Nepal Electricity Authority
Nepal

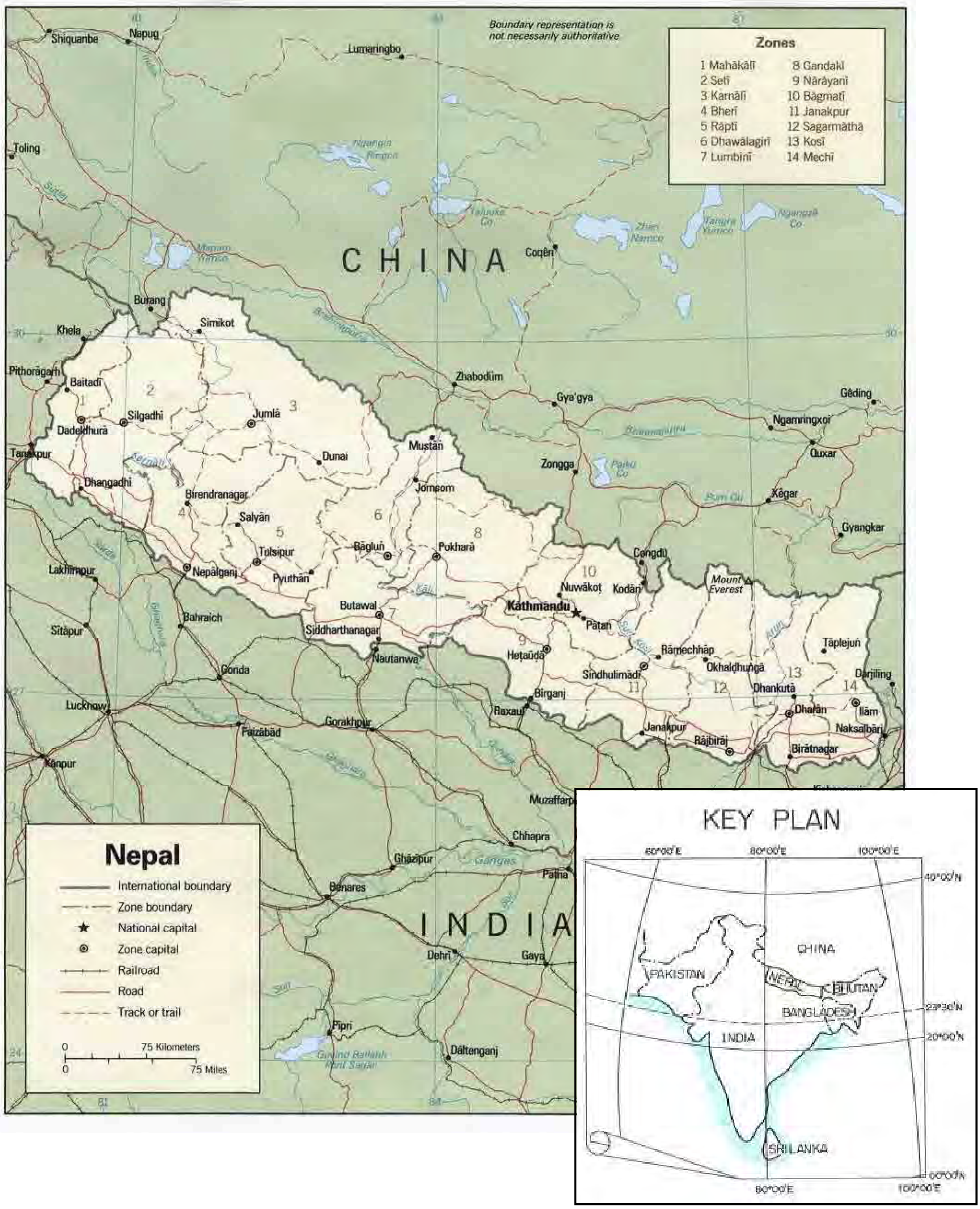
Nationwide Master Plan Study on Storage-type Hydroelectric Power Development in Nepal

Final Report Summary

February 2014

Japan International Cooperation Agency

Electric Power Development Co., Ltd.



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ABBREVIATION

ADB	Asian Development Bank
AR	Autonomous Region
CA	Conservation Area
CFRD	Concrete Faced Rockfill Dam
CITES	Convention on International Trade in Endangered Species of Wild Fauna and Flora
CIWEC	Canadian International Water and Energy Consultants
CPI	Consumer Price Index
CR	Critically Endangered
DD	Detailed Design
Df/R	Draft Final Report
DHM	Department of Hydrology and Meteorology
DOED	Department of Electricity Development
DP	Dynamic Programming
EDF	Électricité de France
EIA	Environmental Impact Assessment
EIRR	Economic Internal Rate of Return
EMP	Environmental Management Plan
EN	Endangered
ENS	Energy Not Supplied
ETFC	Electricity Tariff Fixation Committee
F/R	Final Report
FAO	Food & Agriculture Organization of the United Nations
FGD	Focus Group Discussion
FIRR	Financial Internal Rate of Return
FS (F/S, F.S.)	Feasibility Study
FY	Fiscal Year
GDP	Gross Domestic Product
GIS	Geographical Information System
GLOF	Glacial Lake Outburst Flood
GON	Government of Nepal
GS	Gauging Station
HFT	Himalayan Frontal Thrust
HPP	Hydroelectric Power Plant
HR	Hunting Reserve
HSRS	Hydrosuction Sediment Removal System
Ic/R	Inception Report
ICIMOD	International Centre for Integrated Mountain Development
IDA	International Development Association
IDC	Interest during Construction
IEE	Initial Environmental Examination
IMF	International Monetary Fund
INPS	Integrated Nepal Power System

IPP	Independent Power Producer
IPP	Indigenous People Plan
ISC	International Seismological Center
It/R	Interim Report
IUCN	International Union for Conservation of Nature
JCWR	Nepal-India Joint Committee on Water Resources
JICA	Japan International Cooperation Agency
JPY	Japanese Yen
JSTC	Nepal-India Joint Standing Technical Committee
KBA	Key Biodiversity Area
KIS	Key Informant Survey
LA	Loan Agreement
LC	Least Concern
LNG	Liquefied Natural Gas
LOLP	Loss of Load Probability
Lu	Lugeon value
M	magnitude
Ma	million annum (million years ago)
MBT	Main Boundary Thrust
MCM	Million Cubic Meter
MCT	Main Central Thrust
MFT	Main Frontal Thrust
MHT	Main Himalayan Thrust
MOL	Minimum Operating Level
MOWR	Ministry of Water Resources
MP (M.P.)	Master Plan
MWI	Monsoon Wetness Index
NEA	Nepal Electricity Authority
NEDIN	Nepal Federation of Indigenous Nationalities
NERC	Nepal Electricity Regulatory Commission
NESS	Nepal Environmental and Scientific Services Ltd.
NGO	Nongovernmental organization
NP	National Park
NP BZ	National Park Buffer Zone
NRs	Nepalese Rupee
NSC	National Seismological Centre
NT	Near Threatened
ODA	Official Development Assistance
OJT	On-the-JOB Training
PMF	Probable Maximum Flood
PPA	Power Purchase Agreement
Pr/R	Progress Report
Pre FS (Pre-FS)	Pre Feasibility Study
PROR	Peaking run-of river
PS (P/S)	Power Station

RAP	Resettlement Action Plan
RESCON	Reservoir Conservation
ROR	Run-of-river
RQD	Rock Quality Designation
Rs (Rs.)	Rupee
S/W	Scope of Work
SAARC	South Asian Association for Regional Cooperation
SEA	Strategic Environmental Assessment
SHM	Stakeholder Meeting
SS (S/S)	Substation
STDF	South Tibetan Detachment Fault
STDS	South Tibetan Detachment System
STO	Storage
TAR	Tibet Autonomous Region
TL	Transmission Line
TOD	Time of Day
TOE (toe)	Tonnes of oil equivalent
UNDP	United Nations Development Programme
USAID	United States Agency for International Development
VDC	Village Development Committee
VU	Vulnerable
WASP	Wien Automatic System Planning Package
WB	World Bank
WDPA	World Database on Protected Areas
WECS	Water and Energy Commission Secretariat
WR	Wildlife Reserve
WR BZ	Wildlife Reserve Buffer Zone

Chapter 1 Introduction

1.1 Background

The Federal Democratic Republic of Nepal (hereinafter referred to as "Nepal") is located between 80^{o} 4' and 88^{o} 12' East longitude and 26^{o} 22' and 30^{o} 27' North latitude and is a land locked country, comprising a total of 147,181 km^2 of land, with an average length of 880 km east to west and an average breadth of 190 km from north to south. The country is bordered by India on the East, South, and West, and China on the North, while the elevation of the land ranges from 90 to 8,848 m.

The population of Nepal, as estimated by the Central Bureau of Statistics (CBS), was recorded at 26.49 million in FY 2011/2012. The population growth was recorded at 1.35% per annum. The population distribution is 50.27% in the Terai region, 43% in the Hills and mid-mountain region and 6.73% in the Himalayan region.

The GDP per capita is about US $735 in FY 2011/2012 fiscal year. The GDP growth rate is staying at 3.8% (CBS, FY 2011/2012) due to the influence of rolling blackouts for a long time to a normal state and prolonged political turmoil, while in recent years, major SAARC countries have achieved economic growth of more than 5%.

The main industry is agriculture, accounting for about 33.0 percent of GDP, about 65.7% of the working population (FY2009/2010). Tourism and textile processing industry are core businesses following agriculture. Tourism is a key means of foreign currency acquisition, accounting for more than 20% of the acquisition of foreign currency before 1996 when the national conflict began, however it was reduced to 10% or less since 2002 by the decrease in the amount of tourists. However, the number of tourists mainly from China and India increased with the restoration of civil order, and more than 500,000 tourists visited in 2007, the most ever. Tourism is being revived by governmental policy.

Major exports are industrial products, ready-to-wear items, carpets, and food such as tea and spices. India, the U.S., Bangladesh and Germany are the main export destinations. On the other hand, the main imports are petroleum products, industrial products, gold, silver, food and food processing, etc., and countries such as India, China, the United Arab Emirates and Indonesia are major sources of imports. Every year the import surplus is expanding, and the trade deficit of FY 2009/2010 had reached US$ 5.08 billion (32.0% of the GDP ratio). The mechanism is to cover the deficit in grants and foreign remittances mainly from overseas migrant workers. Since the largest partner is India in terms of both exports and imports, maintaining friendly relations with India has a vital importance.

Nepal is rich in water resources, its potential water power is 83,000 MW and economically exploitable water power is 42,000 MW. As of the end of FY2012/13, however, the total installed capacity of the existing hydroelectric power stations is only about 709 MW. In addition, since most of hydroelectric power plants are run-of-river type, their output decrease seriously in dry seasons. Consequently, rolling blackouts of as long as 14 hours a day are implemented and it poses many problems for living conditions and economic activity. To cope with these circumstances, the government of Nepal worked out a "National Electricity Crisis Resolution Action Plan" and "10-Year Hydropower Development Task Force" at the end of 2008. These projects declare that it is absolutely necessary to construct storage-type hydroelectric power plans which are able to supply electricity stably even in dry seasons to solve the current power shortage at an early date.

However, construction of storage-type hydroelectric power plants should be carried out systematically taking into consideration the consistency of overall water development, hydrological and geological characteristics, environmental impact, etc. Therefore, the government of Nepal requested the government of Japan to work out a nationwide master plan for storage-type hydroelectric power development.

1.2 Purpose of Study

This Study will contribute to solving problems like power shortage and the seasonal change of power output by moving ahead with hydroelectric power development with due consideration for social and natural environment based on the above-mentioned master plan, and it will also contribute to improving the environment of daily life and economic activity in Nepal.

In addition, technology transfer and human resource development on storage-type hydroelectric power development are intended through cooperative work with officials of the Nepalese government.

1.3 Scope of Study

The scope of the Study is based on the above-mentioned Scope of Work agreed between the Government of Nepal and the Japan International Cooperation Agency (JICA) in June 30, 2011.

The Study aims at preparation of a master plan for storage-type hydroelectric power development for domestic demand in Nepal as mentioned below.

- To prepare a power development plan for 20 years from 2013, and clarify the importance of storage-type hydroelectric power development.
- To select promising storage-type hydroelectric power projects from 65 potential projects listed in the long list prepared by the NEA, taking into account technical, environmental, economical and financial issues. The development scale of these promising projects should be about 100 MW to 300 MW. The long list is attached at the end.
- To study the order of development, development scale and timing, methods of funding, etc. of the promising projects and to prepare a master plan for storage-type hydroelectric power development for the next two decades.

Further, the target values in existing power development plans are deemed as conditions not given in this Study. The optimization of the power development plan is to be implemented based on the power demand forecast in consideration of the GDP growth ratio of each sector, the forecasted price increase of electricity and so on.

In addition, since a storage-type hydroelectric power project accompanies a large-scale development, the impact on the natural and social environment is generally large. Therefore, an attention will be paid to select a promising site with the maximum consideration to the impact on the natural and social environment from an early stage of project formulation through the Strategic Environmental Assessment (SEA), and to pay attention to the cumulative impact in case that development has progressed in the future.

Chapter 2 Power Demand Forecast

2.1 Objective

The objective of the power demand forecast is to forecast the 20-year evolution of power demand by setting the model parameters representing the following economic, policy and technical factors of the power market: 1) the future path of economic development in Nepal, 2) the pricing scenarios developed to ease market distortion in order to attract private sector investment, 3) a modality to handle the lost electricity demand because of intensive power shedding, and 4) the way to handle assumed damage caused by the load shedding to the industry and service sectors. In addition to the above factors, the NEA's and IPPs' future electricity supply plans, efficiency improvement of the NEA's core businesses, assumed power generation, purchase and power trade portfolio, and generation facility development schedules were examined to set the values of the parameters. In the master plan, the demand forecast was optimized based on the proposed power development master plans.

2.2 Current Demand Forecasting Model and its Evaluation

The demand forecasting model adopted by the NEA for the nation-wide power demand forecast is a dynamic model employing principles of economic theories. The model calculates demand of a year based on the demand of previous year and parameters defined prior to the model run. The structure of the model is relatively simple, necessary parameters are not numerous, and the requirement of information to be fed to the model is moderate. In the case of Nepal socioeconomic data sets necessary to feed into the model are fairly easy to correct. The parameters of the forecasting model can be set in such a way that future prices of electricity are determined to correct the distorted power market, and that magnitudes of future economic growth can be determined to reflect, for example, the desired process of economic recovery. The model was employed to determine 1997 forecasts financed by the ADB, and 2008 forecast done by the NEA. Thus, comparisons with other demand forecasts can be implemented easily. Because of the above reasons in this study, the model is selected to forecast the future demand of electricity. In the previous section, the first term of the model for the consumer sector was used to determine equilibrium seasonal prices of electricity.

NEA's model consists of three sub-models: namely, 1) a sub-model for domestic sector demand, 2) a sub-model for industry, and the commerce and service sector, and 3) a sub-model for irrigation. Since the demands from 2) and 3) are demands for production activities, the supply of power to the demands should be prioritized.

2.3 Power Demand Forecast with Consideration of Lost Demand

2.3.1 Determination of Economic Development and Power Pricing Scenarios

Scenarios of economic development and power pricing are represented by the parameter values set to run the power demand forecast model. Among these parameters, the price elasticity with respect to electricity consumption, income elasticity with respect to electricity consumption, and the propensity of electricity consumption with respect to changes in GDP growth are not easy to measure, and there are limited numbers of studies to determine these parameters. For this study, these parameters are adopted from the study[1] supported by the ADB in 1997, and they are modified according to the assumptions established for consumer behaviors. Other parameters are examined and defined based on past performance, and the measured values are representing current economic conditions. By changing these parameters, the base case, low case and high case scenarios are established for calculation and implementation of sensitivity analysis.

2.3.2 Establishment of Parameters and Sensitivity Analysis

(1) Establishment of Base Case Parameters

Expected GDP growth for the domestic sector and other sectors is selected based on the current performance of the sectors, expected real price increases of electricity until FY2018/19, and the subsequent constant electricity price during the period of FY2019/20 to FY2031/32. During the period of electricity price increases, the GDP growth of all sectors are to become slow, and then once the prices become stable, the best growth performance based on past data is given to the mode. The maximum growth rates are 4.5% in the domestic sector, 7% in the industry sector, and in the commerce and service sectors and other sectors, it is 7%. In addition, the initial growth rates for parts of the industry sector which are affected by load shedding are moderate at 3%.

Income elasticity with respect to electricity consumption for the domestic sector is 1.3 until the fifth year, and afterwards a value of 1.4 is assigned. As for the income elasticity, the larger the value, the rate of increase in electricity consumption becomes larger with respect to the increase in income. If the elasticity is 1.3, a 1% increase in income should result in a 1.3 % increase in electricity consumption. The major consumption of electricity by the domestic sector is light. It is assumed that as GDP (or income) grows more electric household items are purchased, and hence the consumption of electricity increases. For the industry sector, it is also assumed that along with economic development, mechanization will take place and the consumption of electricity will increase accordingly. Therefore, the propensity to electricity consumption will be increased from 1.2 to 1.4 by FY2020/21. In terms of the commerce and service sector, their electricity consumption is less responsive with respect to GDP growth, and thus the value of 1.2 is assigned throughout the forecasting period. For the other sector, consisting of mainly the public sector, the propensity to consume with respect to GDP growth should be low because the public sector is less responsive to changes in GDP growth. Therefore, the other sector is given a propensity of 1.1 throughout the period.

Regarding the price of electricity, it is assumed that in the 8th year of the forecasting period (FY2020/21), the price is assumed to reach 12 Rs/kWh, which should be an appropriate price of electricity for the NEA based on examination of the balance sheet and profit and loss statements. A too rapid increase in price must not be economically and politically viable, and therefore small rates of price increases are assigned. In the table, if the parameter is 1, then this year's price is the same as last year. If the value is 1.1, then a 10% increase from the previous year is achieved, and the same value is 0.9, then a 10% decrease is achieved. Electricity prices of all

[1] Nepal Electricity Authority and Asian Development Bank. 1997. Power system master plan for Nepal - Load forecast final report. Kathmandu.

the sectors will reach 12 Rs/kWh in FY2018/19 except for prices of the irrigation sector and exports to India. The price of irrigation is a subsidized price of 4.48 Rs/kWh, and it is assumed to be subsidized continuously with a slight increase in the prices up to the NEA's break-even price of 9 Rs/kWh. By the same token, considering the lower Indian electricity price, the price of electricity imports will gradually increase up to the break down price of 9 Rs/kWh by FY2018/19.

Price elasticity with respect to electricity consumption is usually a negative value due to the fact that a higher price level yields a lower level of consumption. The lowest price elasticity of -0.4 is assigned to the domestic sector. It means that if the price increases by 1%, then consumption decreases by 0.4%. It is assumed that the demand of the domestic sector is more elastic than the demand of industry, and the commerce and service sectors. Up to FY2020/21 it is assumed that the industry sector shows a relatively elastic price, and after then the demand becomes less elastic with respect to price due to a relatively lower electricity cost against higher value added products. Therefore, a value of -0.2 for the industry sector is assigned after FY2021/22.

Due to the inelastic price nature of electricity consumption by the commerce and service sector, a price elasticity of -0.1 is assigned throughout the forecasting period. A portion of the cost of electricity must be small in this sector, and it will likely respond in a small magnitude with respect to changes in the electricity price. Regarding the other sector, mainly consisting of the public sector, the elasticity of the sector must be small, and is considered to be 0 throughout the forecasting period. The sector does not respond to price changes due to the public nature of electricity consumption.

For the number of new connections, it is assumed that 263,000 new connections are added in 2013 and the number of new connections gradually increases up to 300,000 in FY2016/17. After that the numbers are set to reflect a gradual decline in the number of new connections. These assumptions are set based on past performance and the current rural electrification policy. The annual average consumption of newly connected consumers is assumed to be 400 kWh in FY2012/13, and the consumption gradually increases up to 650 kWh/year. Regarding the consumption of newly established industries, the value set by NEA in their 2008 forecasting is followed. Up to FY2021/22, about 22 GWh of new demand is added to the forecast. For the irrigation sector, by referring to the actual growth rates achieved in the past, it is determined that the annual growth rate of electricity demand from the sector is 6%, and the annual incremental demand from newly established irrigation projects is determined to 4.2 GWh throughout the forecasting period based on the assumptions established by the NEA's 2008 forecasting. For electricity trading, based on the actual declining growth trend in the past annual growth rate of electricity, exports are determined as 1% throughout the forecasting period.

Parameters regarding efficiency of generation, transmission, and distribution of NEA operation are the system loss and system load factors. Based on past data, system loss including th NEA's own consumption reached 27% in FY2011/12, and during the past 20 years, an improvement of the factor is hardly recognized. In FY2008/09 and FY2010/11, the system loss reached 29%. System loss includes technical loss and non-technical loss such as electricity theft. However, both types of losses should be decreased if technical capacity and consumer management are improved. In any case, additional investments should be considered to address these issues, and normalization of a pricing regime must be achieved to secure resources for investment. It is assumed that such resources are available and the technical loss will decline up to 17% by FY 2023/24. The average load factor in the past is about 62%, reflecting dominance of domestic consumption. It can be envisaged that the load factor will increase due to an increase in the industry consumption ratio to the total energy supply. However, it is determined that for the time being, dominance of the domestic sector will continue, and a highly assessed load factor will be adjusted to be low by reduction in load shedding. Therefore, a 52% load factor is assumed during the period of forecasting.

The last discussion regarding the parameter setting for the demand forecasting is whether the departing point is the actual supply/consumption of power in FY2010/11, or the FY 2010/11 consumption including the assumed demand loss caused by load shedding. In this case, by assuming that if there is no load shedding, the assumed lost demand by the load shedding is recovered completely, and thus, it is determined that the starting point of the demand forecasting is FY 2010/11 consumption, including the assumed demand loss. However, if the load shedding continues for a sufficient period of time, the industry sector and other production sectors can be damaged to an irreversible state. In this case, the assumed lost demand cannot be recovered, and the selection of initial demand for forecasting needs to be determined carefully with additional information.

(2) Sensitivity Analysis of Power Demand Forecasting

To perform a sensitivity analysis, a high case and a low case are established with respect to the base case. The parameters chosen for the sensitivity analysis are power prices and GDP growth rates in concerned sectors (i.e. domestic, industry, commerce, other, irrigation (agriculture), and power export sectors). The selection of these parameters are based on the assumption that the adjustment of the power market by increasing the power prices results in both improvement of the NEA's financial position and by laying a foundation for Nepalese economic development.

<Power prices>

The sector-wise power prices are calculated from the NEA's financial data in FY2010/11. The prices in 2011 are: domestic sector: 6.65 Rs/kWh; industry sector: 6.26 Rs/kWh; commerce sector: 9.30 Rs/kWh; other sector (mainly public sector): 7.27 Rs/kWh; irrigation (agriculture) sector: 4.48 Rs/kWh; and power export sector: 7.80 Rs/kWh. By considering that the 2012 price adjustment would result in a 20% price increase in the same year, the prices in FY2012/13 are determined. The discussion in the previous section indicates that the financially viable prices for the NEA are estimated to be 12.00 Rs/kWh for the domestic, industry, commerce and other sectors, whereas it is 9.00 Rs/kWh for the irrigation and export sectors. Based on these pricing schedules, the high case and low cases are established by setting an earlier or later financial year than that of the base case when the financially viable pricing is achieved.

For base case, it was already assumed that the financially viable pricing is achieved in FY2018/19. With respect to this timing, for the high case, FY2016/17 (two years earlier than that of the base case) is set for the year to reach the viable pricing, and for the low case, FY2021/22 (three years later than that of the base case) is set for the year to reach the viable pricing. In the former case the favourable environment for economic development can be achieved five years earlier than that of the base case, and in the latter case the unfavourable condition lasts five years longer than the condition of the base case. Because the price elasticity of power for electricity consumption is negative, a rapid increase in power prices results in a decrease in power demand. Therefore, it is expected that in the high case although power market adjustment can be achieved within a short period of time, the rapid increase in power prices must depress the growth of power demand during the same period.

<Sector-wise GDP growth rate>

Consistent with the assumption that the adoption of the financially viable pricing schedule of the NEA by the power market also lays the foundation for accelerated economic development, sector-wise GDP growth rates for all the sectors for the high case and the low case are determined in relation to the rates selected for the base case.

For the high case, the sector-wise power prices reach the viable price schedule in FY2016/17, and therefore, the growth rates for all sectors are set higher than those of the base case after FY2016/17. In particular, the growth rates of the domestic and industry sectors are set higher from 2016/17 through FY2031/32, the last year of the forecasting. In the case of the commerce and other sectors, which generally show higher growth rates than those of the domestic and industry sectors, they are assumed to have higher growth rates than those of the base case only in the period from FY2016/17 to FY2018/19 when the viable price schedule is achieved in the base case.

For the low case the sector-wise power prices increase gradually until FY2021/22 when the viable price schedule is attained. The distortion of the power market and the allocation of public subsidies to the market are assumed to last for fifteen years. This should result in the reduction of public investment for infrastructure and other measures necessary to achieve faster economic growth. Thus, growth rates of industry, commerce, and other sectors are set lower than those of the base case from the early years of the forecasting period. Regarding the domestic sector, because a large part of the population in the sector depends on the primary sector economy in rural areas, and the inflows of overseas remittance to the population are significant, the low performance of the industry and commerce sectors are assumed to have a small impact on the domestic sector. Therefore, the growth rates of the domestic sector are set the same as the ones in the base case.

2.3.3 Results of Sensitivity Analysis

Results of the base case demand forecast with the set parameters are shown in Figure 2.3.3-1 and Figure 2.3.3-2.

The power demand will gradually grow until FY2021/22, and increase relatively faster after FY2021/22. In the last year (FY2031/32) of the forecast, demand for power at the generation point will reach 19,493 GWh, which is almost 3.6 times higher than electricity including lost demand by load shedding (5,380 GWh) in FY2011/12. If compared with the actual power supply of 4,146 GWh in FY2011/12, the demand in the last year of the forecast period is 4.7 times larger than the actual supply in FY2011/12. In this case, during the coming 20 years, the supply capacity must be four to five times larger than the current capacity.

Regarding peak load forecasting, by FY2031/32 the peak load at the generation point needs to reach 4,279 MW. The current peak load with lost consumption by load shedding is 1,027 MW, and thus, at least the generation capacity should be increased fourfold. If the actual peak load of 579 MW in FY2011/12 is considered, the total system capacity must be increased by seven times.

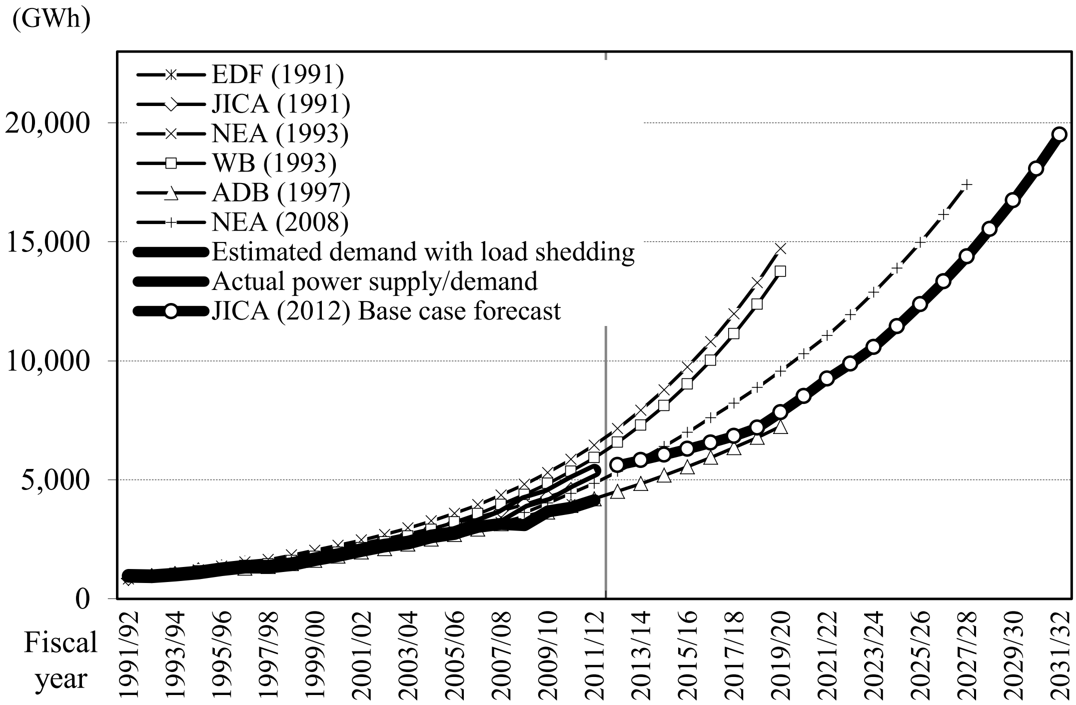
The forecasted evolution of power demand and associated peak load, as well as the slow growth of the electricity market will continue until FY2018/19 due to the gradual increase of the real price of electricity and moderate settings of economic growth rates. This indicates that the adjustment of the power market will require economic costs, and the cost may be increased as measured to address the distortion of power market delays. Therefore, it is recommended that the market adjustment should be started as soon as possible to increase the NEA's revenue for its necessary investment. At the same time, the NEA must improve its productivity and efficiency in order to reduce the cost of electricity supply and system losses.

