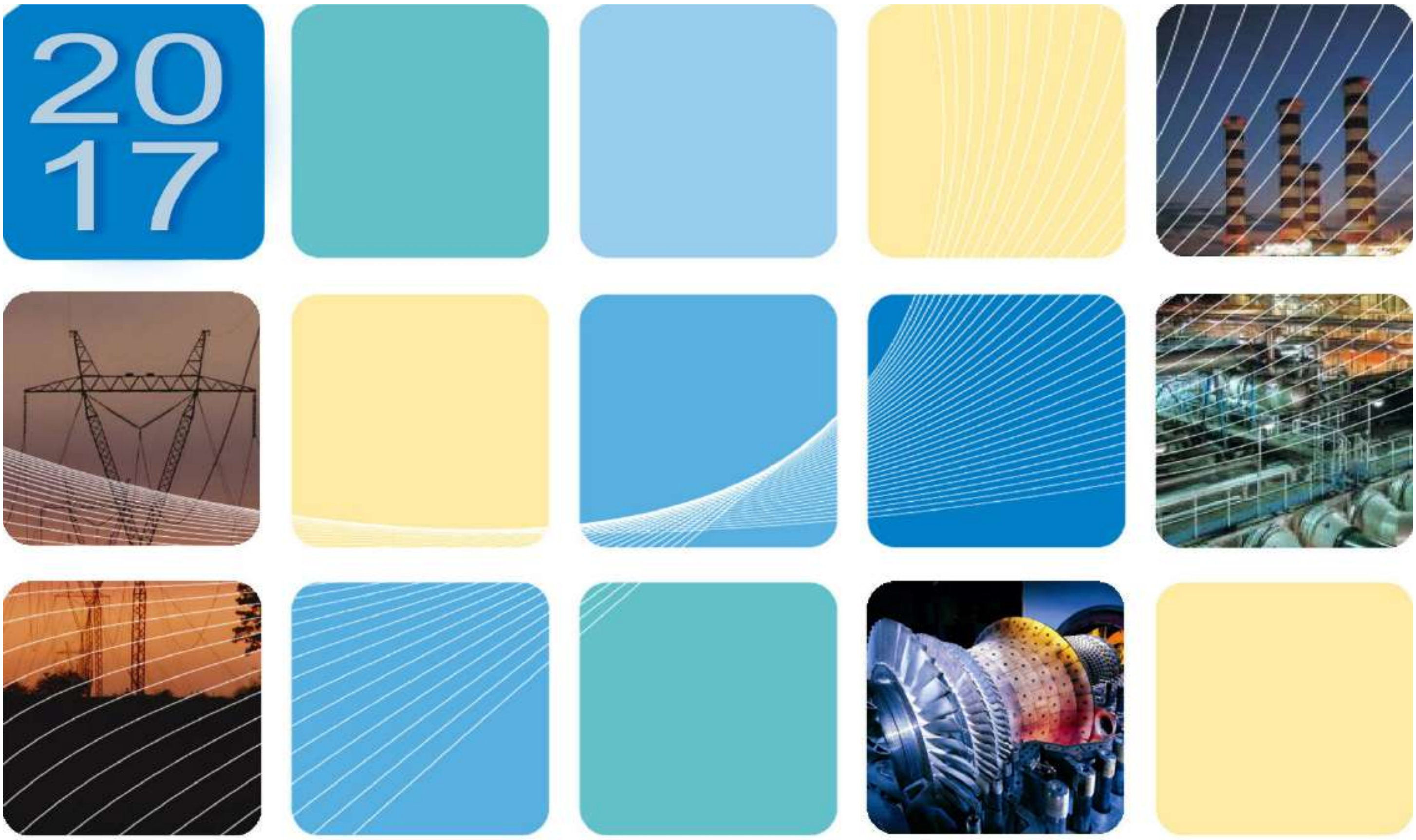
| ADB GRANT NO: 0213 -TAJ |

|February 2017 |



FINANCIAL MANAGEMENT · ENTERPRISE RESTRUCTURING · INVESTMENT PLANNING

Tajikistan

POWER SECTOR DEVELOPMENT MASTER PLAN FINAL REPORT

REGIONAL POWER TRANSMISSION PROJECT |
SECTOR OPERATIONAL PERFORMANCE IMPROVEMENT

• SUBMITTED BY:

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DOCUMENT CONTROL AND VERIFICATION SHEET

Job Title: Regional Power Transmission Project – Sector Operational Performance Improvement

Contract No: ADB Grant No: 0213-TAJ

Document Name: Power Sector Development Master Plan Final Report

Document History:

Version	Date	Prepared	Checked	Approved
1.0	June, 2015	A.Carias/G.Lian/Amal Mani		
1.1	July, 2016	A.Carias/G.Lian/Amal Mani		
1.2	February, 2017	A.Carias/G.Lian/Amal Mani		

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ABBREVIATIONS

ADB	Asian Development Bank
AMS	Antimonopoly Service
BBL	Barrel
BCM	Billion Cubic Meters
BOOT	Build, Own, Operate, Transfer
BT	Barki Tojik
CAPS	Central Asia Power System
CAREC	Central Asia Regional Economic Cooperation
CASA	Central Asia – South Asia
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture Sequestration
CFB	Circulating Fluidized Bed
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
CNPC	China National Petroleum Corporation
COD	Commercial Operation Date
CPV	Cumulative Present Value
CSCL	Corporate Solutions Consulting Limited
CSP	Concentrated Solar Power
EBRD	European Bank for Reconstruction and Development
EIA	U.S. Energy Information Administration
EE	Energy Efficiency
EEMP	Energy Efficiency Master Plan
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement and Construction
EUE	Expected Unsupplied/Unserved Energy
FGD	Flue Gas Desulphurization
GDP	Gross Domestic Product
GENSIM	Generation Simulation Software
GHG	Greenhouse Gases
GJ	Giga Joule
GoT	Government of Tajikistan
GT	Gas Turbine
GWh	1,000 MWh
HFO	Heavy Fuel Oil
HHV	Higher Heating Value
HPP	Hydro Power Plant
HRSG	Heat Recovery Steam Generator
IAEA	International Atomic Energy Agency

IDC	Interest During Construction
IGCC	Integrated Gasification Combined Cycle
IPP	Independent Power Producer
KWh	1 unit of electricity or 1000 watt hours
LDC	Load Duration Curve
LFO	Light Fuel Oil (Diesel)
LNG	Liquefied Natural Gas
LOLP	Loss of Load Probability
MCR	Maximum Continuous Rating
MCM	Million Cubic Meter
MEDT	Ministry of Economic Development and Trade
MHI	Manitoba Hydro International Ltd.
MoEI	Ministry of Energy and Industry
MoEWR	Ministry of Energy and Water Resources
MSD	Medium Speed Diesel
MWh	1000 KWh
NERC	North American Electric Reliability Corporation
O&M	Operation and Maintenance
PC	Pulverized Coal
PMF	Probable Maximum Flood
PPA	Power Purchase Agreement
PSDMP	Power Sector Development Master Plan
PV	Photovoltaic
ROR	Run-of-River
RRS	Rayons of Republic Subordination
RT	Republic of Tajikistan
SAES	State Agency for Energy Supervision
TALCO	Tajik Aluminium Company (Formally TadAZ)
TEAS	Techno-Economic Assessment Study
ToR	Terms of Reference
TPP	Thermal Power Plant
TUTAP	Turkmenistan, Uzbekistan, Tajikistan, Afghanistan, Pakistan
UNDP	United Nations Development Programme
VAT	Value Added Tax
WB	World Bank

ES EXECUTIVE SUMMARY

Corporate Solutions Consulting Limited (CSCL) in association with Manitoba Hydro International Ltd. (MHI) was contracted by the Asian Development Bank (ADB) to develop a Power Sector Development Master Plan (PSDMP) for Tajikistan. This document reports on the analysis and results of the work associated with developing a master plan as prepared by a project team of CSCL and MHI staff. The Master Plan Report presents the parameters, criteria, generation options, and formulates, develops and analyses integrated power system expansion plans for new generation and transmission additions taking into account the increase in demand, the aging of the existing generation fleet, and the economic costs of potential generation resources to supply the increasing demand.

As part of the overall work to arrive at the most appropriate manner in which to supply the future electricity needs of Tajikistan the following reports have been issued previously and their findings have been incorporated in this final PSDMP:

- The Inception Report
- The Demand Forecast Report
- The Planning Parameters and Generation Options Report issued in August 2013 as well as revised version issued in November 2014
- The Energy Efficiency and Promotion Plan Report
- The Master Plan Draft Report issued in June 2015.

ES.1 THE ELECTRICITY SECTOR IN TAJIKISTAN

In Tajikistan, the Ministry of Energy and Water Resources (MoEWR) is responsible for the entire energy sector, which comprises the electricity sector as well as oil and gas. The MoEWR is responsible for the energy policy and the development of standards.

The power sector in Tajikistan is dominated by Barki Tojik (BT) which is responsible for most generation, transmission and generation. The electricity customers for the Gorno Badakhshan autonomous region are supplied by Pamir Energy.

The MoEWR and the Ministry of Economic Development and Trade (MEDT) are responsible for many aspects of the energy sector in Tajikistan. In addition, other ministries and institutions handle matters related to energy and these include:

- The Committee for Environmental Protection
- The Ministry of Finance
- The State Committee for Investments
- The Antimonopoly Service (AMS)
- The State Statistical Committee under the Office of the President
- The State Agency for Measurements, Standardization and Certification
- Other Institutions related to construction, transport and industry.

Regulation of the energy sector is the responsibility of the Antimonopoly Service (AMS) under the Government of the Republic of Tajikistan. The AMS is responsible for the tariff methodology, tariff level proposals, service quality, consumer complaints and anti-competitive behavior. MoEWR is responsible for licensing, approval of investment plans and technical and safety standards. Final approval and amendment of tariffs for end-users is within the competency of the President.

BT is required to submit its budget and plans for approval to the Ministry of Finance and the MEDT.

Development of the energy sector in Tajikistan is guided by the following laws and legal acts:

- Constitution of RT
- The Law of RT “On Energy”
- The Law of RT “On Energy Savings and Energy Efficiency”

- The Law of RT “On Privatization of State Property”
- The Law of RT “On Licensing of Separate Types of Activity”
- The Law of RT “On Concessions”
- The Law of RT “On Usage of Renewable Energy Sources”
- The Law of RT “On Safety of Hydrotechnical Facilities”
- The Law of RT “On Nature Protection”
- Tax Code of RT
- Water Code of RT
- A number of industry-specific Orders of the Government of the RT
- Other legal acts and international norms recognized by RT.

The total installed capacity in the BT grid amounts to 5,346 MW of which the hydro capacity accounts for 4,926 MW (92%) with the remaining being supplied by 3 CHP plants; Dushanbe-1, Yavan and Dushanbe-2. However, the current available capacity is only 4,785 MW which is expected to increase to 5,269 MW once the hydro plants are rehabilitated. The Yavan plant has not operated during the last few years and the Dushanbe-1 plant operates on a limited basis due to fuel availability issues. Both Dushanbe-1 and Yavan can use natural gas or mazout (heavy fuel oil, HFO). Dushanbe-2 uses coal.

On average, the hydro plants can generate a total of 19,492 GWh per year but the generation is greatly reduced over the late autumn and winter periods due to reduced hydrological flows thus seriously affecting the system’s capability to meet the demand.

In 2012, the total consumption in the BT grid amounted to 13,627 GWh and it is widely acknowledged that Tajikistan has been suffering from a lack of generation to meet some of the demand over the October to March period. The lack of generation leads to load shedding and unserved energy and this in turn has a negative impact on the development of business opportunities. The World Bank report on Tajikistan’s Winter Energy Crisis, dated November 2012, identifies the unmet (or “unserved”) demand at an estimated value of 2,700 GWh for the year 2012 at the consumer level and this value was used in the demand forecast work. Taking into account losses in transmission and distribution of electricity, the deficit at the generation level amounts to about 3,100 GWh during winter compared to total winter supply requirement of 11,200 GWh, a gap of about 28%.

Presently BT has two power purchase agreements (PPAs) with Afghanistan and one with Kyrgyzstan for a sale of 600 GWh between May and September which is renewed annually. All other PPAs have been terminated. Under the first PPA, with Afghanistan, the contracted energy is 1,007 GWh per year with an annual guaranteed energy of 650.8 GWh to be delivered between April and October. The second PPA has no contracted capacity and energy. For the CASA 1000 project, negotiations are almost complete for Tajikistan and Kyrgyzstan to export to Afghanistan and Pakistan in 2021. The Tajikistan’s share of the firm exports amounts to 1,331.5 GWh per year but additional quantities may be exported if available (up to 5,000 GWh).

The BT’s grid system consists of transmission lines at three different voltage levels, 500 kV, 220 kV and 110 kV. At present, it includes approximately 489 km of 500 kV lines, 1,960 km of 220 kV lines and 4,327 km of 110 kV lines. The BT transmission system has three substations at 500 kV, 23 substations at 220 kV and 154 substations at 110 kV. The 500 kV transmission lines include a double circuit between the Nurek HPP and Regar substation, a single circuit between the Regar and Dushanbe substations as well as a single circuit between the Dushanbe and the Sughd substations.

All interconnections between the BT and Uzbek system have been disconnected. The BT’s grid system used to be interconnected to the Uzbek network at 500 kV and 220 kV.

Presently, there are only three main interconnections between Tajikistan and other systems, which are as follows:

- A 220 kV, 53 km long, transmission line connects the Kanibadan substation in Tajikistan to the Aigul-Tash 220 kV substation in Kyrgyzstan

- A 220 kV double-circuit transmission line between Sangtuda (Tajikistan) and Pul-e-Khumri (Afghanistan) which will allow Tajikistan to export up to 500 MW to Afghanistan was constructed in 2011
- A 110 kV, 63 km single circuit transmission line from Tajikistan to Kunduz in Afghanistan.

The CASA 1000 project, will require the construction of a 500 kV AC transmission line from Kyrgyzstan to the Sughd 500 kV substation (477 km), the construction of a 500 kV AC transmission line from Regar substation to the "Sangtuda" converter substation (115 km), the construction of two 1,300MW DC converter stations, one near Sangtuda-1 HPP and one near Peshawar as well as an HVDC transmission line ± 500 kV from Sangtuda to Pakistan (800 km).

ES.2 ELECTRICITY DEMAND AND SUPPLY

Load forecasting is a critical element of electric power utility planning. The purpose of any form of load forecasting is to estimate the most likely future level of demand to serve as the basis for supply planning. This includes the planning of distribution and transmission facilities as well as the construction and operation of existing and new generation plant.

The demand forecast methodology/approach selected to obtain the required forecast for any particular system, is generally dependent on the quality and availability of the input data. Due to the lack of data and the fact that the usual approaches cannot be applied straightforwardly, several other studies have recommended that a modified approach be used for load forecasting and the project team concurs with this approach. The approach used was based on the concept of econometric modelling but it avoids the need to apply historical data.

Future annual growth of electricity demand was obtained by multiplying the expected future annual growth rate of GDP by its demand elasticity for that specific year and adjusting it for a possible decrease in consumption resulting from an increase in the tariff. The impact of the latter effect depends on the assumptions for price elasticity. The unserved demand has to be considered in the analysis and as such, the consumption in the base year to which the percentage increases are applied has to be increased by the estimated value of unserved energy to obtain the "actual" demand.

The BT grid forecast was obtained following the above approach and to this the effect of the energy efficiency measures were applied which resulted in a reduction of the demand. In addition, the PPA requirements for the CASA 1000 and the existing PPAs for firm energy were added to obtain an overall demand for the BT grid. In order to determine the robustness of the base or medium growth forecast, the project team developed two additional forecast scenarios; low and high. The actual demand is expected to be within the range given by the high and low scenarios.

Figure ES- 1 shows the comparison of the energy demand forecast for the main grid under three different growth scenarios. Table ES- 1 presents the peak capacity demand forecast for the main grid under three different growth scenarios.

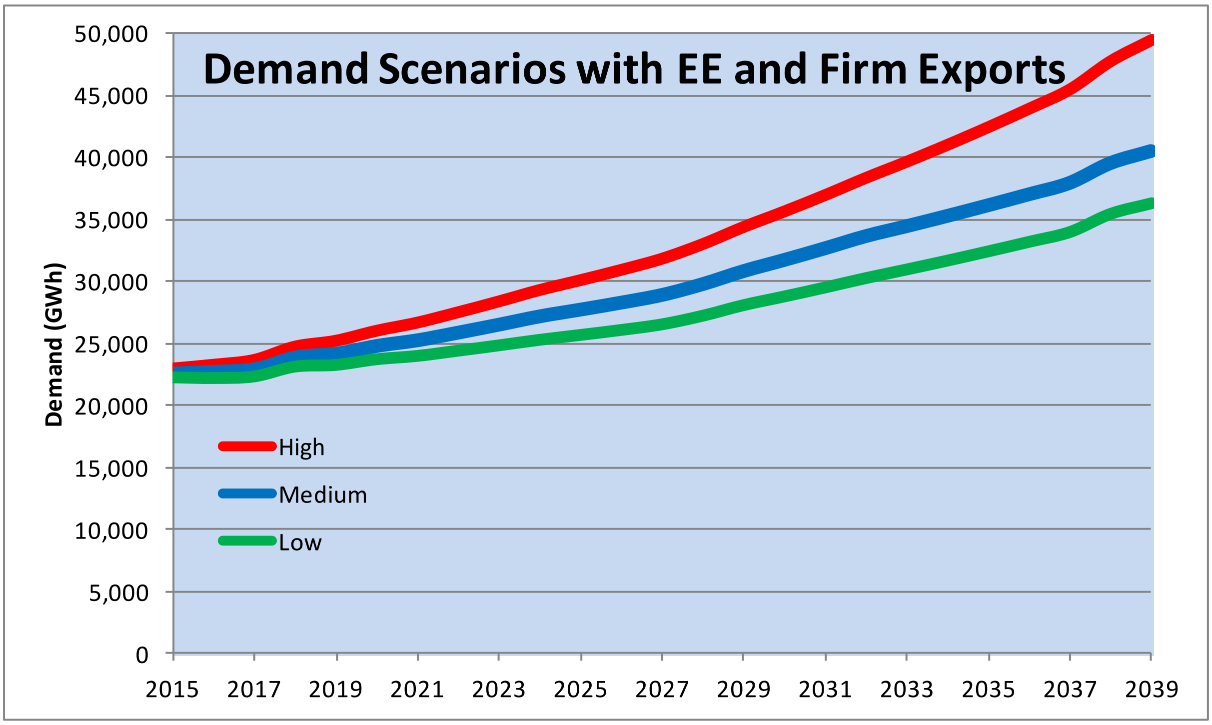

Figure ES- 1: Comparison of Energy Forecasts for main Grid

Under the medium growth forecast the overall growth for domestic load and firm exports is expected to grow at 2.08% for the period between 2015 and 2039. Table ES- 2 provides other energy growth rates for different time periods and growth scenarios.

Table ES- 1: Comparison of Main Grid Peak Demand (MW)

Growth Scenario	2015	2020	2025	2030	2039
Low	4,095	4,261	4,658	5,253	6,659
Medium	4,184	4,494	5,073	5,835	7,473
High	4,243	4,710	5,510	6,566	9,167

Table ES- 2: Expected Growth Rates for the Main Grid

Growth Scenario	2015-39	2015-25	2020-30	2025-39
Low	2.08%	1.45%	1.97%	2.52%
Medium	2.46%	2.07%	2.49%	2.74%
High	3.25%	2.74%	3.20%	3.62%

By examining the capacity and energy balances or deficits obtained it is possible to determine the extent of the surplus or shortages and the timing and size of the required new generation additions. Since the Tajik system is hydro dominated and hence energy constrained, the balance is only carried out for energy since in this type of systems there is usually an over installation of capacity.

Based on the demand forecast, taking into account energy efficiency projects and firm exports, and the available supply, the energy balance was carried out on a monthly basis for the BT supplied system for the period from 2015 to 2018 using both the firm (95% probability of exceedance) and average hydro energy. The resulting energy balance is presented in Figure ES- 2.

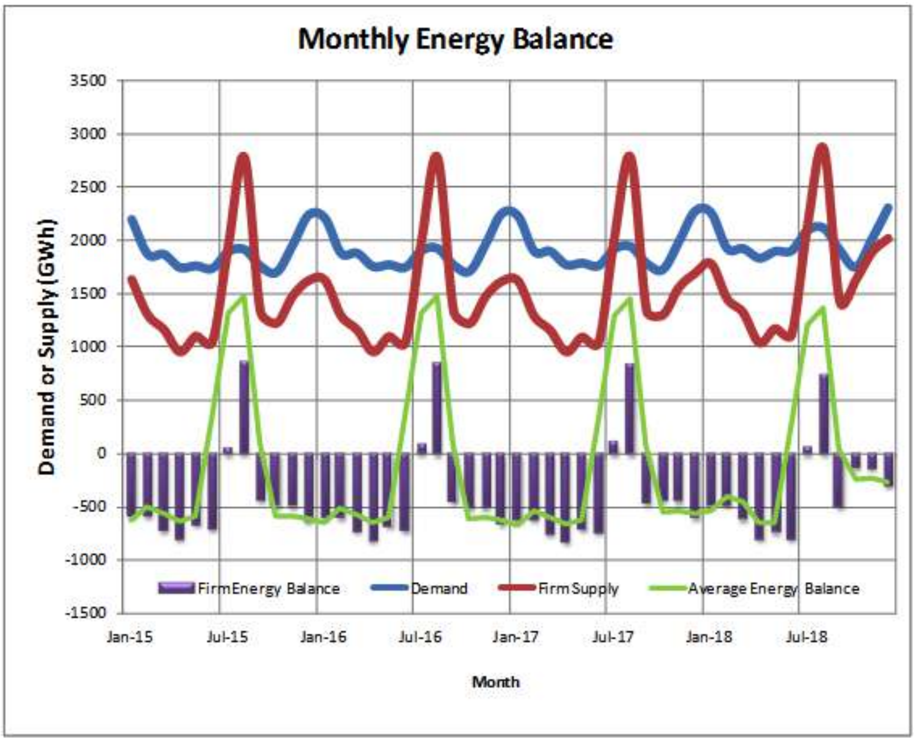

Figure ES- 2: Energy Balance for 2015 to 2018

From Figure ES- 2 it is clear that the system needs firm energy additions as soon as possible in the form of generating units or imports from other systems. There are generating units that can be brought into service in a very short time (six months), however, their cost is quite high. It is estimated that in order to eliminate the unserved energy, new generation of the order of 500 MW or more (in addition to the committed generation and that under discussion) would need to be commissioned. As the lead time to bring in additional capacity is long, the BT system could be faced with severe energy shortages in the short term unless very favourable hydrology conditions are encountered during the winter months or energy can be imported from other systems.

ES.3 PLANNING PARAMETERS AND CRITERIA

According to normal industry practice, a power sector master plan is developed by comparing the cumulative present value of generation and transmission system costs, for a given alternative against the base alternative, for a number of predetermined years at an appropriate discount rate. To do so in a fair manner, it is necessary to establish a set of planning parameters and criteria prior to the development of the alternatives in order to ensure that they all have comparable performance.

The assumptions and criteria presented in this report were developed from several sources, including previous planning reports, in-house criteria used in previous similar assignments and international best practices.

The parameters and criteria covered in the report were classified into several groups including; general and economic, generation, fuel price forecast and transmission.

ES.3.1 General and Economic Parameters

The analysis was carried out using economic costs rather than financial costs. Financial costs should be used to evaluate the identified best options going forward when these have been selected based on several key factors.

The development of the PSDMP was carried out from a national perspective by maximizing the benefits to all Tajiks. The PSDMP covered the entire territory of Tajikistan and took into account existing policies and programs.

The principal general and economic parameters are shown below with information justifying their selection given in Section 4 of the report:

- *Planning Horizon* - the PSDMP was intended to cover a development period of 20 years but due to the potential impact of the major Rogun project the system was modelled from 2015 to 2039. This extended period covers the time required to construct the Rogun Hydroelectric power plant and to fill its reservoir
- *Present Worth Cost and datum* - All costs are expressed at January 2015 prices. All present - worth and discounting calculations also use January 2015 as their reference point
- *Escalation* – Real costs expressed at January 2015 price levels omitting projections for general price inflation during the planning period are used
- *Currency* - All monetary values are expressed in U.S. dollars
- *Discount Rates* - The 10% discount rate is used as the base discount rate. The study also includes discount rates of 8% and 12% as part of the sensitivity analysis
- *Foreign Exchange Rates* - As all costs are expressed in U.S. dollars, foreign exchange rates are not required
- *Insurance and Interim Replacement* – Is assumed to be 0.25% of the total capitalized cost for each of these components on an annual basis
- *Cost of Expected Unsupplied Energy* - The cost of expected unserved energy (EUE) is set at $1/kWh. EUE cost should only start to be taken into account in year 2019
- *Duties and Taxes* -Duties, levies, royalties and taxes are not included in this economic study
- *Interest During Construction (IDC)* - The impact of construction periods of different lengths of construction periods is taken into account by distributing the capital over the entire construction period
- *ExportTariffs* – CASA firm exports set at $68.20/MWh while surplus power is set at $68.20/MWh.

ES.3.2 Generation

Hydrological Conditions - the “Dry” (95% probability of exceedance) hydrologic condition is used in the generation system reliability analysis while the P50 is used in the production cost analysis.

Reliability Criteria - For the present study a LOLP reliability criterion of 5 days per year is used along with an annual EUE criterion of 1% with no monthly EUE to exceed 5%.

Emissions Criteria -. For the present study a penalty of $5 per tonne of equivalent CO_2 emissions and other emissions, representing a cost to society, is levied against thermal options.

Candidate Generation Resources - The types of generation expansion candidates considered to meet the growing demand over the planning horizon include the following categories:

- Hydroelectric including both storage and run-of-river HPPs
- Coal fired power generation including CHP
- Natural gas fuelled power generation including GT and CCGT
- Fuel oil fire generation including diesel, GT and CCGT
- Non-hydro renewable including wind, solar and geothermal
- Other power generation technologies including nuclear.

ES.3.3 Fuel Price Forecast

A fuel price forecast is required for generation options considering the use of petroleum products, natural gas and coal. The prices for HFO and natural gas for Tajikistan are likely to follow closely international prices for crude oil and natural gas. The comparison of forecasts resulted in the selection of $80/BBL as a crude price and a value of $10/GJ imported natural gas including delivery charges.

For domestic coal used in CHP-2 and conventional power plants to be located at mine mouth is aasumed a price of US$45/tonne. For coal power plants close to the mine and where transportation is required a price of US$ 55/tonne) is assumed. These prices reflect recent local prices for coal delivered to existing plants.

ES.3.4 Transmission

The following transmission planning criteria have been proposed:

- Study Area and Horizon – Main BT system with planning horizons including 2013 (studies for that year have been ongoing), 2020, 2025, 2035 and 2039
- Bus Voltages - Facilities will be planned to operate between 0.95 pu and 1.05 pu in steady state and between 0.9 pu and 1.1 pu for post fault. It is our understanding that presently the post fault criteria are not met
- Thermal Loading – Less than 100% of rating of the facility. Emergency loading limits are presently set at 110% for transmission lines and 120% for transformers
- Spinning Reserve - Generation reserve could be set to equal the greater of the largest loss of power from a credible contingency or the loss of the largest generating unit. This could improve system recovery significantly
- VAr Reserve - Sufficient VArs should be available to support stable steady state operation and that following the loss of any single element either in summer or winter
- Capital Costs and Economic Criteria - The transmission equipment costs have been developed based on the latest costs in Tajikistan for transmission lines at different voltages and for substations. In addition, it is assumed that the annual operation and maintenance charges would be equal to 1.5% per year of the total capital investment for each item of equipment.

ES.3.5 Future Regional Interconnections

In addition to the existing 220 kV and 110 kV interconnection lines with Afghanistan and the 220 kV interconnection with Kyrgyzstan, there are currently several regional interconnection projects under consideration, which include:

- Reconnecting the Tajikistan grid with the Uzbekistan and Kyrgyzstan grids and being part of the Central Asia Power System (CAPS)
- CASA-1000 project which involves plans for construction of a 500 kV link between Kyrgyzstan, Tajikistan, Afghanistan and Pakistan.
- Construction of a 500 kV transmission line Rogun-Peshawar is under discussion
- Construction of a 550 km, 500 kV transmission line to Xinjiang Uyghur Autonomous Region on China
- Turkmenistan, Uzbekistan, Tajikistan, Afghanistan, Pakistan (TUTAP) interconnection with a maximum annual energy export from Tajikistan of 4,000 GWh.

There are two additional lines to Afghanistan and Pakistan being addressed, only one will be considered at this stage.

ES.4 GENERATION RESOURCES AND TECHNOLOGIES

Tajikistan possesses vast amounts of hydropower resources that could be developed to generate electrical energy. Currently, only about 4% of the nation's hydro power potential is being used. Tajikistan also has large amounts of explored and proven coal reserves which could be used to develop coal fired power generation projects. As mentioned by several local entities, thermal generation could supplement the hydro generation and alleviate the winter electricity crisis.

ES.4.1 Hydroelectric Potential

The country's hydropower resources are ranked at the 8th position in the world, in the order of 527 TWh per year, of which only 4% is currently being used. Although there is a vast hydropower potential, most of the assessment of the potential was carried out during the Soviet Union era. A very small number of prefeasibility or feasibility studies were provided to the study team. These included the Techno-Economic Assessment Study (TEAS) for Rogun Hydroelectric Construction Project, the Feasibility Study for the Shurob HPP, the Prefeasibility Study for Fandarya River HPP, the Feasibility Study of Sanobad HPP, the Nurabad 1 and Nurabad 2 presentation, the Feasibility Study of Nurek 2, the study for Ayni HPP and the Yavan Feasibility Study.

The Rogun TEAS considered 3 dam heights each with 3 different installed capacities. The selected dam height was 1,290 MASL which is equivalent to a dam height of 335 m. The selected capacity amounted to 3,600 MW divided over 6 units (6x600 MW). According to the TEAS, the generating units are to be brought on line in a staged manner, two at the time, with the first two units to start generating some 73 months after the start of construction and the last two units after 127 months. The dam is to be completed after 163 months of construction and the reservoir is expected to be filled up some 18 years after the start of construction.

