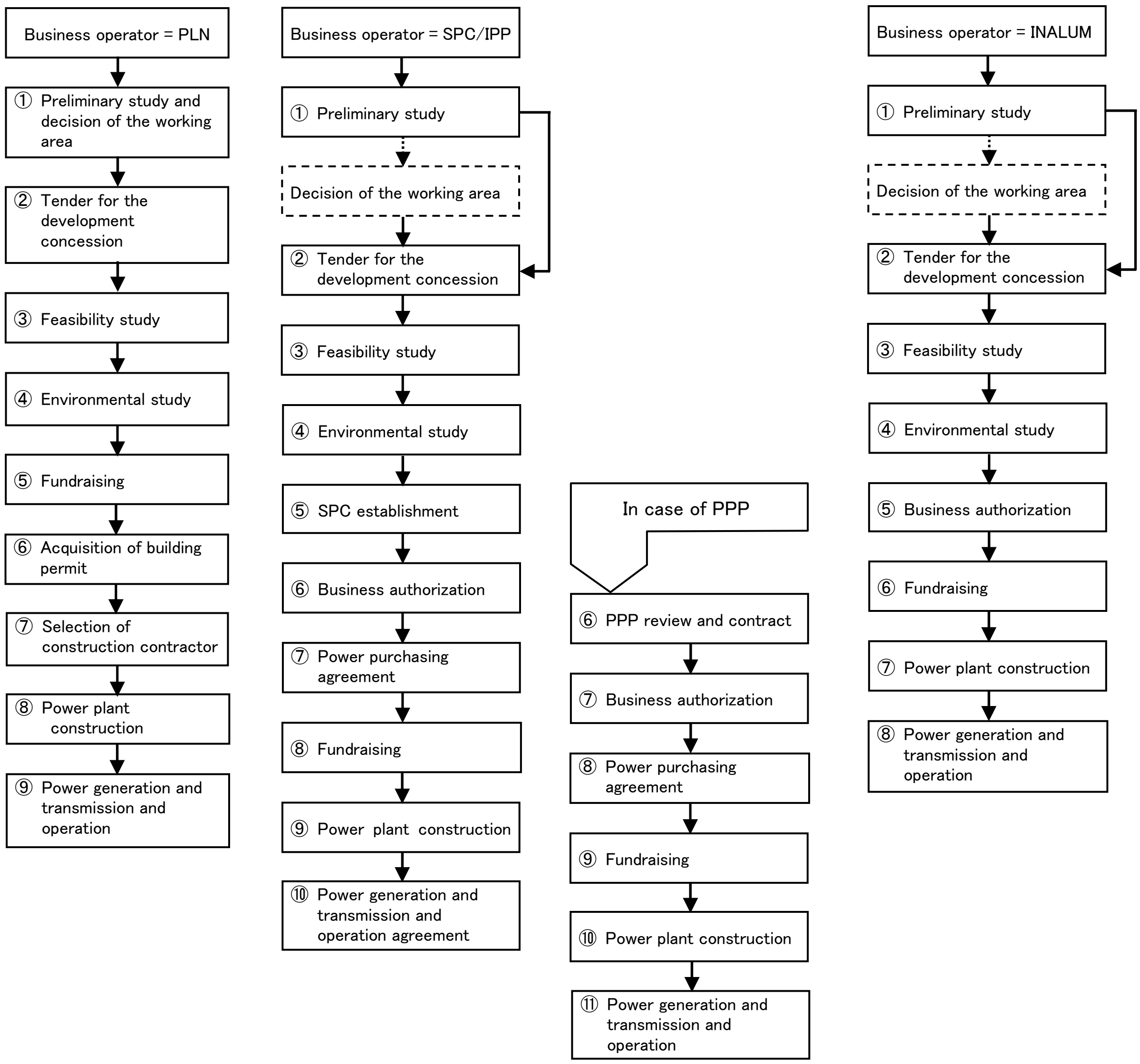
The following table outlines the legal and institutional problems and important points to consider in the development procedure under each type of operator.

Procedure	Legislation	Contents for Examination
When the business operator is PLN		
③ Environmental study	Presidential Decree No.36/2005	- Confirmation under the Forest Law concerning transmission line construction - Acquisition or leasing of land for power plant and transmission line structures, etc.
	Environment Ministry Ministerial Ordinance No.17/2001	- Implementation of AMDAL
⑤ Acquisition of building permit		Permission is required from the regency if the development site is in one regency, province if it spans multiple cities and regencies, and central government if it spans multiple provinces.
When the business operator is an SPC/IPP		
④ Environmental study		Same as above
⑤ SPC establishment	Law No.25/2007 (New Investment Law)	- Application of the New Investment Law - Investment by foreign investors in generation, transmission and distribution is limited to 95% maximum. - The permitted investment period is 30 years (+ 30 years with additional investment).
	Government Regulation No.36/2008	− It is assumed that the maximum corporation tax rate of 25% is set.
⑥ PPP review and contract	No.67/2005	Confirm the following contents of government support in joint public and private development: - Fundraising support, debt guarantee - Land expropriation
⑥, ⑦ Business authorization	Presidential Decree No.29/2004	- Application to the Investment Coordinating Board for investment permission - Application for location should be made to the city or regency land bureau with jurisdiction.
	Government Regulation No.3/2005	- Confirmation that the PKUK (PLN) cannot supply good quality and reliable power in the area
⑦, ⑧ Power purchasing agreement	Ministerial Decree No.9&10/2005	- Detailed rules are not currently prescribed concerning the leasing of the PLN transmission network, and it is thus realistically impossible to lease transmission lines. The power sale price is adjusted with PLN, however, it is necessary to comply with the provisions established by the government.
	Government Regulation No.3/2005	Power sale prices are displayed in rupiahs and require approval by the minister, provincial governor or regency governor. However, in some projects, special provision is granted for conversion into dollars (the Sarulla geothermal project is in dollars).
When the business operator is INALUM		
③ Environmental study		Same as above
④ Business authorization		Legal examination is required to determine whether additional investment is subject to the 1967 foreign investment law or the new investment law. When additional power resources are viewed as business expansion, it is necessary to acquire expansion authorization according to Ministry of Industry Ministerial Decree No.41/2008.

Procedure	Legislation	Contents for Examination
		The following procedure assumes a new business activity.
	Presidential Decree No.29/2004	- Application to the Investment Coordinating Board for investment permission - Application for location should be made to the city or regency land bureau with jurisdiction.
	Law No.25/2007 (New Investment Law)	- Application of the New Investment Law - Investment by foreign investors in generation, transmission and distribution is limited to 95% maximum. - Business concession is granted for 30 years + extension of 30 years.
	Government Regulation No.36/2008	- It is assumed that the maximum corporation tax rate of 25% is set.

6.9.2 Case of Geothermal Development

The following figure schematically shows the geothermal development procedure and legal requirements according to the type of operator, i.e. PLN, private operator (special purpose company: SPC/IPP) or INALUM.　According to the Geothermal Energy Law, the geothermal development procedure is divided into five stages, namely preliminary study → exploration (decision of the development area) → feasibility study (FS) → development → utilization. Up until the tender for development concession, depending on the scale of development, responsibility resides with the regency in the smallest units, provinces when the development spans multiple regencies, and the central government when the development spans multiple provinces.



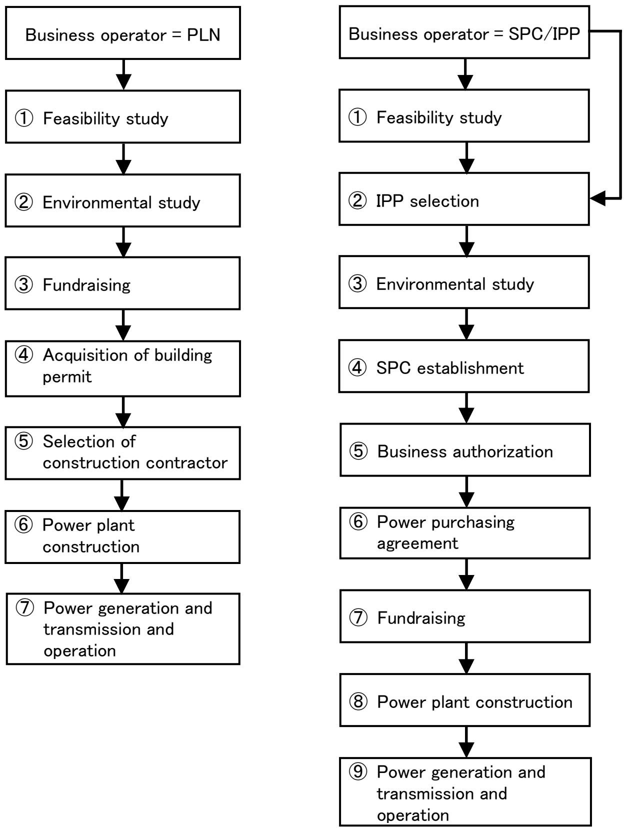
The following table outlines the legal and institutional problems and important points to consider in the development procedure under each type of operator.

Procedure	Legislation	Contents for Examination
When the business operator is PLN		
① Preliminary study and decision of the working area		The costs of steam production and power generation are determined at this point, however, the operator is not guaranteed to receive the development concession.
② Tender for the development concession		- If the bidder has implemented a preliminary study but hasn't presented the minimum cost, it can modify cost to the lowest level. If it doesn't modify the cost accordingly, it cannot obtain the development concession, however, the preliminary study costs are compensated.
④ Environmental study	Presidential Decree No.36/2005	- Confirmation under the Forest Law concerning transmission line construction - Acquisition or leasing of land for power plant and transmission line structures, etc.
	Environment Ministry Ministerial Ordinance No.17/2001	- Implement AMDAL for geothermal power plants with capacity of more than 55 MW, or less than 55 MW if located in a protected area. Otherwise, submit a UKL and UPL.
		- Concerning air, water quality and noise, the following environmental criteria are set. Criteria for atmospheric emissions: hydrogen sulfide; wastewater criteria: hydrogen sulfide, ammonia, mercury, arsenic, water temperature, and pH; noise criteria: maximum sound pressure according to the type of land use. - In order to keep resident relocation to a minimum, depending on the terrain and positional relationship of the geothermal reservoir, it is important to make full use of incline boring technology when digging wells.
⑥ Acquisition of building permit		Permission is required from the regency if the development site is in one regency, province if it spans multiple cities and regencies, and central government if it spans multiple provinces.
When the business operator is an SPC/IPP		
① Preliminary study		It is necessary to estimate the costs of steam production and power generation at this point.
② Tender for the development concession		Same as above
④ Environmental study		Same as above
⑤ SPC establishment	Law No.25/2007 (New Investment Law)	- Application of the New Investment Law - Investment by foreign investors in generation, transmission and distribution is limited to 95% maximum. - The permitted investment period is 30 years (+ 30 years with additional investment).
	Government Regulation No.36/2008	- It is assumed that the maximum corporation tax rate of 25% is set. - Following revision of the tax law in October 2008, 5% of the investment amount is deducted from the taxable income for 6 years after the start of operation, and the depreciation period can be reduced by half.

Procedure	Legislation	Contents for Examination
⑥ PPP review and contract	No.67/2005	Confirm the following contents of government support in joint public and private development: - Fundraising support, debt guarantee - Land expropriation
⑥, ⑦ Business authorization	Presidential Decree No.29/2004	- Application to the Investment Coordinating Board for investment permission - Application for location should be made to the city or regency land bureau with jurisdiction.
	Government Regulation No.3/2005	- Confirmation that the PKUK (PLN) cannot supply good quality and reliable power in the area
⑦, ⑧ Power purchasing agreement	Ministerial Decree No.9＆10/2005	- Detailed rules are not currently prescribed concerning the leasing of the PLN transmission network, and it is thus realistically impossible to lease transmission lines. The power sale price is adjusted with PLN, however, it is necessary to comply with the provisions established by the government.
	Government Regulation No.3/2005	Power sale prices are displayed in rupiahs and require approval by the minister, provincial governor or regency governor. However, in some projects, special provision is granted for conversion into dollars (the Sarulla geothermal project is in dollars).
When the business operator is INALUM		
① Preliminary study		It is necessary to estimate the costs of steam production and power generation at this point.
② Tender for the development concession		Same as above
④ Environmental study		Legal examination is required to determine whether additional investment is subject to the 1967 foreign investment law or the new investment law. When additional power resources are viewed as business expansion, it is necessary to acquire expansion authorization according to Ministry of Industry Ministerial Decree No.41/2008. The following procedure assumes a new business activity.
	Presidential Decree No.29/2004	- Application to the Investment Coordinating Board for investment permission - Application for location should be made to the city or regency land bureau with jurisdiction.
	Law No.25/2007 (New Investment Law)	- Application of the New Investment Law - Investment by foreign investors in generation, transmission and distribution is limited to 95% maximum. - Business concession is granted for 30 years + extension of 30 years.
	Government Regulation No.36/2008	- It is assumed that the maximum corporation tax rate of 25% is set.

6.9.3 Case of Hydropower Development

The following figure shows the flow of procedures for developing hydropower as a power resource in the cases of PLN and private operator (special purpose company: SPC/IPP) development.



The following table outlines the legal and institutional problems and important points to consider in the development procedure under each type of operator.

Procedure	Legislation	Contents for Examination
When the business operator is PLN		
① Feasibility study		PLN or a private operator under supervision of PLN implements the activity.
② Environmental study	Presidential Decree No.36/2005	Implementation of AMDAL and clearance of issues
④ Acquisition of building permit		Permission is required from the regency if the development site is in one regency, province if it spans multiple cities and regencies, and central government if it spans multiple provinces.
When the business operator is an SPC/IPP		
① Feasibility study		The SPC can participate from the feasibility study or from the IPP selection stage.
③ Environmental study		Same as above
④ SPC establishment	Law No.25/2007 (New Investment Law)	- Application of the New Investment Law - Investment by foreign investors in generation, transmission and distribution is limited to 95% maximum. - The permitted investment period is 30 years (+ 30 years with additional investment).
	Government Regulation No.36/2008	- Corporate tax is set at a maximum rate of 25%.
⑤ PPP review and agreement	No.67/2005	Confirm the following contents of government support in joint public and private development: - Fundraising support, debt guarantee - Land expropriation
⑤, ⑥ Business authorization	Presidential Decree No.29/2004	- Application to the Investment Coordinating Board for investment permission - Application for location should be made to the city or regency land bureau with jurisdiction.
	Government Regulation No.3/2005	- Confirmation that the PKUK (PLN) cannot supply good quality and reliable power in the area
⑥, ⑦ Power purchasing agreements	Ministerial Decree Nos.9 ＆ 10/2005	- Detailed rules are not currently prescribed concerning the leasing of the PLN transmission network, and it is thus realistically impossible to lease transmission lines. The power sale price is adjusted with PLN, however, it is necessary to comply with the provisions established by the government.
	Government Regulation No.3/2005	- Power sale prices are displayed in rupiahs and require approval by the minister, provincial governor or regency governor. However, in some projects, special provision is granted for conversion into dollars (the Sarulla geothermal project is in dollars).

Chapter 7 Promising Options for Power Supply

7.1 Procedure for Selecting Power Supply Options

The procedure for selecting supply options in each power resource mode and feasible options based on the business model is indicted below.

Confirmation of development potential in each power resource mode	- Confirmation of development potential in each power resource mode (coal, gas, geothermal, hydropower) in the North Sumatra Grid, based on existing materials
↓ Extraction of a promising draft plan in each power resource mode	- In the development potential plan, compare the scale of development, generating cost, social and environmental issues and grid inter-connection and extract a promising plan.
↓ Examination of the business model	- Examination of power supply and operator (IPP project (SPC), PLN project (ODA)) according to the business mode
↓ Examination of supply options (200MW~600MW) combining different power resource modes	- Examine supply options combining each power resource mode for the following: 200MW = INALUM 400MW = INALUM (200MW) + public use (200MW) 600MW = INALUM (200MW) + public use (400MW)
↓ Application of the business model under investment and loan options and power supply options corresponding to the business model	- Examine Japanese ODA in the case of PLN, and investment and loan by JBIC syndicate in the case of IPP. Moreover, apply the business model in the 400 MW and 600 MW options.
↓ Economic and financial analysis and assessment	- Setting of economic and financial assessment conditions, reduction of works costs, special loan conditions, implementation of sensitivity analysis that considers interest, etc., and examination of risk in the power utility
↓ Selection of a feasible supply option	- Selection of a feasible option from the power supply options based on general assessment that includes economic and financial considerations.

7.2 Examination of the Business Model

Business models geared to securing power supply for INALUM plant expansion and public uses are summarized below.

7.2.1 SWAP

In Phase 1 study (2009), a swap scheme (power supply based on power interchange) is proposed whereby INALUM will receive power supply from PLN and it will supply power to PLN from a separately constructed power plant. This plan targets a swap between peak power using the Tampur-1 hydropower plant and base power from PLN grid. However, in this Study, construction of Tampur-1 is deemed to be impossible for social and natural environmental reasons, etc. Therefore, swapping will not be feasible unless INALUM itself owns/operates a new power resource. If INALUM does come to own/operate a power plant, and it is a coal-fired thermal power plant, the swap between peak power and base power will become technically feasible. However, in this case, it is clear that generating costs will be expensive because the plant factor will drop. Moreover, depending on the timing of plant expansion, in the case where existing power resource plans advance smoothly, the value of public use peak power will decline and the necessity of swapping will fall[1].

Therefore, swapping is not deemed to be a very feasible option.

7.2.2 PPP Business

The PPP (public-private partnership) model is available as an approach for fund procurement and operation. Through ensuring collaboration between the public and private sectors, this aims to promote the introduction of private sector capital. A possible scenario here would be for PLN or another state-owned enterprise to acquire government funds (Indonesian government budget or ODA, etc.) and the private sector to implement operation. The PPP model is displaying rapid growth and five projects[2] have already been announced in the electric power field. However, in the case where power resources for INALUM are included, a necessary condition would be to secure the agreement of PLN. Concerning this point, there were numerous pessimistic opinions from Indonesian officials at the time of the field surveys. Moreover, in the case where PLN is the partner, it will be difficult to secure state budget

[1] In the case where RUPTL 2010 proceeds smoothly, the backup rate over the entire Sumatra Grid will be 62% and a situation of excess supply can be expected.

[2] Of these, PLN is the partner in four projects (coal-fired thermal power), while the provincial government is implementing the other project (a hydropower development project).

funding for a plan that includes power supply to a specific enterprise (INALUM).

Meanwhile, in the case where the supply destination is not specified but power for the INALUM plant expansion is purchased from PLN, particularly if coal-fired thermal power or gas-fired thermal power is adopted, there is a strong likelihood of a PPP with PLN as the partner. Concerning the hydropower and geothermal energy options identified in Chapter 5, due to the powerful authority of the local government, it will be difficult to realize a PPP project with strong involvement by PLN. Moreover, in the case where INALUM is nationalized, it will become possible to form a PPP with the IPP that currently holds the development concession for Sarulla-2. In this case, it will be possible to promote development through investing public funds for investigation of reserves and to reduce generating cost through using ODA; however, since it would be difficult for INALUM to directly receive power supply from Sarulla-2 for the reasons described earlier, it would still be necessary to purchase power from PLN and there would be no merit for INALUM concerning the power price. In view of this situation, it has been decided to omit the PPP based on nationalization of INALUM from the Study.

7.2.3 IPP Business

Under the current legal system, the IPP business model entails an electric power utility license holder obtaining general electricity supply authorization and supplying power for the public benefit. In such cases, the operator which can be a public enterprise, cooperative association or private enterprise implements construction and power generation and sells power to PLN, which then supplies the power to general consumers. In line with the growing trend towards decentralization in recent years, IPPs are increasingly taking part in local energy resource developments in fields such as hydropower and geothermal energy, etc. However, since it is highly unfeasible for IPPs to take part in medium-scale (10~100 MW) hydropower development due to the need for large initial investment, large risks in terms of social and natural environmental problems and scant experience among most IPPs in this sector, there is concern that hydropower development will stagnate from now on. Meanwhile, people who related to provincial government are increasingly acquiring development concessions for new hydropower development and geothermal energy development plans in Indonesia, making it difficult for the central government and PLN to participate.

7.2.4 Captive Power and Private Power Generation

This is a business model for supplying electric power for specific purposes or to specific consumers. Under the existing law, separate licenses apply to CP (power supply to specific consumers) or private generation businesses and to IPP (power supply for the public benefit/power sale to PLN). PLN is promoting the utilization and purchase of excess power from CP in order to alleviate the critical power supply and demand situation. An example of CP is PLTGU Cikarang (gas combined cycle plant with capacity of 150 MW, the operator is PT. Cikarang Listrindo), which supplies electric power to the Cikarang industrial estate in East Jakarta. This sells excess power to PLN at a PPA sale price of 4.47 cent/kWh.

Under the present Electricity Law (Law No.30/2009 and related ordinances), in cases where private power generation or CP power generation is conducted, power supply can be requested from PLN (the power supplier), and if PLN declares it impossible to supply power, it is possible to conduct business upon acquiring authorization from the central government (Ministry of Energy and Mineral Resources) or the local government. Moreover, in the case where INALUM independently develops and operates a power plant and uses this for aluminum smelter, this will be a private generating utility. In the event where INALUM is nationalized, it will be possible to utilize ODA, however, ODA cannot be applied in cases of subcritical coal-fired thermal power.

7.2.5 PLN Business

Power resources for the public benefit are supplied from PLN. PLN constructs power plants and transmission lines and supplies power to consumers. In recent years, there is growing participation by IPPs in the power generating utility, however, PLN is basically the main operator regarding transmission and distribution[3]. In key grid supply areas, PLN is the only purchaser of power apart from CP.

[3] Excluding areas not inter-connected to key grids.

7.3 Selection of the Power Supply Option

The Study examines three options in total: namely the basic 200 MW supply option to supply the power required for INALUM plant expansion, plus the 400 MW and 600 MW options for supplying the INALUM power and an additional 200 MW and 400 MW respectively for public use purposes. Concerning the supply resources, supply options that can cover 400 MW and 600 MW supply are proposed by combining the power resources extracted in Chapter 5 (Promising Potential Sites). All the power resources are scheduled to go into operation after 2013, when the INALUM plant expansion plan is realized.

7.3.1 200 MW Supply Option (for INALUM plant expansion)

For the reasons cited below, the power resources for INALUM plant expansion are limited to proposals that entail either power purchasing from PLN or installation by an SPC of coal/gas thermal power facilities near the smelter plant.

- ♦ The hydropower planning sites identified in Chapter 5 are primarily the run-of-river type, however, because they cannot offer the stable power supply that reservoir systems can, they are not suited to power supply for aluminum smelter. Moreover, since each location can only generate medium-scale capacity (10~100 MW), it would be too costly and thus unfeasible to install dedicated transmission lines. Moreover, compared to other forms of power resource development, hydropower generation, even on the medium scale, entails a broad planning area and numerous risks in terms of social and environmental impacts, land acquisition and compensation issues. Since such risks would be too great for a SPC to handle, it would be necessary to have total support from the provincial government.

- ♦ Concerning geothermal energy, the only site deemed to possess potential of around 200 MW is Sarulla-2, however, because this is being developed for power sale to PLN, there is little likelihood that power could be supplied to INALUM.

(1) 200 MW supply option assuming power purchase from PLN

In the case where power for INALUM plant expansion is purchased from PLN, since the current RUPTL 2010 does not consider demand for INALUM plant expansion, it would be necessary to develop new power resources other than those indicated in the plan. The following paragraphs describe options for new 200 MW development assuming the case where power is purchased from PLN. However, in this case, the INALUM power purchase price is assumed to be a uniform value irrespective of the supply option and generating mode. Moreover, there is a strong possibility that electricity tariffs will increase from now on (see Tables 6.2-2 and 6.2-3 in Chapter 6).

(a) Coal-fired thermal power generation; develop new coal-fired thermal power (200 MW).

In order to respond to the additional demand for INALUM plant expansion, this option entails developing new coal-fired thermal power not stated in the current RUPTL 2010. In this case, there is no need to locate facilities next to the aluminum smelting plant, and the location conditions are more relaxed compared to the option of gas-fired thermal power development for INALUM plant expansion. Specifically, the plan for installation near Kuala Tanjung, which is mentioned in RUPTL 2010, has high feasibility in terms of fuel transportation and transmission convenience.

