No.

Ministry of Energy and Mines
Electricite du Laos
EDL-Generation Public Company
Lao People's Democratic Republic

LAO PEOPLE'S DEMOCRATIC REPUBLIC

STUDY ON

POWER SUPPLY AND DEMAND IN CENTRAL REGION IN

LAO PEOPLE'S DEMOCRATIC REPUBLIC

FINAL REPORT

AUGUST 2012

JAPAN INTERNATIONAL COOPERATION AGENCY

NIPPON KOEI CO., LTD.

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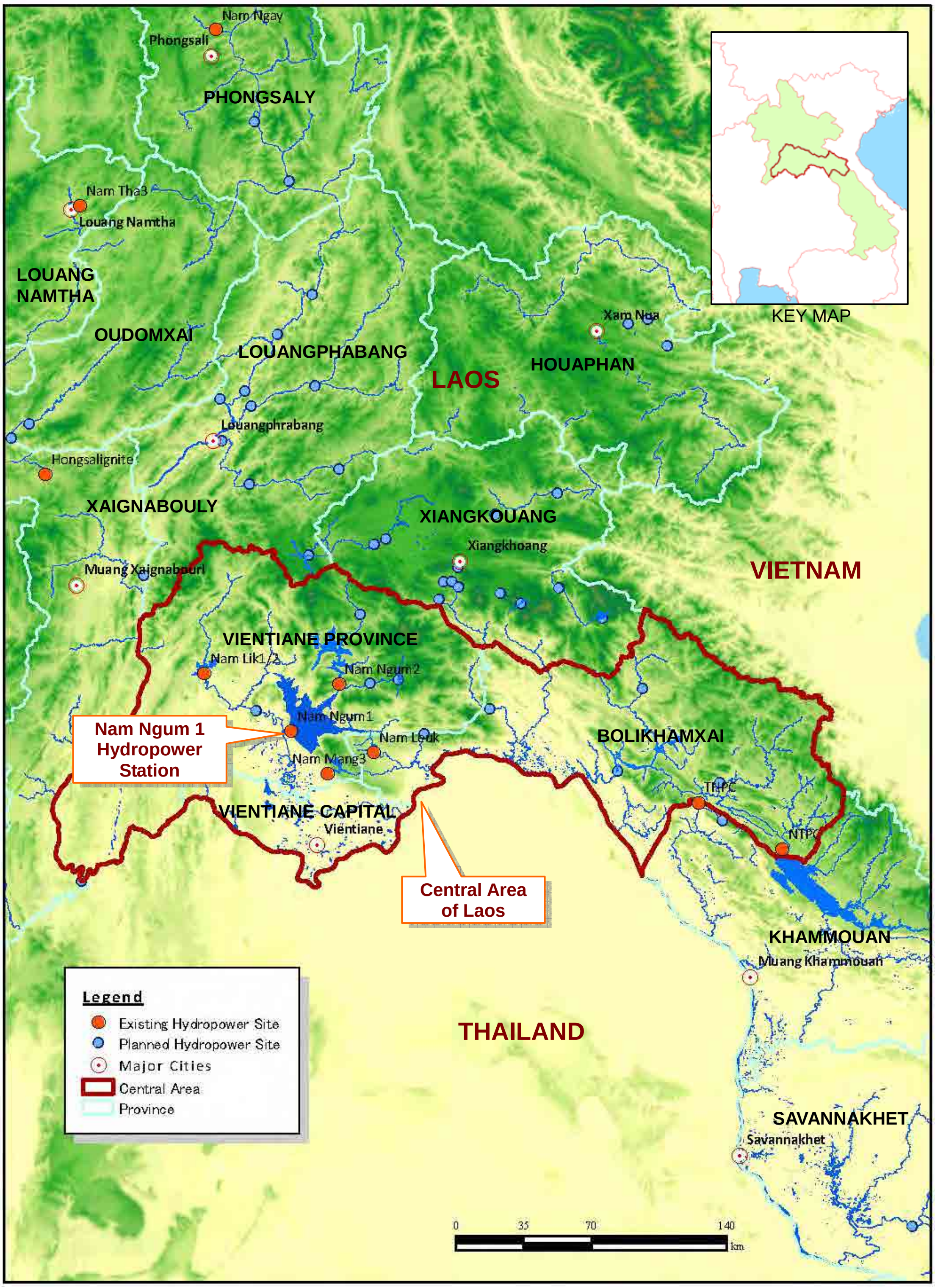

Prepared by the Study Team

<u>Location Map of the Study Area</u>

STUDY

ON

POWER SUPPLY AND DEMAND IN CENTRAL REGION

IN

LAO PEOPLE'S DEMOCRATIC REPUBLIC

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Abbreviations

Terms	
Abbreviations	**English**
Lao PDR agencies	
DMH	Department of Meteorology and Hydrology
CDEP	Committee for Development of Electric Power
CPC	Committee for Planning and Cooperation
DEB	Department of Energy Business, MEM
DEPP	Department of Energy Policy and Planning, MEM
DEM	Department of Energy Management, MEM
DOE	Former Department of Electricity, MEM
EDL	Electricite du Laos
EDL-Gen	EDL-Generation Public Company
FIMC	Foreign Investment Management Committee
GOL	Government of Lao PDR
LNCE	Lao National Committee for Energy
LWU	Lao Women’s Union
MEM	Ministry of Energy & Mines
MONRE	Ministry of Natural Resources and Environment
STEA	Science, Technology & Environment Agency
WREA	Water Resources and Environment Agency
Foreign organizations	
ADB	Asian Development Bank
EGAT	Electricity Generation Authority of Thailand
EVN	Electricity of Vietnam
IMF	International Monetary Fund
IUCN	World Conservation Union (Switzerland)
JICA	Japan International Cooperation Agency (Japan)
MOI	Ministry of Industry of Vietnam
MPI	Ministry of Planning and Investment of Vietnam
NEPO	National Energy Policy Office of Thailand
NTEC	Nam Theun 2(NT2) Electricity Company
NTPC	Nam Theun 2(NT2) Power Company
PEA	Provincial Electricity Authority in Thailand
PRGF	Poverty Reduction and Growth Fund
UNDP	United Nations Development Program
WCD	World Commission on Dams
Others	
AAU	Assigned Amount Unit
B.	“Ban” Village in Laotian language
BOT	Built-Operate-Transfer
CA	Concession Agreement
CDM	Clean Development Mecah
CER	Certified Emission reduction
COD	Commercial Operation Date
ECA	Export Credit Agencies
EIA	Environmental Impact Assessment
EMMP	Environmental Management & Monitoring Plan
EPC	Engineering, Procurement and Construction
EPMs	Environmental Protection Measures
ERU	Emission Reduction Unit
ET	Emission Trading
FS	Feasibility Study
FARD	Focal Area for Rural Development
GHG	Green House Gas
GIS	Geographic Information System
GMS	Greater Mekong Sub-region
GPS	Global Positioning System
HEPP	Hydroelectric Power Project
ICB	International Competitive Bidding
IEE	Initial Environmental Examination
IOD	Initial Operation Day
IPDP	Indigenous Peoples Development Plan
IPP	Independent Power Producer
IPP(d)	Independent Power Producer for domestic power supply

Terms	
Abbreviations	**English**
IPP(e)	Independent Power Producer for exporting electricity
IWRM	Integrated Water Resources Management
JI	Joint Implementation
LA	Loan Agreement
LEPTS	Lao Electric Power Technical Standard
LLDC	Least Less-Developed Countries
MOU	Memorandum of Understanding
NBCA	National Biodiversity Conservation Area
NEM	New Economic Mechanism
NGOs	Non Governmental Organizations
NNRB	Nam Ngum River Basin
O&M	Operation and Maintenance
ODA	Official Development Assistance
PDA	Project Development Agreement
PDP	Power Development Plan
PPA	Power Purchase Agreement
S/W	Scope of Works
SIA	Social Impact Assessment
SPC	Special Purpose Company
SPP	Small Power Producer
TOR	Terms of Reference
Unit/Technical Terms	
B-C, B/C	B: Benefit and C: Cost
EIRR, FIRR	Economic/Financial Internal Rate of Return
EL.( ) m	Meters above Sea level
FSL.	Full Supply Level of Reservoir
GDP	Gross Domestic Product
GWh	Giga Watt Hour (one billion watt hour)
IRR	Internal Rates of Return
LWL	Low Water Level of Reservoir
MAP	Mean Annual Precipitation
MAR	Mean Annual Runoff
MCM	Million Cubic Meter
MOL.	Minimum Operation Level of Reservoir
MW	Mega Watt (one million watt)
PMF	Probable Maximum Flood
PMP	Probable Maximum Precipitation
US$	US Dollar

CHAPTER 1 INTRODUCTION

1.1 BACKGROUND

Current Status of Power Supply

In Lao People's Democratic Republic (PDR), the domestic power load and energy demand from 2001 to 2010 rapidly increased from 13.4% to 15.0%, respectively. This increase in electricity demand is mainly due to the increase in electrification rate of households, which is directed through the Lao government's electricity policy. Other factors such as construction of a speed railway and development of copper or bauxite mining are also the driving forces that increase total electricity demand. This increasing trend in electricity demand is expected to continue.

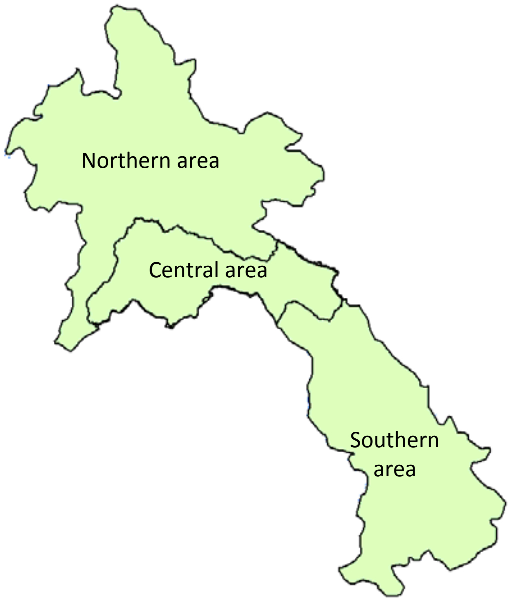
In 2010, the total installed capacity of power plants including independent power producer (IPP) projects in Lao PDR accumulated to 2557 MW. From the total capacity, the installed capacity for domestic supply is 492 MW. The 155 MW capacity of the Nam Ngum 1 (NN1) Hydropower station shares 31.5% of the domestic supply in Lao PDR.

Export of power to neighboring countries is one of the methods for acquisition of foreign exchange for Lao PDR. The power export and import balance, which excludes IPP power production, was positive until 2005. However, due to the increase in domestic power demand, the power import exceeded the power export. In 2001, the annual import and export of electricity energy were 183 GWh and 797 GWh, respectively. In 2010, the annual import energy exceeded the export energy as annual import and export of electricity were 796 GWh and 344 GWh respectively. The unit price of imported power is set to be higher than that of the exported power. This induces a deficit in the power exchange in a financial aspect. Therefore, it is necessary to develop new power plants to earn foreign exchange, reduce import power, and extend the transmission line in the country to cover the domestic power demand.

Electric Power Policy and Hydropower Development Plan

In August 2010, the Power Development Plan (PDP), with an objective year from 2010 to 2020 was formulated to achieve the target to secure social development through power supply and acquisition of foreign exchange by the power export. After the formulation of the PDP, it is recognized that PDP should be updated with the updated power demand forecast, and the PDP was updated in August 2011 by the study done among relevant authorities. The updated version of PDP is called PDP 2010-2010 (Revision-1). In the updated PDP, the revision of the demand forecast was made for the electricity demand of the speed railway construction and operation, and mining development in the southern area of the country.

It is noted that PDP 2010-2020 (Revision-1) newly divided the country to three areas namely northern, central and southern area. The province included in the each area is shown in Figure 1.1.1.



Northern: Phongsaly, Oudomxai, Luangnamtha, Bokeo, Huaphanh, Luangpabang, Xayabuly and Xiengkhouang provinces

Central: Vientiane Capital, Vientiane and Bolikhamxai provinces.

Southern: Khammouan, Savannakhet, Salavan, Sekong, Champasak and Attapeu Provinces.

Source; PDP 2010-2012 (Revision-1), prepared by the Study Team

Figure 1.1.1 Defined Areas in PDP 2010-2020 (Revision-1)

The PDP 2010-2020 (Revision-1) estimated the power supply and demand balance in the northern area, central area, and southern area. In the northern area, PDP 2010-2020 (Revision-1) estimated that the energy demand and peak load exceeds the power supply capacity until 2014. Power supply is expected to exceed the power demand after 2015. The deficit in power supply until 2014 is planned to be resolved by importing power from China. After 2015, the excess in power supply and demand balance is planned to be delivered to the central area. In the central area, peak load and energy demand will not be fulfilled until 2020. The deficit in power supply will be covered by importing power from the northern area, or importing from the Electricity Generating Authority of Thailand (EGAT). In the southern area, the power demand is anticipated to exceed power supply due to its mining development. Therefore, it is necessary to import power to the southern area to compensate the power supply deficit.

The power supply and demand balance in the whole country of Lao PDR is expected to be negative (power demand will exceed power supply). Therefore, it is necessary to import power from China, Vietnam and Thailand as it is described in the PDP 2010-2020 Revision-1.

The PDP 2010-2020 (Revision-1) described that the power development potential exists in the northern area, and in the same time, the large bulk demand exists in the southern area due to its mining development. The PDP 2010-2020 Revision-1 describes the power supply plans to resolve the supply and demand imbalance as follows:

(1) The energy surplus in the northern area will be delivered to the central area

(2) The importing power from the northern area that passes through the central area is necessary.

If the above power supply plan is implemented, domestic power demand in the whole country of Lao PDR will be covered by the domestic power supply after 2016. This requires the timely reinforcement of the power system/grid of the northern area, the central area and the southern area.

The Electricite du Laos (EDL) also formulates the power development policy for securing power supply capability against power demand. The power policy of EDL stated in PDP 2010-2020 Revision-1 is as follows:

- EDL will invest on new power plants;
- Purchase from small power producers (SPP) and domestic independent power producer (IPP(d)) projects;
- Purchase off-take from IPP(e) projects;
- Continue to import power from neighboring countries to the area where there is no network access; and
- Continue to exchange (import/export) power from neighboring countries to increase the reliability and security of power supply.

Nam Ngum 1 Hydropower Expansion Plan

Photo taken by the Study Team
Nam Ngum 1 Hydropower Station (2012)

The Nam Ngum 1 (NN1) Hydropower station (155 MW) is being operated to meet the power demand in the central area. The power demand in the central and northern areas is met by coordinated operation between the NN1 Hydropower Station (155 MW), Nam Leuk hydropower station (60 MW), Nam Mang 3 hydropower station (40 MW), and Nam Lik 1/2 hydropower station (100 MW) which commenced its operation in year 2010. During rainy season, the power supply capability exceeds the power demand of the central and northern areas and a surplus of power supply is exported to Thailand. Whereas, the aggregated power output of the four power stations falls below the daily load during peak hours of the dry season due to less inflow of water into the reservoirs. In this case, the power shortage is supplemented with power import from Thailand.

In this circumstance, the NN1 hydropower station expansion was studied in the preparatory survey on the Nam Ngum 1 hydropower station expansion by JICA in 2009. The survey studied to add 40MW turbine and generator beside the existing power house, and a final report was submitted in January 2010. The purpose of the expansion is to increase the power output during night peak hours from 6:00 p.m. to 10:00 p.m. by allocating reservoir water from off-peak hours to peak hours to meet the increased power demand. The survey showed that the expansion of the power plant enables to decrease the import of power import during peak hours. It also increases the annual energy by reducing spill-out during rainy season. The survey considers the inflow regime changes due to the storage effect of the Nam Ngum 2 (NN2) hydropower that aims to export power to Thailand.

The comparison of the expansion scale resulted in the optimum expansion of 40 MW. The project is also feasible with respect to the economic aspect. The electricity tariff in Lao PDR was used to calculate its financial internal rate of return (FIRR). The study results showed an FIRR of 2.75%. This low FIRR indicates that the project is financially feasible provided that a low interest soft loan is given. EDL did not give any concrete decision on the project, and project type ODA yen loan was not available to Lao PDR during the preparatory survey stage, therefore, a request for an ODA yen loan for the expansion of the NN1 hydropower station was not made by the Lao government .

Two years have passed since the report was submitted and it was understood that the external conditions have been changed since the preparatory survey. The changes in external conditions include a large modification in power demand forecast, modification in power development plan, modification in transmission line network development plan, changes in electricity tariff, power exchange condition with EGAT, and foreseen yen loan interest rate. Furthermore, the shape of the daily load curve is important to fit-in the peak load of the NN1 expansion, and therefore daily load curve should be updated. In this line, it is necessary to confirm the necessity of NN1 expansion plan along the changes in the external conditions.

1.2 OBJECTIVES OF THE STUDY

The objectives of the Study are: to review the power supply and demand balance in the central area of Lao PDR, to clarify the issues which impede supply for the peak load demand in the central area, and to identify optimum countermeasures which includes the expansion of the NN1 hydropower station to meet the peak load demand. The expansion scale of NN1 hydropower station is presumed to 40MW.

1.3 STUDY AREA

The study area is the central area of Lao PDR (Vientiane Capital, Vientiane and Bolikhamxai Province). The northern area and neighboring country (such as Thailand) is included, if necessary.

1.4 COUNTERPART OF THE STUDY

The main counterpart of the preparatory survey is the EDL and the EDL-Generation Public Company (EDL-Gen), with technical support of MEM. The NN1 hydropower station is under the control of EDL-Gen. If necessary, the Study Team will collect information from hydropower IPPs such as NN2 hydropower and Nam Lik 1/2 hydropower.

1.5 TEAM MEMBERS

In order to assess the various work items such as detailed study of power supply and demand, or re-evaluation of NN1 expansion project, the Study Team was organized with the corresponding members as shown in Table 1.1.1 below.

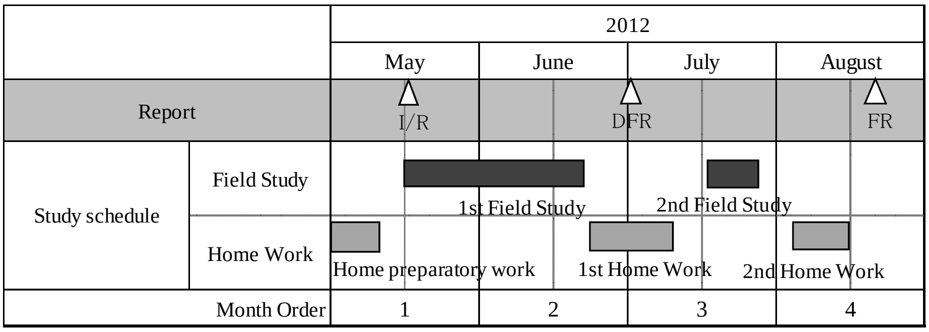
Table 1.1.1 Study Team Staff Composition

No.	Name	Position/Field of Expertise
1	Sohei UEMATSU	Team Leader/Hydrology and Basin Network Operation
2	Masahiro IWABUCHI	Power Supply and Demand Analysis/Power System Analysis
3	Yusaku MAKITA	Economic and Financial Analysis
4	Mayumi GOTO	Environmental and Social Consideration

Prepared by the Study Team

1.6 TEAM ACTIVITIES

Team member conducts the field study from the mid of May 2012 to the end of June and one week in the end of July 2012. The team activities of the study is shown in Figure 1.6.1.



I/R: Inception Report

DFR: Draft Final Report

FR: Final Report

Prepared by the Study Team

Figure 1.6.1 Team Activities of the Study

CHAPTER 2 PRESENT SITUATION OF THE POWER SECTOR IN LAO PDR

2.1 OUTLINE OF POWER SECTOR IN LAO PDR

The Ministry of Energy and Mines (MEM) is a regulatory ministry for the electric power and mining sectors in Lao PDR. The Electricite du Laos (EDL) is a national power entity under MEM which is responsible for the transmission and distribution of electricity assets in Lao PDR. EDL manages electricity imports into its grids and exports from its power stations. The EDL Generation Public Company (EDL-Gen) is a public company responsible for the power generation and maintenance of previous EDL-owned power stations.

EDL was established in 1959. It started with only a small unit for small-scale power generation and electric power supply to parts of Vientiane City and the French base residing in the area. EDL gradually expanded its service area and now covers the whole country.

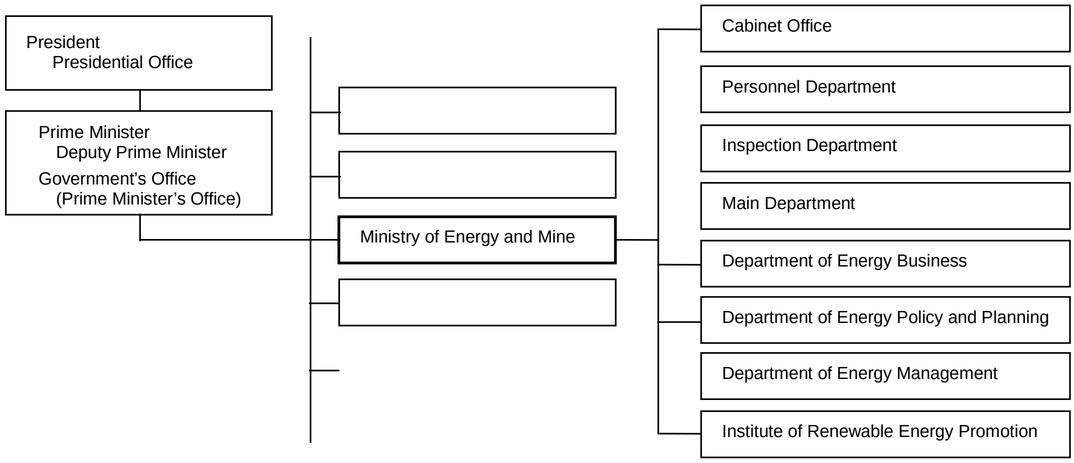
The Department of Electricity (DOE) was established by the Ministry of Industry and Handicraft (MIH) in 1994. The DOE was responsible for the management and planning for the electric power sector, managing the strategy, policies and legal framework of its electricity and power development plans. In 2006, the department was transferred to MEM which was established as a ministry for the mining and energy industry in 2006. In 2012, the organization of MEM was reformed and DOE was divided into two departments and one institute.

2.1.1 Organization of the Ministry of Energy and Mines

In 2012, Department of Electricity (DOE) in MEM was reorganized into two departments and one institute namely the Department of Energy Policy and Planning (DEPP), the Department of Energy Management (DEM) and the Institute of Renewable Energy Promotion. Among these departments, DEPP is placed as the center of energy-related policy making.

Other than former DOE departments, MEM is composed of the Department of Energy Business (DEB), the Cabinet Office, the Inspection Department and the Personnel Departments. DEB was previously named “Department of Energy Promotion and Development” and this department is a regulatory authority to manage IPP project development and examining proposed projects.

Figure 2.1.1 shows the present status and organization of the Ministry of Energy and Mines.

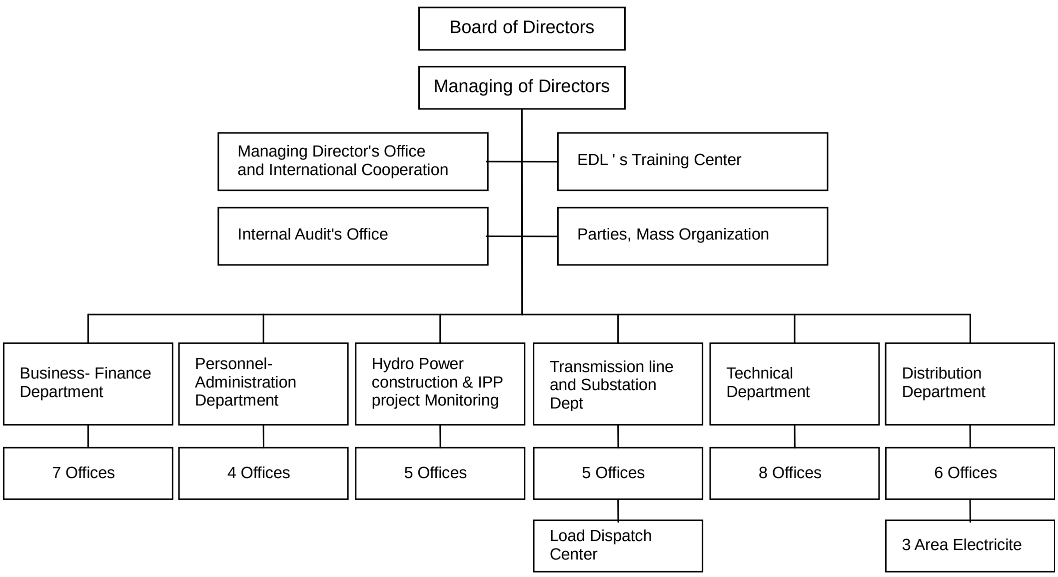


Source: MEM

Figure 2.1.1 Organizational Chart of the Ministry of Energy and Mines (MEM)

2.1.2 Present Status and Organization of EDL

EDL was established in 1959 as an electricity department of the Ministry of Public Utilities. EDL was then incorporated as a public service corporation in 1997. According to the directives of the Government of Lao for its business restructuring on electricity industries in Lao PDR, the generation section was separated into the EDL-Gen in 2011. Therefore, EDL is in charge of electrical transmissions in the national level as well as the design, construction, operation/ management of power distribution equipment, and managing importing and exporting power with neighboring countries. EDL implements power development projects, including large-scale hydroelectric projects for domestic power supply. The developed power plants are to be transferred to EDL-Gen for operation and maintenance. Figure 2.1.2 shows the present organization of EDL.



Source: EDL

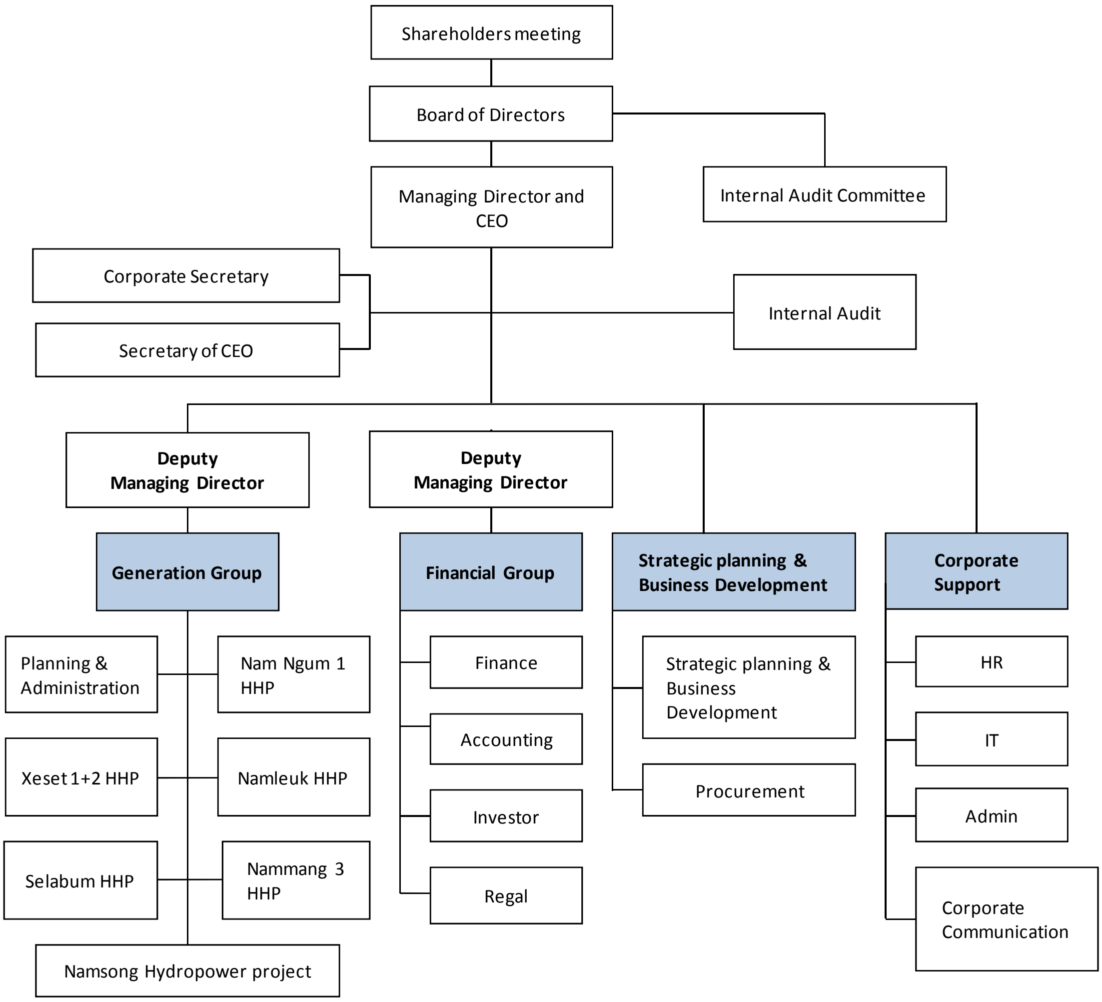
Figure 2.1.2 Organizational Chart of EDL

2.1.3 Present Status and Organization of EDL-Gen

EDL-Generation Public Company (EDL-Gen) was established on the 15th of December 2010 as the first publicly-held enterprise in Lao PDL listed on the Lao Securities Exchange (LSX).

According to the directives of the Government of Lao on the business restructuring of its electricity industry in Lao PDR, the function of power generation of EDL was separated from EDL to EDL-Gen Company. Figure 2.1.3 shows the present organization of EDL-Gen.

At present, the EDL-Gen is in charge of the operation and maintenance of existing hydroelectric power stations which includes Nam Ngum 1, Nam Leuk, Xeset 1, Xeset 2, Selabam and Nam Dong.



Source: EDL-Gen

Figure 2.1.3 Organizational Chart of EDL-Gen

2.2 CURRENT OPERATION PATTERN OF EXISTING POWER STATIONS

2.2.1 General

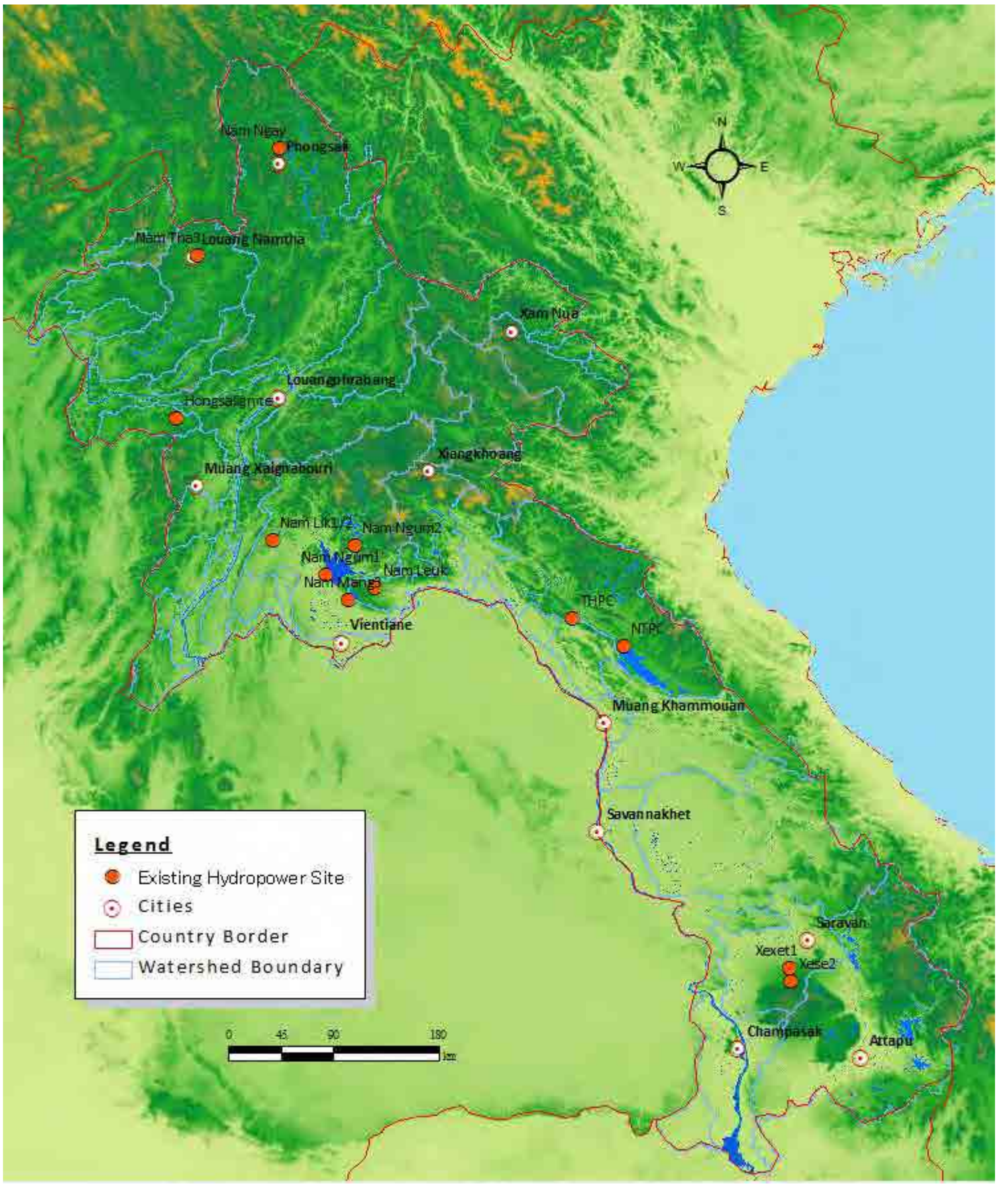
Currently, there are 16 small to large scale hydropower stations in operation. Among these hydropower stations, nine hydropower stations are owned by EDL. The existing hydropower stations in Lao PDR are shown in Table 2.2.1, and the principal hydropower stations are shown in Figure 2.2.1.