The average growth rate of power during the 20-year forecasting period is 7%, and the average growth of the peak load is also 7%. The actual average growth rate of power generation during the last 20 years is 9% for energy and 8% for generation capacity, and it is assumed that keeping an average growth rate of 7% in the next 20 years must be a moderate target. On the other hand, development of an appropriate generation portfolio required development of an appropriate number of storage type power plants, which require a relatively long gestation period and high development cost to ensure a constant and steady supply of electricity throughout the year. In addition to a higher level of investment, the market adjustment and improvement of the NEA's financial position have to be achieved concurrently. Therefore, keeping 7% average growth must require multidimensional investment, market adjustment, and an institutional strengthening approach.

In terms of the sector-wise growth of power demand, rapid growth of power demand from the irrigation sector is worth mentioning. Although the sector's power demand is 2.7% of the total demand, the sector shows an average growth rate of 7.6%, indicating recent good performance of the agriculture sector. However, the sector could suffer from erratic weather, so the power demand growth has to be monitored closely. The commerce and service sector shows an annual average growth of 7.3%, and the domestic sector shows an average annual growth rate of 8%. Increased purchase power due to a recent increase in remittances is one positive factor for the power demand growth from the commerce and service sector. However, the economy, which is heavily dependent on remittances, may erode its production base. From this point of view, the industry sector's slow growth of power demand indicated by an annual average growth of 7.1% during the forecasting period is a concern. The power supply should be stabilized as soon as possible, particularly to support the development of this sector in order to enhance the production capacity of Nepal.

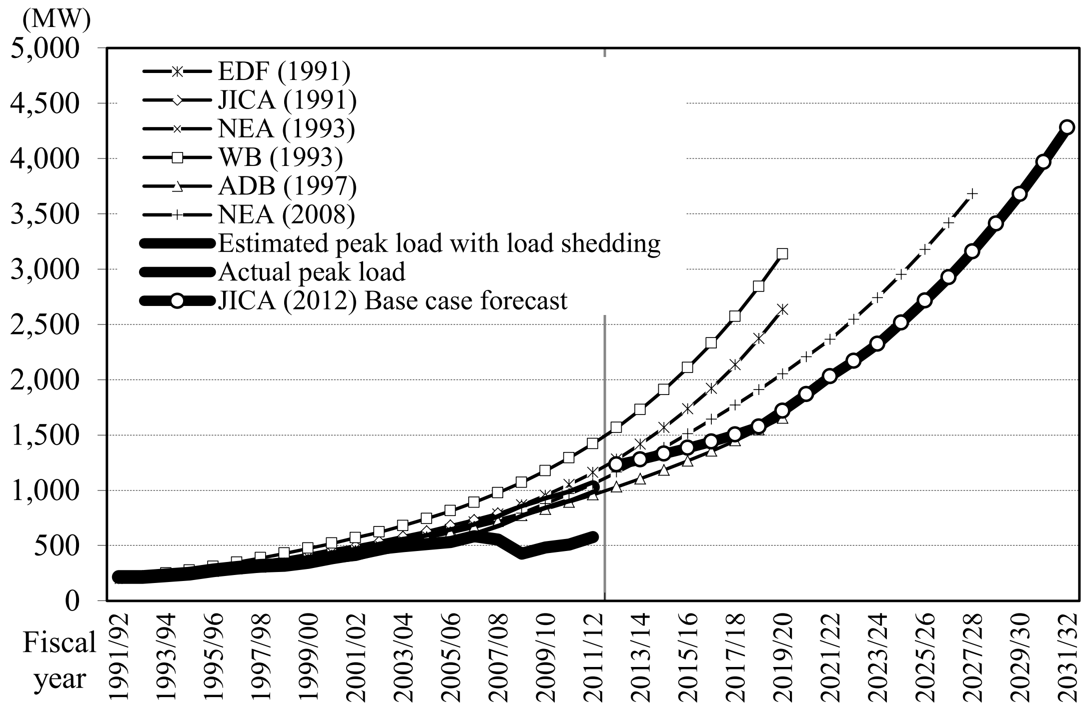
The comparison with other forecasts performed by various organizations reveals that 1991 forecasts by the EDF and 1997 forecasts by the ADB are close to the actual past of demand development and peak load development. Their forecasts seem to be moderate. The development of the demand with assumed lost demand due to load shedding is close to the NEA's 2008 forecast. The current demand and supply gap is mainly caused by sluggish development of generation capacity and expansion of the distribution network that is proceeding too quickly, and it is recommended that the balanced development of both fronts must be promoted.

Based on the current situation of power market distortion, the NEA's financial issues, and intensive load shedding as a result of inadequate planning in the past, the forecasting exercise was performed by addressing these issues. Thus, during the forecast period, 7 years until FY2018/19 are allocated for the adjustment of the distorted (underpriced) power market which requires decision-making with a long-term vision, planning, and investment for the development of an appropriate mixture of generation options including storage type hydropower plants. This adjustment scenario expects the recovery and growth of the economy after FY2018/19. The power demand forecast presented in this section is based on a scenario of growth which requires the firm determination of policy makers, the NEA, and other major players involved with the power sector in Nepal.



Prepared by the JICA Study Team.

Figure 2.3.3-1 Comparison between Various Base Case Power Demand Forecasts



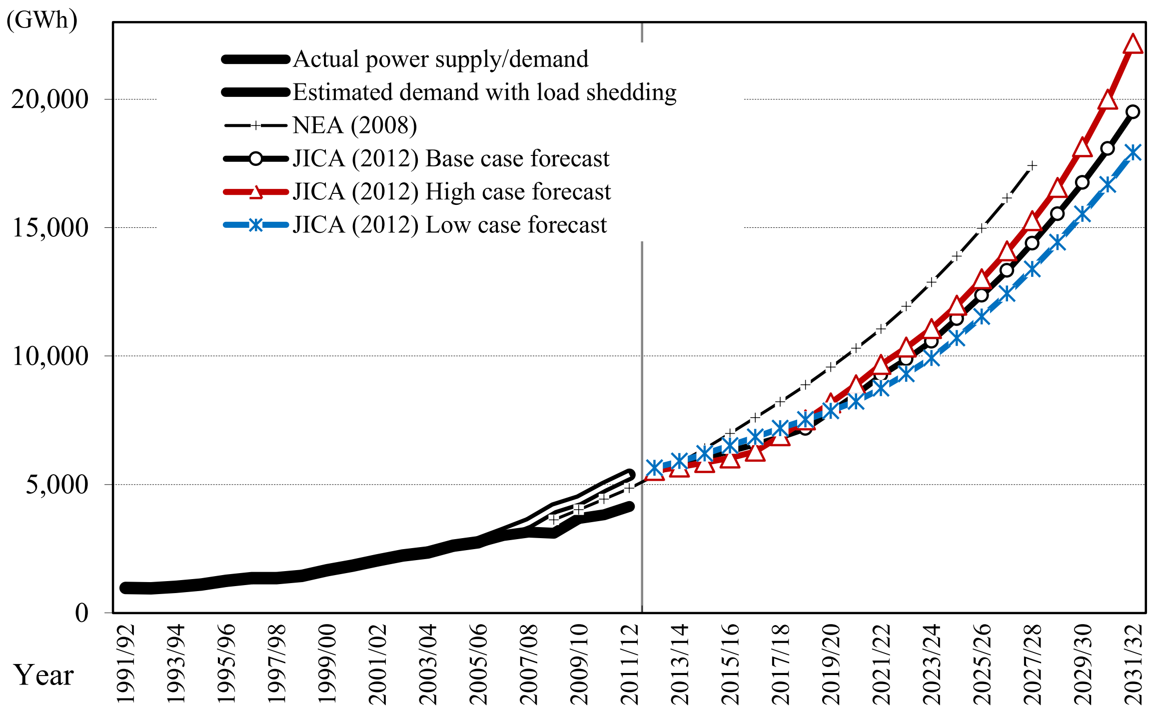
Prepared by the JICA Study Team.

Figure 2.3.3-2 Comparison between Various Base Case Peak Load Forecasts

2.3.4 Adopted Demand Forecast Scenario

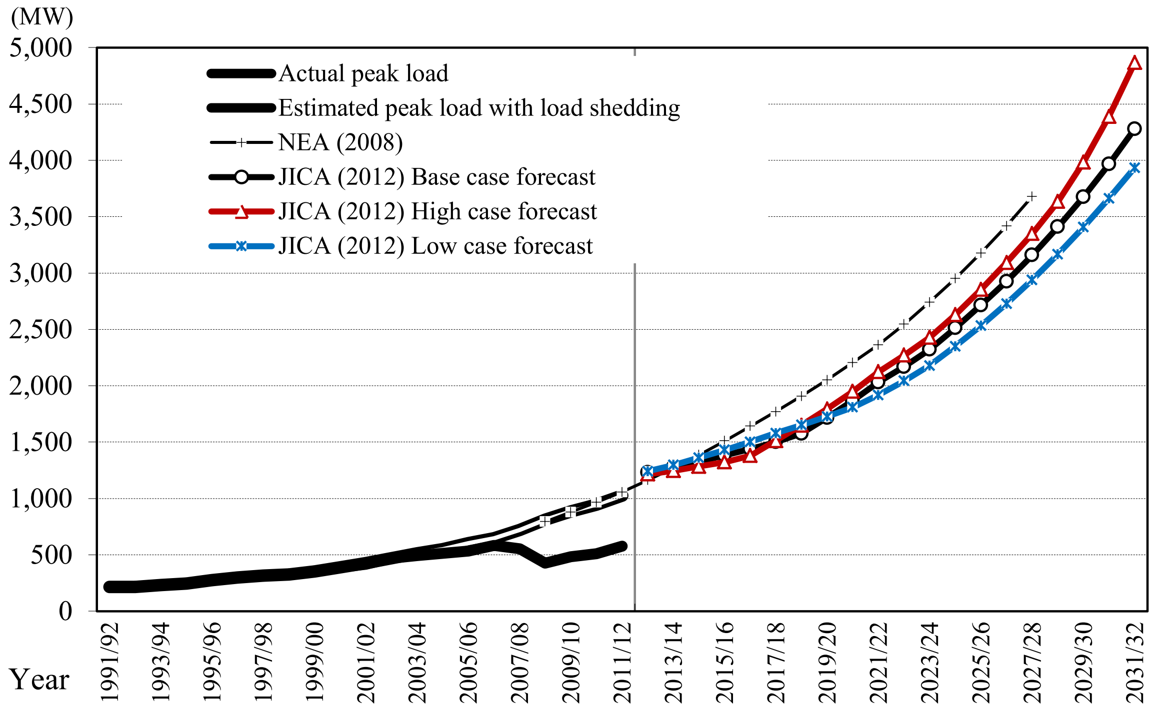
The results of the sensitivity analysis with the base, high, and low cases are shown in Figure 2.3.4-1 and Figure 2.3.4-2. The high case exhibits the lowest demand growth during the first five years from FY2012/13 due to a rapid increase in the power prices. This period considers the power market adjustment period with rapid elimination of the government's subsidies to correct the market distortion. This result indicates that once the financially viable price schedule is achieved in FY2016/17, robust economic growth can be expected thereafter. The power demand in the high case catches up to the demands of the base and low cases in FY2018/19, and reaches 22,166 GWh in FY2031/32.

The low case shows more or less the same demand increase with the demand increase of the base case until FY2021/22, when the viable price schedule is achieved in the base case. However, the base case's growth in demand thereafter stagnates and the difference between the power demands of the base and low cases increases over time. At the end of the master plan period in FY2031/32, the demand of the low case reaches 17,921 GWh, which is about 80% of the high case demand in the same fiscal year.



Prepared by the JICA Study Team.

Figure 2.3.4-1 Sensitivity Analysis of Power Demand Forecasts



Prepared by the JICA Study Team.

Figure 2.3.4-2 Sensitivity Analysis of Peak Load Forecasts

For forecasting the peak load for all three cases, it is assumed that the structure of the domestic sector dominating the power market stays unchanged during the forecasting period. Since the Nepalese power market structure during the past 20 years is dominated by the domestic sector, and shows on average about 62% of the load factor, a load factor of 52% is assumed during the entire period of the forecasting. This assumption of a constant load factor results in the same trend exhibited both by the power demand forecasts and peak load forecasts. In the high case, the peak load in the last forecasting year (FY2031/32) reaches 4,866 MW, whereas in the low case the peak load reaches 3,934 MW, which is about 80% of the high case peak load in the same year.

The results of the sensitivity analysis indicate that from the point of view of long-term economic development earlier adjustment of a distorted power market is recommended for implementation. Although in the short run the quick adjustment comes with the temporal stagnation of the economy due to an increase in power prices, in the long run recovery from stagnation and robust economic growth can be expected once the adjustment of the market is achieved.

Chapter 3 Power Development Plan

In this chapter, a power development plan to meet the demand that was forecasted in Chapter 2 is worked out taking into consideration the existing generation facilities, the projects under construction and stages in preparation[2], and the candidates of storage-type projects selected in Chapter 5.

3.1 Existing Power Generation Facilities

As of the end of FY2011/12[3], the existing power generation facilities in Nepal consist of 459,150 kW of large-scale hydroelectric power plants (HPPs) and 18,380 kW of small-scale HPPs owned by the NEA, 187,581 kW of HPPs owned by IPPs, and 53,410 kW of diesel power plants and 100 kW of photovoltaic power plants owned by the NEA. The total installed capacity is 718,621 kW. (Table 3.1-1)

Table 3.1-1 Installed Capacity of Existing Generation Facilities

Power Station	Installed Capacity (kW)
NEA's Major Hydro	**459,150**
Middle Marsyangdi	70,000
Kaligandaki A	144,000
Marsyangdi	69,000
Kulekhani No. 1	60,000
Kulekhani No. 2	32,000
Trhisuli	24,000
Gandak	15,000
Modi Khola	14,800
Devighat	14,100
Sunkoshi	10,050
Puwakhola	6,200
NEA's Small Hydro	**13,844**
NEA's Small Hydro (Isolated)	**4,536**
IPP's Major Hydro	**142,600**
Khimit	60,000
Bhotekoshi	36,000
Chilime	22,000
Indrawati No. 3	7,500
Jhimruk	12,000
Andhi Khola	5,100
IPP's Small Hydro	**44,981**
Hydro Total	**665,111**
Diesel	**53,410**
Duhabi Multifuel	39,000
Hetauda	14,410
NEA's Solar	**100**
Grand Total	**718,621**

Source: A Year in Review FY2011/12, NEA

[2] Projects that are in the detailed design stage or their PPA have been concluded.
[3] Since the planning period of power development plan is from FY2012/13 to FY2031/32, the existing facilities at the end of FY2011/12 were used as the existing power generation facilities.

3.2 Problems of the Existing Power Generation System

There are two major problems in the existing power generation system in Nepal. One is the absolute shortage of supply capacity, and the other is the decrease in generating capacity in the dry season.

3.2.1 Absolute Shortage of Supply Capacity

In Nepal, power demand has surpassed supply capacity since the mid-2000s. Since then, the country has been under the situation of an absolute power shortage, and long hours of load shedding have been inevitable. In January 2013, load shedding for 14 hours a day, 97 hours a week was implemented for about half a month.

In FY2011/12, the peak demand was 1,027 MW and the total installed capacity of generation facilities in the country was 719 MW, equivalent to only 70% of the peak demand. In addition, the supply capacity falls in the dry season as described in Clause 3.2.2, the electricity actually supplied was about 580 MW including import from India, it was less than 60% of the power demand.

From now on, development of supply capacity more than the increase in power demand is required to resolve shortage in supply capacity and to meet the increase in power demand.

3.2.2 Decrease in Generating Capacity in the Dry Season

Another problem is a decrease in generating capacity in the dry season. In Nepal, about 86% of the total installed capacity is ROR-type and PROR-type HPPs. Since power plants of these types are, in general, operated in accordance with river flow, their generating capacity decreases in the dry season when the river flow is low.

The supply capacity for the whole country falls from December to May. It sinks to about 55%, and in some years to about 45%, from mid-March to mid-April.

Regarding ROR- and PROR-type HPPs, the supply capacity sinks to about 50%, and in some years to about 40%, in the same period.

On the other hand, the monthly change of power demand is not large like supply capacity, even in the month with the minimum demand, the demand in that month is about 90% of the demand in the month with the maximum demand. The demand increases from December to April when the supply capacity sinks, and it is relatively small from July to October when the supply capacity is large. Therefore, it is necessary to construct power generation facilities whose generating capacities do not drop, or drop only a small amount, even in the dry season.

Since power supply by thermal power generation is difficult in Nepal, and the required installed capacity of ROR-type hydroelectric power generation to meet the demand in the dry season is about twice as much as the demand, construction of storage-type HPPs is the most realistic countermeasure to cope with the supply shortage in the dry season.

Currently, since there are only two storage-type HPPs in Nepal, the Kulekhani No. 1 and No. 2 HPPs, necessary and appropriate data for evaluating supply capacity of storage-type power generation in the dry season are not available. For this reason, the supply capacity of storage-type HPPs is estimated on the following conditions.

- The equivalent duration of peaking is presumed to be 12 hours for storage-type HPPs to be constructed from now.
- The load factor in the dry season is presumed to be 57%, which is same as the load factor used in the power demand forecast described in Chapter 2.

From these conditions, the supply capacity of storage-type HPPs in the dry season is estimated at 88% (= (12 hrs / 24 hrs) / 0.57 × 100) of the installed capacity. Therefore, if all the newly required supply capacity (2,242 MW) is assumed by only storage-type HPPs, it is necessary to construct storage-type HPPs totaling 2,550 MW (= 2,242 / 0.8). This is about 57% in the total capacity compared to the case that all the newly required supply capacity is only secured by ROR-type HPPs.

In general, reservoir areas of storage-type HPPs are larger than ROR-type HPPs, and construction of storage-type HPPs has a larger impacts on the natural and social environment than ROR-type HPPs. Meanwhile, since the installed capacity of one storage-type HPP is larger than one ROR-type HPP in general, and a decrease in the generating capacity of storage-type HPPs in the dry season is smaller than ROR-type HPPs, the number of storage-type HPPs necessary to be constructed is smaller than the number ROR-type HPPs that have a similar supply capacity in the dry season.

3.3 Fundamental Scenarios for the Power Development Plan

The power development plan for the next 20 years is made out based on the following scenario, taking into consideration the above-mentioned problems of the power generation system and the characteristics of power generation methods in Nepal.

- The main electric power source in the national grid (INPS) is hydroelectric power generation utilizing hydropower energy that is one of the country’s abundant domestic resources.
- Storage-type hydroelectric power generation is developed for securing the supply capacity of the INPS by compensating the decrease in supply capacity of ROR-type hydroelectric power generation in the dry season.
- ROR-type hydroelectric power generation is developed continuously for utilizing abundant hydropower energy.
- Import of electricity from India is kept on for power supply to the areas near the border.
- Power generation with renewable energies like wind power and solar power is promising in the long term. However, this is not considered in the power development plan in the next two decades because the proportion in the INPS is considered to be very small taking into consideration its generation cost and effects on stability of the power network.

3.4 Installed Capacity of Existing Power Generation Facilities

As described in Section 3.1, the total installed capacity of power generation facilities owned by the NEA and IPPs is 718,621 kW. Among this capacity, 714,085 kW is connected to the INPS.

In the power development plan in this chapter, the following supply capacities are also considered as the supply capacity of existing power generation facilities based on the information obtained from

NEA about the power supply plan in FY2013/14.

- Increment in the total installed capacity of small-scale HPPs owned by IPPs: 136,089 kW

Since information on the commencement year of commercial operation of “The incremental amount of the total installed capacity of small-scale HPPs owned by IPPs” was not obtained, this is considered to be a part of the existing supply capacity in FY2011/12. Therefore the total installed capacity of small-scale HPPs owned by IPPs is 181,070 kW (= 44,981 + 136,089) in the power development plan. As for the existing wind power plants, they are not considered in the power development plan because the supply capacity is very small in the INPS and detailed information on them was not available.

As a result, the total installed capacities of exiting generation facilities as of the end of FY2011/12 in the power development plan are 796,664 kW of hydroelectric power generation and 53,410 kW of diesel power generation, the total is 850,074 kW. (The right column of Table 3.4-1)

Table 3.4-1 Installed Capacity of Existing Generation Facilities

Power Station	Installed Capacity in FY2011/12 (kW)	
	A Year in Review FY2011/12	Generation Expansion Plan
NEA’s Major Hydro	**459,150**	**459,150**
Middle Marsyangdi	70,000	70,000
Kaligandaki A	144,000	144,000
Marsyangdi	69,000	69,000
Kulekhani No. 1	60,000	60,000
Kulekhani No. 2	32,000	32,000
Trhisuli	24,000	24,000
Gandak	15,000	15,000
Modi Khola	14,800	14,800
Devighat	14,100	14,100
Sunkoshi	10,050	10,050
Puwakhola	6,200	6,200
NEA’s Small Hydro	**13,844**	**13,844**
NEA’s Small Hydro (Isolated)	**4,536**	-----
IPP’s Major Hydro	**142,600**	**142,600**
Khimit	60,000	60,000
Bhotekoshi	36,000	36,000
Chilime	22,000	22,000
Indrawati No. 3	7,500	7,500
Jhimruk	12,000	12,000
Andhi Khola	5,100	5,100
IPP’s Small Hydro	**44,981**	**181,070**
Hydro Total	**665,111**	**796,664**
NEA’s Diesel	**53,410**	**53,410**
Duhabi Multifuel	39,000	39,000
Hetauda	14,410	14,410
NEA’s Solar	**100**	-----
Grand Total	**718,621**	**850,074**

3.5 Projects under Construction and Projects with a High Probability of being Constructed

As of June 2013, the projects listed in Table 3.5-1 are under construction or with a high probability of being constructed. In the power development plan in this study, these projects are considered to be implemented and put into commercial operation according to schedule.

Table 3.5-1 Projects under Construction or with a High Probability of being Constructed

Project Name	Type	Installed Capacity (MW)	Annual Energy (GWh)	Commercial Operation (FY)	Remarks
Kulekhani III	STO	14	40.85	2015/16	
Chameliya	PROR	30	184.21	2015/16	
Khani Khola	ROR	25	114	2015/16	
Upper Sanjen	ROR	11	82.4	2016/17	
Sanjen	ROR	42.9	251.9	2016/17	
Upper Trishuli 3A	ROR	60	489.9	2016/17	
Upper Tamakoshi	PROR	456	2,281	2016/17	
Madhya (Middle) Bhotekoshi	ROR	102	542	2017/18	
Rasuwagadi	ROR	111	613.88	2017/18	
Rahughat	PROR	32	186.12	2017/18	
Upper Marsyangdi	ROR	50	317	2017/18	
Mistri	ROR	42	225	2017/18	
Upper Trishuli 3B	ROR	37	296.34	2019/20	
Upper Modi A	ROR	42	214.87	2020/21	
Tanahu	STO	140	484.4	2020/21	
Budhi Gandaki	STO	600	2,674	2022/23	
Total		1,794.9	8,997.87		

Source: NEA

3.6 Candidate Projects for Hydroelectric Power Generation

3.6.1 Promising Storage-type Hydroelectric Power Projects selected by Study Team

As described in Chapter 5, the Study Team ranked the 67 storage-type hydroelectric power projects (including two projects that were added later) in the long list prepared by NEA in 2009 by comparison study from technical, environmental and economical aspects. Then the Study Team selected ten projects listed in Table 3.6.1-1 as the candidate projects for the power development plan in the next two decades.

Detailed studies including a site survey were conducted on these ten projects. Since the results proved that the Kokhajor-1 project is not feasible from the viewpoint of economic efficiency, this project was excluded from the candidates of the power development plan.

The result of the detailed studies also proved that since the planned powerhouse site of the Lower Jhimruk project is located in the planned reservoir area of the Naumure project, these two projects are not able to coexist. Regarding the Naumure project, the Ministry of Irrigation has a plan of an irrigation project at this site and this irrigation project is not able to coexist with the Lower Jhimruk project either. Meanwhile, there is a possibility of implementing the Naumure project as a multipurpose project for power generation and irrigation. Taking these points into consideration, the

Naumure project was selected as one of the candidate projects and the Lower Jhimruk project was excluded from them.

Table 3.6.1-1 Candidates Storage-type Hydroelectric Power Project selected by the Study Team

Project Name	Type	Installed Capacity (MW)	Annual Energy (GWh)	Project Cost* (MUS$)	The Earliest Possible Commissioning Year (FY)	Remarks
Dudh Koshi	STO	300	1,909.6	1,141.0	2023/24	
Nalsyau Gad	STO	410	1,406.1	966.9	2023/24	
Andhi Khola	STO	180	648.7	665.8	2025/26	
Chera-1	STO	148.7	563.2	576.9	2027/28	
Madi	STO	199.8	621.1	637.3	2027/28	
Naumure	STO	245	1,157.5	954.5	2027/28	
Sun Koshi No. 3	STO	536	1,883.6	1,690.5	2028/29	
Lower Badigad	STO	380.3	1,366.0	1,209.8	2028/29	
(Kokhajor-1)	STO	111.5	278.9	476.5	-----	Excluded from the candidates in this study. (Low economical efficiency)
(Lower Jhimruk)	STO	142.5	454.7	520.9	-----	Excluded from the candidates in this study. (Overlapping with the Naumure Project)

*: FY2012/13 price

3.6.2 Development of ROR-type Hydroelectric Power Generation

In Table 3.5-1, in the projects under construction or with a high probability of being constructed, other than the Upper Modi A project that is scheduled to be put into operation in FY2019/20, there is not any specific ROR-type project that is scheduled to be put into operation in and after FY2018/19. Nevertheless many survey or construction licenses for ROR-type HPPs have been issued by the DOED. It is presumed that since many of them have been issued to IPPs, it is difficult for the NEA (or the government) to estimate the commissioning year of these projects.

However, development of ROR-type hydroelectric power generation must be continued even after FY2018/19 for utilizing plentiful hydropower energy in the country. In the power development plan in this chapter, development of ROR-type hydroelectric power generation is considered as follows.

- The total installed capacity of candidate ROR-type HPPs in and after FY2018/19 is about 100 MW/year including the Tamakoshi V and Upper Arun HPPs brought by the NEA.
- in the same way as the promising storage-type HPPs listed in Table 3.6.1-1, these ROR-type HPPs are not necessarily to be put into operation in the earliest possible commissioning year shown in the table. If the reference year’s supply reliability is satisfied by construction of HPPs by the previous years, the implementation schedule of the said ROR-type HPPs is postponed one or more years.

Table 3.6.2-1 shows these candidates of ROR-type projects.

Table 3.6.2-1 Candidates of ROR-type Project

Project Name	Type	Installed Capacity (MW)	Annual Energy (GWh)	Project Cost* (MUS$)	The Earliest Possible Commissioning Year (FY)	Remarks
ROR-1	ROR	100	594	183	2018/19	
ROR-2					2019/20	
ROR-3					2020/21	
Tamakoshi V		87	460.5	189	2021/22	
ROR-4		100	594	183	2022/23	
ROR-5					2023/24	
Upper Arun	PROR	335	2,734.2	748	2024/25	
ROR-6	ROR	100	594	183	2027/28	
ROR-7					2028/29	
ROR-8					2029/30	
ROR-9					2030/31	
ROR-10					2031/32	

*: FY2012/13 price

3.6.3 Power Imports from India

In the power development plan in this chapter, the following two long-term import contracts were considered based on the result of discussion with the NEA.

- Power Sales Agreement between PTC India Limited and Nepal Electricity Authority (2011): 150 MW from FY 2015/16
- Free annual energy from Tanakpur HPP based on Minutes of Meeting of 8th Indo-Nepal Power Exchange Committee Meeting (2007): 12 MW (equivalent to 70 GWh)

As a result, the maximum amount of power import from India in the power development plan is 12 MW until FY2014/15, and 162 MW in and after FY2015/16.