(b) Gas-fired thermal power generation; develop new gas-fired thermal power (200 MW).

In order to respond to the additional demand for INALUM plant expansion, this option entails developing new gas-fired thermal power not stated in the current RUPTL 2010. As is also the case in the coal-fired thermal power option described above, constraints are eased concerning selection of the location.

(c) Geothermal power development: out of the 300 MW development potential at Sarulla 2, development of 190 MW not mentioned in RUPTL

As was mentioned in Chapter 5, the only promising geothermal energy development site deemed to possess reserves of 200 MW is Sarulla-2. However, a power purchasing agreement has already been signed with PLN concerning the Sarulla development including Sarulla 2, and power from any future developments will also be sold to PLN. Furthermore, although Sarulla covers a wide area divided into four districts, it is regarded as a single working area and the development concession targets all of it. Accordingly, it will be difficult to directly receive power from this site for supply to INALUM.
According to the Master Plan Study for Geothermal Power Development (2007), Sarulla-2 is said to have development potential of 300 MW, of which 110 MW will be developed by 2014 (according to RUPTL 2010). The Study here targets the remaining 190 MW not

mentioned in RUPTL 2010.

Additionally, apart from the problem of development concession (bulk sale of power to PLN), the following insurmountable obstacles to utilizing power from Sarulla-2 for the INALUM plant expansion are forecast. Accordingly, this option has been omitted from the targets of the Study[4].

- PLN has no history of leasing transmission lines for specific enterprises; moreover, no detailed regulations have been stipulated about leasing.

- Considering the high construction cost and problems of land expropriation, compensation and social and natural environment, etc. it would be risky and unrealistic for an IPP to construct a long distance dedicated transmission line for directly transmitting power.

- The Sarulla-2 development potential of 300 MW is the figure obtained in the pre-FS stage according to the Master Plan Study for Geothermal Power Development (2007), however, this currently has no technical corroboration based on well investigation, etc.

- Adjusting the Sarulla-2 plans to provide power solely for INALUM plant expansion would entail negotiations for transfer with the existing concession holder, and this would involve risk of higher costs. Meanwhile, it is necessary to conduct timely discussion in negotiations regarding geothermal power development. Moreover, development of Sarulla-2 cannot be started until development of Sarulla-1 (110 MW) is finished. Therefore, it would take many years before the Sarulla-2 (190 MW) development can start generating power.

(d) Hydropower generation; new development of three run-of-river and regulating reservoir type sites (total output: 177.4 MW)

Concerning Tampur-1 (330 MW) and Jambu Aye (160 MW), which were proposed as promising hydropower sites in Phase 1, as was described in Chapter 5, development is deemed to be unfeasible due to the social and natural environment and other factors.

[4] Chapter 8 Addendum 1 shows reference figures concerning the power sale price to INALUM (assuming installation of a dedicated transmission line) in the event where the above obstacles are overcome.

Accordingly, in this Study we have identified four feasible sites for hydropower development based on run-of-river and small-scale regulating reservoir systems. Of these, since the Wampu site (45 MW) is already mentioned in RUPTL 2010, the remaining three sites are targeted here. Another option is to purchase power from Asahan No.3 (174 MW), which is currently under construction and scheduled to start operation in 2014; however, since this is being built by PLN to supply power for civilian purposes and the civilian power supply and demand situation is under pressure, it will be difficult to secure power supply for a specific enterprise. Moreover, in the current environment of increasing decentralization, it is becoming difficult to secure the understanding of local residents and local governments regarding hydropower development, which is recognized as a unique local resource. Accordingly, since it is increasingly difficult for the central government and PLN to compile new development plans, it is likely that IPP will be the primary model for developing the three target sites[5].

(2) 200 MW supply option assuming construction of a new power plant for INALUM plant expansion

In the case where a dedicated power plant for INALUM plant expansion is constructed, as was described above, since there is little possibility regarding hydropower and geothermal power plants, the options are limited to coal-fired thermal power or gas-fired thermal power. In this case, the power plant will be either a captive power or a private generating facility. Moreover, it is necessary to sign a backup agreement[6] with PLN to provide insurance in the event where the dedicated plant breaks down.

(a) Supply based on coal-fired power generation; installation of a dedicated coal-fired thermal power plant (200 MW) close to the aluminum smelting plant

There is no problem regarding development potential for geothermal and hydropower development, however, a feasibility study (F/S) including EIA would be needed. Also, it would be necessary to coordinate with the PLN development plans (RUPTL) and to gain

[5] Even if an IPP conducts hydropower development in place of PLN, since it will still be necessary to implement long-term study and examination including Pre-F/S, F/S, reviews and EIA compilation, etc., numerous obstacles need to be cleared before realizing construction and operation compared to other power resources. Therefore, unless a special agency of the central government and/or provincial government becomes involved with authority, it is realistically impossible for an IPP to conduct hydropower development in Indonesia in recent years.

[6] Concerning additional charges in the case of a backup contract, there are no clear stipulations. Last year, when a Japanese corporation installed a 65 MW private generating plant and sought a backup contract with PLN, an additional charge for backup power of 100% higher than the conventional tariff was demanded (negotiations are still ongoing).

recognition as a new project. Moreover, since coal-fired power generation would be dependent on the price of coal, any inflation in coal prices would be likely to cause inflation in the generating unit price, and it would be necessary to conduct contract negotiations with the coal company in order to secure a stable supply of coal. If these issues could be overcome, compared to the case of geothermal or hydropower generation, it would be easier to conduct study, design and construction work and to concretely schedule the start of generation in the case of coal-fired thermal power generation. Coal would mainly be purchased from Kalimantan or South Sumatra in this case, so it is possible that transportation expenses could lead to higher generating costs. Meanwhile, Indonesia is currently promoting the construction of coal-fired thermal power plants based on the Crash Program for non-petroleum power resources development, however, it should be noted that work on power plants under this program is well behind schedule due to land acquisition and environmental issues in the mining districts designated to supply coal.

(b) Supply based on gas-fired power generation; installation of a dedicated gas-fired thermal power plant (200 MW) close to the aluminum smelting plant

This plan is conditional on obtaining an appropriate supply of gas as fuel, and feasible options for this are a pipeline from South Sumatra or supply from the marine LNG base off the coast of Medan. However, both these options are in the planning stage and it is necessary to carefully monitor future developments. In this case too, it would be necessary to conduct an F/S including preparation of an EIA, and to coordinate with PLN development plans (RUPTL) and secure recognition as a new undertaking. The price of gas would be decided in negotiations with the supplier (PGN), and price fluctuations could be expected depending on the demand and supply conditions. Moreover, since the unit price of gas-fired power generation would be dependent on the price of purchased gas, it is likely that inflation in the price of gas would cause the generating unit price to rise. It would thus be essential to conduct price negotiations with a view to securing cheap and stable gas supply. If these issues could be overcome, compared to the case of geothermal or hydropower generation, it would be easier to conduct study, design and construction work and to concretely schedule the start of generation in the case of gas-fired thermal power generation.

Table 7.3-1 200 MW Supply Option (for INALUM Plant Expansion): Outline and Development Risks

Serial No.	Power resource mode	Outline of the supply mode	Anticipated business model	Feasibility/issues in recent years
(1) 200 MW supply option assuming power purchase from PLN: the INALUM purchase tariff is a uniform rate irrespective of the power resource mode and generating cost (inflation of 37% is expected by 2015).				
PLN-200-①	Coal-fired thermal	Install a new coal-fired thermal power plant (sub-critical) that isn't stated in RUPTL 2010-2019.	PLN/IPP There is a possibility regarding a PPP based on PLN+IPP.	Possibility of realization: Medium Sumatra has abundant reserves of low calorie coal, so it is relatively easy to procure fuel. Since development is requisite on the power resources being used for INALUM, an issue is whether each operator can take initiative. Technical confirmation entailing investigation of coal price trends, coal supply stability and location conditions, etc. is required.
PLN-200-②	Gas-fired thermal	Install a new gas-fired thermal power plant (200 MW) that isn't stated in RUPTL 2010-2019.	PLN/IPP There is a possibility regarding a PPP based on PLN+IPP.	Possibility of realization: Medium It is necessary to carefully monitor progress in LNG base or pipeline construction. Technical confirmation entailing investigation of gas price trends, gas supply stability and location conditions, etc. is required.
PLN-200-③	Geothermal	Out of the 300 MW development potential at Sarulla-2, newly develop the 190 MW not stated in RUPTL.	The IPP that acquires the development concession	Possibility of realization: Medium Since development of Sarulla-1 is already behind schedule, it is likely that development of Sarulla-2 would also be delayed. Technical confirmation entailing investigation of the amount of development potential is required.
PLM-200-④	Hydropower	Develop Toru-1, Simango-2 and Raisan-3,4 (total output: 177.4MW).	IPP Local cooperation is a required condition for development by PLN.	Possibility of realization: Low Hydropower development by an IPP would be difficult due to the lack of implementation capacity. Technical confirmation entailing investigation of the amount of development potential and location conditions, etc. is required.

Serial No.	Power resource mode	Outline of the supply mode	Anticipated business model	Feasibility/issues in recent years
(2) 200 MW supply option assuming construction of a new dedicated power plant for INALUM plant expansion: a backup contract is required to provide insurance in the event where the dedicated power plant breaks down				
INALUM-200-①	Coal-fired thermal	Install a dedicated coal-fired thermal power plant (sub-critical 200 MW) close to the aluminum smelting plant.	SPC The power plant is a Captive Power or private generating facility. If INALUM is nationalized, application of ODA will be a possibility.	Possibility of realization: High Authorization as a specific power supplier/private power generator is required. Technical confirmation entailing investigation of coal price trends, coal supply stability and location conditions, etc. is required.
INALUM-200-②	Gas-fired thermal	Install a dedicated gas-fired thermal power plant (200 MW) close to the aluminum smelting plant.	SPC The power plant is a Captive Power or private generating facility. If INALUM is nationalized, application of ODA will be a possibility.	Possibility of realization: Medium It is necessary to carefully monitor progress in LNG base or pipeline construction. Project delays are forecast. Authorization as a specific power supplier/private power generator is required. Technical confirmation entailing investigation of gas price trends, gas supply stability and location conditions, etc. is required.
—	Geothermal	Not applicable		Development concession for Sarulla-2 is set conditional on bulk sale of power to PLN.
—	Hydropower	Not applicable		It is difficult to secure stable power supply for aluminum smelting.

7.3.2 400 MW Supply Option (200 MW for INALUM + 200 MW for Civilian Use)

As in the case of the 200 MW supply options described above, the 400 MW supply options are divided into proposals that entail either power purchasing from PLN or construction of a dedicated power plant.

(1) 400 MW supply option assuming power purchase from PLN

As options for purchasing 200 MW for INALUM plant expansion from PLN and separately securing another 200 MW for civilian purposes, it is possible to combine the supply options ①~④ shown in 7.3.1 (1) or to newly construct a 400 MW class coal-fired or gas-fired thermal power plant (see section 7.3.1 for the contents of separate plans). Incidentally, concerning hydropower and geothermal energy, since the development potential for 400 MW has not been confirmed in Chapter 5, no supply options based on these modes alone have been set.

(a) Supply based on combination of geothermal energy and hydropower; geothermal energy (Sarulla-2: 190 MW) + hydropower at three locations (177.4 MW)

Since this supply option entails development at four locations, each in different areas and with different operators, it would be fundamentally difficult to synchronize development with expansion of the INALUM aluminum smelting plant.

(b) Supply based on combination of geothermal energy and coal-fired thermal power; geothermal energy (Sarulla-2: 190 MW) + coal-fired thermal power (200 MW)

Compared to option ① above, this option is more feasible, however, it would be necessary to coordinate between INALUM, the IPP and PLN regarding the development schedule.

(c) Supply based on combination of geothermal energy and gas-fired thermal power; geothermal energy (Sarulla-2: 190 MW) + gas-fired thermal power (200 MW)

The issues in this option are the same as those described under option ② above.

(d) Supply based on combination of hydropower and coal-fired thermal power; hydropower at three locations (177.4 MW) + coal-fired thermal power (200 MW)

The issues in this option are the same as those described under option ① above.

(e) Supply based on combination of hydropower and gas-fired thermal power; hydropower at three locations (177.4 MW) + gas-fired thermal power (200 MW)

The issues in this option are the same as those described under option ① above.

(f) Supply based on combination of coal-fired thermal power and gas-fired thermal power; coal-fired thermal power (200 MW) + gas-fired thermal power (200 MW)

Compared to options ①~⑤ above, this option is more feasible, however, it would be necessary to coordinate between INALUM, the IPP and PLN regarding the development schedule. Other prerequisites would be to conduct a detailed investigation of location conditions, confirm price trends for coal and gas, and secure stable supply.

(g) Supply based on construction of a new 400 MW coal-fired thermal power plant; coal-fired thermal power (400 MW)

This supply option entails constructing the new coal-fired thermal power plant described in section 7.2.1 (1) ③ but with total plant capacity of 400 MW. The issues in this option are the same as those described under option ⑥ above.

(h) Supply based on construction of a new 400 MW gas-fired thermal power plant; gas-fired thermal power (400 MW)

This supply option entails constructing the new gas-fired thermal power plant described in section 7.2.1 (1) ④ but with total plant capacity of 400 MW. The issues in this option are the same as those described under option ⑥ above.

(2) 400 MW supply option assuming construction of a dedicated power plant for INALUM and securing of power resources for civilian purposes

As options for constructing a 200 MW dedicated power plant for INALUM plant expansion and securing an additional 200 MW for civilian purposes, it is possible either to combine supply options ① and ② described in section 7.3.1 (2) and ③ and ④ described in 7.3.1 (1), or to construct a new 400 MW class coal-fired or gas-fired thermal power plant. In this case, it is necessary to sign a backup agreement with PLN to provide insurance in the event where the dedicated plant breaks down (see section 7.3.1 for contents of individual plans).

(a) Supply based on dedicated coal-fired thermal power for INALUM and geothermal energy for civilian purposes

Dedicated coal-fired thermal power (200 MW) for INALUM and geothermal energy (Sarulla-2: 190 MW) for civilian purposes

(b) Supply based on dedicated coal-fired thermal power for INALUM and hydropower for civilian purposes

Dedicated coal-fired thermal power (200 MW) for INALUM and hydropower from three sites (177.4 MW) for civilian purposes

(c) Supply based on dedicated gas-fired thermal power for INALUM and geothermal energy for civilian purposes

Dedicated gas-fired thermal power (200 MW) for INALUM and geothermal energy (Sarulla-2: 190 MW) for civilian purposes

(d) Supply based on dedicated gas-fired thermal power for INALUM and hydropower for civilian purposes

Dedicated gas-fired thermal power (200 MW) for INALUM and hydropower from three sites (177.4 MW) for civilian purposes

(e) Supply based on installation of a new 400 MW coal-fired power plant; coal-fired thermal power for INALUM plant expansion and civilian purposes

This supply option entails constructing the new coal-fired thermal power plant described in section 7.3.1 (2) ① but with total plant capacity of 400 MW. In this case, the power plant would be constructed close to the aluminum smelting plant. Moreover, as is described later, the business model in this case would entail a captive power or private generating plant operated by an SPC and power for civilian purposes would be sold as excess power[7] to PLN. It would be necessary to conduct a detailed investigation of location conditions, confirm price trends for coal, and secure a stable supply.

(f) Supply based on installation of a new 400 MW gas-fired power plant; gas-fired thermal power for INALUM plant expansion and civilian purposes

This supply option entails constructing the new gas-fired thermal power plant described in section 7.3.1 (2) ② but with total plant capacity of 400 MW. In this case, the power plant would be constructed close to the aluminum smelting plant. As in option ⑤ above, the business model in this case would entail a captive power or private generating plant operated by an SPC and power for civilian purposes would be sold as excess power to PLN. It would be necessary to conduct a detailed investigation of location conditions, confirm price trends for gas, and secure a stable supply of gas as fuel.

[7] If the power is regarded as excess power, it is likely to be sold at a low price sufficient only to cover operating costs (fuel expenses and personnel expenses, etc.). There have been a few examples of generation as captive power. In one of these, the CP of Chikalang industrial estate sells excess power to PLN at a price of 4.47 ¢ /kWh.

Table 7.3-2 400 MW Supply Option (200 MW for INALUM Plant Expansion + 200 MW for Civilian Purposes): Outline and Development Risks

Serial No.	Power resource mode	Outline of the supply mode	Anticipated business model	Feasibility/issues in recent years
(1) 400 MW supply option assuming power purchase from PLN: the INALUM purchase tariff is a uniform rate irrespective of the power resource mode and generating cost (inflation of 37% is expected by 2015).				
PLN-400-①	Geothermal+ hydropower	Develop geothermal energy at Sarulla-2 (190 MW)＋hydropower at Toru-1, Simango-2 and Raisan-3, 4 (177.4 MW) Total output: 367.4 MW	Geothermal: IPP Hydropower: IPP Local cooperation is a required condition for hydropower development by PLN.	Possibility of realization: Low Delays are forecast in the Sarulla-2 development schedule. There is a lack of implementation capacity regarding hydropower development by IPPs. Feasibility is low due to the differing work sites and operators. Technical confirmation entailing investigation of the amount of development potential is required.
PLN-400-②	Geothermal+ coal-fired thermal power	Develop Sarulla-2 (190 MW) and coal-fired thermal power (sub-critical 200 MW) Total output: 390 MW new installation	Geothermal: IPP Coal: PLN/IPP	Possibility of realization: Medium Delays are forecast in the Sarulla-2 development schedule. Technical confirmation entailing investigation of the amount of geothermal development potential, coal price trends, coal supply stability and location conditions, etc. is required.
PLN-400-③	Geothermal+ gas-fired thermal power	Develop Sarulla-2 (190 MW) and gas-fired thermal power (200 MW) Total output: 390 MW new installation	Geothermal: IPP Gas: PLN/IPP	Possibility of realization: Low Delays are forecast in the Sarulla-2 development schedule. It is necessary to carefully monitor progress in LNG base or pipeline construction. Project delays are forecast. Technical confirmation entailing investigation of the amount of geothermal development potential, gas price trends, gas supply stability and location conditions, etc. is required.
PLN-400-④	Hydropower + coal-fired thermal power	Develop Toru-1, Simango-2 and Raisan-3,4 (total capacity 177.4 MW) and coal-fired thermal power (sub-critical 200 MW) Total output: 377.4 MW	Hydropower: IPP Local cooperation is a required condition for hydropower development by PLN. Coal: PLN/IPP There is a possibility regarding a PPP based on PLN+IPP.	Possibility of realization: Low There is a lack of implementation capacity regarding hydropower development by IPPs. Feasibility is low due to the differing work sites and operators. Technical confirmation entailing investigation of the amount of hydropower development potential is required. Technical confirmation of coal price trends, coal supply stability and location conditions, etc. is required
PLM-400-⑤	Hydropower + gas-fired thermal power	Develop Toru-1, Simango-2 and Raisan-3,4 (total capacity 177.4 MW) and gas-fired thermal power (200 MW).	Hydropower: IPP Local cooperation is a required condition for hydropower development by PLN.	Possibility of realization: Low There is a lack of implementation capacity regarding hydropower development by IPPs. Feasibility is low due to the differing work sites and operators. Technical confirmation entailing investigation of the amount of hydropower development

		Total output: 377.4 MW	Gas: PLN/IPP There is a possibility regarding a PPP based on PLN+IPP.	potential, gas price trends, gas supply stability and location conditions, etc. is required.
PLM-400-⑥	Coal-fired thermal power + gas-fired thermal power	Develop coal-fired thermal power (sub-critical 200 MW) and gas-fired thermal power (200 MW). Total output: 400 MW	IPP/PLN There is a possibility regarding a PPP based on PLN+IPP.	Possibility of realization: Medium Sumatra has abundant reserves of low calorie coal, so it is relatively easy to procure fuel. Technical confirmation of coal/gas price trends, coal/gas supply stability and location conditions, etc. is required. It is necessary to carefully monitor progress in LNG base or pipeline construction. Project delays are forecast.
PLM-400-⑦	Coal-fired thermal power	Develop coal-fired thermal power (sub-critical 400 MW)	IPP/PLN There is a possibility regarding a PPP based on PLN+IPP.	Possibility of realization: High Sumatra has abundant reserves of low calorie coal, so it is relatively easy to procure fuel. Technical confirmation of coal price trends, coal supply stability and location conditions, etc. is required.
PLM-400-⑧	Gas-fired thermal power	Develop gas-fired thermal power (sub-critical 400 MW)	IPP/PLN There is a possibility regarding a PPP based on PLN+IPP.	Possibility of realization: Medium It is necessary to carefully monitor progress in LNG base or pipeline construction. Project delays are forecast. Technical confirmation of gas price trends, gas supply stability and location conditions, etc. is required.

Serial No.	Power resource mode	Outline of the supply mode	Anticipated business model	Feasibility/issues in recent years
(2) 400 MW supply option assuming construction of a new dedicated power plant (200 MW) for INALUM plant expansion + securing of 200 MW for civilian purposes: a backup contract is required to provide insurance in the event where the dedicated power plant breaks down				
INALUM-400-①	Coal-fired thermal power + geothermal	Supply based on dedicated coal-fired thermal power for INALUM (subcritical 200 MW) and geothermal power for civilian purposes (Sarulla2: 190 MW)	Coal: SPC If INALUM is nationalized, application of ODA will be a possibility regarding coal-fired thermal power. Geothermal: IPP	Possibility of realization: Medium Delays are forecast in the Sarulla-2 development schedule. Technical confirmation entailing investigation of the amount of geothermal development potential, coal price trends, coal supply stability and location conditions, etc. is required. Concerning dedicated thermal power supply, authorization as a specific power supplier/private power generator is required.
INALUM-400-②	Coal-fired thermal power + hydropower	Supply based on dedicated coal-fired thermal power for INALUM (subcritical 200 MW) and hydropower for civilian purposes (3 sites, total output 177.4 MW)	Coal: SPC If INALUM is nationalized, application of ODA will be a possibility regarding coal-fired thermal power. Hydropower: IPP Local cooperation is a required condition for hydropower development by PLN.	Possibility of realization: Low There is a lack of implementation capacity regarding hydropower development by IPPs. Technical confirmation of coal price trends, coal supply stability and location conditions, etc. is required. Concerning dedicated thermal power supply, authorization as a specific power supplier/private power generator is required. If coal-fired thermal power is developed for INALUM, the problems surrounding delay of hydropower development can be mitigated.
INALUM-400-③	Gas-fired thermal power + geothermal	Supply based on dedicated gas-fired thermal power for INALUM (200 MW) and geothermal power for civilian purposes (Sarulla2: 190 MW)	Gas: SPC If INALUM is nationalized, application of ODA will be a possibility Geothermal: IPP	Possibility of realization: Low Delays are forecast in the Sarulla-2 development schedule. It is necessary to carefully monitor progress in LNG base or pipeline construction. Project delays are forecast. Technical confirmation entailing investigation of the amount of geothermal development potential, gas price trends, gas supply stability and location conditions, etc. is required. Concerning dedicated thermal power supply, authorization as a specific power supplier/private power generator is required.

INALUM-400-④	Gas-fired thermal power + hydropower	Supply based on dedicated gas-fired thermal power for INALUM (200 MW) and hydropower for civilian purposes (3 sites, total output 177.4 MW)	Gas: SPC If INALUM is nationalized, application of ODA will be a possibility. Hydropower: IPP Local cooperation is a required condition for hydropower development by PLN.	Possibility of realization: Low There is a lack of implementation capacity regarding hydropower development by IPPs. It is necessary to carefully monitor progress in LNG base or pipeline construction. Project delays are forecast. Technical confirmation of gas price trends, gas supply stability and location conditions, etc. is required. Concerning dedicated thermal power supply, authorization as a specific power supplier/private power generator is required.
INALUM-400-⑤	Coal-fired thermal power	Install a dedicated coal-fired thermal power plant (sub-critical 400 MW) close to the aluminum smelting plant.	SPC Captive power/private generating plant If INALUM is nationalized, application of ODA will be a possibility.	Possibility of realization: High Authorization as a specific power supplier/private power generator is required. It is highly likely that power supply for civilian purposes will be regarded as excess power (thereby lowering the power sale price). Technical confirmation of coal price trends, coal supply stability and location conditions, etc. is required
INALUM-400-⑥	Gas-fired thermal power	Install a dedicated gas-fired thermal power plant (400 MW) close to the aluminum smelting plant.	SPC Captive power/private generating plant If INALUM is nationalized, application of ODA will be a possibility.	Possibility of realization: Medium It is necessary to carefully monitor progress in LNG base or pipeline construction. Project delays are forecast. Authorization as a specific power supplier/private power generator is required. It is highly likely that power supply for civilian purposes will be regarded as excess power (thereby lowering the power sale price). Technical confirmation of gas price trends, gas supply stability and location conditions, etc. is required.