Table 2.2.1 Existing Power Plants in Lao PDR

No.	Power Plant	Province	Installation Cap. (MW)	Comercial Operation Date	Owner-ships (Note*)	Market	Remarks
1	Nam Dong	Luangprabang	1	1970	EdL	Laos	
2	Selabam	Champasak	5	1970	EdL	Laos	
3	Nam Ngum 1	Vientiane	155	1971	EdL	Laos/ Thailand	
4	Xeset 1	Saravane	45	1990	EdL	Laos/ Thailand	
5	Nam Ko	Oudomxay	1.5	1996	EdL	Laos	
6	Theun-Hinboun	Bolikhamxay	210	1998	IPP(e)	Laos/ Thailand	
7	Houay Ho	Champasak/ Attapeu	152.1	1999	IPP(e)	Laos/ Thailand	150MW (Export) and 2.1MW (Domestic)
8	Nam Leuk	Vientiane	60	2000	EdL	Laos/ Thailand	
9	Nam Ngay	Phongsaly	1.2	2003	EdL	Laos	
10	Nam Mang 3	Vientiane	40	2004	EdL	Laos/ Thailand	
11	Xeset 2	Saravane	76	2009	EdL	Laos	
12	Nam Theun 2	Khammuane	1088	2009	IPP(e)	Laos/ Thailand	Off take 75 MW (Domestic)
13	Nam Ngum 2		615	2011	IPP(e)	Thailand	
14	Nam Lik 1/2		100	2010	IPP(d)	Laos	
15	Nam Tha 3	Luangnamtha	1.25	2011	IPP(d)	Laos	
16	Nam Nhon	Borkeo	3	2011	IPP(d)	Laos	
	Micro-hydro		0.15	2011	EDL	Laos	
	Micro-hydro		1.178	2010	Prov.	Laos	
	Solar		0.474	2011	Prov.	Laos	
	Diesel		1.513	2011	Prov.	Laos	
	Total		**2557.4**				
	EdL		**384.85**				
	IPP(d)		**104.25**				
	IPP(e)		**2065.1**				
	Prov.		**3.17**				

EdL: Electricité du Laos (EdL)
IPP: Independent Power Producer
IPP(e): Exporting IPP
IPP(d): Domestic IPP

Note: Install capacity of "micro-hydro" is aggregate of install capacity of micro-hydro power plants.
Source: PDP 2010-2020 Revision-1



Prepared by the Study Team

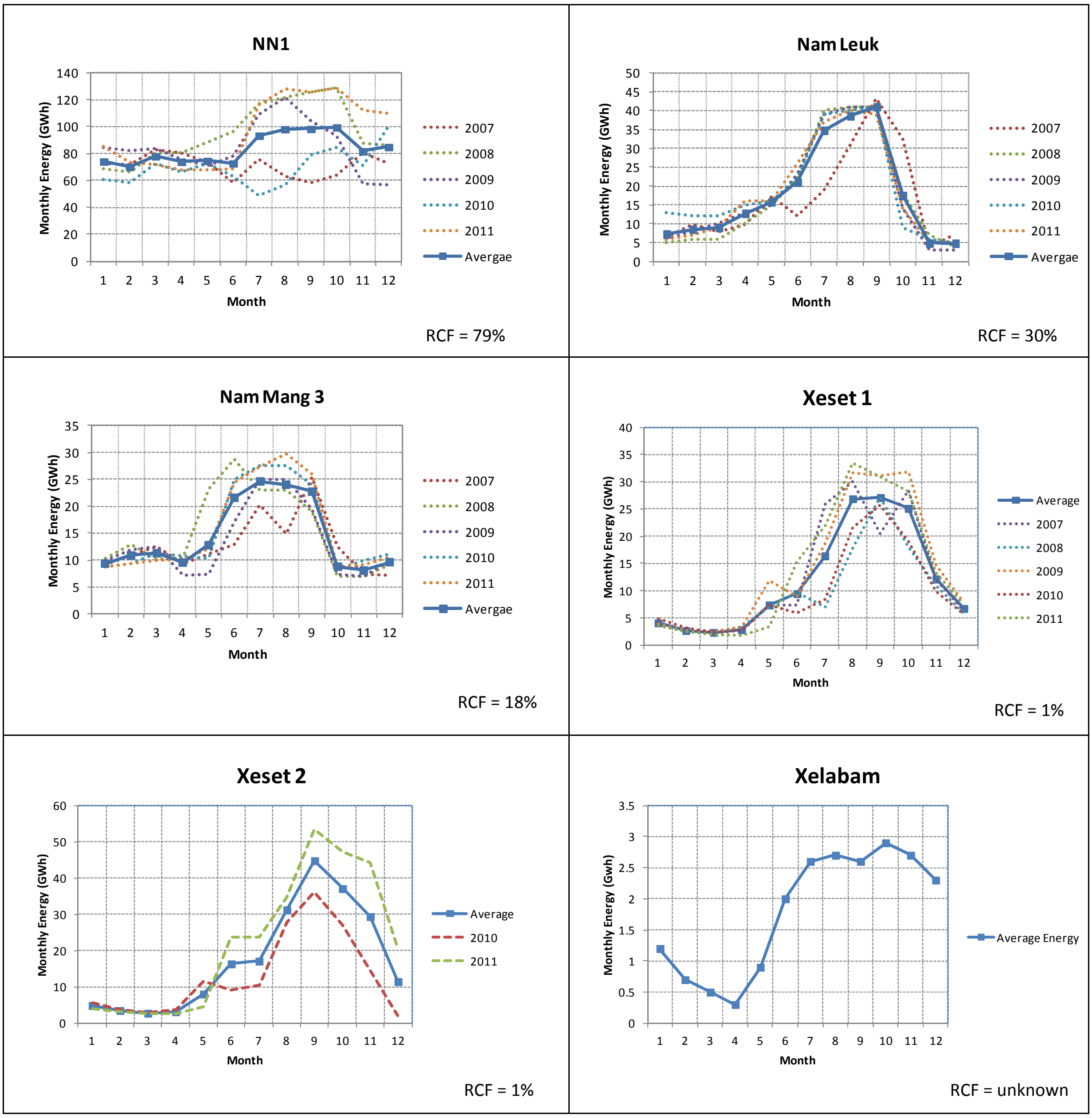
Figure 2.2.1 Principal Existing Hydropower Stations in Lao PDR

2.2.2 Monthly Energy Output of Existing Power Stations

In this study, the operation record of the medium to large scale hydropower operations for domestic power supply are collected from EDL-Gen's power stations and IPP(d).

(1) EDL-Gen's Hydropower Stations

The monthly operation pattern of the medium to large scale hydropower stations for the past five years are collected and shown in Figure 2.2.2.



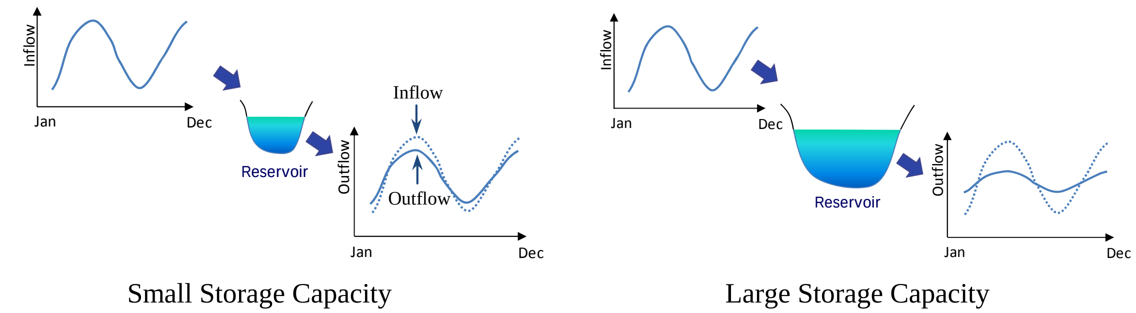
Prepared by the Study Team

Figure 2.2.2 Monthly Energy Fluctuation of Existing Hydropower Plants Owned by EDL-Gen

The regulating capacity factor (RCF) shown in the figure above is the percentage of effective storage to annual inflow. It measures how much annual inflow can be stored in the reservoir.

Regulating Capacity Factor (RCF) (%) = Effective Storage (m^3) / Annual Inflow (m^3)

If the storage capacity is large enough to store water during wet season for use during dry season, the hydropower can generate energy even in dry season. If the storage capacity is just for one-day power generation usage, the power generation during dry season is strictly limited. This storage effect can be illustrated in the following figure.



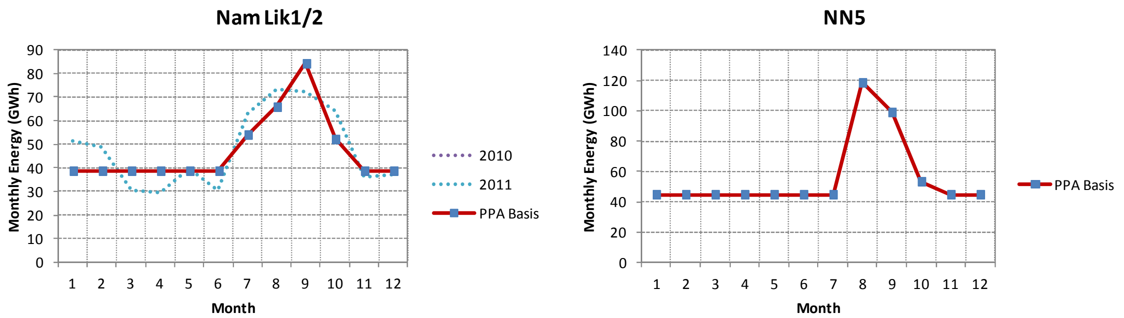
Prepared by the Study Team

Figure 2.2.3 Difference of Storage Effect Between Large and Small Storage Capacity

As Xeset 1 and Xeset 2 have small RCF of 1%, this results in the significant decrease in monthly energy during the dry season. NN1, on the other hand, has a large storage capacity (RCF=79%), therefore, it can generate a certain amount of electricity during dry season. Nam Leuk and Nam Mang 3 have RCFs of 30% and 18%, respectively, and the drop in monthly energy production in the dry season is still significant. The dry season monthly energy of Nam Leuk is about 18% to the monthly energy in wet season. For the Nam Mang 3 case, the dry season monthly energy is 40% to that of the wet season. Nam Mang 3 is also responsible for irrigation supply, therefore it has to stably release water for power generation during the dry season.

(2) IPP for Domestic Power Supply

The hydropower plant of IPP(d) is currently only Nam Lik 1/2 is in operation, and Nam Ngum 5 (IPP(d)) is planned to commence the operation in the end of year 2012. The operations record of Nam Lik 1/2 and monthly average capacities of Nam Lik 1/2 and Nam Ngum 5 stated in the PPA are shown in Figure 2.2.4.



Prepared by the Study Team

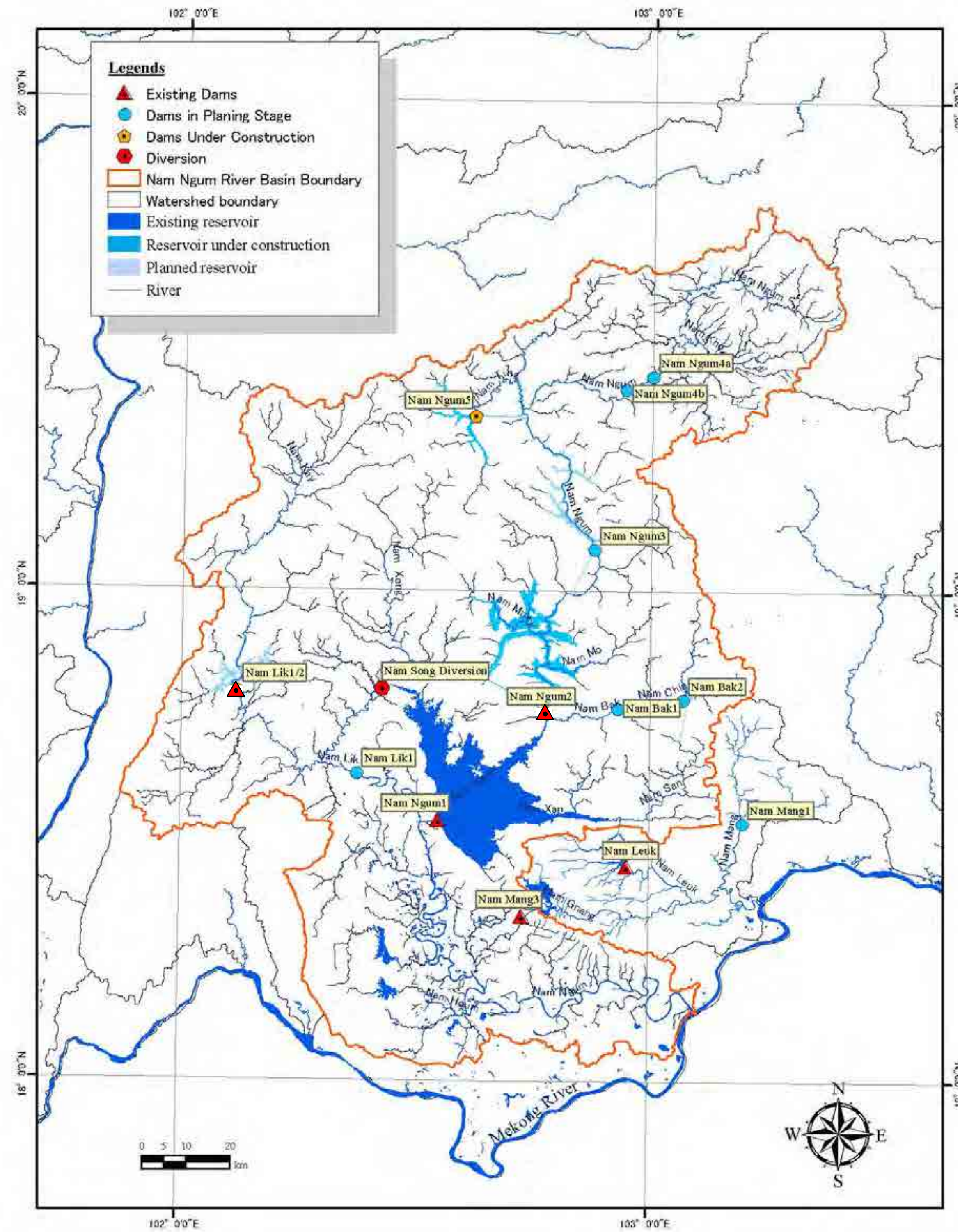
Figure 2.2.4 Monthly Energy Output of Nam Lik1/2 and Nam Ngum 5

As shown in the figure above, the monthly average capacity is constant except during rainy season. The operation record of Nam Lik 1/2 shows some departure from the planned monthly energy.

Unlike EDL-Gen's hydropower stations, the IPP(d) hydropower stations have a more stable energy output except during the wet season.

2.2.3 Daily Energy Output of Existing Power Stations

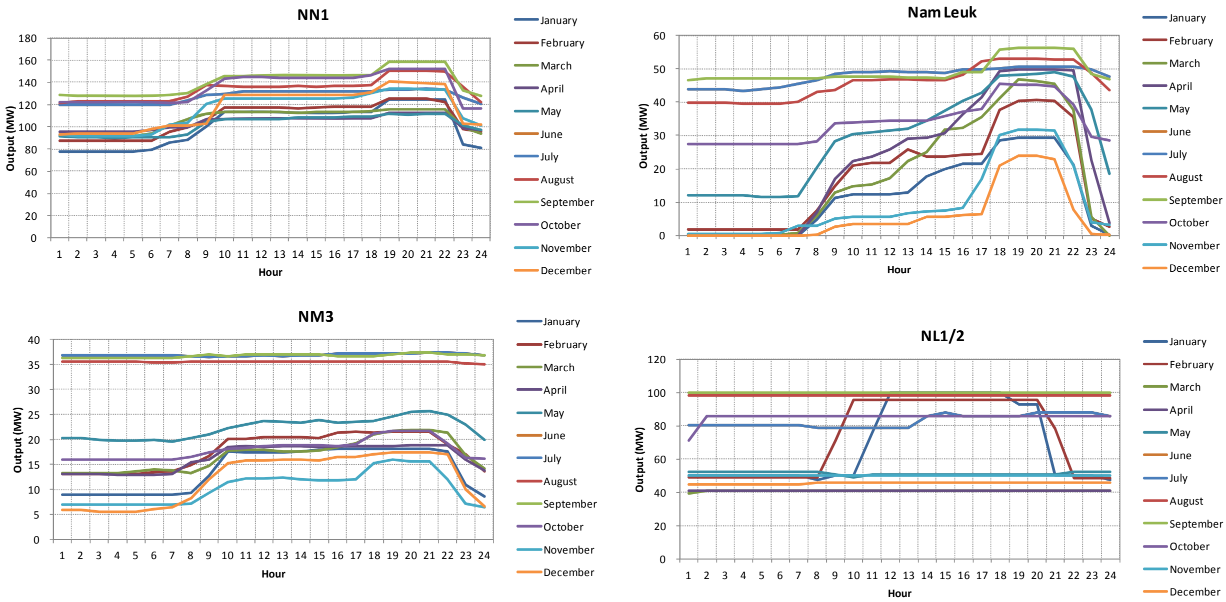
The daily power generation records available for the Study are NN1, Nam Leuk, Nam Mang 3 and Nam Lik 1/2. The location map of these hydropower stations are shown in Figure 2.2.5.



Source：Preparatory Survey on Nam Ngum 1 Hydropower Station Expansion

Figure 2.2.5 Location Map of Hydropower Stations in NNRB

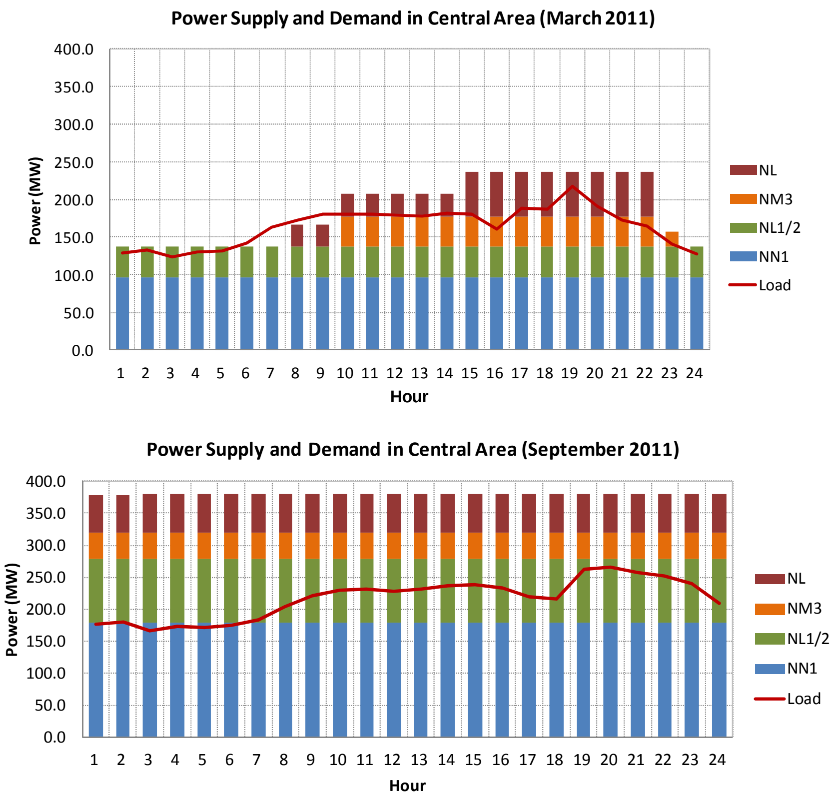
The average daily operation record on weekdays for these power stations during the recent past five years are shown in the figure below.



Prepared by the Study Team

Figure 2.2.6 Daily 24-Hour Operation of Nam Ngum 1, Nam Leuk, Nam Mang 3 and Nam Lik 1/2 Hydropower Stations.

The aggregate output of the power stations for supplying power to the central area is shown in Figure 2.2.7.



Prepared by the Study Team

Figure 2.2.7 Power Supply for Central Area in March and September 2011

In general, NN1 power station supplies power for base load as well as peak load during the dry season. It is noted that, in the dry season of 2011, NN1 does not operate for peak power supply since the power supplies closely meet the daily demand as shown in Figure 2.2.7. Therefore, it was not necessary for NN1 to increase power during peak hours.

2.3 PRESENT SITUATION OF ELECTRICAL POWER SUPPLY AND DEMAND BALANCE

2.3.1 Power Demand in Laos

In Lao PDR, the average annual growth rate of domestic energy consumption and peak power demand has recorded an increase of more than 10% from 2001 to 2010, mainly because of the rapid increase of power demand in the country. The total average growth rate of energy consumption from 2001 to 2011 is relatively higher at 14.6%. As of 2011, the total energy consumption has reached 2,832.2 GWh, which consists of 1548.5 GWh in the central area, 278.7 GWh in the northern area and 1,004.9 GWh in the southern area as shown in Table 2.3.1.

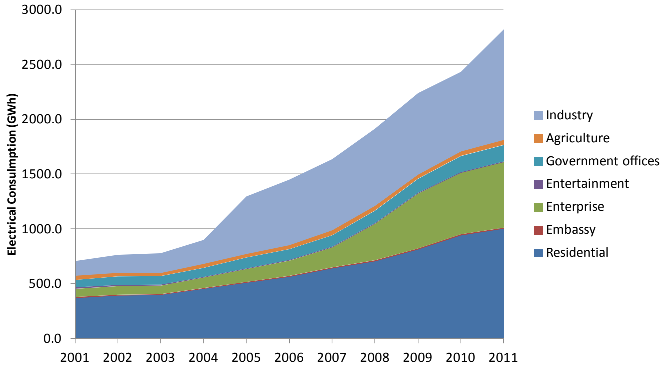
The energy consumption in the central area accounts for 54.7% of the total consumption of the whole country. The peak load has also rapidly increased from 191.7 MW in 2001 to 649.3 MW in 2011 for the whole country. Out of the total peak load, 60.6% (393.6 MW) was being supplied to the central region.

Table 2.3.1 Record of Energy Consumption and Peak Load in Lao PDR

Region/Year	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Annual Growth
Energy consumption (GWh)												
Northern	33.9	43.2	49.0	65.3	85.6	106.8	136.1	162.1	193.1	246.9	278.7	23.4%
Central	504.5	537.0	558.5	597.8	561.9	698.3	814.7	1,030.9	1,267.7	1458.2	1548.5	11.9%
Southern	189.6	204.3	211.2	239.6	363.6	595.5	692.3	722.7	797.0	856.2	1,004.9	18.1%
Total	**728.0**	**784.6**	**818.7**	**902.8**	**1,011.1**	**1,400.6**	**1,643.1**	**1,915.7**	**2,257.8**	**2,561.4**	**2,832.2**	14.6%
Growth Rate		**8%**	**4%**	**10%**	**12%**	**39%**	**17%**	**17%**	**18%**	**13%**	**11%**	
Peak Load (MW)												
Northern	8.6	11.0	12.4	16.6	21.7	27.1	34.5	41.1	49.0	62.6	70.7	23.4%
Central	111.1	118.4	118.3	136.5	151.6	163.0	186.0	235.4	322.2	370.6	393.6	13.5%
Southern	72.0	75.3	101.6	96.0	118.0	142.0	144.0	145.0	146.7	157.6	185.0	9.9%
Total	**191.7**	**204.7**	**232.3**	**249.0**	**291.3**	**332.1**	**364.5**	**421.5**	**520.0**	**590.9**	**649.3**	13.0%
Annual Growth		**7%**	**13%**	**7%**	**17%**	**14%**	**10%**	**16%**	**23%**	**14%**	**10%**	

Source: PDP 2010-2020

The energy demand for residential users has been growing at an annual rate of over 10% from 1990 and reached 1,003 GWh (35.5%) in 2011. About 1,009.51 GWh (35.8%) is for industrial demand.



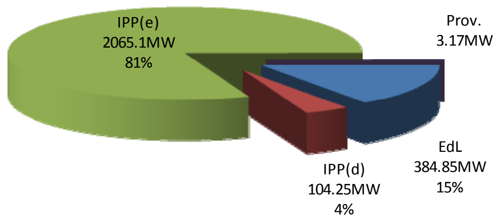
Consummners Type	2011
Residential	1,003.17
Embassy	9.43
Enterprise	597.73
Entertainment	7.78
Government offices	148.99
Agriculture	46.31
Industry	1,009.51
Total (GWh)	2,823

Source: PDP 2010-2020

Figure 2.3.1 Statistics of Electrical Consumption by Consumer Category

2.3.2 Power Generation in Laos

The existing power plants in Lao PDR are listed in Table 2.1.1. The ratio of generation by EDL, IPP(e) and IPP(d) is shown in Figure 2.3.2.



Source: PDP 2010-2020 Revision 1

Figure 2.3.2 Ratio of Generation by EDL, IPP (e) and IPP (d)

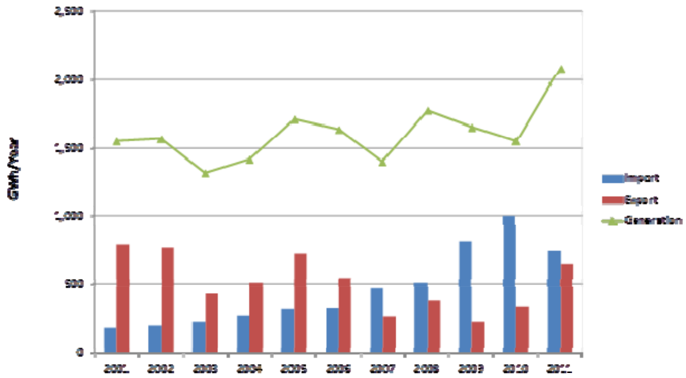
The installation capacity achieved 2,557 MW total in 2011. However, 2065 MW of the installed capacity was used for generation of power for export purposes by IPPs. The rest of the generating facilities, i.e. EDL and domestic IPP, estimated at 489 MW are used for domestic use, which does not reach the peak demand of 649 MW as stipulated in Sub-Clause 2.2.1. The power import from neighboring countries compensates for the power shortage.

2.3.3 Power Trade with Neighbor Countries

(1) Past Record of Power Trade

Power trade is being carried out with Thailand, China and Vietnam. The power interchanges with Thailand accounts for the largest volume among the transactions.

In Lao PDR, power export used to be one of the significant means to earn foreign exchange. The gross amount of export, except for IPP, was larger than that of import until 2006. Hence, the import amount has exceeded the export amount in yearly gross amount since 2007. In 2009 and 2010, the import drastically exceeded the export by 589 GWh and 653 GWh, respectively. The export grew and import decreased because of precipitation augmentation in 2011, as shown in Figure 2.3.3.



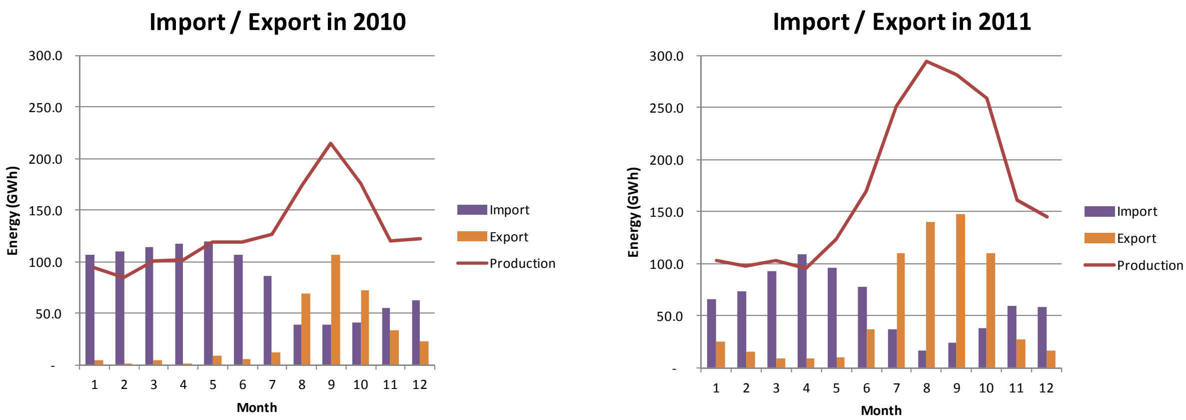
Source : PDP 2010-2020 Revision-1

Figure 2.3.3 Past Record of Power Trade with Neighbor Countries

Future power demand is expected to drastically increase because of new developments on copper and bauxite mining. New special promotion zones (SEZ) and the increase in rate of expansion of household electrification has been planned by the government. It is presumed that this trend will continue as of this time. However, an interchange tariff in import from Thailand is set at a higher rate than the export from Lao PDR. In addition, in the agreement with EGAT, the escalation of fuel cost is supposed to be annually reviewed to the excess portion of the import tariff. Overpower import from EGAT could be a financial predicament of EDL. However, the existing power stations in the Lao PDR are not sufficient to cater to growing domestic power demand. Accordingly, the development of new power sources for domestic use is urgently needed.

(2) Seasonal Variation of Power Import and Export

Figure 2.3.4 shows the seasonal variation of power import and export in recent years.



Prepared by Study Team

Figure 2.3.4 Seasonal Variation of Power Trade

As indicated in the above record in 2010 and 2011, the power export generally exceeds the import during rainy season. On the contrary, the power import exceeds the export during dry season in recent years. The volume of power export tends to follow the annual energy production, which depends on the rainfall variation. For example, the export relatively increased in 2011 because it was a wet year.

(3) International Interconnection Transmission Lines with Thailand

Table 2.3.2 shows the list of existing international interconnection transmission lines, except expanded 22 kV distribution lines, for power import from Thailand.

Table 2.3.2 Existing International Interconnection Transmission Lines

No.	Substations		Length	No. of Circuit		Voltage	Conductor	Capacity
	EDL (Area)	EGAT	(Km)	Existing	Futrue	(kV)	(Sq.mm)	(MW)
1	Phontong (Central)	Nongkhai	26	2	2	115	240	100 x 2
2	Thanaleng (Central)	Nongkhai	9	1	1	115	240	100
3	Paksan (Central)	Bungkan	11	1	2	115	240	100
4	Thakhek (South)	Nalhonphanom	10	2	2	115	240	100 x 2
5	PakBo (South)	Mukdahan 2	5	1	2	115	240	100
6	Bang Yo (South)	Sirinthon P/S	61	1	1	115	240	100

Prepared by the Study Team based on PDP 2010-2020 Revision 1

Currently, there are six 115 kV transmission lines internationally connecting the EGAT system in Thailand and the EDL domestic system in Lao PDR. Three out of six transmission lines are connecting the Vientiane Capital and Nonkai in Thailand. The interconnection between EDL Phontong Substation and EGAT Nongkai Substation consists of double circuits. Between the EDL Paksan Substation and EGAT Bungkan Substation, there is currently one circuit that is strung on the towers, which will be reinforced to double circuit in the future. The interconnection between EDL Thanaleng and EGAT Nongkai is a single circuit. The capacity of a single ACSR 477 MCM conductor with 240 mm^2 diameter is 100 MW for 115 kV.

2.4 FINANCIAL STATUS OF EDL AND EDL-GEN

2.4.1 EDL

Table 2.4.1 presents the financial statements of EDL from 2007 to 2010. Its salient features are characterized as follows:

(1) Profitability

EDL has recorded a constant net profit from 2007 to 2010. However, its operational profit rates have been as low as 1% to 4%, except in 2008 when the revenue was significantly higher, reflecting an energy sales increase by 279 kWh from the previous year. The return on assets (ROA) was also low at around 1% to 2.9%, mainly due to its low domestic tariff level as discussed in Section 2.3.3. EDL has constantly received in-kind subsidy in the form of additional capital contribution from the government, which accounts for 37,590 million Kip in 2009 and 12,480 million Kip in 2010.

(2) Debt

As a state-owned company, EDL funding relies on capital contribution from the government and borrowings from external assistance loans from JBIC, World Bank, ADB, etc., denominated in foreign currencies. Its debt to assets accounts for around 40% indicating that the company is not heavily in debt. However, the recent debt service coverage ratios (0.88 in 2009 and 0.80 in 2010) show that the operating cash flow of EDL cannot cover the debt service, mainly due to its low profitability.

(3) Liquidity

The current liquidity ratio in 2010 (0.81) is below 1.0, indicating that the company has less capacity to meet short-term obligations. On the other hand, the debtor days, which indicates the average revenue collection period, has been improved from 123 days in 2007 to 80 days in 2010.