Once the reservoir is completely filled up, Rogun can produce an annual average generation of 14,210 GWh (an annual capacity factor of close to 51% based on this energy and the installed capacity) and the Vakhsh system including Rogun 34,173 GWh. The respective firm energy amounts to 11,748 GWh and that for the Vakhsh system amounts to 28,623 GWh.

The capital cost estimates for the project were not made available in the TEAS version reviewed. For the selected alternative (1,290 MASL and 3,600 MW) it is assumed that the capital cost to complete the Rogun hydroelectric power plant would be of the order of US$ 5,500 million.

In the "without" Rogun scenarios, the cost of decommissioning the existing Rogun facilities has to be considered and in this case a cost of US$ 200 million is being assumed. The cost of the works to provide protection against the probable maximum flood has been assumed as $1,000 million which is considered as an additional cost in the scenarios "without" Rogun.

Given the likely year to start construction for Rogun HPP, the required construction period for its stage 1 and 2 to be brought on line and the construction period for the Shurob HPP outlined in the feasibility study (11 years), the Shurob HPP was not considered since it would only be available very late during the simulation period and it would thus not generate sufficient benefits during the remaining study period to offset its costs. However, it was included in the generation expansion studies considering early Rogun generation.

As indicated above, feasibility studies were provided for other hydroelectric power plants. Nurabad-1 and Nurabad-2 were not considered. Table ES- 3 presents the installed capacity, energy capability and capital cost of each of the candidate hydroelectric projects with feasibility or prefeasibility study reports.

Table ES- 3: Capability and Cost of Hydro Projects with Studies

Hydro Project	Installed Capacity		Annual Energy		Capital Cost
	No of Units	Total (MW)	Average (GWh)	Firm (GWh)	(US$, million)
Fandarya	5	182.5	569	475	305.1
Sanobad	1	125	1,082	1,053	280.0
Nurek 2 [1]	4	100	579.9	517.9	148.5
Ayni		160	637	579	304.0
Yavan		126	451	394	255.5
Shurob	4	862.5	3,213	2,656	1,710

Note: [1] Energy values for 2022

It should be noted that the capital cost estimate for the Sanobad project does not include the cost for a 220 kV transmission line and associated substations to connect the project to the main grid. In addition, there are many other potentially important candidate projects which could be developed to form a part of the future development plan and a ranking of their potential should be carried out in order to define priorities for the preparation of detailed feasibility studies of the most likely options.

A) Early Rogun Generation

Work has been on-going at the Rogun site for many years and the entities responsible for the project consider that the project could start producing power at a much earlier date than that implied in the TEAS. Informed sources in Tajikistan believe that the first two units could be on line sometime in the mid of 2019 with the next two units to be in service in January 2023 and the last two units to be in service by July 2023.

As an alternative to the dates identified in the TEAS, it was decided to consider this alternate in-service dates for Rogun and thus denominating it Early Rogun Generation. In this case, the minimum reservoir level is expected to be reached 39 months after the commissioning of units 5 and 6 . The dam is to be completed 90 months after the commissioning of units 5 and 6 (January 2027) the reservoir is expected to be filled some 5 years after the dam is completed (December 2031). It should be noted that call for tenders for certain major equipment and works has been published.

It is assumed that the capital cost to complete the Rogun hydroelectric power plant would be of the order of US$ 5,500 million with US$1,500 million to be spent from 2015 to 2019 for the units 5 and 6. Other costs occur in 2019 so that the works for the total project can continue. Other data and information is similar to that used in the case considering the TEAS dates.

ES.4.2 Thermal Generation

Based on previous studies, there are at least three coal mines that could be used to supply fuel for power generation in the near future; Ziddy, Shurob and Fon Yagnob. These three mines have a total estimated proven reserve of around 1,020 million tonnes and could supply several new power plants with a total capacity greater than 5,000 MW.

For the PSDMP, the selected candidate coal-fired power units include 50 MW CHP, 150 MW CHP, 150 MW TPP and 350 MW TPP, all with CFB boilers as this technology fits well with the existing system conditions and requirements as well as system demand requirements in the planning horizon.

According to the information collected from the MoEWR, the potential reserve of oil and gas in Tajikistan was estimated at some 1,034 million tonnes of oil equivalent. Among this amount, oil reserve contributes some 118 million tonnes and the balance by natural gas. There are several companies active in the oil and gas exploration in Tajikistan,

Various gas turbine technologies have been developed and used around the world fuelled by natural gas or diesel fuel to generate electricity. Simple cycle gas turbine plants are traditionally used primarily for peak-load demands, as it is possible to quickly and easily bring them on line. Gas turbines can be combined with a steam turbine to form a combined cycle unit. For this study, the net sizes selected for CCGTs are 150 MW and 300 MW and the net sizes for GTs are 50 and 100 MW. In the case of a 300 MW unit, it is expected that there would be two GTs, each rated at some 100 MW and one steam turbine rated at 100 MW.

The principal characteristics of the thermal generation options are presented in Section 5.

ES.4.3 Non-Hydro Renewable Energies

There are no commercial operational wind power plants in Tajikistan, however supplementing the dominant hydropower with wind energy could be justifiable in certain regions.

It appears that the most promising areas for wind generation are the Pamirs northward of the Sarez Lake in GBD, the Turkmenistan ridge in the Zeravshan river headwater and the region from the Vakhsh ridge to the boundary with Afghanistan. Among these areas, only the Turkmenistan ridge in the Zeravshan river headwater with average wind speed up to 9 m/s could contribute a certain amount of wind power capacity as others are far away from the main grid and their access to the main grid is at present difficult.

Wind power is therefore not considered as a priority supply option to the power sector master plan. Nevertheless, since wind power is technically feasible, a total of 20 MW was included in the master plan. With technological improvements and cost reduction this technology can become more attractive.

Since the specific costs of solar energy are still significantly higher than that of other technologies, solar energy was not considered as a priority supply option to the PSDMP. However, since solar PV is technically feasible, a total of 50 MW is included in the master plan. With technological improvements and cost reduction this technology can become more attractive.

ES.5 GENERATION EXPANSION PLANS

Studies were undertaken to arrive at a series of generation expansion plans that meet the electrical demand in Tajikistan with a certain degree of reliability at a minimum cost. This process is quite complex and analysed many different combinations of resources with different in service dates using a set of parameters and criteria that are common to all of the scenarios.

The results obtained are dependent upon many variables including the system demand, the reliability criteria, the fuel, capital and O&M costs, level and price of exports and discount rate. Should any one of these variables change it is then possible that a different combination of resources and their respective in-service could result in a higher or lower overall cost depending upon the variable changed and its magnitude of change.

In order to arrive at a least cost of supply, many generation expansion scenarios were developed, and analysed following three main themes:

- Theme 1 – considered the system demand with the EE programs and without Rogun
- Theme 2– considered the system demand with EE programs and with Rogun
- Theme 3 – considered the system demand with EE programs and with Early Rogun Generation

Eight generation expansion scenarios were developed under Theme 1 taking into account the different resources available and these consisted of 150 MW and 350 MW coal units, 300 MW combined cycle units and several hydroelectric power plants. The results of these generation expansion plans indicated that in the case of thermal unit additions only, the expansion scenarios with the 350 MW coal units resulted in lower costs than the ones with 150 MW coal units or 300 MW combined cycle units. The least cost generation expansion scenario under Theme 1 included 350 MW coal units and two hydro power plants. Based on the results for the Theme 1 generation expansion scenarios it was decided to analyse only two generation expansion scenarios under Theme 2 and Theme 3 and these were the scenarios with the addition of only the 350 MW coal units (Scenario 1) and the one with the addition of 350 MW coal units and two HPPs (Scenario 7). At a discount rate of 10%, the cost difference between scenario 7 and scenario 1 amounted to $172 million and this is due to the fact that Scenario 1 has a higher cost for fuel and O&M while Scenario 7 has a higher cost for capital investment ($113 million). By comparing the CPV of the generation expansion scenarios for Theme 1 with and without the effects of the EE programs it is possible to determine the net benefits of the EE programs under the two generation expansion scenarios (Scenario 1 and Scenario 7) retained. The EE programs net benefits under Scenario 1 amount to $217 million and those under Scenario 7 amount to $192 million.

Table ES- 4 presents the generation expansion sequences under consideration for Themes 1 and 2 so that a direct comparison between the themes and scenarios can be made. The generation expansion scenarios under Theme 3 are somewhat similar to those under Theme 2 with the exception of the timing of Rogun unit additions, the hydro plant and coal units additions.

Based on the retained generation expansion scenarios (1 and 7), generation expansion sequences were developed under Theme 2 assuming that the first two units of Rogun would be commissioned in 2025, the next two in 2028 and the last two units in 2029, the first two units being rated at 400 MW each and the other four 600 MW each. The Rogun reservoir would only be completely filled up by the end of 2036.

It should be noted that under Theme 2, the total net capacity by the end of the study period for the generation expansion scenarios analysed is some 1,600 MW more than that under Theme 1 since the energy generation capability of Rogun, with a capacity factor of 51%, is lower than that of coal fired units which can achieve capacity factors of 80% or higher thus the generation expansion plans with Rogun would require more total net installed capacity than those without Rogun.

Table ES- 4: Comparison of Generation Expansion Sequences Under Themes 1 and 2

<table>
<tr><th></th><th colspan="2">Theme 2</th><th colspan="2">Theme 3</th></tr>
<tr><th></th><th>Scenario 1</th><th>Scenario 7</th><th>1</th><th>7</th></tr>
<tr><td colspan="5"></td></tr>
<tr><td>Year</td><td colspan="4">Detailed Generation System Expansion Plan</td></tr>
<tr><td>2014</td><td></td><td></td><td></td><td></td></tr>
<tr><td>2015</td><td></td><td></td><td></td><td></td></tr>
<tr><td>2016</td><td colspan="2">CHP 2x150 MW</td><td colspan="2">CHP 2x150 MW</td></tr>
<tr><td>2017</td><td></td><td></td><td></td><td></td></tr>
<tr><td>2018</td><td></td><td></td><td></td><td></td></tr>
<tr><td>2019</td><td colspan="2">Coal 2x150 MW and Coal 350 MW</td><td colspan="2">Coal 2x150 MW, Coal 350 MW and Rogun 2x400 MW</td></tr>
<tr><td>2020</td><td colspan="2">Coal 350 MW</td><td colspan="2">Coal 350 MW</td></tr>
<tr><td></td><td colspan="2">10 MW Solar Power in Each of 2021 to 2025, 10 MW Wind in 2021 and 2025, 10 MW Mini Hydro in 2022 and 2024</td><td colspan="2">10 MW Solar Power in Each of 2021 to 2025, 10 MW Wind in 2021 and 2025, 10 MW Mini Hydro in 2022 and 2024</td></tr>
<tr><td>2021</td><td>CHP -128 MW and Coal 350 MW</td><td>CHP -128 MW and Coal 350 MW</td><td>CHP -128 MW</td><td>CHP -128 MW</td></tr>
<tr><td>2022</td><td>Coal 350 MW</td><td>Hydro 100 MW</td><td></td><td></td></tr>
<tr><td>2023</td><td></td><td>Hydro 125 MW</td><td>Rogun 4x600 MW</td><td>Rogun 4x600 MW</td></tr>
<tr><td>2024</td><td></td><td></td><td></td><td></td></tr>
<tr><td>2025</td><td>Rogun 2x400 MW</td><td>Rogun 2x400 MW</td><td></td><td></td></tr>
<tr><td>2026</td><td></td><td></td><td></td><td></td></tr>
<tr><td>2027</td><td></td><td></td><td></td><td></td></tr>
<tr><td>2028</td><td>Rogun 2x600 MW</td><td>Rogun 2x600 MW</td><td></td><td></td></tr>
<tr><td>2029</td><td>Rogun 2x600 MW</td><td>Rogun 2x600 MW</td><td></td><td></td></tr>
<tr><td>2030</td><td></td><td></td><td></td><td></td></tr>
<tr><td>2031</td><td></td><td></td><td></td><td></td></tr>
<tr><td>2032</td><td></td><td></td><td></td><td></td></tr>
<tr><td>2033</td><td></td><td></td><td>Coal 350 MW</td><td>Hydro 100 MW and 125 MW</td></tr>
<tr><td>2034</td><td></td><td></td><td></td><td></td></tr>
<tr><td>2035</td><td></td><td></td><td></td><td>Coal 350 MW</td></tr>
<tr><td>2036</td><td></td><td></td><td>Coal 350 MW</td><td></td></tr>
<tr><td>2037</td><td></td><td></td><td></td><td></td></tr>
<tr><td>2038</td><td></td><td>Coal 250 MW</td><td></td><td>Coal 250 MW</td></tr>
<tr><td>2039</td><td>Coal 100 MW</td><td></td><td>Coal 100 MW</td><td></td></tr>
</table>

The generation expansion scenarios under Theme 3 considered that the first two units of Rogun HPP would start their operation from July 2019, the next two units from January 1, 2023 and the last two units from July 1, 2023. By the end of the study period the total generation additions under Theme 3 were the same as those under Theme 2 with the exception of their respective timing as several unit additions were delayed as Rogun was advanced. By comparing the cumulative present value (CPV) of the generation expansion scenarios under Theme 2 and Theme 3 it is possible to determine the benefits or costs associated with Rogun. For the sequences with Rogun there would be a decrease in fuel and O&M costs, as well as the decommissioning and the flood protection cost and significant benefits due to the increase in revenue from non-firm exports. However, these benefits would be off-set by the capital and operating cost of Rogun. The resulting CPV at the base discount rate (10%) for the Themes 1, 2 and 3 is shown below.

Theme	CPV ($, million)	
	Scenario 1	Scenario 7
1 – Without Rogun	6,811	6,639
2 – With Rogun	6,505	6,303
3 – Early Rogun	6,322	6,256

From the above values it is clear that expansion scenarios considering the addition of the Rogun HPP are more economic than those without at the base discount rate of 10%.

The benefits associated with each theme were determined against the results obtained for Theme 1 scenarios and are shown below.

Theme	Benefits[1] ($, million)	
	Scenario 1	Scenario 7
2 – With Rogun	306	336
3 – Early Rogun	489	383

Note: [1] Relative to Theme 1 – Without Rogun

From the values presented in the above table it can be observed that the Early Rogun scenarios provide greater benefits than those of the With Rogun scenarios.

The benefits for the With Rogun scenarios are of the order of 4 to 5% of the total scenario cost while the benefits for the Early Rogun scenarios are of the order of 6 to 7% of the total scenario cost. Both of these benefits may appear to be relatively small and this could be due to several factors such as the methodology/approach used, the relatively high discount rate used (the benefits are much larger at 8% discount rate), the economic life of plants and a variety of other factors. Also possible, but unlikely, that the study may not have included some of the benefits associated with Rogun since decommissioning costs and the cost of the works required to provide protection against the PMF have been accounted for. The study also included an environmental penalty against the coal fired units for CO2 emissions but did not take into account the effects on generation capability at Nurek of decreased generation due to sedimentation accumulation since this would occur outside the study period. However, since the decreased generation would likely occur so far into the future, once this is discounted at the base discount rate its value would be very small.

The benefits under Theme 3 are greater than those under Theme 2 due to several factors. In the Early Rogun cases there is a significant reduction in the fuel cost (coal required to generate electricity in the absence of the HPP) since the hydro power plant in commissioned at a much earlier date, there is also a reduction in the O&M costs since the installation of other type of plants is reduced and the capital requirements (for other plants) are less since the investments are postponed. Another factor favoring the Early Rogun case is the increase in value and quantity of the non-firm exports due to the fact that the HPP starts generating at an earlier date.

On the cost side, the present worth of the plant's capital cost and O&M account for close to 50% of the overall cost and thus when all the different factors are taken into account, the Early Rogun scenarios present reasonable benefits when compared to the respective costs of the scenarios developed under Theme 1.

Cross comparison of the Theme 2 and Theme 3 results is relatively difficult since there is a difference in the cash disbursements for the Rogun HPP under the two themes which could skew the results obtained and influence the selection decision. The selected cash disbursements for the Early Rogun cases should be calculated with the same level of accuracy as those obtained from the TEAS for the studies undertaken for Rogun under Theme 2.

For both Theme 2 and Theme 3, the generation expansion sequence developed under Scenario 7 produced an overall lower CPV and was thus selected to be brought forward to determine the transmission requirements.

Figure ES- 3 to Figure ES- 6 present the annual capacity installation and annual energy generation for scenario 7 of Themes 2 and 3. As can be observed the total installation for Theme 3 is larger than that in Theme 2 and under Theme 3 there is more energy exported.

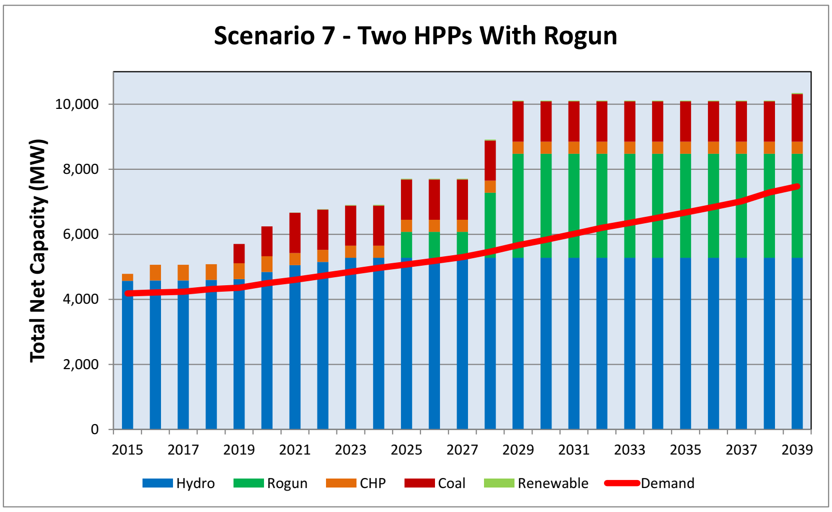

Figure ES- 3: Theme 2, Scenario 7 – With Rogun, Annual Capacity Installation

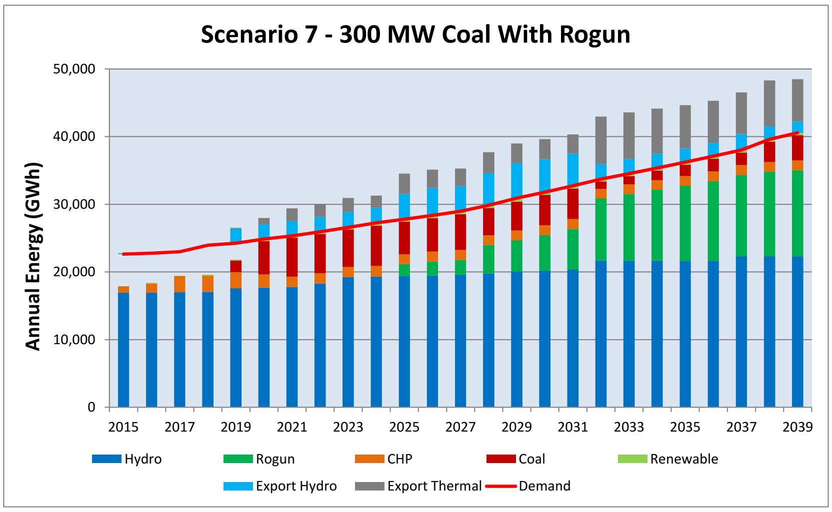

Figure ES- 4: Theme 2, Scenario 7 – With Rogun, Annual Energy Generation

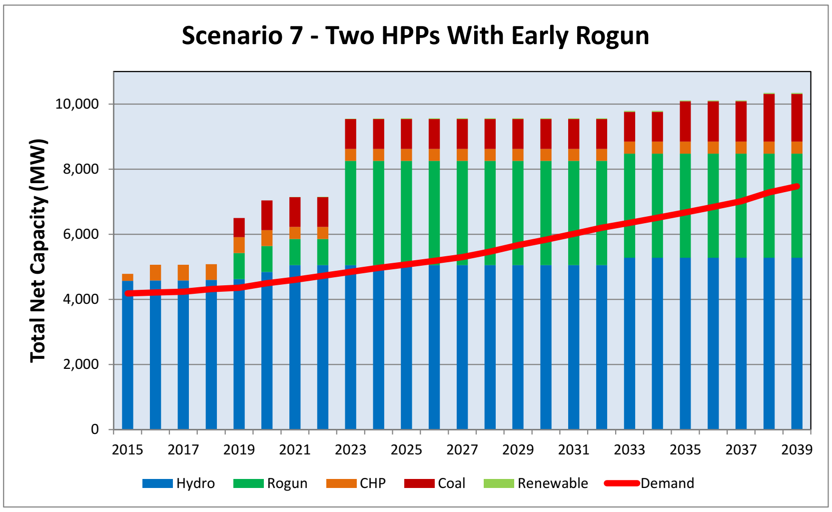

Figure ES- 5: Theme 3, Scenario 7 – With Early Rogun, Annual Capacity Installation

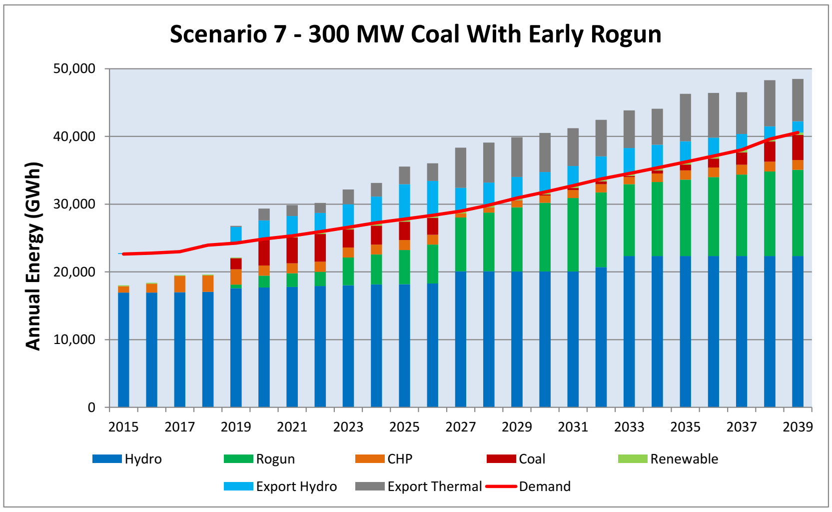

Figure ES- 6: Theme 3, Scenario 7 – With Early Rogun, Annual Energy Generation

Sensitivity studies were carried out for both generation expansion scenarios 1 and 7 under Theme 2 and Theme 3 and are presented in the respective sections. The sensitivity studies were carried out to determine the sensitivity of the generation expansion sequences to changes in the economic parameters used in the analysis. Meaningful variations of these parameters were selected to demonstrate the robustness of the planning results under conditions that could reasonably be expected. Sensitivity was investigated to variations in the following parameters:

- Demand Forecast
- Capital cost of plants
- Fuel price
- Discount rate and
- Price of export energy

The results of the sensitivity analysis to the high and low growth rates indicate that the generation expansion scenarios are not overly sensitive to demand growth with the high growth demand presenting an increased difference in the CPV between the cases without and with Rogun. In order for the generation expansion plans with Rogun to have the same CPV as the plan without Rogun, the following changes to individual parameters would be required.

Parameter	Base	Break Even Change
Capital Cost (%)	0	20
Fuel Cost (%)	0	-40
Discount Rate (%)	10	11.5
Non-Firm Export Price ($/MWh)	68	<40

ES.6 TRANSMISSION EXPANSION PLANS

Studies were undertaken to arrive at a series of transmission expansion plans to evacuate the generation and supply the demand under three different generation expansion plans (without Rogun, with Rogun and Early Rogun)

The approach to the transmission studies consisted in taking the data provided by BT and developing transmission expansion plans that could be used to supply the demand and evacuate the generation under each of the selected generation expansion plans. The expansion plans were then compared on a cost basis.

The conclusions and recommendations on transmission facilities required to meet load serving and generation evacuation requirements are based on steady state powerflow analysis. The data required to perform system dynamic response analysis was not available and hence dynamic studies were not carried out. The dynamic study is normally a confirmatory analysis while the load flow analysis is the investigative part of the study. As such, this is not likely to have major impacts on the overall conclusions, however, BT is encouraged to perform confirmatory studies when dynamic data is available.

The load for the 2014/15 network results in low voltages during the steady state operation. Additional shunt reactive power devices were added in the models to obtain an acceptable system intact voltage profile. Depending on the summer or winter load, the reactive power requirement varies between the North and South regions. During summer, steady state voltage violations are predominantly observed in the Sughd region, while in winter the voltage violations were observed in the Southern part of the country.

There are two contingencies that resulted in non-converged solution of the existing system. The outage of the 500 kV line from Regar to Dushanbe and the outage of the 500 kV line from Dushanbe to Sughd result in non-convergence. The primary reason for non-converged solution is due to the fact that both these contingencies presently split Tajikistan electrically into two areas and there is not insufficient generation in the North to maintain reliable operation. The recommended mitigation measures are detailed in Appendix E and basically consist in the addition of a second line from Dushanbe to Sughd.

The proposed network for the generation expansion without Rogun was designed to meet N-1 requirements. A powerflow case representing each of the 5 representative years was developed based on the generation expansion plan and the load forecast. The generation expansion plan used in this section is predominantly based on the development of thermal power plants located primarily in the Sughd region.

Two cases representing the winter and summer load scenario were developed for each of the representative years. In addition, the following import and exports were also considered:

- Power import from Kyrgyzstan (455 MW)
- Power export (1300 MW) to Peshawar (Pakistan)
- 900 MW power export to Xinjiang, China
- 1,000 MW power export from Rogun to Peshawar.

The export from Lolazar to Peshawar may have to be reconsidered in view of the present negotiation status for this project.

Based on the season, the availability of generation varies; in the winter months, when there is less hydro generation and heavy loading due to heating requirements there is not as much power to evacuate to other systems as there is in the summer. As such the exports are significantly reduced. However, the transmission system is designed considering maximum generation under maximum load and maximum export, this places the most stress on the transmission network.

Transmission facilities needed to evaluate power from the new power plants were identified. N-0 and N-1 studies were performed on each of the cases to identify violations and transmission upgrades/ resources needed to maintain the system intact and N-1 compliance and the required additions are recommended. Sensitivity studies were also performed assuming maximum generation in the south and minimum in the north and vice versa. The transmission expansion plan is designed to cater to a number of different dispatch scenarios. Figure ES- 7 shows the transmission lines (500kV and 220V) that are recommended under the Without Rogun generation expansion plan.

The transmission and substation upgrades necessary to support the projected load and generation growth until the year 2039 for the generation expansion plans with Rogun were determined using an approach similar to that used for the plans without Rogun. Powerflow cases representing each of the 5 representative years were developed based on the generation expansion plan and the load forecast. The generation expansion plan used was based on the development of a hydro power plant at Rogun and some thermal generation in the Sughd region.

Transmission facilities needed to evaluate power from the new power plants were identified. N-0 and N-1 studies were performed on each of the cases to identify violations and transmission upgrades/ resources needed to maintain the system intact and N-1 compliance and the required additions are recommended. Sensitivity studies were also performed assuming maximum generation in the south and minimum in the north and vice versa. The transmission expansion plan is designed to cater to a number of different dispatch scenarios. Figure ES- 8 and Figure ES- 9 show the transmission lines (500kV and 220V) that are recommended under the With Rogun and Early Rogun generation expansion plans.

The transmission facilities recommended for each generation theme are categorised into facilities that are needed to evacuate power from the generating stations and those that are required to supply the load. The transmission facilities for the evacuation of power are different in both plans due to the difference in geographic location of the power plants in both generation expansion plans. However, the facilities recommended to support the load growth and meet the N-1 requirements are mostly the same in both options. This is because the load pattern used in both options is the same.

There are some lines that are unique to each option. These lines are added as specific contingency support for each option. This can be attributed to the difference in power transfer due to the different geographic distribution of generation in each plan.

The transmission facilities required to be added over the study period were costed using unit cost of equipment adapted for Tajikistan. The following total capital costs were obtained:

Component	Capital Cost ($, million)		
	Without Rogun	With Rogun	Early Rogun
New Lines	478.6	588.6	588.6
Substations	213.4	224.9	224.9
Line Upgrades	17.8	17.8	17.8
Capacitors	25.9	22.4	22.4
Total	735.7	853.7	853.7

Figure ES- 7: Recommended Transmission Lines for the Without Rogun Expansion Plan

Figure ES- 8: Recommended Transmission Lines for the With Rogun Expansion Plan

Figure ES- 9: Recommended Transmission Lines for the With Early Rogun Expansion Plan

ES.7 OVERALL COST AND INVESTMENT PLAN

Table ES- 5 presents the combined cost for the generation and transmission components for the selected generation expansion components. It can be seen that the plan without Rogun has a total cost of $7,510 million while the plan with Rogun has a total cost of $7,265 million and the Early Rogun plan has a cost of 7,215 million. As can be seen from the table the transmission CPV is approximately 13% of the total cost in both plans.

Table ES- 5: Total System Cost

Component	CPV ($, million)		
	Without Rogun	With Rogun	Early Rogun
Generation	6,638.7	6303.0	6255.8
Transmission	870.8	962.4	959.2
Total	**7,509.5**	**7,265.4**	**7,215.0**

The difference in the cost between the Rogun plans and the Without plan is $244 million (With Rogun) and $295 million (Early Rogun). It can thus be concluded that the arguments/discussions presented for the generation system are also valid for the entire system and that the addition of the transmission expansion plan costs do not influence the results of the generation expansion themes.

In order to determine the capital requirement over the study period for each of the new generation and transmission facilities added to the system, a series of calculations were carried out by using the annual cash flows outlined in the main body of the report. These capital requirements were made on both economic (no escalation, no taxes) and financial terms and are presented in Table ES- 6.

Table ES- 6: Capital Requirements

Condition	Capital Requirement ($, million)		
	Without Rogun	With Rogun	Early Rogun
Economic	6,822	9,233	9,233
Financial	10,387	12,501	12,145

For the plans without Rogun, the generation component requires 87% of the capital while for the plans with Rogun the generation component requires 90% of the capital. The plans with Rogun require larger amounts of capital under both the economic and financial terms. In financial terms, the plan with Rogun requires $2,111 million more in capital requirements than the plan without Rogun and in economic terms the difference is $2,411 million.