7.3.3 600 MW Supply Option (200 MW for INALUM + 400 MW for Civilian Use)

In this supply case too, options are divided according to those in which power for INALUM is purchased from PLN and those in which a dedicated power plant is constructed.

(1) 600 MW supply option assuming power purchase from PLN

Assuming that 200 MW for INALUM plant expansion is purchased from PLN and another 400 MW for civilian purposes is secured separately, possible options are to revise plant output in options ① and ② shown in 7.3.1 (1) to 400 MW, or to combine options ③ and ④ in the same section , or to newly construct a 600 MW class coal-fired or gas-fired thermal power plant. Plans entailing the combination of three or more power resource modes (for example, geothermal + hydropower + coal-fired thermal power) have been omitted from this Study because there would be too many diverse development areas and operating bodies, making it too difficult to synchronize development with the INALUM plant expansion.

(a) Supply based on combination of geothermal energy and coal-fired thermal power; geothermal energy (Sarulla-2: 190 MW) + coal-fired thermal power (400 MW)

(b) Supply based on combination of geothermal energy and gas-fired thermal power; geothermal energy (Sarulla-2: 190 MW) + gas-fired thermal power (400 MW)

(c) Supply based on combination of hydropower and coal-fired thermal power; hydropower at three locations (177.4 MW) + coal-fired thermal power (400 MW)

(d) Supply based on combination of hydropower and gas-fired thermal power; hydropower at three locations (177.4 MW) + gas-fired thermal power (400 MW)

(e) Supply based on construction of a new 600 MW coal-fired thermal power plant; coal-fired thermal power (600 MW)

This supply option entails constructing the new coal-fired thermal power plant described in section 7.3.1 (1) ① but with total plant capacity of 600 MW. In this case, provided there is no problem in terms of grid stability, it would be possible to introduce a supercritical or ultra-supercritical system with single unit capacity of 600 MW. It would be necessary to investigate the location conditions in detail, confirm trends in the price of coal (fuel) and secure stable supply of coal.

(f) Supply based on combination of a new 600 MW gas-fired thermal power plant; gas-fired thermal power (600 MW)

This supply option entails constructing the new gas-fired thermal power plant described in section 7.3.1 (1) ② but with total plant capacity of 600 MW. One possibility is to upgrade/boost the existing PLN thermal power plant at Belawan (520 MW), even though output in this case would not reach 600 MW. It would be necessary to investigate the location conditions in detail, confirm trends in the price of gas (fuel) and secure stable supply of gas.

(2) 600 MW supply option assuming construction of a dedicated power plant (200 MW) for INALUM plant expansion and securing of 400 MW for civilian purposes

In the case where a 200 MW dedicated power plant for INALUM plant expansion is constructed and an additional 400 MW is secured for civilian purposes, possible options are either to combine supply options ① and ② described in section 7.3.1 (2) with plant output increased to 400 MW, to combine options ③ and ④ described in 7.3.1 (1), or to construct a new 600 MW class coal-fired or gas-fired thermal power plant. In this case, the coal-fired or gas-fired thermal power plant will supply power for INALUM plant expansion (200 MW) as well as 200/400 MW for civilian purposes. Concerning the business model, since a SPC will operate a captive power or private generating power plant, the power for civilian purposes will be sold to PLN as excess power.

(a) Supply based on coal-fired thermal power (INALUM + civilian purposes: 400 MW) and geothermal energy for civilian purposes; coal-fired thermal power (400 MW) and geothermal energy (Sarulla-2: 190 MW) for civilian purposes

(b) Supply based on coal-fired thermal power (INALUM + civilian purposes: 400 MW) and hydropower for civilian purposes; coal-fired thermal power (400 MW) and hydropower from three sites (177.4 MW) for civilian purposes

(c) Supply based on gas-fired thermal power (INALUM + civilian purposes: 400 MW) and geothermal energy for civilian purposes; gas-fired thermal power (400 MW) and geothermal energy (Sarulla-2: 190 MW) for civilian purposes）

(d) Supply based on gas-fired thermal power (INALUM + civilian purposes: 400 MW) and hydropower for civilian purposes; gas-fired thermal power (400 MW) and hydropower from three sites (177.4 MW) for civilian purposes

(e) Supply based on installation of a new 600 MW coal-fired power plant; coal-fired thermal power (600 MW) for INALUM plant expansion and civilian purposes

This supply option entails constructing a new coal-fired thermal power plant with total plant capacity of 600 MW. In this case, the power plant would be constructed close to the aluminum smelting plant. Moreover, the business model in this case would entail a captive power or private generating plant operated by an SPC and power for civilian purposes would be sold as excess power to PLN. In this case, provided there is no problem in terms of grid stability, it would be possible to introduce a supercritical or ultra-supercritical system with single unit capacity of 600 MW. It would be necessary to investigate the location conditions in detail, confirm trends in the price of coal (fuel) and secure stable supply of coal.

(f) Supply based on installation of a new 600 MW gas-fired power plant; dedicated gas-fired thermal power (600 MW) for INALUM plant expansion and civilian purposes

This supply option entails constructing a new coal-fired thermal power plant with total plant capacity of 400 MW. In this case, the power plant would be constructed close to the aluminum smelting plant. As in option ⑤ above, the business model in this case would entail a captive power or private generating plant operated by an SPC and power for civilian purposes would be sold as excess power to PLN. In this case, provided there is no problem in terms of grid stability, it would be possible to introduce a supercritical or ultra-supercritical system with single unit capacity of 600 MW. It would be necessary to conduct a detailed investigation of location conditions, confirm price trends for gas, and secure a stable supply of gas as fuel.

Table 7.3-3 600 MW Supply Option (200 MW for INALUM Plant Expansion + 400 MW for Civilian Purposes): Outline and Development Risks

Serial No.	Power resource mode	Outline of the supply mode	Anticipated business model	Feasibility/issues in recent years
(1) 600 MW supply option assuming power purchase from PLN: the INALUM purchase tariff is a uniform rate irrespective of the power resource mode and generating cost (inflation of 37% is expected by 2015).				
PLN-600-①	Geothermal+ coal-fired thermal power	Develop Sarulla-2 (190 MW) and coal-fired thermal power (400 MW) Total output: 590 MW	Geothermal: IPP Coal: PLN/IPP There is a possibility regarding a PPP based on PLN+IPP.	Possibility of realization: Medium Delays are forecast in the Sarulla-2 development schedule. Technical confirmation entailing investigation of the amount of geothermal development potential, coal price trends, coal supply stability and location conditions, etc. is required.
PLN-600-②	Geothermal+ gas-fired thermal power	Develop Sarulla-2 (190 MW) and gas-fired thermal power (400 MW) Total output: 590 MW	Geothermal: IPP Gas: PLN/IPP There is a possibility regarding a PPP based on PLN+IPP.	Possibility of realization: Low Delays are forecast in the Sarulla-2 development schedule. It is necessary to carefully monitor progress in LNG base or pipeline construction. Project delays are forecast. Technical confirmation entailing investigation of the amount of geothermal development potential, gas price trends, gas supply stability and location conditions, etc. is required. If coal-fired thermal power is developed for INALUM, the problems surrounding delay of hydropower development can be mitigated.
PLN-600-③	Hydropower + coal-fired thermal power	Develop Toru-1, Simango-2 and Raisan-3,4 (total capacity 177.4 MW) and coal-fired thermal power (400 MW) Total output: 577.4 MW	Hydropower: IPP Local cooperation is a required condition for hydropower development by PLN. Coal: PLN/IPP There is a possibility regarding a PPP based on PLN+IPP.	Possibility of realization: Low There is a lack of implementation capacity regarding hydropower development by IPPs. Feasibility is low due to the differing work sites and operators. Technical confirmation entailing investigation of the amount of hydropower development potential is required. Technical confirmation of coal price trends, coal supply stability and location conditions, etc. is required
PLM-600-④	Hydropower + gas-fired thermal power	Develop Toru-1, Simango-2 and Raisan-3,4 (total capacity 177.4MW) and gas-fired thermal power (400 MW) Total output: 577.4 MW	Hydropower: IPP Local cooperation is a required condition for hydropower development by PLN. Gas: PLN/IPP There is a possibility regarding a PPP based on PLN+IPP.	Possibility of realization: Low It is necessary to carefully monitor progress in LNG base or pipeline construction. Project delays are forecast. There is a lack of implementation capacity regarding hydropower development by IPPs. Technical confirmation entailing investigation of the amount of hydropower development potential, gas price trends, gas supply stability and location conditions, etc. is required.

PLM-600-⑤	Coal-fired thermal power	Develop coal-fired thermal power (600 MW) Supercritical or ultra-supercritical introduction is possible (however, confirmation of grid stability is needed).	IPP/PLN There is a possibility regarding a PPP based on PLN+IPP.	Possibility of realization: High Sumatra has abundant reserves of low calorie coal, so it is relatively easy to procure fuel. Technical confirmation of coal price trends, coal supply stability and location conditions, etc. is required.
PLM-600-⑥-a	Gas-fired thermal power	Develop gas-fired thermal power (600 MW)	IPP/PLN There is a possibility regarding a PPP based on PLN+IPP.	Possibility of realization: Medium It is necessary to carefully monitor progress in LNG base or pipeline construction. Project delays are forecast. Technical confirmation of gas price trends, gas supply stability and location conditions, etc. is required.
PLM-600-⑥-b	Gas-fired thermal power	PLN: rehabilitation/boosting of Belawan thermal power plant (520 MW)	PLN	Possibility of realization: Medium It is necessary to carefully monitor progress in LNG base or pipeline construction. Project delays are forecast. Technical confirmation of gas price trends, gas supply stability and location conditions, etc. is required.

Serial No.	Power resource mode	Outline of the supply mode	Anticipated business model	Feasibility/issues in recent years
(2) 600 MW supply option assuming construction of a new dedicated power plant (200 MW) for INALUM plant expansion + securing of 200 MW for civilian purposes: a backup contract is required to provide insurance in the event where the dedicated power plant breaks down				
INALUM-600-①	Coal-fired thermal power + geothermal	Development of coal-fired thermal power (400 MW) for INALUM (200 MW) and civilian purposes (200 MW), and geothermal power for civilian purposes (Sarulla2: 190MW)	Coal: SPC If INALUM is nationalized, application of ODA will be a possibility regarding coal-fired thermal power. Geothermal: IPP	Possibility of realization: Medium Delays are forecast in the Sarulla-2 development schedule. Concerning dedicated thermal power supply, authorization as a specific power supplier/private power generator is required. It is highly likely that power supply from the dedicated plant for civilian purposes will be regarded as excess power. Technical confirmation entailing investigation of the amount of geothermal development potential, coal price trends, coal supply stability and location conditions, etc. is required.
INALUM-600-②	Coal-fired thermal power + hydropower	Development of coal-fired thermal power (400 MW) for INALUM (200 MW) and civilian purposes (200 MW),and hydropower for civilian purposes (3 sites, total output 177.4 MW)	Coal: SPC If INALUM is nationalized, application of ODA will be a possibility regarding coal-fired thermal power. Hydropower: IPP Local cooperation is a required condition for hydropower development by PLN.	Possibility of realization: Low There is a lack of implementation capacity regarding hydropower development by IPPs. Concerning dedicated thermal power supply, authorization as a specific power supplier/private power generator is required. It is highly likely that power supply from the dedicated plant for civilian purposes will be regarded as excess power. Technical confirmation entailing investigation of coal price trends, coal supply stability and location conditions, etc. is required.
INALUM-600-③	Gas-fired thermal power + geothermal	Development of gas-fired thermal power (400 MW) for INALUM (200 MW) and civilian purposes (200 MW), and geothermal power for civilian purposes (Sarulla2: 190MW)	Gas: SPC If INALUM is nationalized, application of ODA will be a possibility Geothermal: IPP	Possibility of realization: Low It is necessary to carefully monitor progress in LNG base or pipeline construction. Project delays are forecast. Delays are forecast in the Sarulla-2 development schedule. Technical confirmation entailing investigation of the amount of geothermal development potential, gas price trends, gas supply stability and location conditions, etc. is required. Concerning dedicated thermal power supply, authorization as a specific power supplier/private power generator is required. It is highly likely that power supply from the dedicated plant for civilian purposes will be regarded as excess power.

INALUM-600-④	Gas-fired thermal power + hydropower	Development of gas-fired thermal power (400 MW) for INALUM (200 MW) and civilian purposes (200 MW),and hydropower for civilian purposes (3 sites, total output 177.4 MW)	Coal: SPC If INALUM is nationalized, application of ODA will be a possibility regarding coal-fired thermal power. Hydropower: IPP Local cooperation is a required condition for hydropower development by PLN.	Possibility of realization: Low It is necessary to carefully monitor progress in LNG base or pipeline construction. Project delays are forecast. Technical confirmation entailing investigation of gas price trends, gas supply stability and location conditions, etc. is required. There is a lack of implementation capacity regarding hydropower development by IPPs. Concerning dedicated thermal power supply, authorization as a specific power supplier/private power generator is required. It is highly likely that power supply from the dedicated plant for civilian purposes will be regarded as excess power.
INALUM-600-⑤	Coal-fired thermal power	Install a coal-fired thermal power plant (600 MW) close to the aluminum smelting plant. Supercritical or ultra-supercritical introduction is possible (however, confirmation of grid stability is needed).	SPC Captive power/private generating plant If INALUM is nationalized, application of ODA will be a possibility for supercritical or ultra-supercritical generation.	Possibility of realization: High Authorization as a specific power supplier/private power generator is required. It is highly likely that power supply for civilian purposes will be regarded as excess power (thereby lowering the power sale price). Technical confirmation of coal price trends, coal supply stability and location conditions, etc. is required
INALUM-600-⑥	Gas-fired thermal power	Install a gas-fired thermal power plant (600 MW) close to the aluminum smelting plant.	SPC Captive power/private generating plant If INALUM is nationalized, application of ODA will be a possibility.	Possibility of realization: Medium It is necessary to carefully monitor progress in LNG base or pipeline construction. Project delays are forecast. Technical confirmation of gas price trends, gas supply stability and location conditions, etc. is required. Authorization as a specific power supplier/private power generator is required. It is highly likely that power supply for civilian purposes will be regarded as excess power (thereby lowering the power sale price).

7.4 Applied Business Model in the Electric Power Supply Options

As is indicated in Tables 7.3-1~7.3-3, numerous cases can be considered for the power supply options outlined in section 7.3 depending on the purpose of power supply (for INALUM or for civilian purposes) and the scale of development (200 MW / 400 MW / 600 MW). Concerning the business models, these can be arranged as shown in Table 7.4-1 according to each power mode and purpose of use for the following reasons.

- ♦ There is a limit to the supply capacity of each selected hydropower and geothermal power resource (each source is less than 200 MW).
- ♦ The construction cost for coal-fired/thermal power development does not change according to the scale of development[8].
- ♦ The business model is almost uniquely set according to the power resource mode and purpose of use of electric power. (Example: hydropower and geothermal energy→IPP, power for INALUM→SPC, etc.)

In Table 7.4-1, the business model in the cases of 'Civil use only' and 'Civil use priority' are PLN, IPP or PPP consisting of PLN with IPP, while the model in the case of power for INALUM is purchasing from PLN. (See Table 6.2-2 and 6.2-3 for power purchase prices). In the case of 'INALUM priority + civil use,' the business operator is an SPC or INALUM in the event where it is nationalized. In cases where the scale of development is 200 MW, INALUM needs to also consider binding a backup contract with PLN (synchronized connection: currently under examination by PLN). In this case, it is necessary to pay a basic charge (normal tariff + additional charge) whether or not there is use, while the metered charge is levied according to the level of power consumption (including additional charge). There are no clear specifications concerning the additional charge. Out of the 'INALUM priority + civil use' cases, if the scale of development exceeds 200 MW, it is possible that the sale of civil power to PLN will be treated as excess power. In this case, only a low sale price sufficient to cover operating costs such as the fuel cost and personnel expenses, etc. can be expected.

[8] Merits of scale can usually be expected in the case of coal-fired/thermal power, however, in a feasibility study such as this case (where there are too many uncertain elements in development conditions to calculate the development costs in detail), since no major differences arise according to the scale of development, in this Study it is assumed that the development cost is simply proportional to the generated output.

Table 7.4-1 Business Model in the Power Supply Options

<table>
<tr><th rowspan="2">Generating mode</th><th rowspan="2">Project</th><th rowspan="2" colspan="2">Generating Capacity (MW)</th><th colspan="5">Business Model</th></tr>
<tr><th>PLN</th><th>IPP</th><th>SPC (CP)</th><th>PPP</th><th>INALUM</th></tr>
<tr><td rowspan="4">Coal</td><td>Close to the smelting plant</td><td colspan="2">200/400/600 (subcritical)</td><td rowspan="2" colspan="2">Not applicable</td><td>INALUM priority + civil use</td><td rowspan="2">Not applicable</td><td>INALUM priority + civil use</td></tr>
<tr><td>Close to the smelting plant</td><td colspan="2">Unit capacity: 450or more (supercritical / ultra-supercritical)</td><td>INALUM priority + civil use</td><td>INALUM priority + civil use</td></tr>
<tr><td>Within the range of the PLN grid</td><td colspan="2">200/400/600 (subcritical)</td><td>Civil use priority</td><td>Civil use priority</td><td rowspan="2">Not applicable</td><td>Civil use priority</td><td rowspan="2">Not applicable</td></tr>
<tr><td>Within the range of the PLN grid</td><td colspan="2">Unit capacity: 450or more (supercritical / ultra-supercritical)</td><td>Civil use priority</td><td>Civil use priority</td><td>Civil use priority</td></tr>
<tr><td rowspan="3">Gas</td><td>Close to the smelting plant</td><td colspan="2">200/400/600</td><td colspan="2">Not applicable</td><td>INALUM priority + civil use</td><td>Not applicable</td><td>INALUM priority + civil use</td></tr>
<tr><td>Belawan rehabilitation</td><td colspan="2">520</td><td>Civil use priority</td><td colspan="4">Not applicable</td></tr>
<tr><td>Inside the PLN grid range</td><td colspan="2">200/400/600</td><td>Civil use priority</td><td>Civil use priority</td><td></td><td>Civil use priority</td><td>Civil use priority</td></tr>
<tr><td>Geothermal</td><td>Sarulla-2</td><td colspan="2">190</td><td>Not applicable</td><td>Civil use priority</td><td>※</td><td colspan="2">Not applicable</td></tr>
<tr><td rowspan="3">Hydro</td><td>Toru-1</td><td>38.4</td><td rowspan="3">177.4</td><td>Civil use only</td><td>Civil use only</td><td rowspan="3" colspan="3">Not applicable</td></tr>
<tr><td>Simanggo-2</td><td>59.0</td><td>Civil use only</td><td>Civil use only</td></tr>
<tr><td>Raisan-3,4</td><td>80.0</td><td>Civil use only</td><td>Civil use only</td></tr>
</table>

※: Sarulla-2 is planned as a civil use power resource in RUPTL 2010 and there is deemed to be little possibility of this plant directly supplying power to INALUM. For reference, Chapter 8 Addendum 1 shows the economic and financial analysis for the case where Sarulla-2 is used as a dedicated supply resource for INALUM.

Chapter 8 Economic and Financial Analysis of Power Supply Options

8.1 Operating Setup and Fundraising

JICA and JBIC have some kinds of financing schemes regarding the project loans. The application of such schemes has a major bearing on the economic feasibility of the project. The following sections examine JBIC and JICA loan schemes and the interest rate levels they entail.

8.1.1 JBIC Finance Schemes

The standard loan terms offered by JBIC differ according to the type of finance, and the following financing schemes are applicable to the power generation project here.

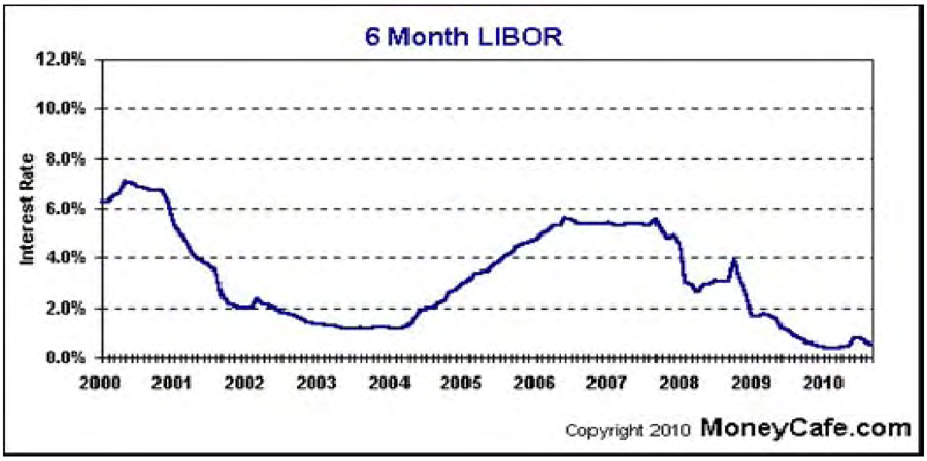
- Finance types
  Finance types are "Import, Investment and Business development (resource development and strengthen international competitiveness) " and "Export loans", and it is thought that the first finance type of import, investment and business development will be applied to the project.

- Loan interest rate of important, investment and business development loan
  The contents are set according to the interest rate for the loan period, the deferment and repayment term.

- Interest rate of yen loans 1.10%
  This is the rate in the case of the loan (10 years (3 year deferment and 7 year payment), while lending rates in other cases of loan and grace period are discussed separately. Additionally, a special interest rate (0.70~0.90%) is applied upon considering promotion of the overseas development and acquisition of important resources for Japan and keeping Japan's international competitiveness.

- Interest rate in case of foreign currency (dollar) loan
  JBIC offers interest rates based on the LIBOR (London Inter-Bank Offered Rate) (6 month rate in US dollars).

The prime loan rate is set with LIBOR +0.25%, but other cases are set by the loan rate between LIBOR +0.5~2.5% recently. JBIC basically sets the interest rate according to each project, so it is necessary to consider the rate over a certain range. (In this Study, the scope of interest rate is considered to reflect the current market found in hearings with major trading companies doing business in Jakarta). The LIBOR varies according to the policy interest rate and credit risk in each country. From around November 2008, the LIBOR plummeted in the wake of the subprime mortgage crisis and Lehman shock. Whereas it fluctuated around 5% in 2006 and 2007, it dropped to 3% level in 2008, 1% level in 2009 and less than 1% in 2010.