Table 2.4.1 Summary of the Financial Status of EDL

(million Kip)

Item	2007	2008	2009	2010
BALANCE SHEET				
Assets	7,767,989	8,165,134	9,433,554	8,958,544
Current Assets	**695,103**	**877,666**	**894,051**	**702,354**
Cash and Cash Equivalents	215,886	393,712	356,683	126,200
Account Receivables	359,902	350,224	341,534	346,569
Other Receivables	14,481	18,792	39,132	49,039
Inventories	104,834	114,938	156,702	180,546
Fixed Assets	**7,072,886**	**7,287,468**	**8,539,503**	**8,256,190**
Joint Venture Investments	301,414	427,682	557,751	3,231,189
Fixed Assets	6,771,472	6,859,786	7,981,752	5,025,001
Liabilities and Equity	7,767,989	8,165,134	9,433,554	8,958,544
Liabilities	**2,903,186**	**3,030,090**	**4,055,443**	**3,509,102**
Current Liabilities	**511,419**	**688,091**	**896,660**	**862,180**
Trade and Other Payables	267,994	313,235	552,752	613,437
Current Income Tax Liabilities	0	51,982	11,906	62,530
Other Taxes Payable	9,596	7,438	7,882	10,378
Interests Accruals	43,952	40,754	27,768	0
Current Portion of LT Borrowings	189,877	274,682	296,352	175,835
Non-current Liabilities	**2,391,767**	**2,341,999**	**3,158,783**	**2,646,922**
Long-term Borrowings	2,310,498	2,107,640	3,077,652	2,609,488
Other Non-current Liabilities	81,269	234,359	81,131	37,434
Equity	**4,864,803**	**5,135,044**	**5,378,111**	**5,449,442**
Contributed Legal Capital	618,210	618,210	655,800	668,228
Retained Earnings	1,806,842	2,165,560	2,373,199	2,422,981
Revaluation Surplus	2,305,168	2,166,868	2,166,868	2,166,868
Other Reserves	134,583	184,406	182,244	191,365
INCOME STATEMENT				
Revenues	1,067,457	1,274,384	1,485,535	1,689,551
Cost of Sales	(815,454)	(765,631)	(1,042,199)	(1,133,179)
Gross Profit	**252,003**	**508,753**	**443,336**	**556,372**
Administrative Expenses	(200,948)	(271,514)	(423,283)	(503,299)
Profit from Operations	**51,055**	**237,239**	**20,053**	**53,073**
Non-operating Income	180,878	143,908	277,427	166,977
Foreign Excange Gains (Loss), net	1,607	24,132	105,691	33,654
Financial Expenses	(102,480)	(91,091)	(118,447)	(132,728)
Profit Before Income Tax	**131,060**	**314,188**	**284,724**	**120,976**
Income Tax Expense	(26,728)	(81,291)	(56,554)	(34,817)
Net Profit for the Year	**104,332**	**232,897**	**228,170**	**86,159**
FINANCIAL RATIOS				
Profitability				
(1) Operational Profit Rate	4.8%	18.6%	1.3%	3.1%
(2) Return on Assets	1.3%	2.9%	2.4%	1.0%
Debt				
(3) Debt to Assets	37.4%	37.1%	43.0%	39.2%
(4) Debt Service Coverage Ratio	1.38	1.79	0.88	0.80
Liquidity				
(5) Current Ratio	1.36	1.28	1.00	0.81
(6) Receivables Turnover	2.97	3.64	4.35	4.88
(7) Debtor Days	123.1	100.3	83.9	74.9

Note: (1) Operational Profit Rate = Profit from Operations / Revenues
(2) Return on Assets = Net Profit / Total Assets
(3) Debt to Assets = Total Liabilities / Total Assets
(4) DSCR = Cash Generated from Operations / (Repayments of Borroiwings + Financial Expenses)
(5) Current Ratio = Current Assets / Current Liabilities
(6) Receivables Turnover = Revenues / Account Receivables
(7) Debtor Days = 365 days / Receivables Turnover

Source: JICA Study Team, based on the audited financial statements of EDL

2.4.2 EDL-Gen

The EDL-Generation Public Company (EDL-Gen) was established on December 15, 2010 in accordance with the Prime Minister's decision No.180 (PMO 180). This decree separated the six existing hydropower plant assets of EDL and their operation, as well as the Nam Xong hydropower plant currently under construction. While EDL holds 75% of the company shares, the rest is owned by private investors through the initial public offering held in December 2010. EDL-Gen has been listed on the Lao Securities Exchange since then. Among the remaining 25% shares, 9.3% is owned by Ratch-Laos Company Limited and RH-International (Singapore), 1.25% is owned by EDL and EDL-Gen officers, and 14.45% is owned by other investors.

Along with the separation from EDL, EDL-Gen concluded the power purchase agreement with EDL in December 2011. The wholesale electricity tariff set for power generation by EDL-Gen is 413.89 Kip/kWh with annual escalation of 1%.

The recent financial status of EDL-Gen is presented in Table 2.4.2. In contrast with the low profitability of EDL as a domestic electricity provider, EDL-Gen has fair profitability as shown in its 10.8% ROA in 2011. The return on equity is calculated as 14.4%. EDL-Gen's capital structure mainly consists of equity investment and debt finance accounts for only 25.2%. The low debt-to-asset rate and high debt service coverage ratio (2.52) indicate that there would be room for further debt finance for investment in the generation capacity development. The existing borrowings of EDL-Gen are derived from the transfer of EDL's long-term borrowings for past generation projects, which are external loans from ADB and other financial institutions.

Table 2.4.2 Summary of the Financial Status of EDL-Gen

(million Kip)

Item	Dec 2010 *	2011
BALANCE SHEET		
Assets	5,052,537	5,238,572
Current Assets	**1,114,774**	**854,140**
Cash and Cash Equivalents	884,782	342,795
Short-term Investment	0	100,000
Trade and Other Receivables	225,367	402,764
Spare Parts and Supplies, net	4,625	3,749
Other Current Assets	0	4,832
Non-current Assets	**3,937,763**	**4,384,432**
Pre-operating Expenses, net	2,382	1,982
Advance Payment for Investment	0	434,923
Assets under Concession, net	3,935,381	3,947,527
Liabilities and Equity	5,052,537	5,238,572
Liabilities	**2,426,233**	**1,319,108**
Current Liabilities	**1,123,645**	**248,832**
Accounts Payable	20,258	874
Current Portion of LT Borrowings	197,742	211,921
Accrued Expenses	19,184	22,228
Accrued Income Tax	2,289	13,786
Other Current Liabilities	884,172	23
Non-current Liabilities	**1,302,588**	**1,070,276**
Long-term Borrowings, net	1,302,588	1,070,276
Equity	**2,626,304**	**3,919,464**
Share Capital	2,605,792	3,474,388
Share Premium	0	15,577
Legal Reserve	2,051	58,408
Retained Earnings	18,461	371,091
INCOME STATEMENT		
Revenues	37,229	881,748
Cost of Sales	(9,768)	(204,671)
Gross Profit	**27,461**	**677,077**
Other Income	69	9,781
Foreign Excange Gains (Loss), net	(1,739)	(3,895)
Profit Before Expense	**25,791**	**682,963**
Administrative Expenses	(597)	(48,013)
Profit Before Financial Costs and Tax	**25,194**	**634,950**
Financial Costs - Interest Expense	(2,393)	(41,278)
Profit Before Corporate Income Tax	**22,801**	**593,672**
Income Tax Expense	(2,289)	(30,104)
Net Profit for the Year / Period	**20,512**	**563,568**
FINANCIAL RATIOS		
Profitability		
(1) Operational Profit Rate	-	72.0%
(2) Return on Assets	-	10.8%
Debt		
(3) Debt to Assets	48.0%	25.2%
(4) Debt Service Coverage Ratio	-	2.15
Liquidity		
(5) Current Ratio	0.99	3.43
(6) Receivables Turnover	0.17	2.19
(7) Debtor Days	2,210	166.7

Note: * Operational period from December 16th to 31th, 2010

Source: JICA Study Team, based on the audited financial statements of EDL-Gen

2.4.3 Electricity Tariff

(1) Domestic Tariff

In 2011, the actual average tariff for EDL customers is 559 Kip/kWh or 7 US centavos. EDL applies a flat rate tariff system, which does not apply time-of-day rates or seasonal rates. It also does not apply a fuel price adjustment mechanism, since the entire generation system consists of hydropower plants. Only metered rates are charged and basic monthly rates to cover fixed expenses are not applied. Tariff revision is made through government approval based on the tariff requirement drafted by EDL.

As shown in the previous section, the past tariff level was not considered sufficient for cost recovery and sound profitability. According to estimates in the Tariff Study Update (2009) implemented through World Bank support, the entire tariff revenue including exports covers only 61% of the costs. Another concern observed is the large difference in tariff levels among customer segments. Cross-subsidizing continuously exists from medium and high voltage customers (101% cost recovery) to low voltage customers (50% cost recovery). In the consumer category, it is observed that industrial and commercial consumers greatly cross-subsidize residential and agriculture (irrigation) customers. The study concluded that the average tariff required for 2016 to meet a sustainable profitability level would be 1,270 Kip/kWh, which is more than double the average tariff in 2008 (542 Kip/kWh).

Table 2.4.3 presents the latest domestic tariff schedule of EDL. In response to the recommendation made by the said study in March 2012, the government decided to gradually increase the domestic tariff until 2017. The planned tariff increase is about 20% in 2012 and 2% annually from 2013 through 2017. From the 2011 tariff level, the total increase will be around 32% by 2017. Compared to the said study, the decided tariff increase is still regarded as insufficient. Moreover, the cross-subsidy system will not change since the increase in tariff rates are the same for all customer segments.

Table 2.4.3 EDL Domestic Electricity Tariff

Kip/kWh

Domestic Tariff (Kip/kWh)	2010	2011	2012							2013	2014	2015	2016	2017
			Jan-Feb	Mar	Apr	May	June	Jul	Aug-Dec					
Residential														
0-25 kWh	203	269	269	277	285	294	303	312	321	328	334	341	348	355
26-150 kWh	301	320	320	330	339	350	360	371	382	390	398	405	414	422
> 150 kWh	773	773	773	796	820	845	870	896	923	941	960	979	999	1,019
Non-residential Low Voltage (400 V)														
Agriculture & Irrigation	362	313	399	411	423	436	449	463	476	486	496	506	516	526
Government	674	656	656	676	696	717	738	760	783	799	815	831	848	865
Industry	607	591	591	609	627	646	665	685	706	720	734	749	764	779
Commercial & Services	835	835	835	860	886	912	940	968	997	1,017	1,037	1,058	1,079	1,101
International Organizations	1,077	1,077	1,077	1,109	1,143	1,177	1,212	1,249	1,286	1,312	1,338	1,365	1,392	1,420
Entertainment	1,106	1,106	1,106	1,139	1,173	1,209	1,245	1,282	1,321	1,347	1,374	1,401	1,429	1,458
Education & Sport	-	-	-	676	696	717	738	760	783	799	815	831	848	865
Non-residential Medium Voltage (22 kV)														
Agriculture & Irrigation	308	340	340	350	361	372	383	394	406	414	422	431	439	448
Government	573	557	557	574	591	609	627	646	665	678	692	706	720	734
Industry (<5MW)	516	502	502	517	533	549	565	582	599	611	624	636	649	662
Industry (>5MW)	-	-	-	647	647	647	647	647	647	660	673	687	700	714
Commercial & Services	709	709	709	730	752	775	798	822	847	864	881	898	916	935
Entertainment	-	-	-	1,082	1,115	1,148	1,183	1,218	1,255	1,280	1,350	1,331	1,358	1,385
Education & Sport	-	-	-	574	591	609	627	646	665	678	692	706	720	734
High Voltage (115kV)														
High Voltage	-	-	-	647	647	647	647	647	647	660	673	687	700	714

Source: EDL

(2) Off-take Tariff between EDL-Gen and EDL

As described in the section above, the off-take tariff between EDL-Gen and EDL is set at 413.89 Kip/kWh with an annual escalation of 1%. It applies a flat rate system and does not differentiate the tariffs by time or season.

(3) International Trade Tariff

Although electricity export is one of the major sources of foreign currency acquisition, EDL imports electricity to meet the demand-supply balance mainly due to seasonal change in energy generation. The following table shows the cross-border trade tariff with EGAT (Thailand) via high voltage transmission lines (115kV). In addition, EDL imports electricity at 10/25/35 kV from PEA (Thailand), EVN (Vietnam) and China in border regions at the local level.

Table 2.4.4 International Trade Tariff

	From	To	Peak (Mon-Fri 09:00-22:00)	Off-peak (Mon-Fri 22:00-09:00, Holidays 24hrs)	Locations	Remarks
EDL Export	**EDL**	**EGAT (Thailand)**	**THB 1.60 / kWh (4.99 US cents)**	**THB 1.20 / kWh (3.75 US cents)**	Nam Ngum 1(C1) , Xeset 1 (South)	
EDL Import	**EGAT (Thailand)**	**EDL**	**THB 1.74 / kWh (5.43 US cents)**	**THB 1.34 / kWh (4.18 US cents)**	Vientiane (C1), Bolixamxai (C1), Khamouan (C2), Savannaket (C2), Bangyo (Sounth)	*** For C1 and South PPAs: Surcharges applied in case of EDL annual trade deficit with EGAT**
	EGAT (Thailand)	**EDL**	THB 2.7595 / kWh (8.61 US cents)	THB 1.3185 / kWh (4.12 US cents)	Xepon Gold & Copper Mine (C2), Cement Factory (C2)	Fixed Service Charge, Demand Charge, Fuel Adjustment are applied

*** PPAs for C1 and South: The following surchage is applicable in case of EDL annual trade deficit with EGAT**

Unit Price: Demand Charge = 74.14THB/kW
Energy Charge: Peak = 3.8376 THB/kWh, Off-peak = 2.33966THB/kWh
Ft (Fuel Adjustment: Variable) = 0.30 THB/kWh (as of June 2012, Ministry of Energy, Thailand)
Servive Charge = 312.24THB/month (Fixed)

A. Normal Import Tariff (THB) = Annual Peak Import (kWh) * 1.74 THB/kWh + Annual Off-peak Import (kWh) * 1.34 THB/KWh
B. Identify the month of maximum energy consumption (kWh) by EDL:
(i) Demand Charge (THB) = Peak load of the month (kW) * 74.14THB/kW
(ii) Energy Charge (THB) = Peak Import of the month (kWh) * 3.8376 THB/kW + Off-peak Import of the month (kWh) * 2.3966 THB/kWh
(iv) Ft Charge (THB) = Total Import of the month * Ft (THB/kWh)
(v) Service Charge (THB) = 312.24 THB (Fixed)
(vi) Sum of (iii) to (vi) divided by Total Import of the Month (kWh) = Average Tariff (THB/kWh)
C. Average Normal Import Tariff (A. divided by total annual import) minus (vi) Average Tariff (THB/kWh) = Surcharge Unit Price (THB/kWh)
D. C. Surcharge Unit Price (THB/kWh) * Annual Excess Import (deficit) (kWh) = Surcharge Payment of the year (THB)

Source: EDL

The import tariff from EGAT for Xepon mines and the cement factory in Central 2 is similar to that with large-scale customers in Thailand and could be regarded close to a direct transaction between EGAT and these customers. On the other hand, the tariff for C1, C2 and the south grids[1] has characteristics of (i) small price difference between peak time and off-peak time (about 1.25 US cents/kWh) and (ii) basic import tariff is THB 0.14/kWh (0.44 US cents/kWh) higher than export to EGAT. Surcharge payment is required additionally in case EDL imports exceed its exports in a year. Surcharge calculation is based on the domestic tariff in Thailand. The excess import by EDL is virtually charged with similar prices as the electricity consumers in Thailand (7.3 to 12.0 US cents/kWh). This would be a heavy financial burden to EDL in case of trade deficit with EGAT.

[1] The international trade tariff for Nam Ngum 1 was revised in August 2011 to the one indicated in the table above, which, however, is yet to be implemented. However, the present analysis uses this new tariff for economic projection upon recommendation from EDL officials.

According to the said Tariff Study Update, the cost recovery level of the EDL export tariff is estimated at 98% and its profitability is deemed questionable. As far as it is balanced, the cross-border electricity trade between EDL and EGAT is regarded as a mutual interchange under international cooperation. It is considered that the trade tariff is set as a great subject to the domestic tariff system on the Thai side because EDL is only capable of exporting excess supply after satisfying the domestic demand, thus its export is regarded as a non-firm energy. The international trade tariff may not be fully considered in representing the economic value of the energy supply.

CHAPTER 3 POWER SUPPLY AND DEMAND BALANCE FORECAST

3.1 REVIEW OF ENERGY AND PEAK DEMAND FORECAST IN PDP

3.1.1 Procedure for Review of Demand Forecast in PDP

(1) Demand Forecast in PDP

EDL officially announced and incorporated the future power demand projection and power supply plan for the whole Lao PDR service areas in the Power Development Plan (PDP) 2010-2020 (Revision-1) issued in August 2011 which is the latest official development plan. The records of the power consumption and development plan for the whole Lao PDR and specifically, also for the northern, central, and southern areas are summarized in the PDP.

EDL estimates shown in the PDP include the overall future power demand from 2011 to 2021 based on the provincial demands at substation points. It also presents the future demand load for large-scale industrial activities such as mining activities, construction and operation of railway, construction of hydropower stations, and special promotion zones. The method applied for the demand projection is the same with the previous study conducted by JICA in 2002. The total power demand projection is the sum of the projection per province/end-user such as households, industries, agriculture, and services. In case there are any changes in the operation plans of large-scale consumers, EDL updates the demand projection accordingly.

The PDP includes full details of the demand forecast, which is mainly categorized into residential sector and large industries. The demand for residential sector is projected based on the number of population, households and villages. These forecasts will not be changed in this Study. Meanwhile, the Study Team particularly reviewed the large industrial demand in the latest PDP because of the delay in the implementation of various projects.

(2) Review points of demand forecast for large industries

The demand load for large industries is individually reviewed in the following manner:

1) Load for the construction and operation of railway project

The Laos-China High-speed Railway Project is now underway. The project is a railway network that extends from Lao-China border to Vientiane. The demand load for the construction of railway was originally considered for four years from the start of the construction work in 2011. The load for the railway station and running trains was estimated until 2015 in the latest PDP.

According to the Department of Energy Policy and Planning, MEM replied that the construction work has not yet commenced and that MEM has no information on its commencing time. Consequently, the Study Team estimated that the given time period for railway demand is three years behind the original schedule, i.e. construction will start in 2014 and operation of trains in 2018.

Table 3.1.1 shows the demand load for railway projects considered in the demand forecast.

Table 3.1.1 Demand Load of Railway Project

Province	Descriptions	Unit	2014	2015	2016	2017
Oudomxai	Sub-Total	**(MW)**	**52.0**	**52.0**	**52.0**	**52.0**
		(GWh)	**273.3**	**273.3**	**273.3**	**273.3**
1	Ban Nampheng, Namo District	(MW)	20.0	20.0	20.0	20.0
		(GWh)	105.1	105.1	105.1	105.1
2	Ban Houaymok, Xai Dictrict	(MW)	32.0	32.0	32.0	32.0
		(GWh)	168.2	168.2	168.2	168.2
Luangprabang	Sub-Total	**(MW)**	**39.6**	**39.6**	**39.6**	**39.6**
		(GWh)	**208.1**	**208.1**	**208.1**	**208.1**
1	Ban Phonxai, Luangprabang District	(MW)	27.0	27.0	27.0	27.0
		(GWh)	141.9	141.9	141.9	141.9
2	Ban Kiewtaloun, Xiengngeun District	(MW)	12.6	12.6	12.6	12.6
		(GWh)	66.2	66.2	66.2	66.2
Vientiane Pro	Sub-Total	**(MW)**	**25.4**	**25.4**	**25.4**	**25.4**
		(GWh)	**133.5**	**133.5**	**133.5**	**133.5**
1	Ban Phukham, Kasi District	(MW)	11.6	11.6	11.6	11.6
		(GWh)	61.0	61.0	61.0	61.0
2	Ban Phatang, Vangvieng District	(MW)	6.3	6.3	6.3	6.3
		(GWh)	33.1	33.1	33.1	33.1
3	Ban Houaypamom, vangvieng District	(MW)	4.0	4.0	4.0	4.0
		(GWh)	21.0	21.0	21.0	21.0
4	Ban Nongboua, Phonhong District	(MW)	3.5	3.5	3.5	3.5
		(GWh)	18.4	18.4	18.4	18.4
Vientiane Cap	Sub-Total	**(MW)**	**2.9**	**2.9**	**2.9**	**2.9**
		(GWh)	**15.2**	**15.2**	**15.2**	**15.2**
	Ban Xai, Xaithanee District	(MW)	2.9	2.9	2.9	2.9
		(GWh)	15.2	15.2	15.2	15.2

Province	Station	Unit	2018	2019	2020	2021
Luangnamtha	Sub-Total	**(MW)**	**1.00**	**1.00**	**1.00**	**1.00**
		(GWh)	**5.26**	**5.26**	**5.26**	**5.26**
1	Borten	(MW)	1.00	1.00	1.00	1.00
		(GWh)	5.26	5.26	5.26	5.26
Oudomxai	Sub-Total	**(MW)**	**4.00**	**4.00**	**4.00**	**4.00**
		(GWh)	**21.02**	**21.02**	**21.02**	**21.02**
1	Nathong	(MW)	1.00	1.00	1.00	1.00
		(GWh)	5.26	5.26	5.26	5.26
2	Houanam	(MW)	1.00	1.00	1.00	1.00
		(GWh)	5.26	5.26	5.26	5.26
3	Vanggnan	(MW)	1.00	1.00	1.00	1.00
		(GWh)	5.26	5.26	5.26	5.26
4	Nakoktai	(MW)	1.00	1.00	1.00	1.00
		(GWh)	5.26	5.26	5.26	5.26
Luangprabang	Sub-Total	**(MW)**	**4.00**	**4.00**	**4.00**	**4.00**
		(GWh)	**21.02**	**21.02**	**21.02**	**21.02**
1	Phulay	(MW)	1.00	1.00	1.00	1.00
		(GWh)	5.26	5.26	5.26	5.26
2	Phonxai	(MW)	1.00	1.00	1.00	1.00
		(GWh)	5.26	5.26	5.26	5.26
3	Houanaming	(MW)	1.00	1.00	1.00	1.00
		(GWh)	5.26	5.26	5.26	5.26
4	Bansen	(MW)	1.00	1.00	1.00	1.00
		(GWh)	5.26	5.26	5.26	5.26
Vientiane Pro	Sub-Total	**(MW)**	**10.00**	**10.00**	**10.00**	**10.00**
		(GWh)	**52.56**	**52.56**	**52.56**	**52.56**
1	Phonekeo	(MW)	1.00	1.00	1.00	1.00
		(GWh)	5.26	5.26	5.26	5.26
2	Boumfok	(MW)	1.00	1.00	1.00	1.00
		(GWh)	5.26	5.26	5.26	5.26
3	Phatang	(MW)	1.00	1.00	1.00	1.00
		(GWh)	5.26	5.26	5.26	5.26
4	Vangvieng	(MW)	1.00	1.00	1.00	1.00
		(GWh)	5.26	5.26	5.26	5.26
5	Vangmon	(MW)	1.00	1.00	1.00	1.00
		(GWh)	5.26	5.26	5.26	5.26
6	Vangkhee	(MW)	1.00	1.00	1.00	1.00
		(GWh)	5.26	5.26	5.26	5.26
7	HinHeup	(MW)	1.00	1.00	1.00	1.00
		(GWh)	5.26	5.26	5.26	5.26
8	Phonhong	(MW)	1.00	1.00	1.00	1.00
		(GWh)	5.26	5.26	5.26	5.26
9	Saka	(MW)	1.00	1.00	1.00	1.00
		(GWh)	5.26	5.26	5.26	5.26
10	Phonsoung	(MW)	1.00	1.00	1.00	1.00
		(GWh)	5.26	5.26	5.26	5.26
Vientiane Cap	Sub-Total	**(MW)**	**2.00**	**2.00**	**2.00**	**2.00**
		(GWh)	**10.51**	**10.51**	**10.51**	**10.51**
1	Vientiane Cap Neua	(MW)	1.00	1.00	1.00	1.00
		(GWh)	5.26	5.26	5.26	5.26
2	Vientiane Cap Tai	(MW)	1.00	1.00	1.00	1.00
		(GWh)	5.26	5.26	5.26	5.26

Prepared by Study Team

With regards to the load forecast for running high-speed trains, EDL estimated only 10 MW for demand load in Luangnamtha Province as stated in the PDP. Since there is no concrete information on electricity demand for the project, the Study Team maintained the load forecast without revision. It is recommended for EDL to review the power demand for the operation of trains in the future.

2) Load of special economic zone (SEZ)

The Study Team collected information on the demand load of SEZ in the future at the Secretariat

Office of Lao National Committee for SEZ. However, the Study Team did not obtain further SEZ projects, therefore, the demand load of SEZ were considered as shown in Table 3.1.2.

Table 3.1.2 Demand Load of Special Economic Zones

Province	Descriptions	Units	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Savannakhet	Sub-Total	(MW)	15.75	79.95	114.25	164.25	164.25	164.25	164.25	174.25	174.25	174.25	174.25
		(GWh)	82.782	420.217	600.498	863.298	863.298	863.298	863.298	915.858	915.858	915.858	915.858
	1 Pakbo	(MW)	13.2	17.4	21.7	21.7	21.7	21.7	21.7	21.7	21.7	21.7	21.7
		(GWh)	69.38	91.45	114.06	114.06	114.06	114.06	114.06	114.06	114.06	114.06	114.06
	2 Kenkkok	(MW)	2.55	2.55	2.55	2.55	2.55	2.55	2.55	2.55	2.55	2.55	2.55
		(GWh)	13.40	13.40	13.40	13.40	13.40	13.40	13.40	13.40	13.40	13.40	13.40
	3 SASEZ (A)	(MW)				30	30	30	30	30	30	30	30
		(GWh)				157.68	157.68	157.68	157.68	157.68	157.68	157.68	157.68
	4 SASEZ (B)	(MW)			30	30	30	30	30	30	30	30	30
		(GWh)			157.68	157.68	157.68	157.68	157.68	157.68	157.68	157.68	157.68
	5 SASEZ (C)	(MW)		60	60	60	60	60	60	60	60	60	60
		(GWh)		315.36	315.36	315.36	315.36	315.36	315.36	315.36	315.36	315.36	315.36
	6 SASEZ (D)	(MW)				20	20	20	20	20	20	20	20
		(GWh)				105.12	105.12	105.12	105.12	105.12	105.12	105.12	105.12
	7 Airport	(MW)								10	10	10	10
		(GWh)								52.56	52.56	52.56	52.56
Luangnamtha	Sub-Total	(MW)		2	5	10	12	20	20	20	20	20	20
		(GWh)		10.51	26.28	52.56	63.07	105.12	105.12	105.12	105.12	105.12	105.12
	1 Special Zone	(MW)		2	5	10	12	20	20	20	20	20	20
		(GWh)		10.51	26.28	52.56	63.07	105.12	105.12	105.12	105.12	105.12	105.12
Khammuan	Sub-Total	(MW)		2	5	10	20	20	30	30	30	50	50
		(GWh)		10.51	26.28	52.56	105.12	105.12	157.68	157.68	157.68	262.80	262.80
	1 Special Zone	(MW)		2	5	10	20	20	30	30	30	50	50
		(GWh)		10.51	26.28	52.56	105.12	105.12	157.68	157.68	157.68	262.80	262.80
Champasak(Pakxong)	Sub-Total	(MW)				2	3	5	10	12	20	20	20
		(GWh)				10.51	15.77	26.28	52.56	63.07	105.12	105.12	105.12
	1 Special Zone	(MW)				2	3	5	10	12	20	20	20
		(GWh)				10.51	15.77	26.28	52.56	63.07	105.12	105.12	105.12

Source: PDP 2010-2020 Revision-1

3) Load for the construction of hydropower stations

EDL considered the demand load for the construction of hydropower stations into the load forecast. These loads were commonly calculated as 15% of installed capacity for each hydropower station, with an estimated demand period of two years before the commercial operation date (COD).

The Study Team addressed that the calculation of 15% installed capacity may be adequate for the construction of small scale power stations but not for large-scale hydropower stations which needs a higher demand load. The Study Team suggested the following demand loads be applied for the construction of power stations in the load forecast.

Table 3.1.3 Load for the Construction of Hydropower Station

Installation Capacity of Hydropower Station	Load Calculation
Equal or less than 10 MW	15% of installation capacity
More than 10 MW and equal or less than 100 MMW	2.5 MW
More than 100 MW and equal or less than 150 MMW	3 MW
More than 10 MW and equal or less than 200 MMW	3.5 MW
More than 200 MW	4 MW

Prepared by the Study Team

In addition, the Study Team adjusted/updated the construction timing of individual hydropower stations in accordance to COD.

4) Load for the operation of mining

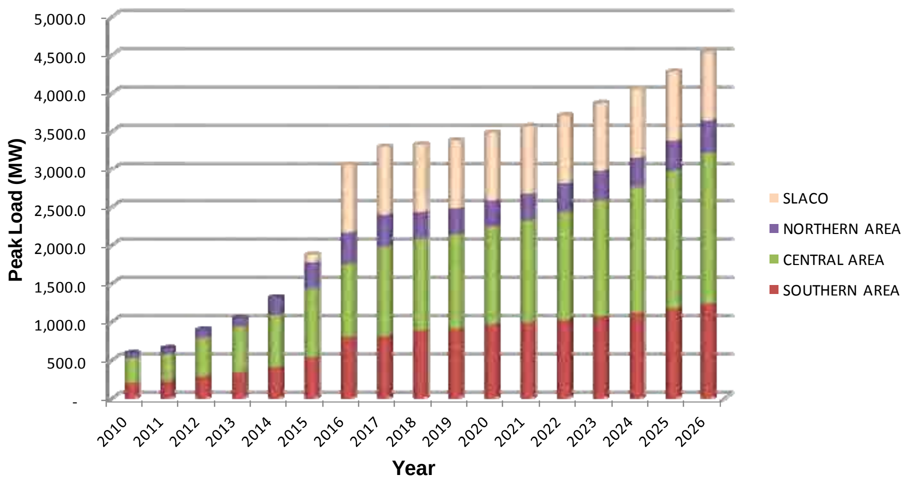
The Study Team collected information from the Department of Mines and confirmed that further specific demand for the development of new mining was not available.

The power required for the bauxite mining project of the Sino-Lao Corporation (SLACO) in the southern area is estimated at 900 MW for the first stage. Due to a large demand for mining activities, the load forecast was studied distinctly with or without SLACO. The SLACO demand will be discussed with development scenarios (Case 1 to Case 4) in Sub-Clause 3.3.1.

3.1.2 Annual Energy and Peak Load Demand Forecast Reviewed by the Study Team

Based on the review of large-scale industrial electricity demands, the annual energy and peak load demand forecast for northern, central and southern area were updated by the Study Team.

As shown in Figure 3.1.1, the peak load for Lao PDR is projected to rapidly increase in 2017 with an additional demand of 900 MW for SLACO. The peak load will achieve 2577 MW in 2020 and 3374 MW in 2025 (excluding SLACO). The peak load for the central area is also projected to increase from 196.2 MW in 2010, to 1,274.9 MW in 2020 and 1,800.3MW in 2025.



Prepared by the Study Team

Figure 3.1.1 Peak Load Forecast for Lao PDR

The annual energy and peak demand forecast until 2021 for northern, central, and southern areas are detailed in Table 3.1.4.

Table 3.1.4 Annual Energy and Peak Load Forecast in Lao PDR

Energy Demand (Including System Losses)

Unit: GWh

	Actual 2010	Forecast 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
NORTHERN AREA	**284.0**	**378.2**	**544.5**	**593.7**	**1,255.2**	**1,992.4**	**2,463.3**	**2,521.8**	**2,110.7**	**2,071.8**	**2,108.3**	**2,129.5**
RESIDENTIAL SECTOR	284.0	314.4	342.6	370.8	400.6	431.4	464.1	499.4	539.2	582.1	628.3	678.2
LARGE INDUSTRIES	-	63.8	201.9	222.9	854.6	1,561.0	1,999.2	2,022.4	1,571.4	1,489.7	1,480.0	1,451.3
CENTRAL AREA	**1,634.8**	**1,814.9**	**2,764.5**	**3,288.2**	**3,832.8**	**5,004.0**	**5,322.7**	**6,372.9**	**6,537.2**	**6,792.6**	**7,060.4**	**7,434.1**
RESIDENTIAL SECTOR	1,403.6	1,504.2	1,615.6	1,739.2	1,877.0	2,030.9	2,202.9	2,395.3	2,660.0	2,968.0	3,326.9	3,746.0
LARGE INDUSTRIES	231.1	310.7	1,148.9	1,549.1	1,955.8	2,973.2	3,119.7	3,977.6	3,877.2	3,824.6	3,733.5	3,688.0
SOUTHERN AREA	**1,048.0**	**1,209.0**	**1,590.1**	**1,946.4**	**2,369.3**	**3,337.6**	**5,013.9**	**5,077.9**	**5,526.6**	**5,634.8**	**6,003.1**	**6,172.3**
RESIDENTIAL SECTOR	608.9	664.9	739.5	813.0	892.5	979.2	1,074.0	1,180.9	1,317.1	1,469.4	1,640.0	1,831.6
LARGE INDUSTRIES	439.1	544.1	850.6	1,133.4	1,476.8	2,358.4	3,939.9	3,897.0	4,209.5	4,165.4	4,363.0	4,340.6
TOTAL FOR RESIDENTIAL SECTOR	**2,296.6**	**2,483.5**	**2,697.7**	**2,923.1**	**3,170.0**	**3,441.4**	**3,741.0**	**4,075.6**	**4,516.4**	**5,019.5**	**5,595.3**	**6,255.9**
TOTAL FOR LARGE INDUSTRIES	**670.2**	**918.6**	**2,201.4**	**2,905.4**	**4,287.2**	**6,892.6**	**9,058.8**	**9,897.1**	**9,658.1**	**9,479.7**	**9,576.5**	**9,479.9**
GRAND TOTAL	**2,966.8**	**3,402.1**	**4,899.1**	**5,828.4**	**7,457.2**	**10,334.0**	**12,799.9**	**13,972.7**	**14,174.5**	**14,499.2**	**15,171.8**	**15,735.8**

Peak Load

Unit: MW

	Actual 2010	Forecast 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
NORTHERN AREA	**65.9**	**81.4**	**107.5**	**115.5**	**225.6**	**338.9**	**409.4**	**418.8**	**347.3**	**339.7**	**344.5**	**346.7**
RESIDENTIAL SECTOR	65.9	71.2	75.7	80.1	84.6	89.0	93.7	98.7	104.3	110.3	116.7	123.5
LARGE INDUSTRIES	-	10.2	31.8	35.4	141.0	249.8	315.7	320.1	242.9	229.4	227.8	223.2
CENTRAL AREA	**321.7**	**347.5**	**497.1**	**597.9**	**687.4**	**900.5**	**953.5**	**1,166.3**	**1,193.7**	**1,234.3**	**1,274.9**	**1,331.5**
RESIDENTIAL SECTOR	289.7	305.3	322.6	341.7	363.0	386.6	412.9	442.2	483.7	531.7	587.3	651.8
LARGE INDUSTRIES	32.0	42.1	174.5	256.2	324.4	513.9	540.5	724.1	710.0	702.6	687.5	679.7
SOUTHERN AREA	**196.2**	**220.9**	**286.0**	**329.6**	**397.3**	**529.0**	**796.0**	**807.5**	**881.9**	**900.1**	**958.3**	**985.3**
RESIDENTIAL SECTOR	136.2	145.3	158.3	170.4	183.2	196.9	211.7	228.3	249.8	273.4	299.6	328.6
LARGE INDUSTRIES	60.0	75.6	127.7	159.2	214.1	332.1	584.2	579.2	632.2	626.6	658.6	656.7
TOTAL FOR RESIDENTIAL SECTOR	**491.8**	**521.8**	**556.7**	**592.2**	**630.7**	**672.6**	**718.3**	**769.1**	**837.8**	**915.5**	**1,003.7**	**1,104.0**
TOTAL FOR LARGE INDUSTRIES	**92.0**	**127.9**	**334.0**	**450.8**	**679.5**	**1,095.8**	**1,440.5**	**1,623.4**	**1,585.1**	**1,558.6**	**1,574.0**	**1,559.5**
GRAND TOTAL	**583.8**	**649.8**	**890.7**	**1,043.0**	**1,310.2**	**1,768.3**	**2,158.9**	**2,392.6**	**2,422.9**	**2,474.1**	**2,577.6**	**2,663.5**

Prepared by the Study Team

3.2 REVIEW OF GENERATION DEVELOPMENT PLAN IN PDP

3.2.1 Procedures for the Review of Generation Development Plan in PDP

EDL has a policy for the development of power resources to meet the rapidly growing electricity demand of the whole country, as mentioned below:

- EDL will put an investment on new power plants.
- Purchase from small power producers (SPP) and domestic independent power producer IPP(d) projects.
- Purchase off-take from IPP(e) projects,
- Continue to import power from neighboring countries to provide power supply in areas with no network access, and
- Continue to exchange (import/export) power from neighboring countries to increase reliability and security of power supply.