Figures ES-10 and ES-11 show the annual capital requirements for the expansion plans with and without Rogun under economic and financial conditions. As can be seen there are large annual capital requirements for both plans but they are more accentuated for the plan with Rogun. Under financial terms the maximum combined (generation and transmission) annual capital requirement is $1,286 million in 2024, followed by $1,280 million in 2023 for the plan with Rogun. Moreover, the capital requirements up to 2025 of the plan with Rogun represent 69% of the total requirements over 25 years while those for the plan with Early Rogun represent 75% and those for the without Rogun represent 47% of the total.

Capital investment requirements are often an essential factor in determining whether to proceed with a project. When the economic benefits of competing projects are relatively similar, often the project with less capital investment requirements is selected. In this case, Theme 1 –scenario7 (without Rogun) has a higher CPV and a lower capital investment requirement.

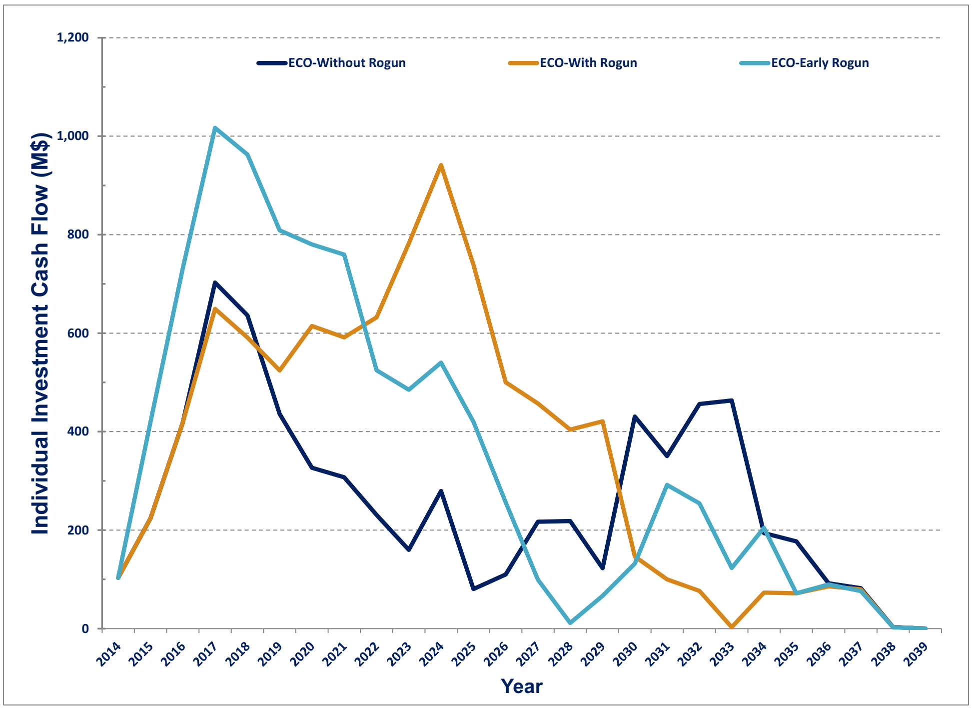

Figure ES- 10: Annual Economic Capital Requirements

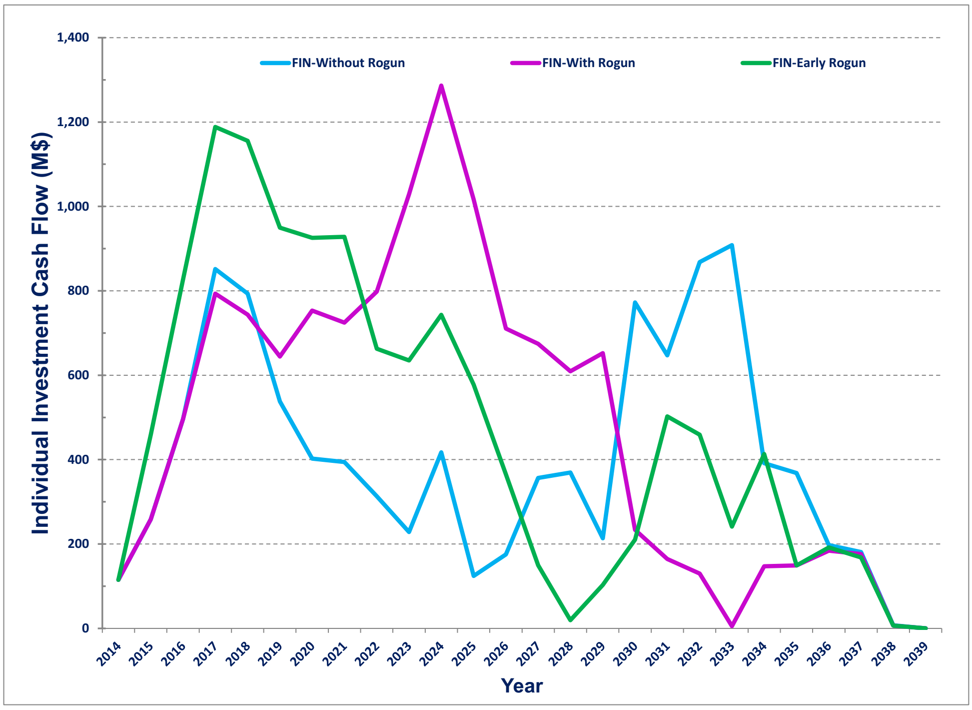

Figure ES- 11: Annual Financial Capital Requirements

The selected expansion plans included two mini hydro power plants. No capital requirements were included for these two plants since costs for these plants are site specific and they were not provided to the study team and in addition, the costs tend to be small and often funded by grants under bilateral aid.

For the expansion scenarios without Rogun there are a total of 25 generation additions. However, of these, one considers the energy efficiency program, the other the decommissioning of Rogun, and the third the construction of facilities to provide protection against the PMF. In the first 10 years of the plan, there is a need for the completion of the rehabilitation of all the existing hydro power plants and to add two 150 MW CHP coal fired units, two new hydro power plants, 2 wind plants, 5 solar plants, 2 x 150 MW coal fired units and 3 x 350 MW coal fired units.

For the expansion scenarios without Rogun, there are a total of 31 transmission line projects and 45 substation projects required over the study period. Of these, 22 transmission line projects and 37 substation projects are required during the first 10 years (until 2025).

For the expansion scenarios with Rogun there are a total of 19 generation additions with one considering the energy efficiency program. In the first 10 years of the plan there is a need to add similar generation facilities to those of the plan without Rogun in addition to the two units of Rogun which are assumed to start generating in 2025. There is a feasibility study available for Rogun on the World Bank web site issued in August, 2014.

For the expansion scenarios with Early Rogun there are a total of 19 generation additions with one considering the energy efficiency program. In the first 10 years of the plan there is a need to add similar generation facilities to those of the plan without Rogun in addition to two 400 MW Rogun in 2019 and 4 x 600 MW Rogun units by 2023.

There is a feasibility study for the two 150 MW CHP coal fired units in Chinese and Russian. There is also a prefeasibility study for Sanobad and a presentation for Nurek -2. The wind plants and solar plants considered in the PSDMP are of the generic type and studies have to be carried out in order to define the basic parameters.

The PSDMP assigned the location for the coal fired units based on the existing coal mines in Tajikistan and no specific studies have been carried out to determine the best location for these plants. Mine mouth locations were assumed to be at Shurob, Fon Yagnob and Ziddy.

1. INTRODUCTION

This section presents the background to the project, identifies the purpose of the report and provides a summary of the report's contents.

1.1 BACKGROUND

Tajikistan is principally supplied with electricity generated by hydroelectric power plants. Unfortunately these power plants do not have large reservoirs to store water to produce electricity during the periods when the hydrological inflows are at their minimum (winter). There is therefore generally a shortage of between 4,000 and 4,500 GWh during the autumn/winter period with a significant suppression of supply resulting in some consumers having power less than 24 hours per day. This lack of supply also has a significant impact on the economy of the country and its ability to expand.

During the spring/summer period generation exceeds demand by the same amount as the shortage during the autumn/winter period. In the former Soviet Union this excess generation in spring/summer was "sold" to Uzbekistan and Kazakhstan in exchange for gas and coal which was used for thermal generation to replace hydro generation by Tajikistan during the autumn/winter. Unfortunately this co-operation ended with the collapse of the Soviet Union when the former Soviet States became independent countries.

Corporate Solutions Consulting Limited (CSCL) in association with Manitoba Hydro International Ltd. (MHI) and others was contracted by the Asian Development Bank (ADB) to develop a Power Sector Development Master Plan (PSDMP) for Tajikistan. As part of the work associated with the Master Plan, CSCL is required to generate several deliverables. This document reports on the analysis and results of the work associated with developing a master plan as prepared by a project team of CSCL and MHI staff. The Master Plan Report presents the parameters, criteria, generation options, and formulates, develops and analyses integrated power system expansion plans for new generation and transmission additions taking into account the increase in demand, the aging of the existing generation fleet, and the economic costs of potential generation resources to supply the increasing demand.

The country consists of four administrative divisions, the provinces of Sughd and Khatlon, the autonomous province of Gorno-Badakhshan (which occupies 45% of country's territory but has less than 3% of the total population) and the Rayons of Republic Subordination (RRS). Presently the Gorno-Badakhshan (GBD) autonomous region is not connected with the other regions of the country via high voltage transmission lines (there is a long 35 kV distribution line).

The country is divided into five electricity regions:

- Sughd (north)
- Khatlon (south)
- Dushanbe and surrounding areas
- Rayons of Republic Subordination (RRS) excluding Dushanbe
- Gorno-Badakhshan Autonomous Region

The first four regions are supplied by the main grid of Barki Tojik (BT) while the electricity customers in the Gorno-Badakhshan autonomous region are supplied by Pamir Energy.

The master plan work is concentrated on the four BT supplied regions since the autonomous region has a relatively small demand, has a relatively small portion of the population and there is lack of information on the demand and its growth potential as well as its resources.

As part of the overall work to arrive at the most appropriate manner in which to supply the future electricity needs of Tajikistan prior other reports have been issued, namely:

- The Inception Report
- The Demand Forecast Report
- The Planning Parameters and Generation Options Report issued in August 2013 as well as revised version issued in November 2014
- The Energy Efficiency and Promotion Plan Report

- The Master Plan Draft Report issued in June, 2015.

The inception report documented the findings of two specialists that travelled to Tajikistan at the start of the assignment, set out the information required to complete the master plan in an orderly manner, summarized the electric power sector in Tajikistan, described the electric power systems, presented the principal planning assumptions, set out the general requirements for the generation planning software and presented a revised work plan and schedule.

The demand forecast report presented the medium, low and high demand forecast arrived at by taking into consideration several macro-economic variables, existing demand characteristics as well as specific spot loads. The projection of the demand associated with TALCO was considered separately from the regions forecast.

The planning parameters and generation options report was not specifically included in the list of deliverables set out under the scope of work in the Terms of Reference (ToR) and was prepared to define the parameters that were to be used in PSDMP and to list the options that would be considered for new generation.

The energy efficiency and promotion report was an identified deliverable in the ToR and was prepared to identify opportunities, in the electrical sector, that could be subject to the application of measures for using less energy to provide the same or better level of service. Loss reduction and reduced consumption at TALCO were not included since these were already taken into account in the demand forecast report.

The master plan draft report summarized the results of the demand forecast and energy efficiency promotion reports, presented the generation options and criteria outlined in the planning parameters and generation options report and described the work undertaken to arrive at the generation and transmission expansion plans developed to meet the demand in Tajikistan in a reliable and cost effective manner.

This final report incorporates additional information provided by the MoEWR and comments received from the stakeholders following their review of the draft report.

1.2 Purpose of the Sector Development Master Plan Report

The principal objective of the power sector development master plan is to arrive at a plan to enhance the energy security and energy efficiency of Tajikistan. The master plan is to cover aspects related to generation, transmission and rehabilitation and expansion for the next 20 years. The study is to forecast demand, assess the condition of the existing plants and proposes alternatives to meet the forecasted demand, including new domestic generation and regional transmission lines. The study is to also address policy measures to promote energy efficiency and to address the development of an action plan.

The study horizon of 20 years had to be revised in order to accommodate long lead time projects such as the Rogun hydroelectric power plant and is now taken as 25 years staring from 2015.

The principal purpose of the master plan report is to document the approach used and the analysis undertaken to arrive at the most appropriate manner to supply the electricity demand in Tajikistan taking into account technical and economic considerations.

The final Master Plan Report has been prepared to present the parameters, criteria, generation options, and to formulate, develop and analyse integrated power system expansion plans for new generation and transmission additions taking into account the increase in demand, the aging of the existing generation fleet, and the economic costs of potential generation resources to supply the increasing demand.

1.3 Information Collection

The inception visit comprising the Power System Specialist and Generation Specialist took place between 10 July, 2012 and 23 July, 2012.

Prior to this visit the specialists submitted to BT a list of information required for demand forecasting and generation planning. While in Dushanbe, the specialists met a few of the national consultants and other relevant project personnel. A visit to existing cascade hydro plants near Dushanbe was organised which allowed the consultants to gain a valuable insight into the operation of the power system in Tajikistan together with a view of the ruggedness of the country's topography.

A meeting was held with BT's Working Group on Technical Issues headed by the Deputy Chairman of BT during which several items related to the project were discussed. Meetings with other BT officials took place during various occasions in which the discussions focused on several topics relevant to the planning process. These discussions addressed the need to obtain the existing Power Purchase Agreements, existing planning reports, demand forecast reports, planning criteria, renewable energy outlook for Tajikistan and specific project technical reports.

A second information collection mission was undertaken by the Power System Specialist from 4 September to 4 October, 2012 to conduct additional meetings and collect missing data. During this mission significant data was collected for the demand forecast activity and several ministries were contacted and met with regard to economic development for Tajikistan.

Members of the project team visited Dushanbe from 7 February to 4 March, 2013 and 1 May to 15 May, 2013 to meet relevant entities, carry out project discussions, obtain models to be used by the project and collect additional and missing data.

Work on preparing the PSDMP was suspended in September 2013 pending the publication of the Rogun Feasibility Study reports. Work recommenced on the PSDMP when these became available in early 2014. The Power System Specialist visited Dushanbe from 8 March to 17 March, 2014 to restart the project and from 28 October to 13 November, 2014 to work with Ministry of Energy and Water Resources (successor of the MoEI) officials and collect feasibility reports for various hydroelectric and thermal power plants that had not been made available previously.

The master plan draft report was issued and presented to the stakeholders in early June, 2015. Comments were received in late September, 2015 which required clarifications from BT and the Ministry. The clarifications were received in mid December, 2015 and March 2016.

Appendix A provides a list of the data collected.

1.4 REPORT CONTENTS

1.4.1 Report Outline

This report is organised into nine sections and five appendices as follows:

Section ES Executive Summary, provides a summary of the overall contents of the report focusing on the electricity sector in Tajikistan, the electricity supply and demand, the planning parameters and criteria, the generation resources and technologies, the generation expansion plans formulated and analysed, the transmission expansion plans for the selected generation expansion plan, the economic and financial analysis and the key findings arising from the studies carried out

Section 1 Introduction, presents the background to this report, the purpose of the report, the data collection process and the reference scope of work

Section 2 Electricity Sector in Tajikistan, provides a brief overview of the regulatory and institutional framework including the introduction of the main players in the sector, gives an overview of the supply and demand situation in Tajikistan including the estimated unmet demand in the winter, the TALCO requirements and the historical peak demand, shows the existing power purchase agreements and describes the existing transmission

Section 3 Electricity Supply and Demand, introduces the approach and methodology used to arrive at the demand forecast under the base or medium forecast as well as for the low and high forecasts, derives the forecasts and presents the short term energy and capacity balance

Section 4 Planning Parameters and Criteria, presents the parameters to be used throughout the study related to planning horizon, economics, including discount rate, exchange rates, cost of losses and cost of expected unsupplied energy, generation including reliability criteria, emissions criteria, candidate generation resources and generation planning software, fuel prices, transmission and future regional interconnections

Section 5 Generation Resources and Technologies, presents a list of generation resources along with imports and energy efficiency measures that could be available to meet the increased resource requirements. The resources include hydroelectric projects, thermal projects, non-hydro renewable projects and other energy resources. An initial screening of the generation resources is provided

Section 6 Generation Expansion Plans, describes the principal decision factors used in the formulation and development of the generation expansion scenarios (for the Tajikistan national electricity grid) which were studied in preparing the PSDMP, presents the generation expansion scenarios along with their respective analysis and results and selects the least cost generation expansion plans

Section 7 Transmission Expansion Plans for Selected Scenarios, provides an overview of approach used, the relevant information obtained, an analysis of the existing transmission system, the transmission facilities required to evacuate the generation and meet the demand under two selected generation expansion cases and capital costs associated with the required facilities.

Section 8 Overall Cost and Investment Plan, presents the economic analysis for the combined generation and transmission system and also presents the investment plan, in both economic and financial terms, for the two selected system expansion plans

Section 9 Key Findings, presents a list of generation resources along with imports and energy efficiency measures that could be

Appendix A List of Data Collected, contains a list of the data collected from various sources starting with the inception visit to the present.

Appendix B Power and Energy of Selected Hydropower Plants, presents the hydrological studies carried out to determine the power and energy for the existing Vakhsh river hydropower plants, for the Kairakkum hydropower plant after rehabilitation and for candidate hydropower plants with either pre-feasibility or feasibility studies

Appendix C Generation Resources and Technologies, provides a description of the energy resources available for electric power generation, including both domestic and imported fuels as well as generation technologies suitable to Tajikistan. The main technical and economic parameters of the suitable technologies are also presented

Appendix D Detailed Addition and Retirement Schedule and Total System Cost by Scenario, contains detailed information of system additions, retirements and performance for each generation expansion plan developed and analysed. It also presents annual costs for capital additions, O&M, fuel expenditures and potential revenues derived from the sale of contracted and/or surplus electricity

Appendix E Transmission Expansion Plans, details the transmission facilities required to evacuate the generation and supply the demand for the two selected generation expansion plans. It also determines the costs associated with the required transmission facilities.

1.4.2 Reference Scope of Work

The scope of work for the Master Plan as presented in Section 3 subtask B1 of the terms of reference states:

> *(iv) Assessing potential energy sources for generation development; prepare and analyse options.*
>
> *(v) Analysis of existing power purchasing agreements signed with neighboring countries to understand their impact or long-term effects on national economy and energy security issues.*
>
> *(vi) Identification of series of technically feasible and cost optimized long-term generation capacity expansion scenarios for next 20-year period with consideration given to prospects for in-state generation development as well as through trade with neighboring countries.*

(vii) Modeling existing transmission network using PSS/E or similar software and carrying out load flow, short circuit, transient stability, and reliability analysis to identify bottlenecks and remedial measures.

(viii) Studying the required expansions in each islanded network to cope with future demand for electricity and grid interconnection of power plants identified in the generation development plan.

(ix) Developing series of transmission and distribution expansion plans matched to the demand forecast and generation expansion scenarios ensuring efficient and reliable power system for all possible operating scenarios.

(x) Developing cost database to evaluate costs associated with each development proposal. The cost data base should include the methodology for updating costs in future reflecting price escalations.

(xi) Preparation of an assessment of the annual financial requirement and net present values of generation, transmission and distribution investments associated with each system development identified in the master planning process.

(xii) Providing the detailed 20-year program of capital works, and prepare detailed project reports for projects to be covered in the first 10 years.

(xvii) Impact and benefit analysis, especially for establishing a priority list of projects to guide the energy sector's investment program.

2. ELECTRICITY SECTOR IN TAJIKISTAN

This section presents a brief outlook of the power sector in Tajikistan, identifies the entities involved, addresses the regulatory and institutional framework, presents an overview of the of the supply, describes the existing power purchase agreements, summarizes the existing and historical supply including that for TALCO and estimated unmet demand and describes the existing transmission.

2.1 INTRODUCTION

In Tajikistan, the Ministry of Energy and Water Resources (MoEWR) is responsible for the entire energy sector, which comprises the electricity sector as well as oil and gas. Previously, the Ministry of Energy and Industry (MoEI) held this responsibility but this ministry has been replaced. The MoEWR is responsible for the energy policy and the development of standards.

The country is divided into five electricity regions:

- Sughd (north)
- Khatlon (south)
- Dushanbe and surrounding areas
- Rayons of Republic Subordination (RRS) excluding Dushanbe
- Gorno-Badakhshan Autonomous Region

The first four regions are supplied by the main grid of BT while the electricity customers in the Gorno-Badakhshan autonomous region are supplied by Pamir Energy.

The entire electrical energy system of Tajikistan has been created in the last 70 years. The first Varzob hydropower plant (HPP) was commissioned in 1936, while the latest large HPP, Sangtuda came into service in 2012. While later sections provide additional details, it is worthwhile mentioning that the largest HPPs in Tajikistan are: Nurek HPP with a capacity 3,000 MW, Sangtuda-1 HPP with a capacity 670MW and Baypaza HPP with a capacity 600 MW.

2.2 REGULATORY AND INSTITUTIONAL FRAMEWORK

The MoEWR and the Ministry of Economic Development and Trade (MEDT) are responsible for many aspects of the energy sector in Tajikistan. Within the MEDT there is a group that addresses issues related to planning and statistics. In addition, other ministries and institutions handle matters related to energy and these include:

- The Committee for Environmental Protection which regulates the sustainable management of energy resources and monitors the environmental regulations (emissions, pollution, waste)
- The Ministry of Finance which provides financial aid for EE projects and other institutions including the SAES
- The State Committee for Investments which is entrusted with creating attractive conditions for attracting investment
- The Antimonopoly Service (AMS) which establishes energy pricing and electrical tariffs
- The State Statistical Committee under the Office of the President which addresses energy statistics
- The State Agency for Measurements, Standardization and Certification
- Other Institutions related to construction, transport and industry

As seen from the above, coordination of activities amongst all these institutions is necessary and will become more and more important in the medium and long term.

Regulation of the energy sector is the responsibility of the Antimonopoly Service (AMS) under the Government of the Republic of Tajikistan. The AMS is responsible for the tariff methodology, tariff level proposals, service quality, consumer complaints and anti-competitive behavior. MoEWR is responsible for licensing, approval of investment plans and technical and safety standards. Final approval and amendment of tariffs for end-users is within the competency of the Government of the Republic of Tajikistan.

Foreign investments in the electric power sector are permitted and supported by law. Construction of new generating capacities requires government permission and must be conducted through a tender process. Foreign investors may be granted tax discounts and other benefits.

BT is required to submit its budget and plans for approval to the Ministry of Finance and the MEDT.

2.2.1 General

Development of the energy sector in Tajikistan is guided by the following laws and legal acts:

- Constitution of RT
- The Law of RT “On Energy”
- The Law of RT “On Energy Savings and Energy Efficiency”
- The Law of RT “On Privatization of State Property”
- The Law of RT “On Licensing of Separate Types of Activity”
- The Law of RT “On Concessions”
- The Law of RT “On Usage of Renewable Energy Sources”
- The Law of RT “On Safety of Hydrotechnical Facilities”
- The Law of RT “On Nature Protection”
- Tax Code of RT
- Water Code of RT
- A number of industry-specific Orders of the Government of the Republic of Tajikistan
- Other legal acts and international norms recognized by RT.

These acts determine government policy and regulatory measures in the energy and energy saving sectors and the authority of the government and other related public agencies. They also define the administrative procedures for energy companies and property rights in the energy sector, including the protection of consumer rights. They point to the necessity of having a specialized state agency for energy control, to determine energy efficiency standards, certification and metrology procedures, and liabilities for breach of energy legislation.

The following subsections provide a brief summary of each of the above laws and legal acts:

2.2.2 The Law of the Republic of Tajikistan “On Energy”

The legislative framework of the energy sector was introduced with passing the law “On Energy” №123 dated 10 November 2000. This Law determines that “all entities in the energy sector are allowed to function under the different ownership forms (state, private, public, mixed and joint).” However, the law keeps the government or delegated government agencies as the principal agencies to manage the energy sector. This law also addresses the specifics of how the energy sector functions, which includes: monitoring activities of energy companies, protecting their property and consumer rights protection, determining tariff setting policies in the energy sector, and establishing the authority of the government to approve concession agreements on energy facilities, including offering concessions to foreign investors. A new version of this law, initiated by the Government, was accepted with modifications and additions on 30 May 2007.

2.2.3 The Law of the Republic of Tajikistan “On Energy Savings and Energy Efficiency”

The law “On Energy Savings and Energy Efficiency” № 1018 dated 19 September, 2013 regulates social relations in the field of energy conservation and efficiency and determines the order of use of energy resources and products. The law intends to monitor and promote the effective use of energy resources and products, develop and implement the effective technologies in different sectors for the use of energy resources, to oversee and monitor the effective use of energy resources in the public sector, to protect the environment and standardize and certify energy efficient equipment, materials, buildings, vehicles and other energy consuming products.

2.2.4 The Law of the Republic of Tajikistan “On Privatization of State Property”

The law “On Privatization of State Property” dated 16 May 1997, with amendments and additions in 2002 and 26 March 2009.

2.2.5 Tax Code of the Republic of Tajikistan

A part of the tax code dated 3 December 2004 determines a “royalty on water”. Amendment number 774, dated 28 June 2011, to the Water Code of the Republic of Tajikistan however states that hydropower plants with a capacity of less than 30,000 kW are exempt.

2.2.6 Other Laws and Aspects

There are other laws that also contribute to the regulatory and institutional framework and a few of these are briefly mentioned below.

Until recently, energy efficiency was regulated by the law “On Energy Conservation” №524 dated 06 February 2002. The goal of this Law was to provide a legislative framework for government policy on energy conservation while taking into consideration the interests of consumers, energy suppliers and producers. It also aimed to stimulate scientific work, and introduce energy efficient technologies and information mechanisms to increase energy efficiency.

To date, there is no separate law on renewable energy but work is being carried out on the use of renewable energy especially mini-hydros. In the last few years, Tajikistan has prioritized energy conservation/efficiency. As an example, a decree in 2009 ordered the replacement of energy saving lamps in public buildings and streets. Also 240,000 lower income families were provided with 1,920,000 lamps..

There is also a law addressing the safety of hydraulic facilities to which every hydroelectric power plant has to comply.

2.2.7 Barki Tojik

BT is a vertically integrated utility. It is an open joint stock company in which all shares belong to the state, managed by a chairman who is appointed by, and reports to, the President of Tajikistan. There is a supervisory board comprising of ministers and chaired by the prime minister. Chairman and deputy chairmen are responsible for specific portfolios (i.e., generation, distribution, transmission, sales, finance, etc.).

In the past, the northern and southern grids were developed as stand-alone systems with the energy requirements of the northern grid being met by a mixture of local hydro generation and energy sent from the Rayons of Republican Subordination (RRS) and southern regions and wheeled through the Uzbek electrical system This situation was only changed by November, 2009 when a 500 kV transmission line connecting the Dushanbe and the Sughd 500 kV substations (some 215 km apart) was commissioned.

2.2.8 Pamir Energy

The Gorno Badakhshan Autonomous province is Tajikistan’s poorest region, sparsely populated and cut off from the rest of the country during the winter. Providing electricity services in this region is a daunting challenge. Pamir Energy represents an innovative partnership between the government and the international community.

Established in December 2002, Pamir Energy took control of most of BT’s assets in Gorno Badakhshan on the basis of a 25-year concession agreement.

2.3 Overview of the Supply

The following sections provide a summary of the electricity supply and demand situation in Tajikistan over the past few years focusing primarily on the BT supplied grid.

2.3.1 Barki Tojik Supply

The total installed capacity in the BT grid amounts to 5,346 MW when 110 MW of the second Sangtuda – 2 unit is taken into account. The hydro capacity amounts to 4,928 MW (92%). There are two build, own, operate and transfer (BOOT) hydro plants (Sangtuda 1 and 2) with a total installation of 990 MW.

Table 2-1 presents information on the generation plants in Tajikistan including the average annual output and the in-service year. There are three Combined Heat and Power (CHP) plants; Dushanbe-1, Dushanbe-2 and Yavan. The Yavan plant has not operated during the last few years due to the lack of fuel and hot water customers while the Dushanbe-1 plant operates on a limited basis due to fuel availability issues. Both Dushanbe-1 and Yavan plants can use natural gas or mazout (heavy fuel oil, HFO). The Dushanbe-2 power plant is coal fired with the first 50 MW unit being commissioned in January, 2014 while the second unit was commissioned in September, 2014. The third and fourth units at Dushanbe-2 are planned to be in service by 2017 and have a capacity of 150 MW each.

On average, the hydro plants can generate a total of 19,492 GWh per year (45% capacity factor) but the generation is greatly reduced over the late autumn/winter period due to reduced hydrological flows thus seriously affecting the system's capability to meet the demand. While a few units have gone through rehabilitation, most of the BT hydro plants are over 30 years old and in need of rehabilitation. There are plans to rehabilitate several of the existing hydro power plants (HPP) including Nurek, Golovnaya and Kayrakkum.

Two plants on the Varzob cascade have undergone rehabilitation and after the rehabilitation the total installed capacity was increased by 9.5 MW. Rehabilitation works are about to start on the Kayrakkum units and a project is underway to rehabilitate the Golovnaya units.

Table 2-1: Existing Generation Plants in the Barki Tojik System

Plant		Number of Units	Installed Capacity (MW)	Average Annual Output (GWh)	Rehabilitation Capital Budget ($M)	In Service Year	Rehabilitation Schedule
No.	Name						
1	Nurek	9	3,000	11,200	300	1972-1979	2011-2016
2	Baypaza	4	600	2,500	40	1985-1986	
3	**Vakhsh Cascade**		**285**	**1,360**	**270**		**2011-2016**
	Golovnaya	6	240		180	1963-1967	**2014-2020**
	Perepadnaya	3	30		60	1958-1960	
	Central	2	15		30	1964	
4	**Varzob Cascade**		**27**	**102**	**38**		**2011-2012**
	Varzob-1	2	10		16	1936-1937	
	Varzob-2	2	14		22	1949	
	Varzob-3	2	4			1952	
5	Kayrakkum	6	126	600	127	1956-1957	2011-2016
6	Sangtuda-1	4	670	2,730		2008-2009	
7	Sangtuda-2	2	220	1,000		2012	
8	Dushanbe-1 CHP		198			1953-1968	
9	Yavan CHP		120			1969-1970	
10	Dushanbe-2 CHP	2	100			2014	
Total			**5,346**	**19,492**	**775**		

Source: Barki Tojik

As indicated in Table 2-1 some of the hydro plants are to undergo rehabilitation and the schedule shown may have been delayed due to the lack of committed funds but nevertheless the present study assumes that all the plants will undergo rehabilitation by 2027. Table 2-2 presents the current available capacity and the capacity after rehabilitation and these values were used in the development of the generation expansion plans.