Source: Fannie Mae, British Bankers' Association

Figure 8.1-1 Trends in the LIBOR based on US Dollar Rate (6 months)

Table 8.1-1 LIBOR based on US Dollar Rate (6 months)

Month/Average	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Jan	6.24%	5.36%	1.99%	1.35%	1.21%	2.96%	4.81%	5.40%	4.60%	1.75%	0.43%
Feb	6.33%	4.96%	2.07%	1.34%	1.17%	3.15%	4.99%	5.37%	3.04%	1.66%	0.38%
Mar	6.53%	4.71%	2.33%	1.26%	1.16%	3.39%	5.12%	5.32%	2.93%	1.80%	0.39%
Apr	6.61%	4.23%	2.10%	1.29%	1.37%	3.42%	5.29%	5.36%	2.61%	1.74%	0.44%
May	7.06%	3.99%	2.09%	1.22%	1.58%	3.53%	5.32%	5.38%	2.97%	1.57%	0.53%
Jun	7.01%	3.83%	1.95%	1.12%	1.94%	3.69%	5.64%	5.38%	2.91%	1.24%	0.75%
Jul	6.89%	3.69%	1.86%	1.15%	1.99%	3.92%	5.55%	5.39%	3.11%	1.11%	0.75%
Aug	6.83%	3.48%	1.82%	1.21%	1.99%	4.08%	5.45%	5.33%	3.08%	0.93%	0.67%
Sep	6.76%	2.53%	1.75%	1.18%	2.17%	4.22%	5.37%	5.54%	3.12%	0.76%	0.50%
Oct	6.72%	2.17%	1.62%	1.22%	2.30%	4.45%	5.39%	5.13%	3.98%	0.63%	
Nov	6.68%	2.10%	1.47%	1.23%	2.62%	4.58%	5.35%	4.81%	3.12%	0.56%	
Dec	6.21%	1.98%	1.38%	1.22%	2.78%	4.69%	5.37%	4.91%	2.59%	0.49%	
Year Average	6.66%	3.59%	1.87%	1.23%	1.86%	3.84%	5.30%	5.28%	3.17%	1.19%	0.40%
Moving Average	3.13%	2.77%	2.68%	3.02%	3.01%	3.20%	3.07%	2.51%	1.59%	0.79%	0.40%

Note 1: Year Average refers to the average interest rate from January to December each year.
Note 2: Moving Average refers to the average interest rate from the year in question to 2010 (moving average interest rate).

Source: Fannie Mae, British Bankers' Association

The dollar-based LIBOR is determined according to the policy interest rate of leading countries (Ex. the Federal funds rate of the United States) and the credit risk concerning the fiscal and financial issues faced by each country. In other words, the LIBOR is determined by "Policy interest rate", "Credit risk premium" and "Other factors". According to this formula, it is an important prediction when each country's policy interest rates currently less than 1% will return to the past average level. However, it is difficult to be considered that the current rate are unlikely to return to more than 3% in near future. One reason for the consideration is that there is anxiousness that credit risk will be happened as it did in 2008 and 2009, if other country have fiscal crisis like Greece. However, judging from past experience, higher credit risk and higher policy interest rate are inversely proportional, i.e. when the policy interest rate rises, usually the credit risk tends to fall.

Considering this situation, the following scenario can be predicted regarding the LIBOR over the coming 30 years.

2010	: Roughly 0.5% to 0.7%
Until around 2015	: 1.0% = policy interest rate 0.5% + credit risk premium 0.5%
Until around 2020	: 2.5% = policy interest rate 2.3% + credit risk premium of 0.2% at most
Until around 2030	: 3.0% = policy interest rate 3.0% + credit risk premium at almost 0%
Until around 2040	: 4.0% = policy interest rate 4.0% + credit risk premium at almost 0%

In this scenario, the average LIBOR over the 30 year from 2010 to 2040 is roughly 2.53%, which is less than the past average of 3%. It is predicted that the LIBOR will revert to almost the past average level after 2030. Assuming the said terms, the average interest rate offered by JBIC between 2010 and 2040 is set at between 3%~5%.

- Loan ratio in the finance

  The JBIC loan ratio is basically set at 60% of the necessary funds, and the upper limit for overseas loans in the resources projects is 70%. For the project, the loan ratio of 70% shall be adopted.

- Repayment of import, investment and business development

  The standard repayment period of the loan type is 10 years (three years deferment + seven year repayment), however, JBIC sets the period appropriately according to the contents of the project after negotiating between the JICA and project side. In this project, it will be necessary to conduct separate negotiations with JBIC, the repayment period with 12 years following the start of operation is assumed.

8.1.2 ODA Loan Scheme

Special interest rates are applied in projects that contribute to promoting overseas development of resources that are important for Japan and projects that contribute to maintaining the international competitiveness of Japanese industry. This is “Low interest rate ODA loans”. JICA applies such low interest financing in the shape of three schemes, namely “General scheme”, “Preferential scheme”, and “Climate change scheme”. Additionally, another type of scheme in JICA named “Japan technology utilization condition (STEP)” is prepared.

(1) Financing in the general scheme

Target fields in the general scheme are as follows.

- Financing as fundraising support in the mineral exploration business
- Support for development of agriculture, forestry and fisheries, improvement of food conditions and expansion of employment in the industry, etc.
- Support for preparatory study and trial implementation of development activities
- Support of private sector infrastructure projects (role of private financial institutions in preparing the financing environment)
- Investment (Regarding overseas financing, although all sectors are targeted, the investment is conducted with respect to projects that are difficult to implement on the private sector and have high potential for economic cooperation).

As Indonesia is a medium income country, general terms scheme are given as 1.40% interest, repayment period of 25 years, grace period of 7 years and untied procurement.

(2) Target fields for application of preferential scheme

- Projects related to the global environment
- Projects for support of human resources development
- Small and medium enterprises
- Support for peace keeping

In the case of Indonesia, preferential schemes are given as 0.65% interest, repayment period of 40 years, grace period of 10 years and untied procurement.

(3) Climate change scheme

This scheme is designed to support projects that make a contribution to development and economic growth of developing countries and reduction of GHG emissions; for example, it can be used to raise funds for utilization of renewable energy (geothermal power development, etc.) and high efficiency energy (supercritical coal-fired thermal power generation, etc.) and introduction of energy saving equipment, etc. In the case of Indonesia, climate change scheme is given as 0.30% interest, repayment period of 40 years, grace period of 10 years and untied procurement.

(4) Japan technology utilization scheme (STEP)

This program aims to utilize Japanese excellent technology and know-how in order to promote 'visible assistance' via technology transfer to developing countries. The targets are countries that tied loans can be provided according to OECD rules.

- ♦ Eligible projects include power generation, transmission and distribution, petroleum and gas transportation and storage facilities, and environmental projects, etc., conditional on Japanese technology, equipment and materials being needed and actually utilized.
- ♦ Interest rate and repayment period are reviewed every year so as to make it possible to extend tied aid.
- ♦ In terms of procurement conditions, main contractors are tied to Japanese firms, while subcontractors are generally untied. Joint ventures (JV) with the borrowing country are permitted for main contractors, but these are conditional on the Japanese firm being the leading partner.
- ♦ STEP covers up to 100% of eligible items in the total project cost.
- ♦ Regarding procurement from Japan, not less than 30% of the total amount of contract(s) financed by STEP loan must be accounted for by goods from Japan and services provided by Japanese firms.

8.1.3 Financing conditions and Interest Scenarios

(1) Sublease financing cost

Sublease financing cost arises when funding for the project is provided via an Indonesian bank other financial agencies. Sublease financing cost will not arise if the project is directly financed by a Japanese bank. In this Project, the interest rate scenario was compiled assuming that sublease financing cost will not arise for the JBIC financing but that the sublease financing rate will be between 0.5~1.0% for ODA loans.

(2) JBIC syndicated interest scenario

Bearing in mind the JBIC rule of LIBOR＋α (3~5%), it is assumed that the city bank interest rate is set around 0.5~1.0% higher than that. As a result, it is thought that the JBIC syndicated loan interest rate will fluctuate in the range of 4~6% between 2015 and 2040. Accordingly, the following scenarios shall be assumed for JBIC syndicate interest, i.e. 4%, 5%, 6%, and 7%. (7% is based entirely on capital of private sector judging from past experience.) Also, assuming that 30% of the total investment is derived from own capital, therefore the financing ratio will become 70%.

(3) JICA financing and interest scenarios

JICA schemes for ODA financing comprise the general scheme where the interest rate is 1.4%, the preferential scheme where the interest rate is 0.65%, and the climate change scheme where the interest rate is 0.3%. Taking into account a sublease financing ratio in Indonesia of 0.5~1.0%, the ODA interest rate scenarios here will be 1.5%, 2.0%, 2.5% and 3.0%. Also, assuming that 15% of the total investment is derived from own capital in line with Japan's ODA financing, therefore the financing ratio will become 85%.

8.2 Conditions and Criteria of Feasibility Study

8.2.1 Financial Analysis Policy

(1) Project criteria

Project criteria are generally conducted as financial analysis based on "Direct accounting principles". In particular, when project feasibility is expressed in a manner that is dependent on fund procurement, rather than estimating the inherent profitability of the project, sometimes the project feasibility is determined by the quality of fund procurement. However, project feasibility is essentially independent of fund procurement, and the project feasibility that is independent of fund procurement should be used to determine the profitability of a project. As achieving the purposes, the internal rate of return method that is based on the present value method has been prepared and is used widely today. However, concerning projects for infrastructure construction or energy development, etc. that have an extremely strong public-ness, the internal rate of return is often low, and such projects cannot be realized without support from governments, international development agencies and financial institutions. The phenomenon is particularly true of projects in newly emerging nations, middle-income countries and developing countries. In such cases, investors, city banks and trading firms use the return on equity (ROE) as an indicator of profitability and financial stability in projects. The ROE varies according to the interest rate on loans but it tends to increase in projects where funds are obtained at low interest rates. This is known as the 'leverage effect.' Usually in projects of a highly public-ness, the ROE is calculated in order to indicate profitability to project owners and stakeholders, while the internal rate of return (IRR) is calculated in order to assess project feasibility for the recipient government and international financial agencies and to provide a comparison with other projects.

(2) Appraisal by IRR and ROE

For a long time, the IRR criterion was set at no less than 15% throughout the world. In this case, assuming an interest rate of 7% on a loan with 70% of total investment, the ROE will be approximately 20%. Such an investment return was previously standard practice for private sector enterprises, however, the situation has undergone major change following the Lehman shock, global recession, fiscal worsening of the EU, worldwide deflation and low interest policies, etc. In other words, due to the low interest rates applied to fund procurement now, profitability can still be secured even when the IRR is low. Moreover, although a higher ROE is better for completely privatized enterprises working in a totally competitive environment, this is not necessarily the case for project investors who receive low interest loans and debt guarantees from governments and international agencies. Parties and investors in nationally or internationally assisted projects should not expect excessive benefits. Rather, project stakeholders should be more interested in the incidental benefits of projects such as holding good bilateral relations, expansion of employment and supplying stably products to Japan, etc.

Considering the current conditions of investors and financing institutions in Indonesia, since ROE in the range of 15~20% is expected, power tariffs should be set to realize the ROE. In the financial analysis, the anticipated ROE is 18% in private sector projects conducted by JBIC syndicates, while the ROE of projects receiving ODA financing is 15%. Within a power tariff regime that satisfies the above ROE levels, since the long-term interest rate in JBIC syndicate loans is estimated at between 4~7%, the IRR is deemed to be between 8~14% (twice the interest rate). Meanwhile, in ODA projects, since the interest rate is in the range of 1~3%, the IRR in state-owned or public project operators is deemed to be in the range of 2~6%.

(3) Effective interest rate

Borrowing rates in emerging and developing countries are generally higher than in developed countries. For example, in Indonesia where the inflation percentage is 6% in 2010, the short-term interest rate is between 15 and 16%. In other words, the interest rate is determined in a manner that includes the inflation rate. This is referred to as the nominal interest rate, however, in this financial analysis, since inflation factors are excluded, the effective interest rate that doesn’t include inflation is used. Until now the effective interest rate in emerging and developing countries has usually been around 7%, while in developed countries with smaller demand for funds, it has been around 5%. However, the present effective interest rate in Indonesia is between 9~10%, so it cannot say it is low interest rate.

(4) Discount rate

The discount rate that is used for linking future cash flow and generating unit prices to current value is basically determined in conjunction with the weighted average capital cost (WACC). However, in reality, the effective interest rate in a country is usually used as the discount rate. Accordingly, since the effective interest rate in Indonesia is currently around 10%, and 10% discount rate is used in that country’s economic analysis materials (Geothermal Plan by PLN in 2006), 10% discount rate shall be used in the project too.

8.2.2 Financial Analysis Conditions

(1) Analysis at actual prices

In the Project analysis, inflation factors based on domestic conditions in Indonesia will basically not be taken into consideration. This does not mean that all costs will remain as they are at present costs and prices. For example, even if there is no inflation in Indonesia, there are factors that cause cost and price inflation in international markets. Looking at global economic trends, it is expected that energy prices and prices for food and mineral resources, etc. will increase from now on. Such factors will be incorporated into the accounting as 'escalation in actual prices.'

(2) Energy prices

Experts consider that energy prices for crude oil, coal and natural gas, etc. will increase on a global scale due to increased mining costs and extending transportation distances, irrespective of inflation in Indonesia. For example, the crude oil price stands at 80 USD/barrel on the WTI base (in 2010), however, the Government of Saudi Arabia is of the opinion that, 'crude oil prices should increase by an amount equivalent to dollar depreciation (2.0~2.5% per year),' hinting at a price of 130 USD/bbl by 2030. In the short term, energy prices rise and fall according to respective conditions, however, in the long run, coal and natural gas prices display the same trends as crude oil prices. Accordingly, it is assumed that coal and gas prices will increase at a similar rate to the crude oil price in the project.

(3) Calculation term

The financial assessment term has been set as 30 years in consideration of the average service life of equipment and the duration of business concessions in Indonesia.

(4) Construction costs

The construction costs used in the economic and financial analysis basically include only power generation plant cost. Therefore the long distance transmission facility costs are not included. In case of power generation plants near to the smelting factory, it is assumed that the power can be transmitted directly to the smelting factory, and unspecified location power generators send the power near transmission facilities of PLN.

(5) O/M costs

O/M costs indicate thermal fuel costs, personnel costs, supplies expenses and repair costs, etc., and the method for setting these items will be as follows.

Table 8.2-1 Method for Estimating O&M Costs by Power Generation

Coal	Natural Gas	Geothermal	Hydropower
6.0% of construction cost and Fuel cost	5.0% of construction cost and Fuel cost	3.5% of construction cost and replacement well cost	2.0% of construction cost

Note) O&M cost for coal-fired thermal power has been set at 6.0% because use of lignite is assumed.

(6) Composition of the power generation cost

Taking into consideration the above points, fuel costs will increase over the duration of the project, meaning that the ratio of fixed costs such as depreciation and interest, etc. will grow relatively smaller. However, since fuel costs for coal and gas, etc. will increase, the variable cost profit ratio excluding fuel costs for coal-fired and gas-fired thermal power will increase at the same rate as inflation in the amount of crude oil. However, in the case of hydropower and geothermal power generation, since no fuel costs are incurred, there is no cost increase due to escalation.

(7) Power tariffs

Concerning costs, variable costs will increase at the same rate as crude oil while fixed costs will hardly change at all. Conversely, fixed costs may decline in line with decreases in lending interest rates. Accordingly, upon incorporating variable costs and fixed costs, the power tariffs will increase at a lower rate than the price of crude oil. In other words, the increase rate will be lower than the prices of gas and coal. However, since the variable cost profit (but the variable cost profit rate is constant) will increase, and also the earnings will increase over time.

(8) Depreciation, tax rate, preferential measures system

- Considering the deterioration term in coal-fired thermal power, gas-fired thermal power and geothermal power generation, the depreciation period of target equipment is set at 25 years, while the depreciation period in hydropower generation has been set at 30 years to coincide with the economic calculation period (there are also cases of 40 years and 50 years).

- The corporation tax rate based on the latest tax system shall be 25%.
- Under the revised tax law of October 2008, in the case of geothermal power generation, 5% of pretax profits will be deducted from taxable income for six years from the start of operation.

8.3 Profitability calculation and evaluation

When calculating and evaluating profitability of the projects, the following scenarios will be prepared.

(1) Subcritical coal-fired thermal power and gas-fired thermal power

Concerning the subcritical coal-fired and gas-fired thermal power cases described in Chapter 7, in evaluating of profitability, there is no disparity in economic and financial analysis (apart from the economic scale) for the 200 MW, 400 MW and 600 MW cases. Accordingly, the 200 MW option is analyzed in the economic and financial analysis. In other words, the calculated power generation unit cost and power tariffs are equal in all cases.

(2) Supercritical/ Ultra supercritical coal-fired thermal power

Concerning the supercritical and ultra-supercritical coal-fired thermal power generation cases, which are technically subject to constraints on scale, the minimum scale possible for construction is set without adhering to the 200, 400 or 600 MW classifications. Here, a scale of 450 MW has been set. Moreover, in cases of supercritical and ultra-supercritical coal-fired thermal power generation, climate change loans are applicable when applying for ODA financing.

(3) Geothermal power generation

In the case of geothermal power generation, since the generated steam varies according to the well, it is set in the range of 6~10 MW per well. Here, a figure of 8 MW/well is evaluated. Moreover, climate change loans are applied when applying for ODA financing for geothermal power generation.

(4) Reconstruction of existing facilities

Concerning the reconstruction of existing facilities such as the upgrading of Belawan (gas-fired thermal power plant), new capacity will be combined with existing capacity to give the following: 520 MW (= 400 MW (new installation) + 120 MW (existing plant)).

The following table shows calculation and evaluation cases for options according to power generation mode and type of operator as selected in Chapter 7. Economic and financial analysis is conducted for the cases in each cell.

Table 8.3-1 Cases by Power Generating Mode, by Project Operator and by Type of Finance

Power generating mode	Project name	Capacity	Project Operator				
			PLN	IPP	SPC	PPP	INALUM
			ODA	JBIC	JBIC	ODA	ODA
			ROE=15%	ROE=18%	ROE=18%	ROE=15%	ROE=15%
Coal	Near to the smelting plant	200/400/600 MW Subcritical			C_SPC_ Near		C_INA_ Near
	Near to the smelting plant	450 MW or higher Supercritical / Ultra-supercritical			C_SPC_ NU450		C_INA_ NU450
	Unspecified location	200/400/600 MW Subcritical	C_PLN_ Any	C_IPP_ Any		C_PPP_ Any	
	Unspecified location	450 MW or higher Supercritical / Ultra-supercritical	C_PLN_ AU450	C_IPP_ AU450		C_PPP_ AU450	
LNG	Near to the smelting plant	200/400/600 MW			L_SPC_ Near		L_INA_ Near
	Belawan upgrading	520 MW	L_PLN_ Belaw				
	Unspecified location	200/400/600 MW	L_PLN_ Any	L_IPP_ Any		L_PPP_ Any	
Geothermal	Sarulla-2	190 MW		S_IPP Sarul			
Hydropower	Total	177.4 MW	H_PLN_ Total	H_IPP_ Total			
	Toru-1	38.4 MW	H_PLN_ Touru	H_IPP_ Touru			
	Simanggo-2	59.0 MW	H_PLN_ Simang	H_IPP_ Simang			
	Raisan-3,4	80.0 MW	H_PLN_ Raisan	H_IPP_ Raisan			

8.3.1 Economic Analysis for Coal-fired Thermal Power Generation Options

(1) Subcritical coal-fired thermal power generation by SPC near to the smelting plant

- ♦ The SPC can use JBIC syndicate loans in this case
- ♦ Subcritical construction costs are set upon referring to the latest cases in Indonesia
- ♦ Assuming application of a JBIC syndicate loan, the average interest rate is estimated at 5%
- ♦ If capacity is 400 MW or higher, power is supplied for INALUM and domestic uses

Table 8.3-2 Calculation Results for Subcritical Coal-fired Thermal Power Generation by an SPC near to the Smelting Plant

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_SPC_ Near	4%	4.3	5.8	11.6	18.0
	5%	4.3	5.9	12.1	18.0
	6%	4.4	5.9	12.5	18.0
	7%	4.4	6.0	12.9	18.0

Table 8.3-3 Preconditions for Subcritical Coal-fired Thermal Power Generation by an SPC Near to the Smelting Plant

Plant Preconditions		Finance Preconditions	
Capacity	200MW	Investment	160 million USD
Operation rate	70%	Capital	30% of necessary funds
Generating efficiency	39.0%	Grace/Repayment	None/12 years
Coal price	45USD/t (4500kcal/kg)	Depreciation period	25 years

Note) The price of coal is escalated with 2.0% per year.

(2) Subcritical coal-fired thermal power generation by INALUM near to the smelting plant

- ♦ Assuming application of a JBIC syndicated loan, the average interest rate is estimated at 5%

Table 8.3-4 Calculation Results for Subcritical Thermal Power Generation by INALUM

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_INA_ Near	4%	4.3	5.5	10.2	15.0
	5%	4.3	5.6	10.6	15.0
	6%	4.4	5.6	11.0	15.0
	7%	4.4	5.7	11.5	15.0

Table 8.3-5 Preconditions for Subcritical Thermal Power Generation by INALUM

Plant Preconditions		Finance Preconditions	
Capacity	200MW	Investment	160 million USD
Operation rate	70%	Capital	30% of necessary funds
Generating efficiency	39.0%	Grace/Repayment	None/12 years
Coal price	45USD/t (4500kcal/kg)	Depreciation period	25 years

Note) The price of coal escalates by 2.0% per year.

(3) Supercritical/ Ultra-supercritical coal-fired thermal power generation by SPC near to the smelting plant

- Power is supplied for INALUM and to PLN
- Assuming the IPP is eligible for a JBIC syndicated loan, the average interest rate is estimated at 5%

Table 8.3-6 Results for Supercritical/ Ultra-supercritical Coal-fired Thermal Power Generation by an SPC near to the Smelting Plant

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_SPC_NU450	4%	5.0	7.5	11.5	18.0
	5%	5.1	7.6	12.0	18.0
	6%	5.2	7.7	12.4	18.0
	7%	5.2	7.8	12.8	18.0

Table 8.3-7 Preconditions for Supercritical/ Ultra-supercritical Coal-fired Thermal Power Generation by an SPC near to the Smelting Plant

Plant Preconditions		Finance Preconditions	
Capacity	450MW	Investment	585 million USD
Operation rate	70%	Capital	30% of necessary funds
Generating efficiency	41.0%	Grace/Repayment	None/12 years
Coal price	45 USD/t (4500kcal/kg)	Depreciation period	30 年

Note) The price of coal is escalated with 2.0% per year.

(4) Supercritical/ Ultra-supercritical coal-fired thermal power generation by INALUM near to the smelting plant

- Power is supplied for INALUM and via PLN for domestic uses.
- In this case, since the project is eligible for a climate change yen loan, an ODA low interest at 2% can be used.

Table 8.3-8 Results for Supercritical/ Ultra-supercritical Coal-fired Thermal Power Generation by INALUM

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_INA_ AU450	1.5%	4.9	5.1	2.3	15.0
	2.0%	5.0	5.2	2.9	15.0
	2.5%	5.0	5.3	3.4	15.0
	3.0%	5.1	5.4	3.9	15.0

Table 8.3-9 Preconditions for Supercritical/ Ultra-supercritical Coal-fired Thermal Power Generation by INALUM

Plant Preconditions		Finance Preconditions	
Capacity	450MW	Investment	585 million
Operation rate	70%	Capital	15% of necessary funds
Generating efficiency	41.0%	Grace/Repayment	10 years/30 years
Coal price	45 USD/t (4500kcal/kg)	Depreciation period	30 years

Note) The price of coal is escalated with 2.0% per year.

(5) Subcritical coal-fired thermal power generation by PLN at an unspecified location

- The average interest rate on fund procurement by PLN is estimated at 5%.
- However, the power purchase price is according to the PLN tariff scheme.

Table 8.3-10 Results for Subcritical Coal-fired Thermal Power Generation by PLN at an Unspecified Location

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_PLN_ Any	4%	4.3	5.5	10.2	15.0
	5%	4.3	5.6	10.6	15.0
	6%	4.4	5.6	11.0	15.0
	7%	4.4	5.7	11.5	15.0

Table 8.3-11 Preconditions for Subcritical Coal-fired Thermal Power Generation by PLN at an Unspecified Location

Plant Preconditions		Finance Preconditions	
Capacity	200MW	Investment	160 million USD
Operation rate	70%	Capital	30% of necessary funds
Generating efficiency	39.0%	Grace/Repayment	None/12 years
Coal price	45 USD/t (4500kcal/kg)	Depreciation period	25 years

Note) The price of coal is escalated with 2.0% per year.

(6) Subcritical coal-fired thermal power generation by an IPP at an unspecified location

- Assuming the IPP is eligible for a JBIC syndicated loan, the average annual interest rate is estimated at 5%.
- Since the IPP will basically sell power to PLN, INALUM will have to purchase it via PLN.