Although EDL has been updating the PDP every three months, the Study Team reviewed and renewed the annual supply capacity in PDP in the following manners:

1) For confirming the projects of EDL power stations, the Study Team carried out hearing investigation to EDL engineers. The accuracy of CODs for all planned power stations was confirmed from the project status. If the project is delayed, the COD will be postponed to an appropriate year, considering four to five years of construction period depending on the scale of the project.
2) For confirming the projects for IPP power stations including IPP(d) and off-take from IPP(e), the Study Team carried out hearing investigations to persons in charge of IPP projects in the Department of Energy Business Additionally, the Study Team confirmed the project status in the progress report for IPP projects. Then, COD was also checked similarly to the above (1).
3) If a project has serious technical issue and cannot move ahead, such project would be deemed canceled and deleted from the project list[1].
4) If the Study Team was not able to obtain any information on the project status, the COD of such project would remain the same as stated in the PDP.
5) The annual supply capacities up to 2026 for the northern, central, and southern areas were updated in the “demand–supply balance sheets” attached in Appendix-3 of the PDP.

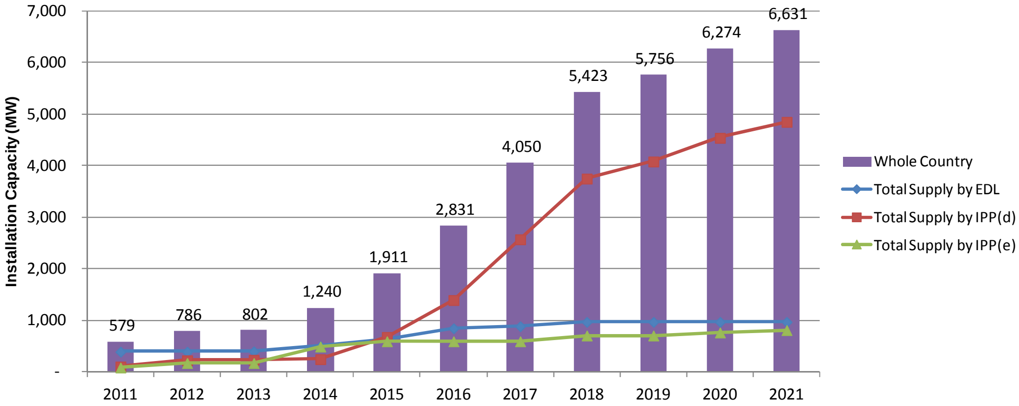
3.2.2 Generation Development Plan Reviewed by the Study Team

Based on the results of the review of the generation development plan, a list of projects with their

[1] In this Study, only one project (Nam Ngum Down hydropower station) was deleted from the list of generation development plan in the demand-supply balance done by the Study Team, because it was found out that the head was too small during its F/S.

installed generation capacity, COD, installation capacity, plant factor, annual supply, and energy in the future is shown in Tables 3.2.1 to 3.2.6 (enclosed in the end of this Chapter).

In summary, the installed generation capacity for the whole country is assumed to achieve 1911MW in 2015 and 6274 MW in 2020 as shown in Figure 3.2.1.



Prepared by the Study Team

Figure 3.2.1 Projection of Installed Generation Capacity

The sum of the installed generation capacity of IPP power stations (including IPP(e) and IPP(d)) will occupy 84.6% of the whole country in 2020. Of the total installed capacity, only 15.4% will be owned by EDL. This means most of the power generation for domestic use will be provided by IPPs in the future. The IPP hydropower stations are obliged to guarantee the daily generation required in the PPA. This means that IPP power stations may not flexibly be able to contribute to the power system control.

There are some important cautions in this assumption of installed generation capacity, as mentioned below.

(1) The power station projects listed in the PDP were basically kept without deletion. The Study Team only reviewed and updated the COD. For instance, even if the project seems inactive due to any problem such as financial difficulty, environmental or social issues, the project will be kept. The projection of annual installed capacities in the future includes such project.

(2) In case of hydropower station, if the actual generation does not reach the installed generation capacity, the actual generation will be reduced to one third to one fourth in dry season, depending on the seasonal variation of water level on the rivers.

With the various circumstances cited above, the actual generation will be less than the installed generation capacity.

3.2.3 Uncertain Large-Scale Power Generation in the Future

There are some large-scale hydropower projects and coal-fired power projects envisioned to be constructed in Laos. The existence or nonexistence of such project will give a significant impact to the demand-supply balance in the future.

(1) Mekong Hydropower Stations

Some hydropower projects were planned to use the water resources of Mekong River. The projects listed in the generation development plan include the Xayabury hydropower project (60 MW), Pak Beng hydropower project (114 MW), Laung Prabang hydropower project (150 MW) in the north, Don Sahong hydropower station (240 MW), and Thakho hydropower station (50 MW) in the south.

According to the information obtained from the Department of Energy Business, the most advanced project among the Mekong projects is the Xayabury hydropower project. All preparation works for this project have been completed and is now waiting for the approval of the Mekong River Committee before the commencement of the construction. The possibility for implementation of subsequent Mekong projects is assumed to depend on the progress of the Xayabury hydropower project.

(2) Sekong 4, Sekong 5, and Nam Kong 1 Hydropower Stations

The Sekong 4 (300 MW), Sekong 5 (190 MW), and Nam Kong 1 (75 MW) are expected to supply the high power demand of SLACO (900 MW) and export the generated energy to Cambodia (300 MW) in the southern area.

(3) M. Kalum Coal-Fired Power Station

The M. Kalum Coal-Fired Power Station, 600 MW (300 MW x 2 phases) together with the coal mining development in Sekong Province is planned to be constructed. According to the Department of Mines, the concrete data in regard to coal reserve estimation (of whichever lignite or anthracite) is not yet available.

It shall be remarked that the prospective coal mine location is just in the dam reservoir of Sekong 4. Consequently, both Sekong 4 and M. Kalum will not be developed at the same time.

3.2.4 Development Scenarios in PDP

EDL analyzed four cases of the supply-demand balance in the PDP. The difference in each case is based on the presence or absence of the SLACO demand of each power station of M. Kalum, Sekong 4 and 5, Nam Khon 1, and Mekong projects, as stated below.

(1) Case 1 excluded power demand of SLACO and hydropower projects of Sekong 4 and 5 and Nam Kong.

(2) Case 2 included power demand of SLACO. The Sekong 4 and 5, and Nam Kong 1 will supply SLACO with power through EDL system. The hydropower stations in Mekong River that are on the stage of development (Xayabury, Don Sahong, and Thakho) are also taken into consideration, but M. Kalum was not included.

(3) Case 3 also included the SLACO demand. All major projects, i.e., M. Kalum, Sekong 4 and 5, Nam Kong 1, and all Mekong projects are included. However, as mentioned in the foregoing paragraph, since both power plants of M. Kalum and Sekong 4 may not be developed at the same time, Case 3 was considered not feasible.

(4) Case 4 also included the SLACO demand, Sekong 4 and 5 and Nam Kong 1, but M. Kalum and Mekong hydropower projects were not considered.

The above four development scenarios are summarized in Table 3.3.1. The four options were mainly differentiated by large-scale projects in the southern area. It will not significantly affect the demand-supply balance in the central area. Even in the northern area, only 60 MW off-take from Xayabury hydropower project on Mekong River was needed for the case study. Hence in this Study, the demand-supply balance for Case 1 to Case 4 will be discussed in detail in the southern area in Sub-clause 3.3.3.

Table 3.3.1 EDL Development Scenarios

Case	M. Kalum	Sekong 4 & 5 Nam Kong 1	Mekong Hydropower Development	SLACO Demand
Case 1	x		X	
Case 2		x	X	x
Case 3	x	x	X	x
Case 4		x		x

Note) "x" in column: the project will exist
blank in column: the project will not be implemented.
Prepared by the Study Team based on PDP 2010-2020 Revision-1

3.3 POWER DEMAND–SUPPLY BALANCE ANALYSIS ON ANNUAL BASIS

EDL estimated the demand-supply balance for the northern, central and southern areas for Case-1 in the PDP. The Study Team revised this demand-supply balance in consideration of the updated peak load and installed generation capacity in the above sub-clause (reserved margin was not considered).

3.3.1 Demand–Supply Balance for the Central Area of Lao PDR

The peak load and power generation forecast for the central area were combined into Table 3.3.2 and Table 3.3.3 to see the demand-supply balance.

Table 3.3.2 Comparison of the Demand and Supply Energy for the Central Area

Central Unit: GWh

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Demand	1,634.8	1,814.9	2,764.5	3,288.2	3,832.8	5,004.0	5,322.7	6,372.9	6,537.2	6,792.6	7,060.4	7,434.1
Supply	1,806.0	1,831.0	2,155.5	2,155.5	2,224.8	2,224.8	2,224.8	3,281.6	4,988.0	4,988.0	4,988.0	4,988.0
Balance	171.2	16.0	-609.1	-1,132.8	-1,608.1	-2,779.3	-3,097.9	-3,091.4	-1,549.2	-1,804.5	-2,072.4	-2,446.0

Prepared by the Study Team

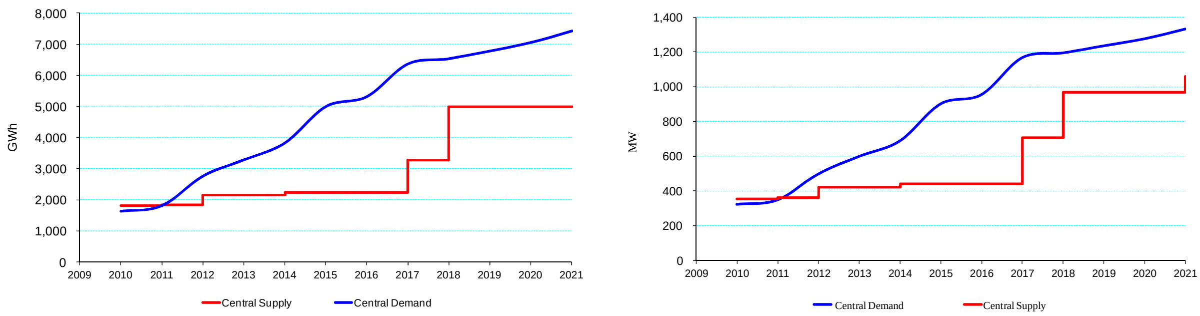
Table 3.3.3 Comparison of the Peak Load and Supply Capacity for the Central Area

Central Unit: MW

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Demand	321.7	347.5	497.1	597.9	687.4	900.5	953.5	1,166.3	1,193.7	1,234.3	1,274.9	1,331.5
Supply	355.0	361.0	422.6	422.6	441.6	441.6	441.6	705.6	969.6	969.6	969.6	1,059.6
Balance	33.3	13.5	-74.5	-175.3	-245.8	-458.9	-511.9	-460.7	-224.1	-264.7	-305.3	-271.9

Prepared by the Study Team

The annual power generation up to 2011 in the central area seemed sufficient in the balance sheet. The installed generation capacity also seemed to have enough supply. However, the power supply for the central area will fall short of demand in 2012 and the power shortage will be experienced in the future.



Prepared by the Study Team

Figure 3.3.1 Demand–Supply Balance for the Central Area

As mentioned in Sub-clause 3.2.2, the actual output may be reduced from one third to one fourth during dry season, depending on the seasonal variation of water level. Besides, the load will significantly vary from peak to off-peak in a day. Therefore, the annual demand-supply balance may be used to see the rough estimates of demand-supply balance as initial step, and further analysis on the monthly and daily basis will be required.

3.3.2 Demand-Supply Balance for the Northern Area of Lao PDR

In the future, the transmission line networks for the northern, central, and southern areas will be integrated with 115 kV and 230 kV transmission lines. The demand-supply balance for the northern and southern areas will affect the power system in the central area through the transmission network. Hence, the northern and southern demand-supply balances were also reviewed by the Study Team in this Study.

The updated demand-supply balance for the northern area is summarized in Table 3.3.4 and Table 3.3.5[2].

[2] Xayabury, 60MW off-take from IPP(e) (Mekong Development, COD in 2020) is included.

Table 3.3.4 Comparison of the Demand and Supply Energy for the Northern Area

North Unit: GWh

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Demand	284.0	378.2	544.5	593.7	1,255.2	1,992.4	2,463.3	2,521.8	2,110.7	2,071.8	2,108.3	2,129.5
Supply	20.6	37.7	537.7	574.7	607.3	2,726.1	5,957.1	6,747.6	9,910.5	10,774.2	11,915.2	12,880.4
Balance	-263.4	-340.5	-6.8	-19.0	-647.8	733.7	3,493.8	4,225.7	7,799.8	8,702.4	9,806.9	10,751.0

Prepared by the Study Team

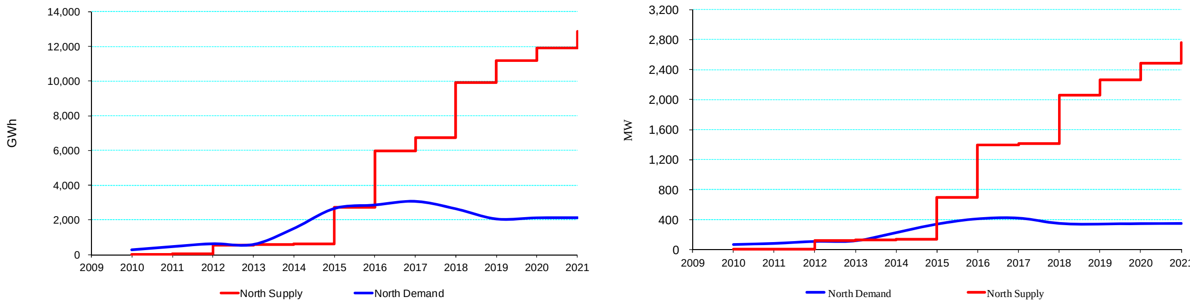
Table 3.3.5 Comparison of the Peak Load and Supply Capacity for the Northern Area

North Unit: MW

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Demand	65.9	81.4	107.5	115.5	225.6	338.9	409.4	418.8	347.3	339.7	344.5	346.7
Supply	3.7	7.4	127.4	132.4	141.0	694.5	1,401.5	1,416.5	2,062.5	2,260.8	2,488.8	2,755.8
Balance	-62.2	-74.0	19.8	16.8	-84.6	355.6	992.0	997.6	1,715.2	1,921.1	2,144.3	2,409.1

Prepared by the Study Team

As presented in the above balance sheet, the annual power generation in the northern area from 2010, 2011 and 2014 resulted negative values. Accordingly the supply in the said period were not enough to meet to the demand. Meanwhile, the power generation will rapidly increase after 2015 due to the completion of large scale projects, including Nam Ou 2, 5, and 6 (540 MW in total) in 2016 and Nam Ou 1, 3, 4, and 7 (616 MW in total) in 2018. Accordingly, the power balance will be extremely improved in 2016 and surplus power is expected to be fed to the central from the northern area or to be exported to neighboring countries through transmission networks. The surplus energy in the northern area is supposed to achieve 10,175 GWh in 2021.



Prepared by the Study Team

Figure 3.3.2 Demand–Supply Balance for the Northern Area

It was also noted that most of the supply coming from hydropower stations needs to go down to one third or one fourth during dry season. Therefore in the coming years, power supply in the northern area would experience the possibility that the demand–supply balance will encounter power shortage during peak demand in dry season.

3.3.3 Demand–Supply Balance for the Southern Area of Lao PDR

The demand-supply balances for the southern area are presented in the following development scenarios: Case 1 to Case 4, as illustrated in Figure 3.3.3.

As for Case 2, Case 3, and Case 4, the demand–supply balance will face a serious problem in power shortage to meet the demand, including SLACO in 2016. The Study Team tentatively selected Case 1 for further study and analysis on a monthly and daily demand-supply balance in the central area. Although Case 1 included an uncertainty on the implementation of M. Kalum Coal-fired Power Plant (600 MW), this power source can replace Sekong 4 and 5 and Nam Kong 1 (total 565 MW) since both have approximately the same scale of power generation, if M. Kalum project is not realized.

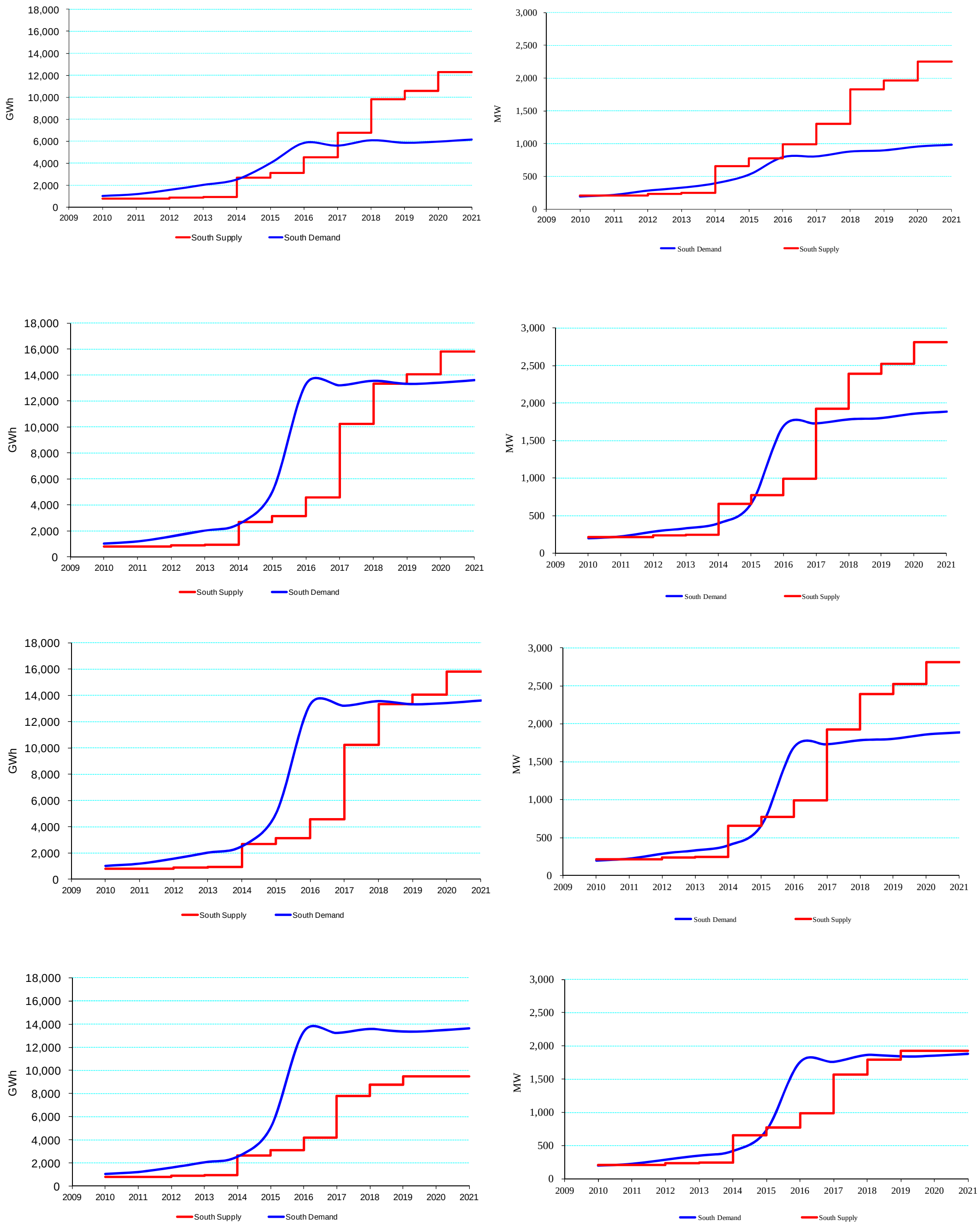
Energy Demand-Generation Peak Load–Installation Capacity

Case 1:

Case 2:

Case 3:

Case 4:



Prepared by the Study Team

Figure 3.3.3 Demand–Supply Balance for the Southern Area

As per demand–supply balance for Case 1 in Table 3.3.6 and Table 3.3.7, the annual power generation in the southern area from 2010 to 2016 is insufficient in the balance sheets. The supply capacity is also increasing a little bit slower as well, compared to that of the demand. The power generation for the southern area will exceed in 2017 after completion of some large-scale power developments, including M. Kalum. Accordingly, the power balance will be improved in 2017 and the surplus energy may be transmitted to the central or may be exported to neighboring countries. The surplus energy in the southern area is supposed to achieve 6143 GWh in 2021.

Table 3.3.6 Comparison of the Demand and Supply Energy for the Southern Area (Case 1)

South Unit: GWh

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Demand	1,048.0	1,209.0	1,590.1	1,946.4	2,369.3	3,337.6	5,013.9	5,077.9	5,526.6	5,634.8	6,003.1	6,172.3
Supply	798.6	798.6	894.6	948.6	2,671.6	3,132.1	4,196.2	6,396.2	9,461.3	10,199.3	12,315.3	12,315.3
Balance	-249.4	-410.4	-695.5	-997.8	302.4	-205.4	-817.7	1,318.3	3,934.7	4,564.5	6,312.3	6,143.0

Prepared by Study Team

Table 3.3.7 Comparison of the Peak Load and Supply Capacity for the Southern Area (Case 1)

South Unit: MW

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Demand	196.2	220.9	286.0	329.6	397.3	529.0	796.0	807.5	881.9	900.1	958.3	985.3
Supply	211.1	211.1	236.1	247.0	657.0	775.0	988.0	1,303.0	1,826.0	1,961.0	2,251.0	2,251.0
Balance	14.9	-9.8	-49.9	-82.6	259.7	246.0	192.0	495.5	944.1	1,060.9	1,292.7	1,265.7

Prepared by the Study Team

3.3.4 Demand – Supply Balance for Whole Country

Since the regional power system for the southern area will be integrated into the northern and central system in 2014, the analysis of demand-supply balance for the whole country is also important for the study on power trade with neighboring countries. The total demand-supply balance of all areas are summarized in the Table 3.3.8 and Table 3.3.9.

Table 3.3.8 Comparison of the Demand and Supply Energy for the Whole Country

Whole country Unit: GWh

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Demand	2,966.8	3,402.1	4,899.1	5,828.4	7,457.2	10,334.0	12,799.9	13,972.7	14,174.5	14,499.2	15,171.8	15,735.8
Supply	2,625.1	2,667.2	3,587.7	3,678.8	5,503.7	8,083.0	12,378.1	16,425.4	24,359.8	25,961.6	29,218.6	30,183.8
Balance	-341.6	-734.9	-1,311.4	-2,149.6	-1,953.5	-2,251.0	-421.8	2,452.7	10,185.3	11,462.4	14,046.8	14,448.0

Prepared by Study Team

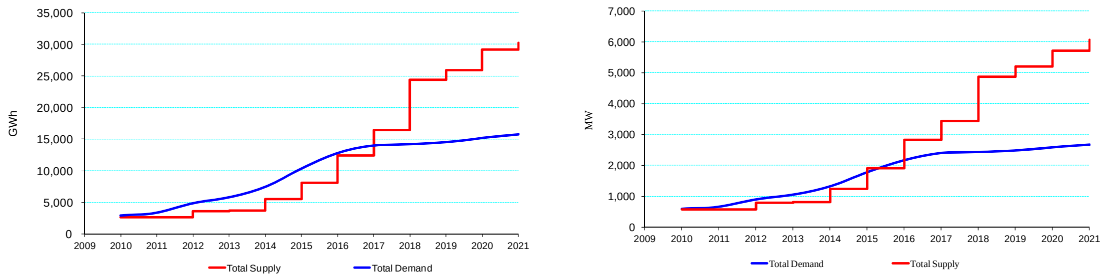
Table 3.3.9 Comparison of the Peak Load and Supply Capacity for the Whole Country

Whole country Unit: MW

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Demand	583.8	649.8	890.7	1,043.0	1,310.2	1,768.3	2,158.9	2,392.6	2,422.9	2,474.1	2,577.6	2,663.5
Supply	569.8	579.4	786.0	801.9	1,239.5	1,911.0	2,831.0	3,425.0	4,858.0	5,191.4	5,709.4	6,066.4
Balance	-14.0	-70.3	-104.6	-241.1	-70.7	142.7	672.2	1,032.5	2,435.2	2,717.3	3,131.8	3,402.9

Prepared by the Study Team

As shown in the balance sheet, the amount of annual power generation in the whole country from 2010 to 2016 warns a power shortage. However, the annual power generation will exceed the energy demand in 2017 onwards, and the balance will achieve 14,448 GWh in 2021.



Prepared by the Study Team

Figure 3.3.4 Demand–Supply Balance for the Whole Country

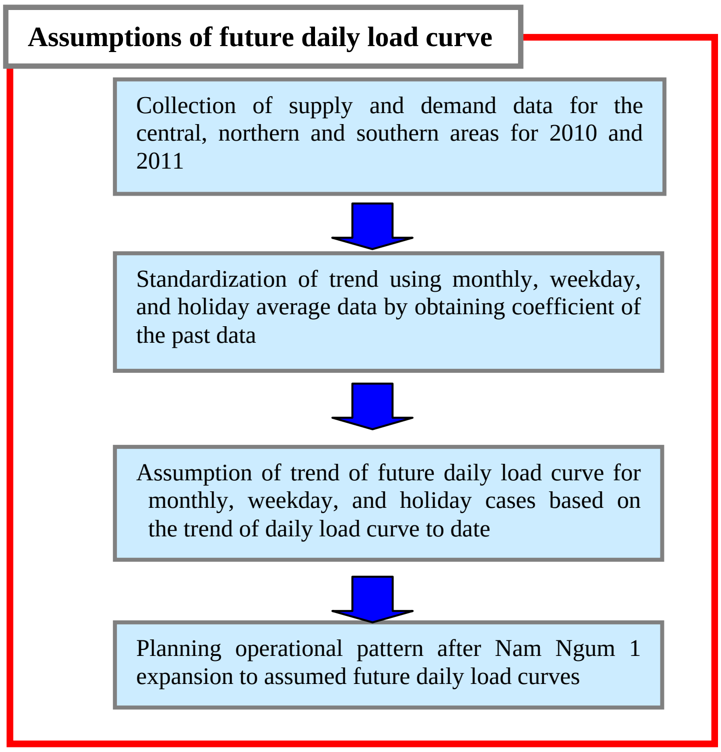
Special attention should be given to the annual balance analysis because the actual supply capacity of hydropower stations has to be reduced to one third to one fourth during dry season, following the seasonal water level on rivers. The load will also vary significantly with time during peak or off-peak each day. Therefore, such analysis of the annual demand-supply balance is used for unveiling an outline of the initial step, and further demand-supply analysis on monthly and daily basis are required for the central area.

3.4 POWER DEMAND–SUPPLY BALANCE ANALYSIS ON MONTHLY AND DAILY BASIS

3.4.1 Assumptions of Future Daily Load Curve Trend

(1) Methodology of Assumption of Daily Load Curve Trend

In order to study the reinforcement of peak power supply in the central area, future daily load curve was assumed first. In the review of the pattern, no change has been noted in the daily load curve collected from the existing substations, and therefore, the future load curves were assumed to keep the same pattern as the past load curves for the time being. In order to formulate the pattern of future daily load curves, the actual recent data were averaged and divided by past peak power value, and coefficients were obtained from the past data. The daily load curves were demonstrated by applying the future peak demand in the northern, central and southern areas, which were projected until 2025. The curves were assumed and shown in monthly, weekday, and holiday cases in the future (in 2014, 2017, 2020, and 2025). The process is shown in the flow chart below (Figure 3.4.1).

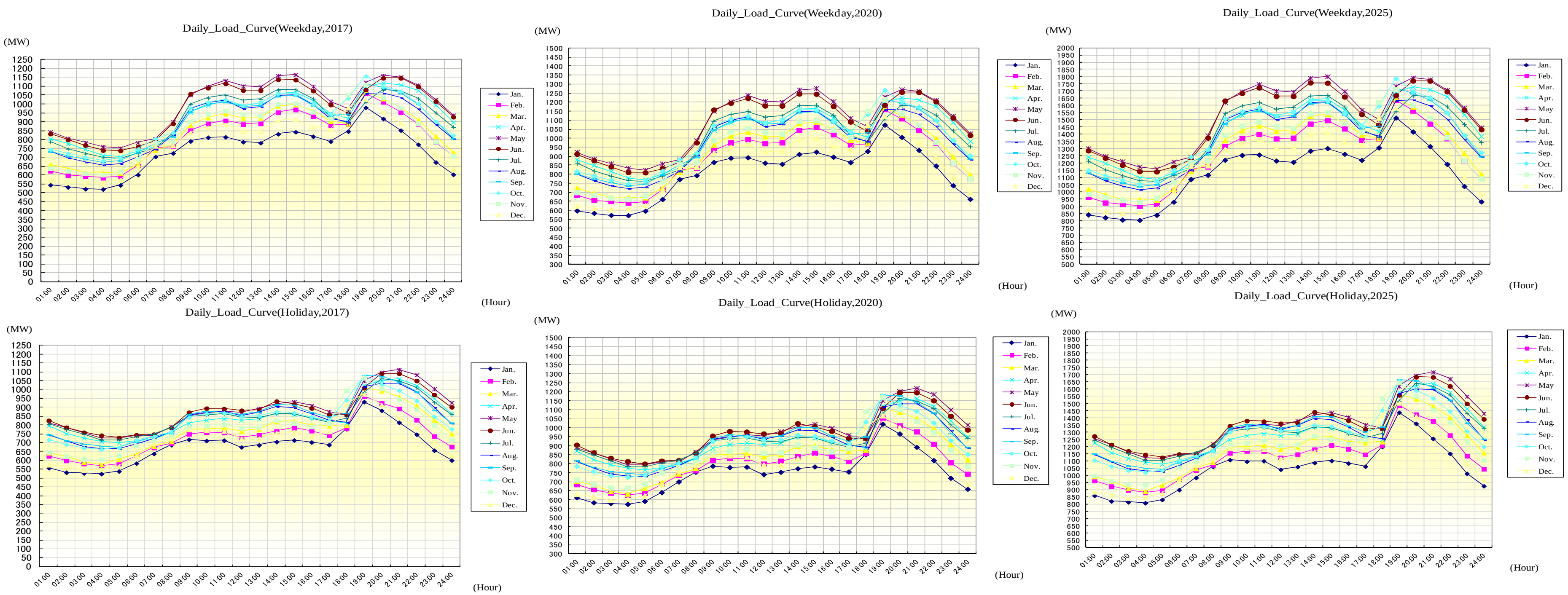


Prepared by the Study Team

Figure 3.4.1 Assumptions of Future Daily Load Curve

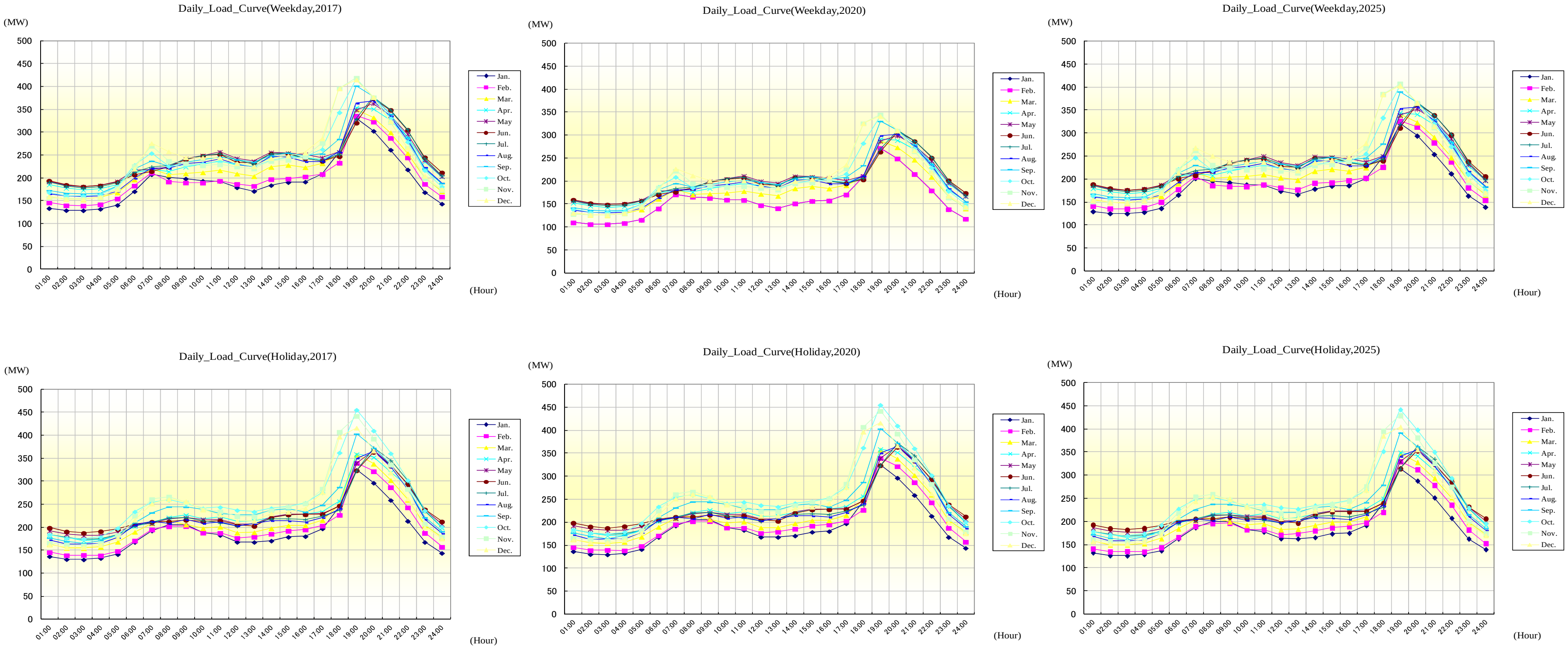
(2) Future Trend of Daily Load Curve for the Central Area

Figures 3.4.2 to 3.4.7 show the daily load curves during weekdays and holidays, for 2017, 2020, and 2025. It is in 2017 that the extension of NN1 will be completed and will begin its operation. The figure of the daily load curve was presumed to show the same trend. Therefore, the difference between the demand of off-peak and peak time becomes larger. For these daily demand variations, an optimal power supply for peak demand in the central area will be proposed, including operational plan for NN1 for high production to commensurate an appropriate reservoir operation.