Table 2-2: Capacity of Generation Plants After Rehabilitation

Plant		Number of Units	Installed Capacity (MW)	Currently Available (MW)	Capacity After Rehabilitation[3] (MW)
No.	Name				
1	Nurek	9	3,000	2,690	3,069
2	Baypaza	4	600	550	600
3	**Vakhsh Cascade**		**285**	**285**	**304**
	Golovnaya	6	240	240	259
	Perepadnaya	3	30	30	28
	Central	2	15	15	17
4	**Varzob Cascade**		**28**	**28**	**38**
	Varzob-1	2	10	10	20
	Varzob-2	2	14	14	14
	Varzob-3	2	4	4	4
5	Kayrakkum [1]	6	126	126	152
6	Sangtuda-1	4	670	670	670
7	Sangtuda-2	2	220	220	220
Subtotal Hydro			**4,929**	**4,569**	**5,053**
8	Dushanbe-1 CHP [2]		198	128	128
9	Yavan CHP		120	0	0
10	Dushanbe-2 CHP [2]	2	100	88	88
Subtotal Thermal			**418**	**216**	**216**
Total			**5,347**	**4,785**	**5,269**

Notes: (1) Total installed capacity after rehabilitation is 174 MW
(2) Run only in winter season, from October to March
(3) Expected to be completed by 2020

Table 2-3 shows the energy generated by the hydro and CHP plants over the period 2002 to 2012 as well as the imports and exports. There has been a net import from 2002 to 2010 but for 2011 and 2012, Tajikistan became a net electrical energy exporter.

Table 2-3: Energy Production in BT Grid from 2002 to 2012 (GWh)

Source	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Hydro Power Plants				16,815	16,503	16,936	14,496	14,007	14,558	13,828	14,345
Heating Plant				99	197	336	252	147	27	34	40
Subtotal (GWh)	15,105	16,302	16,352	16,913	16,700	17,272	14,748	14,155	14,585	13,862	14,385
Import	1,052	1,061	1,081	1,042	1,557	1,057	1,917	1,276	339	65	14
Export	266	1,017	694	798	948	969	1,054	1,232	179	190	675
Sangtuda - 1							1,106	1,698	1,616	2,152	1,863
Sangtuda - 2											498
Total Available (GWh	15,891	16,346	16,739	17,157	17,309	17,360	16,717	15,897	16,361	15,888	16,085

Source: Barki Tojik

Two new hydro plants were added to the system, on a BOOT basis, Sangtuda-1 in 2008 and Sangtuda-2 in 2012 (one unit of two). As can be seen from Table 2-3, these two plants are expected to make a significant contribution to the overall energy availability in the country. The energy production values indicate that hydro meets most of Tajikistan's needs and that there has been a shift from net importing in the earlier years to net exporting in the last two years shown.

The total available energy in Tajikistan has remained stagnant from 2002 to 2012 even though some years it has been higher than others.

Figure 2-1 shows the energy production in Tajikistan in a graphical form. The figure indicates that there has been a decrease in energy generation by the BT hydro power plants after 2007 which has been compensated by the addition of Sangtuda plants. Also of note from the figure is the reversal of the system from a net importer to a net exporter.

The Dushanbe-1 CHP plant has generated limited energy over the past 11 years, producing a maximum of 336 GWh in 2007, due to the lack of fuel to operate over the late autumn/winter, otherwise it could generate 600 GWh or more.

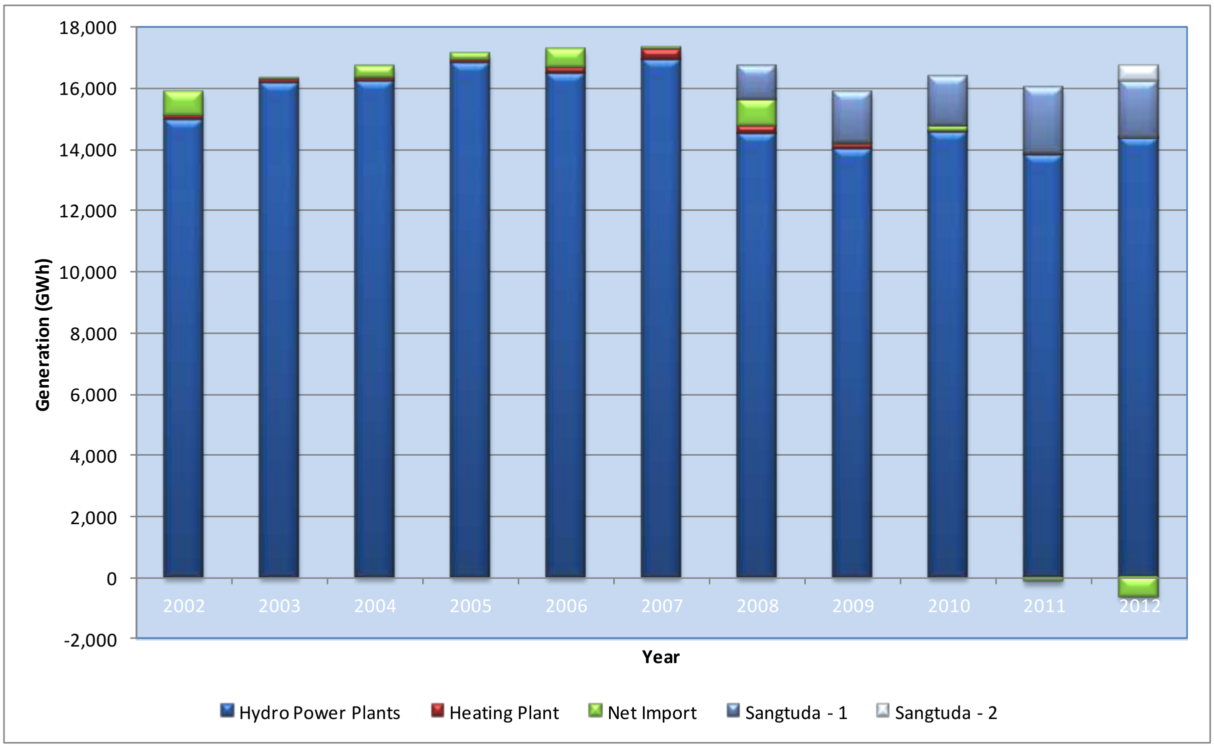

Figure 2-1: Historical Electricity Generation and Net Imports

Appendix B1 presents the results of the studies carried out to arrive at energy estimates of operating the existing Vakhsh River cascade system under average and firm (95% probability of exceedance) consisting of Nurek and five other HPPs operating in cascade. Appendix B2 presents similar energy estimates but for the Kairakkum power plant.

Energy estimates for the Varzob cascade were obtained from previous year's generation patterns.

2.3.2 Pamir Energy Supply

Established in December 2002, Pamir Energy took control of most of BT's assets in the GBD area on the basis of a 25-year concession agreement. The total installed capacity on the Pamir Energy system is some 43 MW, which are all HPPs as shown in Table 2-4.

Table 2-4: Existing Generation Plants of Pamir Energy

No.	Plant Name	Installed Capacity (kW)	Available Capacity (KW)	In Service Year
1	Pamir	28,000	21,000	1994, 2005
2	Khorog	9,000	8,800	1970
3	Namangut	2,500	1,850	1974
4	Vanj	1,200	1,050	1968
5	Oksu(Murgoub)	640	300	1964
6	Kalai-Humb	208	80	1959
7	Shujand	832	550	1969
8	Savnob	80	40	1984
9	Sipanj	160	120	1992
10	Andaribak	300	260	1999
11	Tekharv	360	300	1995
Total		**43,280**	**34,350**	

Source: MoEI

In addition to the Pamir-1 and Khorog HPPs, Pamir Energy manages and operates another nine small/mini hydro power plants in its extensive service area. These HPPs provide electricity to small villages and towns.

Total installed capacity managed by the company amounts to 43 MW. It should be noted that 95% of the available capacity is obtained from the four largest plants.

At this time, information on the plans to increase the available capacity at the plants in the Pamir Energy system was not available to the PSDMP study team.

2.4 Existing Power Purchase Agreements With Neighbouring Countries

Presently BT has two power purchase agreements (PPAs) with Afghanistan and one with Kyrgyzstan which is renewed on an annual basis. The first PPA with Afghanistan was signed on 28 August, 2008 and the Second was signed on 20 November 2009.

For the CASA 1000 project, negotiations completed between Tajikistan,Kyrgyzstan, Afghanistan and Pakistan. The Tajikistan's share of the firm exports amounts to 1,331.5 GWh per year but additional quantities may be exported if available (up to 4,000 GWh).

2.4.1 The 2008 PPA

A PPA between BT and Da Afghanistan Breshna Moassasa Company of the Islamic Republic of Afghanistan was signed on 28 August, 2008 for a commercial operation date (COD) of 1 April, 2010. The contract has a duration of 20 years and is divided into 2 phases; Phase 1 started on 1 April 2010 and is to terminate on 30 April, 2015 while Phase 2 is to start on 1 May, 2015 and end on 30 April, 2030.

Under the PPA the delivery point is set to be the border between the two countries but the transmission line connecting the two electrical systems originates at the Sangtuda – 1 HPP 220 kV substation and ends at the Pul-e-Khumri. The distance between the 220 kV substations is 281 km and according to a sketch attached to the PPA, the transmission line consists of a double circuit with 2 x 400 mm^2 conductors per phase. The total losses in the transmission line are to be divided according to the distance that the line occupies in each country or 117/281 of the total losses in Tajikistan and 164/281 of the total losses in Afghanistan.

The contracted energy is 1,007.6 GWh per year with an annual minimum guaranteed energy of 650.8 GWh to be delivered between April and October. The maximum hourly delivery was set at 178.8 MWh. However, Afghanistan will take any additional energy that BT could make available for export. This study assumes that the firm export is 681.5 GWh per year.

The price agreed for all energy was 3.5 ¢/kWh escalated at 3%per year which in 2015 had a value of 3.79 ¢/kWh. The PPA contains a clause outlining the penalties for failure to deliver the minimum energy but the penalty is relatively small.

The PPA languages are English and Russian with English to prevail and the applicable law is that of Tajikistan and Afghanistan. Disputes are to be resolved by the London Court of International Arbitration using United Nations Commission of International Trade Law (UNCITRAL) rules.

2.4.2 The 2009 PPA

A PPA between BT and Da Afghanistan Breshna Moassasa Company of the Islamic Republic of Afghanistan was signed on 20 November, 2009 for a COD of 1 January, 2010. The contract has a duration of 4 years from COD and is automatically extended for a further period unless one the parties notify the other party of its termination at least 30 days prior to the expiry date. For this report it is assumed that this PPA will be renewed after each term.

Under this PPA, two transmission lines deliver the energy from Tajikistan to Afghanistan. The first transmission line is a 110 kV transmission line with its origin at the Geran 220/110/35 kV and ends at the Kunduz substation in Afghanistan. The second transmission line originates at the 35/120 kV Lower Pyanj substation and is probably used to supply border towns in Afghanistan.

There is no contracted capacity and energy, the transmission lines will evacuate the power and energy made available by the BT dispatch centre. For study purposes it was assumed that the transmission lines could evacuate a maximum of 50 MW and that energy would be exported when Tajikistan was in a surplus mode (summer time).

The price agreed for all energy was 2.8 ¢/kWh with no escalation.

2.4.3 PPA with Kyrgyzstan

A PPA with BT and National Electric Network of Kyrgyzstan was signed on 21 May 2014. The contract was to be in effect from 1 May to 30 September, 2014 and the PPA did not contain a renewal clause but it is understood that a new contract is negotiated every year.

Under the PPA, BT is to deliver 600 GWh of electricity at the border of the two countries between May and September with a voltage deviation of ±10% and a frequency deviation of ± 0.2 Hz. The daily deliveries are to be coordinated between the two utilities according to the dispatch procedures.

The contract price was set at 2.0 US¢/kWh. Penalties under the contract are not to exceed 1% of the contract amount (us$120,000). Dispute settlement is to be at the defendant’s country and according to the defendant’s laws.

2.5 CHARACTERISTICS OF EXISTING AND HISTORICAL SUPPLY

The project team was provided with the consumption data from 2007 to 2012 for each of the four regions and by customer type. The customer types have been classified into 6 major groups by BT as:

- Industry and Agriculture (excluding TALCO and irrigation)
- Government and Utilities
- Water Pumping
- Residential
- Residential Heating
- TALCO

Figure 2-2 to Figure 2-5 show the electricity consumption for each region and customer type for the period 2007 to 2012. Until recently, the residential consumption was the largest in the four regions with the exception of Sughd where water pumping was predominant reflecting agricultural activity in the region. In the past few years, the Khatlon region has seen a surge in the water pumping consumption surpassing that of the residential consumption.

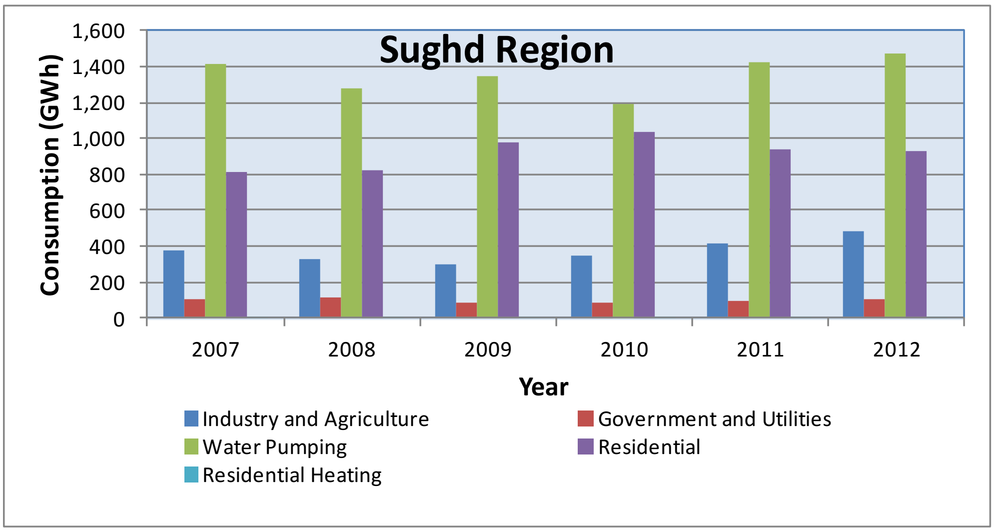

Figure 2-2: Sughd Region Consumption by Customer Type

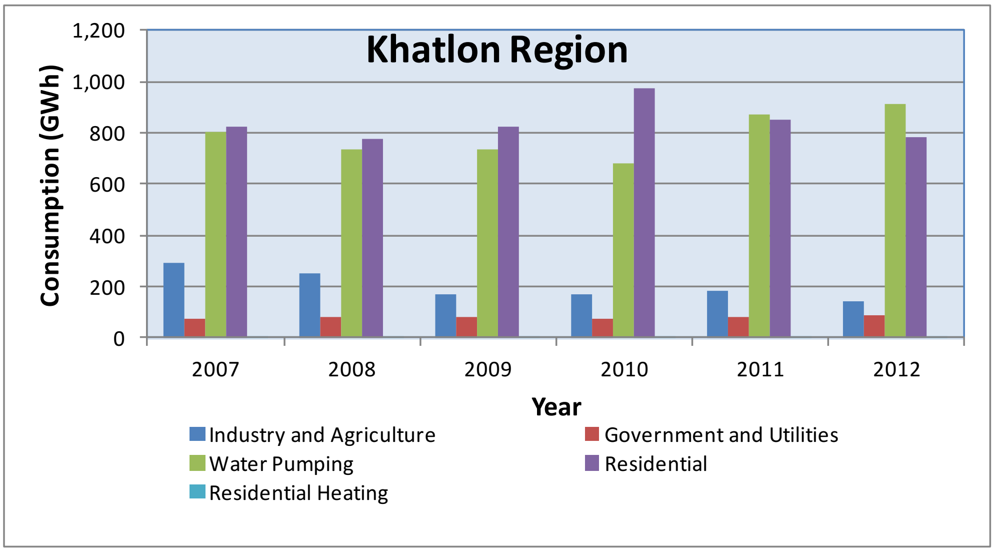

Figure 2-3: Khatlon Region Consumption by Customer Type

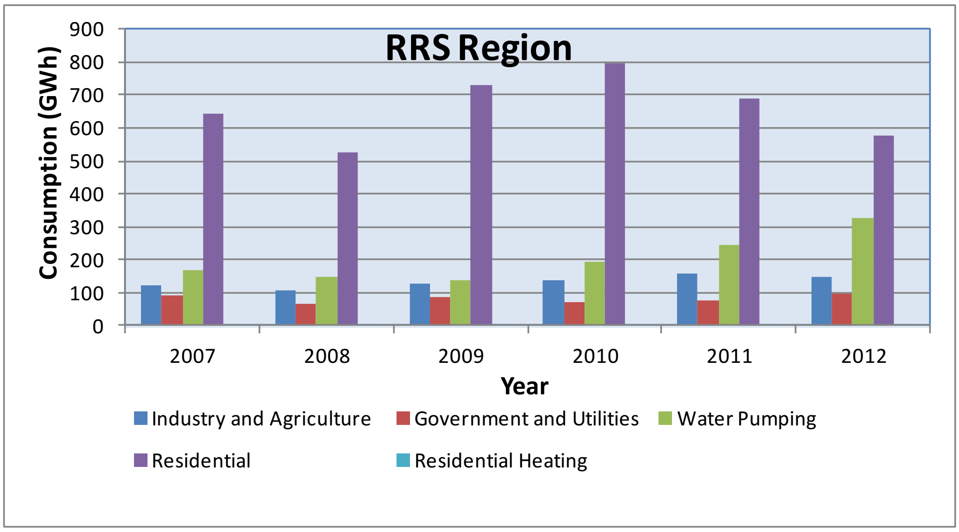

Figure 2-4: RRS Region Consumption by Customer Type

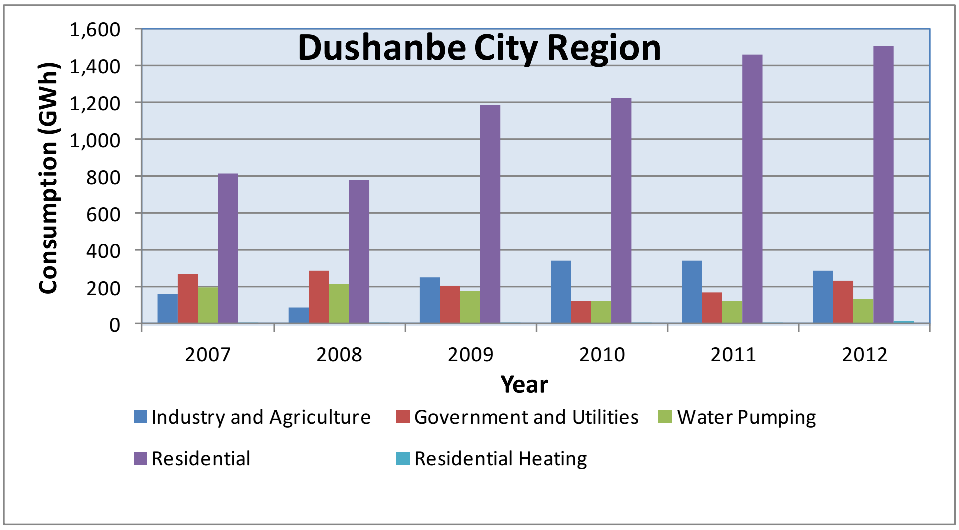

Figure 2-5: Dushanbe Region Consumption by Customer Type

Table 2-5 presents the consumption by customer type from 2007 to 2012 where it is clearly shown that the overall consumption has not grown over the last 6 years. However, a 4% per annum growth was experienced in the residential category and 2% per annum growth was achieved in the industry and water pumping categories and this growth was offset by a decline in the TALCO consumption.

Table 2-5: Consumption by Customer Type

Customer Type	2,007	2,008	2,009	2,010	2,011	2,012
Industry and Agriculture	960	778	845	1,001	1,101	1,066
Government and Utilities	535	548	470	347	426	523
Water Pumping	2,583	2,378	2,397	2,194	2,661	2,853
Residential	3,099	2,906	3,721	4,023	3,938	3,806
Residential Heating	2	1	8	4	8	20
Total without Talco (GWh)	**7,178**	**6,611**	**7,443**	**7,569**	**8,134**	**8,268**
TALCO (GWh)	**7,229**	**7,107**	**6,364**	**6,456**	**5,483**	**5,360**
TOTAL for Country (GWh)	**14,407**	**13,718**	**13,807**	**14,025**	**13,617**	**13,627**

Source: Barki Tojik

Figure 2-6 shows the total consumption in the BT supplied grid from 2007 to 2012. This figure clearly shows that TALCO has the largest consumption followed by residential customers which over the last 6 years have grown from a 22 % share of the total to 28 % in 2012. The third largest customer type is water pumping.

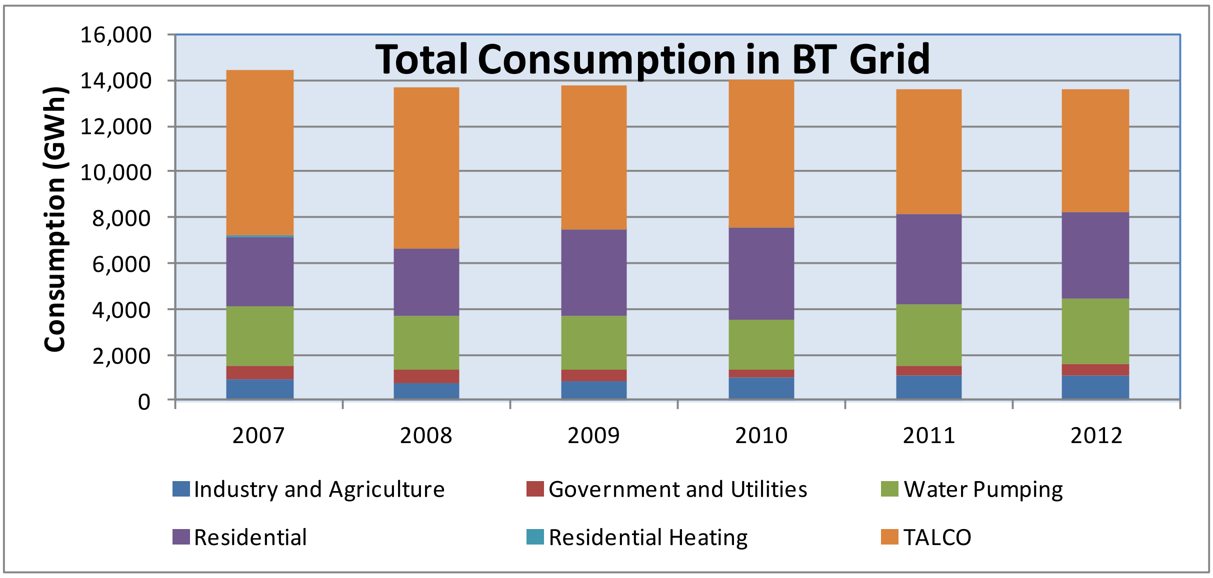

Figure 2-6: Total Consumption by BT Grid

2.5.1 Losses

Based on information provided by BT, transmission system technical losses have been reduced from 8% of supply in 2007 to 4.6% in 2012. This can be explained, in part, by the increased use of 500kV transmission lines instead of 220kV transmission lines but also by additional 220 kV transmission lines being built to reduce transmission congestion and overload. These losses are within the range experienced in various transmission systems.

The values provided by BT indicated that total distribution system losses are of the order of 17% and have remained virtually unchanged since 2007.The net figure (total energy received from transmission minus estimated distribution losses determined by “norms”) provides the amount (kWh) that should be billed.

Table 2-6 presents the system losses from 2007 to 2012 and of notice is the overall percentage losses or system losses which have ranged from 17.7% of supply to 13.1%. Since the approach used to determine the demand forecast is a bottom up type of approach, which implies that the consumption is determined first and then the losses are added, the losses in terms of consumption are more relevant and in this case they have ranged from 21.6% to 15.1%.

Table 2-6: Historical BT System Losses

Item	2007	2008	2009	2010	2011	2012
Supply (GWh)	17,360	16,717	15,897	16,361	15,888	16,085
Consumption (GWh)	14,407	13,718	13,807	14,025	13,617	13,627
Difference (GWh)	2,953	2,999	2,090	2,336	2,272	2,458
Declared Losses (GWh)	2,888	2,964	2,086	2,316	2,257	2,429
% of consumption	20.0	21.6	15.1	16.5	16.6	17.8
% of Supply	16.6	17.7	13.1	14.2	14.2	15.1

Source: BT Data

2.6 UNMET DEMAND

The difficulties of the Tajik power sector over the last years have resulted in a significant amount of unmet or unserved energy (energy that could not be supplied to customers). Over the years there have been several studies stating the estimated amount of unmet energy and these range from 2,650 GWh to 3,789 GWh per season (a season is from the beginning of October to the end of March). The unmet energy is heavily dependent on climatic conditions, the variations of water availability for the hydro power plants to generate electricity and to a smaller extent to the availability of mazout to fire the Dushanbe CHP plant.

Available information from BT and an UNDP report on Sustainable Energy provide values for unmet energy ranging from 2,139 to 2,430 GWh. To use this total annual unmet demand one needs to allocate it to the different customer types. Our information suggests that TALCO is not being curtailed during the winter since it is supplied directly from the transmission system. In determining the allocation of the unmet energy by customer type it was assumed that only half of the government and utilities demand would be affected and since water irrigation is mainly a summer load it was assumed that only 5% of this demand could be faced with curtailments. Residential customers encounter the biggest curtailments with some customers, particularly those in the rural areas having power for only a few hours during the day.

An assumed annual unmet demand of 2,430 GWh was distributed amongst the regions according to their weights in terms of the overall demand used to determine the unmet energy. Table 2-7 shows the results of the distribution where it can be seen that the Dushanbe region accounts for 37% of the total unmet energy and 40% of the total residential unmet demand.

Table 2-7: Distribution of Unmet Energy by Region and By Customer Type

Customer Type	Sughd	Khatlon	RRS	Dushanbe	Total
Industry and Agriculture	224	66	68	131	489
Government and Utilities	23	20	22	54	120
Water Pumping	34	21	7	3	65
Residential	428	360	265	693	1,746
Residential Heating	0	0	0	9	9
Total (GWh)	**709**	**468**	**363**	**890**	**2,430**

2.7 TALCO

The state-owned aluminium company (TALCO) is the largest consumer of electricity in Tajikistan accounting for a large portion of total electricity consumption in various years. The smelter was constructed in the early 1970s in conjunction with the Nurek hydropower plant. TALCO is the largest aluminium plant in Central Asia and the central element in Tajikistan's industrial base.

TALCO's demand has varied from 5,360 GWh to 7,229 GWh per year. This represents 40% to 50% of the total demand with the lower value being experienced in 2012. The lower value was reached during 2012 and may not be representative of the future demand. It is assumed that a value of the order of 6,500 GWh could be more representative of TALCO's future demand prior to efficiency improvements and other demand reduction measures are to be applied.

It is recognized that during the last 2 years, and due to a variety of reasons, TALCO's demand has been considerably curtailed but it is expected that in the very near future TALCO's demand level be returned to its previous levels.

2.8 PEAK DEMAND

BT provided inconsistent monthly peak demand for the years 2008 to 2011 which lead us to disregard those set of values. BT also provided system hourly supply data for the period 2006 to 2011 which when analysed appeared to be consistent. Figure 2-7 shows the monthly peak demand for 2008 to 2011 (data for 2010 was not available for all regions) in which it can be seen that the peak demand occurs either in December or November, with January also having a high demand, and the summer months present lower peaks then the rest of the year.

For the year 2008 the peak demand amounted to 3,490 MW and by 2011 the peak demand had decreased to 3,298 MW. As seen from Figure 2-7, the peak demand in 2008 and 2009 decreased significantly in the month of February and this may be due to large power curtailments.

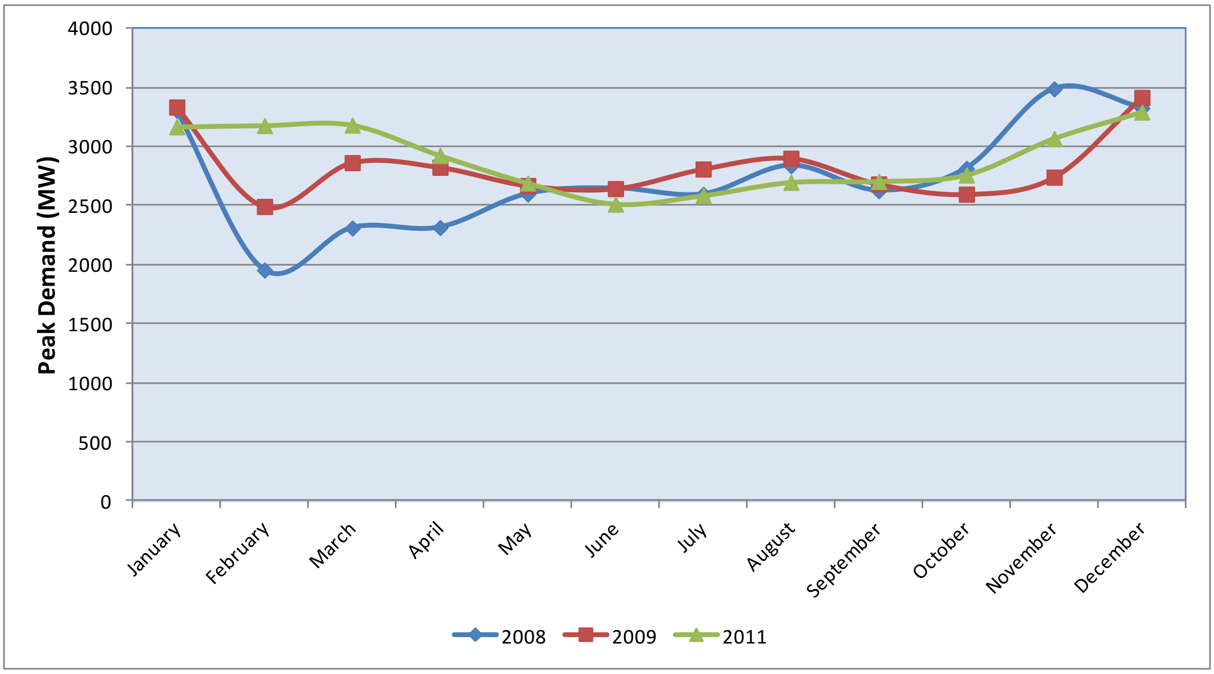

Figure 2-7: Historical Peak Demand

2.9 TRANSMISSION

2.9.1 Barki Tojik Existing Transmission

The BT's grid system consists of transmission lines at three different voltage levels, 500 kV, 220 kV and 110 kV. At present, it includes approximately 489 km of 500 kV lines, 1,960 km of 220 kV lines and 4,327 km of 110 kV lines. The BT transmission system has three substations at 500 kV, 23 substations at 220 kV and 154 substations at 110 kV.