Table 8.3-12 Results for Subcritical Coal-fired Thermal Power Generation by an IPP at an Unspecified Location

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_IPP_ Any	4%	4.3	5.8	11.6	18.0
	5%	4.3	5.9	12.1	18.0
	6%	4.4	5.9	12.5	18.0
	7%	4.4	6.0	12.9	18.0

Table 8.3-13 Preconditions for Subcritical Coal-fired Thermal Power Generation by an IPP at an Unspecified Location

Plant Preconditions		Finance Preconditions	
Capacity	200MW	Investment	160 million USD
Operation rate	70%	Capital	30% of necessary funds
Generating efficiency	39.0%	Grace/Repayment	None/12 years
Coal price	45 USD/t (4500kcal/kg)	Depreciation period	25 years

Note) The price of coal escalates by 2.0% per year.

(7) Subcritical coal-fired thermal power generation by a PPP at an unspecified location

- Assuming the PPP is eligible for a JBIC syndicated loan, the average annual interest rate is estimated at 5%.
- However, in cases where the PPP sells power via PLN, the PLN tariff scheme will be adhered to.

Table 8.3-14 Results for Subcritical Coal-fired Thermal Power Generation by a PPP at an Unspecified Location

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_PPP_ Any	4%	4.3	5.5	10.2	15.0
	5%	4.3	5.6	10.6	15.0
	6%	4.4	5.6	11.0	15.0
	7%	4.4	5.7	11.5	15.0

Table 8.3-15 Preconditions for Subcritical Coal-fired Thermal Power Generation by a PPP at an Unspecified Location

Plant Preconditions		Finance Preconditions	
Capacity	200MW	Investment	160 million USD
Operation rate	70%	Capital	30% of necessary funds
Generating efficiency	39.0%	Grace/Repayment	None/12 years
Coal price	45 USD/t (4500kcal/kg)	Depreciation period	25 years

Note) The price of coal escalates by 2.0% per year.

(8) Supercritical/ Ultra-supercritical coal-fired thermal power generation by PLN at an unspecified location

- PLN supplies power for INALUM and for domestic uses.
- In this case, since PLN is eligible for a climate change yen loan, an ODA loan can be used, and the interest rate is estimated at around 2.0%.
- However, the purchase price of power for INALUM is according to the PLN tariff scheme.

Table 8.3-16 Results for Supercritical/ Ultra-supercritical Coal-fired Thermal Power Generation by PLN at an Unspecified Location

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_PLN_AU450	1.5%	4.9	5.1	2.3	15.0
	2.0%	5.0	5.2	2.9	15.0
	2.5%	5.0	5.3	3.4	15.0
	3.0%	5.1	5.4	3.9	15.0

Table 8.3-17 Preconditions for Supercritical/ Ultra-supercritical Coal-fired Thermal Power Generation by PLN at an Unspecified Location

Plant Preconditions		Finance Preconditions	
Capacity	450MW	Investment	585 million USD
Operation rate	70%	Capital	15% of necessary funds
Generating efficiency	41.0%	Grace/Repayment	10 years/30 years
Coal price	45 USD/t (4500kcal/kg)	Depreciation period	30 years

Note) The price of coal escalates by 2.0% per year.

(9) Supercritical/ Ultra-supercritical coal-fired thermal power generation by an IPP at an unspecified location

- ♦ The IPP supplies power via PLN for INALUM and domestic uses.
- ♦ Assuming the IPP is eligible for a JBIC syndicated loan, the average annual interest rate is estimated at 5%.

Table 8.3-18 Results for Supercritical/ Ultra-supercritical Coal-fired Thermal Power Generation by an IPP at an Unspecified Location

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_IPP_ AU450	4%	5.0	7.5	11.5	18.0
	5%	5.1	7.6	12.0	18.0
	6%	5.2	7.7	12.4	18.0
	7%	5.2	7.8	12.8	18.0

Table 8.3-19 Preconditions for Supercritical/ Ultra-supercritical Coal-fired Thermal Power Generation by an IPP at an Unspecified Location

Plant Preconditions		Finance Preconditions	
Capacity	450MW	Investment	585 million USD
Operation rate	70%	Capital	30% of necessary funds
Generating efficiency	41.0%	Grace/Repayment	None/12 years
Coal price	45 USD/t (4500kcal/kg)	Depreciation period	30 years

Note) The price of coal is escalated with 2.0% per year.

(10) Supercritical/Ultra-supercritical coal-fired thermal power generation by a PPP at an unspecified location

- ♦ Power is supplied for INALUM and for domestic uses.
- ♦ In this case, since the project is eligible for a climate change yen loan, an ODA loan can be used, and annual interest rate is estimated at around 2%.
- ♦ However, since power for INALUM is purchased via PLN, the purchase tariff is set according to the PLN tariff scheme.

Table 8.3-20 Results for Supercritical/ Ultra-supercritical Coal-fired Thermal Power Generation by a PPP at an Unspecified Location

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_PPP_ AU450	1.5%	4.9	5.1	2.3	15.0
	2.0%	5.0	5.2	2.9	15.0
	2.5%	5.0	5.3	3.4	15.0
	3.0%	5.1	5.4	3.9	15.0

Table 8.3-21 Preconditions for Supercritical/ Ultra-supercritical Coal-fired Thermal Power Generation by a PPP at an Unspecified Location

Plant Preconditions		Finance Preconditions	
Capacity	450MW	Investment	585 million USD
Operation rate	70%	Capital	15% of necessary funds
Generating efficiency	41.0%	Grace/Repayment	10 years/30 years
Coal price	45 USD/t (4500kcal/kg)	Depreciation period	30 years

Note) The price of coal escalates by 2.0% per year.

(11) Description of additional simulation

See the additional simulations regarding economic and financial analysis under “Japanese specifications for subcritical coal-fired thermal power generation” and “Simulation results assuming a coal price of 55 USD/ton”.

8.3.2 Economic Analysis for Gas-fired Thermal Power Generation Options

(1) Gas-fired thermal power generation by SPC near to the smelting plant

- A 200 MW gas-fired (LNG) thermal power plant is constructed near to INALUM.
- A new combined cycle power plant is installed.
- Assuming application of a JBIC loan, the JBIC syndicate average interest rate is estimated at 5.0%.

Table 8.3-22 Calculation Results for Gas-fired Thermal Power Generation by an SPC near to the Smelting Plant

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
L_SPC_ Near	4%	8.5	8.7	2.6	18.0
	5%	8.6	8.8	3.1	18.0
	6%	8.7	8.9	3.6	18.0
	7%	8.7	8.9	4.1	18.0

Table 8.3-23 Preconditions for Gas-fired Thermal Power Generation by an SPC near to the Smelting Plant

Plant Preconditions		Finance Preconditions	
Capacity	200MW	Investment	216 million USD
Operation rate	70%	Capital	30% of necessary funds
Generating efficiency	45.0%	Grace/Repayment	None/12 years
LNG price	7 USD/MMbtu	Depreciation period	25 years

Note) The price of LNG escalates by 2.0% per year.

(2) Gas-fired thermal power generation based on upgrading of Belawan power plant near to the smelting plant

- An LNG gas-fired thermal power plant is constructed by PLN.
- An existing plant is upgraded to a combined cycle system.
- PLN supplies power for INALUM and for civilian purposes.
- Assuming the project is eligible for an ODA loan, the average annual interest rate is estimated at 2.5%.
- However, power for INALUM is purchased according to the PLN price scheme.

Table 8.3-24 Calculation Results for Gas-fired Thermal Power Generation based on Upgrading of Belawan

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
L_PLN_ Belaw	1.5%	8.2	8.4	2.8	15.0
	2.0%	8.2	8.4	3.2	15.0
	2.5%	8.3	8.5	3.7	15.0
	3.0%	8.4	8.5	4.2	15.0

Table 8.3-25 Preconditions for Gas-fired Thermal Power Generation
based on Upgrading of Belawan

Plant Preconditions		Finance Preconditions	
Capacity	520MW	Investment	449 million USD
Operation rate	70%	Capital	15% of necessary funds
Generating efficiency	45.0%	Grace/Repayment	7 years/25 years
LNG price	7 USD/MMbtu	Depreciation period	25 years

Note) The price of LNG escalates by 2.0% per year.

(3) Gas-fired thermal power generation by PLN at an unspecified location

- ♦ Power is generated from LNG in a combined cycle system and a power plant is eventually constructed.
- ♦ Assuming an ODA loan can be used for PLN fundraising, the average annual interest rate is estimated at 2.5%.
- ♦ However, the purchase price of power for INALUM is according to the PLN price scheme.

Table 8.3-26 Calculation Results for Gas-fired Thermal Power Generation
by PLN at an Unspecified Location

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
L_PLN_ Any	1.5%	8.5	8.7	2.6	15.0
	2.0%	8.6	8.8	3.1	15.0
	2.5%	8.7	8.9	3.6	15.0
	3.0%	8.7	8.9	4.1	15.0

Table 8.3-27 Preconditions for Gas-fired Thermal Power Generation
by PLN at an Unspecified Location

Plant Preconditions		Finance Preconditions	
Capacity	200MW	Investment	216 million USD
Operation rate	70%	Capital	15% of necessary funds
Generating efficiency	45.0%	Grace/Repayment	7 years/25 years
LNG price	7 USD/MMbtu	Depreciation period	25 years

Note) The price of LNG escalates by 2.0% per year.

(4) Gas-fired thermal power generation by an IPP at an unspecified location

- ♦ The IPP supplies power to INALUM via PLN.
- ♦ Assuming the IPP is eligible for a JBIC syndicated loan, the average annual interest rate is estimated at 5.0%.

Table 8.3-28 Calculation Results for Gas-fired Thermal Power Generation by an IPP at an Unspecified Location

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
L_IPP_ Any	4%	8.6	10.7	11.7	18.0
	5%	8.6	10.8	12.1	18.0
	6%	8.7	10.9	12.6	18.0
	7%	8.8	11.1	13.0	18.0

Table 8.3-29 Preconditions for Gas-fired Thermal Power Generation by an IPP at an Unspecified Location

Plant Preconditions		Finance Preconditions	
Capacity	200MW	Investment	216 million USD
Operation rate	70%	Capital	30% of necessary funds
Generating efficiency	45.0%	Grace/Repayment	None/12 years
LNG price	7 USD/MMbtu	Depreciation period	25 years

Note) The price of LNG escalates by 2.0% per year.

(5) Gas-fired thermal power generation by a PPP at an unspecified location

- ♦ Power is generated from LNG in a combined cycle system and a power plant is eventually constructed.
- ♦ If plant capacity is 400 MW or higher, power is supplied for INALUM and civilian purposes.
- ♦ Since the PPP is treated as a state-owned enterprise, it is assumed that an ODA loan can be used and that the average annual interest rate is 2.5%.
- ♦ However, in cases where the PPP sells power via PLN, the purchase price of power for INALUM is according to the PLN price scheme.

Table 8.3-30 Calculation Results for Gas-fired Thermal Power Generation by a PPP at an Unspecified Location

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
L_PPP_ Any	1.5%	8.5	8.7	2.6	15.0
	2.0%	8.6	8.8	3.1	15.0
	2.5%	8.7	8.9	3.6	15.0
	3.0%	8.7	8.9	4.1	15.0

Table 8.3-31 Preconditions for Gas-fired Thermal Power Generation by a PPP at an Unspecified Location

Plant Preconditions		Finance Preconditions	
Capacity	200MW	Investment	216 million USD
Operation rate	70%	Capital	15% of necessary funds
Generating efficiency	45.0%	Grace/Repayment	7 years/25 years
LNG price	7 USD/MMbtu	Depreciation period	25 years

Note) The price of LNG escalates by 2.0% per year.

8.3.3 Economic Analysis for Geothermal Power Generation Options

(1) Geothermal power generation by an IPP

- The business is doing under IPP entity.
- Well efficiency is assumed to be 8 MW/well.
- The JBIC syndicate average interest rate is estimated at 5%.
- Corporate tax is levied pretax profit that incentive with 5% reduction from pretax profit is given for six years.

Table 8.3-32 Results for Geothermal Power Generation by an IPP

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
S_IPP_ Sarul	3%	4.2	8.8	10.7	18.0
	4%	4.3	9.0	11.2	18.0
	5%	4.5	9.2	11.6	18.0
	6%	4.6	9.4	12.1	18.0

Table 8.3-33 Preconditions for Geothermal Power Generation by an IPP

Plant Preconditions		Finance Preconditions	
Capacity	190MW	Investment	586 million USD
Operation rate	80%	Capital	30% of necessary funds
Replacement well	1.2 wells	Grace/Repayment	None/12 years
Drilling cost	5.5 million USD/well	Depreciation period	25 years

(2) Description of additional simulation

See the additional simulation for economic and financial analysis assuming the business operator is an SPC or PPP.

8.3.4 Economic Analysis for Hydropower Generation Options

(1) Hydropower generation by PLN

- PLN is the project operator.
- Toru-1 (38.4 MW), Simanggo-2 (59 MW) and Raisan-3,4 (80 MW) have total capacity of 177.4 MW.
- Assuming the project is eligible for an ODA loan, the average annual interest rate on fundraising by PLN is estimated at 2.5%.

Table 8.3-34 Results for Total Hydropower Generation by PLN (177.4 MW)

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
H_PLN_ Total	1.5%	2.4	3.1	3.4	15.0
	2.0%	2.5	3.5	3.9	15.0
	2.5%	2.6	3.5	4.4	15.0
	3.0%	2.8	3.6	4.9	15.0

Table 8.3-35 Results for Toru-1 (38 MW) Hydropower Plant Operation by PLN

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
H_PLN_ Toru	1.5%	1.6	2.2	3.3	15.0
	2.0%	1.7	2.3	3.9	15.0
	2.5%	1.8	2.4	4.4	15.0
	3.0%	1.9	2.5	4.9	15.0

Table 8.3-36 Results for Simanggo-2 (59 MW) Hydropower Plant Operation by PLN

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
H_PLN_ Simanggo	1.5%	2.0	2.6	3.4	15.0
	2.0%	2.1	2.7	3.9	15.0
	2.5%	2.2	2.9	4.4	15.0
	3.0%	2.3	3.0	4.9	15.0

Table 8.3-37 Results for Simanggo-2 (59 MW) Hydropower Plant Operation by PLN

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
H_PLN_ Raisan	1.5%	3.3	4.4	3.4	15.0
	2.0%	3.5	4.8	3.9	15.0
	2.5%	3.8	4.9	4.4	15.0
	3.0%	4.0	5.1	4.9	15.0

Table 8.3-38 Preconditions for PLN Hydropower Generation Cases

Total Plant Preconditions		Total Finance Preconditions	
Capacity	177.4MW	Investment	361 million USD
Operation rate	61%	Capital	15% of necessary funds
		Grace/Repayment	7/25 years
		Depreciation period	30 years
Toru-1 Plant Preconditions		Toru-1 Finance Preconditions	
Capacity	38.4MW	Investment	82 million USD
Operation rate	92%	Capital	15% of necessary funds
		Grace/Repayment	7/25 years
		Depreciation period	30 years
Simanggo-2 Plant Preconditions		Simanggo-2 Finance Preconditions	
Capacity	59MW	Investment	118 million USD
Operation rate	71%	Capital	15% of necessary funds
		Grace/Repayment	7/25 years
		Depreciation period	30 years
Raisan-3,4 Plant Preconditions		Raisan-3 & 4 Finance Preconditions	
Capacity	80W	Investment	161 million USD
Operation rate	42%	Capital	15% of necessary funds
		Grace/Repayment	7/25 years
		Depreciation period	30 years

(2) Hydropower generation by an IPP

- ♦ The project operator in an IPP and total capacity at three locations is 177.4 MW.
- ♦ Toru-1 (38.4 MW), Simanggo-2 (59 MW) and Raisan-3,4 (80 MW)
- ♦ Assuming the IPP is eligible for a JBIC syndicated loan, the average annual interest rate is estimated at 5.0%.

Table 8.3-39 Results for Total Hydropower Generation by an IPP (177.4 MW)

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
H_IPP_ Total	4%	2.4	7.4	11.7	18.0
	5%	2.6	7.6	12.2	18.0
	6%	2.7	7.9	12.7	18.0
	7%	2.9	8.1	13.2	18.0

Table 8.3-40 Results for Toru-1 (38 MW) Hydropower Plant Operation by an IPP

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
H_IPP_ Toru	4%	1.7	5.1	11.7	18.0
	5%	1.8	5.3	12.2	18.0
	6%	1.9	5.5	12.7	18.0
	7%	2.0	5.6	13.2	18.0

Table 8.3-41 Results for Simanggo-2 (59 MW) Hydropower Plant Operation by an IPP

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
H_IPP_ Simanggo	4%	2.0	6.2	11.7	18.0
	5%	2.2	6.4	12.2	18.0
	6%	2.3	6.6	12.7	18.0
	7%	2.4	6.8	13.2	18.0

Table 8.3-42 Results for Raisan-3,4 (80 MW) Hydropower Plant Operation by an IPP

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
H_IPP_ Raisan	4%	3.5	10.4	11.7	18.0
	5%	3.7	10.8	12.2	18.0
	6%	3.9	11.2	12.7	18.0
	7%	4.1	11.5	13.2	18.0

Table 8.3-43 Preconditions for IPP Hydropower Generation Cases

Total Plant Preconditions		Total Finance Preconditions	
Generating capacity	177.4MW	Investment	510 million USD
Operating rate	61%	Capital	30% of necessary funds
		Grace/Repayment	None/12 years
		Depreciation period	30 years
Toru-1 Plant Preconditions		Toru-1 Finance Preconditions	
Generating capacity	38MW	Investment	82 million USD
Operating rate	92%	Capital	30% of necessary funds
		Grace/Repayment	None/12 years
		Depreciation period	30 years
Simanggo-2 Plant Preconditions		Simanggo-2 Finance Preconditions	
Generating capacity	59MW	Investment	118 million USD
Operating rate	71%	Capital	30% of necessary funds
		Grace/Repayment	None/12 years
		Depreciation period	30 years
Raisan-3,4 Plant Preconditions		Raisan-3,4 Finance Preconditions	
Generating capacity	80W	Investment	161 million USD
Operating rate	42%	Capital	30% of necessary funds
		Grace/Repayment	None/12 years
		Depreciation period	30 years

8.4 Project Feasibility Evaluation based on Economic and Financial Analysis

The following table sums up the power generating costs and power tariffs in each case.

Table 8.4-1 Power Generating Cost for Power Generating Mode and Type of Operator (1)

Generating Mode	Project Name	Capacity	Project Operator					Issues
			PLN	IPP	SPC	PPP	INALUM	
			ODA	JBIC	JBIC	ODA	ODA	
			ROE=15%	ROE=18%	ROE=18%	ROE=15%	ROE=15%	
Coal	Near to the smelting plant	200/400/600 MW Subcritical			C_SPC_ Near 4.3/5.9		C_INA_ Near 4.3/5.6	(1) In the case of INALUM, costs and tariffs rise because it is necessary to prepare a backup power resource. (2) The INALUM power purchase price differs depending on whether the power plant is made a separate operating body or is incorporated into INALUM.
	Near to the smelting plant	450MW or higher Supercritical / Ultra-supercritical			C_SPC_ NU450 5.1/7.6		C_INA_ NU450 5.0/5.2	
	Unspecified location	200/400/600 MW Subcritical	C_PLN_ Any 4.3/5.6	C_IPP_ Any 4.3/5.9		C_PPP_ Any 4.3/5.6		(3) A power purchasing contract for 200 MW is required between PLN and INALUM, however, under the current social situation of power shortages, negotiations could drag on. (4) An issue is whether or not PLN will implement tariff steps with respect to a large-scale consumer. (5) In the case of an IPP, it is necessary to conduct negotiations between the IPP, PLN and INALUM.
	Unspecified location	450 MW or higher Supercritical / Ultra-supercritical	C_PLN_ AU450 5.0/5.2	C_IPP_ AU450 5.1/7.6		C_PPP_ AU450 5.0/5.2		
LNG	Near to the smelting plant	200/400/600 MW			L_SPC_ Near 8.6/10.8		L_PPP_ Near 8.7/8.9	(6) This issue is the same as in (1); moreover, cost feasibility is low because LNG is used.
	Belawan upgrading	520 MW	L_PLN_ Belaw 8.3/8.5					(7) This case depends on internal conditions in PLN. It is possible LNG power generation will be conducted in North Sumatra as an example of domestic market priority (DMO).
	Unspecified location	200/400/600 MW	L_PLN_ Any 8.7/8.9	L_IPP_ Any 8.6/10.8		L_PPP_ Any 8.7/8.9		(8) In the case of an IPP, cost feasibility is low because LNG is used. PLN may conduct LNG power generation as an example of DMO.

Figures on the left indicate the power generating unit cost (¢/kWh), while figures on the right indicate the power sale tariff (c/kWh).

Table 8.4-2 Power Generating Cost for Power Generating Mode and Type of Operator (2)

Generating Mode	Project Name	Capacity	Project Operator					Issues
			PLN	IPP	SPC	PPP	INALUM	
			ODA	JBIC	JBIC	ODA	ODA	
			ROE=15%	ROE=18%	ROE=18%	ROE=15%	ROE=15%	
Geothermal	Sarulla-2	190 MW		S_IPP Sarul 4.5/9.2				(1) Current regulations require that an IPP sells power to PLN, however, examine the possibility of consigning transmission from IPP to INALUM.
Hydropower	Total	177.4 MW	H_PLN_ Total 2.6/3.5	H_IPP_ Total 2.6/7.6				(2) For hydropower generation, the power tariff greatly differs between the case of using ODA funds and the case of IPP base (with JBIC syndicate). This is due to the difference in the interest burden, making it less likely for hydropower generation by an IPP. (3) Rather than INALUM purchasing hydroelectric power from an IPP (generating charge + transmission cost), it may be cheaper to conduct routine power purchase from PLN.
	Toru-1	38.4 MW	H_PLN_ Touru 1.8/2.4	H_IPP_ Touru 1.8/5.3				
	Simanggo-2	59.0 MW	H_PLN_ Simang 2.2/2.9	H_IPP_ Simang 2.2/6.4				
	Raisan-3,4	80.0 MW	H_PLN_ Raisan 3.8/4.9	H_IPP_ Raisan 3.7/10.8				

Figures on the left indicate the power generating unit cost (¢/kWh), while figures on the right indicate the power sale tariff (c/kWh).

Supplementary 1: Generating Cost and Power Tariff in Case of Geothermal Power Generation with Independent Transmission Line

Concerning the option of utilizing Sarulla-2 as dedicated power for INALUM plant expansion (this was regarded as a promising option in Phase 1), since the following items have been confirmed in this Study, this is treated as a domestic power resource operated by an IPP in the simulation here.

- ♦ Development concessions for the area that includes Sarulla-2 have already been acquired, making it compulsory for all generated power to be sold to PLN.

- ♦ As options for transmitting power to the INALUM aluminum smelting plant, either the PLN transmission line can be used or a dedicated transmission line can be installed, however, both cases are unfeasible for the following reasons:
  - ・ PLN has no experience of leasing transmission lines to specific enterprises, and no detailed regulations have been compiled for such an arrangement.
  - ・ Since constructing a long-distance dedicated transmission line would incur construction cost and problems regarding land expropriation, compensation and social and natural environmental impacts, etc., the development risk would be too great for an IPP.

- ♦ In order to realize dedicated facilities for INALUM plant expansion, assignment negotiations would be required with the current license holder and there would be a rick of increased costs. However, timely discussions and negotiations between related parties are needed in the case of geothermal power generation. Moreover, there is a strong possibility that development of Sarulla-2 (110 MW) cannot be started until work is finished on the Sarulla-1 development. Accordingly, it will take many years for work on Sarulla-2 (190 MW) to be finished and power generation to commence.

As just references, the following paragraphs show the results of simulation financial appraisal results in the case where the above issues are all resolved.

(1) Geothermal power generation by an SPC using its own independent transmission line

- The project operator is an SPC supplying power to INALUM via its own independent transmission line
- Assuming the project is eligible for a JBIC syndicated loan, the average annual interest rate is estimated at 5%
- There is an incentive whereby 5% reduction to pretax profit when corporate tax is calculated for six years

Supplementary Table 1-1 Results for Geothermal Power Generation by an SPC using its Own Transmission Line

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
RS_SPC_Sarul	3%	4.4	9.5	10.8	18.0
	4%	4.6	9.7	11.1	18.0
	5%	4.8	9.9	11.6	18.0
	6%	5.0	10.1	12.0	18.0

Supplementary Table 1-2 Preconditions for Geothermal Power Generation by an SPC using its Own Transmission Line

Plant Preconditions		Finance Preconditions	
Generating capacity	190MW	Investment	632 million USD
Operating rate	80%	Capital	30% of necessary funds
Replenishment well	1.2	Grace/Repayment	None/12 years
Drilling cost	5.5 million USD/well	Depreciation period	25 years

The investment amount includes transmission cost of 230,000 USD/km x 200 km.