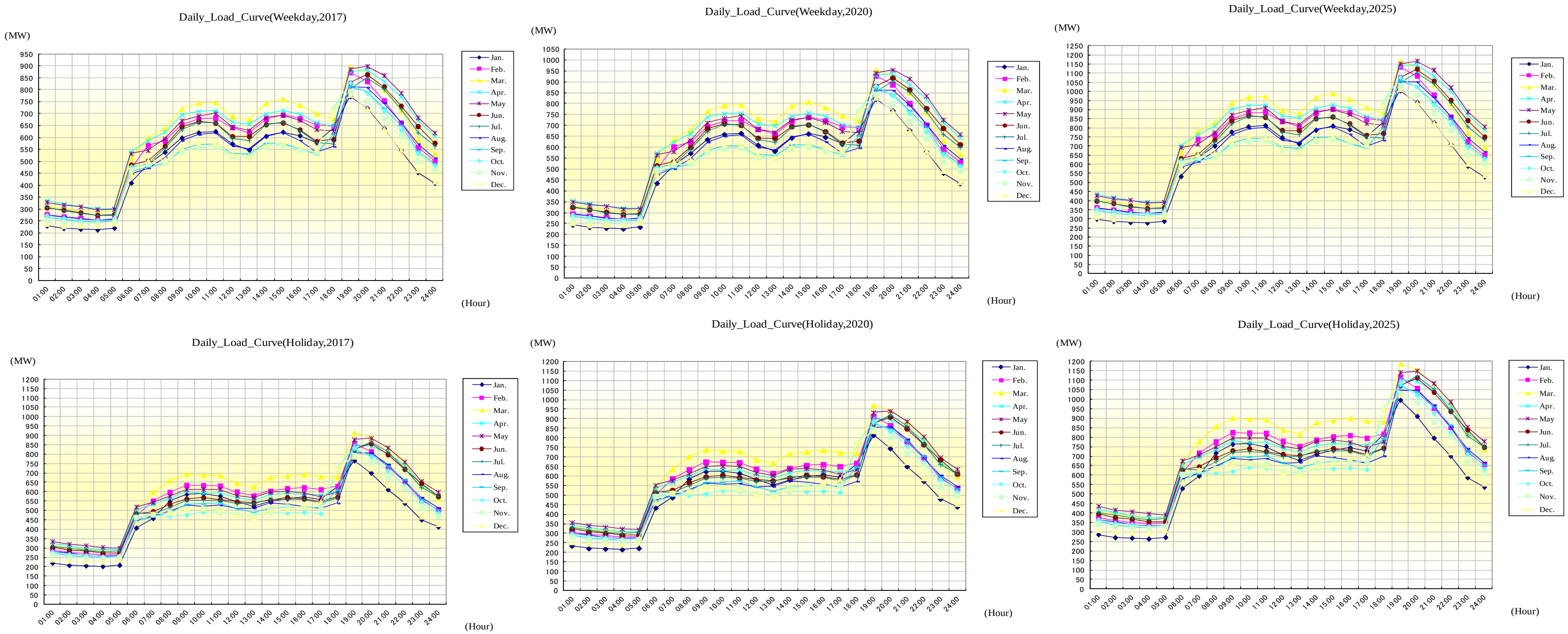
Prepared by the Study Team

Figure 3.4.2 Daily Load Curves for the Central Area



Prepared by the Study Team

Figure 3.4.3 Daily Load Curves for the Northern Area



Prepared by the Study Team

Figure 3.4.4 Daily Load Curves for the Southern Area

Prepared by the Study Team

Figure 3.4.5   Daily Load Curves for the Whole Country

3.4.2 Assumptions of the Future Monthly and Daily Power Generation

(1) General

Hydropower is the main source of electricity supply in Lao PDR. However, hydropower production energy is influenced by hydrological fluctuation. As Lao PDR climate belongs to a monsoon climate, the country has a distinct dry and wet season in a year. Thus hydropower electricity production significantly drops during dry season. This reduction in electricity energy is exemplified by the actual operation pattern as discussed in Chapter 2.

The reduction in electricity production during dry season affects the nation's power demand and supply balance. Therefore in this Study, the monthly energy production of hydropower stations are carefully estimated for all planned hydropower stations listed in PDP 2010-2020 (Revision-1). This section describes the procedure of power generation estimation and result of the estimates.

(2) Methodology

The power generation pattern of hydropower plants are estimated for existing and planned hydropower stations. The general methodology of estimation of each station is shown in Table 3.4.1.

Table 3.4.1 Method of Estimation of Power Generation Pattern

Type	Method
Existing Power Station	Existing power stations operation pattern is estimated from the past operation record.
Planned Power Project which PPA Made	The planned power project which PPA has signed and if PPA can be referred to the Study Team, the monthly capacity stated in PPA is used.
Planned Power Project with Study Level	1) If the study report is available and the power simulation result is presented, the monthly energy value will be used. 2) If the study report is not available for the Study, the power generation pattern will be estimated by the plant factor.

Prepared by the Study Team

For estimating the power generation pattern of the hydropower project (which has no PPA and no available study report for the Study Team), the Study Team first considered the hydropower operation role in the power system and the power generation pattern will be estimated by reservoir size and owner type i.e., EDL-Gen's power stations or IPP(d).

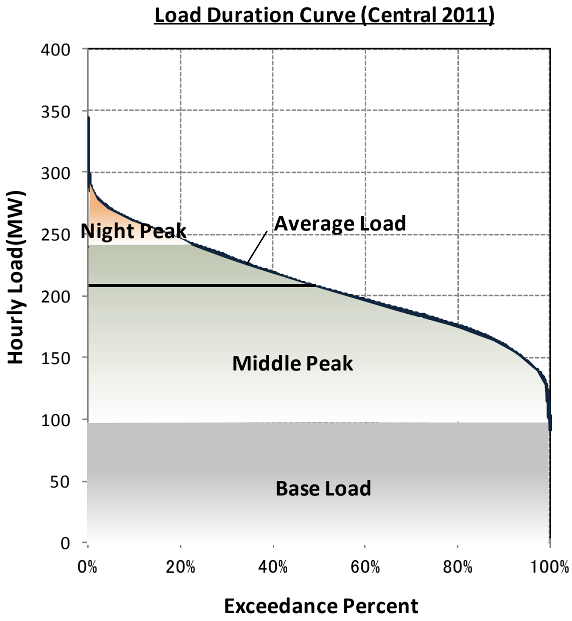
(3) Hydropower Type by Reservoir Size

In general, the role of the hydropower is determined by the relative reservoir storage size to its annual inflow. The relation of storage size and annual inflow is expressed by the regulating capacity factor (RCF) (%) which formula is shown below.

Regulating Capacity Factor (RCF) (%) = Effective Storage/Annual Inflow

If the storage has a capacity that is less than the volume of one day inflow, then the RCF value will be very low. In this case, the hydropower station is assumed as a run-of-river type hydropower, and a run-of-river type hydropower generally operates for base load power supply. If RCF value is high enough to store water for a month's inflow to the reservoir, then the role of the hydropower will be for peak or middle peak power supply.

The allocation of the power supply for base, middle, and peak loads in the central area can be shown in the load duration curve in central area in 2011 as shown in Figure 3.4.6.



Prepared by the Study Team

Figure 3.4.6 Load Duration Curve of the Central Area in 2011 and Power Generation Role

Thus the role of the hydropower was generally defined below.

Hydropower Type	Role in Power Supply
Run-of-river	Base load power supply
Pondage	Peak power supply
Reservoir	Base and peak power supply

The threshold of pondage type and reservoir type ranges from 5% to 20% (in general) in Japan. However, considering the distinct dry and wet season difference in Laos, the Nam Leuk (RCF=30%) station run as a pondage type hydropower station. Approximately 30% of RCF values can be considered as a threshold of the pondage and reservoir type, and this threshold was considered to estimate the operation of the hydropower plants.

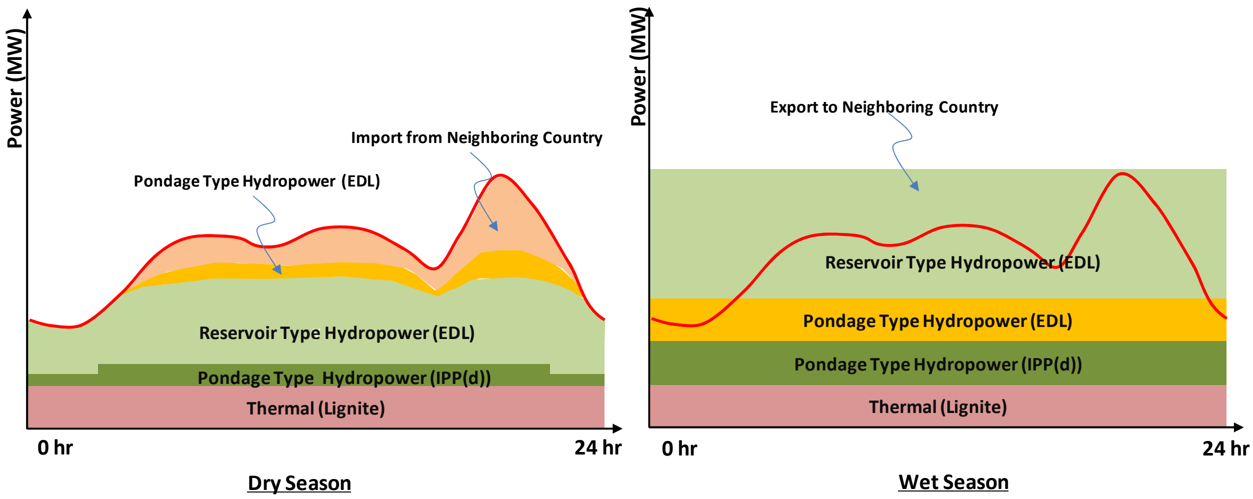
(4) Hydropower Type by Owner Type

The operation of hydropower station differs on the type of ownership. EDL-Gen is relatively flexible in operation since EDL-Gen does not have contractual constraints. While IPP operation is less flexible than those of EDL-Gen since it follows the operation schedule stated in the power purchase agreement (PPA). The characteristics of anticipated hydropower operation by owner type are as follows:

- **EDL-Gen** : Hydropower stations owned by EDL-Gen. Dispatch schedule of hydropower station is flexible to changes in load pattern.
- **IPP(d)** : Hydropower stations by IPP for domestic supply. It operates and complies with the rules stipulated in the PPA which generally forms as a take-or-pay contract. Operation is less flexible than the power stations of EDL-Gen. Tariff is flat rate, therefore no incentive for peak power generation.
- **IPP(e)** : Hydropower stations by IPP for export. Operations follows the PPA contract. Operation is independent from domestic supply.

(5) Conceptual Power Operational Pattern

Considering the facts of power generation pattern described above, the power operational pattern of dry and wet seasons in current hydropower composition is considered as follows.



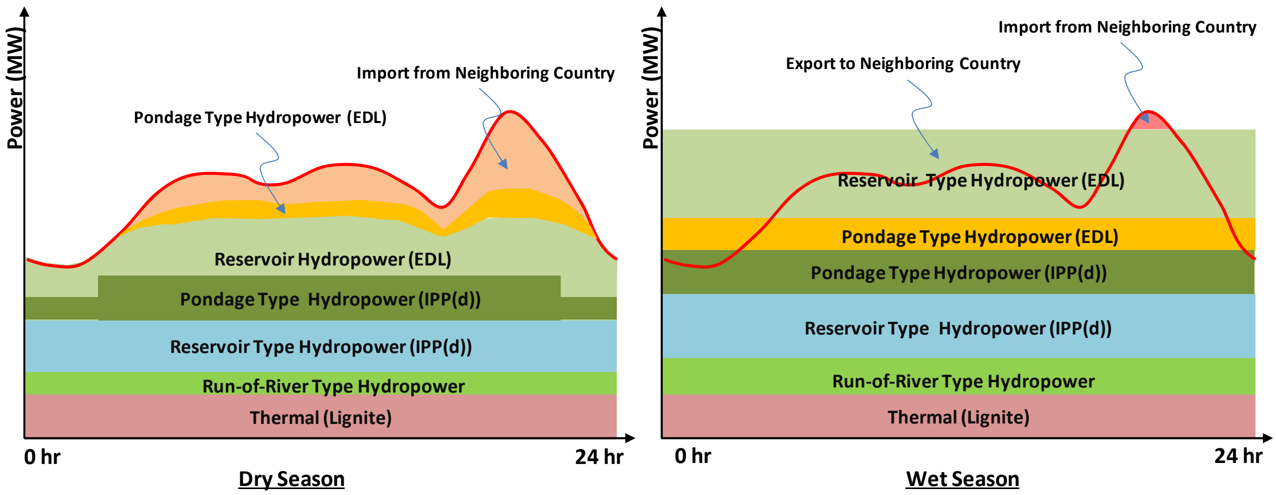
Prepared by the Study Team with hearing from MEM and EDL.-Gen

Figure 3.4.7 Conceptual Operational Pattern of the Current Operation

As shown in Figure 3.4.7, the base load power is supplied by coal (lignite) and IPP(d) power plants. The rest of the difference between the daily load curve and power supply is covered by the output from EDL-Gen power plants output. The shortfall of the power supply to the demand is covered by power import from EGAT. During dry season, pondage type EDL power plants will supply power during peak hours.

During wet seasons, all hydropower operates at full capacity for 24 hours, and excess power is exported to neighboring countries.

In the later years, the power source composition will be differed to the current situation as many of IPP(d) hydropower stations will enter the national grid. The anticipated daily operational pattern in the future is shown in Figure 3.4.8.



Prepared by Study Team with hearing from MEM and EDL.-Gen

Figure 3.4.8 Conceptual Operational Pattern of Future Operation

As shown above, the IPP reservoir type and pondage type will enter first to the base load power supply, then EDL-Gen power plants will operate to follow the load curve.

(6) Operational Pattern of Planned Hydropower Projects Referred to PPA and Study Reports

- Planned hydropower project with PPA can be referred

The following hydropower stations are referred to as estimated monthly capacity stated in the PPA between IPP(d) and EDL.

Hydropower Plants Estimated by PPA	Nam Ngum 5, Nam Ngiep 2, Nam Ou 1-7, Xekaman1+Xanxai, Xenamnoy

- Planned hydropower project with PPA can NOT be referred, and the study reports can be referred

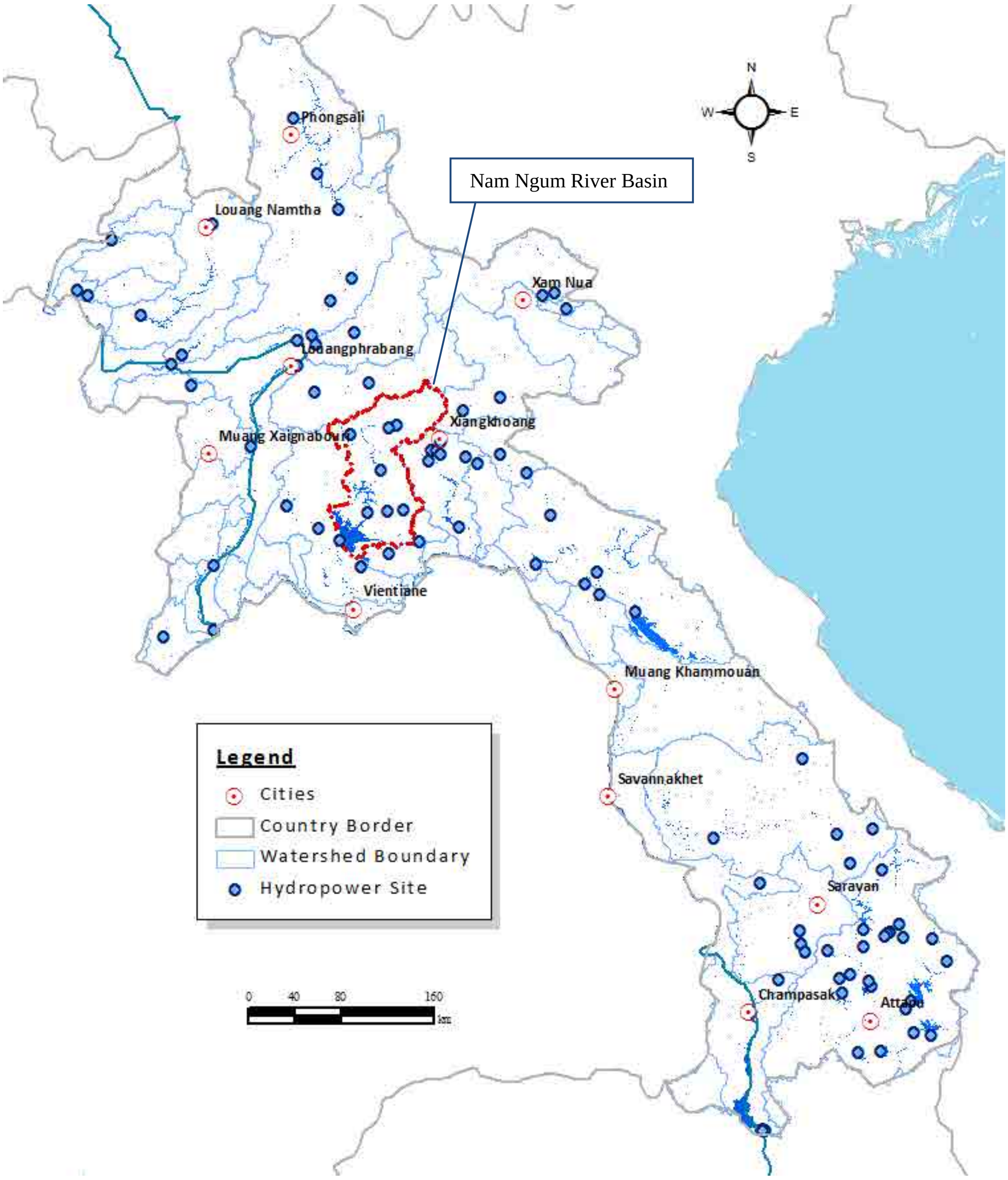
The following hydropower stations are referred in the study reports.

Hydropower Plant Output Referred in the Study Report	Nam Khan 2, Nam Lik1

(7) Estimation of the Operational Pattern of Planned Hydropower Projects by Plant Factor

- Objective power plants

The Study Team estimated the power generation of planned hydropower stations which have no PPA and study reports available for the Study. The objective hydropower plants are those located in the whole area of Lao PDR, since the northern and southern areas will be connected to the central area by a 230 kV transmission line, the power system of the nation performs like a single power system. The location of hydropower plants in Lao PDR is shown in Figure 3.4.13.

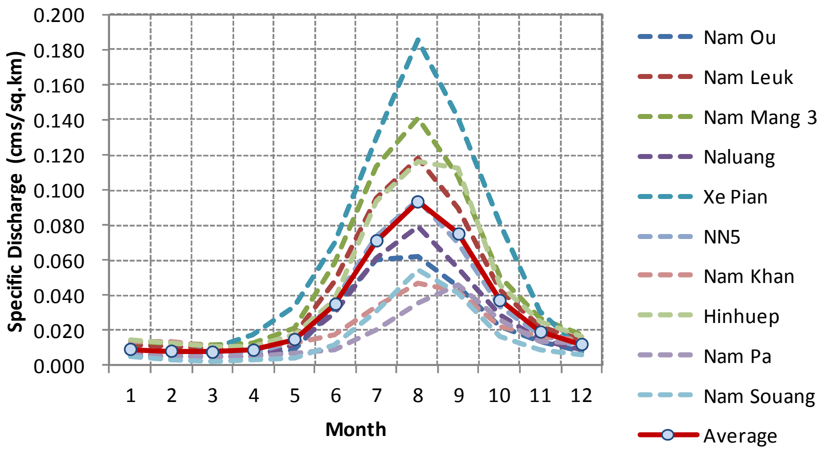


Prepared by the Study Team

Figure 3.4.9 Planned and Existing Hydropower Stations in Lao PDR

- Homogenous in Rainfall Pattern

The rainfall pattern in Lao PDR is similar in all parts of the nation. The specific discharge of rivers in Lao PDR is shown in Figure 3.4.9.



Data Source; DMH

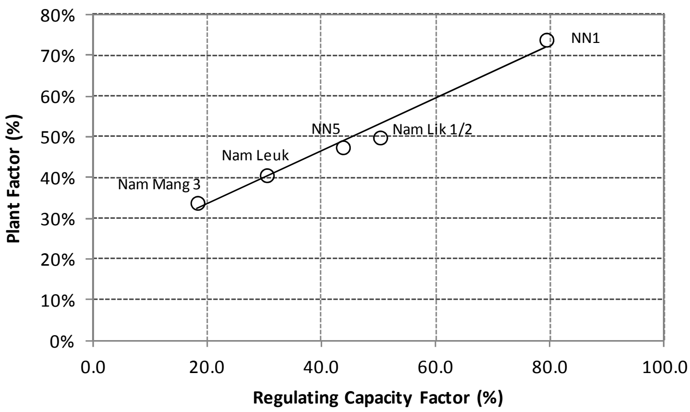
Figure 3.4.10 Specific Discharge of Rivers in Laos PDR

As shown in Figure 3.4.10, the discharge peak in August and the discharge is low during dry season from November to May.

The monthly energy is dependent on the seasonal fluctuation of river discharge. If the inflow pattern is the same, then, the monthly energy pattern will be alike. For the simulation of hydropower station output, the average specific discharge pattern was used for the Study.

- Estimation of Hydropower Type by Plant Factor (PF)

The relationship between RCF and PF in the central area is shown in Figure 3.4.11.



Prepared by the Study Team

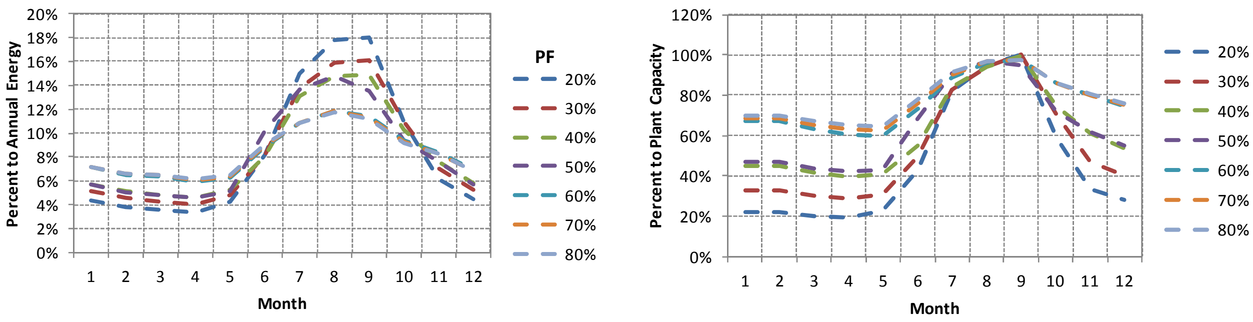
Figure 3.4.11 Relationship Between Regulating Capacity Factor and Plant Factor

As shown in the figure, the RCF and PF values are almost proportional, although it is not always the case. This means that RCF can be estimated if the PF value is known. The PF value is listed for all planned hydropower projects in PDP 2010-2020 (Revision-1). The power operation for all power stations can be estimated using the PF value in PDP 2010-2020 (Revision-1).

- Estimation of Power Output by Plant Factor

The power output of hydropower varying RCF from 20% to 80% is simulated by mass curve method using the average specific discharge and adjusted to fit with the past operation records pattern.

The estimated hydropower monthly energy and average power output for the plant factor varying from 20% to 80% is shown in Figure 3.4.12.



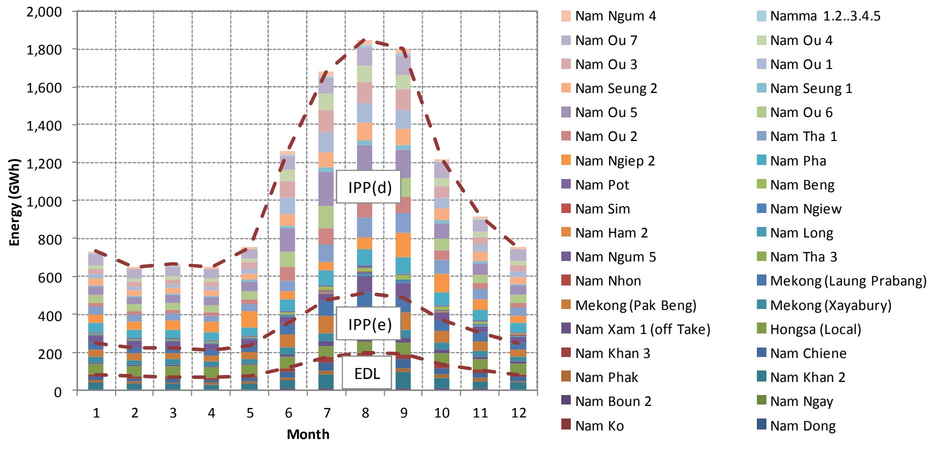
Prepared by the Study Team

Figure 3.4.12 Percent of Monthly Energy to Annual Energy Simulated for Each Plant Factor

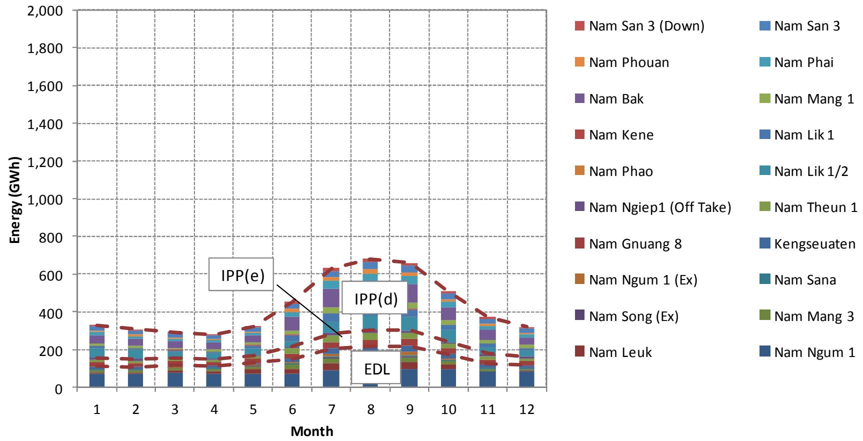
(8) Estimated Monthly Energy

As discussed in the previous section, power output of all planned hydropower stations these were listed in PDP 2010-2020 (Revision-1), were estimated by referring to PPA, study reports, and by estimating by plant factor.

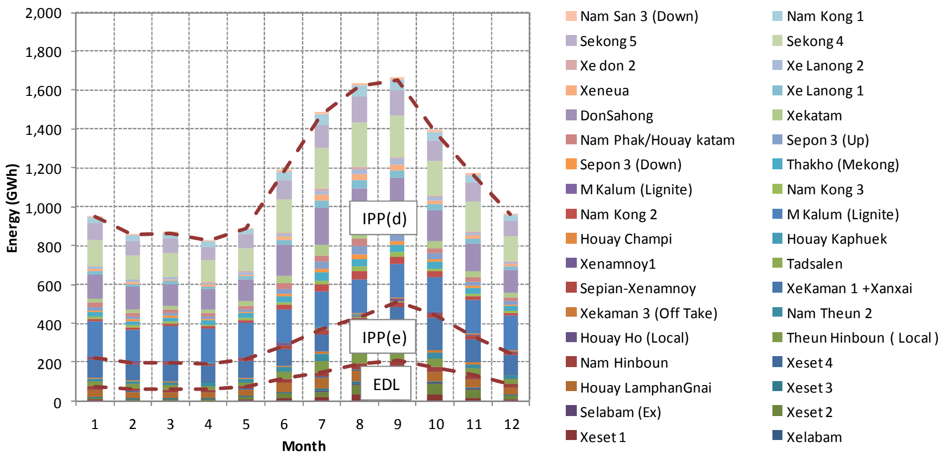
The estimated monthly energy is shown in Figure 3.4.13.



Northern Area



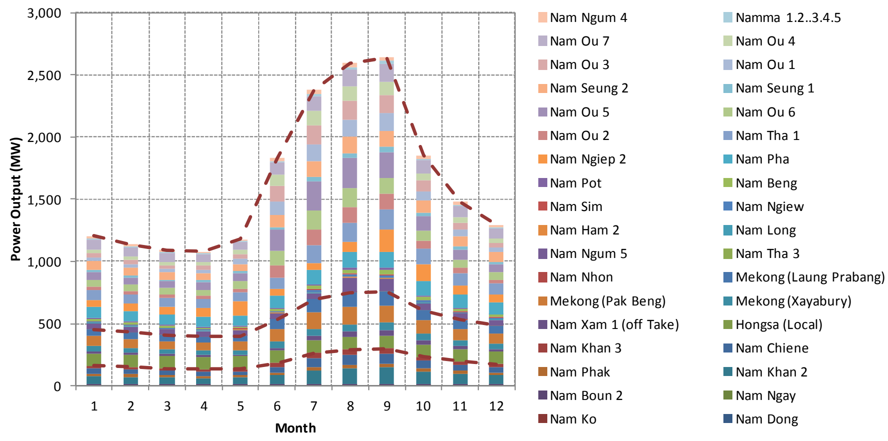
Central Area



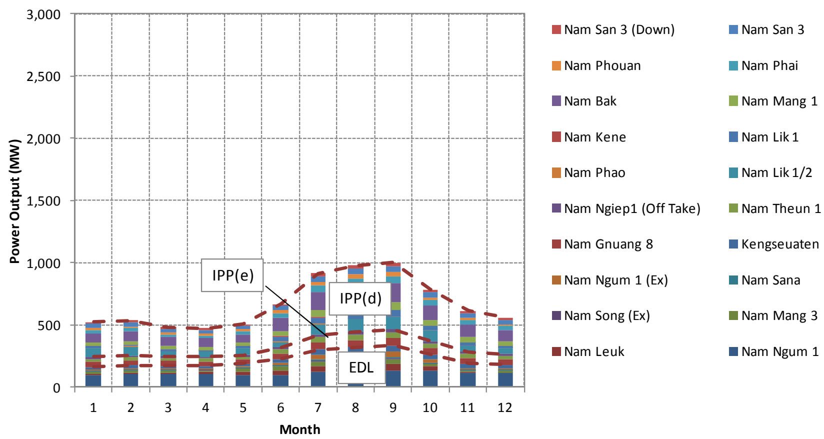
Southern Area

Prepared by the Study Team

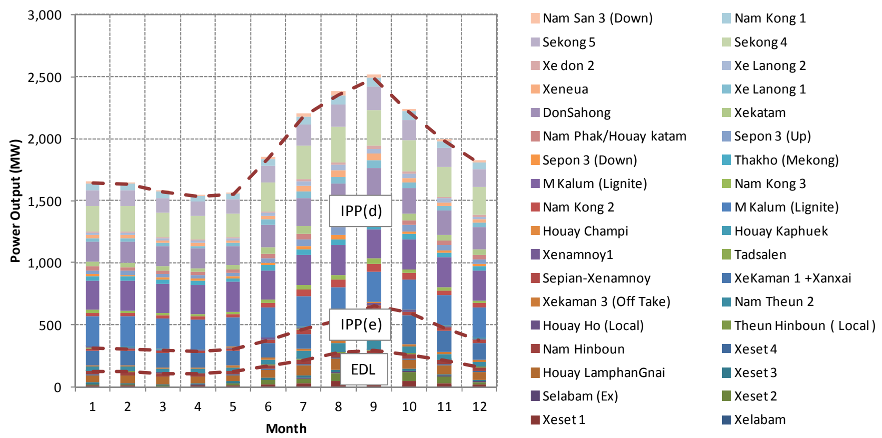
Figure 3.4.13 Estimated Monthly Energy for the Northern, Central, and Southern Areas



Northern Area



Central Area



Southern Area

Prepared by the Study Team

Figure 3.4.14 Estimated Monthly Power for the Northern, Central, and Southern Areas

(9) Estimated Daily Operation

The daily operational pattern was estimated by using estimated monthly energy as described above.