The 500 kV transmission lines include a double circuit between the Nurek HPP and Regar substation, a single circuit between the Regar and Dushanbe substations as well as a single circuit between the Dushanbe and the Sughd substations.

The 220 kV system south of Dushanbe may become constrained following a single contingency. The 220 kV system north of Dushanbe includes a significant amount of irrigation load and is susceptible to low voltages and may be also be susceptible to fault induced delayed voltage recovery.

The 110 kV lines are split into two categories, the first are those that are used for distribution purposes and those that are used for transmission purpose. This adds a level of complexity as all 110 kV lines are terminated into transmission facilities. Distribution faults on those facilities will impact the bulk electric system. If the distribution system that is operated at voltages below 110 kV do not have this impact as faults are isolated from bulk electric system by transformers. Therefore only faults that cause the transformation between the lower voltage levels and the bulk electric system to trip will impact the bulk electric system

Figure 2-8 provides a map showing the high voltage transmission system in Tajikistan for transmission voltages above 220 kV.

2.9.2 Interconnections

All interconnections between the BT and the Uzbek system have been disconnected. The BT's grid system used to be interconnected to the Uzbek network at 500 kV and 220 kV. The 500 kV circuits connected the Regar substation to the Guzar and Surkhan substations in Uzbekistan, two 220 kV circuits connected the Regar substation to Gulcha and to Sherabad respectively and another two 220 kV circuits connected the Sughd substation to the Electricity Networks 20 grid.

This action has impacted the internal operation of the BT bulk electric system as most of the facilities have been planned with these facilities in-service. This requires BT to reinforce areas that have become congested due to this action. It also leaves BT with a long-term planning quandary. If there is a possibility that some or all of these interconnections can be re-energized, then future planning scenarios will have to consider this.

Presently, there are only three main interconnections between Tajikistan and other systems, which are as follows:

- A 220 kV, 53 km long, transmission line connects the Kanibadan substation in Tajikistan to the Aigul-Tash 220 kV substation in Kyrgyzstan
- A 220 kV double-circuit transmission line between Sangtuda (Tajikistan) and Pul-e-Khumri (Afghanistan) which allows Tajikistan to export up to 400 MW to Afghanistan was constructed in 2011
- A 110 kV, 63 km long, single circuit transmission line from Tajikistan to Kunduz in Afganistan.

In addition the CASA 1000 interconnection is expected to be in service by early 2021. This interconnection will require the construction of a 500 kV AC transmission line from Kyrgyzstan to the Sughd 500 kV substation (477 km), the construction of a 500 kV transmission line from the Regar substation to the converter substation atSangtuda (115 km), the construction of two 1,300MW DC converter stations, one at Sangtuda and the other near Nowshera, as well as an HVDC transmission line ± 500 kV from Sangtuda to Afghanistan and Pakistan (800 km).

2.9.3 Barki Tojik Committed Transmission

The perspective transmission system development originally provided to the study team included several projects some of which were associated with the CASA 1000 project and others to the Rogun HPP.

Table 2-8 presents a list of probable committed transmission line projects along with the most probable in-service year. It should be noted that some of these transmission lines could have already been constructed (Dushanbe-1 to Dushanbe-2) or are undergoing construction while others are still waiting for financing.

Table 2-8: List of Committed Transmission Lines

Transmission Project	Probable In Service Year
220 kV Transmission line – 220 kV "Geran-Rumi" including reconstruction of substations "Geran" and "Rumi"	2015
220 kV Transmission line – 220 kV "Kayrakkum HPP – Asht"	2015
Double circuit 220 kV transmission line Dushanbe-1 Dushanbe-2 CHP	2021
220 kV Transmission line Kairakkum to Sughd	2017
Construction of two 110 kV double circuit transmission lines from Dushanbe CHP to existing 110 kV line "Novaya-Severnaya	2014
Shahrinay substation 2 x 220/110/35/10 kV transformers 125 MWA each	2015
Reconstruction of 220 kV switchgear at "Kairakkum HPP"	2017
Construction of 220 kV transmission lines "Ayni-Rudaki"	2017
Reconstruction of 220/35/10 kV Ravshan substation (Tursunzade District) with the replacement of main and auxiliary equipment and construction of new 110 kV switchgear.	2018
Construction of 110/10 kV substation with 2 x 16,000 kV transformers at Kahorov Street, Dushanbe City.	2013
Construction of 110/10 kV substation with 2 x 16,000 kV transformers at Bukhoro Street, Dushanbe City and construction of 110 kV cable.	2013 – 2014
Reconstruction of Regar 500 substation with the replacement of 2 x 500/220/35 kV transformers 2x3x267 MVA	2013 – 2014
Construction of 220/110/10 kV "Bahoriston" substation in Sughd Region with 2 x 125 MVA transformers with decoupled outlet to existing 110-220 kV lines.	2020
Construction of two 110 kV/10kV substations in Khujan	2013 -2014
Construction of 220/110/10 kV Sayhun Substaion in Khujand City	2022
Construction of 220 kV Switchyard Dushanbe CHP	2021
Construction of 220 kV transmission line and 220 kV Substation to supply the Dangara free economic zone	2018

2.9.4 Pamir Energy

The Pamir Energy Electrical system is composed of several HPPs and distribution lines using 35 kV and 10 kV voltage levels.

Evacuation of power from the power plants to the demand centres is done using distribution lines either rated 35 kV or 10 kV. The 35 kV distribution level lines are mounted either on double circuit steel towers or on single circuit wood poles. The region is connected to BT's Khatlon (south) region through a long 35 kV line with limited transfer capability and the major load centres are not connected to each other due to distance and load level.

In addition to this, the Pamir Energy system is also interconnected with the Afghanistan distribution system, and could therefore be used to provide electricity to Afghanistan.

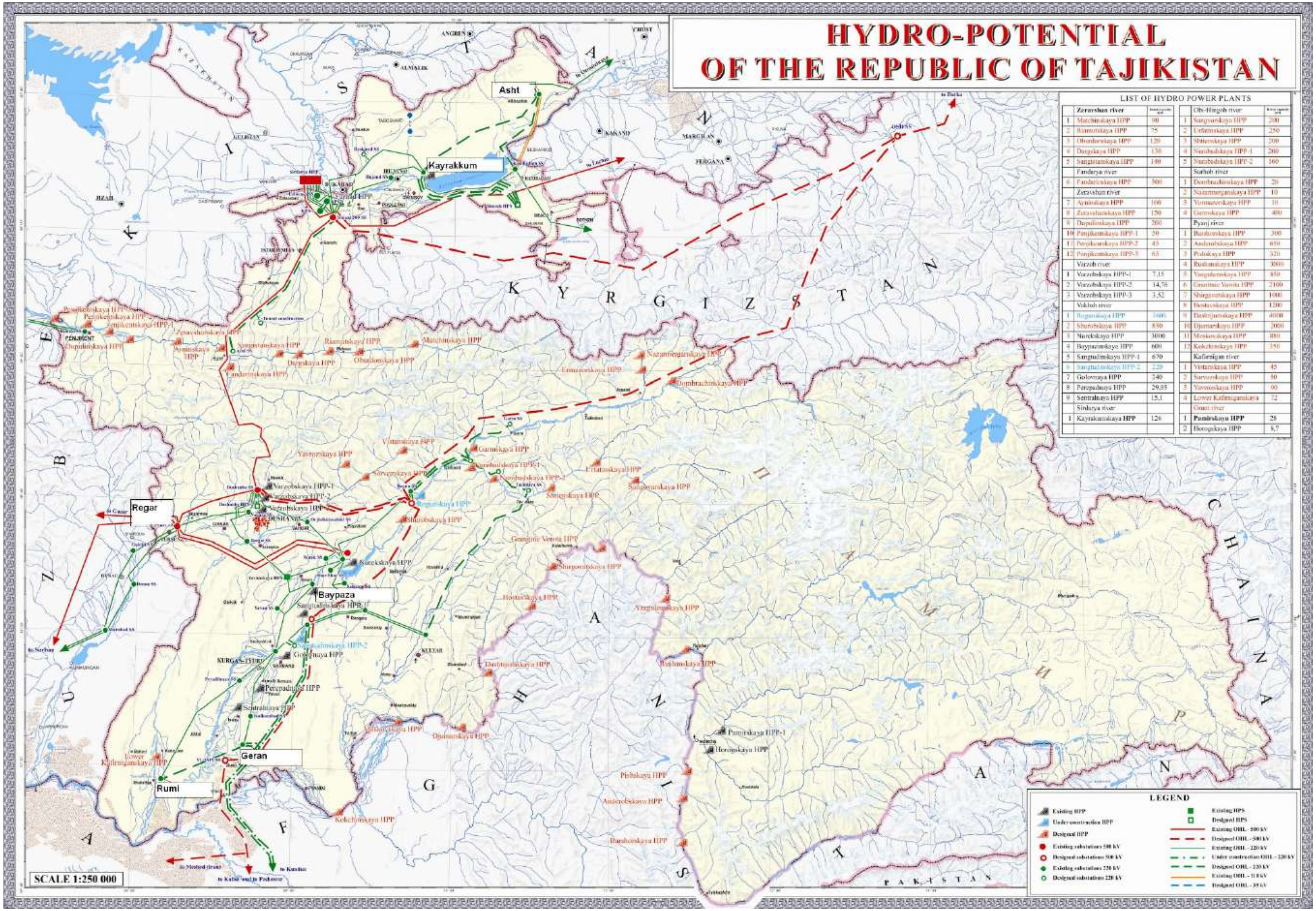

Figure 2-8: Simplified Transmission Map

3. ELECTRICITY DEMAND AND SUPPLY

This section introduces the approach and methodology used to arrive at the demand forecast under the base or medium forecast as well as for the low and high growth forecasts, derives the forecasts and presents the short term energy and capacity balance including the energy efficiency projects and firm energy exports.

3.1 INTRODUCTION

Load forecasting is a critical element of electric power utility planning. The purpose of any form of load forecasting is to estimate the most likely future level of demand to serve as the basis for supply planning. This includes the planning of distribution and transmission facilities as well as the construction and operation of existing and new generation plant.

Load forecasting also extends beyond the system planning level into revenue analysis and financial planning. In the overall planning framework, the results of the financial analysis, particularly the implied tariff levels required to support the development plan, should be used where possible to adjust the load forecast to the extent required, and then check whether there is a need to modify the expansion plan.

The principal objective of the current study is to apply a number of analytical techniques to adjust and project the historical energy consumption statistics to the end of the study period. This process determines the expected demand at each of the major supply points on the Tajik electrical system.

This report section summarizes the studies described in Demand Forecast Report and for reasons outlined in Section 4 extends the forecasts to 2039 by assuming the same load growth levels as those in the period of 2028 to 2032.

3.2 APPROACH

The demand forecast methodology/approach selected to obtain the required forecast for any particular system, is generally dependent on the quality and availability of the input data. The availability of historical data plays a key role in the methodology to be used and the subsequent forecast results, with the understanding that the availability of longer periods of accurate historical data typically yields better forecasts.

The demand forecast presented in the Demand Forecast Report considered unmet/unserved demand but not the application of energy efficiency measures outside of those assumed for TALCO. The effect of energy efficiency measures on the demand forecasts are incorporated into the forecast presented in this section.

Due to the fact that the usual approaches cannot be applied straightforwardly, several other studies have recommended that a modified approach be used for load forecasting and the project team concurs with this approach. The proposed approach is based on the concept of econometric modelling but it avoids the need to apply historical data.

The approach uses the links between explanatory and target parameters, as is the case in an econometric analysis. However, it does not base the actual values of the explanatory parameters on (regression) calculations, but on estimates and assessments that are put together from experience gained in other countries. Moreover, the approach is confined to two main explanatory variables, which are the development of the GDP and the development of the price of electricity. The link is then established through the (estimated) demand elasticity and the (estimated) price elasticity for electricity (in real terms).

Based on the above approach, future annual growth of electricity demand was obtained by multiplying the expected future annual growth rate of GDP by its demand elasticity for that specific year and adjusting it for a possible decrease in consumption resulting from an increase in the tariff. The impact of the latter effect depends on the assumptions for price elasticity.

As previously mentioned, the unserved demand has to be considered in the analysis. For this purpose, the consumption in the base year to which the percentage increases are applied has to be increased by the estimated value of unserved energy to obtain the “actual” demand.

The BT grid forecast was obtained following the approach described above and to this the effect of the energy efficiency measures were applied which resulted in a reduction of the demand. In addition, the PPA requirements for the CASA 1000 and the existing PPAs for firm energy were added to obtain an overall demand for the BT grid.

In order to determine the robustness of the base or medium growth forecast, the project team developed two additional forecast scenarios; low and high. The actual demand is expected to be within the range given by the high and low scenarios.

Details of the model parameters and assumptions are presented in the Demand Forecast Report and a summary of the main parameters is given below in Table 3-1to Table 3-5. The unserved energy for 2012 was assumed to be 2,700 GWh

Table 3-1: GDP Growth Rates

Period	Base Case	High Growth	Low Growth
2014-2018	6.0%	7.0%	5.0%
2019-2024	6.0%	7.0%	5.0%
2025-2032	5.0%	5.0%	4.5%

Table 3-2: Estimated Tariff Increases

Demand Scenario	Base Growth		High Growth		Low Growth	
Period	**Increase (%,p.a.)**	**Tariff (¢/KWh)**	**Increase (%,p.a.)**	**Tariff (¢/KWh)**	**Increase (%,p.a.)**	**Tariff (¢/KWh)**
2014-2016	10.3		8.2		13.9	2.5
2017	10.3	2.5	8.2		8.0	
2018	7.2		8.2	2.5	8.0	
2019-2027	7.2	5.0	6.5	4.4	8.0	5.8
2028-2032	0	5.0	0	4.4	0	5.8

Table 3-3: Income and Price Elasticities

Customer Type	Income Elasticity	Price Elasticity
Industry and Agriculture	0.90	0
Government and Utilities	0.70	-0.30
Water Pumping	0.50	-0.15
Residential	0.90	-0.20
Residential Heating	0.90	-0.20
TALCO	0	0

Table 3-4: Assumed Loss Level

Year	Loss Level (%)
2014	16.8
2015	15.9
2016	15.0
2017	14.6
2018	14.2
2019	13.8
2020	13.0

Table 3-5: TALCO's Demand with Energy Efficiency Measures

Year	Demand (GWh)
2014	6,280
2015	6,060
2016	5,850

3.3 Main Grid Demand Forecast Without Energy Efficiency

Demand forecasts developed by others and reviewed as part of this assignment did not include the addition of large energy consuming projects that are likely to be added to the grid in the future. These other forecasts just considered organic growth.

In the present analysis, it was recognized, at an early stage, that the forecast should incorporate the most likely new "large" projects requiring electricity supply. For ease of identification these projects were called "Spot Loads". Discussions were held with both the Ministry of Energy and Industry (MoEI) and BT to arrive at consistent lists of new large projects. As a result of this process thirteen "large" projects were identified for implementation up to 2020 with a total demand of 1,160 GWh.

3.3.1 Medium or Base Demand Forecast

The main grid forecast under medium or base conditions is shown in Table 3-6 for the main grid by customer type for selected representative years including losses. Table 3-7 presents the medium forecast by region and customer type for each planning horizon year. The main grid demand is expected to grow from 21,963GWh (including unserved energy) in 2015 to over 39,000 GWh by 2039. The average growth is 2.4%. The growth for the four regions together during the study period is expected to be of the order of 3.5% and the difference in percentage growth is simply due to the fact that TALCO's demand is stagnant over the study period.

The forecast for the main grid by region is illustrated graphically in Figure 3-1.

Table 3-6: Main Grid Forecast by Customer Type (GWh)

Customer Type	2015	2020	2025	2030	2039
Industry and Agriculture	1,901	2,473	3,190	3,975	5,732
Government and Utilities	704	765	840	957	1,198
Water Pumping	3,117	3,397	3,718	4,118	4,902
Residential	6,521	7,825	9,420	11,417	15,809
Residential Heating	35	42	51	61	85
Regions Subtotal (GWh)	12,280	14,503	17,218	20,529	27,726
TALCO	6,060	5,850	5,850	5,850	5,850
Spot Loads	610	1,161	1,161	1,161	1,161
Losses	3,013	2,797	3,150	3,580	4,516
Total Main Grid (GWh)	21,963	24,311	27,379	31,120	39,253

Growth (% per annum)	2015-39	2015-20	2015-25	2020-30	2025-39
Regions (no Losses)	3.5%	3.4%	3.4%	3.5%	3.5%
Main Grid	2.4%	2.1%	2.2%	2.5%	2.6%

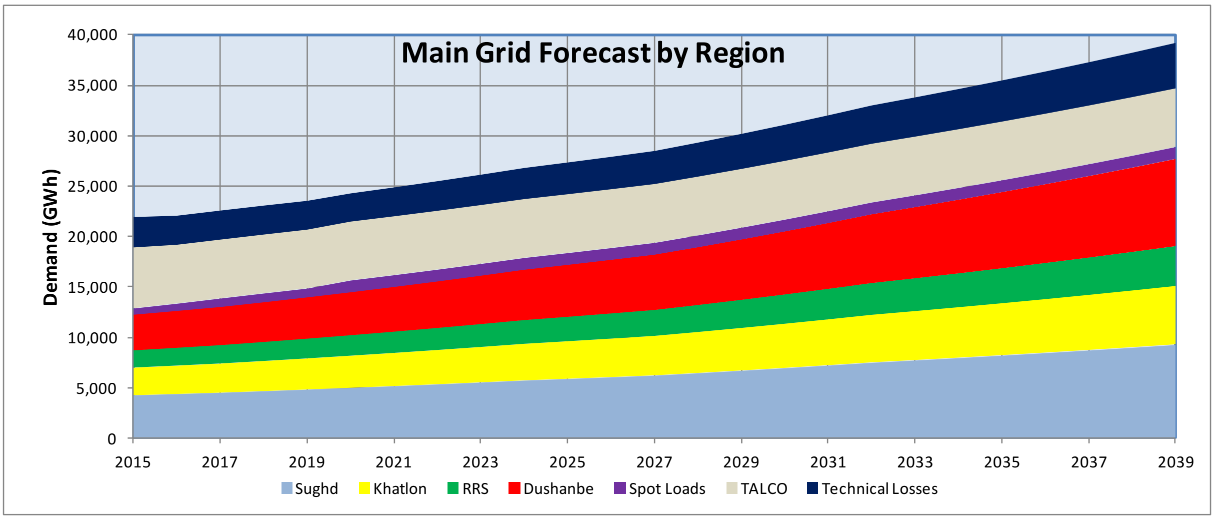

Figure 3-1: Main Grid Forecast by Region

As can be seen from Figure 3-1 the regions with the largest demand are Sughd and Dushanbe, with Sughd always having a higher demand. The figure also demonstrates the relative importance of TALCO's demand and over time its relative share of the total demand is expected to decrease.

From Table 3-6 it can be observed that by 2039, the residential customers will require the largest demand followed by TALCO and industry and agriculture.

Table 3-7: Main Grid Forecast Including TALCO, Spot Loads and Losses

Main Grid Demand Including TALCO, Spot Loads and Losses

Customer Type	Annual Consumption Demand (GWh)																								
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Industry and Agriculture	1,901	2,004	2,112	2,226	2,347	2,473	2,607	2,748	2,896	3,052	3,190	3,333	3,483	3,640	3,804	3,975	4,154	4,341	4,517	4,700	4,890	5,088	5,294	5,508	5,732
Government and Utilities	704	712	720	735	750	765	780	796	813	829	840	852	863	893	924	957	990	1,025	1,048	1,072	1,096	1,120	1,146	1,171	1,198
Water Pumping	3,117	3,163	3,209	3,270	3,333	3,397	3,462	3,529	3,597	3,666	3,718	3,771	3,824	3,920	4,018	4,118	4,221	4,327	4,405	4,484	4,565	4,647	4,730	4,815	4,902
Residential	6,521	6,739	6,964	7,240	7,527	7,825	8,135	8,457	8,792	9,140	9,420	9,708	10,005	10,455	10,926	11,417	11,931	12,468	12,898	13,343	13,803	14,280	14,772	15,282	15,809
Residential Heating	35	36	37	39	41	42	44	46	47	49	51	52	54	56	59	61	64	67	69	72	74	77	80	82	85
Subtotal	12,280	12,655	13,043	13,511	13,997	14,503	15,028	15,576	16,145	16,737	17,218	17,716	18,229	18,965	19,731	20,529	21,361	22,228	22,937	23,670	24,428	25,212	26,022	26,860	27,726
TALCO	6,060	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850
Spot Loads	610	711	835	868	868	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161
Total	**18,950**	**19,216**	**19,728**	**20,229**	**20,715**	**21,514**	**22,040**	**22,587**	**23,156**	**23,748**	**24,230**	**24,727**	**25,241**	**25,976**	**26,742**	**27,540**	**28,372**	**29,239**	**29,948**	**30,681**	**31,439**	**32,223**	**33,033**	**33,871**	**34,737**
Region	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Sughd	4,219	4,344	4,474	4,629	4,789	4,956	5,130	5,311	5,499	5,695	5,856	6,022	6,193	6,430	6,677	6,934	7,202	7,481	7,711	7,950	8,196	8,451	8,714	8,986	9,267
Khatlon	2,720	2,795	2,872	2,967	3,065	3,167	3,272	3,381	3,495	3,613	3,708	3,805	3,906	4,056	4,212	4,374	4,543	4,719	4,860	5,006	5,156	5,312	5,473	5,638	5,809
RRS	1,740	1,794	1,850	1,917	1,987	2,060	2,136	2,215	2,297	2,383	2,453	2,524	2,599	2,705	2,816	2,932	3,053	3,179	3,282	3,388	3,498	3,612	3,730	3,852	3,977
Dushanbe	3,601	3,722	3,847	3,998	4,155	4,319	4,490	4,668	4,853	5,045	5,202	5,364	5,532	5,773	6,025	6,288	6,563	6,850	7,084	7,326	7,577	7,837	8,106	8,384	8,672
Subtotal	12,280	12,655	13,043	13,511	13,997	14,503	15,028	15,576	16,145	16,737	17,218	17,716	18,229	18,965	19,731	20,529	21,361	22,228	22,937	23,670	24,428	25,212	26,022	26,860	27,726
TALCO	6,060	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850
Spot Loads	610	711	835	868	868	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161
Total	**18,950**	**19,216**	**19,728**	**20,229**	**20,715**	**21,514**	**22,040**	**22,587**	**23,156**	**23,748**	**24,230**	**24,727**	**25,241**	**25,976**	**26,742**	**27,540**	**28,372**	**29,239**	**29,948**	**30,681**	**31,439**	**32,223**	**33,033**	**33,871**	**34,737**
Technical Losses	15.9%	15.0%	14.6%	14.2%	13.8%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%
Technical Losses (GWh)	3,013	2,882	2,880	2,872	2,859	2,797	2,865	2,936	3,010	3,087	3,150	3,215	3,281	3,377	3,476	3,580	3,688	3,801	3,893	3,989	4,087	4,189	4,294	4,403	4,516
Electricity Required by the System (GWh)	**21,963**	**22,098**	**22,608**	**23,101**	**23,574**	**24,311**	**24,905**	**25,523**	**26,166**	**26,835**	**27,379**	**27,942**	**28,522**	**29,353**	**30,218**	**31,120**	**32,060**	**33,040**	**33,841**	**34,670**	**35,526**	**36,412**	**37,328**	**38,274**	**39,253**
Peak Demand																									
System Load Factor	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
TALCO Load Factor	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Spot Loads	81%	81%	81%	81%	81%	81%	81%	81%	81%	81%	81%	81%	81%	81%	81%	81%	81%	81%	81%	81%	81%	81%	81%	81%	81%
Region's Load Factor	50%	50%	50%	51%	51%	51%	51%	52%	52%	52%	52%	52%	53%	53%	53%	53%	54%	54%	54%	54%	54%	54%	55%	55%	55%
Talco Peak Demand (MW)	818	784	781	778	775	770	770	770	770	770	770	770	770	770	770	770	770	770	770	770	770	770	770	770	770
Spot Loads (MW)	99	115	134	140	139	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185
System Peak Demand (MW	**4,179**	**4,204**	**4,301**	**4,395**	**4,485**	**4,625**	**4,738**	**4,856**	**4,978**	**5,106**	**5,209**	**5,316**	**5,427**	**5,585**	**5,749**	**5,921**	**6,100**	**6,286**	**6,439**	**6,596**	**6,759**	**6,928**	**7,102**	**7,282**	**7,468**

Annual Growth - Supply Without TALCO & Spot Loads

2015-20	2.5%	2020-25	3.4%	2025-39	3.5%	2015-39	3.3%	2030-39	3.6%
		2015-2025	3.0%	2020-39	3.5%				

Annual Growth - Supply With TALCO & Spot Loads

2015-20	2.1%	2020-25	2.4%	2025-39	2.6%	2015-39	2.4%	2030-39	2.6%
		2015-2025	2.2%	2020-30	2.5%				

The main grid peak demand forecast is shown in Figure 3-2 and is expected to reach close to 7,500 MW by 2039 or an increase of some 3,290 MW with respect to that in 2015.

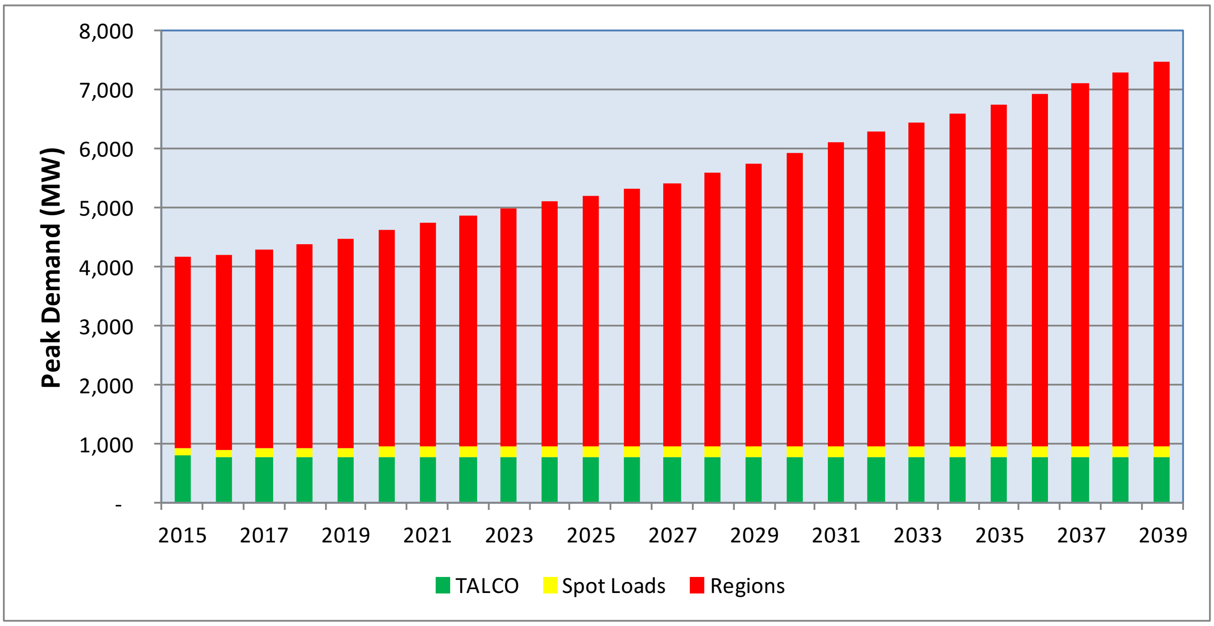

Figure 3-2: Peak Demand for the Main Grid

3.3.2 High and Low Demand Forecasts

In order to determine the medium forecast robustness to changes in the principal parameters, a sensitivity analysis was carried out. The two key variables in the approach used are the GDP and the tariff price.

Two demand growth scenarios were considered:

- A low growth scenario with decreased GDP and increased tariff rises
- A high growth scenario with increased GDP and decreased tariff rises

With the approach used, a higher GDP growth implies a greater percentage change in the growth while a decreased tariff rise implies a smaller decrease in the growth.

The main grid forecast under high growth conditions is presented in Table 3-8 and as shown the main grid demand is expected to grow from 22,276 GWh (including unserved energy) in 2015 to over 48,000 GWh by 2039. The average growth is 3.3%. The growth for the four regions together during the study period is expected to be of the order of 4.4%.

The main grid forecast under low growth conditions is presented in Table 3-9 and shown the main grid demand is expected to grow from 22,276 GWh (including unserved energy) in 2015 to over 35,000 GWh by 2039. The average growth is 2.0%. The growth for the four regions together during the study period is expected to be of the order of 3.0%.