(2) Geothermal power generation by PPP using its own independent transmission line

- The project operator is a PPP supplying power to INALUM via its own independent transmission line.
- Assuming the project is eligible for a climate change ODA loan, the average annual interest rate is estimated at 2.0%.
- There is an incentive whereby 5% reduction to pretax profit when calculating corporate tax for six years.

Supplementary Table 1-3 Results for Geothermal Power Generation by PPP using its Own Transmission Line

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
RS_PPP_ Sarul	1.5%	4.3	4.6	1.9	15.0
	2.0%	4.5	4.8	2.5	15.0
	2.5%	4.8	5.0	3.1	15.0
	3.0%	5.0	5.2	3.7	15.0

Supplementary Table 1-4 Preconditions for Geothermal Power Generation by PPP using its Own Transmission Line

Plant Preconditions		Finance Preconditions	
Generating capacity	190MW	Investment	632 million USD
Operating rate	80%	Capital	15% of necessary funds
Replenishment well	1.2	Grace/Repayment	10/30 years
Drilling cost	5.5 million USD/well	Depreciation period	30 years

The investment amount includes transmission cost of 230,000 USD/km x 200 km.

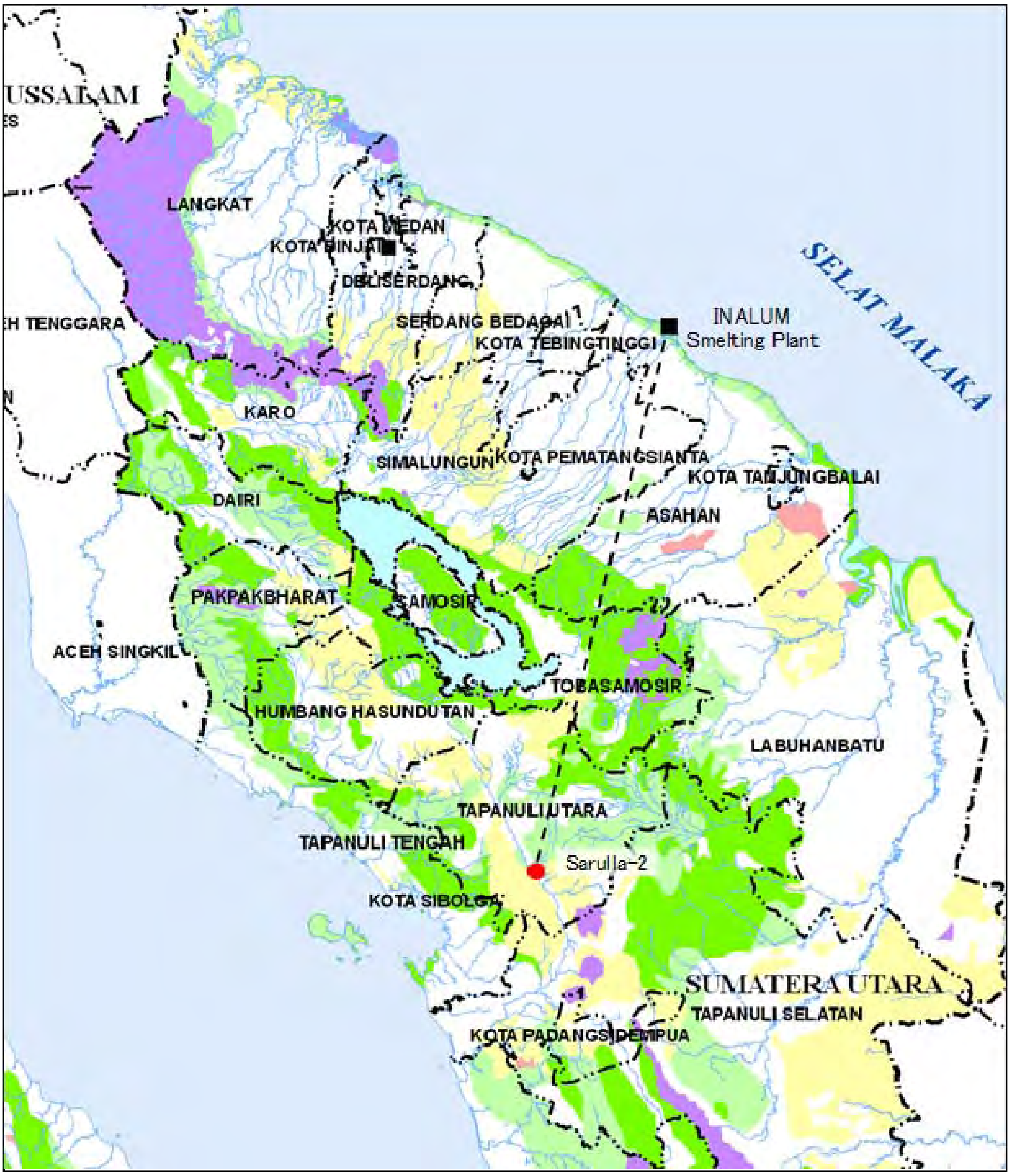
(3) Comparison of power generating cost according to project operator

As it is indicated below, when an SPC is adopted as the business model, the power generating cost is higher than in the case of supplying power for domestic uses because of the added cost of installing a dedicated transmission line. Meanwhile, in the hypothetical case where INALUM is nationalized and ODA can be used, the ROE will become 15% and the power tariff will fall to around 5.0 ¢/kWh.

Supplementary Table 1-5 Generating Cost at Sarulla-2 Geothermal Power Plant

Type	Project Operator	Generating Cost (¢/kWh)	Power tariff (¢/kWh)
Case where Sarulla-2 is developed for civilian purposes	IPP	4.5	9.2
Case where Sarulla-2 is developed for INALUM (reference)	SPC	4.8	9.9
	PPP (IPP + state-owned INALUM)	4.5	4.8

Note) In the reference case, it is assumed that a dedicated transmission line (200 km) is installed. See supplementary figure 1-1.



Supplementary Figure 1-1 Dedicated Transmission Line Route from Sarulla-2 to the INALUM Aluminum Smelting Plant (Reference)

Supplementary 2: Power Generating Cost and Power Tariff Assuming Construction Cost for a Subcritical Thermal Power Plant Based on Japanese Specifications

Here, economic and financial analysis is carried out assuming subcritical thermal power generation based on Japanese specifications. The settings in each case are as indicated below.

Supplementary Table 2-1 Subcritical Thermal Power Generation Cases Based on Japanese Specifications

Power generating mode	Project name	Capacity	Project Operator				
			PLN	IPP	SPC	PPP	INALUM
			ODA	JBIC	JBIC	ODA	ODA
			ROE=15 %	ROE=18 %	ROE=18 %	ROE=15 %	ROE=15 %
Coal-fired thermal power	Near to the smelting plant Japanese specifications	200MW Subcritical			RC_SPC_ Near		RC_INA_ Near
	Unspecified location Japanese specifications	200MW Subcritical	RC_PLN _Any	RC_IPP_ Any		RC_PPP_ Any	

(1) Subcritical thermal power generation by an SPC based on Japanese specifications near to the smelting plant

- ♦ Construction cost is set at 800 USD/kW assuming local specifications and 1,300 USD/kW assuming Japanese specifications.
- ♦ Assuming the project is eligible for a JBIC syndicated loan, the average annual interest rate is estimated at 5%.

Supplementary Table 2-2 Calculation Results for Subcritical Thermal Power Generation by an SPC Near to the Smelting Plant

	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_SPC_ Near	4%	5.8	8.3	11.6	18.0
	5%	5.8	8.4	12.0	18.0
	6%	5.9	8.5	12.4	18.0
	7%	6.0	8.6	12.9	18.0

Supplementary Table 2-3 Preconditions for Subcritical Thermal Power Generation by an SPC Near to the Smelting Plant

Plant Preconditions		Finance Preconditions	
Capacity	200MW	Investment	260 million USD
Operating rate	70%	Capital	30% of necessary funds
Generating efficiency	39.0%	Grace/Repayment	None/12 years
Coal price	45USD/t (4500kcal/kg)	Depreciation period	25 years

Note) The price of coal escalates by 2.0% per year

(2) Subcritical thermal power generation by INALUM based on Japanese specifications near to the smelting plant

- ♦ Assuming the project is eligible for a JBIC syndicated loan, the average annual interest rate is estimated at 5%.
- ♦ Construction cost is set at 800 USD/kW assuming local specifications and 1,300 USD/W assuming Japanese specifications.

Supplementary Table 2-4 Results for Subcritical Thermal Power Generation by INALUM Near to the Smelting Plant

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_INA_ Near	4%	5.1	7.2	10.1	15.0
	5%	5.2	7.3	10.5	15.0
	6%	5.3	7.4	10.9	15.0
	7%	5.4	7.5	11.4	15.0

Supplementary Table 2-5 Preconditions for Subcritical Coal-fired Thermal Power Generation by INALUM Near to the Smelting Plant

Plant Preconditions		Finance Preconditions	
Generating capacity	200MW	Investment	260 million USD
Operating rate	70%	Capital	30% of necessary funds
Generating efficiency	39.0%	Grace/Repayment	None/12 years
Coal price	45USD/t (4500kcal/kg)	Depreciation period	25 years

Note) The price of coal is escalated with 2.0% per year

(3) Construction of a subcritical thermal power plant based on Japanese specifications by PLN in an unspecified location

- The average interest rate for fund procurement by PLN is estimated at 5%.
- Construction cost is set at 800 USD/kW assuming local specifications and 1,300 USD/kW assuming Japanese specifications.

Supplementary Table 2-6 Calculation Results for a Subcritical Coal-fired Thermal Power Plant based on Japanese Specifications by PLN in an Unspecified Location

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_PLN_ Any	4%	5.1	7.2	10.1	15.0
	5%	5.2	7.3	10.5	15.0
	6%	5.3	7.4	11.0	15.0
	7%	5.4	7.5	11.4	15.0

Supplementary Table 2-7 Preconditions for a Subcritical Coal-fired Thermal Power Plant based on Japanese Specifications by PLN in an Unspecified Location

Plant Preconditions		Finance Preconditions	
Generating capacity	200MW	Investment	260 million USD
Operating rate	70%	Capital	30% of necessary funds
Generating efficiency	39.0%	Grace/Repayment	None/12 years
Coal price	45USD/t (4500kcal/kg)	Depreciation period	25 years

Note) The price of coal escalates by 2.0% per year

(4) Construction of a subcritical thermal power plant based on Japanese specifications by an IPP in an unspecified location

- Assuming the IPP is eligible for a JBIC syndicated loan, the average annual interest rate is estimated at 5%.
- Construction cost is set at 800 USD/kW assuming local specifications and 1,300 USD/kW assuming Japanese specifications.

Supplementary Table 2-8 Calculation Results for a Subcritical Coal-fired Thermal Power Plant based on Japanese Specifications by an IPP in an Unspecified Location

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_IPP_ Any	4%	5.1	7.6	11.6	18.0
	5%	5.2	7.7	12.1	18.0
	6%	5.3	7.8	12.4	18.0
	7%	5.4	7.9	12.9	18.0

Supplementary Table 2-9 Preconditions for a Subcritical Coal-fired Thermal Power Plant based on Japanese Specifications by an IPP in an Unspecified Location

Plant Preconditions		Finance Preconditions	
Generating capacity	200MW	Investment	260 million USD
Operating rate	70%	Capital	30% of necessary funds
Generating efficiency	39.0%	Grace/Repayment	None/12 years
Coal price	45USD/t (4500kcal/kg)	Depreciation period	25 years

Note) The price of coal is escalated with 2.0% per year

(5) Construction of a subcritical thermal power plant based on Japanese specifications by a PPP in an unspecified location

- Assuming the PPP is eligible for a JBIC syndicated loan, the average annual interest rate is estimated at 5.0%.
- However, in cases where the PPP sells power via PLN, the PLN tariff scheme will be adhered to.
- Construction cost is set at 800 USD/kW assuming local specifications and 1,300 USD/kW assuming Japanese specifications.

Supplementary Table 2-10 Calculation Results for a Subcritical Coal-fired Thermal Power Plant based on Japanese Specifications by a PPP in an Unspecified Location

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_PPP_ Any	4%	5.1	7.2	10.1	15.0
	5%	5.2	7.3	10.5	15.0
	6%	5.3	7.4	11.0	15.0
	7%	5.4	7.5	11.4	15.0

Supplementary Table 2-11 Preconditions for a Subcritical Coal-fired Thermal Power Plant based on Japanese Specifications by a PPP in an Unspecified Location

Plant Preconditions		Finance Preconditions	
Generating capacity	200MW	Investment	260 million USD
Operating rate	70%	Capital	30% of necessary funds
Generating efficiency	39.0%	Grace/Repayment	None/12 years
Coal price	45USD/t (4500kcal/kg)	Depreciation period	25 years

Note) The price of coal escalates by 2.0% per year

Supplementary 3: Cost and Power Tariff in Each Case when the Coal Price is 55 USD/ton

Generating cost and power tariff assuming coal-fired thermal power generation when the coal price of 55 USD/ton are simulated for the following cases.

Supplementary Table 3-1 Trial Calculation Cases when Coal Price is 55 USD/ton

Power generating mode	Project name	Capacity	Project Operator				
			PLN	IPP	SPC	PPP	INALUM
			ODA	JBIC	JBIC	ODA	ODA
			ROE=15 %	ROE=18 %	ROE=18 %	ROE=15 %	ROE=15 %
Coal-fired Thermal Power	Near to the smelting plant	200MW Subcritical			C_SPC_ Near		C_INA_ Near
	Near to the smelting plant	450MW or higher Supercritical / Ultra-supercritical			C_SPC_ NU450		C_INA_ NU450
	Unspecified location	200MW Subcritical	C_PLN_ Any	C_IPP_ Any		C_PPP_ Any	
	Unspecified location	450MW or higher Supercritical / Ultra-supercritical	C_PLN_ AU450	C_IPP_ AU450		C_PPP_ AU450	
	Near to the smelting plant Japanese specifications	200MW Subcritical			RC_SPC_ Near		RC_INA_ Near
	Unspecified location Japanese specifications	200MW Subcritical	RC_PLN _Any	RC_IPP_ Any		RC_PPP_ Any	

(1) Subcritical coal-fired thermal power generation near to the smelting plant

Supplementary Table 3-2 Subcritical Coal-fired Thermal Power Generation by an SPC Near to the Smelting Plant Near

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_SPC_ Near	4%	4.9	6.4	11.6	18.0
	5%	4.9	6.5	12.1	18.0
	6%	5.0	6.6	12.5	18.0
55 USD/t	7%	5.0	6.6	13.0	18.0

Supplementary Table 3-3 Subcritical Coal-fired Thermal Power Generation by INALUM Near to the Smelting Plant

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_INA_	4%	4.9	6.1	10.1	15.0
Near	5%	4.9	6.2	10.6	15.0
	6%	5.0	6.3	11.0	15.0
55 USD/t	7%	5.0	6.3	11.5	15.0

(2) Supercritical/ Ultra-supercritical coal-fired thermal power generation near to the smelting plant

Supplementary Table 3-4 Supercritical/ Ultra-supercritical Coal-fired Thermal Power Generation by an SPC Near to the Smelting Plant

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_SPC_	4%	5.6	8.1	11.6	18.0
NU450	5%	5.7	8.2	12.0	18.0
	6%	5.8	8.3	12.4	18.0
55 USD/t	7%	5.8	8.4	12.9	18.0

Supplementary Table 3-5 Supercritical/ Ultra-supercritical Coal-fired Thermal Power Generation by INALUM Near to the Smelting Plant

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_INA_	1.5%	5.5	5.7	2.3	15.0
NU450	2.0%	5.6	5.8	2.9	15.0
	2.5%	5.6	5.9	3.4	15.0
55 USD/t	3.0%	5.7	6.0	3.9	15.0

(3) Subcritical coal-fired thermal power generation at an unspecified location

Supplementary Table 3-6 Subcritical Coal-fired Thermal Power Generation by a PPP at an Unspecified Location

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_PLN_	4%	4.9	6.1	10.1	15.0
Any	5%	4.9	6.2	10.6	15.0
	6%	5.0	6.3	11.0	15.0
55 USD/t	7%	5.0	6.3	11.5	15.0

Supplementary Table 3-7 Subcritical Coal-fired Thermal Power Generation by an IPP at an Unspecified Location

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_IPP_	4%	4.9	6.4	11.6	18.0
Any	5%	4.9	6.5	12.1	18.0
	6%	5.0	6.6	12.5	18.0
55 USD/t	7%	5.0	6.6	13.0	18.0

Supplementary Table 3-8 Subcritical Coal-fired Thermal Power Generation by a PPP at an Unspecified Location

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_PPP_	4%	4.9	6.1	10.1	15.0
Any	5%	4.9	6.2	10.6	15.0
	6%	5.0	6.3	11.0	15.0
55 USD/t	7%	5.0	6.3	11.5	15.0

(4) Supercritical/ Ultra-supercritical coal-fired thermal power generation by PLN at an unspecified location

Supplementary Table 3-9 Supercritical/ Ultra-supercritical Coal-fired Thermal Power Generation by PLN at an Unspecified Location

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_PLN_	1.5%	5.5	5.7	2.3	15.0
AU450	2.0%	5.6	5.8	2.9	15.0
	2.5%	5.6	5.9	3.4	15.0
55 USD/t	3.0%	5.7	6.0	3.9	15.0

Supplementary Table 3-10 Supercritical/ Ultra-supercritical Coal-fired Thermal Power Generation by an IPP at an Unspecified Location

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_IPP_	4%	5.6	8.1	11.6	18.0
AU450	5%	5.7	8.2	12.0	18.0
	6%	5.8	8.3	12.5	18.0
55 USD/t	7%	5.8	8.4	12.9	18.0

Supplementary Table 3-11 Supercritical/ Ultra-supercritical Coal-fired Thermal Power Generation by a PPP at an Unspecified Location

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
C_PPP_	1.5%	5.5	5.7	2.4	15.0
AU450	2.0%	5.6	5.8	2.9	15.0
	2.5%	5.6	5.9	3.4	15.0
55 USD/t	3.0%	5.7	6.0	3.9	15.0

(5) Subcritical thermal power generation based on Japanese specifications at an unspecified location

Supplementary Table 3-12 Subcritical Coal-fired Thermal Power Generation based on Japanese Specifications by PLN, PPP and State-owned INALUM at an Unspecified Location

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
55 USD/t	4%	5.8	7.8	10.1	15.0
	5%	5.8	7.9	10.6	15.0
	6%	5.9	8.0	11.0	15.0
	7%	6.0	8.1	11.4	15.0

Supplementary Table 3-13 Subcritical Coal-fired Thermal Power Generation based on Japanese Specifications by SPC and IPP at an Unspecified Location

Case	Interest	Cost	Power Tariff	IRR	ROE
	%	¢/kWh	¢/kWh	%	%
55 USD/t	4%	5.8	8.3	11.6	18.0
	5%	5.8	8.4	12.0	18.0
	6%	5.9	8.5	12.5	18.0
	7%	6.0	8.6	13.0	18.0

8.5 Recommended Power Supply Options

Table 8.5-1 summarizes the economic and financial evaluation and development feasibility of each power supply option (see Tables 7-1 through 7-3). As a result of appraising each option's feasibility from the viewpoints of ① certainty of realization in the near future, ② issues in development (see Tables 7-1 through 7-3) and ③ power generating cost in each mode (Table 8.4-1 and Table 8.4-2), the following power supply options have high feasibility and are recommended in the Study. In the supply options that assume power purchase from PLN, INALUM purchases power according to the PLN tariff scheme at a uniform rate irrespective of the supply scale and generating mode. The power purchase tariff is currently 7.35 ¢/kWh, however, it is likely to increase to around 10.07 ¢/kWh by 2015, so there will be little merit for the INALUM side. Moreover, it is assumed that the power plant will supply power to INALUM, however, in this case there is little motivation for an SPC or operator other than INALUM (IPP, PLN or a PPP combining both) to conduct such power resource development. Consequently, all of the options that are based on power purchasing from PLN have low feasibility and cannot be recommended.

(1) First recommended option: Development of a 200 MW dedicated coal-fired thermal power plant for INALUM by an SPC or INALUM (Serial No: INALUM-200-①)

(a) Certainty of realization in the near future

Since the SPC or INALUM can independently conduct planning and development, this has the fewest uncertain elements of all the power generation options.

(b) Issues in development

Technical confirmation of coal price trends, coal supply stability and location conditions, etc. is required. Moreover, authorization as a specific power supplier/private power generator is required.

(c) Power generating cost

Project Operator	Power Generating Cost (¢/kWh)	Power Sale Price (¢/kWh)
SPC	4.3	5.9
INALUM	4.3	5.6

Note: Transmission costs and power access facility costs are not included.

(d) General assessment

Among the options entailing dedicated power plant development by an SPC or INALUM, in view of the power generating cost and certainty of development, coal-fired thermal power generation (subcritical 200 MW) is the most feasible option in the all cases. In this case, it is necessary to secure backup in the event of plant failure, however, assuming that RUPTL 2010 progresses smoothly, the backup tariff can fall in line with increase in reserve capacity.

(2) Second recommended option: Development of a 200 MW dedicated coal-fired thermal power plant for INALUM by an SPC or INALUM, combined with securing 200 MW of hydropower generation for domestic uses. (Serial No: INALUM-400-②)

(a) Certainty of realization in the near future

Since the SPC or INALUM can independently conduct planning and development of the dedicated coal-fired thermal power plant for INALUM plant expansion, this option has relatively few uncertain elements regarding development. There is a high degree of uncertainty concerning the timing of hydropower development, however, it is not absolutely necessary to synchronize the development with the expansion of the INALUM aluminum smelting plant.

(b) Issues in development

Technical confirmation of coal price trends, coal supply stability and location conditions, etc. is required. Moreover, authorization as a specific power supplier/private power generator is required. Concerning hydropower development, it is necessary to conduct technical confirmation of the development potential and location conditions, etc. and to coordinate between the project operators.

(c) Power generating cost

Generating Mode	Project Operator	Power Generating Cost (¢/kWh)	Power Sale Price (¢/kWh)
Coal-fired thermal power for INALUM (subcritical 200 MW)	SPC	4.3	5.9
	INALUM	4.3	5.6
Hydropower for civilian purposes (177.4MW)	IPP	2.6	7.6
	PLN	2.6	3.5

Note: Transmission costs and power access facility costs are not included.

(d) General assessment

Among the 400 MW supply options, the case where an SPC or INALUM develop a dedicated power resource is the most feasible in terms of the power generating cost and certainty of development. This option also entails conducting hydropower development for domestic uses, and hydropower can make the greatest contribution to PLN finances because it entails the least expensive power generating cost. Although hydropower has low immediate feasibility due to the lack of development capability among IPPs and the need for difficult negotiations with PLN and the local authorities, if the power supply for INALUM can be secured via coal-fired thermal power, the delay in hydropower development can be alleviated. Moreover, if PLN can conduct development in cooperation with the local community, it will be possible to utilize ODA, thereby improving the contribution to PLN finances. This factor can benefit the negotiations for preferential treatment regarding PLN backup tariffs.

(3) Third recommended option: Development of a 200 MW dedicated coal-fired thermal power plant for INALUM by an SPC or INALUM, combined with securing 200 MW of geothermal power generation for domestic uses.（Serial No: INALUM-400-①）

(a) Certainty of realization in the near future

Since the SPC or INALUM can independently conduct planning and development of the dedicated coal-fired thermal power plant for INALUM plant expansion, this option has relatively few uncertain elements regarding development. It is uncertain whether or not the geothermal power development can be timed to coincide with the expansion of the INALUM aluminum smelting plant, however, it is not absolutely necessary to synchronize the both.