3.7 Power Development Plan

3.7.1 Practical Development Scenario

The projects under construction or with a high probability of being constructed listed in Table 3.5-1 commence commercial operation according to schedule. The candidate projects to be developed after these projects are the promising storage-type HPPs selected by the Study Team listed in Table 3.6.1-1, and ROR-type HPPs listed in Table 3.6.2-1.

With these projects, a power development plan that is able to resolve the load shedding as early as possible and then secure the required LOLP is drawn up using WASP-IV, the latest version of the "Wien Automatic System Planning Package," a computer program developed by the IAEA. This program draws up a power development plan, or combination of generation facilities to be constructed and their commissioning year, and the least of its total cost (construction cost, fuel cost and O&M cost) in terms of present value.

3.7.2 Power Development Plan

(1) Year of commissioning

Table 3.7.2-1 shows the power plants to be constructed and their commissioning years for the base case of demand forecast.

For the base case, the total installed capacity of generation facilities that are put into operation for the 20 years from FY2012/13 to FY2031/32 is 4,256 MW including the increase in imports from India, and 1,993 MW of this is storage-type hydroelectric power generation.

Table 3.7.2-1 Generation Expansion Plan (Base Case)

FY		2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Existing	—	850.1	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Kulekhani No. 3	**STO**					**14.0**	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Chameliya	PROR					30.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Khani Khola	ROR					25.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Upper Sanjen	ROR						11.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Sanjen	ROR						42.9	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Upper Trishuli 3A	ROR						60.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Upper Tamakoshi	PROR						456.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Madhya (Middle) Bhotekosh	ROR							102.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Rasuwagadi	ROR							111.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Rahughat	PROR							32.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Upper Marsyangdi	ROR							50.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Mistri	ROR							42.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→
ROR-1	ROR								100.0	→	→	→	→	→	→	→	→	→	→	→	→	→
Upper Trishuli 3B	ROR									37.0	→	→	→	→	→	→	→	→	→	→	→	→
ROR-2	ROR									100.0	→	→	→	→	→	→	→	→	→	→	→	→
Tanahu	**STO**										**140.0**	→	→	→	→	→	→	→	→	→	→	→
Upper Mode A	ROR										42.0	→	→	→	→	→	→	→	→	→	→	→
ROR-3	ROR										100.0	→	→	→	→	→	→	→	→	→	→	→
Tamakshi V	ROR											87.0	→	→	→	→	→	→	→	→	→	→
Budhi Gandaki	**STO**												**600.0**	→	→	→	→	→	→	→	→	→
ROR-4	ROR														100.0	→	→	→	→	→	→	→
Upper Arun	PROR															335.0	→	→	→	→	→	→
ROR-5	ROR															100.0	→	→	→	→	→	→
Dudh Koshi	**STO**																**300.0**	→	→	→	→	→
Nalsyau Gad	**STO**																		**410.0**	→	→	→
Andhi Khola	**STO**																				**180.0**	→
ROR-6, -7, -8	ROR																				300.0	→
Chera-1	**STO**																					**149.0**
Madi	**STO**																					**200.0**
Import from India	—	12.0	→	→	→	162.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Added Installed Capacity (MW)		—	0.0	0.0	0.0	219.0	569.9	337.0	100.0	137.0	282.0	87.0	600.0	0.0	100.0	435.0	300.0	0.0	410.0	0.0	480.0	349.0
Total Installed Capacity (MW)		862.1	862.1	862.1	862.1	1,081.1	1,651.0	1,988.0	2,088.0	2,225.0	2,507.0	2,594.0	3,194.0	3,194.0	3,294.0	3,729.0	4,029.0	4,029.0	4,439.0	4,439.0	4,919.0	5,268.0
LOLP* (%)		—	**50.375**	**53.789**	**57.975**	**32.637**	**2.733**	**1.575**	**1.927**	**2.579**	**1.919**	**3.087**	0.130	0.516	1.225	0.666	0.336	1.079	0.440	1.331	1.330	1.232

*: The critical LOLP is 1.375%, equivalent to 5 days/year.

Note: Projects in boldface are storage-type projects.
The total install capacity includes imports from India.

(2) Supply-demand balance

Table 3.7.2-2, Figure 3.7.2-1 and Figure 3.7.2-2 show the supply-demand balance, LOLP, and reserve margin for the base case of demand forecast.

In this table, some peak supply capacities are smaller than peak demand even though LOLP is smaller than the allowable upper limit, 1.375%, and this is equivalent to less than 5 days/year of shortage in the supply capacity. In general, shortage in the supply capacity of ROR-type HPPs concentrates in the dry season, and energy supply by ROR-type HPPs decreases significantly. To cope with this, a part of the storage-type HPPs are operated at the output lower than the installed capacity for a long time to supply base demand. Therefore, the shortage of peak supply capacity occurs for some days within the above-mentioned allowable range. Regarding energy, on the other hand, nearly 100% is supplied in years when the LOLP is within the allowable range.

For the base case, though the Kulekhani No. 3 HPP (14 MW), the Chameliya HPP (30 MW), and the Khani Khola HPP (25 MW) will be put into operation in FY2015/16, the supply capacity is not able to meet the peak demand. The LOLP is improved by comparison with the previous years. It is, however, a significantly large value, 33%. In FY2016/17, the Upper Tamakoshi HPP (456 MW), the Upper Sanjen HPP (11 MW), the Sanjen HPP (42.9 MW), and the Upper Trishuli 3A HPP (60 MW) are put into operation, and the LOLP becomes lower than 3%, however it is larger than 1.375%, the allowable upper limit. After then, between FY2017/18 and FY2021/22, the Nadhya (Middle) Botekoshi HPP (102 MW), the Rasuwagad HPP (111 MW), the Rahughat HPP (32 MW), the Upper Marsyangdi HPP (50 MW), the Mistri HPP (42 MW), the Upper Trishuli 3B HPP (37 MW), the Tanahu HPP (140 MW), the Upper Modi A HPP, and the Tamakoshi V HPP (87 MW) are put into operation. Other than these HPPs, ROR-type HPPs totaling 300 MW are also put into operation, and the LOLP fluctuates in a range between 1.5% and 3%.

In FY2022/23, commissioning of the Budhi Gandaki HPP (600 MW) makes the power demand and supply balanced, and the LOLP becomes lower than the allowable upper limit, 1.375%. Then the Upper Arun HPP (335 MW) is put into operation in FY2025/26, the Dudh Koshi HPP (300 MW) in FY2026/27, the Nalsyau Gad HPP (410 MW) in FY2028/29, the Andhi Khola HPP (180 MW) in FY2030/31, and the Chera-1 HPP (149 MW) and the Madi HPP (200 MW) are put into operation in FY2031/32. Other than these HPPs, ROR-type HPPs totaling 500 MW are also put into operation, stable supply-demand situation continues until FY2031/32.

In Nepal, since almost all of the country’s power comes from hydroelectric power generation, and a significant portion of this consists of ROR-type HPPs whose supply capacity drops in the dry season when the power demand is high, the reserve margin shows a relatively large figure. In the commissioning years of large-scale HPPs like the Budhi Gandaki, the Nalsyau Gad, and the Upper Arun, the reserve margin shows a particularly large figure.

Table 3.7.2-2 Balance of Supply and Demand, LOLP, and Reserve Margin (Base Case)

FY	Installed Capacity (MW)	Peak Demand (MW)	Supply Capacity (MW)	Supply – Demand (MW)	Energy Demand (GWh)	Supply Energy (GWh)	Supply / Demand (%)	LOLP (%)	Reserve Margin (%)
	a	b	c	d = c – b	e	f	g = f / e	h	i = a / b – 1
2012/13	862	1,231	479	-752	5,607	4,707	84.0	**50.375**	-30.0
2013/14	862	1,277	477	-800	5,818	4,787	82.3	**53.789**	-32.5
2014/15	862	1,328	476	-852	6,049	4,865	80.4	**57.975**	-35.1
2015/16	1,081	1,382	696	-686	6,294	5,747	91.3	**32.637**	-21.8
2016/17	1,651	1,439	1,224	-215	6,556	6,527	99.6	**2.733**	14.7
2017/18	1,988	1,501	1,346	-155	6,836	6,819	99.8	**1.575**	32.5
2018/19	2,088	1,575	1,375	-200	7,176	7,154	99.7	**1.927**	32.5
2019/20	2,225	1,717	1,436	-281	7,823	7,788	99.6	**2.579**	29.6
2020/21	2,507	1,867	1,617	-250	8,504	8,481	99.7	**1.919**	34.3
2021/22	2,594	2,031	1,636	-395	9,252	9,198	99.4	**3.087**	27.7
2022/23	3,194	2,169	2,236	67	9,881	9,880	100.0	0.130	47.3
2023/24	3,194	2,321	2,236	-85	10,572	10,568	100.0	0.516	37.6
2024/25	3,294	2,513	2,265	-248	11,447	11,428	99.8	1.225	31.1
2025/26	3,729	2,714	2,537	-177	12,364	12,358	100.0	0.666	37.4
2026/27	4,029	2,925	2,837	-88	13,325	13,320	100.0	0.336	37.7
2027/28	4,029	3,158	2,837	-321	14,386	14,370	99.9	1.079	27.6
2028/29	4,439	3,410	3,247	-163	15,531	15,526	100.0	0.440	30.2
2029/30	4,439	3,676	3,247	-429	16,744	16,721	99.9	1.331	20.8
2030/31	4,919	3,966	3,515	-451	18,066	18,042	99.9	1.330	24.0
2031/32	5,268	4,279	3,712	-567	19,493	19,465	99.9	1.232	23.1

*: Critical LOLP is 1.375%, equivalent to 5 days/year.

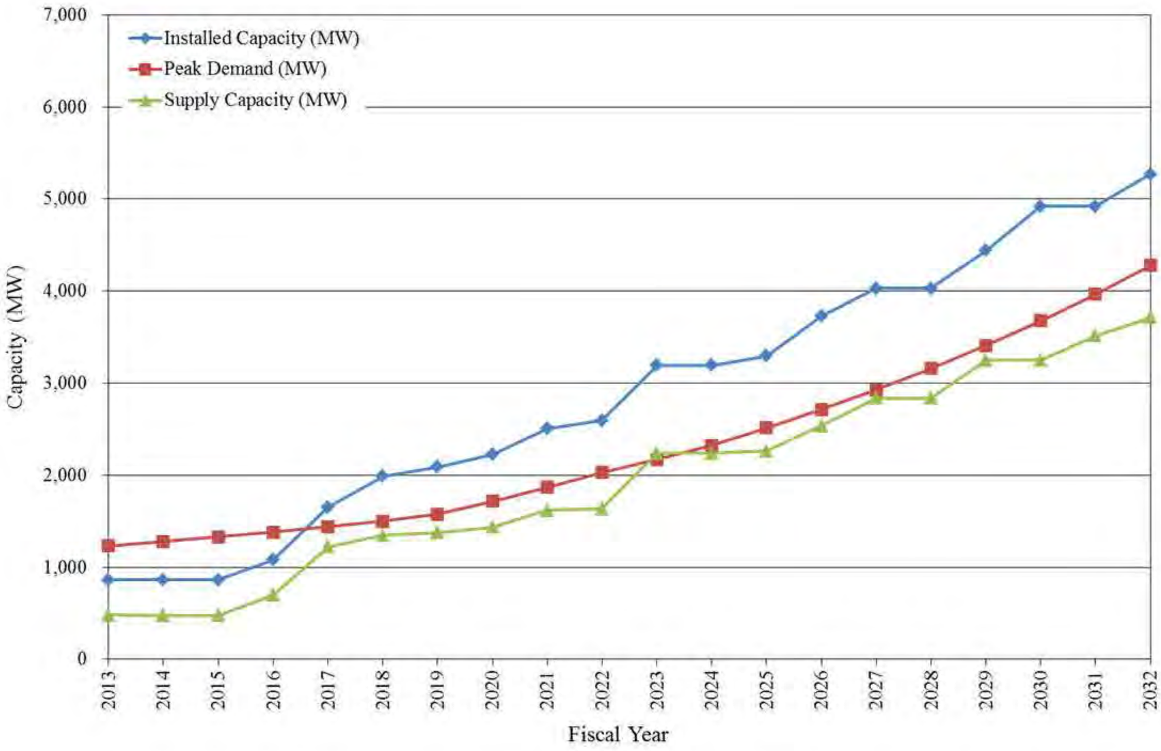


Figure 3.7.2-1 Balance of Supply and Demand (Base Case)

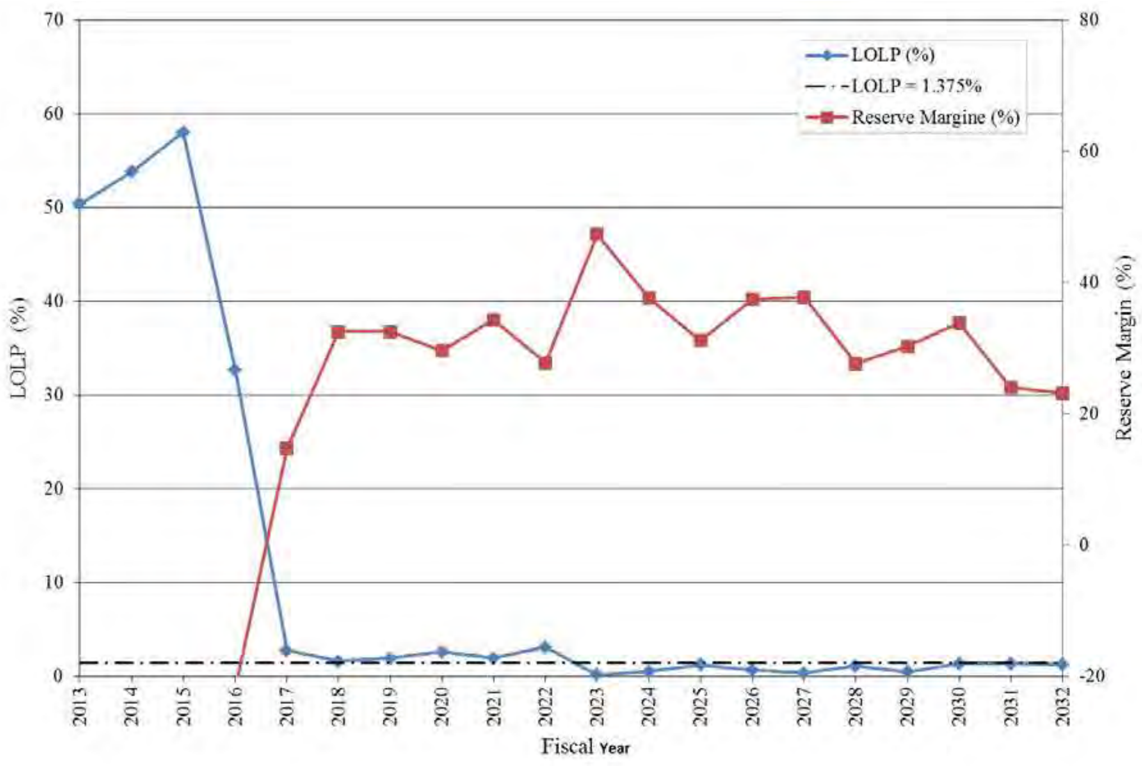


Figure 3.7.2-2 LOLP and Reserve Margin (Base Case)

Chapter 4 Development Plan of Storage-type Hydroelectric Power Projects

4.1 Storage-type Hydroelectric Power Projects to be Implemented

In the power development plan described in Chapter 3, the total installed capacity of hydroelectric power projects (including an increment in imports from India) that start commercial operation in the 20 years from FY2012/13 to FY 2031/32 is 4,256 MW for the base case of demand forecast, 5,317 MW for the high case, and 3,807 MW for the low case. The total installed capacity of storage-type hydroelectric power projects is 1,993 MW for the base case, 3,154 MW for the high case, and 1,644 MW for the low case.

Table 4.1-1 shows the storage-type hydroelectric power projects to be implemented.

Table 4.1-1 Storage-type Projects to be Implemented

Project	Capacity (MW)	Commissioning Year (FY)			Remarks
		Base Case	High Case	Low Case	
Kulekhani No. 3	14	2015/16	2015/16	2015/16	Under construction
Tanahu	140	2020/21	2020/21	2020/21	LA has been concluded.
Budhi Gandaki	600	2022/23	2022/23	2022/23	DD is ongoing.
Dudh Koshi	300	2026/27	2026/27	2027/28	
Nalsyau Gad	410	2028/29	2027/28	2029/30	
Andhi Khola	180	2029/30	2029/30	2031/32	
Chera-1	149	2031/32	2029/30	----	
Madi	200	2031/32	2030/31	----	
Naumure	245	----	2030/31	----	
Sun Koshi No. 3	536	----	2031/32	----	
Lower Badigad	380	----	2031/32	----	
Total Capacity	----	1,993 MW	3,154 MW	1,644 MW	

In all cases, the Dudh Koshi, the Nalsyau Gad, and the Andhi Khola projects are implemented in addition to the Kulekhani No. 3, the Tanahu, and the Budhi Gandaki projects that are now under construction or in preparation of construction.

For the base case of the demand forecast, the Dudh Koshi HPP (300 MW) is put into operation in FY2026/27, followed by the Nalsyau Gad HPP (410 MW) in FY2028/29 and the Andhi Khola HPP (180 MW) in FY2029/30. Then the Chera-1 HPP (149 MW) and the Madi HPP (200 MW) are put into operation in FY2031/32.

For the high case, the Nalsyau Gad and the Madi HPPs are put into operation one year earlier than those for the base case, and the Chera-1 HPP is put into operation two years earlier. In addition to these HPPs, the Naumure HPP (245 MW) is put into operation in FY2030/31, and the Sun Koshi No. 3 (536 MW) and the Lower Badigad (380 MW) HPPs are also put into operation in FY2031/32.

For the low case, the Dudh Koshi and the Nalsyau Gad HPPs are put into operation one year later than those for the base case, and commissioning of the Andhi Khola HPP is two years later than that for the base case. The Chera-1 and other HPPs are not put into operation in and before FY2031/32, the last year of power development plan.

4.2 Investment Necessary to Develop Proposed Storage-type Hydropower Projects

Table 4.2-1 indicates the estimated net cash flow or necessary amount of funds for the base case of the demand forecast during the master plan period. In addition to the funds indicated in the table, additional financial resources to complete hydroelectric power projects currently under construction and ROR-type hydroelectric power projects to be constructed after FY 2018/19 shall be needed to meet the power demand forecasted. In this section, the economic and financial analyses including the Budhi Gandaki project that has a high probability to be constructed but sources and methods of financing has not determined.

During the period of the 20-year master plan (i.e. from FY2012/13 to 2031/32), the total of US$ 4,209 million (interest during construction and price contingency are excluded) is needed for the base case to finance construction of the six (6) proposed storage-type hydroelectric power projects listed in Table 4.2-1. It is assumed that US$ 3,367 million (80% of the total cost) is to be financed from the foreign capital market and the remaining US$ 842 million is to be financed from the domestic capital market. The largest cash flow will be US$ 429 million (US$ 343 million and US$ 86 million to be obtained from foreign and domestic capital markets, respectively) in FY2025/26 needed to finance the construction of storage-type hydroelectric power projects. These cash flow requirements should be considered to be large with respect to the size of Nepal's current GDP (approximately US$ 10 billion); and borrowing from the foreign capital market must be considered. Due to the small size of the domestic capital market, obtaining funds in the range of US$ 16 million to US$ 86 million in each year for the period of 14 years from the market must require the assurance of high returns to the funds obtained. The total amount of investment required for the high case for the implementation of nine (9) projects is US$ 7,149 million, and for the low case for the implementation of four (4) projects is US$ 3,257 million.

Table 4.2-1 Net Cash Flow of the Base Case during the Master Plan Period

Serial no.	Fiscal year	Net cash flow (Million USD at FY2012 price)																													
		Budhi Gandaki			Dudh Koshi			Nalsyau Gad			Andhi Khola			Chera-1			Madi			Naumure			Sun Koshi No.3			Lower Badigad			Total		
		Debt financing (IDC excluded)	Equity financing	Total cost (cash flow basis)	Debt financing (IDC excluded)	Equity financing	Total cost (cash flow basis)	Debt financing (IDC excluded)	Equity financing	Total cost (cash flow basis)	Debt financing (IDC excluded)	Equity financing	Total cost (cash flow basis)	Debt financing (IDC excluded)	Equity financing	Total cost (cash flow basis)	Debt financing (IDC excluded)	Equity financing	Total cost (cash flow basis)	Debt financing (IDC excluded)	Equity financing	Total cost (cash flow basis)	Debt financing (IDC excluded)	Equity financing	Total cost (cash flow basis)	Debt financing (IDC excluded)	Equity financing	Total cost (cash flow basis)	Debt financing (IDC excluded)	Equity financing	Total cost (cash flow basis)
Twenty-year master plan period 1	2012/13																														
2	2013/14																														
3	2014/15																														
4	2015/16	63	16	78																									63	16	78
5	2016/17	63	16	78																									63	16	78
6	2017/18	72	18	90																									72	18	90
7	2018/19	152	38	190	46	12	58																						198	50	248
8	2019/20	197	49	246	52	13	65																						248	62	311
9	2020/21	197	49	246	50	13	63	39	10	49																			286	72	358
10	2021/22	152	38	190	110	27	137	44	11	55																			305	76	382
11	2022/23				109	27	136	42	11	53																			151	38	189
12	2023/24				182	46	228	93	23	116																			275	69	343
13	2024/25				94	24	118	92	23	115	42	11	53	18	5	23	31	8	39										278	69	347
14	2025/26				55	14	69	154	38	192	85	21	106	18	5	23	31	8	39										343	86	429
15	2026/27							80	20	100	106	26	132	33	8	41	34	8	42										252	63	315
16	2027/28							47	12	58	106	26	132	65	16	81	67	17	84										285	71	356
17	2028/29										85	21	106	81	20	102	84	21	105										250	63	313
18	2029/30													81	20	102	84	21	105										166	41	207
19	2030/31													65	16	81	67	17	84										133	33	166
20	2031/32																														
Total		895	224	1,118	698	175	873	590	147	737	423	106	529	362	90	452	400	100	499										3,367	842	4,209

Note: The cost of Budhi Gandaki project was estimated in 1984 in the pre-FS and modified by the Study Team to the 2012 price.

4.3 Analysis of Possible Project Investment Options

The financial internal rate of return (FIRR) or returns to equity investment of each proposed storage-type hydroelectric power project and case-wise FIRR of the base case, high case and low case scenarios were estimated. Based on the obtained values of FIRRs, possible project investment options with funds obtained from public or private sources were also discussed. The economic internal rate of return (EIRR) of each proposed project and case-wise EIRRs of the scenarios were estimated and compared to the examine expected economic impacts of the project and scenarios.

4.3.1 Establishment of Economic and Financial Analyses Frameworks

Construction of storage-type hydroelectric power generation facilities requires a large financial investment. In order to finance the storage-type hydroelectric power projects, particularly by raising private funds, the project should be attractive in terms of its expected financial returns. Political and social risks associated with the projects should also be sufficiently low to promote such investment decisions by private investors. To examine possible investment options of the base case, high case and low case scenarios, the relationships between returns to equity and power prices of each scenario need to be examined. In this section, the framework of financial analysis at a power price of 12 Rs/kWh is introduced. The framework forms the base of the simulation analysis introduced in the later section for the identification of the power price range within which FIRRs become sufficiently large to attract private investment. The framework of EIRR calculation at a power price of 12 Rs/kWh is also introduced in this section. The framework is used to conduct simulation analysis introduced in the next section to examine the expected magnitude of economy-wide impact of the three scenarios.

To conduct financial analysis of the scenarios, cash flows and FIRRs of proposed storage-type hydroelectric power projects are calculated. Furthermore, these cash flows are aggregated for the calculation of FIRR of each scenario. It is also assumed that 80% of the project cost is financed by borrowing at an annual interest rate of 8%, and the remaining 20% of the cost is obtained through equity financing with returns (FIRR) calculated for a 25-year repayment period of borrowing. The interest rate of a loan provided to the industrial sector by the banking sector in 2011 in Nepal was in the rage of 8.0% to 13.5%. In this case, the investment to the power sector in Nepal is considered to be a low risk investment, and therefore, borrowing at 8% interest rate for the project should be reasonable. The assumptions regarding generation capacities of the proposed projects, construction costs without interest during the construction and price contingency, and wet and dry season sellable energy necessary to calculate the returns to equity (FIRR) were also established for the analysis. The calculation of a return to equity (FIRR) for each case is performed for the period of 41 years in which 25-year repayment of all borrowings by 6 projects will be completed. The return to equity (FIRR) for a case is calculated using the aggregated cash flows of all 6 projects included in the case.

The EIRR for each project is calculated for the project period of 50 years. For the determination of EIRR for a case, the EIRR calculation period was set for 61 years within which the 50-year project periods of all the projects in the case can be included.

4.3.2 Analysis of Power Prices and Economic Internal Rate of Return

(1) Project-wise Economic Analysis

Project-wise EIRR calculation was performed assuming that the interest rate of borrowing is 8% and 1%. Among the proposed projects, Budhi Gandaki and Dudh Koshi show the highest EIRR, whereas Madi shows the lowest EIRR indicating it has the least economic impact generated per unit amount of investment. Because EIRR is not sensitive to values of interest rates of loans but is sensitive to power prices, the EIRRs at the interest rates of 8% and 1% are almost identical when the power prices of the two interest regimes are the same.

(2) Case-wise Economic Analysis

Case-wise EIRR calculation was performed assuming that the interest rate of borrowing is 8% and 1%. At the same power price the difference in the EIRR values of the base case, high case and low case is not large. The high case with the largest number of projects (9 projects) and largest investment cost shows the lowest EIRR, and the low case with the smallest number of projects (4 projects) with the smallest investment cost shows the highest EIRR. Because EIRR is not sensitive to values of interest rates of loans but is sensitive to power prices, the EIRRs of each case at the interest rates of 8% and 1% are almost identical when the power prices of the two interest regimes are the same.

4.3.3 Analysis of Power Prices and FIRR - Examination of Private Sector Investment

As indicated in the previous section, the construction of storage-type hydroelectric power generation facilities requires a large financial investment. In order to finance the storage-type hydroelectric power projects by raising private funds, the projects should be attractive in terms of their expected financial returns. Political and social risks associated with the projects should also be sufficiently low to promote such investment by private investors. To examine possible investment options and financial resource mobilization, the relationships between returns to equity and power prices are examined. A simulation analysis is applied to identify the power price range within which FIRRs become sufficiently large to attract private investment.

For financial analysis, it is assumed that storage-type hydroelectric power generation facilities are constructed by an IPP established separately from NEA, and that generated electricity by the IPP is to be sold to NEA. For the calculation of returns to equity financing (i.e. FIRR) it is assumed that 80% of the project cost is financed by borrowing at annual interest rate of 8%, and the remaining 20% of the cost is covered by the equity financing.

Table 4.3.3-1 and Table 4.3.3-2 present results of financial analyses by cases and FIRRs at power prices of 6 Rs/kWh, 8 Rs/kWh, 10 Rs/kWh, 12 Rs/kWh, 14 Rs/kWh, and 16 Rs/kWh. The power prices at 12% FIRR are also indicated in these tables. Because the range of interest rates of time deposits for the period of more than two years is in a range of 5.0% to 12.5% as of 2011, and a return of equity expected by investors can be assumed at 12%.

Table 4.3.3-1 Summary of Project-wise FIRR with 8% Interest on Long-term Debt

Project name	Installed capacity (MW)	Project (financial) cost ('000 USD)	Saleable energy (GWh) Dry season	Wet season	Annual Total	Interest on long- (%)	Return on equity (FIRR) Average power price for dry and wet season (Rs/kWh) 6Rs (%)	8Rs (%)	10Rs (%)	12Rs (%)	14Rs (%)	16Rs (%)	Power price at 12% FIRR (Rs/kWh)
NEA Project													
Budhi Gandaki	600	1,118,400	500	2,000	2,500	8.0%	11.4%	22.6%	29.6%	35.0%	39.5%	33.2%	6.08
Promising Projects													
Dudh Koshi	300	872,513	523	1,386	1,910	8.0%	9.5%	19.4%	25.4%	30.0%	33.8%	36.9%	6.38
Nalsyau Gad	410	737,393	515	853	1,367	8.0%	n.a.	14.0%	20.9%	25.8%	29.7%	32.9%	7.58
Andhi Khola	180	529,088	137	512	649	8.0%	n.a.	n.a.	11.2%	19.1%	24.9%	29.8%	10.18
Chara-1	149	452,083	121	443	563	8.0%	n.a.	n.a.	10.4%	17.8%	23.1%	27.4%	10.36
Madi	200	499,460	171	450	621	8.0%	n.a.	n.a.	9.3%	16.8%	21.9%	26.0%	10.61
Naumure	245	727,968	310	848	1,158	8.0%	n.a.	10.9%	19.4%	25.3%	29.9%	33.8%	8.21
Sun Koshi No.3	536	1,289,280	336	1,548	1,884	8.0%	n.a.	1.6%	13.6%	19.4%	23.7%	27.1%	9.57
Lower Badigad	380	922,695	355	1,011	1,366	8.0%	n.a.	2.9%	14.1%	19.8%	24.0%	27.4%	9.45

Note: 1) n.a. (not applicable) means that the FIRR cannot be calculated due to negative net present values.