Table 3-8: Main Grid High Growth Forecast

Customer Type	2015	2020	2025	2030	2039
Industry and Agriculture	1,934	2,625	3,533	4,595	7,159
Government and Utilities	723	824	946	1,119	1,554
Water Pumping	3,168	3,562	4,015	4,567	5,852
Residential	6,689	8,455	10,698	13,574	20,927
Residential Heating	36	46	58	73	111
Regions Subtotal (GWh)	12,550	15,510	19,249	23,928	35,604
TALCO	6,060	5,850	5,850	5,850	5,850
Spot Loads	610	1,161	1,161	1,161	1,161
Losses	3,056	2,928	3,414	4,022	5,540
Total Main Grid (GWh)	22,276	25,449	29,674	34,962	48,155

Growth (% per annum)	2015-39	2015-20	2015-25	2020-30	2025-39
Regions (no Losses)	4.4%	4.3%	4.4%	4.4%	4.5%
Main Grid	3.3%	2.7%	2.9%	3.2%	3.5%

Table 3-9: Main Grid Low Growth Forecast

Customer Type	2015	2020	2025	2030	2039
Industry and Agriculture	1,853	2,310	2,866	3,495	4,847
Government and Utilities	684	715	752	838	1,082
Water Pumping	3,039	3,214	3,419	3,733	4,483
Residential	6,265	7,145	8,207	9,703	13,456
Residential Heating	34	38	44	52	72
Regions Subtotal (GWh)	11,875	13,421	15,288	17,821	23,940
TALCO	6,060	5,850	5,850	5,850	5,850
Spot Loads	610	1,161	1,161	1,161	1,161
Losses	2,949	2,656	2,899	3,228	4,024
Total Main Grid (GWh)	21,495	23,089	25,199	28,061	34,975

Growth (% per annum)	2015-39	2015-20	2015-25	2020-30	2025-39
Regions (no Losses)	3.0%	2.5%	2.6%	2.9%	3.3%
Main Grid	2.0%	1.4%	1.6%	2.0%	2.4%

Table 3-10 presents a summary of the energy demand forecasts for the main grid for the three growth scenarios studied. By the end of the study period the main grid forecasts show a difference between the medium growth forecast and the low growth forecast of 4,278 GWh and a difference of 8,902 GWh between the medium growth and high growth forecast. The comparison of main grid energy forecasts is shown graphically in Figure 3-3.

Table 3-10: Comparison of Main Grid Energy Forecasts (GWh)

Growth Scenario	2015	2020	2025	2030	2039
Low	21,507	23,089	25,199	28,061	34,975
Medium	21,963	24,311	27,379	31,120	39,253
High	22,276	25,449	29,674	34,962	48,155

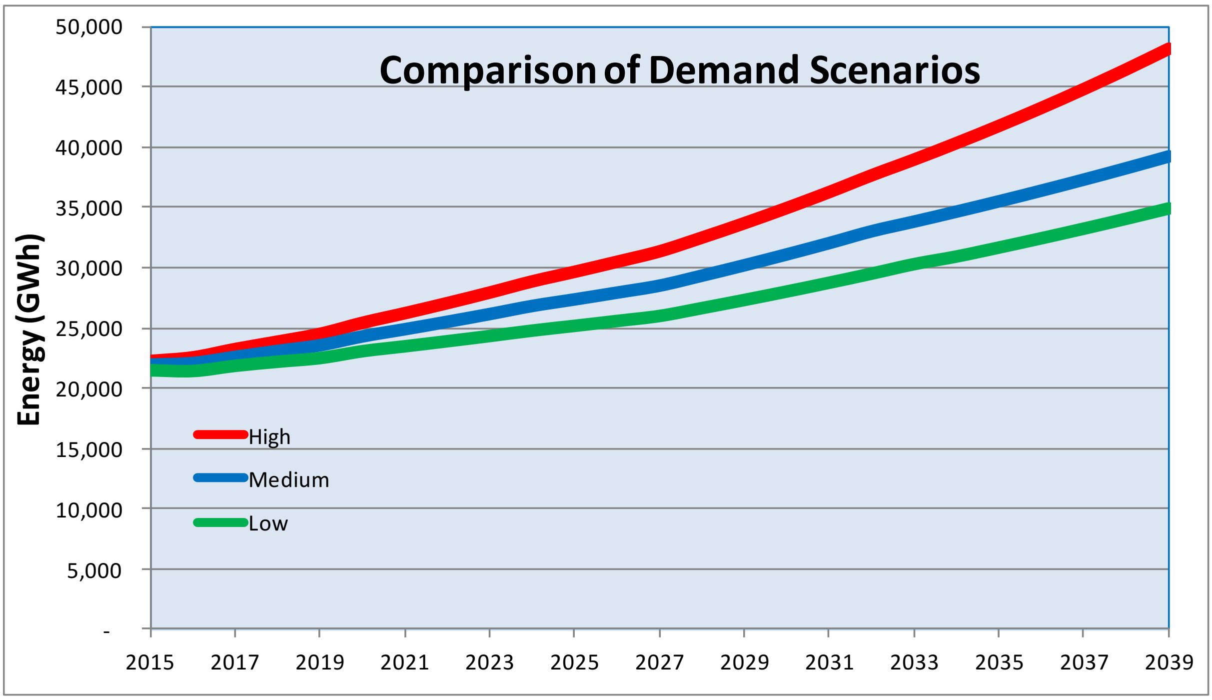

Figure 3-3: Comparison of Growth Scenarios Forecasts

Table 3-11 presents a summary of the peak demands for the three growth scenarios under study. By the end of the study period the difference in peak demand between the medium growth forecast and the low growth forecast is 814 MW while that between the medium and high growth is 1,694 MW.

Table 3-11: Comparison of Main Grid Peak Demand (MW)

Growth Scenario	2015	2020	2025	2030	2039
Low	4,090	4,393	4,794	5,339	6,654
Medium	4,179	4,625	5,209	5,921	7,468
High	4,238	4,842	5,646	6,652	9,162

3.4 Gorno Badakhshan Demand Forecast

Table 3-12 presents a summary of the energy demand forecast for the GBD region for three growth scenarios. Under the medium growth scenario, an expected demand of 235.9 GWh, in 2015, could reach 521.1 GWh by 2039 which represents an annual growth of 3.4%. The growth rates are expected to be the largest after 2027 which coincides with the start of no tariff increases.

For the low growth scenario, the expected demand is likely to reach 438.2 GWh by 2039 and have an average annual growth of 2.8% for the period 2015 to 2039. For the high growth scenario, the expected demand is likely to reach 643.8 GWh by 2039 and have an average annual growth of 4.2% for the period 2015 to 2039.

Table 3-12: Summary of Energy Requirements for GBD

Growth Scenario	2015	2020	2025	2030	2039
Low	228.1	249.6	280.6	323.8	438.2
Medium	235.9	269.3	316.1	372.5	521.1
High	240.9	287.4	351.8	431.0	643.8

Growth(%per annum)	2015-39	2015-20	2015-25	2020-30	2025-39
Low	2.8%	1.8%	2.1%	2.6%	3.2%
Medium	3.4%	2.7%	3.0%	3.3%	3.6%
High	4.2%	3.6%	3.9%	4.1%	4.4%

3.5 LOAD CURVES AND MONTHLY DISTRIBUTIONS

Load duration curves (LDCs) are used by the generation planning software to determine the energy production of each generator or power plant. A load duration curve represents the variation of the load over a certain time period and usually arranges all the load levels in a descending order of magnitude.

Hourly demand values were provided by BT for a period between January 2006 and September 2012 but only the values for 2008 through to 2011 were used. For a variety of reasons some of monthly load duration curves had to be modified and adjusted.

Figure 3-4 presents the adjusted monthly LDCs for January and November as well as the original LDCs for April and August. The four curves appear to be normal and without unreasonable decreases in demand and low minimums.

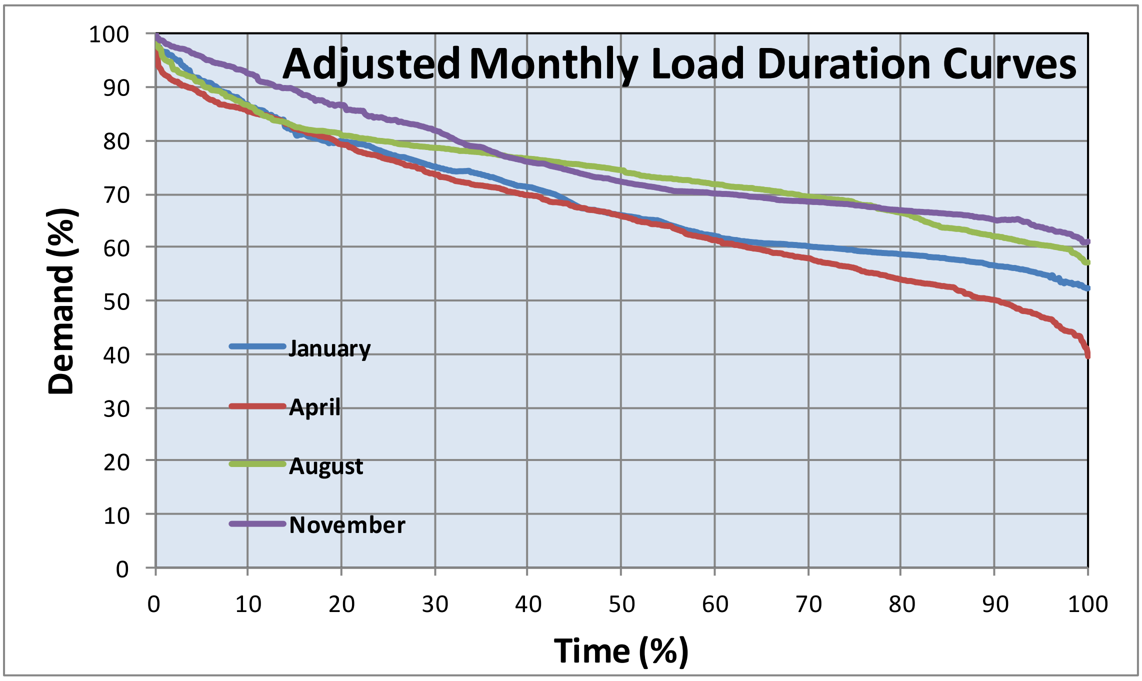

Figure 3-4: Adjusted Monthly LDCs

In addition to the monthly LDCs, the generation planning software also requires the monthly distributions of peak demand and energy so that it can convert the annual values into monthly values.

The monthly capacity distribution used in the study by the generation planning software was arrived at taking into account the monthly capacities for 2009 and 2011 after adjustment for the unserved energy and this tended to decrease the peaks for the summer period and increase those of the winter period.

Table 3-13 presents the monthly capacity and energy distribution. The peak demands consider that the system has a peak in December but January's demand is almost as high. The demand is expected to decrease from February to June but due to irrigation and possibly refrigeration/air conditioning it is likely to increase for the rest of the year. The adjusted monthly energies consider the unserved energy and its associated losses. The table indicates the maximum monthly energy is required in December and February and this is probably due to heating requirements. The energy requirements after January tend to decrease with a rise in July and August probably due to the irrigation and air conditioning/refrigeration demand.

Table 3-13: Monthly Distribution of Energy and Capacity

Month	Energy (% of annual)	Demand (% of peak)
January	10.0	98
February	8.5	95
March	8.5	92
April	7.7	85
May	7.5	80
June	7.4	77
July	8.1	80
August	8.2	80
September	7.5	80
October	7.5	85
November	8.9	90
December	10.2	100
Total/Max	100.0	100

3.6 Demand with Energy Efficiency and Firm Exports

The previous sections presented the demand forecast without energy efficiency and without the firm export commitments under the two existing PPAs as well as the firm exports when the CASA 1000 interconnection comes on line.

Energy efficiency is considered as a generation resource and as such is addressed in Section 5 but can be taken into account by reducing the demand by the levels indicated in that section. The economic viability of energy efficiency is also addressed in the section dealing with generation expansion plans to verify if this measure is worth pursuing.

The existing PPAs require an annual firm energy of 681.5 GWh and Tajikistan share of the contracted firm export under CASA 1000 amounts to 1,331 GWh per year.

Table 3-14 presents the demand forecasts, under three growth scenarios, considering the potential effects of the energy efficiency programs and the firm exports required under the existing PPAs as well as those under the CASA 1000 project. The growth rates are similar to those calculated for the forecasts without energy efficiency projects and without form exports.

Figure 3-5 shows the comparison of the three forecasts graphically. The energy efficiency projects are expected to end by 2037 and this can be seen in the curves for the medium and low growth forecasts.

Table 3-14: Main Grid Forecasts with Energy Efficiency and Firm Exports

Medium Growth			Low Growth			High Growth		
Year	Peak (MW)	Energy (GWh)	Year	Peak (MW)	Energy (GWh)	Year	Peak (MW)	Energy (GWh)
2015	4,184	22,645	2015	4,095	22,176	2015	4,243	22,958
2016	4,209	22,780	2016	4,084	22,119	2016	4,301	23,263
2017	4,232	22,987	2017	4,092	22,250	2017	4,359	23,653
2018	4,318	23,940	2018	4,148	23,048	2018	4,467	24,725
2019	4,358	24,240	2019	4,157	23,186	2019	4,540	25,198
2020	4,494	24,867	2020	4,261	23,645	2020	4,710	26,006
2021	4,602	25,324	2021	4,334	23,917	2021	4,857	26,665
2022	4,720	25,943	2022	4,415	24,339	2022	5,016	27,501
2023	4,842	26,586	2023	4,497	24,774	2023	5,183	28,377
2024	4,969	27,255	2024	4,583	25,223	2024	5,358	29,297
2025	5,073	27,799	2025	4,658	25,618	2025	5,510	30,094
2026	5,180	28,361	2026	4,735	26,025	2026	5,667	30,924
2027	5,298	28,980	2027	4,822	26,482	2027	5,839	31,827
2028	5,464	29,856	2028	4,955	27,181	2028	6,065	33,011
2029	5,663	30,902	2029	5,119	28,040	2029	6,327	34,388
2030	5,835	31,804	2030	5,253	28,744	2030	6,566	35,645
2031	6,014	32,744	2031	5,392	29,476	2031	6,817	36,966
2032	6,200	33,724	2032	5,536	30,234	2032	7,081	38,355
2033	6,353	34,525	2033	5,669	30,934	2033	7,330	39,660
2034	6,510	35,353	2034	5,807	31,658	2034	7,589	41,024
2035	6,673	36,210	2035	5,949	32,406	2035	7,861	42,451
2036	6,842	37,095	2036	6,097	33,179	2036	8,144	43,942
2037	7,016	38,011	2037	6,249	33,978	2037	8,441	45,502
2038	7,287	39,606	2038	6,497	35,452	2038	8,842	47,781
2039	7,473	40,584	2039	6,659	36,307	2039	9,167	49,487

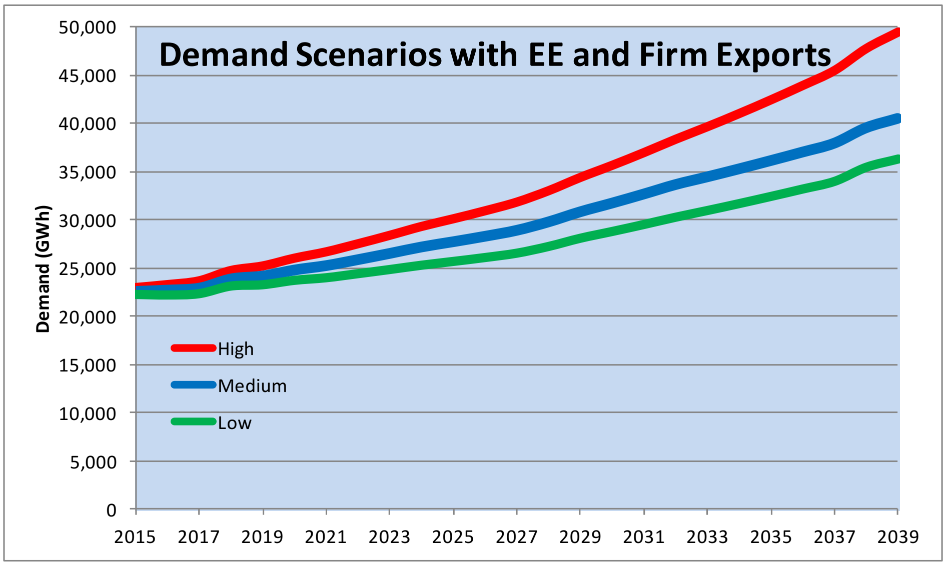

Figure 3-5: Comparison of Forecasts with Energy Efficiency and Firm Exports

3.7 SHORT TERM DEMAND AND SUPPLY SITUATION

By examining the capacity and energy balances or deficits obtained it is possible to determine the extent of the surplus or shortages and the timing and size of the required new generation additions. Since the Tajik system is hydro dominated and hence energy constrained, the balance is only carried out for energy since in this type of systems there is usually an over installation of capacity.

Based on the demand forecast, taking into account energy efficiency projects and firm exports, and the available supply, the energy balance was carried out on a monthly basis for the BT supplied system for the period from 2015 to 2018 using both the firm (95% probability of exceedance) and average hydro energy. Both of these energies are presented in the Tables in Appendix B. The monthly capacity and energy demands were determined by multiplying the annual values by the monthly percentages outlined in section 3.5.

The firm hydro energy was used to ensure that the system demand can be supplied with a certain degree of reliability. It should be noted that the firm energy is less than the average energy which will cause the surpluses to be decreased and the deficits to be increased.

The energy balance considered that the Dushanbe – 1 CHP could operate at 198 MW output during the winter months and the Dushanbe – 2 two first units would also operate during the winter months. Due to the lack of fuel the Yavan CHP was not considered to be able to operate. The Dushanbe – 2 plant is to comprise 2x50 MW units and 2x150 MW units. The 2x150 MW units were assumed to be commissioned by October 2016 and December 2016 respectively.

In addition, there are advanced discussions with independent power producers (IPPs) regarding the construction of several coal fired units. For the present study it was assumed that these would be 150 MW and 350 MW units. The 150 MW units would be located at Shurob. The 350 MW units would be located at Fon Yagnob.

All CHP units are considered to operate from October to the end of March with a plant factor of 75%. Other coal units are assumed to be available to operate throughout the year with a capacity factor of 75%.

Table 3-15 and Table 3-16 present the energy balance for the BT system for the year 2015 under firm and average hydrological conditions. The expected peak demand is 4,184 MW in December and the largest monthly energy demand is 2,243 GWh also in December.

As shown in Table 3-15, under firm hydrological conditions, ten out of the 12 months show deficits in energy (unsupplied) with the largest deficit being encountered in April amounting to 794 GWh or close to 45% of the demand for that month. The total unserved energy for 2015 is 6,017 GWh. The table also shows that only two months (July and August) with a total surplus of 913 GWh.

Under average hydrological conditions eight out of 12 months show energy deficits with the largest being April with a deficit of 632 GWh. The total unserved energy in this case is 4,675 GWh and from June to September there is a surplus of 3,205 GWh.

As with most energy constrained systems, the system appears to have the required capacity but lacks the energy to meet the demand. The results presented in Table 3-15 and Table 3-16 clearly indicate that the system has peaking capability but lacks base load plants of the order of 1000 MW to supply the unserved demand in the winter period.

A similar exercise was carried out for 2016 to 2018 and the monthly energy balance results are presented in Figure 3-6. As can be observed, the maximum demand period occurs during the lower generation months and this tends to produce the large energy deficits in the winter months.

Figure 3-6 shows a slowly increasing demand as can be seen by comparing the starting and end values and also an almost steady supply capability between 2015 and the autumn of 2016 with the increase being noticeable in 2017due to the addition of the Dushanbe – 2 CHP units.

From 2015 to 2017, the unserved energy is of the order of 5,500 GWh under firm hydrological conditions and 4,200 GWh under average hydrological conditions. This is expected to decrease significantly once the committed plants and those under discussion come in service.

From Figure 3-6 it is clear that the system needs firm energy additions as soon as possible in the form of generating units. There are generating units that can be brought into service in a very short time (six months), however, their cost is quite high. It is estimated that in order to eliminate the unserved energy shown in Figure 3-6, new generation with a capability of the order of 500 MW or more (in addition to the committed generation and that under discussion) would be needed to be built. As the lead time to bring in additional capacity is long, the BT system could be faced with severe energy shortages in the short term unless very favourable hydrology conditions are encountered during the winter months or energy can be imported from other systems.

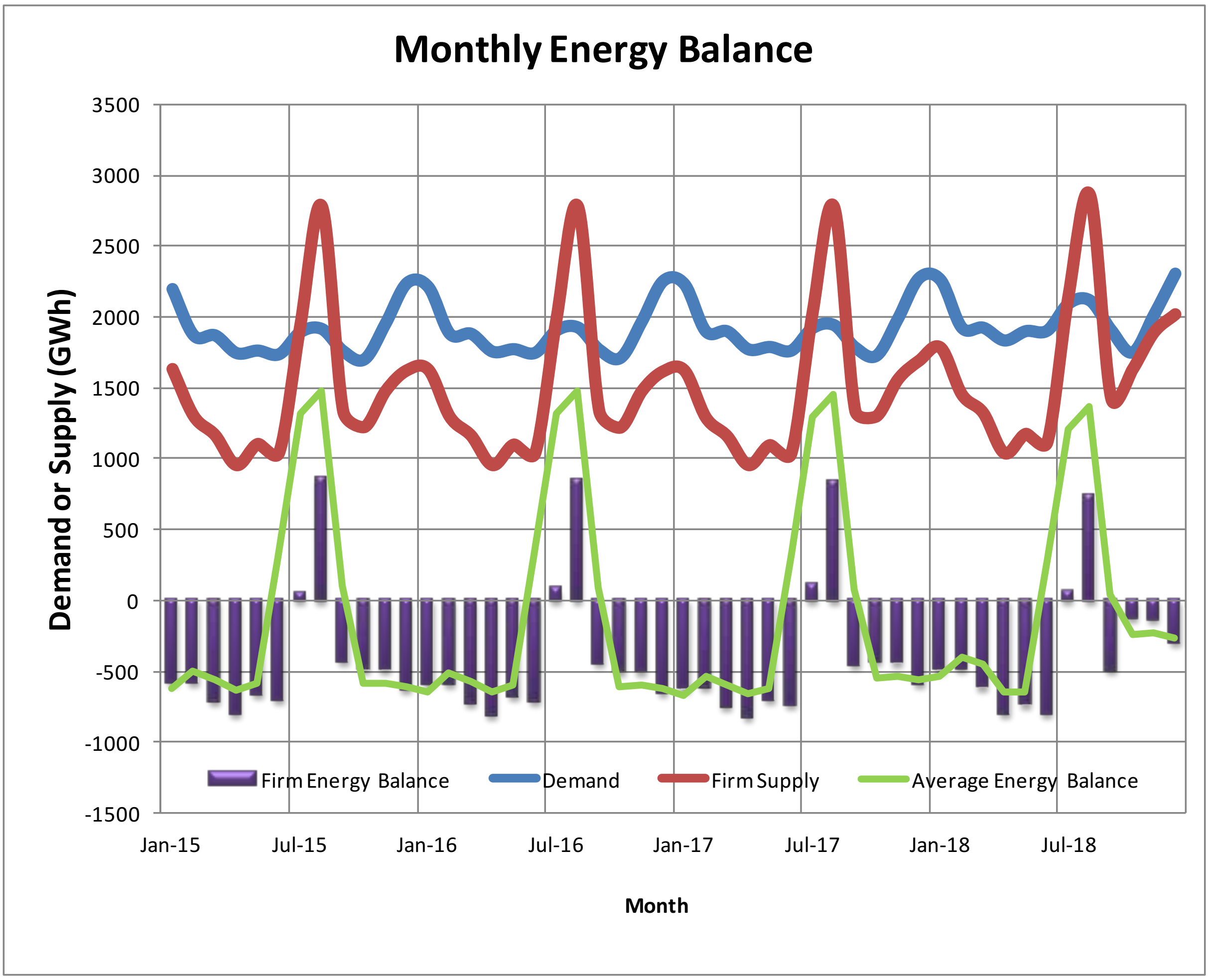

Figure 3-6: Monthly Energy Balances for 2015 to 2018

Table 3-15: Energy Balance under Firm Hydro Conditions

Year 2015	January	February	March	April	May	June	July	August	Sept.	October	Novem.	Decem.	Annual
Peak Demand (MW)	4,100	3,974	3,849	3,556	3,347	3,221	3,347	3,347	3,347	3,556	3,765	4,184	4,184
Energy (GWh)	2,199	1,869	1,869	1,744	1,761	1,736	1,893	1,915	1,758	1,700	1,957	2,243	22,645
Existing Capacity (MW) [1]													
Vakhsh System	4,456	4,153	4,014	4,401	4,455	4,653	4,792	4,802	4,853	4,543	4,440	4,409	4,853
Kairakkum	138	151	152	152	150	144	135	103	98	98	120	121	152
Varzob	38	38	38	38	38	38	38	38	38	38	38	38	38
Subtotal Hydro	4,632	4,342	4,204	4,591	4,643	4,835	4,965	4,943	4,989	4,679	4,598	4,568	4,989
Dushanbe -1 [2]	198	198	198	-	-	-	-	-	-	198	198	198	198.0
Dusbanbe - 2 [2]	100	100	100	-	-	-	-	-	-	100	100	100	100.0
Yavan CHP [3]	-	-	-	-	-	-	-	-	-	-	-	-	0.0
Subtotal Thermal	298	298	298	0	0	0	0	0	0	298	298	298	298.0
Total	4,930	4,640	4,502	4,591	4,643	4,835	4,965	4,943	4,989	4,977	4,896	4,866	4,989.1
Existing Energy Generation Capability (GWh) [4]													
Vakhsh System	1,390	1,077	934	899	1,046	985	1,886	2,727	1,301	1,008	1,249	1,387	15,890
Kairakkum	71	62	59	48	49	49	53	45	25	41	61	65	629
Varzob	1	2	2	2	4	4	5	5	5	3	2	2	38
Subtotal Hydro	1,462	1,140	995	950	1,099	1,039	1,944	2,777	1,331	1,053	1,313	1,454	16,557
Dushanbe -1 [5]	110	100	110	-	-	-	-	-	-	110	107	110	648.6
Dusbanbe - 2 [5]	56	56	56							56	56	56	334.8
Yavan CHP	-	-	-	-	-	-	-	-	-	-	-	-	0.0
Subtotal Thermal	166	156	166	0	0	0	0	0	0	166	163	166	983
Total	1,628	1,296	1,161	950	1,099	1,039	1,944	2,777	1,331	1,219	1,476	1,620	17,540
Capacity and Energy Balance													
Capacity Excess (Deficit) (MW)	830	665	653	1,035	1,296	1,614	1,618	1,596	1,642	1,421	1,130	683	653
Energy Excess (Deficit) (GWh)	-570	-573	-708	-794	-662	-697	51	862	-427	-481	-482	-622	-5,104

Notes: [1] Firm hydro capacity including maintenance
[2] CHP plants assumed to be on line from October through the end of March [3] Yavan assumed to be off line due to lack of fuel
[4] Based on firm (95% probability of exceedance) hydro energy
[5] Dushanbe CHP Plants assumed to have a capacity factor of 75%

Table 3-16: Energy Balance under Average Hydro Conditions

Year 2015	January	February	March	April	May	June	July	August	Sept.	October	Novem.	Decem.	Annual
Peak Demand (MW)	4,100	3,974	3,849	3,556	3,347	3,221	3,347	3,347	3,347	3,556	3,765	4,184	4,184
Energy (GWh)	2,199	1,869	1,869	1,744	1,761	1,736	1,893	1,915	1,758	1,700	1,957	2,243	22,645
Existing Capacity (MW) [1]													
Vakhsh System	4,506	4,253	4,099	4,477	4,615	4,804	4,825	4,826	4,857	4,546	4,440	4,409	4,857
Kairakkum	149	151	151	152	152	150	148	123	119	119	143	146	152
Varzob	38	38	38	38	38	38	38	38	38	38	38	38	38
Subtotal Hydro	4,693	4,442	4,288	4,667	4,805	4,992	5,011	4,987	5,014	4,703	4,621	4,593	5,014
Dushanbe -1 [2]	198	198	198	-	-	-	-	-	-	198	198	198	198.0
Dusbanbe - 2 [2]	100	100	100	-	-	-	-	-	-	100	100	100	100.0
Yavan CHP [3]	-	-	-	-	-	-	-	-	-	-	-	-	0.0
Subtotal Thermal	298	298	298	0	0	0	0	0	0	298	298	298	298.0
Total	4,991	4,740	4,586	4,667	4,805	4,992	5,011	4,987	5,014	5,001	4,919	4,891	5,014.0
Existing Energy Generation Capability (GWh) [4]													
Vakhsh System	1,316	1,130	1,063	1,043	1,098	1,963	3,150	3,336	1,807	886	1,131	1,375	19,300
Kairakkum	91	84	82	64	68	62	56	54	43	54	74	89	822
Varzob	3	3	3	5	7	8	8	9	9	6	4	4	69
Subtotal Hydro	1,409	1,218	1,149	1,111	1,173	2,034	3,214	3,400	1,859	946	1,209	1,468	20,191
Dushanbe -1 [5]	110	100	110	-	-	-	-	-	-	110	107	110	648.6
Dusbanbe - 2 [5]	56	56	56							56	56	56	334.8
Yavan CHP	-	-	-	-	-	-	-	-	-	-	-	-	0.0
Subtotal Thermal	166	156	166	0	0	0	0	0	0	166	163	166	983
Total	1,576	1,374	1,315	1,111	1,173	2,034	3,214	3,400	1,859	1,112	1,372	1,634	21,174
Capacity and Energy Balance													
Capacity Excess (Deficit) (MW)	891	765	737	1,111	1,459	1,770	1,664	1,640	1,667	1,445	1,153	708	708
Energy Excess (Deficit) (GWh)	-623	-496	-555	-632	-588	298	1,321	1,484	101	-587	-585	-609	-1,470

Notes: [1] Average hydro capacity including maintenance
[2] CHP plants assumed to be on line from October through the end of March [3] Yavan assumed to be off line due to lack of fuel
[4] Based on Average hydro energy
[5] Dushanbe CHP Plants assumed to have a capacity factor of 75%

4. PLANNING PARAMETERS AND CRITERIA

This section presents a brief overview of the planning parameters and criteria used in this study. The parameters and criteria have been divided into several groups such as general and economic, generation, fuels and transmission.