(b) Issues in development

Concerning the coal-fired thermal power development, the same issues as in the first and second recommended options apply. Concerning the geothermal development, issues concern delays in development of Sarulla-1 and the fact that development potential has not been technically confirmed yet.

(c) Power generating cost

Generating Mode	Project Operator	Power Generating Cost (¢/kWh)	Power tariff (¢/kWh)
Coal-fired thermal power for INALUM (subcritical 200 MW)	SPC	4.3	5.9
	INALUM	4.3	5.6
Geothermal power for civilian purposes (190MW)	IPP	4.5	9.2

Note: Transmission costs and power access facility costs are not included.

(d) General assessment

This option entails conducting geothermal power development for domestic uses at Sarulla-2 in tandem with coal-fired thermal power development for INALUM. The development concession for Sarulla-2 has already been obtained and, apart from the timing of development, feasibility is high. If the INALUM power source is secured through coal-fired thermal power development, the delay in the Sarulla-2 development can be alleviated. However, since the geothermal development operator is an IPP, as in the second recommended option (INALUM-200-②), there is little chance of securing preferential treatment from PLN for backup power in the event of failure of the coal-fired thermal power plant.

(4) Fourth recommended option: Development of a 400 MW coal-fired thermal power plant by an SPC or INALUM, and supply of 200 MW for INALUM and 200 MW for domestic uses （Serial No: INALUM-400-⑤）

(a) Certainty of realization in the near future

Since the SPC or INALUM can independently conduct planning and development, this option has relatively few uncertain elements regarding development.

(b) Issues in development

Issues are the same as in the first recommended option, i.e. technical confirmation of coal price trends, coal supply stability and location conditions, etc. is required, and it is necessary to secure authorization as a specific power supplier/private power generator.

(c) Power generating cost

Project Operator	Power Generating Cost (¢/kWh)	Power Sale Price (¢/kWh)
SPC	4.3	5.9
INALUM	4.3	5.6

Note: Transmission costs and power access facility costs are not included.

(d) General assessment

Concerning backup in the event of plant failure, this option is better than the first three recommended options, however, excess power for civilian purposes is likely to be sold at a low price. In the event where RUPTL 2010 progresses smoothly, since there is concern that the excess power sale price will decline even more in line with increase in the reserve margin, there is a strong possibility that losses arising from excess power sale will be greater than the increased cost of securing backup power.

(5) Fifth recommended option: Development of a 600 MW (Supercritical/Ultra-supercritical) coal-fired thermal power plant by an SPC or INALUM, and supply of 200 MW for INALUM and 400 MW for domestic uses (Serial No: INALUM-400-⑥)

(a) Certainty of realization in the near future

Since the SPC or INALUM can independently conduct planning and development, this option has relatively few uncertain elements regarding development.

(b) Issues in development

Issues are the same as in the first recommended option, i.e. technical confirmation of coal price trends, coal supply stability and location conditions, etc. is required, and it is necessary to secure authorization as a specific power supplier/private power generator.

(c) Power generating cost

In the event where INALUM is nationalized, ODA would become applicable to supercritical or ultra-supercritical coal-fired thermal power and the power sale price would be lower than in the case of subcritical generation (5.6→5.2 ¢kW); however, since the plant cost would be expensive, the generating unit cost would conversely increase (4.3→5.0 ¢kWh).

Project Operator	Power Generating Cost (¢/kWh)	Power Sale Price (¢/kWh)
SPC	5.1	7.6
INALUM (state-owned)	5.0	5.2

Note: Transmission costs and power access facility costs are not included.

(d) General assessment

The 600 MW supply option entails supplying 400 MW for civilian purposes, however, if the plans of RUPTL 2010 advance smoothly, there is a risk of creating excess supply. Thus there is little likelihood that 400 MW will be needed for civilian purposes. Moreover, since more power will be sold at low prices as excess power, the resulting loss will be greater than in the 400 MW option. Therefore, the 600 MW supply option is less feasible than the 200 MW and 400 MW options. Through introducing supercritical generation in this option, participation by a Japanese firm can be anticipated. However, issues exist in that the generating unit cost will be higher than in subcritical generation, and there is concern over the impact on grid stability. Moreover, because the power plant entails a single equipment unit, backup from PLN would be necessary in the event of plant failure and this would lead to further cost increase. In consideration of these points, this option has the lowest feasibility among the recommended options.

Table 8.5-1 (a) Power Supply Options (200 MW Supply Options): Financial Efficiency and Feasibility Assessment

(1) 200 MW supply options assuming power purchase from PLN: The INALUM power purchase tariff is a uniform charge (scheduled to increase by 37% by 2015) regardless of the power generating mode and generating unit cost

Serial No.	Generating Mode	Plant Output MW		Project Operator	Financial Analysis Case	Economic & Financial Analysis Result ¢/kWh		INALUM Plant Expansion Power Tariff (PLN Power Tariff) ¢/kWh	feasibility of Development
						Generation Unit Cost	Power Sale Price		
PLN-200-①	Coal-fired thermal power	200 (Subcritical, local specifications)		PLN	C_PLN_Any	4.3	5.6	7.35 + Tariff hike (2015:10.07 ¢/kWh)	Although there is risk concerning coal price fluctuations and certainty of procurement, etc., the power generating unit cost and power sale price are second lowest behind hydropower and feasibility is high. However, as the development is geared to providing a power resource for INALUM, an issue concerns whether or not each operator can gain an incentive. Moreover, in the case where power is used for the INALUM plant expansion, there is no merit for INALUM.
				IPP	C_IPP-Any	4.3	5.9		
				PPP	C_PPP_Any	4.3	5.6		
PLN-200-②	Gas-fired thermal power	200.0		PLN	L_PLN_Any	8.7	8.9		It is necessary to carefully monitor progress in the LNG loading point and gas pipeline plans, and delays are currently projected. Both the power generating unit cost and power sale price are high; moreover, since the PLN power tariff is even higher if the operator is an IPP, feasibility is low.
				IPP	L_PLN_Any	8.6	10.8		
				PPP	L_PPP_Any	8.7	8.9		
PLN-200-③	Geothermal power	190.0		IPP	S_IPP_Sarul	4.5	9.2		In 2015, because the IPP power sale price is lower than the PLN power tariff, and the development concession has already been set, feasibility is high. However, since development of Sarulla-1 is facing delays, feasibility of early completion is low. Since power is purchased from PLN, there is no merit for INALUM.
PLN-200-④	Hydropower	Touru-1	38.4	IPP	H_IPP_Touru	1.8	5.3		Overall, the power generating unit cost and power sale price are cheaper than the PLN tariff, and this mode makes the best contribution to improving PLN finances. However, in the case where the project operator is an IPP, the degree of contribution to improving PLN finances is lower than in the case of development by PLN. Since IPPs have little implementation capability in the hydropower development field, implementation in the near future is not very feasible. Furthermore, since it is also difficult for PLN to conduct development based on local consensus, immediate realization is again unfeasible. Even if development is realized, since power is purchased from PLN, there is no merit for INALUM.
				PLN	H_PLN_Touru	1.8	2.4		
		Simango-2	59.0	IPP	H_IPP_Simang	2.2	6.4		
				PLN	H_PLN_Simang	2.2	2.9		
		Raisan-3,4	80.0	IPP	H_IPP_Raisan	3.7	10.8		
				PLN	H_PLN_Raisan	3.8	4.9		
		Overall	177.4	IPP	H_IPP_Total	2.6	7.6		
				PLN	H_PLN_Total	2.6	3.5		

(2) 200 MW supply options assuming construction of a new dedicated power plant for INALUM plant expansion: A backup contract is needed to provide insurance in the event of failure of the dedicated power plant

Serial No.	Generating Mode	Plant Output MW	Project Operator	Financial Analysis Case	Economic & Financial Analysis Result ¢/kWh		INALUM Plant Expansion Power Tariff (PLN Power Tariff) ¢/kWh	feasibility of Development
					Generation Unit Cost	Power Sale Price		
INALUM-200-①	Coal-fired thermal power	200 (Subcritical, local specifications)	SPC	C_SPC_Near	4.3	5.9	5.9 + backup tariff	**First recommended option:** The backup tariff applies in the event where the power plant experiences failure, however, the cost of generating power for INALUM plant expansion is around half the cost of purchasing power from PLN, so this is the most advantageous case. Concerning the backup tariff, in the case where RUPTL 2010 progresses smoothly, the tariff will fall in line with increase in reserve capacity.
			INALUM	C_INA_Near	4.3	5.6	5.6 + backup tariff	
INALUM-200-②	Gas-fired thermal power	200.0	SPC	L_SPC_Near	8.6	10.8	10.8 + backup tariff	There is concern that the project will be impacted by progress in the LNG loading point and gas pipeline construction plans. Since there is little difference in power generating cost compared to the case of purchasing power from PLN, there is no merit for INALUM.
			INALUM	L_INA_Near	8.7	8.9	8.9 + backup tariff	

: Recommended option

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Table 8.5-1 (b-1) Power Supply Options (400 MW Supply Options): Financial Efficiency and Feasibility Assessment

(1) 400 MW supply options assuming power purchase from PLN: The INALUM power purchase tariff is a uniform charge (scheduled to increase by 37% by 2015) regardless of the power generating mode and generating unit cost

Serial No.	Generating Mode	Plant Output MW		Project Operator	Financial Analysis Case	Economic & Financial Analysis Result ¢/kWh Generation Unit Cost	Economic & Financial Analysis Result ¢/kWh Power Sale Price	INALUM Plant Expansion Power Tariff (PLN Power Tariff) ¢/kWh	feasibility of Development
PLN-400-①	Geothermal power	190.0		IPP	S_IPP_Sarul	4.5	9.2	7.35 ＋ Tariff hike (2015：10.07 ¢/kWh)	Since hydropower enables cheaper power generating unit cost and power sale price than the PLN tariff, this mode makes the best contribution to improving PLN finances; however, since IPPs have little implementation capability in the hydropower development field and it is difficult for PLN to conduct development based on local consensus, implementation in the near future is not very feasible. Moreover, concerning geothermal power, since development of Sarulla-1 is behind schedule, it is difficult to synchronize development with expansion of the INALUM aluminum smelting plant. Accordingly, this is not a feasible case. In the case where power is used for the INALUM plant expansion, there is no merit for INALUM. Since the development partially entails power supply for INALUM, an issue concerns whether or not each operator can gain an incentive.
	Hydropower	Toru-1	38.4	IPP	H_IPP_Touru	1.8	5.3		
				PLN	H_PLN_Touru	1.8	2.4		
		Simango-2	59.0	IPP	H_IPP_Simang	2.2	6.4		
				PLN	H_PLN_Simang	2.2	2.9		
		Raisan-3,4	80.0	IPP	H_IPP_Raisan	3.7	10.8		
				PLN	H_PLN_Raisan	3.8	4.9		
		Overall	177.4	IPP	H_IPP_Total	2.6	7.6		
				PLN	H_PLN_Total	2.6	3.5		
PLN-400-②	Geothermal power	190.0		IPP	S_IPP_Sarul	4.5	9.2		Concerning geothermal power, it is possible that the development will not coincide with INALUM smelting plant expansion (due to delays in Sarulla-1), however, since the development concession has already been set, feasibility is high except for the issue of scheduling. Coal-fired thermal power entails the second lowest power generating cost and power sale price behind hydropower, so there are few issues regarding feasibility; moreover, because the development can be timed to coincide with the INALUM plant expansion, any delays in geothermal power development can be covered. However, in the case where power is used for INALUM plant expansion, since this is purchased from PLN, there is no merit for INALUM. Since the development partially entails power supply for INALUM, an issue concerns whether or not each operator can gain an incentive.
	Coal-fired thermal power	200 (Subcritical, local specifications)		PLN	C_PLN_Any	4.3	5.6		
				IPP	C_IPP-Any	4.3	5.9		
				PPP	C_PPP_Any	4.3	5.6		
PLN-400-③	Geothermal power	190.0		IPP	S_IPP_Sarul	4.5	9.2		Since the power sale price is high, there is little feasibility regarding immediate implementation regarding both geothermal power (due to delays in Sarulla-1) and gas-fired thermal power (impacted by progress of the LNG loading point and gas pipeline), and power is purchased from PLN, this option is not feasible.
	Gas-fired thermal power	200.0		PLN	L_PLN_Any	8.7	8.9		
				IPP	L_PLN_Any	8.6	10.8		
				PPP	L_PPP_Any	8.7	8.9		
PLN-400-④	Hydropower	Toru-1	38.4	IPP	H_IPP_Touru	1.8	5.3		Out of all the options involving a combination of differing power generating modes, this one entails the lowest overall power generating cost. Since IPPs have little implementation capability in the hydropower development field and it is difficult for PLN to conduct development based on local consensus, it is difficult to synchronize implementation with the INALUM plant expansion, however, by combining with coal-fired thermal power, which entails little risk concerning the development timing, problems of scheduling can be alleviated. However, in the case where power is used for INALUM plant expansion, since this is purchased from PLN, there is no merit for INALUM. Feasibility is low.
				PLN	H_PLN_Touru	1.8	2.4		
		Simango-2	59.0	IPP	H_IPP_Simang	2.2	6.4		
				PLN	H_PLN_Simang	2.2	2.9		
		Raisan-3,4	80.0	IPP	H_IPP_Raisan	3.7	10.8		
				PLN	H_PLN_Raisan	3.8	4.9		
		Overall	177.4	IPP	H_IPP_Total	2.6	7.6		
				PLN	H_PLN_Total	2.6	3.5		
	Coal-fired thermal power	200 (Subcritical, local specifications)		PLN	C_PLN_Any	4.3	5.6		
				IPP	C_IPP-Any	4.3	5.9		
				PPP	C_PPP_Any	4.3	5.6		
PLN-400-⑤	Hydropower	Toru-1	38.4	IPP	H_IPP_Touru	1.8	5.3		Regarding hydropower, since IPPs have little implementation capability in the hydropower development field and it is difficult for PLN to conduct development based on local consensus, implementation in the near future is not very feasible, whereas concerning gas-fired thermal power, since implementation is impacted by progress of the LNG loading point and gas pipeline, etc., feasibility is even lower than implementation in each individual mode alone. Therefore, this is not a feasible case. In the case where power is used for INALUM plant expansion, since this is purchased from PLN, there is no merit for INALUM. Feasibility is low.
				PLN	H_PLN_Touru	1.8	2.4		
		Simango-2	59.0	IPP	H_IPP_Simang	2.2	6.4		
				PLN	H_PLN_Simang	2.2	2.9		
		Raisan-3,4	80.0	IPP	H_IPP_Raisan	3.7	10.8		
				PLN	H_PLN_Raisan	3.8	4.9		
		Overall	177.4	IPP	H_IPP_Total	2.6	7.6		
				PLN	H_PLN_Total	2.6	3.5		
	Gas-fired thermal power	200.0		PLN	L_PLN_Any	8.7	8.9		
				IPP	L_PLN_Any	8.6	10.8		
				PPP	L_PPP_Any	8.7	8.9		
PLN-400-⑥	Coal-fired thermal power	200 (Subcritical, local specifications)		PLN	C_PLN_Any	4.3	5.6		Concerning gas-fired thermal power, due to uncertainty over the LNG loading point and gas pipeline construction plans, it is difficult to synchronize development with the INALUM plant expansion; moreover, since the power generating cost is expensive, the benefits of coal-fired thermal power are offset. Accordingly, this is not a feasible case. Since the development partially entails power supply for INALUM, an issue concerns whether or not each operator can gain an incentive.
				IPP	C_IPP-Any	4.3	5.9		
				PPP	C_PPP_Any	4.3	5.6		
	Gas-fired thermal power	200.0		PLN	L_PLN_Any	8.7	8.9		
				IPP	L_PLN_Any	8.6	10.8		
				PPP	L_PPP_Any	8.7	8.9		
PLN-400-⑦	Coal-fired thermal power	400 (Subcritical, local specifications)		PLN	C_PLN_Any	4.3	5.6		Although there is risk concerning coal price fluctuations and certainty of procurement, etc., the power generating unit cost and power sale price are second lowest behind hydropower and feasibility is high. Also, concerning the lack of incentive for operators regarding power supply for INALUM, since power for civilian purposes is developed at the same time, the situation is better than in the 200 MW supply options. Since the development partially entails power supply for INALUM, an issue concerns whether or not each operator can gain an incentive; moreover, since power is purchased from PLN, there is no merit for INALUM.
				IPP	C_IPP-Any	4.3	5.9		
				PPP	C_PPP_Any	4.3	5.6		
PLN-400-⑧	Gas-fired thermal power	400.0		PLN	L_PLN_Any	8.7	8.9		There is concern that feasibility will be affected due to the impact of progress in the LNG loading point and gas pipeline, etc. Since there is little difference in power generating cost compared to the case of purchasing power from PLN, there is no merit for INALUM.
				IPP	L_PLN_Any	8.6	10.8		
				PPP	L_PPP_Any	8.7	8.9		

Note) See the 200 MW supply options for the case where Japanese specifications are adopted for coal-fired thermal power (subcritical). In the case of adopting Japanese specifications, it is necessary to verify the necessity (technical feasibility, durability, reliability, etc.).

Table 8.5-1 (b-2) Power Supply Options (400 MW Supply Options): Financial Efficiency and Feasibility Assessment

(2) 400 MW supply options entailing Construction of a new dedicated power plant (200 MW) for INALUM + Securing of 200 MW for civilian purposes: A backup contract is needed to provide insurance in the event of failure of the dedicated power plant

Serial No.	Generating Mode	Plant Output MW		Project Operator	Financial Analysis Case	Economic & Financial Analysis Result ¢/kWh		INALUM Plant Expansion Power Tariff (PLN Power Tariff) ¢/kWh	feasibility of Development
						Generation Unit Cost	Power Sale Price		
INALUM-400-①	Coal-fired thermal power	200 (Subcritical, local specifications)		SPC	C_SPC_Near	4.3	5.9	5.9 + backup tariff	**Third recommended option:** The option of coal-fired thermal power development for INALUM plant expansion by an SPC or INALUM itself is the best case in terms of feasibility and power generating cost. If power for INALUM can be secured from coal-fired thermal power, the problems surrounding delay in Sarulla-2 can be alleviated. However, since the geothermal power operator is an IPP, there is no preferential treatment regarding the backup tariff like in the following case (INALUM-400-②).
				INALUM	C_INA_Near	4.3	5.6	5.6 + backup tariff	
	Geothermal power	190.0		IPP	S_IPP_Sarul	4.5	9.2	Civilian purposes	
INALUM-400-②	Coal-fired thermal power	200 (Subcritical, local specifications)		SPC	C_SPC_Near	4.3	5.9	5.9 + backup tariff	**Second recommended option:** The option of coal-fired thermal power development for INALUM plant expansion by an SPC or INALUM itself is the best case in terms of feasibility and power generating cost. This options entails development of coal-fired thermal power for INALUM and development of hydropower for civilian purposes. Hydropower can make the greatest contribution to PLN finances because it entails cheap generating costs. Since IPPs have little implementation capability in the hydropower development field and it is difficult for PLN to conduct development based on local consensus, immediate implementation is unfeasible, however, the hydropower development delays can be alleviated if power for INALUM plant expansion is obtained from coal-fired thermal power. Moreover, if PLN can conduct development in cooperation with the local community, the development will be eligible for ODA, thereby making a further contribution to improving PLN finances. This will help secure a more favorable outcome in negotiations with PLN concerning the backup power tariff.
				INALUM	C_INA_Near	4.3	5.6	5.6 + backup tariff	
	Hydropower	Toru-1	38.4	IPP	H_IPP_Touru	1.8	5.3	Civilian purposes	
				PLN	H_PLN_Touru	1.8	2.4		
		Simango-2	59.0	IPP	H_IPP_Simang	2.2	6.4		
				PLN	H_PLN_Simang	2.2	2.9		
		Raisan-3,4	80.0	IPP	H_IPP_Raisan	3.7	10.8		
				PLN	H_PLN_Raisan	3.8	4.9		
		Overall	177.4	IPP	H_IPP_Total	2.6	7.6		
				PLN	H_PLN_Total	2.6	3.5		
INALUM-400-③	Gas-fired thermal power	200.0		SPC	L_SPC_Near	8.6	10.8	10.8 + backup tariff	Since the power sale price is high, feasibility of immediate implementation is low for geothermal power (due to delays in the Sarulla-1 development) and gas-fired thermal power (due to impact of progress in the LNG loading point and gas pipeline construction plans) and power for INALUM plant expansion must be purchased from PLN, this case is not feasible.
				INALUM	L_INA_Near	8.7	8.9	8.9 + backup tariff	
	Geothermal power	190.0		IPP	S_IPP_Sarul	4.5	9.2	Civilian purposes	
INALUM-400-④	Gas-fired thermal power	200.0		SPC	L_SPC_Near	8.6	10.8	10.8 + backup tariff	Development of gas-fired thermal power for INALUM plant expansion by an SPC or INALUM itself is not feasible because it entails high power generating cost and is impacted by progress of the LNG loading point and gas pipeline construction plans.
				INALUM	L_INA_Near	8.7	8.9	8.9 + backup tariff	
	Hydropower	Toru-1	38.4	IPP	H_IPP_Touru	1.8	5.3	Civilian purposes	
				PLN	H_PLN_Touru	1.8	2.4		
		Simango-2	59.0	IPP	H_IPP_Simang	2.2	6.4		
				PLN	H_PLN_Simang	2.2	2.9		
		Raisan-3,4	80.0	IPP	H_IPP_Raisan	3.7	10.8		
				PLN	H_PLN_Raisan	3.8	4.9		
		Overall	177.4	IPP	H_IPP_Total	2.6	7.6		
				PLN	H_PLN_Total	2.6	3.5		
INALUM-400-⑤	Coal-fired thermal power	400 (Subcritical, local specifications)		SPC	C_SPC_Near	4.3	5.9	5.9 + Excess sale profit and loss	**Fourth recommended option:** Concerning backup at times of power plant failure, this is more advantageous than the 200 MW supply options, however, it is likely that power for civilian purposes will be sold as excess power at a low price. If the plans of RUPTL 2010 proceed smoothly, in line with the resulting higher reserve margin, there is concern that the excess power sale price will be driven down even lower.
				INALUM	C_INA_Near	4.3	5.6	5.6 + Excess sale profit and loss	
INALUM-200-②	Gas-fired thermal power	400.0		SPC	L_SPC_Near	8.6	10.8	10.8 + Excess sale profit and loss	Since the development is impacted by progress of the LNG loading point and gas pipeline construction plans, there is little difference in power generating cost compared to the case of purchasing from PLN and the 200 MW for civilian purposes becomes excess power, this is not a feasible case.
				INALUM	L_INA_Near	8.7	8.9	8.9 + Excess sale profit and loss	

Note) See the 200 MW supply options for the case where Japanese specifications are adopted for coal-fired thermal power (subcritical). In the case of adopting Japanese specifications, it is necessary to verify the necessity (technical feasibility, durability, reliability, etc.).