The results indicate that large-scale projects with high investment costs tend to have large salable electricity energy and they yield high FIRR even though power prices are relatively low. The financial analysis of the NEA presented in the next section indicates that the NEA's average purchase price of electricity from IPPs in FY2010/11 is 9.21 Rs/kWh at the 2012 constant price. Even prices lower than the 2011 purchase price exhibit better than those of the cut-off FIRR of 12% for some projects. For example, Budhi Gandaki, Dudh Koshi and Nalsyau Gad projects exhibit rates of return to equity (FIRR) of 22.6%, 19.4%, and 14.0% at the price of 8 Rs/kWh, respectively. At the 12% cut-off FIRR value for investment, wholesale power prices of the projects become 6.08 Rs/kWh, 6.38 Rs/kWh, and 7.58 Rs/kWh for the Budhi Gandaki, Dudh Koshi, and Nalsyau Gad projects, respectively. These prices are significantly lower than the FY2010/11 average purchase price of the NEA, and therefore these projects should be considered attractive for investors as long as the NEA purchases power at the 2011 purchase price.

As shown in the financial analysis of the NEA presented in the next section, the appropriate power purchase price is estimated to be 5.18 Rs/kWh at the 2012 constant price. To maintain the NEA's financially viability, the NEA needs to purchase power from IPPs at a price less than or equal to 5.18 Rs/kWh. In this case, FIRRs of the all projects concerned become less than 12% and are not attractive for private sector investment.

Table 4.3.3-2 Summary of FIRR of the Cases with 8% Interest on Long-term Debt

Case	Interest on long-term debt (%)	Return on equity (FIRR) Average power price for dry and wet season (Rs/kWh) 6Rs (%)	8Rs (%)	10Rs (%)	12Rs (%)	14Rs (%)	16Rs (%)	Power price at 12% FIRR (Rs/kWh)
Base Case	8.0%	5.6%	18.7%	26.5%	32.2%	36.8%	40.8%	6.79
High Case	8.0%	-0.6%	16.7%	25.5%	31.8%	36.7%	40.9%	7.24
Low Case	8.0%	8.9%	20.4%	27.7%	33.2%	37.8%	41.6%	6.42

Table 4.3.3-2 shows a summary of FIRR of the three cases with 8% interest on long-term debt. The low case shows the highest FIRR followed by the base case, and the high case shows the lowest FIRR values. The highest development cost is incurred by the high case scenario which shows the smallest FIRR, whereas the low case requires the smallest development cost but shows the highest FIRR. However, the differences of FIRR among the three cases are relatively small. Because 12% of FIRR is considered to be a cut-off value of investment decision-making, wholesale power prices should be charged by IPPs becomes in the range of 6.42 Rs/kWh - 7.24 Rs/kWh. Since this range is lower than the NEA's FY2010/11 purchase price of 9.21 Rs/kWh at the 2012 price, all three cases should attract private sector investment.

However, as analyzed in the next section, this high purchase price is the major cause of the NEA incurring financial loss, and it should be adjusted accordingly. The analysis suggested that an appropriate power purchase price is 5.18 Rs/kWh at the 2012 constant price, and that with this price the calculated FIRRs of all the cases become less than 12% indicating private investment to the power development to be unattractive.

In order to promote implementation of the medium- to long-term hydroelectric power development with active participation of IPPs and private sector investment, the establishment of a stable and good investment environment is the key to achieve such hydroelectric power development. If the risk of changes in feasibility and profitability of planned hydroelectric power projects is high because of a volatile socioeconomic and political environment, the investment to hydroelectric power development projects can be high risk, discouraging such investment. It can be said that the NEA's high power purchase price offered to IPPs is a mechanism to transfer such risks borne by IPPs to NEA where government support can be obtained as a last resort. IPPs also try to reduce risks by selecting relatively small ROR-type hydroelectric power projects with a short construction period. Although hydroelectric power development by IPPs should be promoted further, the development only by IPPs will not be able to address the insufficient power supply and high cost of the electricity supply. Therefore, the development of storage-type hydroelectric power projects, though its cost is high, should also be considered for implementation.

Based on the above discussions, the following policy measures need to be considered to address risks associated with the hydropower development by IPPs.

1) To determine appropriate wholesale prices by a fully distributed cost method to secure a reasonable level of profit of IPPs.
2) To provide long-term and low-interest loans to IPPs to reduce financial costs for the provision of power with a low price.
3) To promote private sector investment to hydroelectric power development through the reduction of investment risk by securing access to the large power market in India. In this case, the establishment of a bilateral agreement between India and Nepal should be considered to reduce political and economic risks.

4.3.4 Analysis of Power Prices and FIRR - Examination of Public Sector Investment

In the previous section, 80% of the construction cost including interest during the construction period is assumed to be financed by borrowing from commercial banks at the annual interest rate of 8%. In this section, the 80% of the construction cost is assumed to be financed by low interest loans obtained from public institutions such as government banks, bilateral and multilateral development partners and banks in order to lower prices of electricity and/or to increase returns to equity (FIRR). However, it should be appropriate to lower prices of electricity to achieve fair and wide distribution of economic benefit and welfare rather than to increase returns to equity due to the public nature of the low cost loans. In this section, possibility of the NEA to implement hydroelectric power development projects including large storage-type hydroelectric power project by mobilizing low-cost government and donor resources will be examined.

<Examination of cost and retail price of electricity>

NEA generates electricity by itself and purchases electricity from IPPs and the Indian electricity market. Based on the balance sheet and profit and loss statement in the annual report FY2010/2011, the unit cost of electricity and retail price at delivery point are calculated. In FY2010/11, the NEA generated 2,096 GWh by its own generation facilities and purchased 1,733 GWh from IPPs and the Indian market. The total of 3,829 GWh of electric energy was secured by the NEA at generation and purchase points. On the other hand, the total of 2,728 GWh of energy was distributed at distribution points indicating a very high system loss of approximately 28%.

The unit cost per kWh at the distribution point is calculated in order to compare the unit cost with the retail price of electricity at the distribution point. The generation cost of electricity by the NEA's own facilities and cost of power purchase are different, whereas the cost of transmission and distribution is identical regardless of the methods of electricity generation or purchase.

In FY2010/11, the NEA reported a loss of Rs 6,089 million. Including incomes other than the sale of electricity, the total income from electricity business is reported to be Rs 17,947 million. The total cost of the same year amounts to Rs 25,414 million, which resulted in the total loss of Rs 7,472 million. The primary reason of this large loss occurring every year since early 2000s is the high power purchase price and low retail price. The high system loss also contributes to the high cost and subsequent loss of profit.

The average retail price of electricity in FY2010/11 is 6.58 Rs/kWh, whereas the cost of electricity generated by the NEA's facilities is 6.01 Rs/kWh. In this case, the NEA is able to make profit. The cost of 6.01 Rs/kWh consists of the cost of generation at 1.19 Rs/kWh, the cost of operation at 2.78 Rs/kWh which includes the cost of transmission, distribution, administration, and depreciation, and the cost of interest payment and welfare at 2.04 Rs/kWh. The total cost of electricity purchased is 13.32 Rs/kWh which is high and causes the NEA's financial loss. The total cost of electricity purchased includes the cost of purchase at 8.50 Rs/kWh, and other cost components are the same as cost of electricity generated by the NEA. The results of this cost analysis revealed that the NEA's loss comes from the fact that the loss caused by the high power purchase price and low retail price cannot be offset by the profit generated by sale of electricity generated by the NEA's own facilities. This also reflected in the fact that the average cost of electricity generation and purchase cost is 9.32 Rs/kWh and the average retail price is 6.58 Rs/kWh indicating a loss of 2.72 Rs/kWh per unit sale of electricity.

<Examination of NEA generation and power purchase at the breakeven point>

From the estimated unit costs of NEA generation and power purchase, the average retail electricity price, and energy demand determined by the base case, NEA generation and power purchase portfolios at the breakeven point are calculated and shown in Table 4.3.4-1. In FY2010/11, for example, actual NEA generation is 1,493 GWh (corresponding load capacity is 279 MW), and required NEA generation at the breakeven point is 2,516 GWh (corresponding load capacity is 471 MW). To reach the breakeven point, NEA generation should be increased by 1,023 GWh. On the other hand, the actual power purchase of 1,234 GWh must be reduced to 212 GWh to reach the breakeven point. In terms of load capacity, the NEA needs an additional 191 MW capacity whereas IPPs have an excess capacity of 191 MW in FY2010/11.

Assuming that the cost structure of NEA in FY2010/11 will remain the same in the future, NEA generation and power purchase at the breakeven point in FY2018/19 and 2031/32 are calculated. In the calculations, generation costs of ROR-type facilities and storage-type facilities are considered equal. Applying the results of the base case demand forecast, the FY2018/19 electricity price is set at 12 Rs/kWh and demand at the supply point is at 5,669 GWh (equivalent to supply energy of 7,176 GWh and generation capacity of 1,575 MW both at the generation point). By the same token, the 2032 electricity price is set at 12 Rs/kWh and demand at the supply point is set at 16,179 GWh (equivalent to supply energy of 19,493 GWh and generation capacity of 4,279 MW both at the generation point) for the calculation of breakeven NEA generation and power purchase.

In FY2018/19 at breakeven point, NEA generation becomes 1,023 GWh, which is 470 GWh less than NEA generation in FY2010/11. On the other hand, power purchase in FY2018/19 becomes

4,646 GWh, showing a significant increase from the 2011 power purchase. This is because the increase in retail electricity price from 6.58 Rs/kWh to 12.00 Rs/kWh results in a decrease in loss caused by the power purchase which can be offset by a lesser amount of profit drawn from the NEA generation. It means that a lesser amount of low-cost NEA generation is required to offset the loss. These results indicate that by expanding low-cost NEA generation, a larger quantity of electricity can be supplied to the power market at a lower retail price in order for the power sector to contribute to the economic growth of Nepal. Lowering the retail electricity price from 12 Rs/kWh to 10 Rs/kWh requires NEA generation of 2,575 GWh, requiring an increase of 1,082 GWh from the NEA generation inFY2010/11. The increase requires additional NEA generation capacity of 436 MW. By the same token, lowering the retail price from 12 Rs/kWh to 10 Rs/kWh in FY2031/32 requires additional NEA generation of 5,856 GWh, which also requires an increase of NEA's generation capacity by 1,665 MW from the capacity in FY2010/11.

Table 4.3.4-1 Results of Breakeven Point Analysis (at 2011 prices)

Breakeven simulation parameters and electrical energy sources / Cases	Unit cost of NEA generation (Rs/kWh)	Unit cost of power purchase (Rs/kWh)	Average sale price (Rs/kWh)	Sale of electrical energy by sources: Total (GWh)	Generated by NEA (GWh)	Purchased by NEA (GWh)	Required generation capacity: System losses (%)	System load factor (%)	Total (MW)	Generated by NEA (MW)	Purchased by NEA (MW)
	a	b	c	d=e+f	e*1	f	g	h	i=j+k	j	k
1. Cases in FY2010/11											
Case 1-1: Actual sale in FY2010/11	6.01	13.32	6.58	2,728	1,493	1,234	29%	86%	510	279	231
Case 1-2: Breakeven in FY2010/11	6.01	13.32	6.58	2,728	2,516	212	29%	86%	510	471	40
Difference between Cases 1-1 and 1-2					1,023	-1,023				191	-191
2. Breakeven cases in FY2018/19											
Case 2-1: Breakeven in FY2018/19 at 12Rs/kWh	6.01	13.32	12.00	5,669	1,023	4,646	21%	52%	1,575	284	1,291
Difference between Cases 1-1 and 2-1			5.42	2,941	-470	3,411			1,065	5	1,060
Case 2-2: Breakeven in FY2018/19 at 10Rs/kWh	6.01	13.32	10.00	5,669	2,575	3,094	21%	52%	1,575	716	860
Difference between Cases 1-1 and 2-2			3.42	2,941	1,082	1,859			1,065	436	629
3. Break even case in FY2031/32											
Case 3-1: Breakeven in FY2031/32 at 10Rs/kWh	6.01	13.32	10.00	16,179	7,349	8,830	17%	52%	4,279	1,944	2,335
Difference between Cases 1-1 and 3-1			3.42	13,451	5,856	7,595			3,769	1,665	2,105

Note: 1) For calculation of breakeven point e = d × (c - b) / (a - b).

<Expansion of NEA generation capacity by the government's investment and concessionary loans >

The above analysis relies on the assumption that the cost of NEA generation is low and 6.01 Rs/kWh at the sale point. To expand this low cost NEA generation, construction of additional generation facilities with the government's investment and concessionary loans from the ODA is assumed. Based on this assumption, a financial analysis is conducted to examine the relationship between retail price of electricity and returns to equity (FIRR). The results of the analysis are presented in Table 4.3.4-2. Eighty percent of the construction costs including interest during the construction is assumed to be financed by concessionary loans with an interest rate of 1% and a repayment period of 25 years, and the rest of the construction costs are assumed to be financed by the government's equity investment to NEA, to which returns to equity (FIRR) are calculated. Since the cost of NEA generation at the sale point in FY2010/11 is 6.01 Rs/kWh, FIRRs of the assumed electricity prices around the cost are calculated. Because the holder of the equity is the government, prices of electricity at 6% of return to the equity (FIRR), which is about half of the commercial rate of return (12%), are calculated.

The FY2010/11 cost of NEA generation 6.01 Rs/kWh at the sale point includes transmission and distribution costs. However, because the above model used to derive FIRR and power prices at 6% FIRR does not consider the transmission and distribution cost of 1.23 Rs/kWh, for the sake of analysis the cost of electricity at 4.78 Rs/kWh at the generation point (derived by subtracting 1.23 Rs/kWh from the cost of NEA generation 6.01 Rs/kWh at the sale point) is used as the threshold value. In order to interpret the results, the threshold value of 4.78 Rs/kWh expressed in 2011 prices is adjusted to the 2012 constant price of 5.18 Rs/kWh by recognizing the 8.3% increase in the consumer price index from 2011 to 2012. Storage-type hydroelectric power projects which show more than 6% FIRR, even though their cost of electricity at the wholesale point is lower than this threshold value (i.e. 5.18 Rs/kWh at the 2012 constant price) are given higher priority for development with the government's investment and concessionary loans.

Based on the results shown in Table 4.3.4-2, the highest priority is given to Dudh Koshi project (3.13 Rs/kWh) followed by Budhi Gandaki project (3.31 Rs/kWh), Nalsyau Gad project (3,77 Rs/kWh), Naumure project (4.23 Rs/kWh), Lower Badigad project (4.66 Rs/kWh), and Sun Koshi No. 3 project (4.90 Rs/kWh).

Table 4.3.4-2 Summary of Project-wise FIRR with 1% Interest on Long-term Debt

Project name	Installed capacity (MW)	Project (financial) cost ('000 USD)	Saleable energy (GWh)			Interest on long- (%)	Return on equity (FIRR) Average power price for dry and wet season (Rs/kWh)						Power price at 6% FIRR (Rs/kWh)
			Dry season	Wet season	Total		3Rs (%)	4Rs (%)	5Rs (%)	6Rs (%)	7Rs (%)	8Rs (%)	
NEA Project													
Budhi Gandaki	600	1,118,400	500	2,000	2,500	1.0%	1.1%	12.4%	18.3%	22.8%	26.5%	29.7%	3.31
Promising Projects													
Dudh Koshi	300	872,513	523	1,386	1,910	1.0%	4.7%	12.1%	16.9%	20.5%	23.6%	26.2%	3.13
Nalsyau Gad	410	737,393	515	853	1,367	1.0%	n.a.	7.8%	13.2%	17.1%	20.2%	22.9%	3.77
Andhi Khola	180	529,088	137	512	649	1.0%	n.a.	n.a.	2.6%	9.2%	13.7%	17.4%	5.45
Chara-1	149	452,083	121	443	563	1.0%	n.a.	n.a.	3.4%	9.3%	13.4%	16.8%	5.38
Madi	200	499,460	171	450	621	1.0%	n.a.	n.a.	2.8%	8.9%	12.9%	16.1%	5.46
Naumure	245	727,968	310	848	1,158	1.0%	n.a.	4.1%	10.8%	15.4%	19.1%	22.2%	4.23
Sun Koshi No.3	536	1,289,280	336	1,548	1,884	1.0%	n.a.	-0.3%	7.7%	12.1%	15.4%	18.2%	4.71
Lower Badigad	380	922,695	355	1,011	1,366	1.0%	n.a.	0.3%	8.0%	12.4%	15.7%	18.4%	4.66

Note: n.a. (not applicable) means that FIRR cannot be calculated due to negative net present values.

The base case-, high case- and low case-wise results of the analysis to determine suitable scenarios for addressing the electricity demand increase by mobilizing the government's investment and concessionary loans are shown in Table 4.3.4-3. Considering the threshold value for 6% FIRR is 5.18 Rs/kWh at the 2012 constant price, and the costs of NEA generation at the generation point for all cases are within the range of 3.32 Rs/kWh to 3.79 Rs/kWh, all cases are considered to be appropriate for implementation by the government's investment and concessionary loans.

Table 4.3.4-3 Summary of FIRR of the Cases with 1% Interest on Long-term Debt

Case	Interest on long-term debt (%)	Return on equity (FIRR) Average power price for dry and wet season (Rs/kWh) 3Rs (%)	4Rs (%)	5Rs (%)	6Rs (%)	7Rs (%)	8Rs (%)	Power price at 6% FIRR (Rs/kWh)
Base Case	1.0%	0.0%	9.6%	15.6%	20.2%	24.0%	27.2%	3.54
High Case	1.0%	-4.1%	7.7%	14.2%	19.1%	23.1%	26.6%	3.79
Low Case	1.0%	2.7%	11.2%	16.8%	21.3%	24.9%	28.1%	3.32

Financial analyses are conducted with respect to the electricity price, returns to equity (FIRR), interest rate of loan, cost of generation, and possibility of mobilization of investment and loans from private and public sectors for hydroelectric power development. Storage-type hydroelectric power projects and the cases showing high returns to equity (FIRR) and being able to pay a high interest rate comparable to commercial rates should attract private sector investors. However, the high returns and interest rates likely result in a negative impact on the country's economic growth. Because the functions of the power sector have the nature of the public sector, endeavoring for stable, reliable, and low cost supply of electricity needs to be achieved with a high priority. Therefore, the NEA should implement storage-type hydroelectric power projects by mobilizing the government's investment and concessionary loans to secure stable, reliable, and fairly priced electricity.

The financial analysis of the NEA's business identified a number of management issues: 1) high system loss significantly contributes to the high cost of electricity delivery, 2) having high electricity purchase prices and low sale price schedules incurs large financial loss and is financially not feasible, and 3) high cost of rural electrification. Therefore, it is recommended that the current efforts of organizational reforms and improvement of management and business efficiency must be continued and strengthened.

Regarding the sector-wide perspective, strong political will to improve policy and market environment of the power sector is needed. The market distortions stemmed from, for example, the unmatched price schedules of IPP generated electricity and the NEA's retail price schedule is a serious concern. Establishment of a competitive wholesale power market should be considered in order to reduce the wholesale price to a reasonable level. Adjustment of the retail price should also be considered to determine a reasonable retail price schedule to secure the NEA's financial soundness and further investment for its core businesses.

Chapter 5 Selection and Evaluation of Promising Projects

As described in Chapter 3, development of storage-type hydroelectric power generation is absolutely necessary for overcoming the current power shortage in the dry season and for meeting an increase in power demand in the future. In 2009, the NEA made out a long list of 65 potential storage-type hydroelectric power projects for the Study. In this chapter, these potential projects were evaluated from technical, economical, and environmental aspects, and promising projects that were candidate projects of the power development plan in Chapter 3 were selected.

5.1 Selection of Promising Storage-type Projects

5.1.1 Projects examined in the Study

The projects examined in the Study are 65 projects in the long list of potential sites of storage-type hydroelectric power projects that was prepared by the NEA in December 2009, and two projects (the Bagmati Multipurpose Project (C-19) and the Nisti-Panah Project (W-27)) that were added by the NEA's request at the start of the Study, in January 2012. These 67 potential projects are shown in Table 5.1.1-1.

Table 5.1.1-1 Projects in the Long List

Eastern River Basin			Central River Basin			Western River Basin		
No.	Project Name	Capacity (MW)	No.	Project Name	Capacity (MW)	No.	Project Name	Capacity (MW)
E-01	Dudh Koshi	300.0	C-01	Kaligandaki-Modi	816.4	W-01	Barbung Khola	122.9
E-02	Dudh Koshi-2	456.6	C-02	Lower Badigad	380.3	W-02	Chera-1	148.7
E-03	Dudh Koshi-3	1,048.6	C-03	Lower Daraudi	120.2	W-03	Chera-2	104.3
E-04	Dudh Koshi-4	1,603.0	C-04	Seti-Trisuli	128.0	W-04	Humla-Karnali	467.1
E-05	Khimti	128.1	C-05	Upper Daraudi	111.4	W-05	Lower Jhimruk	142.5
E-06	Kokhajor-1	111.5	C-06	Kaligandaki-2	660.0	W-06	Madi	199.8
E-07	Likhu-1	91.2	C-07	Budhi Gandaki	600.0	W-07	Mugu Karnali	3,843.8
E-08	Mulghat	2,647.7	C-08	Andhi Khola	180.0	W-08	Sani Bhari-1	763.5
E-09	Piluwa-2	107.3	C-09	Langrang Khola	218.0	W-09	Sani Bhari-2	646.9
E-10	Rosi-2	106.5	C-10	Uttar Ganga	300.0	W-10	Sharada-2	96.8
E-11	Sankhuwa-1	176.0	C-11	Madi-Ishaneshor	86.0	W-11	Thuli Gad-2	119.7
E-12	Tama Koshi-3	330.0	C-12	Kali Gandaki No.1	1,500.0	W-12	Tila-1	617.2
E-13	Tamor No.1	696.0	C-13	Marsyangdi	510.0	W-13	Tila-3	481.9
E-14	Tamor (Terahathum)	380.0	C-14	Seti (Gandaki)	230.0	W-14	Thuli Gad	120.0
E-15	Sun Koshi No.1	1,357.0	C-15	Dev Ghat	150.0	W-15	LR-1	98.0
E-16	Sun Koshi No.2	1,110.0	C-16	Bhomichok	200.0	W-16	BR-3B	801.0
E-17	Sun Koshi No.3	536.0	C-17	Trishulganga	1,500.0	W-17	BR-4	667.0
E-18	Sun Koshi No.3	432.0	C-18	Ridi Khola	97.0	W-18	Surkhet	600.0
E-19	Sun Koshi No.3	190.0	C-19	Bagmati MP *	140.0	W-19	Lakarpata	1,200.0
E-20	Indrawati	91.2				W-20	Bhanakot	810.0
E-21	Kankai	90.0				W-21	Thapna	500.0
						W-22	SR-6	642.0
						W-23	Nalsyagu Gad	400.0
						W-24	Sarada Babai	75.0
						W-25	Naumure (W. Rapti)	245.0
						W-26	Lohare Khola	67.0
						W-27	Nisti-Panah *	90.4

*: Added in January 2012.

5.1.2 Selection Procedure of Promising Projects

Promising projects were selected by the following procedure.

Step-1: Selection of Projects that are subjected to the Evaluation
In the above-mentioned 67 potential projects, there were some projects that were not appropriate for objects of evaluation in the Study. In Step-1, these inappropriate projects were excluded from the potential projects, and the projects to be evaluated in the Study (hereinafter referred to as the candidate projects) were selected.

Step-2: Evaluation of Candidate Projects
Evaluation of the candidate projects selected in Step-1 was conducted. Specifically, scores of all candidate projects were calculated based on the evaluation items and the criteria described in 5.1.4.1 and the weight of evaluation items described in 5.1.4.2, then they were ranked by their score.

Step-3: Selection of Promising Projects
Projects that are promising as the projects to be listed in the master plan of hydroelectric power development in Nepal were selected, taking into consideration the location of each project, overlapping with other projects to which a construction license or a survey license had already been issued.

5.1.3 Selection of Projects that are subjected to the Evaluation (The First Step)

Some projects in the above-mentioned long list were deemed inappropriate as candidates of evaluation in the Study. These projects were excluded and the projects to be evaluated in the Study were selected.

(1) Exclusion of Projects of which Detailed Design or Feasibility Study is in Progress or in Planning

Since the above-mentioned long list was prepared in 2009, more than two years had passed at the start of the Study. In May 2012, when this exclusion was conducted, one project in the long list had already proceeded to the detailed design stage, and feasibility study or pre-feasibility study was planned by the NEA for some projects. Since detailed design is conducted on the premises of the implementation of the project, and feasibility studies and pre-feasibility studies are more detailed studies than this master plan study, the implementation of evaluation on these projects in the Study were deemed as not useful, and these projects were excluded from the projects to be evaluated in the Study. However, these projects were taken into consideration in the Master Plan that was prepared in the final stage of this study. Regarding the Nalsyau Gad project, of which a feasibility study was being carried out at the time, this project was evaluated in the Study since the interim report had already been prepared and it was available to the Study Team. The excluded projects are shown in the column A of Table 5.1.3-1.

(2) Exclusion of Projects that overlap with Other Projects

The locations of the following projects are about the same with other projects. Since it is difficult to implement both projects, the following projects were excluded.

Tamor No. 1 (E-13: 696 MW)

Tamor No. 1 was excluded and E-14: Tamor (Terahathum) (380 MW) was adopted because the study of the Tamor (Terahathum) project was conducted later than Tamor No. 1.

Sun Koshi No. 3 (E-18: 432 MW) and E-19: Sun Koshi No. 3 (190 MW)

These two projects were excluded and E-17: Sun Koshi No. 3 (536 MW) was adopted because this alternative is the optimum development plan in the "Master Plan Study on the Koshi River Water Resources Development" (March 1985, JICA).

Seti (Gandaki) (C-14: 230 MW)

This project was excluded because its location overlaps with the Upper Seti project that is now in the detailed design stage.

Thuli Gad (W-14: 120 MW)

Thuli Gad was excluded and W-11: Thuli Gad -2 (119.7 MW) was adopted because the study of the Thuli Gad -2 project was conducted later than Thuli Gad.

LR-1 (W-15: 98 MW)

LR-1 was excluded and W-26: Lohare Khola (67 MW) was adopted because the study of the Lohare Khola project was conducted later than LR-1.

These excluded projects are shown in the column B of Table 5.1.3-1.

(3) Exclusion of Projects that is not appropriate as exclusion for Storage-type Hydroelectric Power Projects for Domestic Supply in Nepal

From the viewpoints of installed capacity, dam height, project cost, regulating capacity of reservoir[4], number of submerging households, etc., projects that were deemed inappropriate as a storage-type hydroelectric power project in Nepal were excluded.

It should be noted that the projects that were excluded by this screening might be worth studying from the viewpoints of power exports, multi-purpose development, etc.

Installed Capacity

In general, large electric power plants are economically efficient, but they have a large impact on the power system if an accident or trouble happens. The objects of this study are storage-type hydroelectric power plants for domestic supply that are connected to the Integrated Nepal Power System (INPS). Taking into consideration that the total installed capacity of Nepal at the end of FY2010/11 was about 700 MW and that the power demand in FY2027/28 forecasted by the NEA is about 3,700 MW, the adequate size (installed capacity) of one power plant seemed to be several hundred megawatts. In this study, projects whose installed capacity is more than 1,000 MW were excluded. (See the column C of Table 5.1.3-1)

[4] Regulating capacity of reservoir (%) = (Effective storage volume of reservoir) / (Annual inflow) × 100

Dam Height

The highest dam in the world as of January 2012 was the Nurek dam in Tajikistan, and its dam height is 300 m. Since there are technical difficulties in construction of a dam higher than the world's highest dam, problems such as a long construction period because of large dam volume are expected, and projects with a dam higher than 300 m were excluded from the projects to be evaluated in the next stage of this study. (See the column D of Table 5.1.3-1)

Project Cost

The fiscal scale of Nepal is small, and implementation of projects requiring a very large project cost in the near future was deemed difficult. Since the national budget in FY2009/10 was about US$ 4.5 billion and the current project costs are higher than those at the time point of cost estimation, projects whose project cost is more than US$ 2 billion were excluded from the projects to be evaluated in the next stage of this study. (See the column E of Table 5.1.3-1)

Regulating Capacity of Reservoir

Projects whose regulating capacity of reservoir is less than 5% were excluded, taking into consideration that the main role of projects in the Study is seasonal regulation of river flow, that is to store excess river flow in the rainy season and to discharge the stored water in the dry season. (See the column F of Table 5.1.3-1)

Number of Submerging Households

Since a large number of relocation of households has a serious impact on the social environment of the project area, careful judgment is required for implementing such projects. A small number of relocation of households is preferable, but taking into consideration that the development of hydroelectric power generation in Nepal is the one and only means for resolving power shedding to achieve economic growth and to enhance people's living standards, the threshold value in the Study was determined to be 5,000 households. (See the column G of Table 5.1.3-1)

National Park and Protected Areas[5]

Projects that located in the areas stipulated in the "National Parks and Wildlife Conservation Act, 2029" were excluded. (See the column H of Table 5.1.3-1).