4.1 INTRODUCTION

According to normal industry practice, a power sector master plan is developed by comparing generation and transmission system costs of various formulated development alternatives over a pre-defined planning horizon. These costs consist of capital costs, fuel costs, operation and maintenance costs, emissions offset allowances, value of losses and other costs. The comparison is made on the cumulative present value of costs, for a given alternative against the base alternative, for a number of predetermined years at an appropriate discount rate. In order to fairly compare and assess the formulated alternatives, it is necessary to establish a set of planning parameters and criteria prior to the development of the alternatives in order to ensure that they all have the same comparable performance. These parameters and criteria cover all aspects of power system planning work, such as technical, economic, financial and environmental aspects.

The assumptions and criteria presented in this section were developed from several sources, including previous planning reports, in-house criteria used in previous similar assignments and international best practices.

4.2 GENERAL AND ECONOMIC PARAMETERS

The initial analysis is carried out using economic costs rather than financial costs. Financial costs are used to evaluate the identified best options going forward when these have been selected based on several key factors. This implies that the principal analysis is based on economic values that do not take into account such factors as the imposition of taxes, levies or royalties by government or any risk premium that may be charged by private sector investors.

Government taxes, levies and royalties are not included in the calculation of economic costs, as these are a transfer payment between one group in the economy and another, rather than a cost to the economy as a whole. Economic costs are used to determine what the right choices would be from the point of view of the Tajik economy and society as a whole.

The analysis is carried out using a social discount rate, that is, the rate of return on capital expected by society, rather than the investment criteria that may be used by the private sector. Thus, it is difficult to translate the economic costs of projects into the actual cost of projects when they are implemented. For one thing, government will expect royalties or taxes to be paid on labour, materials and resources.

4.2.1 National Focus

The ToR specifies that the PSDMP aims to enhance energy security and energy efficiency of Tajikistan and is to identify a series of technically feasible and cost optimized expansion scenarios, with consideration given to prospects for in-state generation as well as through trade with neighbouring countries. This is therefore a plan for the supply of electricity requirements of Tajikistan and not those of the region.

The development of the PSDMP is to be carried out from a national perspective by maximizing the benefits to all Tajiks and not being concerned with particular interests of individuals or entities. The PSDMP is to cover the entire territory of Tajikistan and will take into account existing policies and programs.

4.2.2 Planning Horizon

In accordance with the requirement outlined in the ToR, the plan is to cover a development period of 20 years and when the PSDMP was started it was intended to model the system from 2013 to 2032. However, two factors have contributed to a change in this horizon. First, due to significant delays in the availability of information, the final PSDMP is now planned for submission in the second quarter of 2016. Secondly, because the PSDMP includes the Rogun project as one of the generation options, and it will take some years for that project to be fully commissioned and absorbed by the system, it has been decided to align the starting date and extend the planning horizon. To accommodate this most important project in PSDMP it was decided to extend the development period to 25 years and to start in 2015, thus a planning horizon from 2015 to 2039.

At the end of the simulation period, the various expansion scenarios may have different plant mixes with different remaining lives and different operation and maintenance costs as well as different investment costs. In order to measure all benefits of the plants that are commissioned in the planning period and to take into account different plant lives, it is a common practice to extend the planning period by a period ranging from 10 to 15 or more years. For the extended period, demand and supply are maintained at the same level as at the end of the simulation period. An extended period of 20 years is used in this study due to the relatively long period to fill the Rogun reservoir.

4.2.3 Cost and Present Worth datum

All costs are expressed at January 2015 prices. All present - worth and discounting calculations also use January 2015 as their reference point.

All economic costs and benefits are to exclude all local taxes, levies, duties and royalties.

4.2.4 Escalation

The economic analysis is to be based on real costs expressed at January 2015 price levels omitting projections for general price inflation during the planning period.

4.2.5 Currency

All monetary values are to be expressed in U.S. dollars.

4.2.6 Discount Rates

Typical practice for ADB studies is to set the discount rate for economic analysis at 10%. This provides a consistent base for the comparison of diverse projects within an economy. In countries where there is significant investment risk, a rate of 12% is sometimes used.

The 10% discount rate is used as the base discount rate. The study also includes discount rates of 8% and 12% as part of the sensitivity analysis.

4.2.7 Foreign Exchange Rates

As all costs are expressed in U.S. dollars, foreign exchange rates are not required.

4.2.8 Insurance and Interim Replacement

The annual costs associated with insurance and interim replacement are assumed to be 0.25% of the total capitalized cost for each of these components.

4.2.9 Cost of Expected Unsupplied Energy

For the present study there have been no discussions to date on the value to be used for the cost of unsupplied/unserved energy.

An economic proxy for the cost of unsupplied/unserved energy can be obtained by dividing the country's GDP by the total electricity consumption. Considering Tajikistan's GDP of US$ 8.508 billion in 2013 and a consumption of 16 billion kWh this would result in a value of about US$ 0.53/kWh which is considered to be very low.

At this time, it is proposed that the cost of unserved or expected unserved energy (EUE) be set at $1/kWh. This value may be considered low relative to those used in other developing countries but given the present economic conditions in Tajikistan and as the country has experienced significant supply crisis over the past several winter seasons it is considered a reasonable starting value.

As the lead time of run-of-river hydro plants and also that for coal/gas fired power plants is at least five to six years, it is further proposed that the EUE cost should only start to be taken into account in the overall cost calculation starting in year 2021.

4.2.10 Cost of Losses

To evaluate the different transmission expansion plans it will be necessary to compare and cost losses between the different expansion plans. The energy value of losses are to be evaluated using the most expensive incremental cost of generation (including both fuel and variable O&M costs) while capacity losses are to be evaluated based on the lowest capital cost of the generation fleet. For this study the energy value of losses will be taken as $50/MWh and the value of capacity losses as $125/kW-yr.

4.2.11 Duties and Taxes

Duties, levies, royalties and taxes are not included in this economic study.

4.2.12 Interest During Construction (IDC)

Interest is a financial cost and as such is excluded from the economic evaluations. The impact of construction periods of different lengths will be taken into account by distributing the capital over the entire construction period. In order to align the distributed investment flow and present value calculation, the interest rate used will be equal to the discount rate.

4.2.13 Export/Import Tariffs

Presently BT has two export PPAs with Afghanistan, one with a defined contracted energy and another based on available energy in the Tajik system. As of 1 January, 2015, the tariff for export through the PPA based on available energy was $28/MWh and that through the PPA with defined contracted energy was $37.9 MWh. The PPA with defined contracted energy has a minimum guaranteed energy while the other PPA is for surplus energy. There is also a PPA with Kyrgyzstan which is renewed on an annual basis with a tariff of $20/MWh for the period of May to September 2014.

In addition, Tajikistan is expected to start exporting energy through the CASA 1000 interconnection by 2019 with a guaranteed minimum energy of 1,331.5 GWh per year. The price for the CASA 1000 export has been negotiated with a value in the order of 68.20 US$/MWh (6.28 ¢/kWh).

In order to simplify the calculations all firm energy (also known as guaranteed) exports are set at 68.20 US$/MWh. The surplus energy is set as outlined below.

For the potential import options over the autumn/winter season, the following tariffs are used:

- $40/MWh for the off-peak import from Uzbekistan

4.2.14 Price of Surplus Power

As Tajikistan experiences power shortage during the autumn/winter period and power surplus in the summer (under average hydrological conditions) and new power plants are likely to be built to meet the power demand in the winter season, surplus power could be available for export.

The value of this surplus power is taken as $68.20per MWh.

4.3 GENERATION

This section provides criteria for the selection of generation expansion candidates and some of the data for these units. System reliability is addressed and the fuel prices to be used by the PSDMP are also derived.

4.3.1 Hydrological Conditions

Hydropower is generated from water moving through the hydrological cycle. Hydroelectric generation is variable by nature and fluctuates with overall water supply conditions. Electricity production is highly correlated to hydrological conditions, i.e. higher precipitation years generally equate to higher power generation years with the opposite also being true. Hydrological conditions are categorized by measuring the quantity of water runoff at a specific geographic point for a specific period of time.

In generation planning studies, hydrologic conditions over the historical recorded years could be analysed and categorized in three or five groups. The three-group classification includes “Dry”, “Average” and “Wet” while the five-group classification includes “Firm”, “Dry”, “Average”, “Wet” and “Flood”. It is noted that different words could be used to represent these hydrologic conditions. For example, the word “General” could be used to replace the word “Average”. Each of these hydrologic condition terms represents an achievable probability (or exceedance level) for a hydro power production level. One example is that 95%, 50%, and 5% are assigned to “Dry”, “Average” and “Wet” respectively. In this case, 95% for the “Dry” condition means that over the number of years analysed, the electricity generation (or water flow) reached the pre-defined production level for at least 95% of the time (on an annual basis).

As the Tajikistan generation system is hydro dominated, the hydro power production level associated with the “Dry” hydrologic condition is applied in generation system reliability analysis, i.e. the expected output of the hydro power plants in the planning horizon are based on the historical output under the “Dry” condition. The production cost analysis is based on the “Average” condition.

4.3.2 Rehabilitation / Retirement of Existing Generating Facilities

Hydroelectric power plants do not usually retire but they are rehabilitated periodically (such as every 40 or 50 years). For the present study, it is not intended to plan for the retirement of any hydro power plant. BT has plans to rehabilitate most of the older existing hydro power facilities.

It is customary to retire thermal power plants sometime after their economic life has ended. In the Tajikistan case, the Yavan CHP has not been operated for several years and this situation is assumed to continue although the plant will not be retired.

4.3.3 Reliability Criteria

The primary objective of the generation expansion planning is to find the least cost long-term expansion scenario that supplies the forecast demand at an acceptable or pre-specified level of reliability. In any given year, it is essential to verify that the generation capacity reserve is sufficient so that the system can meet the load demand even if one or more units are out of service and/or, for systems with significant hydroelectric capacity, drier than planned for hydrological conditions are encountered. The reliability criteria are usually the deciding factor in scheduling the addition of new generating plants. There are usually two types of reliability criteria used in generation expansion planning: deterministic and probabilistic.

4.3.3.1 Deterministic Criteria

There are a number of ways to define deterministic reliability criteria. The core part of these criteria is, however, generation capacity. Depending on the application, these criteria could be measured using the values calculated using generator gross MCR (maximum continuous rating) or gross capacity, net MCR (gross MCR less station services) or net capacity, or seasonal MCR (MCR less seasonal de-rating and/or energy limitation) or seasonal capacity. Some utilities/systems apply the deterministic criteria prior to allowing for generating unit planned maintenance outage while others apply them after.

The deterministic reliability criteria are normally expressed in three different ways: (1) a fixed amount of capacity in MW to account for the random (could also include the planned) outage of one, two or more of the largest units, (2) a percentage of annual peak demand, or (3) a percentage of annual peak demand plus a fixed amount of capacity.

4.3.3.2 Probabilistic Criteria

The commonly adopted probabilistic reliability criteria includes both the loss of load probability (LOLP) and the expected unsupplied energy (EUE), which are obtained from the probabilistic convolution of the load demand and available generation.

LOLP is used to measure the risk associated with having insufficient generation capacity to meet the forecast load demand, which is normally expressed in days per year or hours per year, or as a percentage. For example, a 1% LOLP indicates that the installed generation will not be able to meet the forecast demand in a given year for 3.65 days or 87.6 hours. It is important to understand that a simple LOLP value may have different implications as it could be calculated based on either a daily peak load duration curve or an hourly load duration curve. In the case of the daily peak load duration curve, each day is represented by one point, the highest hourly demand during the day.

EUE is the quantity of expected energy that a system would not be able to serve with the planned generation system in a given year. It is expressed either in MWh or as a percentage in which case it is equal to the expected unsupplied energy divided by the energy demand and multiplied by 100.

For the present study an LOLP reliability criterion of 5 days per year was adopted based on international best practices for similar systems. The annual EUE criterion of 1% with no monthly EUE to exceed 5% was also adopted. It is noted that the annual EUE percentage would be calculated using the annual energy demand while the monthly percentage value would be calculated using the corresponding monthly energy demand. Both the LOLP and EUE calculations are to be based on firm (95% probability of exceedance) hydrological conditions.

4.3.4 Emissions Criteria

The development of any power plant would need to take full account of the environmental impact of the chosen plant type irrespective of its location. Due consideration should be taken to both the direct and indirect environmental effects and, where appropriate, suitable mitigation measures should be put in place to meet all applicable regulations for emissions. The capital cost estimate and O&M costs of a power plant should include the associated costs for the required mitigation measures.

One of the environmental considerations for the thermal plants is the likely emissions from the stacks of those plants (sulphur dioxide, nitrous oxides, carbon dioxide and other greenhouse gases, particulate matter, etc.).

In today's practice it is common, when comparing different forms of generation, to apply an economic levy on thermal plants (or offset allowance) to take into account the cost to society of emissions that, while within the legal limits, do create costs that society as a whole must bear. This is normally done on the basis of the level of emissions such as CO_2, SO_2 and NO_x expected to be emitted by the relevant plant type. Some studies levy a cost in terms of € per tonne for the emissions to represent the societal cost for these emissions. For the present study a penalty of $5 per tonne of equivalent CO_2 emissions and other emissions, representing a cost to society, will be levied against thermal options.

4.3.5 Candidate Generation Resources

The types of generation expansion candidates considered to meet the growing demand over the planning horizon are discussed in detail in Section 5, which include the following categories:

- Hydroelectric including both storage and run-of-river (ROR) HPPs
- Coal fired power generation including CHP
- Natural gas fuelled power generation including GT and CCGT
- Fuel oil fire generation including diesel, GT and CCGT
- Non-hydro renewable including wind, solar and geothermal
- Other power generation technologies including nuclear.

For studies similar to the power sector master plan there are certain values that are required for each of the generation resources including economic life, construction period, outage rates (both planned and unplanned) and cash flows.

Table 4-1 presents the values for these items which follow typical applicable industry values.

Table 4-1: Candidate Plants Characteristics - Life and Outages

Plant/Unit	Economic Life (years)	Construction Duration (Years)	Planned Outages (%)	Unplanned Outages (%)	Cash Flow (%/year)
Storage Hydro	50	6	4	4	10%,15%, 20%, 25%, 20%, 10%
ROR Hydro	50	5	4	4	15%, 25%, 30%, 20%, 10%
Coal TPP (2x350 MW)	30	4	8	7	20%, 25%, 30%, 25%
Coal TPP (2x150 MW)	30	3	8	7	30%, 40%, 30%
CHP	30	3	8	7	30%, 40%, 30%

(2x50 MW)					
Diesel	25	2	4	5	60%, 40%
Gas Turbine	20	2	4	5	60%, 40%
CCGT	25	3	6	6	30%, 40%, 30%
Wind	20	2	-	-	60%, 40%
Solar PV	20	2	-	-	60%, 40%
Geothermal	25	4	8	7	20%, 25%, 30%, 25%
Nuclear	40	8	8	5	10%,10%, 10%, 15%, 15%, 15%, 15%, 10%

Note: Wind and solar plants were not assigned outage values due to the intermittent nature of the resource

4.3.6 Generation Planning Software

In order to simulate the generation system for each individual alternative sequence, the GENSIM generation planning software is used and this software has been utilized extensively to model generation systems. The GENSIM planning model is utilized to evaluate alternative power system expansion plans and to determine utilization information for power system facilities. The model simulates generation system operation over a multi-year planning period in order to determine generation requirements for all hydroelectric and thermal generation facilities, and bulk power supply estimates for an entire utility service area. This information is then utilized within the model to evaluate the economic benefits and costs of the development plan under consideration. The model explicitly accounts for the variability in hydrologic inflow to the hydroelectric plants by using firm hydro capabilities to satisfy specified reliability criteria in determining the timing of generation additions. A range of probable hydro capabilities is then used to calculate the expected energy generation for each plant and the expected fuel and operating costs for the entire system.

GENSIM is a comprehensive package of computer programs. The planning section of the model is highly interactive, which allows the determination of generation commissioning schedules to satisfy a predetermined load forecast with agreed levels of reliability. The operating section determines the probable monthly and annual energy generation for each plant. Both the planning and operating analyses can be performed with either a deterministic or probabilistic generation scheduling method. The economic analysis produces a discounted cash flow of all capital and operating costs to calculate the total present-worth system cost over the entire study horizon.

4.4 FUEL PRICE FORECAST

A fuel price forecast is required for generation options considering the use of petroleum products, natural gas and coal.

To generate electricity and heat, the Dushanbe-1 CHP plant and the Yavan CHP plant can use natural gas, when available, as the main fuel with a cost of some 1,400 Somoni per 1000 cubic metres; i.e. some $7.47/GJ (delivered from the Republic of Uzbekistan); reserve fuel is low-sulphur fuel oil M-100 with a price from $600 to $800 per tonne, i.e. from some $13.88 to $18.51 per GJ (2013 and 2014 values).

4.4.1 Fuel Background in Tajikistan

Tajikistan's existing electricity generation is obtained primarily from hydro power generation. Among the total installed generation capacity of some 5,346 MW in the country (including Yavan CHP plant), hydro power accounts for 92% of the total installation. The nation's hydro power potential is ranked 8th in the world, with a generation capability in the order of 527 TWh per year according to MoEWR, of which only 4% is currently being harnessed. The hydro power potential is sourced from two principal river systems, the Amu Darya (formed with junction of the Vakhsh and Panj) and the Sir Darya. Tajikistan accounts for 64% of the region's outflow.

In addition to water resources, the other resources used for power generation are natural gas and HFO (mazout) in both Dushanbe and Yavan CHPs. Both fuels are imported from other countries. The boilers at Dushanbe CHP were designed for burning natural gas as the primary fuel and HFO as the secondary fuel. Due to unavailability of natural gas, the Dushanbe CHP now uses HFO, which is transported to the site by railway. Due to lack of fuel and hot water customers, the Yavan CHP has not been operated over the past several years.

The accessible oil and gas bearing levels in the country have been almost entirely exhausted. At present there are no known, proved and commercially viable reserves of oil and natural gas in Tajikistan. According to the information collected from the MoEWR the potential oil and gas reserve was estimated at some 1,330 million tonnes of oil equivalent. Of this amount, oil reserve contributes some 177 million tonnes and the balance is natural gas.

Tajikistan has commissioned its first coal fired power plant (Dushanbe-2 CHP) with two 50 MW units in 2014. The coal to fuel the plant is supplied by Ziddy and Fon Yagnob mines and trucked to the power plant. The Ziddy coal field is located on the southern spur of Gissar ridge, some 70 km north of Dushanbe. The Fon Yagnob coal field is located in the Ayni region of Sughd province, 130 km northwest of Dushanbe.

Tajikistan has substantial explored and proven coal reserves. According to the GoT, there are over 40 coal deposits with a total proven reserve of more than 4.5 billion tonnes. There currently are 16 enterprises actively involved in the development of 13 coal deposits.

4.4.2 Basic Assumptions and Availability of Fuels

In 2011, the country imported only 180 million cubic meters (MCM) of natural gas compared to an average of 600 – 700 MCM over the 2000 to 2007 period. The total capacity of the gas trunk lines is over 7 billion cubic meters (BCM), leaving considerable unutilized pipeline capacity. This spare capacity could fuel up to some 4,000 MW of CCGT base load plant.

Both Turkmenistan and Uzbekistan have significant reserves of natural gas. Uzbekistan has committed to long term contracts with China and has indicated a policy goal to increase exports to 30 BCM, even substituting coal for domestic electricity production to increase available natural gas supply for export. However, the immediate availability of natural gas is not clear as Uzbekistan indicated a supply constraint when ending a contract with Tajikistan in April 2012.

Because of the factors described above, it is understood that the prices for HFO and natural gas for Tajikistan could follow closely international prices (particularly the prices in Europe) for crude oil and natural gas. As such it was decided to investigate the publicly available forecasts for crude oil and natural gas as they might provide a good indication of the most likely future price trends.

Although there is substantial coal in Tajikistan, the export price of domestic coal also follows international prices as the coal could be readily transported out of the country via railways. However, the coal delivered at Dushanbe-2 CHP plant does not follow the international coal price, which is the sum of the price at coal mine and the transportation cost.

The fuel prices forecasts were collected from four well known institutions, the EIA (U.S. Energy Information Administration), WB (World Bank), Sproule and Citi financial company.

The EIA collects, analyses, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment.

The WB is a vital source of financial and technical assistance to developing countries around the world and is a unique partnership to reduce poverty and support development.

Sproule is a diversified, world-wide petroleum consulting firm with 60 years of experience in all aspects of the energy sector throughout North America and the World.

Citi is a global financial services company and provides consumers, corporations, governments and institutions with a broad range of financial products and services.

The forecasts produced by each of the following four institutions are very recent and are dated as of:

- The EIA Annual Energy Outlook 2014, released in April 2014
- The WB Commodity Markets Outlook, released in January 2015
- The Sproule forecast was released in January 2015

- The Citi Transitioning to Growth 2014 Annual Outlook.

4.4.3 Crude Oil Forecast

Crude oil price forecasts were collected from three institutions, the EIA, WB and Sproule. Figure 4-1 shows the forecast prices for crude oil over an 11 year period, i.e. from 2015 to 2025. It is important to note that the prices used in all fuel cost forecasts (from Figure 4-1 to Figure 4-3) are expressed in constant 2015 dollars. The EIA price is the Brent spot price. The WB price is for the average spot price around the world and the Sproule price is for UK Brent spot price.

The following could be observed from Figure 4-1:

- The EIA forecast price is expected to decrease for a couple of years and then increase until 2025. Over the forecast period, the price will change from some $100/BBL in 2015 to some $112/BBL in 2025
- The WB forecast predicts that the crude oil price would increase slightly during the forecast period from a starting value of $53/BBL to a value close to $88/BBL by 2015
- The Sproule forecast shows a starting price similar to the of the WB forecast followed by an increase in price until 2017 and then a steady price until the end of the forecast period of $87/BBL.

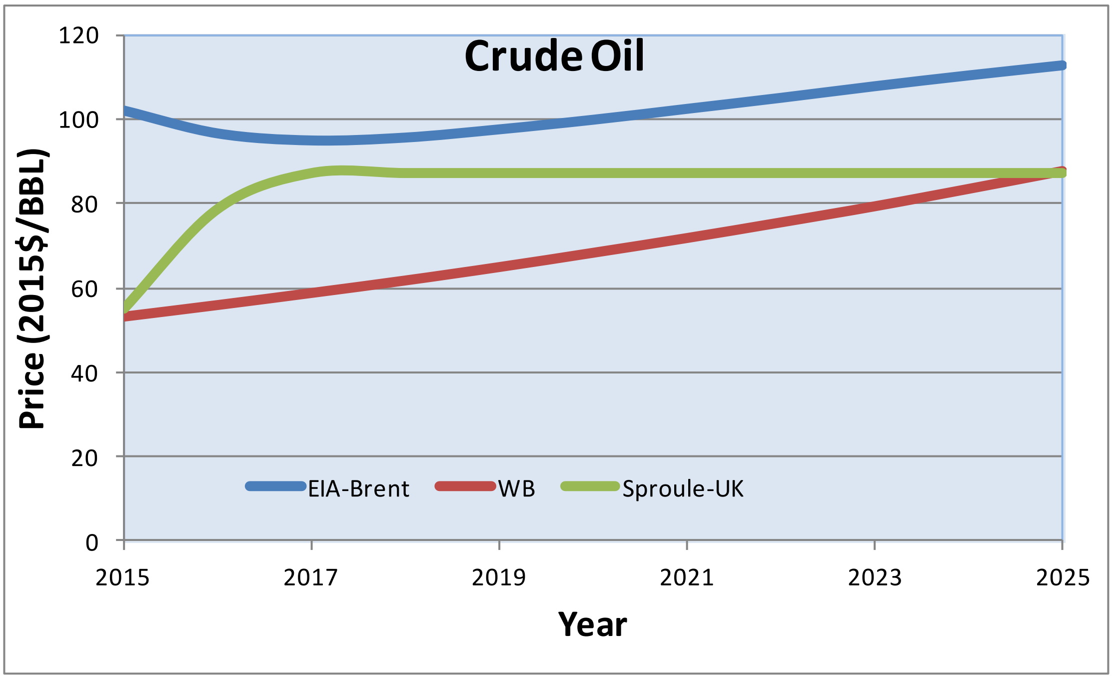

Figure 4-1: Crude Oil Price Forecast

By comparing the three forecasts, it appears that the Sproule forecast is more applicable to the Tajikistan study. The reasons for this conclusion include the following:

- The fuel oil prices in Tajikistan will most likely be based on the UK Brent price
- As the present price is depressed it is very likely that the price will increase in the next few years and then become stable as has occurred in the past
- Although the current Brent spot price is below $55/BBL, it was over $100/BBL for quite some time

For this study, a crude oil price of $80/BBL was selected, which includes the cost of delivery to the nearest port or depot of the applicable refining facilities.

It is realized that current crude prices are quite depressed but this is expected to have a short term duration only with crude oil prices then rising to a level between $80 and $100 per barrel.

Prices for light fuel oil (LFO) and heavy fuel oil (HFO) are 30% higher and 20% lower than the crude price respectively. The heating value for LFO is taken as 6.13 GJ/BBL and that for HFO as 6.594 GJ/BBL.

It is important to note that the price shown in Figure 4-1 is based on the crude oil prices delivered to the main ports or depots and do not include shipping cost from port to refinery, refining cost and delivery cost of the refined products to power plant sites.

4.4.4 Natural Gas Price Forecast

The forecast prices for natural gas were obtained from the EIA, WB and Sproule. Figure 4-2 shows three groups of forecast prices, for Henry Hub (U.S.), Europe and Britain. It can be seen from this figure that the Henry Hub (or USA) prices are much lower than the European prices. The WB forecasts an increase in the USA price and a constant in price for European natural gas. For Britain, similarly to its crude forecast, Sproule forecasts a price increase over the period from 2015 to 2017 and thereafter a constant price.

Given the physical location of Tajikistan and its natural gas sources, one could argue that price forecasts for Europe are more relevant and given the potential of new sources (new sites with potential fracturing application) it is unlikely that there will be any significant price increases. It is also important to note that the prices presented in Figure 4-2 are at the main hubs and they do not include the components required to transmit the gas to its final destinations.

In this study, a price of $10/GJ was selected for imported natural gas, which includes the delivery cost to the power plant sites. It is also noted that the current Government policy on domestic gas is for its use by small users only and Ministry officials have stated that local gas, even if sufficient quantities were found, would not be used for power generation.

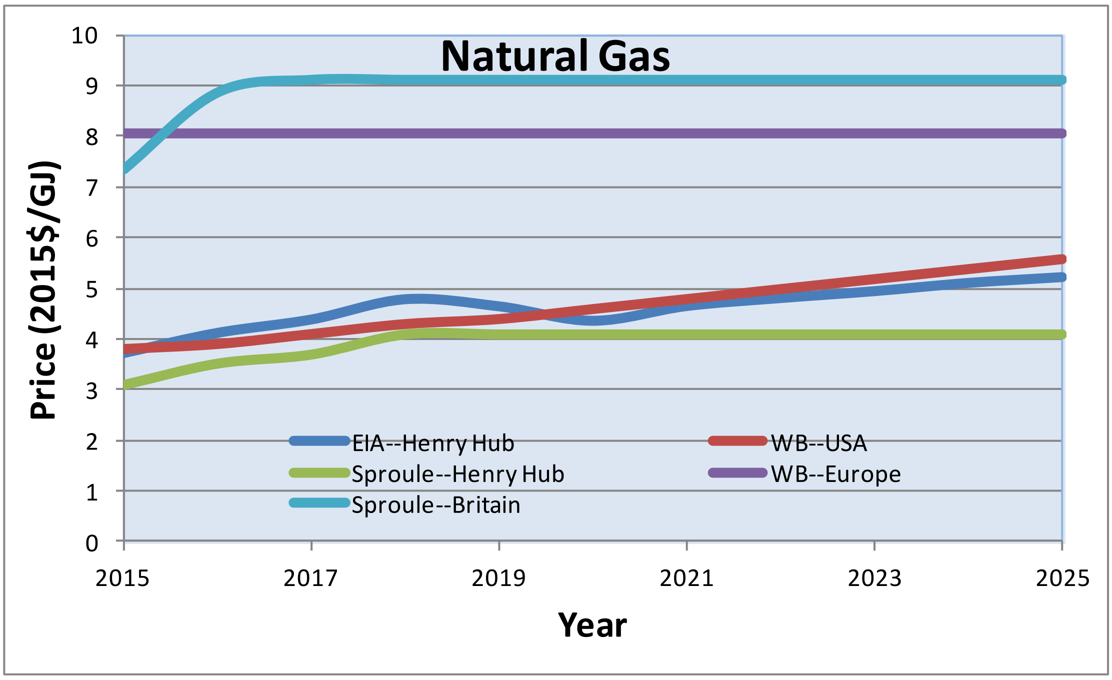

Figure 4-2: Natural Gas Price Forecast

4.4.5 Coal Price Forecast

The coal prices shown in Figure 4-3 were obtained from the forecasts by the EIA and WB and they represent FAS (free alongside ship) or FOB (free on board) prices and do not include the fees and costs for internal unloading, loading and transportation to the plant sites. It is noted that the price forecast from the EIA is for two types of coal mined in the U.S.; one for exported coal and the other for coal to be used in U.S. based power plants. The WB forecast is for Australian coal. The higher EIA price for exported coal is because most of the exports are coking coal which has a higher heat content.

As can be seen from Figure 4-3, the exported coal has a very high price of the order of $160/tonne and this is probably due to the higher heat content for this coal. The EIA forecast for coal used in U.S. based power plants ranges from $53/tonne to $61/tonne while the WB forecast ranges from $67/tonne to $85/tonne.

In its Transitioning to Growth 2014 Annual Outlook, Citi predicts a price of $80/tonne for thermal coal in 2014.

Although the international coal prices are relatively high, the domestic coal used for power generation in Tajikistan is relatively low due to lower “royalty”, taxes and other reasons. The average coal price for Dushanbe-2 CHP was approximately US$70.00 per tonne, which includes some US$40 per tonne for coal at the mine mouth and US$30 per tonne for delivery and handling. As future coal fired power plants (except for CHP plants) are expected to be located near the mine mouth, an overall price of US$ 45 per tonne is assumed, which includes mining and delivery to a mine mouth plant site. For coal power plants located near the coal mines and where some transportation is required a total price of US$55 (40 for coal, 5 for handling and 10 for transportation) per tonne is assumed.