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Table 8.5-1 (c-1) Power Supply Options (600 MW Supply Options): Financial Efficiency and Feasibility Assessment

(1) 600 MW supply options assuming power purchase from PLN: The INALUM power purchase tariff is a uniform charge (scheduled to increase by 37% by 2015) regardless of the power generating mode and generating unit cost

Serial No.	Generating Mode	Plant Output MW		Project Operator	Financial Analysis Case	Economic & Financial Analysis Result ¢/kWh Generation Unit Cost	Economic & Financial Analysis Result ¢/kWh Power Sale Price	INALUM Plant Expansion Power Tariff (PLN Power Tariff) ¢/kWh	feasibility of Development
PLN-600-①	Geothermal power	190.0		IPP	S_IPP_Sarul	4.5	9.2	7.35 ＋ Tariff hike	Sixth recommended option: Concerning geothermal power, it is possible that the development will not coincide with INALUM smelting plant expansion (due to delays in Sarulla-1), however, the development concession has already been set. Coal-fired thermal power entails the second lowest power generating cost and power sale price behind hydropower, so there are few issues regarding feasibility; moreover, because the development can be timed to coincide with the INALUM plant expansion, any delays in geothermal power development can be covered. Since 400 MW of coal-fired thermal power is generated, there is less need for backup for INALUM, however, 200 MW of power for civilian purposes is excess power. In RUPTL 2010, since it is forecast that Sumatra will experience an even bigger supply surplus in future, there will be even less need for civilian power supply from coal-fired thermal power and the excess power tariff will decline even more. Accordingly, this option is no more feasible than the 400 MW supply option (PLN-400-②). Since power for INALUM plant expansion is purchased from PLN and the development partially entails power supply for
	Coal-fired thermal power	400 (Subcritical, local specifications)		PLN	C_PLN_Any	4.3	5.6		
				IPP	C_IPP-Any	4.3	5.9		
				PPP	C_PPP_Any	4.3	5.6		
PLN-600-②	Geothermal power	190.0		IPP	S_IPP_Sarul	4.5	9.2		Since the power sale price is high, feasibility of immediate implementation is low for geothermal power (due to delays in the Sarulla-1 development) and gas-fired thermal power (due to impact of progress in the LNG loading point and gas pipeline construction plans) and power for INALUM plant expansion must be purchased from PLN, this case is not feasible. Since power for INALUM plant expansion is purchased from PLN and the development partially entails power supply for INALUM, an issue concerns whether or not each operator can gain an incentive.
	Gas-fired thermal power	400.0		PLN	L_PLN_Any	8.7	8.9		
				IPP	L_PLN_Any	8.6	10.8		
				PPP	L_PPP_Any	8.7	8.9		
PLN-600-③	Hydropower	Toru-1	38.4	IPP	H_IPP_Touru	1.8	5.3		Overall, the power generating unit cost and power sale price are cheapest out of all the combinations of differing power modes. than the PLN tariff, and this mode makes the best contribution to improving PLN finances. Since IPPs have little implementation capability in the hydropower development field and it is also difficult for PLN to conduct development based on local consensus, implementation in tandem with the INALUM plant expansion is difficult; however, by combining with coal-fired thermal power, which entails little risk concerning the development timing, problems of scheduling can be alleviated somewhat. However, if the power resource development plans stated in RUPTL 2010 are realized, the need to supply power for civilian purposes (200 MW) from coal-fired thermal power will decrease. Accordingly, this option is no more feasible than the 400 MW supply option (PLN-400-④). Since power for INALUM plant expansion is purchased from PLN and the development partially entails power supply for INALUM, an issue concerns whether or not each operator can gain an incentive.
				PLN	H_PLN_Touru	1.8	2.4		
		Simango-2	59.0	IPP	H_IPP_Simang	2.2	6.4		
				PLN	H_PLN_Simang	2.2	2.9		
		Raisan-3,4	80.0	IPP	H_IPP_Raisan	3.7	10.8		
				PLN	H_PLN_Raisan	3.8	4.9		
		Overall	177.4	IPP	H_IPP_Total	2.6	7.6		
				PLN	H_PLN_Total	2.6	3.5		
	Coal-fired thermal power	400 (Subcritical, local specifications)		PLN	C_PLN_Any	4.3	5.6		
				IPP	C_IPP-Any	4.3	5.9		
				PPP	C_PPP_Any	4.3	5.6		
PLN-600-④	Hydropower	Toru-1	38.4	IPP	H_IPP_Touru	1.8	5.3		Regarding hydropower, since IPPs have little implementation capability in the hydropower development field and it is difficult for PLN to conduct development based on local consensus, implementation in the near future is not very feasible, whereas concerning gas-fired thermal power, since implementation is impacted by progress of the LNG loading point and gas pipeline, etc., feasibility is even lower than implementation in each individual mode alone. Therefore, this is not a feasible case. In the case where power is used for INALUM plant expansion, since this is purchased from PLN, there is no merit for INALUM. Moreover, since the development partially entails power supply for INALUM, an issue concerns whether or not each operator can gain an incentive.
				PLN	H_PLN_Touru	1.8	2.4		
		Simango-2	59.0	IPP	H_IPP_Simang	2.2	6.4		
				PLN	H_PLN_Simang	2.2	2.9		
		Raisan-3,4	80.0	IPP	H_IPP_Raisan	3.7	10.8		
				PLN	H_PLN_Raisan	3.8	4.9		
		Overall	177.4	IPP	H_IPP_Total	2.6	7.6		
				PLN	H_PLN_Total	2.6	3.5		
	Gas-fired thermal power	400 (Subcritical, local specifications)		PLN	L_PLN_Any	8.7	8.9		
				IPP	L_PLN_Any	8.6	10.8		
				PPP	L_PPP_Any	8.7	8.9		
PLN-600-⑤	Coal-fired thermal power	Subcritical (Local specifications)	600.0	PLN	C_PLN_Any	4.3	5.6		Although there is risk concerning coal price fluctuations and certainty of procurement, etc., the power generating unit cost and power sale price are second lowest behind hydropower and feasibility is high. Also, since power for civilian purposes is developed at the same time, the incentive for operators concerning power supply for INALUM is better, although considering that there is concern over excess supply in RUPTL 2010, there is little need for 400 MW of power supply for civilian purposes. the situation is better than in the 200 MW supply options. Since power for INALUM plant expansion is purchased from PLN and the development partially entails power supply for INALUM, an issue concerns whether or not each operator can gain an incentive.
				IPP	C_IPP-Any	4.3	5.9		
				PPP	C_PPP_Any	4.3	5.6		
		Supercritical	600.0	PLN	C_PLN_AU450	5.0	5.2		The generating cost is higher than in the case of subcritical generation, however, it is still low enough to improve PLN finances. Moreover, through adopting supercritical generation, the chances of obtaining Japanese participation increase. However, detailed examination is required concerning impact on the grid and the necessity for 400 MW supply for purposes other than INALUM plant expansion. Since power for INALUM plant expansion is purchased from PLN and the development partially entails power supply for INALUM, an issue concerns whether or not each operator can gain an incentive.
				IPP	C_IPP_AU450	5.1	7.6		
				PPP	C_PPP_AU450	5.0	5.2		
PLN-600-⑥-a	Gas-fired thermal power	600.0		PLN	L_PLN_Any	8.7	8.9		There is concern over feasibility because the development is impacted by the progress of the LNG loading point and gas pipeline construction plans. Since the power generating cost is not very different from the case of purchasing from PLN, there is no merit for INALUM. Since the development partially entails power supply for INALUM, an issue concerns whether or not each operator can gain an incentive.
				IPP	L_PLN_Any	8.6	10.8		
				PPP	L_PPP_Any	8.7	8.9		
PLN-600-⑥-b	Gas-fired thermal power	520.0		PLN	L_PLN_Belaw	8.3	8.5		This option is not very feasible because the development is impacted by the progress of the LNG loading point and gas pipeline construction plans and the power generating cost is high, etc. Since power for INALUM plant expansion is purchased from PLN and the development partially entails power supply for INALUM, an issue concerns whether or not each operator can gain an incentive.

Note) See the 200 MW supply options for the case where Japanese specifications are adopted for coal-fired thermal power (subcritical). In the case of adopting Japanese specifications, it is necessary to verify the necessity (technical feasibility, durability, reliability, etc.).

Table 8.5-1 (c-2) Power Supply Options (600 MW Supply Options): Financial Efficiency and Feasibility Assessment

(2) 600 MW supply options entailing Construction of a new dedicated power plant (200 MW) for INALUM + Securing of 400 MW for civilian purposes:

Serial No.	Generating Mode	Plant Output MW		Project Operator	Financial Analysis Case	Economic & Financial Analysis Result ¢/kWh		INALUM Plant Expansion Power Tariff (PLN Power Tariff) ¢/kWh	feasibility of Development
						Generation Unit Cost	Power Sale Price		
INALUM-600-①	Coal-fired thermal power	400 (Subcritical, local specifications)		SPC	C_SPC_Near	4.3	5.9	5.9 + Excess sale profit and loss	Coal-fired thermal power is advantageous in terms of feasibility and power generating cost in the case where INALUM develops the power resource for plant expansion itself. However, considering that there is already concern over excess supply in RUPTL 2010, there is doubt that a further 200 MW needs to be secured for civilian purpose. Moreover, profitability will deteriorate even more if the excess power tariff is applied.
				INALUM	C_INA_Near	4.3	5.6	5.6 + Excess sale profit and loss	
	Geothermal power	190.0		IPP	S_IPP_Sarul	4.5	9.2	Civilian purposes	
INALUM-600-②	Coal-fired thermal power	400 (Subcritical, local specifications)		SPC	C_SPC_Near	4.3	5.9	5.9 + Excess sale profit and loss	Since IPPs have little implementation capability in the hydropower development field and it is difficult for PLN to conduct development based on local consensus, immediate implementation is unfeasible, however, the hydropower development delays can be alleviated if power for INALUM plant expansion is obtained from coal-fired thermal power. Moreover, if PLN can conduct development in cooperation with the local community, the development will be eligible for ODA, thereby making a further contribution to improving PLN finances. This will help secure a more favorable outcome in negotiations with PLN concerning the backup power tariff.
				INALUM	C_INA_Near	4.3	5.6	5.6 + Excess sale profit and loss	
	Hydropower	Toru-1	38.4	IPP	H_IPP_Touru	1.8	5.3	Civilian purposes	However, if the power resource development plans of RUPTL 2010 are realized, the need for coal-fired thermal power to be supplied for civilian purposes (200 MW) will decline. Accordingly, this option is no more feasible than the 400 MW supply option(PLN-400-②).
				PLN	H_PLN_Touru	1.8	2.4		
		Simango-2	59.0	IPP	H_IPP_Simang	2.2	6.4		
				PLN	H_PLN_Simang	2.2	2.9		
		Raisan-3,4	80.0	IPP	H_IPP_Raisan	3.7	10.8		
				PLN	H_PLN_Raisan	3.8	4.9		
		Overall	177.4	IPP	H_IPP_Total	2.6	7.6		
				PLN	H_PLN_Total	2.6	3.5		
INALUM-600-③	Gas-fired thermal power	400.0		SPC	L_SPC_Near	8.6	10.8	10.8 + Excess sale profit and loss	Since the power sale price is high, feasibility of immediate implementation is low for geothermal power (due to delays in the Sarulla-1 development) and gas-fired thermal power (due to impact of progress in the LNG loading point and gas pipeline construction plans) and power for INALUM plant expansion must be purchased from PLN, this case is not feasible.
				INALUM	L_INA_Near	8.7	8.9	8.9 + Excess sale profit and loss	
	Geothermal power	190.0		IPP	S_IPP_Sarul	4.5	9.2	Civilian purposes	
INALUM-600-④	Gas-fired thermal power	400.0		SPC	L_SPC_Near	8.6	10.8	10.8 + Excess sale profit and loss	Development of gas-fired thermal power for INALUM plant expansion by an SPC or INALUM itself is not feasible because it entails high power generating cost and is impacted by progress of the LNG loading point and gas pipeline construction plans. Furthermore, if the power resource development plans of RUPTL 2010 are realized, the need for coal-fired thermal power to be supplied for civilian purposes (200 MW) will decline.
				INALUM	L_INA_Near	8.7	8.9	8.9 + Excess sale profit and loss	
	Hydropower	Toru-1	38.4	IPP	H_IPP_Touru	1.8	5.3	Civilian purposes	
				PLN	H_PLN_Touru	1.8	2.4		
		Simango-2	59.0	IPP	H_IPP_Simang	2.2	6.4		
				PLN	H_PLN_Simang	2.2	2.9		
		Raisan-3,4	80.0	IPP	H_IPP_Raisan	3.7	10.8		
				PLN	H_PLN_Raisan	3.8	4.9		
		Overall	177.4	IPP	H_IPP_Total	2.6	7.6		
				PLN	H_PLN_Total	2.6	3.5		
INALUM-600-⑤	Coal-fired thermal power	Subcritical (Local specifications)	600.0	SPC	C_SPC_Near	4.3	5.9	5.9 + Excess sale profit and loss	Concerning backup in the case of power plant failure, this option is better than the 200 MW supply options, however, it is likely that power for civilian purposes will be sold at a cheap tariff as excess power. In the case where plans of RUPTL 2010 proceed smoothly, since the impact of lower tariff for excess power due to the improved reserve margin is bigger than in the 400 MW supply option (INALUM-400-⑤), this is not a feasible case.
				INALUM	C_INA_Near	4.3	5.6	5.6 + Excess sale profit and loss	
		Supercritical	600.0	SPC	C_SPC_NU450	5.1	7.6	7.6 + Excess sale profit and loss	**Fifth recommended option:** Since the generating cost is higher than in the case of subcritical generation and power is sold at the excess power tariff, profitability is even lower. Moreover, since power is generated by a single unit, backup power needs to be purchased from PLN in the event of failure, leading to even higher generating cost. However, since there is a better chance of obtaining participation by Japanese corporations by adopting supercritical generation, this has been added to the recommended options. Confirmation is required concerning grid stability and the need for 400 MW of supply for purposes other than INALUM plant expansion.
				INALUM	C_INA_NU450	5.0	5.2	5.0 + Excess sale profit and loss	
INALUM-600-⑥	Gas-fired thermal power	600.0		SPC	L_SPC_Near	8.6	10.8	10.8 + Excess sale profit and loss	There is concern over feasibility because the development is impacted by the progress of the LNG loading point and gas pipeline construction plans. Since the power generating cost is not very different from the case of purchasing from PLN, there is no merit for INALUM.
				INALUM	L_INA_Near	8.7	8.9	8.9 + Excess sale profit and loss	

Note) See the 200 MW supply options for the case where Japanese specifications are adopted for coal-fired thermal power (subcritical). In the case of adopting Japanese specifications, it is necessary to verify the necessity (technical feasibility, durability, reliability, etc.).

Chapter 9 Study Results and Issues for the Future

This chapter sums up the updated Study findings based on the power supply options proposed in the Phase 1 study implemented in 2009, combined with new gas-fired thermal power options and more recent data. It also gives recommendations concerning the issues and problems that need to be resolved in future. Since some of the options proposed in Phase 1 are deemed to be unfeasible, these have been omitted from this Study and new options are proposed in their place.

9.1 Study Results

(1) Coal-fired thermal power

Sources of coal supply to North Sumatra are limited to sites in the three provinces of South Sumatra, East Kalimantan and South Kalimantan, where there are abundant reserves. East Kalimantan and South Kalimantan Provinces have abundant reserves of medium quality coal with ample potential for supply to the domestic and oversea market. Meanwhile, coal from South Sumatra province is largely the low quality type suited to consumption in Indonesia.

As for the provinces of North Sumatra, Riau is thought to have some coal reserves, however, unlike the three provinces mentioned above, it does not have the potential to provide a stable supply into the future. Accordingly, there is little feasibility of developing a mine-mouth power plant in the north of Sumatra; rather, it is more appropriate to transfer coal to North Sumatra Province from sites in South Sumatra, East Kalimantan or South Kalimantan. Judging from the transfer distances and state of transportation infrastructure, the best option is thought to be to utilize coal from South Sumatra Province.

So long as the necessary quantity of coal can be secured, there are no particular constraints concerning the power plant site. The required conditions for sites are that water supply can be secured, major equipment can be installed and there is enough land to store coal. Concerning economic and financial efficiency, for example, in the case where an SPC (special purpose company) is established near the INALUM aluminum smelting plant, a power plant and transmission lines are constructed using a JBIC loan and 200 MW subcritical coal-fired thermal power generation is conducted, the estimated power generating unit cost is 4.3 ¢/kWh, the power tariff is 5.9 ¢/kWh, FIRR is 12.1 percent and ROE is 18 percent (see the main text for other calculation cases).

(2) Gas-fired thermal power

The areas having the greatest natural gas potential are Natuna, South Sumatra Province, East Kalimantan Province and West Papua Province. The gas fields around Natuna have the largest reserves and are located close to North Sumatra, however, these reserves have CO2 content of 70 percent and their feasibility cannot be judged from the amount of reserves alone. Sumatra also has gas fields in Aceh Province and North Sumatra Province, however, reserves here are limited and production has been declining in recent years.

Concerning natural gas produced in South Sumatra, since priority is given to supply to Java and it would be necessary to transport it more than 1,000 km by tank lorry, it is not feasible to use this. Moreover, concerning natural gas procurement via pipeline, a pipeline has been installed and is being used between Grissiki in South Sumatra Province and Duri in Riau Province, however, since the remaining section of more than 500 km to Medan is only in the planning stage and so far no specific construction schedule has been set, no date has been set for supply via this route.

Meanwhile, it is scheduled to construct a marine LNG terminal off the coast of Medan in 2013 and this will primarily supply gas to the existing thermal power plant at Belawan (combined cycle plant). Possible options are either to procure gas from East Kalimantan Province and West Papua Province and construct a combined cycle power plant, or to rehabilitate the deteriorated steam generating facilities at the existing Belawan thermal power plant and thereby boost the power resources.

So long as the necessary quantity of natural gas can be secured, there are no particular constraints concerning the power plant site. The required conditions for sites are that water supply can be secured and there is enough land to install major equipment. Concerning economic and financial efficiency, for example, in the case where an SPC (special purpose company) is established near the INALUM aluminum smelting plant, a power plant and transmission lines are constructed using a JBIC loan and 200 MW subcritical coal-fired thermal power generation is conducted, the estimated power generating unit cost is 8.6 ¢/kWh, the power tariff is 8.8 ¢/kWh, FIRR is 3.1 percent and ROE is 18 percent (concerning other calculation cases, see the economic and financial analysis for power options in Chapter 8).

(3) Geothermal energy

Among the promising geothermal energy development sites, only Sarulla-2 has the potential to generate 200 MW of power. However, concerning development of Sarulla (330 MW) including Sarulla-2, a power purchase agreement has been signed with PLN, which means that power from subsequent developments will also be sold to PLN. It would thus be difficult for INALUM to directly obtain power supply from Sarulla. Meanwhile, according to the Geothermal Master Plan Study (2007), it is estimated that Sarulla-2 has development potential for 300 MW, of which 110 MW is planned for development in RUPTL. Accordingly, this Study targeted the remaining 190 MW of potential not stated in RUPTL. However, there are a number of obstacles to developing Sarulla-2 as a dedicated resource for INALUM, including the issue of the development concession.

Concerning economic and financial efficiency, for example, in the case where an IPP is established, a power plant and transmission lines are constructed using a JBIC loan and 200 MW geothermal power generation is conducted, the estimated power generating unit cost is 4.5 ¢/kWh, the power tariff is 9.2 ¢/kWh, FIRR is 11.6 percent and ROE is 18 percent (concerning other calculation cases, see the economic and financial analysis for power supply options in Chapter 8).

(4) Hydropower

In Phase 1, Tampur-1 and Jambu Aye were identified as promising sites since both would possess large reservoirs and be capable of supplying stable power to ILUNAM; however, since both these sites are located in nature protection areas, development would be difficult in terms of the environmental impacts. Moreover, since both sites are located in Aceh Province, which has been at loggerheads with the central government for many years, it would be difficult to conduct development in the long term.

Accordingly, these sites were omitted from the list of promising development sites in the Study. As alternatives, four sites: Toru-1, Simanggo-2, Wampu and Raisan-3,4, were newly proposed as sites with the potential to supply 200 MW. Apart from Wampu, none of these sites is mentioned in RUPTL. Since all four sites are middle-scale regulating reservoir or run-of-river developments, they would entail few environmental problems and are feasible.

Concerning economic and financial efficiency, for example, in the case where an IPP is established, a power plant and transmission lines are constructed using a JBIC loan and 200 MW hydropower generation is conducted at four sites, the estimated power generating unit cost is 2.6 ¢/kWh, the power tariff is 7.6 ¢/kWh, FIRR is 12.2 percent and ROE is 18 percent (concerning other calculation cases, see the economic and financial analysis for power supply options in Chapter 8).

Note: More and more hydropower development concessions are recently being granted to IPPs with links to provincial governments, however, until now PLN has managed hydropower developments of medium scale or larger. Under the current systems in Indonesia, due to the nature of hydropower development, development by an IPP would in reality be difficult and it would be more realistic to conduct development under PLN.

9.2 Issues for the Future

(1) Coal-fired thermal power

Judging from the experience of Japanese thermal power plants that have adopted supercritical pressure or ultra supercritical pressure boilers with excellent thermal efficiency, the minimum unit capacity is generally around 400 MW. Since North Sumatra Grid has a combined generating capacity of approximately 1,700 MW as of 2010, 400 MW would account for roughly 23 percent of total capacity, which would be far higher than the 4 percent or less that is recommended for new power resources. Even in the event where power plants contained in the Crash Program are completed and commence operation, thereby bringing grid capacity up to approximately 3,500 MW by 2015, a 400 MW unit would still account for 11 percent of the grid capacity. In either case, it would be necessary to examine the introduction plan upon conducting system flow analysis and considering the impact on the grid.

In the event where 200 MW of generating capacity is reserved exclusively for INALUM, subcritical steam power generation would be adopted; however since the system would have no backup, it would be necessary to connect to the PLN grid and have power diverted from that in the event of emergency. It would be necessary to examine cost in this event. In this case, fixed power charges would arise irrespective of the said power coordination with PLN, while the specific charge would be levied according to the amount of power consumption. In either case, the tariff would be higher than conventional charges (similar backup measures would also be needed when introducing 400 MW and 600 MW coal-fired thermal power generation).

(2) Gas-fired thermal power

Since it is initially planned for the offshore LNG terminal to supply around 40 mmcfd, it would be necessary to examine in detail whether enough gas for the new power resources can be supplied in line with the expansion plans of the LNG terminal. In the case where a power plant is constructed around Kuala Tanjung near the INALUM plant, it would be necessary to examine, among other things, whether the gas supplier or the consumer invests in the pipeline leading from the existing gas pipeline system around Medan to the power plant. In the case where 200 MW of supply capacity is secured only for the INALUM plant expansion, as in the case of coal-fired thermal power, the backup power source would be necessary.

(3) Geothermal energy

A consortium has signed a power purchase contract with PLN concerning development of Sarulla (330 MW) including Sarulla-2, and the developed power would be sold to PLN under this. Sarulla covers a wide area spanning four sections, however, these are regarded as one working area and the development concession covers all of it. Accordingly, in the case where this area is targeted for development, it would be necessary to conduct discussions and negotiations with the existing stakeholders. Moreover, since development of Sarulla-2 will take place after development of Sarulla-1, it would be necessary to expedite the work on Sarulla-1 if Sarulla-2 is targeted. For this purpose, it would be essential to secure assistance for the drilling and power plant construction.

Meanwhile, according to the Geothermal Master Plan Study (2007), it is estimated that Sarulla-2 has development potential of around 300 MW, however, since this figure was based on the study findings from the Pre-F/S, it would be necessary to conduct a more detailed assessment of reserves through a geothermal development study that includes a well investigation. Since a large amount of budget is necessary for development of geothermal power generation such as Sarulla project including well drilling, it would not be possible without financial assistance of the government.

(4) Hydropower

In this Study, promising sites were selected on condition that projects are planned with a relatively high degree of accuracy, however, all the plans have only reached the initial study phase. Moreover, since a number of years have passed since studies were finished, it is necessary to implement renewed studies. Accordingly, in order to concrete realize development plans quickly, it would be necessary to immediately raise the study accuracy and smoothly advance the work to the design and construction implementation stage. Even though the run-of-river and regulating reservoir type plants proposed in the Study entail smaller environmental impacts than storage reservoir type plants, it would still be necessary to conduct adequate surveys and examinations.

Meanwhile, in line with the advance of decentralization in Indonesia, provincial governments have the authority to grant development concessions for hydropower development. It is also believed that the authority to utilize natural energy resources for hydropower and geothermal development should be held by the areas where those resources are located. Accordingly, it would be necessary to commence advance coordination with provincial governments in each development case.

(5) Legal systems

The New Electric Power Law was enacted in September 2009, however related government ordinances, etc. have not yet been revised in line with this. For example, provisions concerning the leasing of transmission lines have been stipulated in Government Regulations No.3/2005 and No.26/2006, however, detailed provisions have not yet been established. In order to formulate such detailed provisions on the leasing of transmission lines, it would be necessary to conduct examination giving consideration to grid stability and trends in power resources development and demand, however, unless the needs for leasing increase, there is a strong possibility that work on preparing such provisions won’t even begin.

Accordingly, in the Study, it was decided that the leasing of transmission lines would be difficult in the current situation. However, since this factor has the greatest impact on securing a power resource for INALUM plant expansion, it will be necessary to pay close attention to work on detailed provisions.