World Heritage Site

Projects that were located in world heritage sites were to be excluded. However, there was no project in Table 5.1.3-1 that was located in a world heritage site.

(4) Selected Candidate Projects

As the result of exclusion described in the above, 31 projects that are shown in Table 5.1.3-1 with "✓" are selected as the candidate projects.

[5] JICA Guidelines for Environmental and Social Considerations (April 2004) stipulates as follows: "Projects must, in principle, be undertaken outside protected areas that are specifically designated by laws or ordinances of the governments for conservation of nature or cultural heritage."

Table 5.1.3-1 Selection of Candidate Projects

No.	Project Name	Selected Candidate Project	Excluded from Object of Evaluation							
			A	B	C	D	E	F	G	H
			DD, FS or Pre FS Stage	Overlap with Other Project	Installed Capacity > 1,000MW	Dam Height > 300m	Project Cost > US$2,000M	Regulating Capability Factor < 5%	Submerging Houses > 5,000	National Parks and Wildlife Conservation Act
E-01	Dudh Koshi	✓								
E-02	Dudh Koshi-2	✓**						*3.50*		
E-03	Dudh Koshi-3				1,048.6	357.0	2,264.3			
E-04	Dudh Koshi-4				1,603.0	425.0	2,872.6			
E-05	Khimti							2.91		
E-06	Kokhajor-1	✓								
E-07	Likhu-1							2.87		
E-08	Mulghat				2,647.7		2,368.1			
E-09	Piluwa-2	✓								
E-10	Rosi-2	✓								
E-11	Sankhuwa-1									Conservation Area
E-12	Tama Koshi-3	✓								
E-13	Tamor No.1			with E-14						
E-14	Tamor (Terahathum)		Pre FS							
E-15	Sun Koshi No.1				1,357.0			0.19		
E-16	Sun Koshi No.2				1,110.0					
E-17	Sun Koshi No.3 (536 MW)	✓								
E-18	Sun Koshi No.3 (432 MW)			with E-17						
E-19	Sun Koshi No.3 (190 MW)			with E-17						
E-20	Indrawati	✓								
E-21	Kankai								11,700	
C-01	Kaligandaki-Modi	✓								
C-02	Lower Badigad	✓								
C-03	Lower Daraudi	✓								
C-04	Seti-Trisuli							2.56		
C-05	Upper Daraudi	✓								
C-06	Kaligandaki-2		FS						7,000	
C-07	Budhi Gandaki		DD							
C-08	Andhi Khola	✓								
C-09	Langrang Khola									National Park
C-10	Uttar Ganga									Hunting Reserve
C-11	Madi-Ishaneshor	✓								
C-12	Kali Gandaki No.1				1,500.0					
C-13	Marsyangdi								5,170	
C-14	Seti (Gandaki)			with Upper Seti						
C-15	Dev Ghat							0.32		
C-16	Bhomichok							0.07		
C-17	Trishulganga				1,500.0					
C-18	Ridi Khola	✓								
C-19	Bagmati MP *		FS							
W-01	Barbung Khola	✓**						*2.75*		
W-02	Chera-1	✓								
W-03	Chera-2	✓								
W-04	Humla-Karnali							2.73		
W-05	Lower Jhimruk	✓								
W-06	Madi	✓								
W-07	Mugu Karnali				3,843.8	694.0	4,868.1			
W-08	Sani Bhari-1					417.0				
W-09	Sani Bhari-2					330.0				
W-10	Sharada-2	✓								
W-11	Thuli Gad-2	✓								
W-12	Tila-1	✓								
W-13	Tila-3					338.0		2.13		
W-14	Thuli Gad			with W-11						
W-15	LR-1			with W-26						
W-16	BR-3B								9,270	
W-17	BR-4	✓								
W-18	Surkhet								6,600	
W-19	Lakarpata				1,200.0				20,400	
W-20	Bhanakot	✓								
W-21	Thapna	✓								
W-22	SR-6	✓								
W-23	Nalsyagu Gad	✓								
W-24	Sarada Babai	✓								
W-25	Naumure (W. Rapti)	✓								
W-26	Lohare Khola	✓								
W-27	Nisti-Panah *		Pre FS							

* : Added in January 2012

** : These projects are not excluded from the objects of evaluation because of a request by the NEA.

5.1.4 Evaluation of Candidate Projects (The Second Step)

Multi Criteria Analysis (MCA) was adopted for evaluation of the candidate projects in the second stage.

5.1.4.1 Evaluation Items and Evaluation Criteria

The candidate projects selected in "5.1.3 Selection of Projects that are subjected to the Evaluation" were given a score by evaluating the items described below. The weight of each evaluation item is described in "5.1.4.2 Weighting of Evaluation Items."

<u>Technical and Economical Conditions</u>

- Hydrological Conditions
  - Reliability of flow data, risk of a glacier lake outburst flood (GLOF), sedimentation.
- Geological Conditions
  - Geological conditions of the project site, natural hazards (earthquakes), seismicity.
- Lead Time to Implementation of the Project
  - Length of access roads, difficulty level of funding, and reliability of the development plan (current stage of study).
- Benefit by Project
  - Unit generation cost, installed capacity, annual energy production, and energy production in the dry season.

<u>Impact on the Environment</u>

- Impact on the Natural Environment
  - Impact on forest, impact on protected areas, impact on fishes, and impact on conservation species.
- Impact on the Social Environment
  - Impact on the locality by construction of transmission lines, impact on households, impact on agriculture, impact on ethnic minorities, and impact on tourism.

5.1.4.2 Weighting of Evaluation Items

The evaluation items described in Section 5.1.4.1 above were weighted depending on the importance in the objective of the Study, and the development of storage-type hydroelectric power projects in Nepal. Scores of each evaluation item were multiplied by the weight of such evaluation item, and the total of weighted scores of all evaluation items is the evaluation score of the project in question.

The Study Team prepared a draft of weighting taking into consideration the weighting used in other projects[6] in the past, and then it was modified after discussion with the NEA. The Study Team proposed the modified draft of weighting to the first stakeholders meeting and invited comment on it from participants. The final weighting shown in Table 5.1.4.2-1 was determined by reference to useful comments obtained from stakeholders.

The basic ideas for deciding weights of evaluation items are as follows.

- The same weight is attached to the technical and economical conditions and the impact on environment.
- In the technical and economical conditions, importance is placed on the effectiveness of the project.
- In the impact on the environment, the same weight is attached to the impact on natural environment and the impact on the social environment. Regarding the weight of evaluation items in the category of impact on the environment, "Impact on forest," "Impact on protected area," "Impact on conservation species," and "Impact on household" are given larger weights than other evaluation items.[7]

[6] Project for Master Plan Study on Hydropower Development in the Republic of Uganda, 2009, JICA
The Master Plan Study of Hydropower Development in Cambodia, 2009, JICA
Update and Review of Identification and Feasibility Study of Storage Project, 2002, NEA

[7] In this study, the weights of impact on households are 6.25% and 5.1% of the total for the second stage and the third stage of evaluation of the base case, respectively. This study put equivalent or more importance on impact on households when compared with similar studies by JICA in the past. In the above-mentioned "Project for Master Plan Study on Hydropower Development in the Republic of Uganda," the weight of impact of resettlement was 4%, and in "The Master Plan Study of Hydropower Development in Cambodia," 8% were given to the impact on living from viewpoints of resettlement, the possibility of power supply to neighboring households (within a 40 km radius), and the effect of flood protection.

Table 5.1.4.2-1 Weight of Evaluation Item (Base Case)

<table>
<tr><th>Category</th><th>%</th><th>Subcategory</th><th>%</th><th>Evaluation Item</th><th>%</th><th>Point</th></tr>
<tr><td rowspan="13">Technical and Economical Conditions</td><td rowspan="13">50</td><td rowspan="3">Hydrological Conditions</td><td rowspan="3">25</td><td>Reliability of flow data</td><td>25</td><td>3.13</td></tr>
<tr><td>Risk of a GLOF</td><td>40</td><td>5.00</td></tr>
<tr><td>Sedimentation</td><td>35</td><td>4.37</td></tr>
<tr><td rowspan="3">Geological Conditions</td><td rowspan="3">25</td><td>Seismicity</td><td>30</td><td>3.75</td></tr>
<tr><td>Geological conditions of the site</td><td>40</td><td>5.00</td></tr>
<tr><td>Natural hazard (earthquake)</td><td>30</td><td>3.75</td></tr>
<tr><td rowspan="3">Lead Time</td><td rowspan="3">20</td><td>Length of access roads</td><td>25</td><td>2.50</td></tr>
<tr><td>Difficulty level of funding</td><td>35</td><td>3.50</td></tr>
<tr><td>Reliability of development plan</td><td>40</td><td>4.00</td></tr>
<tr><td rowspan="4">Effectiveness of the Project</td><td rowspan="4">30</td><td>Unit generation cost</td><td>25</td><td>3.75</td></tr>
<tr><td>Installed capacity</td><td>20</td><td>3.00</td></tr>
<tr><td>Annual energy production</td><td>20</td><td>3.00</td></tr>
<tr><td>Energy production in the dry season</td><td>35</td><td>5.25</td></tr>
<tr><td rowspan="9">Impact on the Environment</td><td rowspan="9">50</td><td rowspan="4">Impact on the Natural Environment</td><td rowspan="4">50</td><td>Impact on forests</td><td>25</td><td>6.25</td></tr>
<tr><td>Impact on protected areas</td><td>30</td><td>7.50</td></tr>
<tr><td>Impact on fishes</td><td>20</td><td>5.00</td></tr>
<tr><td>Impact on conservation species</td><td>25</td><td>6.25</td></tr>
<tr><td rowspan="5">Impact on the Social Environment</td><td rowspan="5">50</td><td>Impact on locality by construction of transmission line</td><td>20</td><td>5.00</td></tr>
<tr><td>Impact on household</td><td>25</td><td>6.25</td></tr>
<tr><td>Impact on agriculture</td><td>20</td><td>5.00</td></tr>
<tr><td>Impact on ethnic minorities</td><td>20</td><td>5.00</td></tr>
<tr><td>Impact on tourism</td><td>15</td><td>3.75</td></tr>
<tr><td></td><td></td><td></td><td></td><td colspan="2">Total</td><td>100</td></tr>
</table>

In the first stake-holder meeting, an attendee from Madhesi Jana Adhikar Forum, Nepal (Madhesi People's Rights Forum, Nepal: a political party) made a comment that the technical and economical conditions were more important than the impact on environment when the power condition of Nepal was considered[8]. Taking these comments into consideration, two other cases of weighting were prepared, Case 1 that put more importance on the technical and economical conditions (60%) and Case 2 that put more importance on the impact on environment (60%), and effects of difference in weighting on evaluation result were studied.

5.1.4.3 Result of the Evaluation

The 31 candidate projects selected in Section 5.1.3 were evaluated by the evaluation method described in Section 5.1.4.1, then the evaluation scores of each evaluation item were weighted with the weight described in Section 5.1.4.2 and summed up, and the evaluation scores of each candidate project were obtained. Numerical values or information of each evaluation item was obtained from existing project reports, topographical and geological maps, and other literature.

Table 5.1.4.3-1 shows the evaluation score and ranking of candidate projects, and Table 5.1.4.3-2 shows the ranking of each case.

8 See "Appendix-3: Strategic Environment Assessment Report, 12.1 The 1st Stakeholders Meeting"

Table 5.1.4.3-1 Evaluation Score and Ranking

No.	Project Name	P (MW)	Base Case		Case 1		Case 2	
			Score	Ranking	Score	Ranking	Score	Ranking
E-01	Dudh Koshi	300.0	65	6	65	5	65	9
E-02	Dukh Koshi-2	456.6	62	12	61	17	63	12
E-06	Kokhajor-1	111.5	62	13	60	20	64	10
E-09	Piluwa-2	107.3	59	21	57	25	60	19
E-10	Rosi-2	106.5	60	20	58	21	61	17
E-12	Tama Koss-3	287.0	63	10	63	13	63	13
E-17	Sunkosi No.3	536.0	63	11	64	8	62	15
E-20	Indrawati	91.2	58	23	58	24	58	24
C-01	Kaligandaki-Modi	816.4	57	25	58	23	56	25
C-02	Lower Badigad	380.3	62	14	63	14	62	16
C-03	Lower Daraudi	120.2	50	30	52	29	49	31
C-05	Upper Daraudi	111.4	53	27	51	30	54	27
C-08	Andhi Khola	180.0	62	15	64	9	61	18
C-11	Madi- Ishaneshor	86.0	61	17	62	15	59	21
C-18	Ridi Khola	97.0	53	28	53	28	53	28
W-01	Barbung Khola	122.9	61	18	60	19	63	14
W-02	Chera-1	148.7	65	7	64	7	66	4
W-03	Chera-2	104.3	62	16	61	16	63	11
W-05	Lower Jhimruk	142.5	71	2	69	2	73	2
W-06	Madi	199.8	76	1	73	1	78	1
W-10	Sharada-2	96.8	64	9	63	12	65	7
W-11	Thuli Gad-2	119.7	59	22	58	22	60	20
W-12	Tila-1	617.2	66	4	65	6	66	5
W-17	BR-4	667.0	51	29	53	27	49	30
W-20	Bhanakot	810.0	66	5	66	4	65	8
W-21	Thapna	500.0	61	19	64	10	58	23
W-22	SR-6	642.0	58	24	61	18	56	26
W-23	Nalsyagu Gad	400.0	68	3	67	3	70	3
W-24	Sarada Babai	75.0	57	26	55	26	59	22
W-25	Naumure (W. Rapti)	245.0	65	8	64	11	66	6
W-26	Lohare Khola	67.0	50	31	51	31	49	29

E: Eastern River Basin, C: Central River Basin, W: Western River Basin.

Base Case: Technical point 50%, Environmental point 50%
Case 1: Technical point 60%, Environmental point 40%
Case 2: Technical point 40%, Environmental point 60%

Table 5.1.4.3-2 Evaluation Score and Ranking of Each Case

Base Case

Technical point : 50%, Environmental point : 50%

No.	Project Name	P (MW)	Score	Ranking
W-06	Madi	199.8	76	1
W-05	Lower Jhimruk	142.5	71	2
W-23	Nalsyagu Gad	400.0	68	3
W-12	Tila - 1	617.2	66	4
W-20	Bhanakot	810.0	66	5
E-01	Dudh Koshi	300.0	65	6
W-02	Chera-1	148.7	65	7
W-25	Naumure (W. Rapti)	245.0	65	8
W-10	Sharada - 2	96.8	64	9
E-12	Tama Koss-3	287.0	63	10
E-17	Sunkosi No.3	536.0	63	11
E-02	Dukh Koshi-2	456.6	62	12
E-06	Kokhajor-1	111.5	62	13
C-02	Lower Badigad	380.3	62	14
C-08	Andhi Khola	180.0	62	15
W-03	Chera-2	104.3	62	16
C-11	Madi- Ishaneshor	86.0	61	17
W-01	Barbung Khola	122.9	61	18
W-21	Thapna	500.0	61	19
E-10	Rosi-2	106.5	60	20
E-09	Piluwa-2	107.3	59	21
W-11	Thuli Gad - 2	119.7	59	22
E-20	Indrawati	91.2	58	23
W-22	SR-6	642.0	58	24
C-01	Kaligandaki-Modi	816.4	57	25
W-24	Sarada Babai	75.0	57	26
C-05	Upper Daraudi	111.4	53	27
C-18	Ridi Khola	97.0	53	28
W-17	BR-4	667.0	51	29
C-03	Lower Daraudi	120.2	50	30
W-26	Lohare Khola	67.0	50	31

Case-1

Technical point : 60%, Environmental point : 40%

No.	Project Name	P (MW)	Score	Ranking
W-06	Madi	199.8	73	1
W-05	Lower Jhimruk	142.5	69	2
W-23	Nalsyagu Gad	400.0	67	3
W-20	Bhanakot	810.0	66	4
E-01	Dudh Koshi	300.0	65	5
W-12	Tila - 1	617.2	65	6
W-02	Chera-1	148.7	64	7
E-17	Sunkosi No.3	536.0	64	8
C-08	Andhi Khola	180.0	64	9
W-21	Thapna	500.0	64	10
W-25	Naumure (W. Rapti)	245.0	64	11
W-10	Sharada - 2	96.8	63	12
E-12	Tama Koss-3	287.0	63	13
C-02	Lower Badigad	380.3	63	14
C-11	Madi- Ishaneshor	86.0	62	15
W-03	Chera-2	104.3	61	16
E-02	Dukh Koshi-2	456.6	61	17
W-22	SR-6	642.0	61	18
W-01	Barbung Khola	122.9	60	19
E-06	Kokhajor-1	111.5	60	20
E-10	Rosi-2	106.5	58	21
W-11	Thuli Gad - 2	119.7	58	22
C-01	Kaligandaki-Modi	816.4	58	23
E-20	Indrawati	91.2	58	24
E-09	Piluwa-2	107.3	57	25
W-24	Sarada Babai	75.0	55	26
W-17	BR-4	667.0	53	27
C-18	Ridi Khola	97.0	53	28
C-03	Lower Daraudi	120.2	52	29
C-05	Upper Daraudi	111.4	51	30
W-26	Lohare Khola	67.0	51	31

Case-2

Technical point : 40%, Environmental point : 60%

No.	Project Name	P (MW)	Score	Ranking
W-06	Madi	199.8	78	1
W-05	Lower Jhimruk	142.5	73	2
W-23	Nalsyagu Gad	400.0	70	3
W-02	Chera-1	148.7	66	4
W-12	Tila - 1	617.2	66	5
W-25	Naumure (W. Rapti)	245.0	66	6
W-10	Sharada - 2	96.8	65	7
W-20	Bhanakot	810.0	65	8
E-01	Dudh Koshi	300.0	65	9
E-06	Kokhajor-1	111.5	64	10
W-03	Chera-2	104.3	63	11
E-02	Dukh Koshi-2	456.6	63	12
E-12	Tama Koss-3	287.0	63	13
W-01	Barbung Khola	122.9	63	14
E-17	Sunkosi No.3	536.0	62	15
C-02	Lower Badigad	380.3	62	16
E-10	Rosi-2	106.5	61	17
C-08	Andhi Khola	180.0	61	18
E-09	Piluwa-2	107.3	60	19
W-11	Thuli Gad - 2	119.7	60	20
C-11	Madi- Ishaneshor	86.0	59	21
W-24	Sarada Babai	75.0	59	22
W-21	Thapna	500.0	58	23
E-20	Indrawati	91.2	58	24
C-01	Kaligandaki-Modi	816.4	56	25
W-22	SR-6	642.0	56	26
C-05	Upper Daraudi	111.4	54	27
C-18	Ridi Khola	97.0	53	28
W-26	Lohare Khola	67.0	49	29
W-17	BR-4	667.0	49	30
C-03	Lower Daraudi	120.2	49	31

E: Eastern River Basin, C: Central River Basin, W: Western River Basin.

5.1.5 Selection of Promising Projects (The Third Step)

As described in "5.1.4 Evaluation of Candidate Projects," evaluation of technical/economical conditions and the impact on the natural/social environment of the 31 candidate projects were conducted. Based on the evaluation results, the promising projects were selected from the top, as a general rule, taking into consideration 1) the total installed capacity of promising projects, 2) the number of projects in each river basin, and 3) overlap with issued survey/construction licenses for generation, and also the positive and negative effects on the local economy by implementation of power development projects and avoiding concentration of negative effects on the environment and society.

(1) Total Installed Capacity of Promising Projects

Promising projects are projects that are considered to have a high possibility of being included in the master plan of storage-type hydroelectric power project in Nepal as the result of evaluation described in Section 5.1.4 above. For these promising projects, environmental and geological surveys were done by a local consulting firm. The total installed capacity of the promising projects was decided as follows.

In May 2012, when the total installed capacity of promising projects was studied, the required total installed capacity of storage-type hydropower project to be developed by FY2031/32 is estimated at about 2,900 MW. By deducting the existing capacity and power import from the demand, this means that about 2,200 MW of development is required in addition to the Tanahu project (140 MW) and Budhi Gandaki project (600 MW) that are now in the detailed design stage. Taking into consideration that there is a possibility of review on the required development capacity and also a possibility that some promising projects may be judged unfeasible by the results of the environmental and geological survey for the promising projects, the required total installed capacity of promising projects were decided to be about 2,600 MW ($\approx$ 2,200 MW $\times$ 1.2).

(2) Number of Projects in Each River Basin

Kathmandu, the capital city of Nepal with large power demands, is located in the Central Region in terms of administrative areas, and this region corresponds to the western part of the eastern river basin and the eastern part of the central river basin.

However, as shown in Table 5.1.4.3-2, many projects in the western river basin were ranked near the top. Therefore, if promising projects were selected simply by rank, seven or eight out of ten were in the western river basin that is far from Kathmandu. Taking into consideration that these projects are located far from demand centers like Kathmandu, that it will take time for construction of a backbone transmission line to the western river basin to which these projects will be connected, and also taking into consideration the economic effects on regions by development of the projects, the maximum number of promising projects in one river basin was decided to be five (5).

Table 5.1.5-1 shows the promising projects of each case when the number of projects in each river basin was limited to five.

Table 5.1.5-1 Promising Projects (Number of promising projects in each river basin is five or less)

Base Case

Technical : 50%, Environmental : 50%

No.	Project Name	P (MW)	Ranking
W-06	Madi	199.8	1 (W1)
W-05	Lower Jhimruk	142.5	2 (W2)
W-23	Nalsyagu Gad	400.0	3 (W3)
W-12	Tila - 1	617.2	4 (W4)
W-20	Bhanakot	810.0	5 (W5)
E-01	Dudh Koshi	300.0	6 (E1)
W-02	Chera-1	148.7	—
W-25	Naumure (W. Rapti)	245.0	—
W-10	Sharada - 2	96.8	—
E-12	Tama Koss-3	287.0	7 (E2)
E-17	Sunkosi No.3	536.0	8 (E3)
E-02	Dukh Koshi-2	456.6	9 (E4)
E-06	Kokhajor-1	111.5	10 (E5)
C-02	Lower Badigad	380.3	
C-08	Andhi Khola	180.0	
W-03	Chera-2	104.3	
C-11	Madi- Ishaneshor	86.0	
W-01	Barbung Khola	122.9	
W-21	Thapna	500.0	
E-10	Rosi-2	106.5	
E-09	Piluwa-2	107.3	
W-11	Thuli Gad - 2	119.7	
E-20	Indrawati	91.2	
W-22	SR-6	642.0	
C-01	Kaligandaki-Modi	816.4	
W-24	Sarada Babai	75.0	
C-05	Upper Daraudi	111.4	
C-18	Ridi Khola	97.0	
W-17	BR-4	667.0	
C-03	Lower Daraudi	120.2	
W-26	Lohare Khola	67.0	

Case-1

Technical : 60%, Environmental : 40%

No.	Project Name	P (MW)	Ranking
W-06	Madi	199.8	1 (W1)
W-05	Lower Jhimruk	142.5	2 (W2)
W-23	Nalsyagu Gad	400.0	3 (W3)
W-20	Bhanakot	810.0	4 (W4)
E-01	Dudh Koshi	300.0	5 (E1)
W-12	Tila - 1	617.2	6 (W5)
W-02	Chera-1	148.7	—
E-17	Sunkosi No.3	536.0	7 (E2)
C-08	Andhi Khola	180.0	8 (C1)
W-21	Thapna	500.0	—
W-25	Naumure (W. Rapti)	245.0	—
W-10	Sharada - 2	96.8	—
E-12	Tama Koss-3	287.0	9 (E3)
C-02	Lower Badigad	380.3	10 (C2)
C-11	Madi- Ishaneshor	86.0	
W-03	Chera-2	104.3	
E-02	Dukh Koshi-2	456.6	
W-22	SR-6	642.0	
W-01	Barbung Khola	122.9	
E-06	Kokhajor-1	111.5	
E-10	Rosi-2	106.5	
W-11	Thuli Gad - 2	119.7	
C-01	Kaligandaki-Modi	816.4	
E-20	Indrawati	91.2	
E-09	Piluwa-2	107.3	
W-24	Sarada Babai	75.0	
W-17	BR-4	667.0	
C-18	Ridi Khola	97.0	
C-03	Lower Daraudi	120.2	
C-05	Upper Daraudi	111.4	
W-26	Lohare Khola	67.0	

Case-2

Technical : 40%, Environmental : 60%

No.	Project Name	P (MW)	Ranking
W-06	Madi	199.8	1 (W1)
W-05	Lower Jhimruk	142.5	2 (W2)
W-23	Nalsyagu Gad	400.0	3 (W3)
W-02	Chera-1	148.7	4 (W4)
W-12	Tila - 1	617.2	5 (W5)
W-25	Naumure (W. Rapti)	245.0	—
W-10	Sharada - 2	96.8	—
W-20	Bhanakot	810.0	—
E-01	Dudh Koshi	300.0	6 (E1)
E-06	Kokhajor-1	111.5	7 (E2)
W-03	Chera-2	104.3	—
E-02	Dukh Koshi-2	456.6	8 (E3)
E-12	Tama Koss-3	287.0	9 (E4)
W-01	Barbung Khola	122.9	—
E-17	Sunkosi No.3	536.0	10 (E5)
C-02	Lower Badigad	380.3	
E-10	Rosi-2	106.5	
C-08	Andhi Khola	180.0	
E-09	Piluwa-2	107.3	
W-11	Thuli Gad - 2	119.7	
C-11	Madi- Ishaneshor	86.0	
W-24	Sarada Babai	75.0	
W-21	Thapna	500.0	
E-20	Indrawati	91.2	
C-01	Kaligandaki-Modi	816.4	
W-22	SR-6	642.0	
C-05	Upper Daraudi	111.4	
C-18	Ridi Khola	97.0	
W-26	Lohare Khola	67.0	
W-17	BR-4	667.0	
C-03	Lower Daraudi	120.2	

E: Eastern River Basin, C: Central River Basin, W: Western River Basin.

(3) Overlap with Issued Survey and Construction Licenses for Generation

A large number of survey and construction licenses for generation have been issued by the Department of Electricity Development (DOED) under the Ministry of Energy to promote development of hydroelectric power by the private sector.

The NEA and the Study Team checked the locations of projects ranked near the top against the survey and construction licenses (1 MW or more) issued as of May 13, 2012, and found that the locations of the following four projects overlapped with the project areas of issued licenses. The NEA and the Study Team sought a comment from the DOED on the likelihood of implementation of the projects selected in this study in the project area of issued licenses.

Tila 1 (W-12: 617.2 MW)
Bhanakot (W-20: 810 MW)
Tama Koshi 3 (E-12: 287 MW)
Dudh Koshi 2 (E-02: 156.6 MW)

According to the DOED, even if storage-type projects make effective use of river water more than ROR type projects, it is difficult to develop storage-type projects at the site where licenses have already been issued to another agency/company, and it is better not to include these projects in the promising projects of the Study. Taking this into consideration, the NEA and the Study Team decided that these four projects should not be selected as the promising projects.

In the column "Ranking (1)" in Table 5.1.5-2, the promising projects excluding the above-mentioned four projects (shaded projects) are shown.