The monthly energy was allocated in the daily operation by applying the following criteria:

1) Prospective Hydropower Operation of EDL-Gen

- Pondage type:

  [Dry season]: Peak hour operation following load shape

  [Wet season]: 24-hour operation

- Reservoir Type : Storage capacity more than one week

  [Dry season]: Base load + Peak power generation

  [Wet season]: 24-hour operation

2) Prospective Hydropower Operation of IPP(d)

- Pondage type:

  [Dry season]: Peak hour operation (flat)

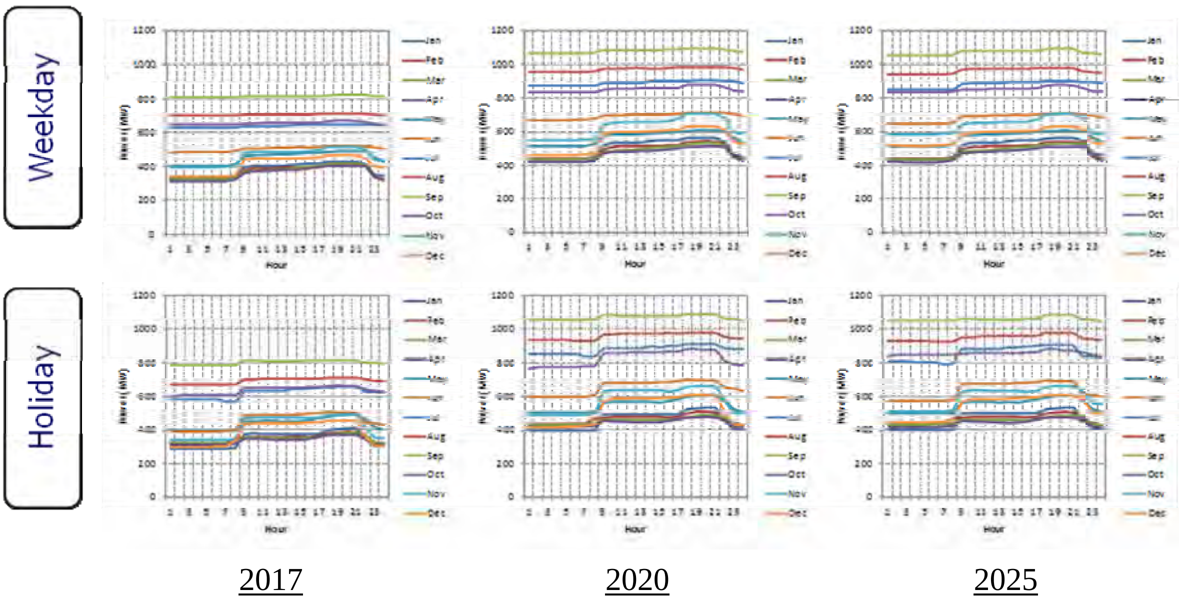
  [Wet season]: 24-hour operation

- Reservoir Type : Storage capacity more than one week.

  [Dry season]: Base load

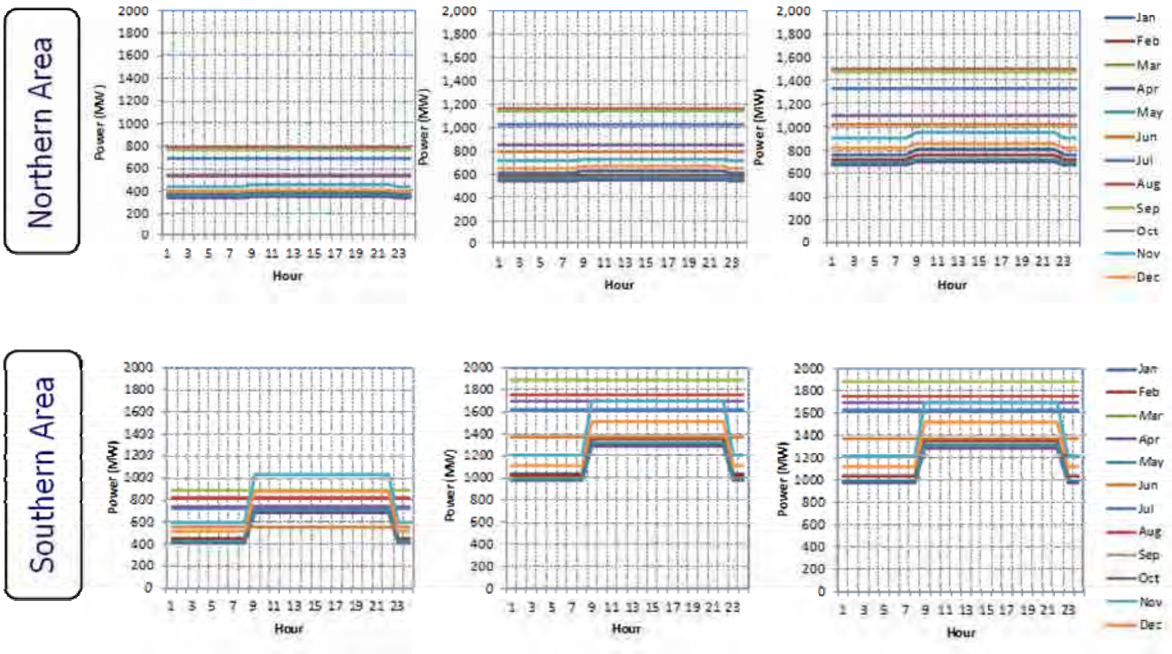
  [Wet season]: 24-hour operation

The daily power operation was estimated for 2017, 2020, and 2025 by using the above criteria and results are shown in Figures 3.4.15 and 3.4.16.



Prepared by the Study Team

Figure 3.4.15 Estimated Daily Power Generation in the Central Area



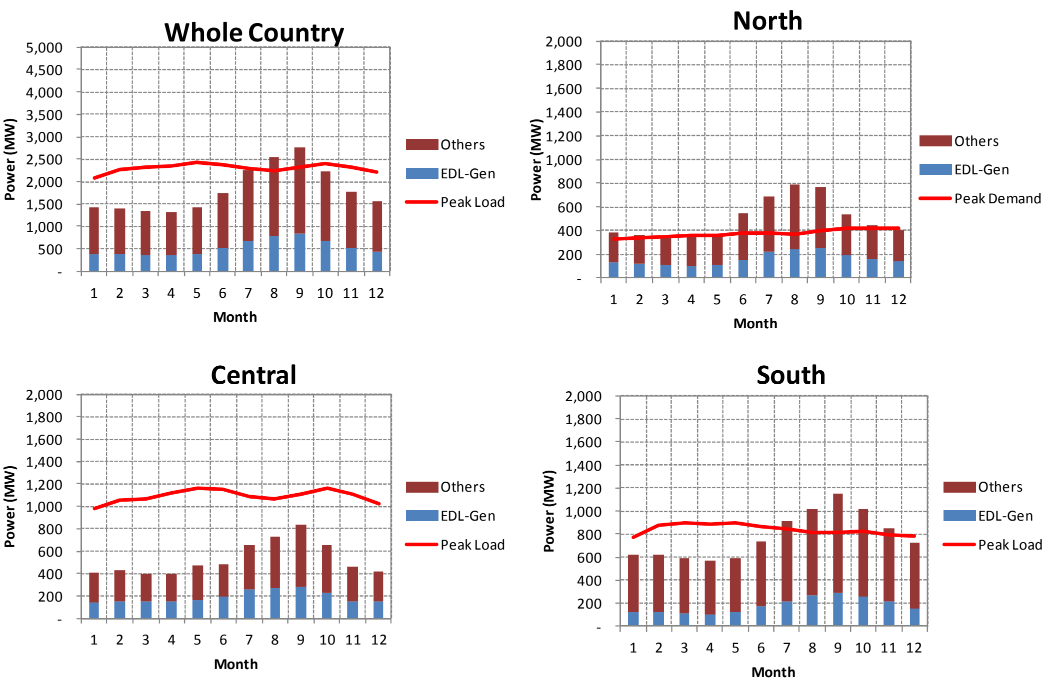
2017 2020 2025

Prepared by the Study Team

Figure 3.4.16 Estimated Daily Power Generation in the Northern and Southern Area

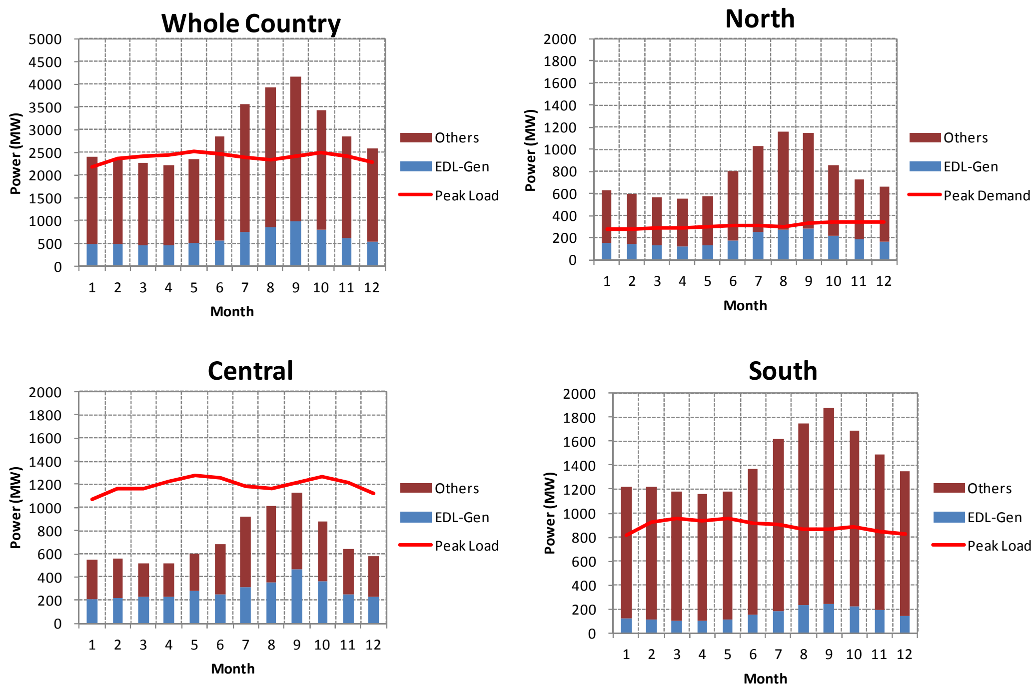
3.4.3 Monthly Demand–Supply Balance in the Whole Country

The monthly demand and supply balance for the whole country, northern, central, and southern areas for year 2017, 2020 and 2025 cases are shown in Figure 3.4.4, Figures 3.4.5 and 3.4.6, respectively..



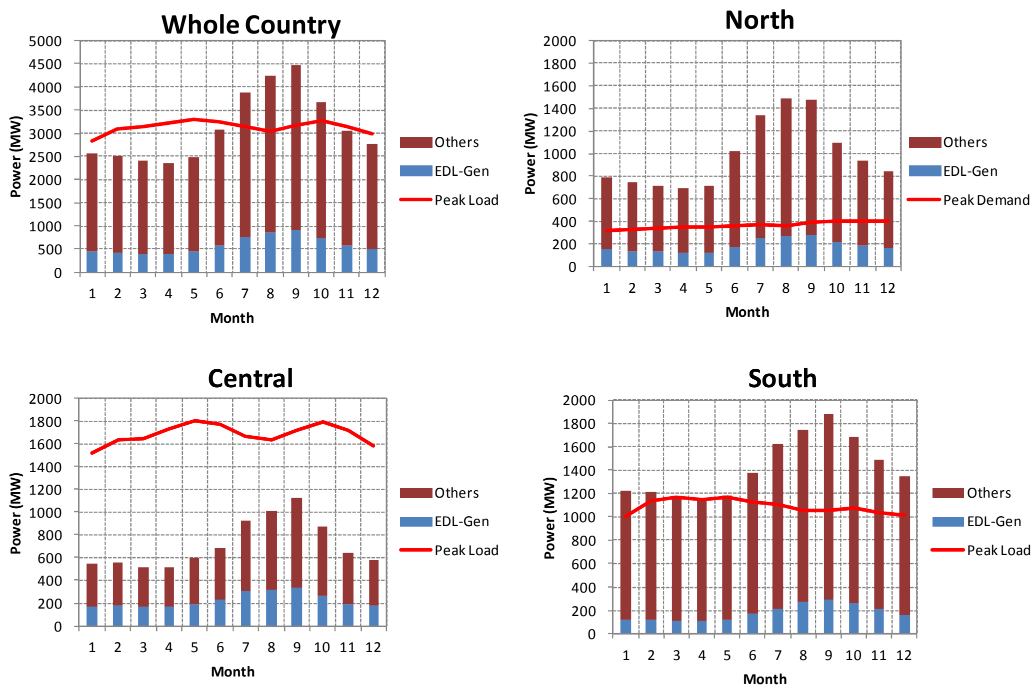
Prepared by the Study Team

Figure 3.4.17 Monthly Power Supply and Demand Balance (Year 2017)



Prepared by the Study Team

Figure 3.4.18 Monthly Power Supply and Demand Balance (Year 2020)



Prepared by the Study Team

Figure 3.4.19 Monthly Power Supply and Demand Balance (Year 2025)

Figure 3.4.17 shows that the monthly power supply during dry season could not meet the demand aggregates of the whole country. The power supply in the northern area in dry season is almost the same to the peak demand, and the power supply is not enough to cover the demand in the southern area.

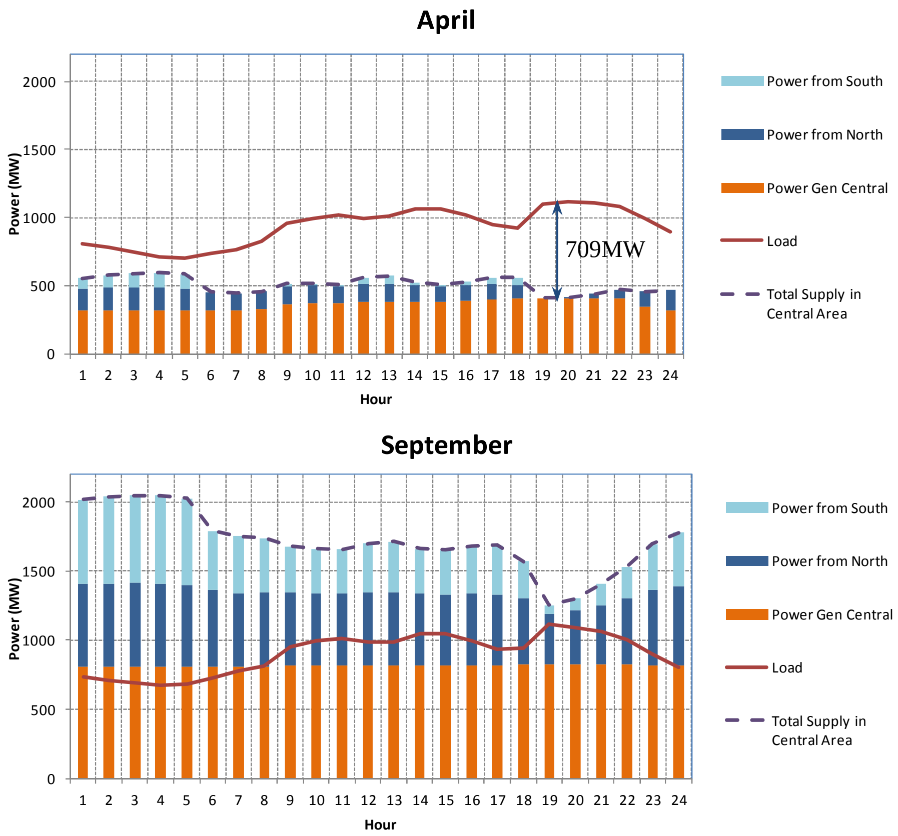
The power deficit in the southern area will be covered by importing power from EGAT. The power shortage in the central area is about 700 MW and this amount should also be imported from EGAT. The power shortage of 700 MW in the central area is difficult to be covered by domestic power plants even if the power operation of all EDL power generation plants change their operation to peak power supply. The power situation in 2017 will be severe for the power supply and demand balance.

Figure 3.4.18 shows that the power supply balance of the whole country is almost exceeding to the peak power demand in 2020. The power shortage in the central area will be covered by the power transferred from the northern and southern areas in 2020. In 2025, power demand will exceed the peak power demand during dry season, thus EDL will import power from EGAT during this season.

3.4.4 Daily Demand–Supply Balance in the Central Area of Lao PDR

The daily power supply and demand balance for dry and wet seasons in the central area in 2017 is shown in Figure 3.4.20. The power supply to the central consists of power output of hydropower stations in central area and power delivered from the northern and southern areas by assuming a surplus power in northern and southern area going to the central area. As shown in the figure the power coming from the northern area and southern areas is limited especially during night peak hours as the power in the north and south is locally consumed before transferring to other area. The power shortage for peak hours in the central is estimated at 709 MW at maximum.

The power supply and demand balance in September (wet season) shows that the power supply will exceed the power demand in the central area with power delivered from the northern and southern area. However, the surplus of power supply for peak hours at night time is relatively small compared with the off-peak hours because the power in the northern and southern area are locally consumed at night time before transferred to other areas.



Prepared by the Study Team

Figure 3.4.20 Daily Power Supply and Demand Balance (Year 2017)

3.5 ISSUES OF POWER SUPPLY FOR PEAK POWER DEMAND IN THE CENTRAL AREA

In the foregoing Sub-clauses 3.1 to 3.4, demand–supply balance for the central area and whole country is discussed on an annual, monthly and daily basis. As a result of these analyses, the issues of power supply for peak power demand in the central area are summarized below.

(1) Reduction of Actual Power Generation during Dry Season

Most of the power consumed in Laos is currently provided by hydropower plants and shortage is compensated by power import from neighboring countries. It is well known that the actual power output of hydropower plants is extremely lower than the rated output of generators during dry season, as stipulated in Sub-clause 3.4.2. Power supply to the central area was assumed to have shortage during peak demand throughout 2017, whereas the north and south areas will have a surplus during wet season which will then be transferred to the central area. However, during dry season, even both northern and central areas will face shortage in power supply. The problem therefore will be the central area not receiving power from the northern or southern areas. During dry season, power import is the only way to compensate power shortage.

Under these circumstances, the development of power resources other than hydropower is desired to avoid depression of power generation during dry season. In the PDP, coal-fired projects of Hongsa

IPP(e) (100 MW off-take from export) and M. Kalum (600 MW) are expected to operate as a base load supply in the future. The construction of Hongas is ongoing, which is expected to commence its commercial operation in 2015. M. Kalum unfortunately seems to be not on track because of unavailability of certain data in resource reserve of lignite.

Each energy resource and power generation method has its own balance of "stability", "environmental performance", and "economic efficiency". Study of possibility of alternative power resources other than hydropower shall be encouraged from a viewpoints of “the best mix of power sources”, to continue delivering a stable supply of electricity at low cost.

(2) Power Shortage for Peak Time Demand

It is observed in the demand–supply balance for 2017 that the expected 709 MW power shortage will be very sever during peak hours between 19:00 to 20:00 in April.

EDL is required to secure a peak load power supply capacity against the peak demand during dry season. The Study Team estimated an additional 709 MW supply to be ensured to compensate power shortage during peak hours. This bulk capacity may be accomplished by more than one kind of power resources, such as: i. shifting the role of some power stations from base load to peak load operation, ii. expansion of generation capacity of hydropower station to shift part of its generation to peak time, iii. increment of power import by reinforcement of transmission lines, and iv. development of new power stations for peak supply.

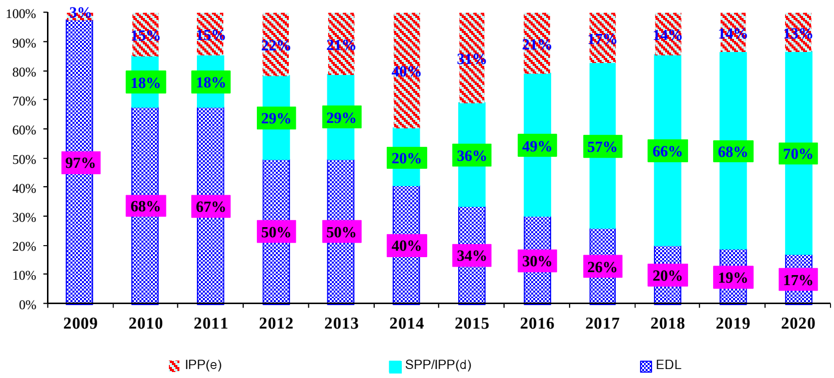
(3) Over Reliance on Power Import in the Future from View of Power Supply Security

If the shortage of electricity in Lao PDR is fully compensated by importing, it is projected that in the future, the proportion of power import to the demand in central area will vary approximately from 20% to 60% during dry season (November to May) in 2017. 60% power supply during peak time must especially depend on the importation of power from Thailand. The power system operation in Lao PDR relies on the power system of EGAT in Thailand.

The situation of overreliance on the EGAT system should be improved so as to reduce the proportion of power importation as much as possible from a viewpoint of power supply security. EDL is encouraged to proceed to reinforce the power generation capacity possibly owned by EDL in Lao PDR.

(4) Low Proportion of Controllable Power Supply Capacity to the Whole Power Supply Capacity

The proportion of the installed generation capacity of EDL-owned power stations will reduce from 68% in 2010 to 17% in 2020.



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Supply by EDL	385	391	391	398	500	640	845	885	969	969	969	969	969	969	969	969
Total Supply by IPP(d)	100	104	225	233	247	679	1,394	1,948	3,185	3,518	3,976	4,286	4,286	4,286	4,286	4,286
Total Supply by IPP(e)	85	85	170	170	492	592	592	592	704	704	764	811	811	811	1,075	1,075
Whole Country	570	579	786	802	1,240	1,911	2,831	3,425	4,858	5,191	5,709	6,066	6,066	6,066	6,330	6,330

Prepared by the Study Team, updating PDP

Figure 3.5.1 Installed Generation Capacity by Ownership

EDL, as owner of the power plants has produced 391 MW of the 579 MW (67% generation capacity) in 2011. Many IPP domestic power generation projects will be completed in 2017 to 2018, although EDL-owned generation capacity will be 885 MW, the occupancy rate will decrease to 25% out of the rapidly growing generation capacity in the whole country of 3425 MW. In 2020, the proportion will be further decreased to 17%.

Generally, the IPP's daily generation pattern is regulated under the conditions mentioned in the PPA between EDL and IPP. The operation cannot flexibly be controlled by EDL due to its intension to increase or decrease the generation according to the power network which changes from time to time.

EDL is recommended to secure more EDL-owned power stations for domestic supply in the future. At least the project of EDL power plants should be implemented on schedule as much as possible.

In addition, it is recommended to change the form of PPA to focus on the power supply peak by splitting current flat tariff to peak and off-peak tariff or simply specifying the operation period to meet peak hours. As it is anticipated, the controllable power capacity for EDL will be very limited to the total capacity in the near future. The increment of peak power supply by IPPs will help the peak power operation of EDL power generation scheduling.

Table 3.5.1 Installed Generation Capacity in the Northern Area

Unit: MW

No.	Power Plant	Energy (GWh)	Firm. Cap (MW)	Inst. Cap (MW)	Plant factors	COD	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	EDL																						
1	Nam Dong	5	0.3	1	54%	1969	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
2	Nam Ko	8	0.5	2	60%	1996	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
3	Nam Ngay	8	0.4	1	76%	2006	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
4	Nam Boun 2	80	8.0	15	61%	2016								15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
5	Nam Khan 2	558	43.3	130	49%	2015							130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0
6	Nam Phak	170	15.0	30	65%	2018										30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
7	Nam Chiene	330	36.0	80	47%	2016								80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
8	Nam Khan 3	222	32.3	47	54%	2016								47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0
	IPP(e)																						
1	Hongsa (Local)	701	100.0	100	80%	2015							100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
2	Nam Xam 1 (off Take)	143	30.0	47	35%	2021													47.0	47.0	47.0	47.0	47.0
3	Mekong (Xayabury)	420	30.0	60	80%	2020												60.0	60.0	60.0	60.0	60.0	60.0
4	Mekong (Pak Beng)	599	80.0	114	60%	2024																114.0	114.0
5	Mekong (Laung Prabang)	660	108.0	150	50%	2024																150.0	150.0
	IPP(d)																						
1	Nam Nhon	12	1.0	2	55%	2011			2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
2	Nam Tha 3	6	0.5	1	50%	2011			1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
3	Nam Ngum 5	500	84.0	120	48%	2012				120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
4	Nam Long	37	5.0	5	84%	2013					5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
5	Nam Ham 2	16	3.0	5	37%	2016								5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
6	Nam Ngiew	63	10.0	20	36%	2016								20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
7	Nam Sim	33	3.2	9	43%	2014						8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
8	Nam Beng	137	13.5	34	46%	2015							13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
9	Nam Pot	71	10.0	15	54%	2017									15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
10	Nam Pha	720	65.0	130	63%	2018							130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0
11	Nam Ngiep 2	723	81.0	180	46%	2015							180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
12	Nam Tha 1	721	75.6	168	49%	2020												168.0	168.0	168.0	168.0	168.0	168.0
13	Nam Ou 2	546	54.0	120	52%	2016								120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
14	Nam Ou 6	818	40.5	180	52%	2016								180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
15	Nam Ou 5	1,156	72.0	240	55%	2016								240.0	240.0	240.0	240.0	240.0	240.0	240.0	240.0	240.0	240.0
16	Nam Seung 1	167	12.6	42	45%	2019											42.0	42.0	42.0	42.0	42.0	42.0	42.0
17	Nam Seung 2	621	40.2	134	53%	2019											134.0	134.0	134.0	134.0	134.0	134.0	134.0
18	Nam Ou 1	799	48.0	160	57%	2018										160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0
19	Nam Ou 3	710	45.0	150	54%	2018										150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
20	Nam Ou 4	569	34.8	116	56%	2018										116.0	116.0	116.0	116.0	116.0	116.0	116.0	116.0
21	Nam Ou 7	915	57.0	190	55%	2018										190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0
22	Namma 1.2..3.4.5	76	6.7	22	39%	2019											22.4	22.4	22.4	22.4	22.4	22.4	22.4
23	Nam Ngum 4	822	-	220	43%	2021													220.0	220.0	220.0	220.0	220.0
	Total for Northern Area						3.7	3.7	7.4	127.4	132.4	141.0	694.5	1,401.5	1,416.5	2,062.5	2,260.8	2,488.8	2,755.8	2,755.8	2,755.8	3,019.8	3,019.8

Data Source; PDP 2010-2020 Revision-1
Prepared by the Study Team

Table 3.5.2 Generation Energy in Northern Area

Unit: GWh

No	Power Plant	Inst. Cap (MW)	Firm. Cap (MW)	Energy (GWh)	Plant factors	COD	2010	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	EDL																						
1	Nam Dong	1.0	0.3	4.7	54%	1969	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
2	Nam Ko	1.5	0.5	7.9	60%	1996	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
3	Nam Ngay	1.2	0.4	8.0	76%	2006	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
4	Nam Boun 2	15.0	8.0	80.0	61%	2016								80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
5	Nam Khan 2	130.0	43.3	558.0	49%	2015							558.0	558.0	558.0	558.0	558.0	558.0	558.0	558.0	558.0	558.0	558.0
6	Nam Phak	30.0	15.0	170.0	65%	2018										170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
7	Nam Chiene	80.0	36.0	330.0	47%	2016								330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0
8	Nam Khan 3	47.0	32.3	222.0	54%	2016								222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0
	IPP(e)																						
1	Hongsa (Local)	100.0	100.0	700.8	80%	2015							700.8	700.8	700.8	700.8	700.8	700.8	700.8	700.8	700.8	700.8	700.8
2	Nam Xam 1 (off Take)	47.0	30.0	143.0	35%	2021													143.0	143.0	143.0	143.0	143.0
3	Mekong (Xayabury)	60.0	30.0	420.0	80%	2020												420.0	420.0	420.0	420.0	420.0	420.0
4	Mekong (Pak Beng)	114.0	80.0	598.9	60%	2024																598.9	598.9
5	Mekong (Laung Prabang)	150.0	108.0	660.0	50%	2024																660.0	660.0
	IPP(d)																						
1	Nam Nhon	2.4	1.0	11.6	55%	2011			11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
2	Nam Tha 3	1.3	0.5	5.5	50%	2011			5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
3	Nam Ngum 5	120.0	84.0	500.0	48%	2012				500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0
4	Nam Long	5.0	5.0	37.0	84%	2013					37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
5	Nam Ham 2	5.0	3.0	16.0	37%	2016								16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
6	Nam Ngiew	20.0	10.0	63.0	36%	2016								63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0
7	Nam Sim	8.6	3.2	32.6	43%	2014						32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6
8	Nam Beng	34.0	13.5	137.0	46%	2015							137.0	137.0	137.0	137.0	137.0	137.0	137.0	137.0	137.0	137.0	137.0
9	Nam Pot	15.0	10.0	70.5	54%	2017									70.5	70.5	70.5	70.5	70.5	70.5	70.5	70.5	70.5
10	Nam Pha	130.0	65.0	720.0	63%	2018									720.0	720.0	720.0	720.0	720.0	720.0	720.0	720.0	720.0
11	Nam Ngiep 2	180.0	81.0	723.0	46%	2015							723.0	723.0	723.0	723.0	723.0	723.0	723.0	723.0	723.0	723.0	723.0
12	Nam Tha 1	168.0	75.6	721.0	49%	2020												721.0	721.0	721.0	721.0	721.0	721.0
13	Nam Ou 2	120.0	54.0	545.8	52%	2016								545.8	545.8	545.8	545.8	545.8	545.8	545.8	545.8	545.8	545.8
14	Nam Ou 6	180.0	40.5	817.9	52%	2016								817.9	817.9	817.9	817.9	817.9	817.9	817.9	817.9	817.9	817.9
15	Nam Ou 5	240.0	72.0	1,156.3	55%	2016								1,156.3	1,156.3	1,156.3	1,156.3	1,156.3	1,156.3	1,156.3	1,156.3	1,156.3	1,156.3
16	Nam Seung 1	42.0	12.6	167.0	45%	2019											167.0	167.0	167.0	167.0	167.0	167.0	167.0
17	Nam Seung 2	134.0	40.2	621.0	53%	2019											621.0	621.0	621.0	621.0	621.0	621.0	621.0
18	Nam Ou 1	160.0	48.0	798.9	57%	2018										798.9	798.9	798.9	798.9	798.9	798.9	798.9	798.9
19	Nam Ou 3	150.0	45.0	709.6	54%	2018										709.6	709.6	709.6	709.6	709.6	709.6	709.6	709.6
20	Nam Ou 4	116.0	34.8	569.0	56%	2018										569.0	569.0	569.0	569.0	569.0	569.0	569.0	569.0
21	Nam Ou 7	190.0	57.0	915.4	55%	2018										915.4	915.4	915.4	915.4	915.4	915.4	915.4	915.4
22	Namma 1.2..3.4.5	22.4	6.7	75.8	39%	2019											75.8	75.8	75.8	75.8	75.8	75.8	75.8
23	Nam Ngum 4	220.0	-	822.2	43%	2021													822.2	822.2	822.2	822.2	822.2
	Total for Northern Area						20.6	20.6	37.7	537.7	574.7	607.3	2,726.1	5,957.1	6,747.6	9,910.5	10,774.2	11,915.2	12,880.4	12,880.4	12,880.4	14,139.3	14,139.3

Data Source; PDP 2010-2020 Revision-1

Prepared by the Study Team

Table 3.5.3 Installed Generation Capacity in the Central Area

Unit: MW

No.	Power Plant	Energy (GWh)	Firm. Cap (MW)	Inst. Cap (MW)	Plant factors	COD	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	EDL																						
1	Nam Ngum 1	1,003	97.3	155	74%	1971	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0
2	Nam Leuk	218	22.4	60	41%	2000	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
3	Nam Mang 3	150	12.8	40	43%	2005	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
4	Nam Song (Ex)	25	2.6	6	48%	2011			6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
5	Nam Sana	50	4.5	14	40%	2014						14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0
6	Nam Ngum 1 (Ex)	88	18.0	40	25%	2017									40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
7	Kengseuaten	214	30.0	54	45%	2018										54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0
	IPP(e)																						
1	Nam Gnuang 8	316	42.0	60	60%	2012				60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
2	Nam Theun 1	250	9.1	50	57%	2018										50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
3	Nam Ngiep1 (Off Take)	122	8.1	22	63%	2018										22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
	IPP(d)																						
1	Nam Lik 1/2	435	70.0	100	50%	2010		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
2	Nam Phao	9	0.7	2	61%	2012				1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
3	Nam Lik 1	256	30.0	60	49%	2018										60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
4	Nam Kene	20	2.0	5	45%	2014						5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
5	Nam Mang 1	225	35.0	64	40%	2017									64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0
6	Nam Bak	744	100.0	160	53%	2017									160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0
7	Nam Phai	280	27.0	60	53%	2018													60.0	60.0	60.0	60.0	60.0
8	Nam Phouan	140	15.0	30	53%	2018										30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
9	Nam San 3	325	30.0	48	77%	2018										48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
10	Nam Ngum (Dow n)	300	27.0	60	57%	0																	
11	Nam San 3 (Dow n)	120	20.0	30	46%	2018													30.0	30.0	30.0	30.0	30.0
11	Nam Feung 3	80	6.0	20	46%	2021																	
12	Nam Feung 2	110	7.5	25	50%	2021																	
13	Nam Feung 1	113	8.4	28	46%	2022																	
	Total for Central Area						255.0	355.0	361.0	422.6	422.6	441.6	441.6	441.6	705.6	969.6	969.6	969.6	1,059.6	1,059.6	1,059.6	1,059.6	1,059.6