Table 5.1.5-2 Promising Projects (taking issued licenses into consideration)

Base Case

Technical point : 50%, Environmental point : 50%

No.	Project Name	P (MW)	Ranking (1)	Ranking (2)
W-06	Madi	199.8	1 (W1)	1 (W1)
W-05	Lower Jhimruk	142.5	2 (W2)	2 (W2)
W-23	Nalsyagu Gad	400.0	3 (W3)	3 (W3)
~~W-12~~	~~Tila - 1~~	~~617.2~~	—	~~4 (W4)~~
~~W-20~~	~~Bhanakot~~	~~810.0~~	—	~~5 (W5)~~
E-01	Dudh Koshi	300.0	4 (E1)	6 (E1)
W-02	Chera-1	148.7	5 (W4)	—
W-25	Naumure (W. Rapti)	245.0	6 (W5)	—
W-10	Sharada - 2	96.8	—	—
~~E-12~~	~~Tama Koss-3~~	~~287.0~~	—	~~7 (E2)~~
E-17	Sunkosi No.3	536.0	7 (E2)	8 (E3)
~~E-02~~	~~Dukh Koshi-2~~	~~456.6~~	—	~~9 (E4)~~
E-06	Kokhajor-1	111.5	8 (E3)	10 (E5)
C-02	Lower Badigad	380.3	9 (C1)	
C-08	Andhi Khola	180.0	10 (C2)	
W-03	Chera-2	104.3		
C-11	Madi- Ishaneshor	86.0		
W-01	Barbung Khola	122.9		
W-21	Thapna	500.0		
E-10	Rosi-2	106.5		
E-09	Piluwa-2	107.3		
W-11	Thuli Gad - 2	119.7		
E-20	Indrawati	91.2		
W-22	SR-6	642.0		
C-01	Kaligandaki-Modi	816.4		
W-24	Sarada Babai	75.0		
C-05	Upper Daraudi	111.4		
C-18	Ridi Khola	97.0		
W-17	BR-4	667.0		
C-03	Lower Daraudi	120.2		
W-26	Lohare Khola	67.0		

Case-1

Technical point : 60%, Environmental point : 40%

No.	Project Name	P (MW)	Ranking (1)	Ranking (2)
W-06	Madi	199.80	1 (W1)	1 (W1)
W-05	Lower Jhimruk	142.50	2 (W2)	2 (W2)
W-23	Nalsyagu Gad	400.00	3 (W3)	3 (W3)
~~W-20~~	~~Bhanakot~~	~~810.00~~	—	~~4 (W4)~~
E-01	Dudh Koshi	300.00	4 (E1)	5 (E1)
~~W-12~~	~~Tila - 1~~	~~617.20~~	—	~~6 (W5)~~
W-02	Chera-1	148.70	5 (W4)	—
E-17	Sunkosi No.3	536.00	6 (E2)	7 (E2)
C-08	Andhi Khola	180.00	7 (C1)	8 (C1)
W-21	Thapna	500.00	8 (W5)	—
W-25	Naumure (W. Rapti)	245.00	—	—
W-10	Sharada - 2	96.80	—	—
~~E-12~~	~~Tama Koss-3~~	~~287.00~~	—	~~9 (E3)~~
C-02	Lower Badigad	380.30	9 (C2)	10 (C2)
C-11	Madi- Ishaneshor	86.00	10 (C3)	
W-03	Chera-2	104.30		
~~E-02~~	~~Dukh Koshi-2~~	~~456.60~~		
W-22	SR-6	642.00		
W-01	Barbung Khola	122.90		
E-06	Kokhajor-1	111.50		
E-10	Rosi-2	106.50		
W-11	Thuli Gad - 2	119.70		
C-01	Kaligandaki-Modi	816.40		
E-20	Indrawati	91.20		
E-09	Piluwa-2	107.30		
W-24	Sarada Babai	75.00		
W-17	BR-4	667.00		
C-18	Ridi Khola	97.00		
C-03	Lower Daraudi	120.20		
C-05	Upper Daraudi	111.40		
W-26	Lohare Khola	67.00		

Case-2

Technical point : 40%, Environmental point : 60%

No.	Project Name	P (MW)	Ranking (1)	Ranking (2)
W-06	Madi	199.8	1 (W1)	1 (W1)
W-05	Lower Jhimruk	142.5	2 (W2)	2 (W2)
W-23	Nalsyagu Gad	400.0	3 (W3)	3 (W3)
W-02	Chera-1	148.7	4 (W4)	4 (W4)
~~W-12~~	~~Tila - 1~~	~~617.2~~	—	~~5 (W5)~~
W-25	Naumure (W. Rapti)	245.0	5 (W5)	—
W-10	Sharada - 2	96.8	—	—
~~W-20~~	~~Bhanakot~~	~~810.0~~	—	—
E-01	Dudh Koshi	300.0	6 (E1)	6 (E1)
E-06	Kokhajor-1	111.5	7 (E2)	7 (E2)
W-03	Chera-2	104.3	—	—
~~E-02~~	~~Dukh Koshi-2~~	~~456.6~~	—	~~8 (E3)~~
~~E-12~~	~~Tama Koss-3~~	~~287.0~~	—	~~9 (E4)~~
W-01	Barbung Khola	122.9	—	—
E-17	Sunkosi No.3	536.0	8 (E3)	10 (E5)
C-02	Lower Badigad	380.3	9 (C1)	
E-10	Rosi-2	106.5	10 (E4)	
C-08	Andhi Khola	180.0		
E-09	Piluwa-2	107.3		
W-11	Thuli Gad - 2	119.7		
C-11	Madi- Ishaneshor	86.0		
W-24	Sarada Babai	75.0		
W-21	Thapna	500.0		
E-20	Indrawati	91.2		
C-01	Kaligandaki-Modi	816.4		
W-22	SR-6	642.0		
C-05	Upper Daraudi	111.4		
C-18	Ridi Khola	97.0		
W-26	Lohare Khola	67.0		
W-17	BR-4	667.0		
C-03	Lower Daraudi	120.2		

E: Eastern River Basin, C: Central River Basin, W: Western River Basin. (Example: "E1" = the 1st place in the Eastern River Basin, "C2" = the 2nd place in the Central River Basin.)

Shaded projects: Excluded projects because of competence of issued licenses.

Ranking (1) : Issued licenses are considered. Ranking (2) : Issued licenses are not considered.

(4) Selection of Promising Projects

As shown in Table 5.1.5-3, the total installed capacity of the promising projects was about 2,600 MW to 2,900 MW that is equal to or more than the required total installed capacity of the promising projects.

Since the projects selected in each case are a little different, 13 projects were selected in total, and seven projects were selected as the promising projects in all cases, three projects in two cases, and three projects in one case.

Taking this into consideration, seven projects selected in all cases and three projects selected in two cases (with "✓" in Table 5.1.4-3) were selected as the promising projects.

Table 5.1.5-3 Selection of Promising Projects

No.	Project Name	P (MW)	Base Case	Case-1	Case-2	Number of selected project	Promising Project
E-01	Dudh Koshi	300.0	E1	E1	E1	3	✓
E-06	Kokhajor-1	111.5	E3	—	E2	2	✓
E-10	Rosi-2	106.5	—	—	E4	1	
E-17	Sunkosi No.3	536.0	E2	E2	E3	3	✓
C-02	Lower Badigad	380.3	C1	C2	C1	3	✓
C-08	Andhi Khola	180.0	C2	C1	—	2	✓
C-11	Madi- Ishaneshor	86.0	—	C3	—	1	
W-02	Chera-1	148.7	W4	W4	W4	3	✓
W-05	Lower Jhimruk	142.5	W2	W2	W2	3	✓
W-06	Madi	199.8	W1	W1	W1	3	✓
W-21	Thapna	500.0	—	W5	—	1	
W-23	Nalsyagu Gad	400.0	W3	W3	W3	3	✓
W-25	Naumure (W. Rapti)	245.0	W5	—	W5	2	✓
Total Installed Capacity (MW)			2,643.8	2,873.3	2,570.3	—	2,643.8

E: Eastern River Basin, C: Central River Basin, W: Western River Basin.
Example: "E1" = the 1st place in the Eastern River Basin, "C2" = the 2nd place in the Central River Basin.

Table 5.1.5-4 shows the promising projects that were finally selected.

Table 5.1.5-4 Promising Projects

No.	Project Name	P (MW)
E-01	Dudh Koshi	300.0
E-06	Kokhajor-1	111.5
E-17	Sunkosi No.3	536.0
C-02	Lower Badigad	380.3
C-08	Andhi Khola	180.0
W-02	Chera-1	148.7
W-05	Lower Jhimruk	142.5
W-06	Madi	199.8
W-23	Nalsyagu Gad	400.0
W-25	Naumure (W. Rapti)	245.0
Total Installed Capacity (MW)		2,643.8

5.2 Evaluation of Promising Projects

Ten promising projects were selected in Section 5.1.5. In this section, evaluation of these ten promising projects were conducted based on the existing documents and the results of site surveys conducted by the Study Team and a Nepalese consulting firm.

5.2.1 Evaluation Items and Evaluation Criteria

The evaluation items and evaluation criteria are basically similar to the items and criteria that were used for the evaluation of candidate projects as mentioned in Section 5.1.4. However, taking into account the comments obtained in the stakeholder meetings, some evaluation items were added and some modifications were made in the evaluation criteria as described below.

Technical and Economical Conditions

- Hydrological Conditions
  - Reliability of flow data, risk of a glacier lake outburst flood (GLOF), and sedimentation.
- Geological Conditions
  - Geological conditions of project site, thrusts and faults [1)], and seismicity.

    [1)]: The name of "Natural hazards (earthquakes)" in Section 5.1.4.1 was changed.
- Time to commencement of commercial operation [2)]

  [2)]: In Section 5.1.4.1, this item was evaluated as "Lead Time to Implementation of the Project" by "Length of access road," "Difficulty level of funding," and "Reliability of the development plan (current stage of study)."
- Effectiveness of Project
  - Unit generation cost, installed capacity, annual energy production, and energy production in the dry season.

Impact on the Environment

- Impact on the Natural Environment
  - Impact on forests, impact on flora [3)], impact on terrestrial fauna [3)], impact on protected areas, impact on aquatic fauna, and the impact of transmission line [4)].

    [3)]: Added items.

    [4)]: This item was moved from "Impact on the social environment."
- Impact on the Social Environment
  - Impact on household, etc., impact on ethnic minorities, impact on agriculture, impact of fishery [5)], impact on tourism, impact on infrastructure [5)], and the impact on the rural economy and development plans [5).]

    [5)]: Added items.

5.2.2 Weighting of Evaluation Items

In the same manner as the evaluation of candidate projects, the evaluation items described in Clause 5.2.1 above were weighted depending on the importance in the objective of the Study. Scores of each evaluation item were multiplied by the weight of such evaluation items, and the total of weighted scores of all evaluation items is the evaluation score of the project in question.

Taking into consideration the results of the questionnaire in the second stakeholders meeting, the following four cases of combination of weights of technical and economical conditions and the impact of the environment were prepared.

Case 1: The same importance on technical and economical conditions and impact on the environment
(50% for technical and economical conditions, 50% for impact on the environment)

Case 2: Technically and economically oriented (60% for technical and economical conditions, 40% for impact on the environment)

Case 3: Environmentally oriented (40% for technical and economical conditions, 60% for impact on the environment)

Case 4: Extremely technically and economically oriented (the average of questionnaire results. 75% for technical and economical conditions, 25% for impact on the environment)

Regarding the subcategories in technical and environmental conditions, and also taking into consideration the result of questionnaire, the weight of hydrological conditions was increased from 25% to 30% and that of the lead time was decreased from 25% to 20%. In the impact on the environment, the weight of the social environment was increased from 50% to 60% and that of the natural environment was decreased from 50% to 40%.

Regarding the weights of individual evaluation items in the category of impact on the environment, relatively large weights were given to “number of household, etc.,” “agriculture,” and “fishery,” as they have an impact on the livelihood of people living in the area.

Table 5.2.2-1 shows the weights and point allocations of Case 1.

Table 5.2.2-1 Weight of Evaluation Item (Case 1: Even weight)

Category	%	Subcategory	%	Evaluation Item	%	Point
Technical and Economical Conditions	50	Hydrological Conditions	30	Reliability of flow data	35	5.25
				Risk of a GLOF	30	4.50
				Sedimentation	35	5.25
		Geological Conditions	25	Seismicity	25	3.13
				Geological conditions of the site	50	6.24
				Thrust and fault	25	3.13
		Lead time	20	Time to commencement of commercial operation	100	10.00
		Effectiveness of the Project	25	Unit generation cost	25	3.13
				Installed capacity	20	2.50
				Annual energy production	10	1.25
				Energy production in the dry season	45	5.62
Impact on the Environment	50	Impact on the Natural Environment	40	Impact on forests	(23)	—
				Forest land	*9*	*1.80*
				Number of trees in the reservoir area	*7*	*1.40*
				Average of crown coverage	*7*	*1.40*
				Impact on flora	(16)	—
				Number of plant species reported	*8*	*1.60*
				Number of plant species of conservation significance	*8*	*1.60*
				Impact on terrestrial fauna	(17)	—
				Number of mammal species reported	*3*	*0.60*
				Number of bird species reported	*2*	*0.40*
				Number of herpetofauna species reported	*2*	*0.40*
				Number of conservation mammalian species reported (reservoir)	*4*	*0.80*
				Number of conservation bird species reported (reservoir)	*3*	*0.60*
				Number of conservation herpetofauna species reported (reservoir)	*3*	*0.60*
				Impact on aquatic fauna	(22)	—
				Number of fish species reported	*9*	*1.80*
				Number of fish species of conservation significance	*9*	*1.80*
				Length of recession area	*4*	*0.80*
				Impact on protected areas	(16)	—
				Number of protected areas in the downstream	*8*	*1.60*
				Number of protected species in the downstream	*8*	*1.60*
				Impact of transmission line	(6)	
				Length of transmission line	*6*	*1.20*
		Impact on the Social Environment	60	Impact on households, etc.	(17)	—
				Number of estimated households	*10*	*3.00*
				Number of schools	*4*	*1.20*
				Number of industries	*3*	*0.90*
				Impact on ethnic minorities	(8)	—
				Number of ethnic minority groups	*8*	*2.40*
				Impact on agriculture	(19)	—
				Impact on irrigation	*9*	*2.70*
				Impact on agricultural land	*10*	*3.00*
				Impact on fishery	(15)	—
				Number of fishermen	*3*	*0.90*
				Number of fish market	*2*	*0.60*
				Availability of fish in the market	*1*	*0.30*
				Sales amount of fish	*3*	*0.90*
				Total income	*3*	*0.90*
				Length of recession area	*3*	*0.90*
				Impact on tourism and culture	(14)	—
				Number of cultural structures	*6*	*1.80*
				Number of tourist facilities	*4*	*1.20*
				Number of tourists	*4*	*1.20*
				Impact on infrastructure	(19)	—
				Impact on roads	*7*	*2.10*
				Impact on bridges	*4*	*1.20*
				Impact on water mill, turbine, hydropower plant	*4*	*1.20*
				Impact on drinking water schemes	*4*	*1.20*
				Impact on the rural economy and development plans	(8)	—
				Impact on market	*4*	*1.20*
				Number of development plans	*2*	*0.60*
				Previous issues	*2*	*0.60*
				Total		100

5.2.3 Result of the Evaluation

Ten promising projects selected in “5.1.5 Selection of Promising Projects” were evaluated by the evaluation method described in “5.2.1 Evaluation Items and Evaluation Criteria,” and each evaluation point was weighted by the weight described in “5.2.2 Weighting of Evaluation Items,” then the evaluation score of each project was obtained by summing up all the weighted points. The numerical values and information, etc. of evaluation items were obtained from existing study reports, topographical and geological maps, and other reference literature, and also from the results of site surveys conducted by the study team and a Nepalese consulting firm.

As the results of the evaluation, though the evaluation score is different case by case, the Nalsyau Gad Project obtained the highest score in the all cases. The Dudh Koshi, Andhi Khola, Chera-1, Lower Jhimruk, and Madi Projects obtained the second to the sixth scores. The Kokhajor-1, Naumure (W. Rapti), Sun Koshi No. 3, and Lower Badigad Projects were seventh to tenth places.

The difference in score between the Nalsyau Gad Project and the second-ranked project was 9 to 14 points, and the difference between the sixth-ranked project and the seventh-ranked project was 2 to 5 points.

Table 5.2.3-1 shows the evaluation score and ranking of each project.

Table 5.2.3-1 Evaluation Score and Ranking (Summary)

No.	Project Name	P (MW)	Case-1		Case-2		Case-3		Case-4	
			Score	Ranking	Score	Ranking	Score	Ranking	Score	Ranking
W-23	Nalsyau Gad	410	77	1	76	1	78	1	75	1
E-01	Dudh Koshi	300	65	2	65	2	64	3	66	2
W-02	Chera-1	148.7	65	2	64	3	66	2	63	4
C-08	Andhi Khola	180	64	4	64	3	63	6	65	3
W-06	Madi	199.8	63	5	62	5	64	3	60	5
W-05	Lower Jhimruk	142.5	63	5	62	5	64	3	60	5
E-06	Kokhajor-1	111.5	58	7	56	7	61	7	51	10
W-25	Naumure (W. Rapti)	245	56	8	56	7	56	8	56	8
E-17	Sun Koshi No .3	536	50	9	53	9	47	9	57	7
C-02	Lower Badigad	380.3	47	10	49	10	45	10	53	9

Case 1: Technical and Economical Conditions = 50%, Impact on the Environment = 50%
Case 2: Technical and Economical Conditions = 60%, Impact on the Environment = 40%
Case 3: Technical and Economical Conditions = 40%, Impact on the Environment = 60%
Case 4: Technical and Economical Conditions = 75%, Impact on the Environment = 25%

Regarding these ten promising projects, the presence or absence of critical obstructive factors was confirmed.

- Projects located in national parks or conservation areas were excluded in the first step of selection of promising projects described in Section 5.1.3 (3). It was also confirmed in the evaluation of the “Impact on Protected Areas” described in Section 5.2.1 (5) 4) that the locations of the ten promising projects are outside of these areas.
- The maximum number of households to be relocated is 1,600 in the Lower Badigad Project.
- Regarding rare species, it was confirmed by an interview with the WWF that there are not any

projects that should not be implemented because of a big impact on a rare species. However, since information about the distribution condition of rare species is insufficient in Nepal, it was not possible to confirm that there are not any critical habitats of rare species in the project areas.

Chapter 6 Transmission Line Expansion Plan

6.1 Conceptual Design of Nepal Power System in 2032

Nepal Power System extends from east to west and demands are located around Kathmandu and south of Central Region. And some promising projects of large size of generation are planned to be located in West Region. Therefore reinforcements of transmission line from east to west will be required. Consequently Nepal Power System in future should be composed of 400 kV transmission lines from east to west, 220 kV transmission lines from north to south, and 220 kV loop transmission line around Kathmandu in order to ensure the power system reliability. Power System Map in FY2031/32 is shown in Figure 6.1-1.

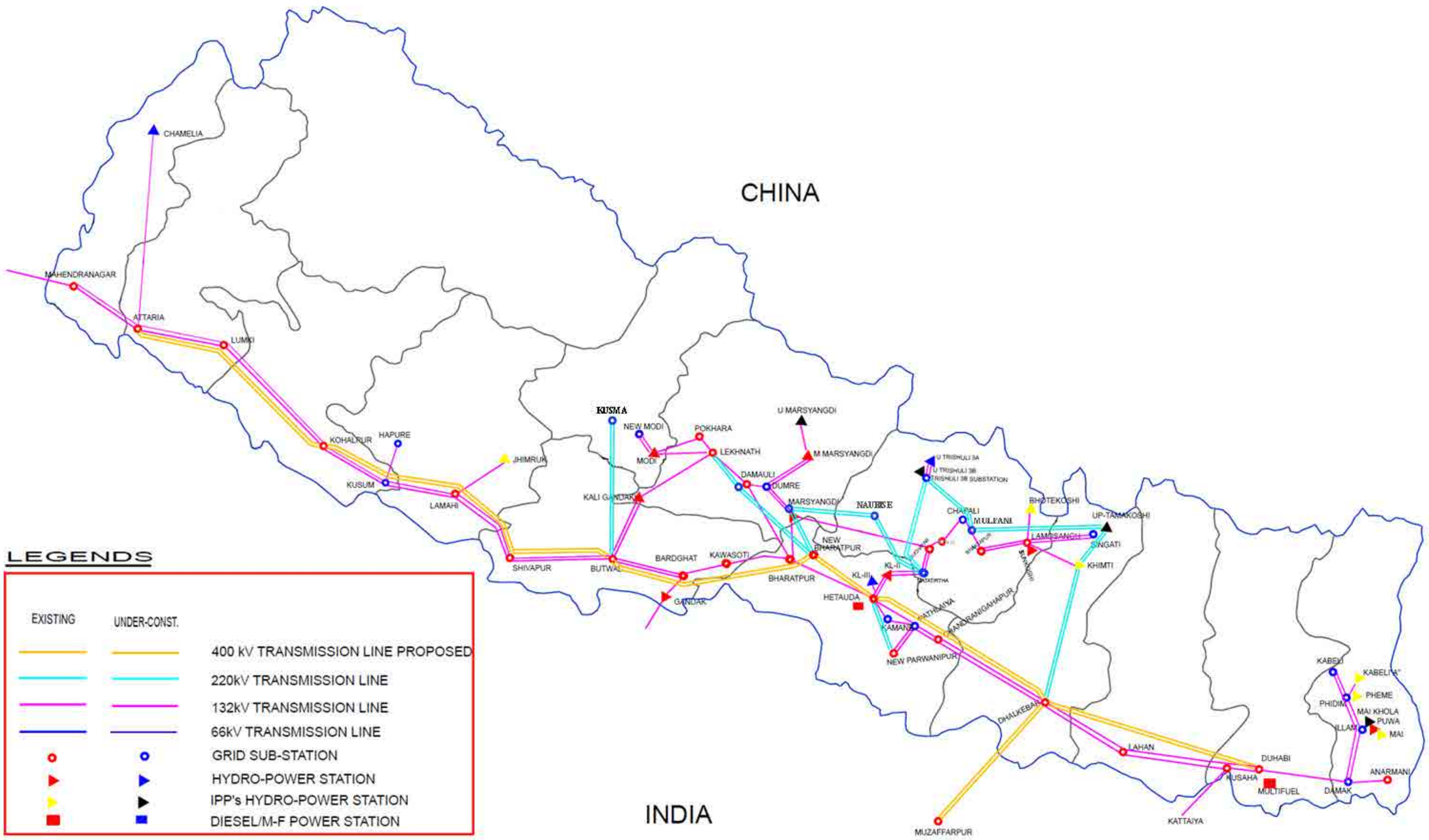


Figure 6.1-1 Power System Map in FY2031/32

6.2 Transmission Facilities Expansion Plan by NEA

The latest Transmission Facilities Expansion Plan offered by the NEA is shown in Table 6.2-1.

Table 6.2-1 Transmission Facilities Expansion Plan by NEA

	Project	Status	Expected Commissioning
1a	Khimti - Dhalkebar D/C, 220 kV TL (75 km), strung S/C & Charged at 132 kV	Under Construction	2012/13
1b	Second Circuit Stringing of Khimti - Dhalkebar D/C, 220 kV TL (75 km)	Tender Preparation	2013/14
2	Capacitor Bank	Under Construction	2011/12
3	Matatirtha 132 kV substation Expansion	Under Construction	2012/13
4	Syangja 132/33 kV, 30 MVa Substation	Under Construction	2012/13
5	Hetauda, Kamane 132/33 kV, 30 MVa Substation	Under Construction	2012/13
6	Pathlaiya 132 kV Switching Substation	Under Construction	2012/13
7	Kusum - Hapure 132 kV Project	Under Construction	2013/14
8	New Hetauda - New Bharatpur DC 220 kV TL (70 km)	Under Construction	2013/14
9	Singati - Lamosangu 132 kV DC Transmission Line (40 km)	Under Construction	2013/14
10	Hetauda - KL-II - Siuchatar 132 kV Second Circuit Stringing	Under Construction	2013/14
11a	Kabeli Corridor Damak Substation	Under Construction	2012/13
11b	Kabeli Corridor Substations Illam, Phidim, Kabeli	Tendering	2014/15
11c	Kabeli Corridor 132 kV Transmission Line (65 km)	Under Construction	2014/15
12	New Bharatpur - Bardaghat DC 220 kV Transmission Line (70 km)	Under Construction	2014/15
13	Dumre - Damauli - Marsyangdi 132 kV Transmission Line (56 km)	Under Construction	2014/15
14	Butwal - Kohalpur 132 kV Second Circuit Stringing	Under Construction	2014/15
15	Chapali 132 kV Substation	Under Construction	2014/15
16	Dhalkebar - Bhittamod 400 kV Transmission Line (40 km) (Nepal Portion Cross Border)	Tender Preparation	2014/15
17	Sunkoshi 132kV Substation	Pending	Pending
18	Lamahi - Ghorahi 132 kV Transmission Line for Ghorahi Cement Industry	Tendering	2014/15
19	Lekhnath - Damauli 220 kV Transmission Line (45 km)	Approached to Tanahu Project	2015/16
20	Thankot - Chapagaun - Bhaktapur 132 kV Transmission Line (28 km)	TL Tender Preparation	2015/16
21	Modi - Lekhnath 132 kV Transmission Line (45 km)	Pending	2015/16
22	Hapure - Tulsipur 132 kV Transmission Line (20 km)	Pending	2015/16
23	Marsyangdi - Kathmandu 220 kV Transmission Line (85 km)	Land Acquisition for SS	2016/17
24	Chilime - Trishuli 220 kV Transmission Line	Pending	2015/16
25	Samudratar - Naubise/Chapali 132 kV Transmission Line (50 km)	Pending	2016/17 scope changed
26	Trishuli 3B Hub Substation	Study	2015/16
27	Ramechhap - Garjang - Khimti 132kV Transmission Line (50 km)	IEE	2015/16
28	Karnali Corridor (Lamki - Upper Karnali) 132 kV Transmission Line (60 km)	Study	2015/16
29	Nepal - India Transmission & Trade Project (Hetauda - Dhalkebar - Duhabi 400 kV Transmission Line)	Tendering	2015/16
30	Madi - Lekhnath 132 kV Transmission Line (22 km)	-	2016/17
31	Baneshwor - Bhaktapur UG Cable 132 kV	Study	2015/16
32	Kohalpur - Mahendranagar 132 kV 2nd Circuit Stringing	Tender Preparation	2015/16

	Project	Status	Expected Commissioning
33	Mirchaiya - Katari 132 kV Transmission Line Cement Industry	Tender Preparation	2015/16
34	Matatirtha - Naubise 33 kV Transmission Line for Cement Industry	Pending	-
35	Matatirtha - Malta 33 kV Transmission Line for Cement Industry	Estimate preparation for tendering	-
36	Tulsipur - Kapurkot 33 kV Transmission Line for Cement Industry	Estimate preparation for tendering	-
37	Mirchaiya Katari 132 kV Transmission Line for Maruti Cement Industry	Tender Preparation	2014/15
38	Koshi 220 kV Corridor (Basantpu r- Kusaha) Transmission Line (90 km) Duhabi - Dharan - Dhankuta - Tirtire	Tender Preparation	2015/16
39	Marsyangdi Corridor with Mid Marsyang -Manang Transmission Corridor (51 km)	Study	2015/16
40	Solu Corridor 132 kV Transmission Line (Katari - Okhaldhunga - Solu) (70 km)	Study	2015/16
41	Kali Gandaki 220 kV Transmission Corridor (150 km)	Pending	2015/16
42	Tamakoshi (Khimti) - Kathmandu 220 kV Transmission Line (100 km)	Survey	2016/17
43	Kaski (Bhurjung) - Parbat (Kushma) 132 kV Transmission Line (65 km)	-	-
44	Kohalpur - Surkhet 132 kV Transmission Line (55 km)	Tender Preparation	2016/17
45	Gulmi (Paudi Amrai) - Arghakhachi - Chanauta 132 kV Transmission Line (60 km)	Survey	2016/17
46	Marsyangdi - Bharatpur 220 kV Transmission Line	Pending	2015/16
47	Bajhang - Deepayal - Attariya 132 kV Transmission Line (110 km)	Pending	2016/17
48	Surkhet - Dailekh - Jumla 132 kV Transmission Line (110 km)	Pending	2016/17
49	Kaligandaki - Gulmi (Jhimruk) 132 kV Transmission Line (90 km)	Pending	2016/17
50	Hetauda - Butwal 400 kV Transmission Line (160 km)	Pending	2016/17
51	Dordi Corridor	Study	2016/17
52	Butwal - Lamki 400 kV Transmission Line (220 km)	Pending	2018/19
53	Lamki - Mahendranagar 400 kV Transmission Line (105 km)	Pending	2018/19
54	Butwal - Lumbini 132 kV Transmission Line	Pending	2018/19
55	Dhalkebar - Loharpatti 132 kV Transmission Line	Pending	2018/19
56	Budhiganga - Umedi - Pahalmanpur 132kV Transmission Line	Study	2018/19
57	Bardiya - Bhrigaon 132kV Substation	-	2018/19
58	Balefi - Barhabise 132 kV Transmission Line	Study	2018/19
59	Rupani 132 kV Substation	Study	2018/19
60	Butwal - Sunauli 400 kV Transmission Line (25 km)	Pending	2019/20
61	Duhabi - Jogbani 400 kV Transmission Line (20 km)	Pending	2019/20
62	Duhabi - Anarmani 400kV Transmission Line (80km)	Pending	2019/20
63	Chandranighahapur Reinforcement Project	Project Completed	

6.3 Additional Transmission Line Plan by Study Team

Transmission Lines recommended by JICA Study Team are shown below.

1) Hetauda S/S - Parawani S/S 220 kV Transmission Line

- For the overloading condition around Parawani S/S

- Hetauda S/S - Parawani S/S, 220 kV Double Circuit, 54 km
- 220 kV/132 kV substaion at Parawani S/S

2) Trishuli S/S -Mulpani S/S 220 kV Transmission Line
   - For the overloading condition around Kathomandu
   - Trishuli S/S -Mulpani S/S 220 kV, Double Circuit, 44 km

6.4 Transmission Line Plan for Planned Generation Projects

6.4.1 Projects under Construction or with High probability of Construction[9]

Transmission lines for the Projects under Construction or with High probability of Construction are shown below.

1) Kulekhani III P/S (14 MW)
   - Kulekhani III P/S - Hetauda S/S, 132 kV, Double Circuit, 3.5 km
2) Tanahu P/S (140 MW)
   - Tanahu P/S - Bharatpur S/S, 220 kV, Double Circuit, 40 km
3) Budhi Gandaki P/S (600 MW)
   - Budhi Gandaki P/S - Naubise S/S, 220 kV, Double Circuit, 65 km
4) Upper Tamakoshi P/S (456 MW)
   - Upper Tamakoshi P/S - Khimti S/S, 220 kV, Double Circuit, 47 km
5) Rahughat P/S (32 MW)
   - Rahughat P/S - Modi S/S, 132 kV, Double Circuit, 28 km
6) Middle Bhotekoshi P/S (102 MW)
   - Middle Bhotekoshi P/S - Barhabise Hub, 220 kV, Double Circuit, 4 km
7) Rasuwagadi P/S (111 MW)
   - Rasuwagadi P/S - Chillime Hub, 132 kV, Double Circuit, 10 km
8) Sanjen P/S (42.9 MW)
   - Sanjen P/S - Chillime Hub, 132 kV, Double Circuit, 1.2 km
9) Upper Sanjen P/S (50 MW)
   - Upper Sanjen P/S - Tadi Kuna S/S, 132 kV, Double Circuit, 20 km
10) Mistri P/S (42 MW)
   - Mistri P/S - Dana S/S, 132 kV, Double Circuit, 4 km
11) Khani Khola P/S (25 MW)
   - Khani Khola P/S - Singati S/S, 132 kV, Double Circuit, 4 km

[9] These projects are in detailed design stage or PPA concluded.

12) Upper Trishuli 3A P/S (60 MW)

- Upper Trishuli 3A P/S - Matatirtha S/S, 220 kV, Double Circuit, 48 km

13) Upper Trishuli 3B P/S (37 MW)

- Upper Trishuli 3B P/S - UpperTrishuli 3A Hub, 220 kV, Double Circuit, 5 km

14) Upper Modi A P/S (47 MW)

- Upper Modi A P/S - New Modi S/S, 132 kV, Double Circuit, 7.5 km

6.4.2 Storage-type Hydroelectric Power Projects by the Study Team

Transmission lines for the Storage-type Hydroelectric Power Projects by the Study Team are shown below.

1) Dudh Koshi P/S (300 MW)

- In order to supply Eastern area and Central area with the electricity Dudh Koshi P/S should be connected to Dhalkebar S/S with 220 kV transmission lines.
- Dudh Koshi P/S - Dhalkebar S/S, 220 kV, Double Circuit, 93 km

2) Andhi Khola P/S (180 MW)

- Andhi Khola P/S should be connected to 220 kV Transmission-Line between Kusma S/S and Butwal S/S.
- Andhi Khola - 220 kV Transmission-Line between Kusma S/S and Butwal S/S, 220 kV, Double Circuit, 5 km

3) Nalsyau Gad P/S (410 MW)

- Nalsyau Gad P/S should be connected to the junction of the transmission line between Chera-1 P/S and Kohalpur 400 kV S/S.
- Nalsyau Gad P/S - Junction, 400 kV, Double Circuit, 55 km

4) Chera-1 P/S (149 MW)

- Chera-1 P/S and Nalsyau Gad P/S would generate relatively much and their site would be far from the load center. Therefore they should be connected to power system with 400 kV transmission lines.
- Chera-1 P/S and Nalsyau Gad P/S would be connected to the 400 kV network planned by the NEA at Kohalpur S/S.
- Chera-1 P/S - Junction, 400 kV, Double Circuit, 25 km
- Junction - Kohalpur 400 kV S/S, 400 kV, Double Circuit, 72 km

5) Naumure P/S (245 MW)

- Naumure P/S and Madi P/S would generate relatively much and their site would be far from the load center. Therefore they should be connected to power system with 400 kV transmission lines.
- Naumure P/S and Madi P/S would be connected to the 400 kV network planned by the NEA at Shivapur S/S.

- Naumure P/S - Junction, 400 kV, Double Circuit, 12 km
- Junction - Shivapur S/S, 400 kV, Double Circuit, 37 km

6) Madi P/S (200 MW)

- Madi P/S should be connected to the junction of the transmission line between Naumure P/S and Shivapur 400 kV S/S.
- Madi P/S - Junction, 400 kV, Double Circuit, 67 km

7) Sun Koshi No.3 (536 MW)

- Sun Koshi No.3 P/S should be connected to Dhalkebar S/S with 220 kV transmission lines.
- Sun Koshi No.3 P/S - Dhalkebar S/S, 220 kV , Double Circuit, 87 km

8) Lower Badigad P/S (380 MW)

- Lower Badigad P/S - Andhi Khola P/S, 220 kV, Double Circuit, 18 km

6.5 Power System Impact Study

6.5.1 Scope of the study

The power system analysis for FY 2031/32 condition was carried out on the Promising Projects.

Power system analysis

- Power Flow Analysis
- Short Circuit Current Analysis
- Dynamic Stability Analysis

6.5.2 Assumptions in the study

The study was carried out based on the criteria and the assumptions below and PSS/E, Version-32 simulation software was used for the analysis.

(1) Criteria for the analysis

1) Voltage (above 66 kV)

- Voltage variation in normal operation: +/- 5% of nominal voltage
- Voltage variation during emergencies: +/- 10% of nominal voltage

2) Frequency variation during emergencies: +/- 5% of nominal frequency

3) Contingency for Load Flow Study: N-1 conditions

4) Load Characteristics

- Active Power: constant current
- Reactive Power: constant admittance

5) Fault Sequence for Stability Analyses

- Above 220 kV: 3 Line to Ground fault - 5 cycles - fault clear
- Up to 132 kV: 3 Line to Ground fault - 7 cycles - fault clear

(2) Demand

- The peak power demand of 4,866 MW in FY2031/32 (High Case) was estimated by the Study Team.

(3) Net Work Data

- The demand in FY 2031/32 would be much more than in FY 2018/19. Therefore the appropriate reinforcement for the Power System was considered with the NEA's latest analyses data for FY 2018/19 condition.
- Muzaffarpur bus was taken as the Swing Bus. And it was connected to Nepal as an inter tie line.

6.5.3 Power Flow Analysis

The results of the power flow analysis were shown in Figure 6.5.3-1 Power Flow Diagram in FY 2031/2032 Peak.

- No thermal criteria violations and no voltage violations were observed on the Power System above 132 kV.
- The transmission line planed by the NEA between Naubise S/S and Matatirtha S/S would be overloading condition when one of the two circuits is out of service and Budhi Gandaki P/S will be in service. Therefore their conductor size should be reviewed.
- The transformers' MVA rating and tap range should be determined based on the expected demand trend and installed generations.
- The voltage of 400 kV transmission lines would tend to be raised by their charging. Therefore appropriate plan for the installing shunt reactors would be required according to the transmission line expansion.
- The voltage of the power system less than 132 kV would be lowered by their increased demands. Therefore appropriate plan for the installing capacitors would be required according to the demand trend.
- Reinforcements of transmission lines and the transformers less than 66 kV Net-Work include the distribution system would be required for the demand increase. And they should be studied considering the demand trend.

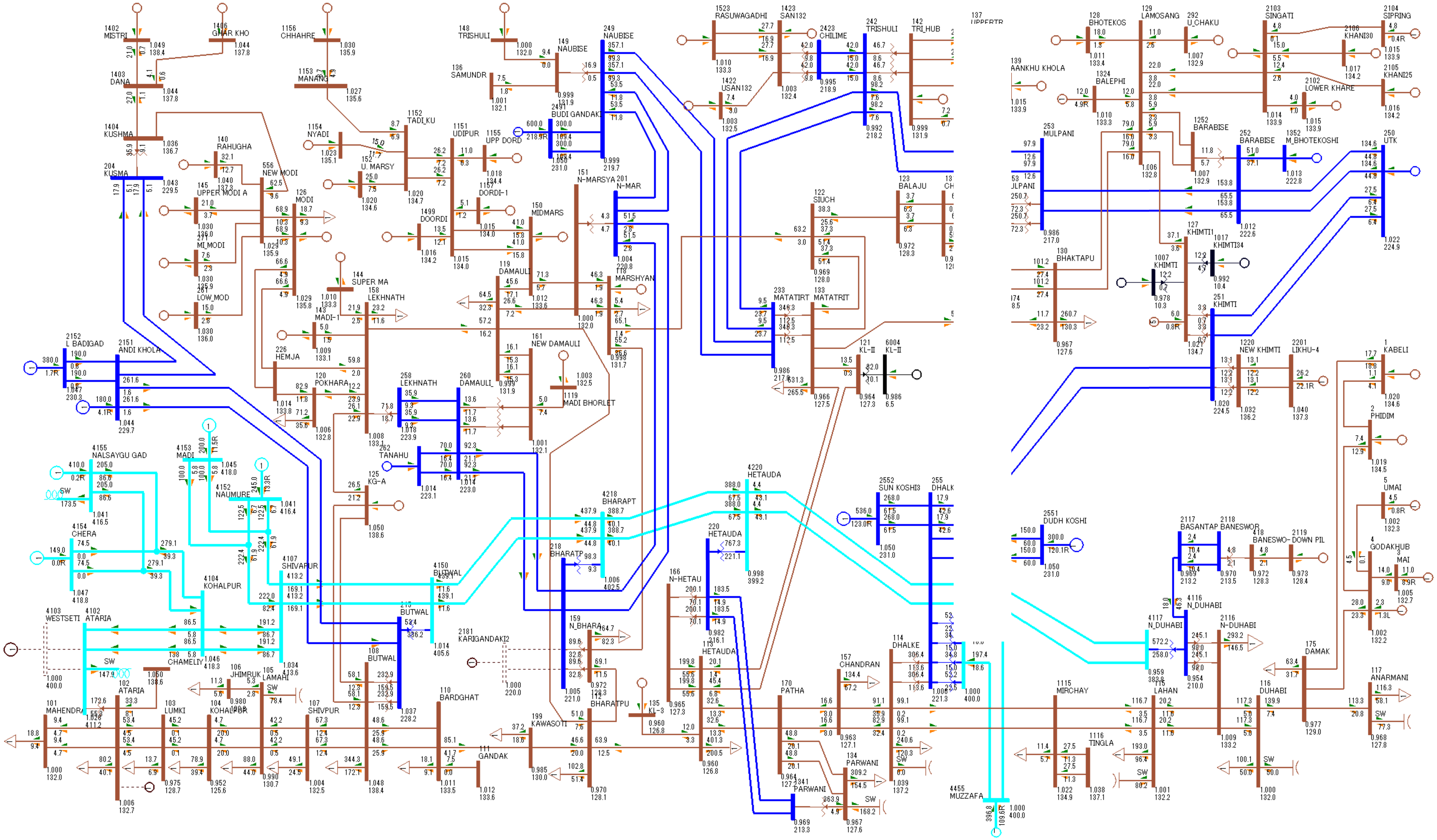


Figure 6.5.3-1 Power Flow Diagram in FY 2031/2032 Peak

6.5.4 Short Circuit Current Analysis

The Three Phase Fault Current at the power stations of the Promising Projects and the substations connected to them are shown in Table 6.5.4-1. Those of the currents were sufficiently small.

Table 6.5.4-1 Short Circuit Current in FY 2031/32 Peak

P/S or S/S		Fault Current	P/S or S/S		Fault Current
New Duhabi S/S	132 kV	12.1 kA	New Bharatpur S/S	132 kV	18.7 kA
	220 kV	9.3 kA		220 kV	17.0 kA
	400 kV	6.8 kA		400 kV	12.2 kA
Dhalkebar S/S	132 kV	24.1 kA	Kusma S/S	132 kV	8.6 kA
	220 kV	23.5 kA		220 kV	8.6 kA
	400 kV	15.1 kA	Andhi Khola P/S	220 kV	12.0 kA
Dudh Koshi P/S	220 kV	9.4 kA	Lower Badigad P/S	220 kV	10.9 kA
Sun Koshi P/S	220 kV	11.6 kA	Butwal S/S	132 kV	17.7 kA
Parawani S/S	132 kV	15.5 kA		220 kV	14.1 kA
	220 kV	10.1 kA		400 kV	11.2 kA
New Hetauda S/S	132 kV	22.5 kA	Shivapur S/S	400 kV	9.9 kA
	220 kV	16.7 kA	Naumure P/S	400 kV	8.3 kA
	400 kV	12.3 kA	Madi P/S	400 kV	6.8 kA
Naubise S/S	132 kV	4.9 kA	Kohalpur S/S	400 kV	7.2 kA
	220 kV	16.5 kA	Chera-1 P/S	400 kV	6.0 kA
Budhi Gandaki P/S	220 kV	12.7 kA	Nalsygu Gad P/S	400 kV	6.0 kA
New Damauli S/S	132 kV	13.8 kA	Ataria S/S	132 kV	8.5 kA
	220 kV	12.4 kA		400 kV	4.5 kA
Tanahu P/S	220 kV	12.0 kA			

6.5.5 Dynamic Stability Analysis

Dynamic Stability Analysis was carried out for the Power System in FY2031/2032.

- As the results of study, it was judged that the power system was stable for all cases.
- Some of the large size units of Hydro Power Generation will be located in Western Area far from load-center. Therefore the Power System Stabilizer will have to be prepared for the large size units because of the power system stability.

6.6 Review for the Transmission Line Expansion Plan

The Power System Analysis was carried out for the Power System in FY2031/32 peak demand. And the results of the analysis showed that any problems on the power system were not observed for the Promising Projects of the Study Team and Transmission Line Expansion Plan of the NEA.

Reinforcements of the Net-Work less than 66 kV include the distribution system would be required for the demand increase. And each of them should be studied according to individual demand growing.

Chapter 7 Environmental and Social Considerations

7.1 Strategic Environmental Assessment

Three steps of the strategic environmental assessments were applied to select a few candidate projects for Feasibility Study from 67 potential projects. Regarding the comparative study of the projects, economic and technical aspects, natural and social environmental aspects were treated equally as possible. In addition, to ensure an objective evaluation, the assessment aimed to align the collected information level and to make a quantitative evaluation. Disclosing information and holding consultation with stakeholders are actively conducted, and three stakeholders meetings were held in this study. The results of the strategic environmental assessment (SEA) are shown in Appendix 3 as the SEA Report. The following is the delineation of the results of the SEA.

7.1.1 Target Setting of SEA

The target of the SEA is to propose 10 promising projects and their developing order in order to fulfill the electricity power demand in FY2031/31 by storage-type hydroelectric power projects in an environmentally sustainable manner without having a serious impact on the natural and social issues.

7.1.2 First Step of SEA

In the first step of SEA, screening of 67 potential projects listed in the long list was conducted to exclude not appropriate project and to select candidate projects. As a result of the screening, (1) five projects which are on-going projects of detailed design of feasibility study, (2) six projects which are located overlapping with other projects, (3) 36 projects which were deemed inappropriate as a storage-type hydroelectric power project in Nepal were excluded, and 31 candidate projects were selected. The details of the process are shown in Chapter 6, Appendix 3 of the SEA report.

7.1.3 Second Step of SEA

The second step aims to select 10 promising projects from Candidate 31 projects. The data used for evaluation are based on the existing documents. No site survey is conducted at this step. 22 items are used for the evaluation; 13 economic and technical items, four natural environmental items and five social environmental items. Each of the evaluation items were quantified and subjected to sensitivity analysis of three patterns. As a result, projects in the western part such as Madi and Lower Jhimruk were ranked at the top. Taking into account the regional balance and conflict with the licenses already issued to other projects, 10 promising projects were selected through consultation with the NEA. The selected projects were Dudh Koshi, Kokhajor-1, Sun Koshi No. 3, Lower Badigad, Andhi Khola, Chera-1, Lower Jhimruk, Madi, Nalsyau Gad and Naumure (W. Rapti). The details of this promising projects selection are shown in Chapter 7, Appendix 3 of the SEA Report.

7.1.4 Third Step of SEA

In the third step of SEA, the site survey about the 10 promising projects selected in the second step of SEA was conducted. Based on the results of the site survey, an overall rating point was given to each project. 11 economic and technical items, 17 natural environmental items, 22 social environmental items, and 63 items in total were used for evaluation. For the evaluation results, four cases of sensitivity analysis were carried out. For example, in Case-1, an equal weight of 50% is placed in both economic and technical items and environmental items. In Case-4, 75% of the weight is placed in economic and technical items. However, the evaluation results were not so different between the four cases. Nalsyau Gad, Dudh Koshi and Andhi Khola projects had relatively high ratings for all cases. Detailed explanations of the alternative study results are described in Chapter 8, Appendix 3 of the SEA report.

7.1.5 Cumulative Impact

Cumulative Impact was studied considering 30 existing hydroelectric power projects, 12 existing irrigation projects (including India downstream), existing road, 21 hydroelectric project plan, investigation rights issue areas for hydroelectric power, 2 large-scale planned irrigation projects and road planning.

Followings are brief results of the assessment. Detail results are shown in Chapter 9, Appendix 3 of the SEA report.

(1) Water Regulation Effects on a Wetland Ecosystem,

In order to see the cumulative effects on water regulation, all the existing and planned storage type hydroelectric power plants were identified and measured the catchment area by river systems. The Karnali river system has two planned projects in different tributaries. If all of the two projects are developed, 3.2% of the river basin will be regulated. As a result, the Bardia National Park Buffer Zone located downstream and 28 protected species might be affected. The Rapti river system has two planned hydroelectric power plants. If two projects are developed, 66.6% of the river basin will be regulated and the Banke National Park Buffer Zone and 15 protected species might be affected. The Gnadaki river system has four existing storage type project and six planned storage type projects. If all the four projects are developed, 64.6 % of the river basin will be regulated. It might violate the Gandaki Irrigation and Power Project Agreement (1959) signed between Nepal and India. In addition, the Chitwan National Park located downstream and 27 protected species might be affected. In the Koshi river system, there are two planned projects in different tributaries. If all the projects are developed, 17.8 % of the river basin will be regulated. It might violate the Kosi Project Agreement signed between Nepal and India. Koshi Tappu Wildlife Reserve and 15 protected species might be also affected.

(2) Barrier effects on migration fish

From an ichthyological point of view, the rivers which have continuing barriers seem to be difficult for the fish to habitat. In particular, for the long distance migration fishes need access to the high mountain areas with cold water that is suitable for spawning. Most of the IUCN red list fish species in Nepal are cold water migration fishes. Currently most of the existing major barriers are concentrated in the Gandaki river system and the Koshi river system. On the other hand, eight other main river systems are free of barriers. However, seven of these rivers do not reach a high mountain area. Only the Karnali river system reaches a cold water area. Some of the existing barriers have fish ladders but some of them do not have any mitigation. Because of a lack of data, actual barrier effects and mitigation effects are not clearly identified. But in case all the planned HPP and Irrigation projects will be developed, it might cause a serious impact on fish diversity in Nepal.

(3) Impact on terrestrial ecosystems through development concentration.

The impact on the forest ecosystem will be accelerated by road construction together with HPP and Irrigation projects. The high risk areas are the Bajhang District in the Far-Western region, Mugu District, Humla District, Kalikot District, Jajarkot District in the Mid-Western region, Myagdi District, Kaski District, Lamjung District in the Western region, Rasuwa District in the Central region, and Solukhumbu District, Sangkhuwasabha District, Taplejung District in the Eastern region.

7.1.6 Mitigation Measures

(1) Mitigation for Individual Project

Chera-1 Project

One of the issues of concern in Chera-1 Project is compensation for resettlement. A survey should take enough time for more than 550 resettlements and be sure to give equality for people during negotiations. If possible, all of the villagers will be able to move to the same area along with their culture. It should also take enough time for a survey for the 60 km transmission line.

Lower Jhimruk Project

The Lower Jhimruk Project needs a detailed biological survey in EIA because a relatively high number of important species are identified. Important forest and grass land as habitats for wild-life should also be identified. The negotiation process for resettlement should be done carefully for ethnic minorities even if the number of people resettled is around 200. Compensation for income from agriculture and fishery should be considered including vocational training.

Madi Project

The Madi Project needs a detailed biological survey including a fish survey and careful mitigation measures in EIA, because flora diversity and number of important fish species are relatively high.

Nalsyau Gad Project

A preliminary transmission survey will be required before EIA or IEE for the transmission line, because the route is around 112 km long. A water regulation plan during the rainy season and dry season should be carefully determined in order to minimize the impact on the protected area and protected species. The household survey for the resettlement should take enough time because it counts around 300 households.

Naumure (W. Rapti) Project

The Naumure Project needs a detailed biological survey in EIA, because 8 km^2 of forest land will be submerged and it will cause habitat loss for terrestrial fauna. Vocational training for people who cannot live on farming might be required because more than 6 km^2 of farm land will be lost.

Lower Badigad Project

The Lower Badigad Project needs a detailed biological survey in EIA because a relatively large number of important mammals and fishes are identified. Relocation area for 1,500 households should be considered for in early stage of designing. Water regulation in rainy season and the refresh rate in dry season should be carefully examined considering the impact on the protected area and protected species.

Andhi Khola Project

There is an 11 MW existing off-grid HPP in the reservoir of Andhi Khola Project. If it has to be stopped for the construction, alternative electricity supply to local people should be considered. In addition to provision of a settlement area for more than 500 resettlements, some income compensation should also be considered for the affected retailing store.

Dudh Koshi Project

A slightly wider area for the mammal and birds survey will be required in order to identify the migration route in the EIA study. The offset mitigation for fish should be considered at an early stage of the EIA study. The number of resettlements is low, but the farm land in the reservoir area is very fertile. It means income compensation for many farmers might be required. The existing EIA report was made based on data in 1997 and it was not approved by the Ministry of Environment. Then the EIA study should be conducted again and get a certificate through the Ministry of Environment.

Kokhajor-1 Project

Forest compensation should be considered carefully in the EIA study. The study for resettlement should be taken care of for each ethnic minority group, even if the number of resettlements is 200, which is relatively low.

Sun Koshi No. 3 Project

The compensation process would be critical for Sun Koshi No. 3 Project, because the number of resettlements will be more than 1,500. In addition, there are some accommodations for tourists. Alternatives for 15 km national highway which will be submerged in the reservoir area should also be prepared. Vocational support and entrepreneurial capability building might be needed for the farmers and fishermen who lose their source of income.

(2) Mitigation for Cumulative Impact

Mitigation for cumulative impact often involves a number of ministries and the mitigation that can be implemented on a project-by-project basis is very small. The followings are the suggestions recommended for three kinds of impact.

Impact on the downstream wetland ecosystems by flow rate adjustment

In case there are a number of projects in the same river system, the impact by water regulation will be significant even if the water regulation rate of each project is not so high. The following are some proposals to reduce such effects even a little.

a) Re-regulating reservoir

A re-regulating reservoir is one of the solutions to average the daily variation of water discharge. It will maintain downstream aquatic ecology and to avoid risk to human and wildlife. However, this might become another barrier for fishes and it cannot control yearly variation.

b) Coordinate operation

Coordinated operation of several storage-types hydroelectric power plants in the same river system might be able to reduce the cumulative impact. In a place where accidents by sudden flooding are a concerned, it careful control of water regulation timing and rates are recommended.

c) Strategic watershed development control

Strategic watershed planning for each watershed with its conservation target is needed coordinating with Department of Energy, Department of Irrigation, Department of water supply, Department of Soil Conservation and Watershed Management, Ministry of Forests and Soil Conservation and other sectors. The acceptable water regulating revel should be identified from the wildlife conservation points of view. Then total volume control can be planned.

Barrier effects on migration fish

Hydropower, irrigation, and water supply will block fish migration. Many planned barriers will accelerate higher risk. The following are some suggested mitigations fir this.

a) Minimizing the number of barriers

Smaller numbers of barriers are better for fishes. Even if fish ladders or other mitigations are installed, they are not perfect mitigation which restores rivers to their original condition. To minimize the number of barriers, constructing a limited number of storage type HPPs seems better than the construction of many small ROR type projects.

b) Barrier free river

Keep at least one or two tributary river corridors in each of the west, center and east areas for the maintenance of key Himalayan fish species. For example, the Thuli Gad and Barun Khola in the Karnali system, the Lundri Khola in the Rapti system, and the Badigad Khola and Budhi Khola in Gnadaki system might be candidate rivers. However, it is recommended to identify these barrier free rivers once the Fish conservation plan have been developed. This plan will be developed based on nationwide fish census to be described hereinafter.

c) Fish ladders and hatcheries

Fish ladders/hatchery are not perfect mitigations but they are better than doing nothing at all. Legalizing provision of fish ladders for projects with dams less than 30m (hydropower, irrigation, or water supply projects) not only for new projects but also existing projects is recommended. It is also recommended to legalizing fish hatcheries in order to deliver affected fish resources for all the projects with dams higher than 30m. If possible, delivering fish resource systems from existing and planned fish hatcheries might be effective after detail examination of the genetic lineage between the rivers.

d) Fish migratable flashing gate

Some new barriers will attach sediment flashing gate at the bottom to the middle level of the dam. If some additional devices might be attached on the gate, fishes might be able to migrate after flashing.

e) Nationwide fish census

Conducting nationwide fish census is recommended in Nepal. There is no reliable fish distribution database and it is difficult to see the actual impact and effect of existing barriers. In order to identify hot spots for fish, periodic nationwide fish census survey is highly recommended.

f) Fish conservation plan

Formulation of fish conservation plan is required before Nepali fish diversity falls into a critical situation. In addition to the cumulative barrier effect, the invasion of exotic fishes to Nepal is also anticipated. Based on the fish monitoring result, a fish conservation plan should be prepared. This fish conservation plan might be useful for appropriate watershed management. Formulating a fish conservation plan is necessary to accomplish sustainable development and the Directorate of Fisheries Development and International NGO will take on big roles for this formulation.

<u>Countermeasures against the Impact of Development Concentration</u>

a) Strategic watershed development control

Strategic watershed development control is required before deregulated development and forest loss. Even if it is outside of the protected area, some forests used for migration corridors and some high grade ecosystem sometimes remain. It should be identified such kind of places and informed to the development department.

b) Assured tree planting

The forest norm in Nepal is giving options to the developer such as planting trees or paying compensation fees to the Department of Forestry. But sometimes, the compensation fee is not correctly used for planting trees, because of lack of planting area. In order to assure planting of trees, developer should be responsible for tree planting from start to finish.

c) Construction road management

Construction of road and access roads for hydropower plants might become a trigger of illegal logging. In case the roads connect to high value forests, they should be controlled carefully.

d) Specialized mitigation organization

Installation of Mitigation organization might be useful. Many HPPs including small size ones will be developed in a few decades in Nepal. However, it is a bit difficult to impose implementation of effective environmental mitigation on each project owner, because they are not not biology professionals. In some cases, not only the planning of mitigation measures but also monitoring and operation are not be able to expect for project owners. In order to solve these problems, establishment of specialized organization in mitigation which covers all the mitigation planning and monitoring work and which is paid by project owners is required. With this kind of organization, rehabilitation of heavily damaged areas can be concentrated on effectively and efficiently.

7.1.7 Stakeholder Meeting

During the Study period, a total of three stakeholders meetings have been conducted in Kathmandu, inviting the mass media, representatives of government agencies and political parties. At the second and third stakeholders meetings, holding those meetings was told to related Districts in which promising projects are located. However, there were no participants from these Districts.

In addition, interviews and hearings were conducted with a wide range of stakeholders such as the western regional office of Bokhara, ministries related to environment and forest, and SEA report evaluation meeting members composed of NGOs, the WWF, each of the related district offices and residents.