Data Source; PDP 2010-2020 Revision-1

Prepared by the Study Team

Table 3.5.4 Generation Energy in the Central Area

Unit: GWh

No	Power Plant	Inst. Cap (MW)	Firm. Cap (MW)	Energy (GWh)	Plant factors	COD	2010	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	EDL																						
1	Nam Ngum 1	155.0	97.3	1,002.9	74%	1971	1,002.9	1,002.9	1,002.9	1,002.9	1,002.9	1,002.9	1,002.9	1,002.9	1,002.9	1,002.9	1,002.9	1,002.9	1,002.9	1,002.9	1,002.9	1,002.9	1,002.9
2	Nam Leuk	60.0	22.4	218.1	41%	2000	218.1	218.1	218.1	218.1	218.1	218.1	218.1	218.1	218.1	218.1	218.1	218.1	218.1	218.1	218.1	218.1	218.1
3	Nam Mang 3	40.0	12.8	150.0	43%	2005	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
4	Nam Song (Ex)	6.0	2.6	25.0	48%	2011			25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
5	Nam Sana	14.0	4.5	49.6	40%	2014						49.6	49.6	49.6	49.6	49.6	49.6	49.6	49.6	49.6	49.6	49.6	49.6
6	Nam Ngum 1 (Ex)	40.0	18.0	88.0	25%	2017									88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0
7	Kengseuaten	54.0	30.0	213.6	45%	2018										213.6	213.6	213.6	213.6	213.6	213.6	213.6	213.6
	IPP(e)																						
1	Nam Gnuang 8	60.0	42.0	316.0	60%	2012				316.0	316.0	316.0	316.0	316.0	316.0	316.0	316.0	316.0	316.0	316.0	316.0	316.0	316.0
2	Nam Theun 1	50.0	9.1	250.0	57%	2018										250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0
3	Nam Ngiep1 (Off Take)	22.0	8.1	122.0	63%	2018										122.0	122.0	122.0	122.0	122.0	122.0	122.0	122.0
	IPP(d)																						
1	Nam Lik 1/2	100.0	70.0	435.0	50%	2010		435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0
2	Nam Phao	1.6	0.7	8.5	61%	2012				8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
3	Nam Lik 1	60.0	30.0	256.0	49%	2018										256.0	256.0	256.0	256.0	256.0	256.0	256.0	256.0
4	Nam Kene	5.0	2.0	19.7	45%	2014						19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7
5	Nam Mang 1	64.0	35.0	224.8	40%	2017									224.8	224.8	224.8	224.8	224.8	224.8	224.8	224.8	224.8
6	Nam Bak	160.0	100.0	744.0	53%	2017									744.0	744.0	744.0	744.0	744.0	744.0	744.0	744.0	744.0
7	Nam Phai	60.0	27.0	280.0	53%	2018										280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0
8	Nam Phouan	30.0	15.0	140.0	53%	2018										140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
9	Nam San 3	48.0	30.0	324.9	77%	2018										324.9	324.9	324.9	324.9	324.9	324.9	324.9	324.9
10	Nam Ngum (Down)	60.0	27.0	300.0	57%																		
11	Nam San 3 (Down)	30.0	20.0	120.0	46%	2018										120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
	Total for Central Area						1,371.0	1,806.0	1,831.0	2,155.5	2,155.5	2,224.8	2,224.8	2,224.8	3,281.6	4,988.0	4,988.0	4,988.0	4,988.0	4,988.0	4,988.0	4,988.0	4,988.0

Data Source; PDP 2010-2020 Revision-1
Prepared by the Study Team

Table 3.5.5 Installed Generation Capacity in the Southern Area

Unit: MW

No.	Power Plant	Energy (GWh)	Firm. Cap (MW)	Inst. Cap (MW)	Plant factors	COD	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	EDL	-	-	-	0%	0																	
1	Xelabam	21	0.6	5	49%	1969	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2	Xeset 1	134	8.4	45	34%	1991	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
3	Xeset 2	310	30.4	76	47%	2009	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0
4	Selabam (Ex)	37	3.1	8	55%	2013					7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
5	Xeset 3	86	8.9	23	43%	2016								23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
6	Houay LamphanGnai	495	43.4	88	64%	2014						88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0
7	Xeset 4	40	5.0	10	46%	2015							10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
8	Nam Hinboun	220	25.0	40	63%	2016								40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
	IPP(e)																						
1	Theun Hinboun (Local)	25	3.0	8	36%	1998	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
2	Houay Ho (Local)	8	2.1	2	45%	1999	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
3	Nam Theun 2	300	52.5	75	46%	2010		75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
4	Xekaman 3 (Off Take)	96	15.0	25	44%	2012				25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
5	XeKaman 1 +Xanxai	1,228	119.3	322	44%	2014						322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0
6	Sepian-Xenamnoy	179	20.0	40	51%	2018										40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
7	Sekong 4 (off Take)	-	42.0	-	0%	2017									-	-	-	-	-	-	-	-	-
	IPP(d)																						
1	Tadsalen	17	1.3	3	61%	2013					3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
2	Xenamnoy1	100	10.0	15	76%	2017									15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
3	Houay Kaphuek	21	2.0	5	48%	2016								5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
4	Houay Champi	27	1.6	5	62%	2018										5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
5	M Kalum (Lignite)	2,100	300.0	300	80%	2017									300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0
6	Nam Kong 2	263	27.0	66	45%	2015							66.0	66	66.0	66	66.0	66.0	66.0	66.0	66.0	66.0	66.0
7	Nam Kong 3	158	9.0	42	43%	2015							42.0	42	42.0	42	42.0	42.0	42.0	42.0	42.0	42.0	42.0
8	M Kalum (Lignite)	2,100	300.0	300	80%	2018										300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0
9	Thakho (Mekong)	360	22.5	50	82%	2020												50.0	50.0	50.0	50.0	50.0	50.0
10	Sepon 3 (Dow n)	150	21.0	30	57%	2016								30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
11	Sepon 3 (Up)	280	49.0	70	46%	2016								70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
12	Nam Phak/Houay katam	307	30.0	45	78%	2016								45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
13	Xekatam	381	45.0	75	58%	2019											75.0	75.0	75.0	75.0	75.0	75.0	75.0
14	DonSahong	1,756	185.0	240	84%	2020												240.0	240.0	240.0	240.0	240.0	240.0
15	Xe Lanong 1	300	27.0	60	57%	2018										60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
16	Xeneua	209	20.3	53	45%	2018										53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0
17	Xe Lanong 2	170	28.0	45	43%	2018										45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
18	Xe don 2	80	30.0	20	46%	2018										20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
19	Sekong 4	1,901	-	300	72%	2017									300	300	300	300	300.0	300.0	300.0	300.0	300.0
20	Sekong 5	1,131	-	190	68%	2017									190	190	190	190.0	190.0	190.0	190.0	190.0	190.0
21	Nam Kong 1	469	-	75	71%	2017									75	75	75	75.0	75.0	75.0	75.0	75.0	75.0
	Total for Southern Area						136.1	211.1	211.1	236.1	247.0	657.0	775.0	988.0	2,032.0	2,391.0	2,630.0	2,816.0	2,816.0	2,816.0	2,816.0	2,816.0	2,816.0

Data Source; PDP 2010-2020 Revision-1

Prepared by the Study Team

Table 3.5.6 Generation Energy in the Southern Area

Unit: GWh

No	Power Plant	Inst. Cap (MW)	Firm. Cap (MW)	Energy (GWh)	Plant factors	COD	2010	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	EDL																						
1	Xelabam	5.0	0.6	21.5	49%	1969	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
2	Xeset 1	45.0	8.4	133.9	34%	1991	133.9	133.9	133.9	133.9	133.9	133.9	133.9	133.9	133.9	133.9	133.9	133.9	133.9	133.9	133.9	133.9	133.9
3	Xeset 2	76.0	30.4	309.9	47%	2009	309.9	309.9	309.9	309.9	309.9	309.9	309.9	309.9	309.9	309.9	309.9	309.9	309.9	309.9	309.9	309.9	309.9
4	Selabam (Ex)	7.7	3.1	37.1	55%	2013					37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1
5	Xeset 3	23.00	8.9	86.1	43%	2016								86.1	86.1	86.1	86.1	86.1	86.1	86.1	86.1	86.1	86.1
6	Houay LamphanGnai	88.0	43.4	495.0	64%	2014						495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0
7	Xeset 4	10.0	5.0	40.0	46%	2015							40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
8	Nam Hinboun	40.0	25.0	220.0	63%	2016								220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0
	IPP(e)																						
1	Theun Hinboun (Local)	8.0	3.0	25.0	36%	1998	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
2	Houay Ho (Local)	2.1	2.1	8.2	45%	1999	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
3	Nam Theun 2	75.0	52.5	300.1	46%	2010		300.1	300.1	300.1	300.1	300.1	300.1	300.1	300.1	300.1	300.1	300.1	300.1	300.1	300.1	300.1	300.1
4	Xekaman 3 (Off Take)	25.0	15.0	96.0	44%	2012				96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0
5	XeKaman 1 +Xanxai	322.0	119.3	1,228.0	44%	2014						1,228.0	1,228.0	1,228.0	1,228.0	1,228.0	1,228.0	1,228.0	1,228.0	1,228.0	1,228.0	1,228.0	1,228.0
6	Sepian-Xenamnoy	40.0	20.0	178.8	51%	2018										178.8	178.8	178.8	178.8	178.8	178.8	178.8	178.8
7	Sekong 4 (off Take)		42.0			2017								-	-	-	-	-	-	-	-	-	-
	IPP(d)																						
1	Tadsalen	3.2	1.3	17.0	61%	2013					17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0
2	Xenamnoy1	15.0	10.0	100.0	76%	2017									100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
3	Houay Kaphuek	5.0	2.0	21.0	48%	2016								21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
4	Houay Champi	5.0	1.6	27.3	62%	2018										27.3	27.3	27.3	27.3	27.3	27.3	27.3	27.3
5	M Kalum (Lignite)	300.0	300.0	2,100.0	80%	2017									2,100.0	2,100.0	2,100.0	2,100.0	2,100.0	2,100.0	2,100.0	2,100.0	2,100.0
6	Nam Kong 2	66.0	27.0	263.0	45%	2015							263.0	263.0	263.0	263.0	263.0	263.0	263.0	263.0	263.0	263.0	263.0
7	Nam Kong 3	42.0	9.0	157.5	43%	2015							157.5	157.5	157.5	157.5	157.5	157.5	157.5	157.5	157.5	157.5	157.5
8	M Kalum (Lignite)	300.0	300.0	2,100.0	80%	2018										2,100.0	2,100.0	2,100.0	2,100.0	2,100.0	2,100.0	2,100.0	2,100.0
9	Thakho (Mekong)	50.0	22.5	360.0	82%	2020												360.0	360.0	360.0	360.0	360.0	360.0
10	Sepon 3 (Dow n)	30.0	21.0	150.0	57%	2016								150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
11	Sepon 3 (Up)	70.0	49.0	280.0	46%	2016								280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0
12	Nam Phak/Houay katam	45.0	30.0	307.0	78%	2016								307.0	307.0	307.0	307.0	307.0	307.0	307.0	307.0	307.0	307.0
13	Xekatam	75.0	45.0	381.0	58%	2019											381.0	381.0	381.0	381.0	381.0	381.0	381.0
14	DonSahong	240.0	185.0	1,756.0	84%	2020												1,756.0	1,756.0	1,756.0	1,756.0	1,756.0	1,756.0
15	Xe Lanong 1	60.0	27.0	300.0	57%	2018										300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0
16	Xeneua	53.0	20.3	209.0	45%	2018										209.0	209.0	209.0	209.0	209.0	209.0	209.0	209.0
17	Xe Lanong 2	45.0	28.0	170.0	43%	2018										170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
18	Xe don 2	20.0	30.0	80.0	46%	2018										80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
19	Sekong 4	300.0		1,901.0	72%	2017									1,901.0	1,901.0	1,901.0	1,901.0	1,901.0	1,901.0	1,901.0	1,901.0	1,901.0
20	Sekong 5	190.0		1,131.0	68%	2017									1,131.0	1,131.0	1,131.0	1,131.0	1,131.0	1,131.0	1,131.0	1,131.0	1,131.0
21	Nam Kong 1	75.0		469.0	71%	2017									469.0	469.0	469.0	469.0	469.0	469.0	469.0	469.0	469.0
	Total for Southern Area						498.5	798.6	798.6	894.6	948.6	2,671.6	3,132.1	4,196.2	9,897.2	12,962.3	14,242.3	15,816.3	15,816.3	15,816.3	15,816.3	15,816.3	15,816.3

Data Source; PDP 2010-2020 Revision-1
Prepared by the Study Team

CHAPTER 4 COMPARATIVE STUDY FOR REINFORCEMENT OF PEAK POWER SUPPLY IN THE CENTRAL AREA

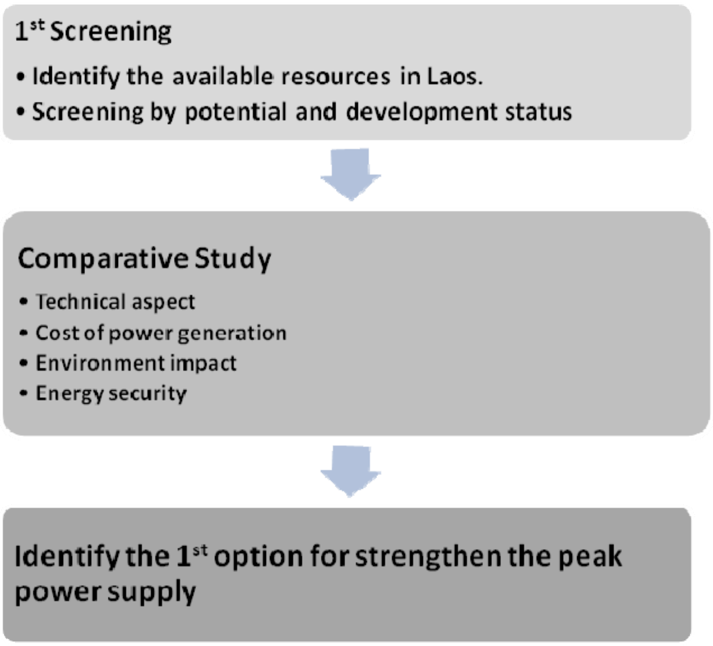
4.1 OBJECTIVE

In the previous chapter, it was identified that the central area of Laos will face a shortage of over 700 MW of power supply in the central area during peak hours at night in 2017. This shortage is anticipated five years after this study period, and hence, the power supply capability especially for peak hours should be urgently strengthened to secure a stable power supply.

In this chapter, countermeasure to strengthen the peak power capacity is examined considering the possible measures applicable to Lao PDR. A comparative study of options is carried out to select the most effective option for reinforcing the peak power supply.

4.2 METHODOLOGY

As this Study aimed to identify the power sources to physically reduce the power shortage of over 700 MW in 2017, a medium to large scale power source was considered for comparative study. Such bulk power sources were selected by screening applicable power sources in Lao PDR. Then, the options were compared in detail. The procedure for selecting the best option is as follows.



Prepared by the Study Team

Figure 4.2.1 Flow Chart for the Comparative Study for Reinforcement of Peak Power Supply in the Central Area

The criteria for screening the alternatives are shown in Table 4.2.1.

Table 4.2.1 Assessment Criteria for Screening Options

Item	Assessment Criteria
(1) Potential	Examining the potential or resource of options. If potential or resource is not available for peak power supply, the option will be eliminated.
(2) Exploitation/Development Status	Examining the development status of the option. If the potential or resource is not exploitable or the technology to harness the energy is not available in Laos, then it is not a realistic option. In this case, the option will be eliminated from the list.

Prepared by the Study Team

As this Study seeks the bulk capacity of power sources, mini or micro hydropower is not considered.

After 1st screening of the options, remaining options were compared considering the items shown in Table 4.2.2.

Table 4.2.2 Assessment Criteria for Comparative Study

Item	Assessment Criteria
(1) Technical Aspect	Options are evaluated for technical aspects like technical difficulties.
(2) Energy Security	The options are compared for energy security i.e. increasing self-sufficiency rate and ensuring power supply stability.
(3) Cost of Power Generation/Purchase	The cost comparison is performed for the preliminary survey level.
(4) Environmental Issue	The environmental issues are studied for each option.

Prepared by the Study Team

After the comparative study, each option was prioritized considering the future power generation plan.

4.3 SCREENING OF ALTERNATIVE POWER SOURCES

4.3.1 Prospective Power Sources

(1) Outline of Alternative Energy Sources

The energy sources used or applicable to Lao PDR is shown in Table 4.3.1.

Table 4.3.1 Energy Sources and Energy Production Methods for Selection of Options

Energy Source	Energy Production Method
Hydropower (Large scale hydro; NN1 Expansion*1)	The electric energy is produced by converting the hydraulic potential energy to electric energy using turbine and generators. The large scale hydro capacity is more than 15MW in Lao PDR. Nam Ngum 1 (NN1) expansion is the first candidate as hydropower exploitable source (See note *1).
Hydropower (Small scale hydro)*2	Hydropower plants with capacity of less than 15 MW are categorized as small scale hydropower.
Coal Thermal	Electric energy is produced by converting heat energy to mechanical energy (steam turbine). Heat energy is produced through coal combustion.
Diesel Engine (Heavy Oil)	Diesel engine is used to drive electric generator. The scale of generator ranges from several kW to MW.
Renewable Energy	Renewable energy comes from natural resources that are replenished at a faster rate than they are consumed. Solar, biomass, wind, and hydro are common renewable energy sources.
Power Import	Power import from neighboring countries is considered as energy source since this option involves directly receiving energy in the form of electricity.

Note;) In the above table, natural gas is not imported from neighboring country in Lao PDR; therefore natural gas is eliminated since its use is not a realistic option.
*1: Since economically and financially viable hydropower potential sites have already been identified, and development rights are held by project owners, NN1 expansion is considered as the first candidate for large scale hydropower since such expansion includes EDL's power station where environmental issues are cleared.
*2: Small scale hydro is normally considered as a form of renewable energy. However, in Lao PDR, small scale hydro involves an installed capacity of less than 15 MW, which can also be considered as medium scale power plant. Therefore, small scale hydro is separated from the renewable energy group.
Prepared by the Study Team

(2) Potential and Current Development Status of Alternative Energy Sources

1) Hydropower (Large Scale; NN1 Expansion)

The exploitable hydropower potential including mainstream of the Mekong River is estimated to be 23,000 MW[1]. The hydropower potential share of the Mekong River is estimated to be 8000 MW. Therefore, the total exploitable hydropower potential in Laos is 15,000 MW, which excludes the Mekong River development. Among this exploitable hydropower capacities, 2560 MW of hydropower is developed while 1,330 MW is under construction. A total capacity of 5,748 MW is identified for the whole country according to the PDP 2010-2020 (Revision-1). This means that around 35% of hydropower potential is developed or will be developed in Lao PDR.

In general, the difficulty in hydropower development includes the risk of geological conditions, and environment impact for natural and social aspects. In addition, the economically and

[1] JICA "Data Collection Study on Energy Sector in Lao PDR, Progress Report", 2012

financially viable hydropower potential sites in Lao PDR are limited as these have been identified been handled by the power developers mainly IPPs.

Feasibility study of NN1 expansion was conducted under the “Preparatory Survey on Nam Ngum 1 Hydropower Station Expansion” in 2010, and expansion scale of 40 MW was recommended through the comparative study in terms of environment, construction method, economic and financial cost benefit analysis. Consequently, the basic design of 40 MW expansion plan was conducted in the Study. Result of the Study shows that NN1 expansion has limited environmental impacts and less geological risks since the additional power house will be installed next to the existing powerhouse. Therefore, NN1 expansion is the next exploitable power source for EDL. In this regard, NN1 expansion is considered as the first option as large scale hydropower energy source.

2) Hydropower (Small Scale)

According to the “Renewable Energy Development Strategy in Lao PDR, 2011[2]” issued by MEM, potential of small scale hydro is 2000 MW. The GoL intends to develop around 650 MW of small hydropower capacity between 2010 and 2025 through the support of private and community sectors. The current development involves small scale hydropower of only 12 MW, which is 0.6% of the total hydropower potential.

3) Coal thermal

The coal reserves in Lao PDR are lignite and anthracite; however, the latter is located in discontinuous layers, which makes exploration and exploitation difficult[1]. Majority of exploitable coal reserves is lignite found in Hongsa, Viengphoukham Khangphaniang and Muong Phane mainly in the northern area of Laos. The total reserve of coal was estimated to be 535.38 million tons, where 510 million tons are located in Hongsa Coalfield[1]. This reserve will be exploited for the Hongsa Lignite Thermal Plant, which aims to export electricity to Thailand. The reserves of coal field other than Hongsa are deemed to be extremely small.

4) Heavy Oil for Diesel Engine and Diesel Power Plant

In Lao PDR, natural resource of fossil fuel has not been identified yet. Lao PDR imports petroleum products such as light diesel oil and gasoline mainly used in the transportation sector. Such fossil fuel product is imported by land transport from Thailand and Vietnam. According to the Institute of Renewable Energy, oil importation of Lao PDR has increased by 5% annually since 2000. The diesel use in the net import of fossil fuel accounted to 55%[2].

The diesel power is mainly used to supply electricity to the off-grid area in Lao PDR. The current installed capacity was estimated to be 17.5 MW, which is operated by the Provincial Department of Energy and Mines[3.]

[2] MEM, “Renewable Energy Development Strategy in Lao PDR”, 2011
[3] World Bank, “Asia Sustainable and Alternative Energy Program, Lao PDR Power to the People, Twenty Years of National

5) Renewable Energy

The potential of renewable energy sources in Lao PDR is summarized in Table 4.3.2.

Table 4.3.2 Potential and Development Plans for Renewable Energy in Lao PDR

Item	Renewable energy types	Potential	Existing	2015		2020		2025	
		MW	MW	MW	Ktoe	MW	Ktoe	MW	Ktoe
A	Electricity			140		243	85	728	416
1	Small	2000	12	80	51	134	23	400	256
2	Solar	511	1	22	14	36	8	33	21
3	Wind	>40		6	4	12	16	73	47
4	Biomass	938		13	8	24	12	58	37
5	Biogass	313		10	6	19	11	51	33
6	Solid Waste	216		9	6	17		36	23
7	Geothermal	59							
B	Biofuel	ML	ML	ML		ML		ML	
1	Ethanol	600		10	7	106	178	150	279
2	Biodiesel	1200	0.01	15	13	205	239	300	383
C	Thermal	Ktoe							
1	Biomass	227			23		29		113
2	Biogass	444			22		44		178
3	Solar	218			17		22		109
Total									
Energy demand					2504		4064		4930
Renewable Energy					172		668		1479
Proportion					7%		20%		30%

Source: Renewable Energy Development Strategy in Lao PDR, 2011

As shown in the above table, development of renewable energy for power generation is just initially undertaken. The GoL is currently promoting renewable energy development based on the development strategy to achieve 30% of total energy consumption covered by renewable energy in 2025; however it is still in a trial stage of development.

6) Power Import

Currently, Lao PDR imports 526.9 GWh of power from EGAT in year 2011. Such power import takes an important role for power supply in the central area of Laos. One of the limitations of the power import is the capacity of interconnection between EGAT and EDL. Table 2.3.3 in Chapter 2 shows the list of existing international interconnection transmission lines (see table below), except the expanded 22kV distribution lines for power import from Thailand.

Existing International Interconnection Transmission Lines

No.	Substations		Length	No. of Circuit		Voltage	Conductor	Capacity
	EDL (Area)	EGAT	(Km)	Existing	Futrue	(kV)	(Sq.mm)	(MW)
1	Phontong (Central)	Nongkhai	26	2	2	115	240	100 x 2
2	Thanaleng (Central)	Nongkhai	9	1	1	115	240	100
3	Paksan (Central)	Bungkan	11	1	2	115	240	100
4	Thakhek (South)	Nalhonphanom	10	2	2	115	240	100 x 2
5	PakBo (South)	Mukdahan 2	5	1	2	115	240	100
6	Bang Yo (South)	Sirinthon P/S	61	1	1	115	240	100

Prepared by the Study Team based on PDP 2010-2020 Revision 1

As shown in the table, the total interconnection capacity is 800 MW without N-1 criteria. This

Electrification" 2012

may be the physical constraints of imports. The power source for the power imports in EGAT is deemed to be generated by combined cycle power stations with natural gas.

4.3.2 First Screening of Options

This Study sought for a power source to mitigate the large shortfall during peak hours, such source should be exploitable and realistic for use as power generation in Lao PDR. The criteria involved in the first screening of options are potential and exploitation status. The result of the evaluation is described below:

(1) Criteria 1: Potential

Coal thermal was eliminated since the exploitable coal reserve is limited in Lao PDR. In addition, coal thermal was regarded as base power supply, which lacked flexibility to meet operation for peak power supply. Therefore, coal thermal was not appropriate for peak power supply. Other resources may not have significant problems in potential aspects.

(2) Criteria 2: Exploitation/Development Status

Renewable energy such as biomass, biofuel, solar, etc. were eliminated since renewable energy other than small hydropower was not a realistic option for bulk power supply. Laos has a biomass potential of 938 MW; however, its used as a biomass power scheme is still under the trial stage.

Large scale and small scale hydropower, and power import were not eliminated since these power serve as substantial power sources in Lao PDR. The diesel engine generators remained as these are still being used in Laos despite its small scale and heavy oil being transported using vehicles. Further, diesel engine generator option may be necessary as an urgent back up for power supply when importing power was not available.

(3) Result of 1st Screening

In summary, the coal thermal and renewable energy, except small scale hydro, were eliminated from the candidate list. The remaining options for comparative study are as follows:

- Large scale hydro (NN1 expansion);
- Small scale hydro;
- Power import; and
- Diesel engine.

4.4 COMPARATIVE STUDY OF OPTIONS

4.4.1 Outline of Each Alternative Power Source

The outline of each option is described below.

(1) NN1 Expansion as Large Scale Hydropower

1) Purpose of NN 1 Expansion

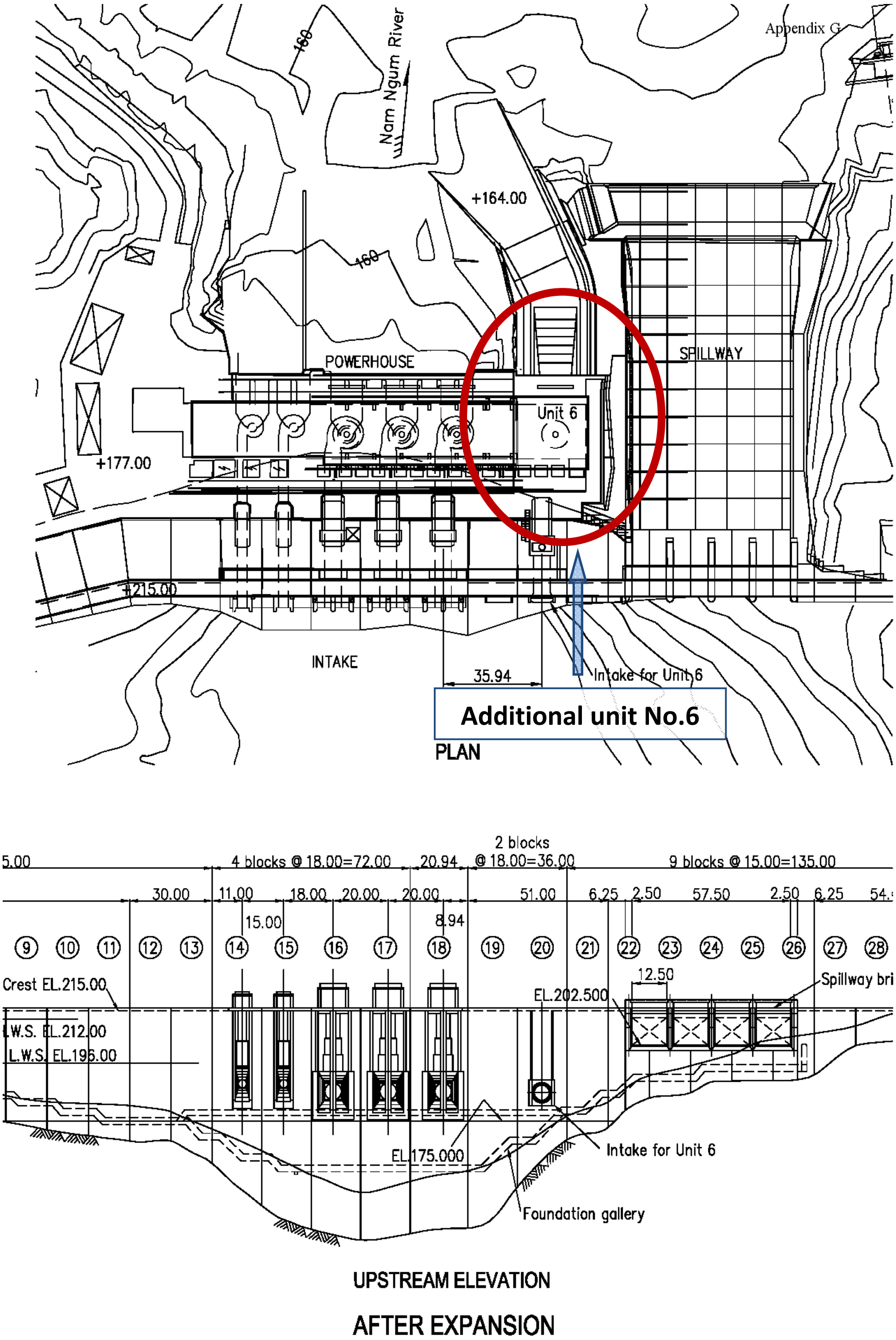
NN1 expansion was studied aiming to strengthen the power supply capacity to:

- Meet increasing power demand especially during peak hours at night; expansion of NN1 hydropower station enables to shift off-peak energy to peak hours at night by utilizing the massive NN1 reservoir capacity.
- Enable low cost maintenance as the operation hours per unit decreases.
- Enable EDL to export surplus power to EGAT during rainy season.

2) Incremental Energy

The expansion of NN1 hydropower station increased the flexibility of reservoir operation. According to the preparatory survey in 2010, annual energy production of NN1 without NN2 was 1012 GWh, which will eventually be 1071 GWh (59 GWh increase) after NN2 completion. Moreover, NN1 expansion of 40 MW will result to 1127 GWh (56 GWh increase from after NN2) in terms of annual energy production. This increment of energy will generate spilled water in the case of without expansion.

The general plan, and section of NN1 expansion plan are shown in Figure 4.4.1.



Source; Preparatory Survey on Nam Ngum 1 Hydropower Station Expansion (2010)

Figure 4.4.1 Nam Ngum 1 Expansion Plan (Additional Unit No.6)

(2) Small Scale Hydropower

As described in Section 4.3, the GoL intended to develop around 650 MW of small hydropower capacity between 2010 and 2025 through the support of private and community sectors. The current development in small scale hydropower is only 12 MW, which is 0.6% of the total hydropower potential. The existing small scale hydropower plants are listed in Table 4.4.1.

Table 4.4.1 List of Existing Small Scale Hydropower Plants in Lao PDR

Name	Location	Year	Capacity (MW)	Ownership
Selabam	Champasak	1970	5.04	EDL
Nam Dong	Luangprabang	1970	1	EDL
Nam Ko	Oudomxay	1996	1.5	EDL
Nam Ngay	Phongsali	2002	1.2	EDL
Nam Tha 3	Luangnamtha	2006	1.25	EDL
Nam Nhon	Borkeo	2011	3	EDL
Total			12.99	

Prepared by the Study Team

The developed mini/micro-hydro power in renewable energy sector is 11.5 MW; therefore, the total of small hydropower contribution is about 25 MW.

The small scale hydropower plants listed in PDP 2010-2020 (Revision -1) are shown in Table 4.4.2.

Table 4.4.2 List of Planned Small Scale Hydropower Plants in PDP in Lao PDR

Name	Location	Year	Capacity (MW)	Ownership
Nam Long	Luangnamtha	2013	5	IPP(d)
Nam Ham 2	Sayaboury	2013	5	IPP(d)
Nam Boun 2	Phongsaly	2014	15	EDL
Nam Sim	Huaphanh	2015	8.6	IPP(d)
Nam Pot	Xieng Khuang	2015	15	IPP(d)
Nam Song	Vientiane	2012	6	EDL
Nam Phao	Bolikhamxai	2012	1.6	IPP(d)
Nam Sana	Vientiane	2013	14	EDL
Nam Kane	Vientiane	2014	5	IPP(d)
Tadsalen	Savanakhet	2013	3.2	IPP(d)
Houaykaper	Saravan	2014	5	IPP(d)
Houaychampi	Champasak	2014	5	IPP(d)
Xeset 4	Champasak	2015	10	EDL
Total			98.4	

Prepared by the Study Team

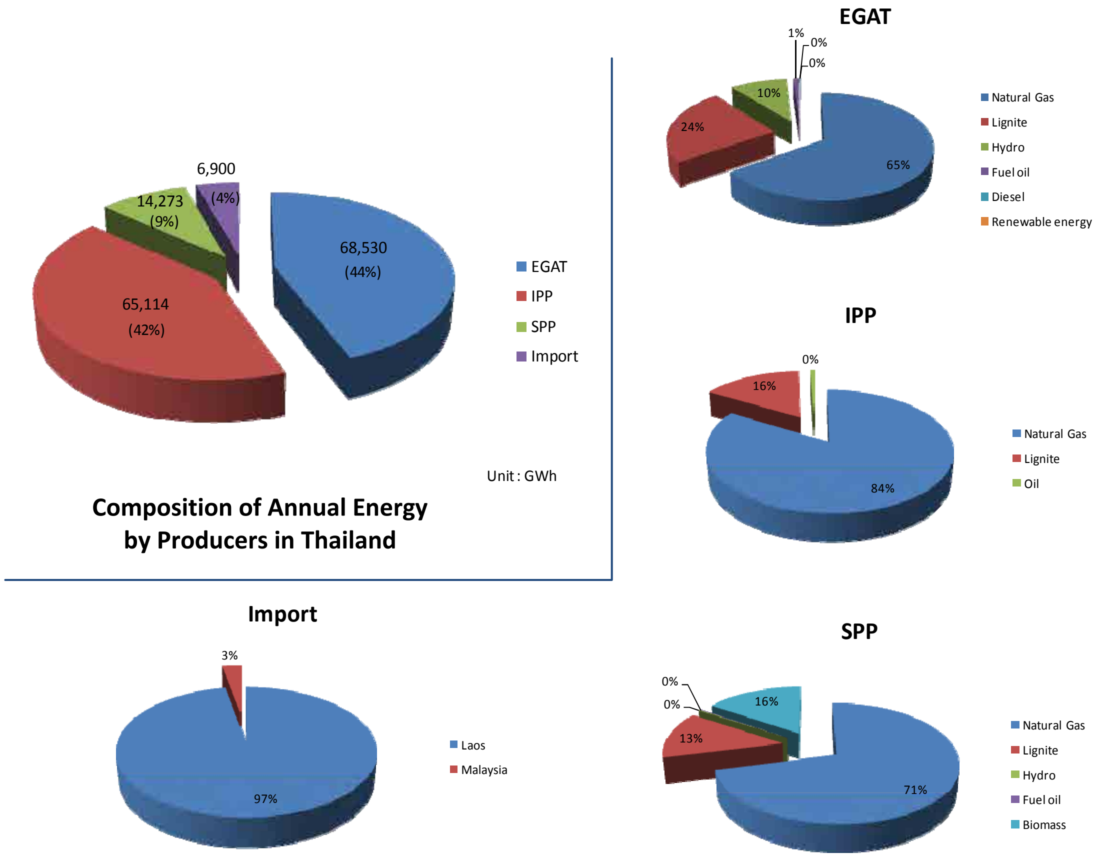
The total capacity of existing and planned small scale hydropower plants is 123.4 MW. This accumulated capacity takes substantial role in power supply although one unit capacity is small.

(3) Power Import

1) Power Supply and Demand Balance of EGAT

a. Power Supply in Thailand

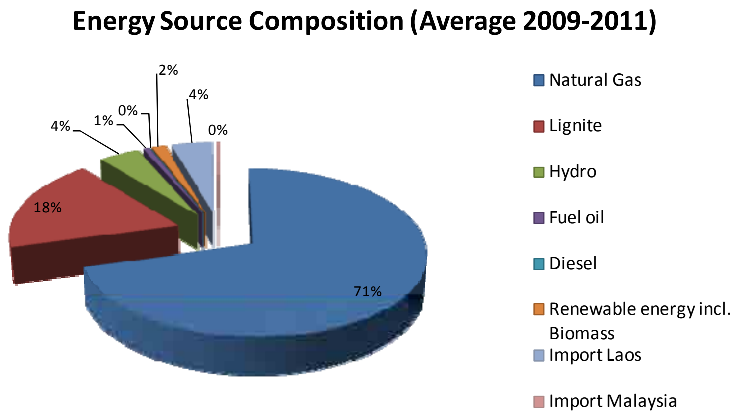
EGAT procures electricity from EGAT-own power plants, IPPs, and SPPs, and imports from Laos and Malaysia. The power sources include natural gas, lignite, hydro, fuel oil, and diesel power plants. The composition of annual energy by producers, and breakdown of power sources are shown in Figure 4.4.2.



Source: EGAT Annual Report 2011

Figure 4.4.2 Composition of Annual Energy by Producers, and Breakdown of Energy Sources in Thailand

The average overall energy source composition between 2009 and 2011 is shown in Figure 4.4.3.



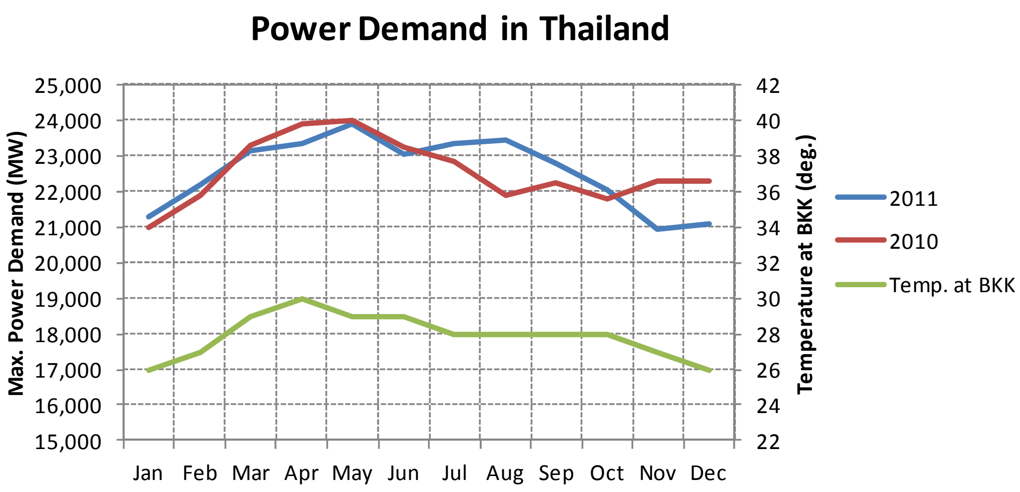
Source: EGAT Annual Report 2011

Figure 4.4.3 Energy Source Composition of EGAT from 2009 to 2011

The energy source composition in Figure 4.4.3 shows that 71% of power source is by natural gas, and 18% is by lignite; therefore, 89% of energy is produced by thermal power plant in Thailand. Lignite is sourced from domestic reserves, while Thailand is the net importer of natural gas and 30% of natural gas demand is covered by imported natural gas[4].

b. Power Demand

The monthly maximum power demand under EGAT jurisdiction is shown in Figure 4.4.4. As shown in the figure, the maximum power demand is increased from March to October, as the average temperature increases during the same period.



Source: EGAT Annual Report 2011

Figure 4.4.4 Power Demand in Thailand with Temperature in Bangkok

Figure 4.4.4 shows that power demand is peaked at April and May. These months are corresponding to the end of dry season in Laos. Power export to Laos is also peaked at these months.

4 JICA "Data Collection Study on Energy Sector in Lao PDR, Progress Report", 2012

c. Power Supply and Demand Balance in Thailand

The maximum monthly power demands and power plant capacities in Thailand were compared as shown in Table 4.4.3.

Table 4.4.3 Power Plant Capacities and Maximum Power Demands (2011)

	Capacity in MW		
Power Source	2011	2010	2009
Thermal Power (EGAT)	4,699	4,699	4,699
Combined Cycle (EGAT)	6,866	6,866	6,196
Hydropower (EGAT)	3,424	3,424	3,424
Diesel (EGAT)	4	4	4
Non-Conventional Energy (EGAT)	5	5	5
IPP	12,082	12,152	12,152
SPP	2,182	2,182	2,092
Total Capacity	31,273	31,342	30,581
Maximum Demand (MW)	23,900	24,010	22,045

Prepared by the Study Team

As shown in the table above, the total capacity of EGAT, IPP, and SPP combined exceeds the maximum power demand for approximately 7000 MW in 2009 to 2011. This 7000 MW surplus can be considered as a reserve capacity. Reserve capacity is used to calculate the reserve margin, which is a percentage of reserve capacity to maximum demand. Reserve margin of EGAT system is calculated to 30%.

Majority of energy source is natural gas for power generation. As Thailand is currently importing 30% of natural gas to serve its demand, increment of exporting energy to EDL is directly increasing the cost of power generation with imported natural gas.

2) Interconnection Capacity

There are currently four circuits of existing international interconnection transmission lines connected from central in Lao PDR to EGAT system in Thailand, as discussed in Sub-clause 3.3.2. The capacities of those circuits were simply summed up at 400 MW in total (without consideration of N-1 criteria).

Up to year 2017, the international interconnection will be reinforced with an additional circuit for 115 kV transmission line from EDL Paksan to EGAT Bungkan. and construction of new 230 kV double circuit transmission line from EDL Nabong 1 to EGAT Nonkhai, as shown in Table 4.4.4. The conductor for this 230 kV line was designed as four ACSR 630 mm^2 conductors per phase, of which the capacity was estimated at 1460 MW with N-1 criteria.

Table 4.4.4 International Interconnection between EGAT and EDL

No.	Substations		Length	No. of	Voltage	Conductor	Capacity
	EDL (Area)	EGAT	(Km)	Circuit	(kV)	(Sq.mm)	(MW)
1	Phontong (Central)	Nongkhai	26	2	115	240	100 x 2
2	Thanaleng (Central)	Nongkhai	9	1	115	240	100
3	Paksan (Central)	Bungkan	11	2	115	240	100 x 2
4	Nabong 1 (Central)	Nongkhai 2	11	2	230	4 x 630	1460 x 2

Prepared by the Study Team

(4) Diesel Power Plant

Diesel power plant is suitable as a domestic energy supply source when importing power is difficult. Lao PDR is a landlocked country where imports for primary energy are basically limited to land transport. Its petroleum product supply for transport and domestic uses is dependent on imports from neighboring countries like Thailand. The country imported approximately 2.8 million barrels of petroleum products in 2006, of which gasoline accounted for 30%, diesel fuel for 65% and heavy fuel oil for 1% (MEM information). Diesel power plant fueled with heavy oil is considered in this comparative study.

In this Study, diesel power plants were assumed to consist of middle-speed and low-speed diesel power plants, which have been exemplified in its neighboring countries like Cambodia.

4.4.2 Technical Assessment of Options

The above described four options are compared technical aspect. Options are evaluated to 3 grade rating, A is highest and C is lowest. The result is described as follows.

(1) Technical Difficulties

Technical difficulty was compared for the options. A comparison on technical difficulties is shown in Table 4.4.5.

Table 4.4.5 Technical Difficulties of Options

Option	Technical Difficulties	Rating
Large Scale Hydropower (NN1 Expansion)	Special method is required for piercing dam body	B
Small Scale Hydropower	Design should consider to avoid geological and hydrological risk	B
Diesel Power Plant	Little difficulty for technical aspect for design and installation	A
Power Import	N/A*1	N/A

Note;) *1: Technical difficulty may not be applicable since this option simply import power using existing T/L.
Prepared by the Study Team

(2) Survey Maturities of Options

Survey maturities are the degree of survey implemented for development. A comparison on availability of energy source is shown Table 4.4.6.

Table 4.4.6 Survey Maturities of Options

Option	Survey Maturities	Rating
Large Scale Hydropower (NN1 Expansion)	Basic Design	A
Small Scale Hydropower	Need Site Survey	C
Diesel Power Plant	Need Site Survey	B*1
Power Import	Study is not required*2	N/A

Note;) *1: Site selection of diesel power plant is rather simple than hydro; therefore rated "B".
*2: Study is not required unless the power import is less than the interconnection capacity.
Prepared by the Study Team

(3) Lead time for construction

Lead time for construction considered survey works prior to undertaking construction. Procurement of funds and environmental issues were not considered.

Table 4.4.7 Lead Time of Options

Option	Lead Time	Rating
Large Scale Hydropower (NN1 Expansion)	1.5 year for D/D and Bidding & Procurement for NN1 Expansion	A
Small Scale Hydropower	5 years from potential survey to procurement	B
Diesel Power Plant	0.5 year for procurement	A
Power Import	No lead time (already contracted with EGAT)	A

Prepared by the Study Team

(4) Life Span

Life spans of the options are shown in Table 4.4.8.

Table 4.4.8 Life Spans of Options

Option	Life Span (years)	Rating
Large Scale Hydropower (NN1 Expansion)	50 to 100	A
Small Scale Hydropower	50 to 100	A
Diesel Power Plant	10 to 20	C
Power Import	-	A

Prepared by the Study Team

(5) Summary of Technical Assessment

A comparative study for the technical aspects are shown in Table 4.4.9.

Table 4.4.9 Summary of Technical Assessment of Options

Options	Technical Difficulties	Survey Maturities	Lead Time	Life Span	General Rating for Technical Assessment
Large Scale Hydropower (NN1 Expansion)	B	A	A	A	A
Small Scale Hydropower	B	C	B	A	B
Diesel Power Plant	A	B	A	C	B
Power Import	N/A	N/A	A	A	A

Prepared by the Study Team

4.4.3 Comparison of Energy Security of Options

In this Study, the Study Team considered energy security for self-sufficiency, power supply stability, and availability of energy source for long term span.

(1) Self-sufficiency

Degree of self-sufficiency for each option was compared as shown in Table 4.4.10.

Table 4.4.10 Degree of Self-sufficiency of Energy of Each Option

Option	Self-Sufficiency	Rating
Large Scale Hydropower (NN1 Expansion)	100% domestic energy	A
Small Scale Hydropower	100% domestic energy	A
Diesel Power Plant	0% (resource are all imported)	C
Power Import	0% (resource are all imported)	C

Prepared by the Study Team

(2) Power Supply Stability

Power supply stability entailed availability of resource to meet peak hours. Comparison of each option is shown in Table 4.4.11.

Table 4.4.11 Power Supply Stability of Each Option

Option	Supply Stability	Rating
Large Scale Hydropower (NN1 Expansion)	Reservoir type hydropower is stable for power supply especially peak power supply	A
Small Scale Hydropower	The power output will be significantly dropped in dry season.	B
Diesel Power Plant	Diesel power is suitable for peak power supply.	A
Power Import	Power is imported following the daily load.	A

Prepared by the Study Team

(3) Long Term Availability of Energy Source

Long term availability of energy source was assessed in view of 1) supply stability and 2) sufficient reserve volume. A comparison in terms of availability of energy source is shown in the table below.

Table 4.4.12 Long Term Availability of Energy Sources of Each Option

Option	Supply Stability	Reserves	Rating
Large Scale Hydropower (NN1 Expansion)	B(long term fluctuation)*3	A	B
Small Scale Hydropower	B	A	B
Diesel Power Plant	C*1	C*1	C
Power Import	B	B*2	B

Note;) *1: As Lao PDR imports fossil fuel from other countries, delivery is by land transport. The long transportation route is affects the rating.
*2: As Thailand is importing natural gas for 30% of its demand, reserves are a “B” rating.
*3: long term fluctuation is cycle more than one year such as climate change.

Prepared by the Study Team

(4) Summary of Energy Security

A comparative study on energy securities is shown in Table 4.4.13.

Table 4.4.13 Summary of Energy Security Comparison for Each Option

Options	Self-sufficiency	Power Supply Stability	Long Term Availability	General Rating for Energy Securities
Large Scale Hydropower (NN1 Expansion)	A	A	B	A
Small Scale Hydropower	A	B	B	B
Diesel Power Plant	C	A	C	C
Power Import	C	A	B	B

Prepared by the Study Team

4.4.4 Cost Comparison of Options

The cost data of each option were considered in the cost comparison. For power sources which do not have precedents in Lao PDR such as those from diesel power plants, available cost in neighboring countries were used as reference in this Study. The cost was evaluated considering price range due to variety of unit size, fuel materials, and so on.

(1) NN1 Expansion as a Large Scale Hydropower

According to the preparatory survey of NN1 expansion in 2010, the total construction cost was estimated to be USD 64.7 million, while O&M cost was USD 0.3 million. Based on this, the development cost can be calculated as USD 1618/kW for this expansion case.

(2) Small scale hydropower

The development cost of small scale hydropower in Lao PDR was generally estimated to range from USD 2525-4694/kW[5]. Meanwhile, O&M cost was estimated as USD 4–90/kW/year.

(3) Power Import

The power tariff of the power import is as follows:

	Period	Normal (THB/kWh)	Emergency (THB/kWh)
Peak	09.00-22.00h	1.74	1.60
Off peak	22.00 – 09.00h	1.34	1.20

In addition, EDL must pay for the excess surcharge in case its annual import exceeded the export amount. The surcharge payment was calculated based on the domestic tariff in Thailand. This indicates that the excess import by EDL is virtually charged with prices similar to those for electricity customers in Thailand. For instance in 2010, THB 1.30/kWh was charged to EDL as surcharge for its excess import, in addition to the basic tariff payments. This surcharge tariff is varied dependent on the maximum monthly energy in a year.

(4) Diesel Power Plant

The cost of the diesel power plant was assumed to the middle to low speed diesel power plant, which

[5] MEM, "Renewable Energy Development Strategy in Lao PDR", 2011

has been used in the neighboring countries. For comparison purposes, diesel power cost applicable in Cambodia was used. The construction cost of diesel power plant was estimated to be around USD 960 /kW. The unit cost of power generation was estimated at USD 148/MWh.

In summary, the cost comparison of the options is shown in Table 4.4.14.

Table 4.4.14 Cost Comparison of Options

	Development Cost (USD/kW)	O&M Cost (USD/kW/year)	Unit Cost of Power Generation (USD/MWh)	Rating
Large Scale Hydro (NN1 Expansion)	1620	7.5	40-80	B
Small Scale Hydro*2	2500-4700	4-90	40-80	C
Diesel Engine	960	-	148	C
Power Import	Peak (THB/kWh) 1.74	Off Peak (THB/kWh) 1.34		A*1

Note;) *1: Rating “A” is conditional as power import tariff is set to a quite low rate, which assumes mutual interchange.
*2: Referred from “Renewable Energy Development Strategy in Lao PDR”, 2011, MEM.
Prepared by the Study Team

Among other power source options, power import from EGAT was apparently the most cost-efficient option. As analyzed in Section 5.6.2, NN1 expansion’s benefit-cost (B/C) ratio was estimated at 0.47 by taking the power trade surplus as an economic benefit. However, the power trade between EDL and EGAT was regarded as mutual interchanges under the international cooperation; and the export and import tariff may not fully represent the actual cost of power supply. In fact, EGAT charged much more expensive rates (Peak: THB 3.8376/kWh, Off-peak: THB 2.3966/kWh) to domestic customers. If said economic analysis applies these EGAT domestic tariff rates as benefits, the B/C ratio of the expansion project will go up to around 1.1, which indicates that the expansion has more economic viability than the power trade option.

4.4.5 Assessing from the Natural and Social Environmental Aspects

(1) Natural Environment

- Air Quality

Impact on the air quality from electricity generation options was studied, taking the concept of life-cycle assessment (LCA) into account. Emissions of SO2 and NOx were assessed from extraction, processing and transportation of fuels, building of power plants, production of electricity, waste disposal, refurbishment, and decommissioning. Result of assessment is shown in Table 4.4.15.

In the case of increased capacity on existing hydropower option, it may not increase the energy produced, and would therefore have an infinite level of environmental impact per kWh (impact would be divided by zero kWh). Accordingly, the option of increase capacity on existing hydropower will affect any negative impact on air quality.

Similar to the option of increased capacity on existing hydropower, power import option may not increase the energy produced and thus, no emission of SO2 and NOx is expected. Accordingly, this option was also rated as A in terms of negative impact on air quality. In the column for power import, emission data on natural gas was also presented as a resource of generating electricity for power import, for reference.[6]

Table 4.4.15 Life-Cycle Emissions of SO2 and NOx

Options	SO2 (t SO2 /TWh)	NOx (t NOx/TWh)	Rating
Increased Capacity on Existing Hydropower	0	0	A
Small Hydro (<10MV)*	25	68	B
Diesel Engine (Heavy Oil)	8013 to9595+	1386+	C
Power Import (Natural Gus)	0 (4 to 15000+)	0 (13+ to 1500)	A (C)

*Data is in the case of less than 10 MV capacity small hydro plant
** Data of SO2 and NOx are from "IEA May 2000. Hydropower Agreement Annex III Volume II: Main Report Chapter3 Comparative Environmental Analysis of Power Generation Option".
Prepared by the Study Team

- CO2 Emission

Similar to the impact on air quality, CO2 emission from the electricity generation was studied taking the concept of LCA into account. The result is shown in Table 4.4.16

The option of increased capacity on existing hydropower emits no CO2 because there would be no expected energy increase. Similar to the option of increased capacity on existing hydropower, power import option may not increase the energy produce as well, thus CO2 will not be emitted. Accordingly, this option was also rated as A.

Table 4.4.16 Life-Cycle Emissions of CO2

Options	CO2 (kt eq.Coe/TWh)	Rating
Increased Capacity on Existing Hydropower	0	A
Small Hydro (<10MV)*	9	B
Diesel Engine (Heavy Oil)	555 to 883	C
Power Import (Natural Gas)	0 (389 to 511)	A (C)

*Data is in the case of less than 10 MV capacity small hydro plant
** Data from "IEA May 2000. Hydropower Agreement Annex III Volume II: Main Report Chapter 3 Comparative Environmental Analysis of Power Generation Option".
Prepared by the Study Team

- Water Quality

Impacts on water quality from the options were evaluated considering two parameters, namely, severity of consequences and immitigability. The result is shown in Table 4.4.17

The option of power import has no impact on water quality. The increased capacity on existing hydropower will make small impact on water quality. In all options, expected severity of

[6] According to the annual report of EGAT 2011, the source of electricity generation comprised 88.3% from thermal power, and 11.7% from hydropower. The fuel source of thermal power comprised 76% from natural gas, 21% from lignite, 1.2% from fuel oil, and 1.8 % from others. In this Study, natural gas is to be considered as the source of electricity generation for the option "power import" because of its dominance in fuel share for electricity generation in Thailand.

consequences ranges from low to medium, which can be minimized with appropriate mitigation measures.

Table 4.4.17 Impacts on Water Quality

Options	Possible Negative Impacts	Severity of Consequences	Immitigability	Rating
Increased Capacity on Existing Hydropower	-Modification to the flow regime	Low	Low	B
Small Hydro	-Release from reservoirs of anoxic water -Modification of the thermal regime -Proliferation of waterborne diseases in shallow stagnant areas -Increased turbidity associated with bank erosion -Modification to the flow regime	Low	Low	B
Diesel Engine (Heavy Oil)	-Waste from cleaning of boiler and flue-gas desulfurization -Thermal pollution	Medium	Low	C
Power Import (Natural Gas)	-Waste from boiler cleaning -Thermal pollution	None (Medium)	None (Low)	A (C)

Prepared by the Study Team

- Wastes

Impact from wastes among options was evaluated considering the expected type of emitted wastes and its amount. The result is shown in Table 4.4.18.

The option of increased capacity on existing hydropower and power import did not cause any impact on the increase of wastes from existing hydropower plant. The wastes emitted from small hydro were mostly organic matters. The wastes emitted from diesel engine include chemical compounds.

Table 4.4.18 Type and Amount of Wastes

Options	Type of Waste	Amount	Rating
Increased Capacity on Existing Hydropower	No	No	A
Small Hydro	-Drifting objects (mostly organic waste) -Sediment (organic waste) -Sludge (organic waste)	Depends on the scale	B
Diesel Engine (Heavy Oil)	-Burned ash (includes toxic chemical compounds) -Sludge	Depends on the scale	C
Power Import (Natural Gas)	No Emission (sludge)	No (Depends on the scale)	A (C)

Prepared by the Study Team

- Ecosystem

The impact on ecosystem from the options was evaluated considering three levels: 1) local and regional ecosystems; the various habitat directory affected by the project, 2) biomass; the largest ecological units, generally defined accruing to dominant vegetation, and 3) genetic diversity at world level; the protection of endangered species. The result is shown in Table 4.4.19

Power import caused the least impact on ecosystem. The impact from increased capacity on existing hydropower and small hydro is site-specific. The impact from the option on the use of diesel engine is climate change, which would have a negative effect at the global level.

Table 4.4.19 Impact on Ecosystem

Options	Source of Final Significant Impacts on Biodiversity	Local and Regional Ecosystems	Biomass	Genetic Diversity at World Level	Rating
Increased Capacity on Existing Hydropower	-Modification of water flow	X			A
Small Hydro	-Barriers to migratory fish -Loss of terrestrial habitat -Change in water quality -Modification of water flow	X X X X			B
Diesel Engine (Heavy Oil)	-Change in water quality -Climate change -Acid precipitation	X X X	X	X	B
Power Import (Natural Gas)	-Change in water quality -Climate change -Acid precipitation	(X) (X) (X)	(X)	(X)	A (B)

*Data from "IEA May 2000. Hydropower Agreement Annex III Volume II: Main Report Chapter 3 Comparative Environmental Analysis of Power Generation Option".
Prepared by the Study Team

- Natural Resource Consumption

The natural resource consumption from options was evaluated considering the type of energy resource and availability at the local level. The result is shown in Table 4.4.20.

The options of increased capacity on existing hydropower and small hydro use water as an energy resource. Because water is renewable and is highly available at the local level, these options have the least impact on the natural resource consumption.

Table 4.4.20 Types of Energy Resource and Its Availability at Local Level

Options	Type of Energy Resource	Availability at Local Level	Rating
Increased Capacity on Existing Hydropower	Water (renewable)	High	A
Small Hydro	Water (renewable)	High	A
Diesel Engine (Heavy Oil)	Diesel (nonrenewable)	No	B
Power Import (Natural Gas)	Natural Gas (nonrenewable)	No	B

Prepared by the Study Team

A summary of comparative study assessed from the natural environmental point of view is shown in Table 4.4.21.

Table 4.4.21 Summary of the Comparative Study from the Natural Environmental Point of View

Options	Description	Rating
Increased Capacity on Existing Hydropower	-Not increase energy thus no emission of CO2, SO2, or NOx -Negative impact is expected on water flow -Negative impact is site-specific -Type of energy resource is renewable	A
Small Hydro	-Very low emission of CO2, SO2, and NOx -Negative impact is expected on water quality and ecosystem -Emitted waste is mostly organic -Negative impact is site-specific -Type of energy resource is renewable	C
Diesel Engine (Heavy Oil)	-Emission of CO2, SO2, and NOx are expected -Negative impact is expected on water quality and ecosystem -Emitted waste includes toxic chemical compounds -Negative impact is not site-specific -Type of energy resource is nonrenewable	C
Power Import (Natural Gas)	-Not increase energy thus no emission of CO2, SO2, or Nox in Laos - Emission of CO2, SO2, or Nox is expected in Thailand -Type of energy resource is non renewable	B

Prepared by the Study Team

(2) Social Environment

- Resettlement

The impact on resettlement for each option was evaluated considering land requirement, severity of consequences, and immitigability. The result is shown in Table 4.4.22.

No impact was expected from the increased capacity on existing hydropower option and power import because no land was required for the project. The options, small hydro, and diesel engine, will need land acquisition for constructing power plants and related facilities; however, the impact can be minimized through appropriate mitigation measures.

Table 4.4.22 Impacts on Resettlement

Options	Land Requirement (km2/TWh/y)**	Severity of Consequences	Immitigability	Rating
Increased Capacity on Existing Hydropower	0	None	None	A
Small Hydro (<10MV)*	2- 152	Low	Low	C
Diesel Engine (Heavy Oil)	-	Low	Low	C
Power Import	0	None	None	A

*Data is in the case of less than 10 MV capacity small hydro plant
**Data from “IEA May 2000. Hydropower Agreement Annex III Volume II: Main Report Chapter 3 Comparative Environmental Analysis of Power Generation Option”.
Prepared by the Study Team

- Agriculture

The impact on agriculture for each option was evaluated considering possible negative impacts, land requirements, and probability of occurrence. The result is shown in Table 4.4.23.

No impact was expected from the increased capacity on existing hydropower option and power import because no land was required for the project. The option, small hydro and diesel engine, will need land acquisition for constructing power plants and related facilities. Moreover, the small hydro option will cause impacts on water availability and water quality. Meanwhile, the diesel engine option will cause acid precipitation and climate change.

Table 4.4.23 Impacts on Agriculture

Options	Possible Negative Impact	Land Requirement (km2/TWh/y)**	Probability of Occurring	Rating
Increased Capacity on Existing Hydropower	-Loss of land -Water availability -Water quality	0	None	A
Small Hydro (<10 MV)	-Loss of land -Water availability -Water quality	2- 152*	X X X	B
Diesel Engine (Heavy Oil)	- Loss of land -Acid precipitation -Climate change	-	X X X	B
Power Import	- Loss of land	0	None	A

*The data is in the case of less than 10 MV capacity small hydro plant
**Data from "IEA May 2000. Hydropower Agreement Annex III Volume II: Main Report Chapter 3 Comparative Environmental Analysis of Power Generation Option".
Prepared by the Study Team

- Fishery

The impact on fishery for each option was evaluated considering possible negative impacts, severity of consequences, and immitigability. The result is shown in Table 4.4.24

No impact was expected from power import for the project. The option of small hydro caused the biggest impact on fishery because it affects migration of fish, water quality, and water flow.

Table 4.4.24 Impacts on Fishery

Options	Possible Negative Impact	Severity of Consequences	Immitigability	Rating
Increased Capacity on Existing Hydropower	-Modification to the flow regime	None	None	A
Small Hydro	-Release from reservoirs of anoxic water -Barriers to migratory fish -Modification of the thermal regime -Proliferation of waterborne diseases in shallow stagnant areas -Increased turbidity associated with bank erosion -Modification to the flow regime	High	Medium	C
Diesel Engine (Heavy Oil)	-Polluted water from cleaning of boiler and flue-gas desulfurization -Thermal pollution	Medium	Low	B
Power Import	None	None	None	A

Prepared by the Study Team

- Tourism

The impact on tourism for each option was evaluated considering possible negative impacts, severity of consequences, and immitigability. The result is shown in Table 4.4.25.

No impact was expected from increased capacity on existing hydropower and power import. The option of small hydro caused the biggest impacts on tourism activities such as fishing, trekking, rafting, kayaking, and landscape. However, the newly constructed reservoir for small hydro could create options for tourism activities.

Table 4.4.25 Impacts on Tourism

Options	Possible Negative Impact	Severity of Consequences	Immitigability	Rating
Increased Capacity on Existing Hydropower	-Fishing -Rafting and Kayaking -Landscape	None	None	A
Small Hydro	-Fishing -Trekking -Rafting and Kayaking -Landscape	Medium	Medium	C
Diesel Engine (Heavy Oil)	-Fishing -Landscape	Medium	Low	B
Power Import	None	None	None	A

Prepared by the Study Team

- Human Health

The impact on human health for each option was evaluated considering possible impacts to human health, severity of consequences, and immitigability. The result is shown in Table 4.4.26.

No impact was expected from increased capacity on existing hydropower and power import. The option, diesel engine, caused the biggest impacts to human health; however, such impact can be minimized through appropriate mitigation measures.

Table 4.4.26 Impacts on Human Health

Options	Source of final significant impact on human health*	Severity of Consequences	Immitigability	Rating
Increased Capacity on Existing Hydropower	None	None	None	A
Small Hydro	-Breach of dams	High	Low	B
Diesel Engine (Heavy Oil)	-Acid precipitation -Photochemical smog -Particulate matter -Climate change	High	Low	C
Power Import (Natural Gas)	None (-Acid precipitation) (-Photochemical smog) (-Climate change)	None (High)	None (Low)	A (C)

*Data from "IEA May 2000. Hydropower Agreement Annex III Volume II: Main Report Chapter 3 Comparative Environmental Analysis of Power Generation Option".
Prepared by the Study Team

A summary of the comparative study assessed from social environmental points of view is shown in Table 4.4.27.

Table 4.4.27 Summary of the Comparative Study from the Social Environmental Points of View

Options	Description	Rating
Increased Capacity on Existing Hydropower	-No land acquisition -No negative impact on agriculture, fishery, tourism or human health	A
Small Hydro	-Land acquisition is expected -Negative impact is expected on agriculture, fishery, tourism	C
Diesel Engine (Heavy Oil)	-Land acquisition is expected -Negative impact is expected on agriculture, fishery, tourism	C
Power Import (Natural Gas)	-No land acquisition -No negative impact on agriculture, fishery, tourism or human health	A

Prepared by the Study Team

4.4.6 Comparison Result of Options

The comparison results of the options are summarized below.

Table 4.4.28 Comparison Results of Options

Options	Technical Assessment	Energy Securities	Cost	Environment	General Rating by Score
Large Scale Hydropower (NN1 Expansion)	A	A	B	A	11
Small Scale Hydropower	B	B	C	C	6
Diesel Power Plant	B	C	C	C	5
Power Import	A	B	A	B	10

Note) General rating by score is aggregates of points by assuming A = 3 pts, B = 2 pts, and C = 1 pt.
Prepared by the Study Team

According to the above comparison table, power import and large scale hydro (NN1 expansion in this case) have almost the same rating. NN1 expansion however has a slightly better score. The NN1 expansion is advantageous in terms of energy securities, but the cost comparison has lower score than that of power import option. However, as it is noted in Section 4.4.4, this result was due to the low tariff rate determined under mutual interchanges as well as international cooperation. EGAT charged much more expensive rates (Peak: THB 3.8376/kWh, Off-peak: THB 2.3966/kWh) to domestic customers. If said economic analysis applies these EGAT domestic tariff rates as benefits, the B/C ratio of the expansion project will go up to around 1.1, which indicates that the expansion has more economic viability than the power trade option.

Therefore, it was concluded that the large scale hydropower development considering NN1 expansion was the first priority project to strengthen the peak power supply capacity. Subsequently, the power import, small scale hydropower and diesel power plant followed.

Although the power import is ranked in second, power import from EGAT is still important for power supply of EDL. Importing from EGAT is important with respect to the power supply reliability for EDL. The detail of role of power import to EDL is described in Chapter 7.1.1.

4.5 CONCLUSION OF COMPARATIVE STUDY OF OPTIONS

A comparative study was carried out among the possible candidate options in Lao PDR. After the screening and subsequent comparative study, it was concluded that NN1 expansion was the first option to strengthen the peak power supply in the central area.

However, it does not mean that the power import option should be abandoned as it still takes a substantial role in power supply in the central area. In 2017, over 700 MW power should be imported although the NN1 expansion scheme is implemented. It is noted that the power supply capacity should be developed continuously to meet the increasing power demand in Lao PDR.