The details of these consultations are shown in Chapter 12 of the SEA Report (Appendix 3) and the Annex 12-21 of the SEA Report in Appendix 5.

(1) The 1st Stakeholders Meeting

On February 17, 2012, the first meeting that was co-hosted by the NEA and the Study Team was organized in Kathmandu. 51 participants including the Study Team were recorded for this meeting.

The purpose of this stakeholders meeting was to enable the stakeholders to understand the objective, goal, study method and schedule, etc. of the Study, and to obtain comments on the appropriateness of evaluation items. In the meeting, the Study Team introduced about 67 candidate projects and explained the evaluation items with which the candidate projects are evaluated. Hearing of comments by a questionnaire survey was also conducted to understand which evaluation items the stakeholders put importance on.

(2) The 2nd Stakeholders meeting

On November 28, 2012, the second meeting that was co-hosted by NEA and the Study Team was organized in Kathmandu. 83 participants including the Study Team were recorded for this meeting.

In this second stakeholders meeting, the process of selecting 10 promising projects among the above 67 candidate projects and their results were explained. Preliminary reports of the site survey of these 10 promising projects, and draft of the evaluation method of these projects were also explained. In the meeting, hearing and collecting the comments to understand the stakeholder's opinions about the evaluation items with which promising projects were evaluated.

(3) The 3rd Stakeholders Meeting

The Study team conducted the evaluation about the 10 promising projects, taking into consideration the comments raised in the second stakeholders meeting and the result of site survey, with the purpose of sharing the results of the Study and the evaluation of 10 promising projects.

On February 13, 2013, the third meeting that was co-hosted by the NEA and the Study Team was held in Kathmandu. 107 participants including the Study Team were recorded for this meeting.

In this meeting, the results of the power demand forecast and the evaluation results of promising projects taking into account the comments collected in the second stakeholders meeting were explained. The opinions were collected from stakeholders about the points which should be carefully noted for making the master plan of storage type hydroelectric power development.

7.2 Suggestions for ElAs in the FS stage

7.2.1 Required documents for Environmental and Social Consideration

(1) Environment Impact Assessment (EIA/IEE)

EIA procedures in Nepal are stipulated in the Amendment (January 27, 2010) of Environment Protection Regulation (1997) and National Environment Impact Assessment Guidelines (1993). Amendment (2010) requires IEE for transmission projects more than 132 kV and hydropower projects from 1 MW to 50 MW. EIA is required for hydropower projects which have an output of more than 50 MW.

(2) Environmental Management Plan

The JICA Guidelines for Environmental and Social Consideration 2010 (hereafter referred to as JICA Guidelines) treats the Environmental Management Plan (IMP) as a part of EIA. But if it requires an updated IMP based on a detailed design, it can be prepared independently.

(3) Resettlement Action Plan

JICA Guidelines are suggesting to follow OP 4.12, Annex A – Involuntary Resettlement Instruments, World Bank, when large number of resettlements will happen.

(4) Indigenous People Plan

JICA Guidelines suggest including an Indigenous People Plan (IPP) which includes the contents in OP 4.10, Annex B – Indigenous People Plan, World Bank, if the projects affect indigenous people. All the 10 projects except the Nalsyau Gad are required to prepare an IPP, because they have confirmed the existence of indigenous people.

7.2.2 Comprehensive Scoping in FS stage

It is difficult to do site specific scoping, because it is undecided which projects will be selected for next the next FS. Then comprehensive scoping for ten promising projects is conducted. The risk of land slide around the reservoir might be high, because most of the sites are located in precipitous terrain. The risk of water accidents would rise if there is no re-regulating pond. The low rate of water rotation might cause eutrophication and dams without sedimentation flash gates raise the flood risk near the back water of the reservoir. All the dams block the migration fishes. If the construction of the transmission line divides the forest, it will have an impact on the environment; the animal migration will be inhibited and the land use of the ground under the transmission line will be limited.

Detail issues which should be considered in the survey, impact assessment, mitigation planning, and monitoring planning in the feasibility stage are described in 13.3, 13.4, 13.5 of the SEA report.

Chapter 8 Conclusion and Recommendations

8.1 Conclusion

The Study Team conducted the "Nationwide Master Plan Study on Storage-type Hydroelectric Power Development in Nepal" for about two years from January 2012 to February 2014. The Study has revealed that, for the base case of the demand forecast, construction of storage-type HPPs totaling 1,993 MW including the Kulekhani No. 3, the Tanahu, and the Budhi Gandaki HPPs that are currently under construction or in the preparation stage is required by FY2031/32 for resolving current load shedding and meeting the increase in power demand.

8.1.1 Power Demand Forecast

The demand forecasting model adopted by the NEA for the nation-wide power demand forecast is a dynamic model employing principles of economic theories, and the Study Team also adopted that model. NEA's model consists of three sub-models: namely, a) a sub-model for domestic sector demand, b) a sub-model for industry, and the commerce and service sector, and c) a sub-model for irrigation. Scenarios of economic growth and prices were reflected in the power demand forecast through setting of parameters.

In addition to the base case, the forecasts for a high case and a low case were conducted, and a sensitivity analysis was conducted. In the high case, GDP growth and a power price increase were set higher than in the base case, and in the low case, they were set lower than in the base case.

As a result, the peak demand and the energy demand in FY 2031/32 were estimated at 4,279 MW and 19,493 GWh respectively for the base case corresponding to 1,027 MW and 5,380 GWh in FY2011/12. The forecasted power demands of each year up to FY 2031/32 are shown in Table 8.1.1-1.

Table 8.1.1-1 Sensitivity Analysis of Power Demand Forecasts

Fiscal year	Comparision of energy demand forecasts (GWh)			Comparision of generation capacity forecasts (MW)		
	Base case	High case	Low case	Base case	High case	Low case
2012/13	5,607	5,537	5,650	1,231	1,216	1,240
2013/14	5,818	5,678	5,907	1,277	1,247	1,297
2014/15	6,049	5,851	6,202	1,328	1,284	1,361
2015/16	6,294	6,031	6,514	1,382	1,324	1,430
2016/17	6,556	6,290	6,847	1,439	1,381	1,503
2017/18	6,836	6,888	7,192	1,501	1,512	1,579
2018/19	7,176	7,512	7,522	1,575	1,649	1,651
2019/20	7,823	8,174	7,869	1,717	1,794	1,728
2020/21	8,504	8,880	8,237	1,867	1,949	1,808
2021/22	9,252	9,670	8,738	2,031	2,123	1,918
2022/23	9,881	10,342	9,307	2,169	2,270	2,043
2023/24	10,572	11,066	9,922	2,321	2,429	2,178
2024/25	11,447	11,974	10,702	2,513	2,629	2,349
2025/26	12,364	13,002	11,538	2,714	2,854	2,533
2026/27	13,325	14,089	12,426	2,925	3,093	2,728
2027/28	14,386	15,260	13,390	3,158	3,350	2,939
2028/29	15,531	16,557	14,426	3,410	3,635	3,167
2029/30	16,744	18,147	15,524	3,676	3,984	3,408
2030/31	18,066	19,993	16,680	3,966	4,389	3,662
203132	19,493	22,166	17,921	4,279	4,866	3,934

8.1.2 Power Development Plan

The total installed capacity of generation facilities in Nepal as of the end of FY 2011/12 was 718,621 kW. Hydroelectric power generation accounts for 93% of this, and 86% of these are ROR-type HPPs. Since their generating capacities drop in the dry season because of a decrease in river flow, the whole supply capacity of the country drops significantly. On the other hand, the power demand peaks in the dry season. Therefore it is necessary to strengthen the supply capacity in the dry season in electric power development from now on.

In general, the generating capacity of thermal power generation is not affected by the dry season. However, since Nepal depends on imports for nearly all of its fossil fuel, a huge amount of foreign currency is necessary for purchasing fuel for thermal power generation. Moreover, costs for long-distance transportation are required because Nepal is a landlocked country. Therefore, it is practically impossible to construct coal-fired or LNG-fired thermal power plants for base load and gas turbine power plants for peak load.

On the other hand, Nepal is rich in hydropower resources and its economically exploitable hydropower is estimated at 42,000 MW. Development of hydroelectric power generation utilizing this plentiful amount of hydropower is one of policies of the country.

Taking these situations into consideration, the power development plan was formulated based on the scenario below.

- The main electric power source in the national grid (INPS) is hydroelectric power generation utilizing hydropower energy that is one of the country’s abundant domestic resources.
- Storage-type hydroelectric power generation is developed for securing the supply capacity of

the INPS by compensating the decrease in the supply capacity of ROR-type hydroelectric power generation in the dry season.

- ROR-type hydroelectric power generation is developed continuously for utilizing abundant hydropower energy.
- Imports of electricity from India is kept on for power supply to the areas near the border.
- Power generation using renewable energy like wind power and solar power is promising in the long term. However, this is not considered in the power development plan in the next two decades because the proportion in the INPS is considered to be very small taking into consideration its generation cost and effects on stability of the power network.

The result of the Study shows that 5,268 MW of the generation facilities, including imports from India, is necessary in FY 2031/32 for the base case of the power demand forecast, and the total installed capacity to be constructed for the 20 years from FY2012/13 to FY2031/32 is 4,257 MW including projects currently under construction and in the preparation stage.

The power development plans for the base/high/low cases of the power demand forecast are shown in Table 8.1.2-1.

Table 8.1.2-1 Power Development Plan

Base Case

FY	Project	Total Installed Capacity (MW)	LOLP (%)
(2011/12)	(Existing)	862.1	——
2012/13	--------	862.1	50.375
2013/14	--------	862.1	53.789
2014/15	--------	862.1	57.975
2015/16	**Kulekhani No. 3 (14)**, Chameliya (30), Khani Khola (25)	1,081.1	32.637
2016/17	Upper Sanjen (11), Sanjen (42.9), Upper Trishuli 3A (60), Upper Tamakoshi (456)	1,651.0	2.733
2017/18	Madhya (Middle) Botekoshi (102), Rasuwagadi (111), Rahughat (32), Upper Marsyangdi (50), Mistri (42)	1,988.0	1.575
2018/19	ROR (100 in total)	2,088.0	1.927
2019/20	Upper Trishuli 3B (37), ROR (100 in total)	2,225.0	2.579
2020/21	**Tanahu (140)**, Upper Modi A (42), ROR (100 in total)	2,507.0	1.919
2021/22	Tamakoshi V (87)	2,594.0	3.087
2022/23	**Budhi Gandaki (600)**	3,194.0	0.130
2023/24	--------	3,194.0	0.516
2024/25	ROR (100 in total)	3,294.0	1.225
2025/26	Upper Arun (335), ROR (100 in total)	3,729.0	0.666
2026/27	**Dudh Koshi (300)**	4,029.0	0.336
2027/28	--------	4,029.0	1.079
2028/29	**Nalsyau Gad (410)**	4,439.0	0.440
2029/30	**Andhi Khola (180)**, ROR (300 in total)	4,919.0	1.331
2030/31	--------	4,919.0	1.330
2031/32	**Chera-1 (149)**, **Madi (200)**	5,268.0	1.232

Note: Projects listed in boldface are storage-type projects.
The total installed capacities include import from India.
The allowable upper limit of LOLP is 1.375%, equivalent to 5 days supply shortage in a year.

High Case

FY	Project	Total Installed Capacity (MW)	LOLP (%)
(2011/12)	(Existing)	862.1	——
2012/13	--------	862.1	49.198
2013/14	--------	862.1	51.573
2014/15	--------	862.1	54.322
2015/16	**Kulekhani No. 3 (14)**, Chameliya (30), Khani Khola (25)	1,081.1	27.323
2016/17	Upper Sanjen (11), Sanjen (42.9), Upper Trishuli 3A (60), Upper Tamakoshi (456)	1,651.0	1.945
2017/18	Madhya (Middle) Botekoshi (102), Rasuwagadi (111), Rahughat (32), Upper Marsyangdi (50), Mistri (42)	1,988.0	1.680
2018/19	ROR (100 in total)	2,088.0	2.695
2019/20	Upper Trishuli 3B (37), ROR (100 in total)	2,225.0	3.334
2020/21	Tanahu (140), Upper Modi A (42), ROR (100 in total)	2,507.0	2.625
2021/22	Tamakoshi V (87)	2,594.0	3.923
2022/23	**Budhi Gandaki (600)**	3,194.0	0.345
2023/24	--------	3,194.0	0.967
2024/25	Upper Arun (335), ROR (200 in total)	3,729.0	0.403
2025/26	--------	3,729.0	1.218
2026/27	**Dudh Koshi (300)**	4,029.0	0.824
2027/28	**Nalsyau Gad (410)**	4,439.0	0.309
2028/29	--------	4,439.0	1.167
2029/30	**Andhi Khola (180)**, **Chera-1 (149)**	4,768.0	1.397
2030/31	**Madi (200)**, **Naumure (245)**, ROR (100 intotal)	5,313.0	1.025
2031/32	**Sun Koshi No. 3(536)**, **Lower Badigad (380)**, ROR (100 in total)	6,329.0	0.672

Note: Projects listed in boldface are storage-type projects.
The total installed capacities include import from India.
The allowable upper limit of LOLP is 1.375%, equivalent to 5 days supply shortage in a year.

Low Case

FY	Project	Total Installed Capacity (MW)	LOLP (%)
(2011/12)	(Existing)	862.1	——
2012/13	--------	862.1	51.054
2013/14	--------	862.1	55.341
2014/15	--------	862.1	60.972
2015/16	**Kulekhani No. 3 (14)**, Chameliya (30), Khani Khola (25)	1,081.1	36.845
2016/17	Upper Sanjen (11), Sanjen (42.9), Upper Trishuli 3A (60), Upper Tamakoshi (456)	1,651.0	3.802
2017/18	Madhya (Middle) Botekoshi (102), Rasuwagadi (111), Rahughat (32), Upper Marsyangdi (50), Mistri (42)	1,988.0	2.389
2018/19	ROR (100 in total)	2,088.0	2.716
2019/20	Upper Trishuli 3B (37), ROR (100 in total)	2,225.0	2.678
2020/21	**Tanahu (140)**, Upper Modi A (42), ROR (100 in total)	2,507.0	1.453
2021/22	Tamakoshi V (87)	2,594.0	2.135
2022/23	**Budhi Gandaki (600)**	3,194.0	0.017
2023/24	--------	3,194.0	0.144
2024/25	--------	3,194.0	0.621
2025/26	ROR (100 in total)	3,294.0	1.338
2026/27	Upper Arun (335), ROR (100 in total)	3,729.0	0.712
2027/28	**Dudh Koshi (300)**	4,029.0	0.370
2028/29	--------	4,029.0	1.117
2029/30	**Nalsyau Gad (410)**	4,439.0	0.435
2030/31	--------	4,439.0	1.275
2031/32	**Andhi Khola (180)**, ROR (200 in total)	4,819.0	1.351

Note: Projects listed in boldface are storage-type projects.
The total installed capacities include import from India.
The allowable upper limit of LOLP is 1.375%, equivalent to 5 days supply shortage in a year.

8.1.3 Development Plan of Hydroelectric Power Generation

In the above-mentioned power development plans, the total installed capacities of storage-type HPPs are 1,993 MW for the base case of demand forecast, 3,154 MW for the high case, and 1,664 MW for the low case. Table 8.1.3-1 shows HPPs that are constructed for each case of the demand forecast and commencement years of commercial operation.

Table 8.1.3-1 Storage-type Projects to be implemented

Project	Capacity (MW)	Commissioning Year (FY)		
		Base Case	High Case	Low Case
Kulekhani No. 3	14	2015/16	2015/16	2015/16
Tanahu	140	2020/21	2020/21	2020/21
Budhi Gandaki	600	2022/23	2022/23	2022/23
Dudh Koshi	300	2026/27	2026/27	2027/28
Nalsyau Gad	410	2028/29	2027/28	2029/30
Andhi Khola	180	2029/30	2029/30	2031/32
Chera-1	149	2031/32	2029/30	----
Madi	200	2031/32	2030/31	----
Naumure	245	----	2030/31	----
Sun Koshi No. 3	536	----	2031/32	----
Lower Badigad	380	----	2031/32	----
Total Capacity	----	1,993 MW	3,154 MW	1,644 MW

As shown in Table 8.1.3-2, the investments required for implementation of these storage-type HPPs excluding the Kulekhani No. 3 and the Tanahu projects are US$ 4,209 million (IDC and price contingency are not included) for the base case, US$ 7,149 million for the high case, and US$ 3,257 million for the low case. In addition to these investments to these storage-type HPPs, there is investment to the projects that are now under construction and in a preparation stage, and investment to ROR-type HPPs to be implemented in and after FY2018/19 to meet the power demand in the future.

Table 8.1.3-2 Construction Cost of Storage-type HPPs

Project	Capacity (MW)	Project Cost (million US$)*		
		Base Case	High Case	Low Case
Budhi Gandaki	600	1,118	1,118	1,118
Dudh Koshi	300	873	873	873
Nalsyau Gad	410	737	737	737
Andhi Khola	180	529	529	529
Chera-1	149	452	452	----
Madi	200	499	499	----
Naumure	245	----	728	----
Sun Koshi No. 3	536	----	1,289	----
Lower Badigad	380	----	923	----
Total	----	4,209	7,149	3,257

*: IDC and price contingencies are not included.

8.2 Recommendations

The Study has revealed that construction of storage-type HPPs totaling 1,993 MW (for the base case of the demand forecast) is required by FY2031/32, including the Kulekhani No. 3, the Tanahu, and the Budhi Gandaki HPPs that are now under construction or in a preparation stage, for resolving current load shedding and meeting an increase in demand. Nepal is abundant in hydropower resources, but meanwhile it has difficulty in developing thermal electric power generation. Therefore, hydroelectric power generation will continue to play a predominant role in electric power supply, not only storage-type but construction of hydroelectric power stations including the ROR-type is very important.

The Study Team makes the following recommendations for further development of hydroelectric power generation in Nepal.

8.2.1 Recommendations on Implementation of Next-level Studies

In general, it takes a long time for hydroelectric power projects in a planning stage to be put into operation, and the storage-type hydroelectric power projects which are included in the power development plan also need 10 to 15 years until the start of commercial operation. Therefore, next-level studies on them should be conducted as early as possible for implementation of these projects on their schedule.

Among the storage-type hydroelectric power projects which were studied by the Study Team, the Dudh Koshi, Nalsyau Gad, and Andhi Khola projects were required to be put into operation in the late 2020s, feasibility studies of these projects have already been finished and the next study level is the review of FS or preparation of the detailed project report. The Study Team recommends conducting next-level studies on these projects taking the following matters into consideration.

(1) Confirmation of Background of Project

<u>Common items</u>

The current situation of economy, society and power sector and challenges

Actual achievement and future plan of cooperation to the power sector by donor countries and international financial institutions

(2) Information Collection of Existing Studies

<u>Common items</u>

Collection of information regarding existing studies and update of information by hearings from related organizations

<u>Dudh Koshi Project</u>

In order to verify the influence on downstream projects such as Sun Koshi Multipurpose Scheme (Phase I) by implementing this project, certain items should be collected. These include items such as the latest information of the Sun Koshi No. 1 hydroelectric power project, the Sun Koshi diversion project that will divert river water from the Kurule dam located downstream of the Sun Koshi No. 1 dam to the Kamala river for irrigation and hydroelectric power generation, and the Sapta Koshi High Dam hydroelectric power project as well.

Andhi Khola Project

The latest information about the raising of the intake dam of the existing Kaligandaki A hydroelectric power plant which locates downstream of this project, and the information about the existing Andhi Khola hydroelectric power plant (IPP) that will be affected by implementing this project.

(3) Review of Layout

Common items

Verification of the optimum type and height of the dam, waterway route, type and location of the powerhouse

Dudh Koshi Project

Management of sedimentation produced by a GLOF

Influence on downstream projects such as the Sun Koshi Multipurpose Scheme (Phase I)

Andhi Khola Project

Impact on this project by the raising of the intake dam of the existing Kaligandaki A hydroelectric power plant

Impact on energy production of the existing Kaligandaki A hydroelectric power plant by implementing this project

Impact on the existing Andhi Khola hydroelectric power plant (IPP)

(4) Meteorological and Hydrological Study

Common items

Update of meteorological and hydrological data

Review of hydrological analysis

Dudh Koshi Project

Sediment simulation considering sedimentation produced by a GLOF

(5) Topographical and Geological Study

Common items

Verification of water tightness at dam and reservoir sites

Verification of activity of faults

(6) Review of Basic Design

Common items

Optimization of parameters for power generation

Adoption of dam type considering topographical and geological conditions at selected dam sites

Detailed study on transmission line routes

Review of Power System Analysis

Dudh Koshi Project

Optimization of the development plan taking into consideration a function of supplying for base demand in the dry season and calculation of energy production

Study on a sand flushing facility that enables disposal of sedimentation produced by a GLOF

Study on a spillway structure that enables handling a GLOF

Nalsyau Gad Project

Study on installation of an appropriate reactive power supply facility based on the capacity of voltage adjustment

Andhi Khola Project

Optimization of the development plan taking into consideration a function of supplying for base demand in the dry season and calculation of energy production

(7) Study on Construction and Procurement Plan

Study on the construction method for structures indicated in the basic design

Study on the procurement schedule for required equipment

(8) Preparation of Project Implementation Schedule

Preparation of an implementation schedule including periods for resettlement, land acquisition, procurement procedure, detailed design, construction, etc.

(9) Estimation of Project Cost

(10) Project Implementation Structure

Confirmation of the implementation structure for the project

Confirmation of the implementing agency in terms of work responsibility, organization structure, personnel distribution, financial situation, technical level, experience of implementation of similar projects, etc.

(11) Operation and Maintenance (O&M) Structure after Commencement of Operation

Confirmation of the structure for operation and maintenance

Confirmation of the O&M agency in terms of work responsibility, organization structure, personnel distribution, financial situation, technical level, experience of O&M for similar projects, etc.

(12) Support for Preparation of EIA and RAP

Verification of the system and organization for environmental and social consideration

Verification of the environmental and social situation at the project site

Support for preparation of TOR of EIA and the stakeholders meeting (especially being secured of direct discussion with the socially vulnerable such as ethnic minorities)

Support for environmental and social investigations (same as above)

Support for prediction and evaluation of impact (including impact on transmission lines and access roads)

Support for mitigation measures (including avoidance, minimization, compensation) and a comparison study of alternatives

Support for preparation of a draft monitoring plan

Preparation of a draft environmental check list

Preparation of an EIA Report and RAP Report and support for disclosure of information (including study of alternative land acquisition by resettlement)

Support for EIA procedures

(13) Poverty Reduction and Promotion of Social Development

Social investigation for communities in the project area in terms of population and households to be profited, including percentage of the poor, the current situation of electrification, electricity tariffs, cost for connection to grid, and the monthly electric power consumption in an average family

(14) Study on Points to Consider for Project Implementation

General circumstances of procurement in similar projects in Nepal

Basic policy of bidding methods and conditions of contracts

Selection method of consultants

Selection policy of contractors

(15) Effectiveness of the Project

The effectiveness of the project will be evaluated in terms of quantitative effect and qualitative effect. The quantitative index in terms of operation and effect and their target values should be established as quantitatively as possible. The number of beneficiary, EIRR, FIRR and the effect by decreasing electricity to be imported from India (GWh and its cost converted to US$) will be established as the quantitative indexes. Further, the effect by increasing electricity to be generated by implementing the project will be estimated and the effect for mitigation of green house gas emissions will be studied.

Further, regarding Chera-1, Madi, Naumure, Sun Koshi No. 3 and Lower Badigad, the following studies are recommended on the next study stage of each project.

<u>Chera-1 Project</u>

Since this project is currently in the desk study level, it is recommended that the project feasibility should be studied in detail by implementing Pre-FS or FS.

<u>Madi Project</u>

Since this project is currently in the desk study level, it is recommended that the project feasibility should be studied in detail by implementing Pre-FS or FS.

<u>Naumure Project</u>

The Pre FS for this project has been completed. Although this project was reviewed as a hydroelectric power project in this study, it is recommended that an FS should be implemented as multipurpose project, since this project could be implemented as a multipurpose project with irrigation.

<u>Sun Koshi No. 3 Project</u>

Since this project is currently in the desk study level, it is recommended that the project feasibility should be studied in detail by implementing Pre-FS or FS. The current power development plan requires resettlement of approximately 1,600 households and relocation of 15 km of paved road. Therefore, mitigation for impact on the social environment including the above should be considered in the next study stage. There is information that the government of Nepal is planning to request the ADB to prepare a Detailed Project Report for this project.

<u>Lower Badigad Project</u>

Since this project is currently in the desk study level, it is recommended that the project feasibility should be studied in detail by implementing Pre-FS or FS. Since there is a large-scale land slide in the reservoir area of the current development plan, a large amount of sediment is predicted. Therefore, countermeasures for sediment should be considered including relocation of dam site in the next study stage.

8.2.2 Other Recommendations

(1) Coordination between Water Resources Development and Environmental Conservation

In Nepal, since water power is virtually the only domestic energy for a couple of decades from now, development of significant amounts of hydroelectric power generation are necessary as described in the above. Meanwhile, agriculture accounts for 37% of GDP, and there are many irrigation development projects for promoting the agricultural industry. If these development projects, hydroelectric power and irrigation, are implemented without coordination, there is concern about considerably negative impact on the natural and social environment in not only the project area but also the downstream area. To minimize this negative impact, the government of Nepal should coordinate among the ministries and agencies in charge of power generation, irrigation, and environmental conservation, and set a target of environmental conservation for water resource development for each river basin.

(2) Reasonable Price Setting

Since the NEA is obliged to purchase electricity from IPPs under the all-quantity buyback at fixed price contract, the NEA has to purchase electricity from IPPs even in the rainy season when the NEA has enough supply capacity or has to pay penalty to IPPs for not buying electricity from them. This procurement arrangement between the NEA and IPPs results in NEAs' poor financial position. Therefore, it is recommended that the purchase price from IPPs should be adjusted and reduced to a reasonable level by establishing a competitive electricity wholesale market.

For the retail power price charged by the NEA, it is considered that the price is still too low to sustain the NEA to be financially sound, even after the 20% price increase in July 2012 when the price determined in 2001 was reviewed and adjusted. Thus, the NEA should consider upward adjustment of the retail price to a level acceptable to consumers and to secure the NEA's good financial position. The upward adjustment should result in contraction of demand due to the rational reaction of consumers instead of forced demand cut by load shedding.

(3) Mobilization of Financial Resources

If the wholesale price of power projects is sufficiently high, the projects will perform financially well, attracting investment from the private sector. However, if the price is too high, the economic growth of the country must be suppressed. Due to the public goods nature of electricity, the NEA has to provide consumers with electricity at the lowest possible price and keep the NEA financially viable. Therefore, the NEA is expected to implement power projects in order to supply electricity at a price through the mobilization of concessional loans under Official Development Assistance (ODA) arrangements or of government funds.

(4) Remediation in System Loss

The system loss of the Integrated Nepal Power System (INPS) is currently more than 25% and the NEA has not been able to achieve reduction in the loss for the last 20 years. Addressing the system loss consisting of a technical loss and a loss by power theft requires a significant amount of investment to improve the INPS. Minimizing the system loss apparently results in an increase in the energy supply, decrease in the frequency of load shedding, and improvement of the financial position of the NEA.

(5) Demand Side Management

One of the high-priority issues of the power sector of Nepal is to resolve load shedding, and this is urgently needed to strengthen the supply capacity. Meanwhile, it is possible to curb the increase in necessary supply capacity by harnessing demand through demand side management (DSM). Since the current total power demand is not so high, the effect of DSM on resolving load shedding is limited. However, DSM will be one of the measures for satisfying the power demand in the future like the construction of power supply facilities. In Nepal, Time of Day (TOD) tariff rates have already been introduced, and in the future, DSM should be aggressively implemented taking into consideration introducing seasonal tariff rates and subsidies for introducing energy saving devices, etc.

(6) Human Resource Development

As stated above, Nepal needs to implement about 5,000 MW of hydroelectric power development projects including ROR-type projects in the next 20 years. However, the number of specialists required for implementing these projects is not enough. The human resource development of specialists for design of hydroelectric power development policy and for planning and evaluation of hydroelectric power development project in particular, is an urgent issue.

In addition, human resource development in the field of environmental surveys is also very important. Improving the ability of working-level researchers for environmental surveys on flora and fauna, social conditions, and the monitoring of impact by project implementation, etc. are required not only by hydroelectric power projects but also for other large-scale projects like irrigation development projects.

One of the concrete ways to help this in the short term is OJT (on the job training) in an actual project by sending experts to related organizations or hiring consultants for human resource development in this field. In the long term, there should be establishment of a course in this field in a college and establishment of a vocational school for education and training of personnel for operation and maintenance.