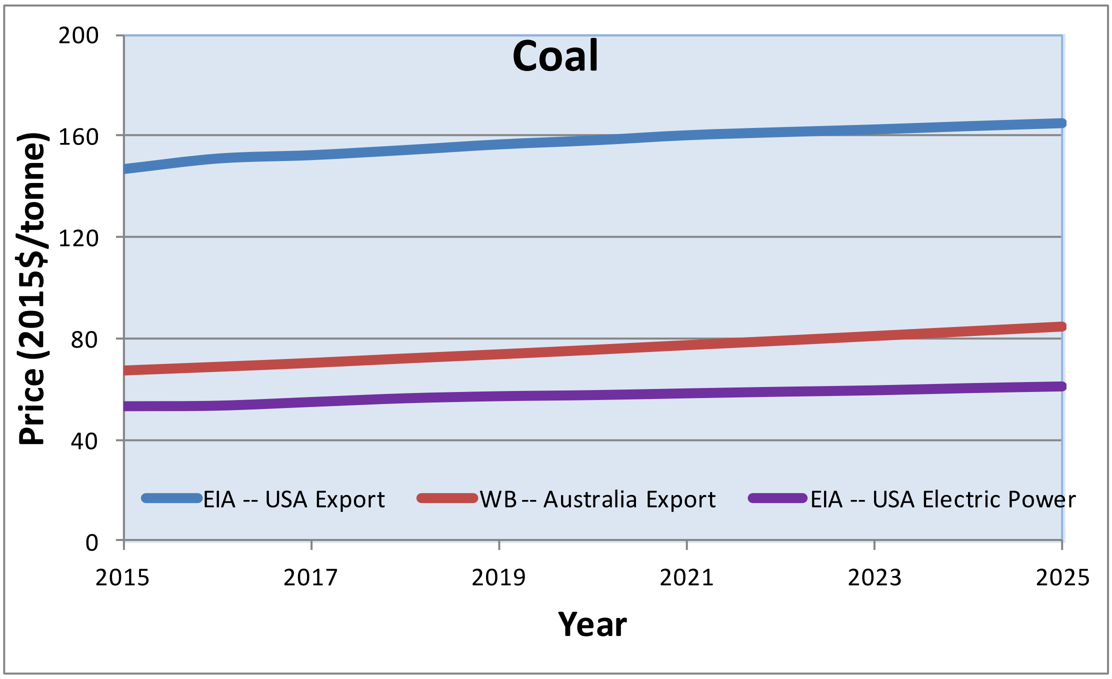

Figure 4-3: Coal Price Forecast

4.4.6 Heat Content of Fuels and Unit Prices of Energy

Table 4-2 shows the proposed unit fuel costs in $/GJ to be used in preparation of the PSDMP, which are $20.23/GJ for LFO, $12.74/GJ for HFO, $3.27/GJ for domestic coal used in CHP plants, $2.10/GJ for domestic coal used in conventional power plants and $10/GJ for imported natural gas. These assumptions are based on the forecasted prices for crude oil, natural gas and coal as well as the following considerations:

- A constant price of $80/BBL is assumed for crude oil, which results in a price of $104/BBL for LFO and $64/BBL for HFO
- A cost of $20/BBL is added to the total costs of LFO and HFO for refining, handling and delivering the fuels to power plant sites.

The higher heating value (HHV) of LFO and HFO is assumed as 6.13 GJ/BBL and 6.594 GJ/BBL respectively.

A price of US$ 70.00/tonne is assumed for domestic coal used in CHP plants and US$ 45.00/tonne for domestic coal used in conventional power plants to be located at mine mouth while for plants near the mine the price is US$55.00.

A value of $10/GJ is assumed for the imported natural gas including delivery charges by presuming the gas trunk line infrastructure does exist and no new pipe lines are required.

Table 4-2: Total Unit Energy Cost

Category	Fuel					
	Crude Oil	LFO	HFO	Coal-CHP	Coal	Natural Gas
	Measurement Unit					
	(BBL)	(BBL)	(BBL)	(Tonne)	(Tonne)	(GJ)
Unit Commodity Price ($)	80	104	64	39.22	39.22	10
Heating Value (GJ/Unit)-HHV		6.13	6.594	21.39	21.39	
Commodity Price ($/GJ)-HHV		16.97	9.71	1.83	1.83	10
Delivery Cost ($/Unit)		20	20	29.41	5.88	Included
Delivery Cost ($/GJ)-HHV		3.26	3.03	1.38	0.28	Included
Total Energy Cost ($/GJ)-HHV		**20.23**	**12.74**	**3.21**	**2.11**	**10**

4.5 APPLICABLE TAXES FOR FINANCIAL REQUIREMENTS

Under the Tax Code of the Republic of Tajikistan (article 343.2) import of goods for the construction of hydro power plants which are important facilities for Tajikistan are exempt from the value added tax (VAT) (which has a rate of 18%) and custom duties (which has a rate from 5% to 15%).

For the implementation of target projects approved by the Government, custom duties are not levied and as such it appears that thermal power plants (TPPs) could be classified as target projects since they would be alleviating power shortages in the winter.

It is also assumed that there would be a 1.2 % inspection fee so that customs can verify that the equipment being brought in is to be used for the intended purposes on 70% of the total cost.

Inflation is assumed to be 3% per year over the entire study period and an interest during construction of 10% is to be applied to the annual cash flows during construction.

4.6 TRANSMISSION

This section presents a brief overview of the planning parameters used for the transmission planning studies which assisted in developing an expansion plan capable of delivering the load requirements from the expected generation locations to the load centres in a reliable and economic manner throughout the 25-year timeframe of the study.

One of the principal objectives of electrical system planning is to develop a power system with a certain performance level within acceptable degrees of adequacy and security based on a trade-off between costs and risks. In order to develop a power system, certain performance measures or criteria were adopted and these measures depend on factors such as availability of generation, voltage levels, size and configuration of the system, control and communication facilities and resource constraints. Practices vary from system to system and the common theme in the various approaches is the acceptable system performance.

Planning criteria are a set of rules or parameters which must be adhered to in carrying out analysis of generation and transmission system expansion alternatives. It is sometimes permissible to have slight deviations when it makes good technical and/or economic sense.

Study criteria are usually developed by experienced personnel with several years of participation in the sector and these are system planners, system operators, economists and other specialists involved in the electricity sector.

4.6.1 Study Area and Horizon

Four internal study areas were used; Dushanbe, Sughd, RRS and Khatlon. Additions in each area merited detailed consideration in that area. For example each area had a set of contingencies. All contingencies in that area were considered when studying additions in that area. However, only one subset of contingencies from the other areas were considered.

Planning horizons include 2014 (studies for that year have been ongoing), 2020, 2025, 2035 and 2039. Uncertainty in results increase in the out-year cases due to errors in load growth forecast, transmission, generation model data, and project deferments.

4.6.2 Technical Criteria

The following is a brief summary of the main criteria used in this study. These are based on internationally accepted practices. Specific criteria normally in use within Tajikistan were considered for inclusion to the list below:

a) Bus Voltages

Facilities will be planned to operate between 0.95 pu and 1.05 pu steady state and between 0.9 pu and 1.1 pu post fault. Any scenario that cannot meet these criteria will be deemed to a failed case. It is our understanding that presently the post fault criteria cannot be met for certain outages.

Studies for the present year will also consider the actions required to return the system to a system normal condition following a contingency.

b) Thermal Loading

Thermal loading will be maintained restricted to lesser value of 100% of the name plate rating of the facility, or the loading at which the limiting contingency will not produce a post fault loading violation.

Emergency loading values will be utilized for short term post contingency analysis if this is consistent with present operating and planning practise within Tajikistan. Emergency loading limits are presently set at 110% for transmission lines and 120% for transformers.

Studies for the present year will also consider the actions required to return the system to a system normal condition following a contingency.

c) Spinning Reserve

Generation reserve will be set in the adequacy standards and will normally be set to equal the greater of the largest loss of power from a credible contingency or the loss of the largest generating unit. Normally half of the generation reserve will be held as spinning reserve. Following loss of generation this could improve system recovery significantly.

d) Load Power Factor

The system is to be planned for a load power factor of a value to be defined by the BT experts and should be between 0.90 and 0.95 at the distribution voltage level.

e) VAr Reserve

Sufficient VArs should be available at each transmission switching substation to support stable steady state operation between 0.90 p.u. and 1.05 p.u.

Sufficient VArs should be available at each transmission switching substation to support stable operation between 0.9 p.u. and 1.1 p.u. following the loss any single contingency.

f) Fault Levels

The maximum fault levels in the system should be below 80% of the rated interrupting capacity of the circuit breakers determined using the generators' transient impedances.

g) *Frequency Criteria*

The system is to be studied at 50Hz. It is assumed that the droop of all governors at generating stations would be set to respond equally to any deviation of frequency. Exceptions to this assumption will need to be noted.

h) Interconnections

Presently all interconnections between Tajikistan and Uzbekistan are open.

Interconnections are normally valuable assets to both parties. Therefore it should be considered that some or all of the interconnections may be reenergized in the future. Transmission additions should recognize this possibility and should not inhibit the re-energization of these facilities. For this reason, out-year cases 10 years and greater will study both scenarios, one with the interconnections energized the other with the interconnections open.

i) *Network Stability*

The system should remain stable following a 3 phase fault resulting in the tripping of a single faulted element.

4.6.3 Capital Costs and Economic Criteria

The economic criteria to be used for comparing alternatives in the transmission studies are shown in Section 4.1 above.

In order to compare overall costs of transmission alternatives, the capital costs of new equipment additions and its associated operation and maintenance costs are required. In addition, the cost of losses should also be incorporated into the overall analysis as different alternatives have different levels of losses.

In order to be able to estimate the capital cost of each transmission alternative considered, unit costs of equipment are required. The transmission equipment costs have been developed based on the latest costs in Tajikistan for transmission lines at different voltages and for substations. The unit cost for transmission lines, substations, transformers and capacitors are presented in Section 7 and Appendix E.

For the present study, it is assumed that the annual operation and maintenance charges would be equal to 1.5% per year of the total capital investment for each item of equipment. It is recognized that transmission lines require a lower percentage for operation and maintenance but substation equipment requires a higher percentage thus the selected value represents an average value for all transmission equipment.

4.7 FUTURE REGIONAL INTERCONNECTIONS

During 2008 and 2009, Tajikistan constructed a North-South 500 kV line connecting its previously separated northern and southern regions. This rendered large power flows through Uzbekistan unnecessary. Over the same time period, the South Kazakhstan and the North Kazakhstan systems were interconnected through a 500 kV transmission link.

In addition to the existing 220 kV and 110 kV interconnection lines with Afghanistan and the 220 kV interconnection with Kyrgyzstan, there are currently several regional interconnection projects under consideration, which include:

- Reconnecting the Tajikistan grid with the Uzbekistan and Kyrgyzstan grids and being part of the CAPS could provide Tajikistan some 950 MW of import during the autumn/winter season. This would involve revitalizing the energy trade that was gradually discontinued after the dissolution of the Soviet Union when the countries decided to reduce their mutual trade and become energy independent. Promotion of regional energy trade is in line with the objectives of the Central Asia Regional Economic Cooperation (CAREC)
- CASA-1000 project for the Central Asia - South Asia Regional Electricity Market, which involves plans for construction of a 500 kV link between Kyrgyzstan, Tajikistan, Afghanistan and Pakistan. The CASA-1000 project will provide 1,300 MW to Pakistan during summer months only, which is the peak demand period for Pakistan. 65% of the required power would be contributed by Tajikistan and 35% by Kyrgyzstan. The project is expected to be in service by 2021
- Construction of a 500 kV transmission line to Rogun-Peshawar is under discussion
- Construction of a 550 km, 500 kV transmission line to Xinjiang Uyghur Autonomous Region on China. The main purpose of the transmission line would be to carry surplus power during the summer months. Although no studies have been made available for our review, it is assumed that this line would be capable of sending 900 MW to the autonomous region

There are two additional lines to Afghanistan and Pakistan being addressed, only one will be considered at this stage.

5. GENERATION RESOURCES AND TECHNOLOGIES

This section provides a brief description of the energy resources available for electric power generation, including both domestic and imported fuels as well as generation technologies suitable to Tajikistan. The main technical and economic parameters of the suitable technologies are also presented in this section as is an initial screening of the options.

5.1 INTRODUCTION

This section provides summaries of the generation resources and their associated technologies available to meet some of the existing and future electrical energy demand in Tajikistan. These resources and technologies were described in the Planning Parameters and Generation Options Report and have been revised in the present report to include the latest available information. A more detailed description of the resources and associated technologies is available in Appendix C.

Tajikistan possesses vast amounts of hydropower resources that could be developed to generate electrical energy but only a limited amount is being used. In addition to the hydro power reserves, Tajikistan has also large amounts of explored and proven coal reserves which could be used to develop coal fired power generation projects. Although the nation has only limited oil and natural gas reserves, it might import fuel oils and natural gas from other countries for power generation.

Other options include the long term power purchase/sale agreements with neighbouring countries for purchasing power during the winter season and selling surplus power during the summer season and in addition to these options, other resources (wind and solar) are also presented in this section.

The section also presents an initial screening of the resources and technologies in order to identify the technologies that are clearly not economical to meet the demand and reduce the number of expansion scenarios analysed.

5.2 HYDROELECTRIC POWER POTENTIAL

As shown in Figure 5-1, the major river basins in Tajikistan include Kafirnigan, Panj, Obikhingou, Surkhob, Vakhsh and Zeravshan.

The country's hydropower resources are ranked at the 8th position in the world, in the order of 527 TWh[1] per year, of which only 4% is currently being used. In addition to the hydro power plants developed and under construction, the potential resources on each of the major river basins are:

- Some 4,450 MW on the Vakhsh River basin
- Some 1,800 MW on the Surkhob River basin
- Some 1,750 MW on the Obikhingou River basin
- Some 1,450 MW on the Kafirnigan River basin
- Some 1,260 MW on the Zeravshan River basin
- Some 17,900 MW on the Panj River basin

Although there is a vast hydropower potential, most of the assessment of the potential was carried out during the Soviet Union era. Only a very small number of prefeasibility or feasibility studies were provided to the study team by MoEI and its successor the MoEWR. These included:

- Techno-Economic Assessment Study (TEAS) for Rogun Hydroelectric Construction Project prepared by the Consortium of Coyne et Bellier of France, Electroconsult of Italy and IPA of the United Kingdom
- The Feasibility Study for the Shurob HPP
- Prefeasibility Study of Fandarya River HPP Construction prepared by EnergoFichtner in 2011

[1] Current Situation and Development Prospects for Energy and Industry in the Republic of Tajikistan

- Feasibility Study of Sanobad HPP in the Pyandzh River prepared for the Aga Khan Fund for Economic Development
- Nurabad 1 and Nurabad 2 presentation for both projects prepared by Design Group Project Consultants PVT Ltd.
- Feasibility Study of Nurek 2 Construction prepared by Nurofar
- Ayni HPP prepared by Farab Energy and Water Projects
- Nurabad-1 Prefeasibility Study Report prepared by OAO TVEA China in 2009 and
- Yavan Feasibility Study Report prepared by Sinohydro Chinese Company in 2008.

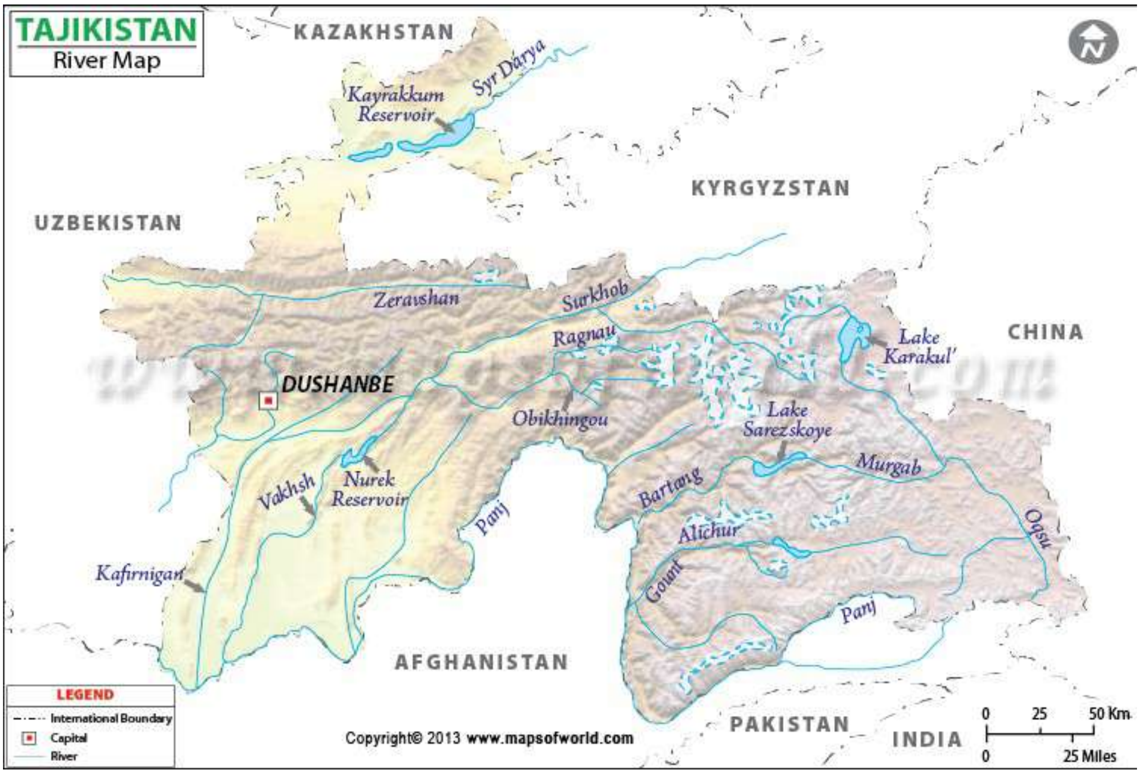

Figure 5-1: River System Map

Reports provided by the Ministry prepared by itself, the World Bank and other consultants indicate that some other studies may have been carried out.

After some deliberation, it was decided that the hydro power potential on the Panj River basin would not be taken into account in this PSDMP because the river forms part of the border with Afghanistan (long negotiations before any project would be built), the sites would be difficult to access due to lack of infrastructure and these HPPs would require long transmission lines to be built.

5.2.1 Rogun Candidate Hydroelectric Power Plant

An abridged version of the TEAS for Rogun Hydroelectric Construction Project prepared by the Consortium of Coyne et Bellier of France, Electroconsult of Italy and IPA of the United Kingdom and issued in August 2014 was downloaded from the World Bank website.

That report version did not have information regarding monthly average and firm energies, likely start year of operation, capital cost for the project, annual disbursements, operation and maintenance costs etc,. It was thus decided to use educated assumptions for these parameters as outlined below.

The TEAS considered 3 dam heights each with 3 different installed capacities. The selected dam height was 1,290 MASL which is equivalent to a dam height of 335 m. The selected capacity amounted to 3,200 MW divided over 6 units (2x400 MW + 4x600 MW).

According to the project schedule, some 73 months after the start of construction, generating units 5 and 6 are to be commissioned in a preliminary mode and start generating energy. The minimum reservoir level is expected to be reached in month 112 of construction. Units 1 to 6 are to be commissioned, in their final arrangement from month 117 to month 127. The dam is to be completed after 163 months of construction and the reservoir is expected to be filled some 18 years after the start of construction.

Based on values presented in the TEAS, the project team developed monthly average and firm energies from the time that the first two units start operation until the reservoir is completely filled. These values are presented in Appendix C. The annual average energy once the Rogun is completely filled amounts to 14,210 GWh and that for the entire Vakhsh system including Rogun amounts to 34,173 GWh. The firm energy for Rogun has been determined (from the TEAS) as 11,748 GWh and that of the Vakhsh system with Rogun as 28,623 GWh. Table 5-1 presents the monthly average and firm energies once the Rogun is completely filled. It should be noted that some winter months' generation is significantly less than the summer months and this is due to the hydrological conditions.

Table 5-1: Rogun Monthly Average and Firm Energies

A) Average Energy of Rogun and Rest of the Vakhsh System after Rogun Reservoir is Completely Filled

Plant	January	February	March	April	May	June	July	August	Septemb.	October	Novemb.	Decemb.	Annual
Rogun	1,129	1,042	920	954	1,098	1,194	1,237	2,027	1,432	923	1,084	1,170	14,210
Vakhsh System With Rogun	2,785	2,612	2,321	2,417	2,795	2,994	3,027	4,270	3,341	2,159	2,600	2,852	34,173

B) Firm Energy of Rogun and Rest of the Vakhsh System after Rogun Reservoir is Completely Filled

Plant	January	February	March	April	May	June	July	August	Septemb.	October	Novemb.	Decemb.	Annual
Rogun	1,047	794	811	810	1,100	1,200	1,241	1,209	1,028	645	847	1,016	11,748
Vakhsh System With Rogun	2,488	2,015	1,935	1,717	2,781	2,969	3,005	3,046	2,502	1,547	2,078	2,540	28,623

Source: TEAS Reservoir Operation Study - Appendices

For the selected alternative (1,290 MASL and 3,200 MW) it is assumed that the capital cost to complete the Rogun hydroelectric power plant would be of the order of US$ 5,500 million. The total capital cost of US$ 5,500 million is an overnight capital cost and includes owner's costs, financial charges (excluding interest) and decommissioning costs. An overnight cost is the cost of a project as if no interest was incurred during the construction period.

Based on a total project cost of US$ 5,500 million, the annual capital disbursements for the project are shown in Table 5-2.

The project is expected to start producing energy well before the reservoir is completely filled and to align capital expenditures with energy generation from the project it was decided to consider three major project milestones:

- The first major milestone is considered to coincide with the commissioning of the first units 5 and 6 and this is expected to start in year 7, after the start of construction, thus the first 6 years of the project's disbursements could be attributed to the first milestone
- The second major milestone is considered to coincide with the commissioning of the 6 units in their final arrangement and this is assumed to occur at the end of year 10 after the start of construction
- The third major milestone is considered to coincide with the completion of the dam and it is assumed to occur at the end of year 14 after the start of construction.

Table 5-2: Capital Disbursements

Year	Disbursement	
	(US$, million)	(%)
1	103.7	1.9

Year	Disbursement	
	(US$, million)	(%)
2	276.1	5.0
3	394.6	7.2
4	531.6	9.7
5	661.9	12.0
6	752.7	13.7
7	738.9	13.4
8	490.3	8.9
9	416.1	7.6
10	392.9	7.1
11	419.4	7.6
12	146.6	2.7
13	100.1	1.8
14	75.1	1.4
Total	**5,500.0**	**100.0**

For each of the above three major milestones it is intended to allocate project costs as follows:

Milestone	Cost (US$, million)	Year After Start of Construction
Commissioning of Units 5 & 6	2,720.6	7
Commissioning of all Units	2,038.3	10
Dam Completion	741.1	14
Total	**5,500.0**	

Once the entire project is completed, the operation and maintenance cost (O&M) is taken as 1.25% of the project's capital cost or US$ 68.75 million per year which is equivalent to US$ 21.5/kW-year. Once the reservoir is completely filled, Rogun is expected to be the regulating power plant in the Vakhsh system with Nurek having its reservoir always filled. The planned maintenance is expected to be carried out during the winter period.

Once Rogun starts operating, the energy production of all the hydroelectric power plants in Tajikistan is expected to surpass the demand especially during the summer months. For this surplus energy it is proposed to sell to undetermined markets at US$ 68.20/MWh. It is important to note that the amount of export is subject to the transferring capability of interconnected transmission lines as well as transmission facilities in the recipients' systems.

In the "without" Rogun scenarios the cost of decommissioning the existing Rogun facilities has to be considered and in this case a cost of US$ 200 million is being assumed. This amount would probably be evenly distributed over a period of 4 years in equal amounts starting in 2017.

The cost of the works required to provide protection against the probable maximum flood (PMF) have had an educated estimate of about US$ 1,000 million and this value is considered as an additional cost in the "without" Rogun scenarios. This amount should only start to be disbursed once Rogun's dam height reaches 300 m (same as Nurek) which coincide with year 12 after the start of construction, and continue for a total 4 years with each year having a disbursement of US$ 250 million.

5.2.1.1 Early Rogun Generation

The above presents the Rogun HPP characteristics based on the data, information and estimates described in the TEAS. However, it should be noted that work has been on-going at the Rogun site for many years and the entities responsible for the project consider that the project could start producing power at a much earlier date than that implied in the TEAS. Informed sources in Tajikistan believe that the first two units could be on line sometime in the mid of 2019 with the next two units to be in service in January 2023 and the last two units to be in service by July 2023. It should be noted that call for tenders for certain major equipment and works has been published.

As an alternative to the dates identified in the TEAS, it was decided to consider these alternate in-service dates for Rogun and thus denominating this alternative Early Rogun Generation. In this case, the minimum reservoir level is expected to be reached 39 months after the commissioning of units 5 and 6 or by October 2022. The dam is to be completed 90 months after the commissioning of units 5 and 6 (January 2027) the reservoir is expected to be filled some 5 years after the dam is completed (December 2031).

The total energy, once the reservoir is filled, is that outlined in Table 5-1 but the project would generate energy starting in mid 2019 and the monthly energies generated from mid 2019 to 2031 are shown in Table C-4 in Appendix C.

In the case of Early Generation, it is assumed that the capital cost to complete the Rogun hydroelectric power plant would be of the order of US$ 5,500 million with US$1,500 million to be spent from 2015 to 2019 for the units 5 and 6. Other costs occur in 2019 so that the works for the total project can continue.

The total capital cost of US$ 5,500 million is an overnight capital cost and includes owner’s costs, financial charges (excluding interest) and decommissioning costs.

The annual capital disbursements for the project were determined based on information obtained from informed sources and the values used in the previous sub-section.

Based on a total project cost of US$ 5,500 million, the assumed annual capital disbursements for the project are shown inTable 5-3.

Table 5-3: Capital Disbursements for Early Rogun Generation

Year	Disbursement	
	(US$, million)	(%)
2015	196.0	3.6
2016	313.7	5.7
2017	396.0	7.2
2018	401.5	7.3
2019	660.7	12.0
2020	752.7	13.7
2021	738.9	13.4
2022	490.3	8.9
2023	416.1	7.6
2024	392.9	7.1
2025	419.4	7.6
2026	246.7	4.5
2027	75.1	1.4
Total	**5,500.0**	**100.0**

Even though the dam is to be completed by January 2027, some US$ 75.1 million are assumed to be spent in 2027 in order to complete some outstanding works.

Once the entire project is completed, the operation and maintenance cost (O&M) is taken as 1.25% of the project's capital cost or US$ 68.75 million per year which is equivalent to US$ 21.5/kW-year. From 2019 to the end of 2022 the O&M is assumed to be US$18.8 million per year and from 2023 to 2027 the O&M is assumed to be US$ 54.6 million per year.

5.2.2 Candidate Hydroelectric Power Plants with Feasibility or Prefeasibility Study Report

As mentioned in Section 5.2, studies were provided by the Ministry for the Fandarya HPP, Sanobad HPP in the Pyandzh River, Nurabad 1 and Nurabad 2, Nurek 2 HPP, Ayni HPP, Shurob HPP and Yavan. Due to some issues in the documentation, the Nurabad-1 and Nurabad-2 projects were excluded.Table 5-4 presents the installed capacity and energy capability of each of the candidate hydroelectric projects with feasibility or prefeasibility study reports.

Table 5-4: Capability of Hydro Projects with Studies

Hydro Project	Installed Capacity		Annual Energy	
	No of Units	Total (MW)	Average (GWh)	Firm (GWh)
Fandarya	5	182.5	569	475
Sanobad	1	125	1,082	1,053
Nurek 2 [1]	4	100	579.9	517.9
Ayni	2	160	637	579
Yavan	4	126	451	394
Shurob	4	862.5	3,213	2,656
Total		1,556.0	6,531.9	5,674.9

Note: [1] Energy values for 2022

The monthly average and firm energy for the above projects as well as the capacity factors based on average energy are presented in Appendix C. Details of the energy studies to arrive at these values are presented in Appendix B3.

Sanobad appears to be under installed and provides constant energy throughout the year. It appears that the construction of Nurek 2 could raise some issues since the plant would be located near a town and the plant could limit the releases at Nurek due to tail water levels.

The Rogun HPP has to be in operation in order for Shurob to achieve its full potential. Given the preceeding premises and the Rogun HPP's likely year to start construction, its required construction period for its stage 1 and 2 to be brought on line as well as the construction period for the Shurob HPP outlined in the feasibility study (11 years), the Shurob HPP was not considered in the initial studies since it would only be available to be commissioned very late during the simulation period and it would thus not generate sufficient benefits during the remaining study period to offset its costs. However, it was included in the generation expansion studies considering early Rogun generation. Given the size of the Shurob HPP, its characteristics are detailed in Appendix C and are summarized after

Table 5-5.

Table 5-5 presents the estimated capital cost for each project as well as the construction period and the lead time. These costs are overnight capital costs and include owner's costs, financial charges (no interest) and decommissioning costs. It should be noted that the capital cost estimate for the Sanobad project does not include the cost for a 220 kV transmission line and associated substations to connect the project to the main Tajik grid. The O&M cost for each of the hydro projects with studies is assumed to be 1.5% of the capital cost per year.

Table 5-5: Lead Time and Capital Cost of Projects with Studies

Project	Lead Time (Years)	Construction Period (Years)	Capital Cost	
			US$, million)	US$/kW
Fandarya	5	2.5	305.1	1,671.8
Sanobad	6	4	280.0	2,240.0
Nurek 2	5	3	148.5	1,485.0
Ayni	5	3	304.0	1,900.0
Yavan	6	3.5	255.5	2,027.8
Shurob	15	11	1,710	1982.6

A) Shurob Candidate Hydroelectric Power Plant

The Shurob HPP feasibility study was prepared in 2011 for the Ministry of Energy and Industry by Nurofar. The Shurob HPP would be located on the Vaksh River, downstream of Rogun and upstream of Nurek, and consist of a rock fill dam and a power house with a total generating capacity of 862.5 MW obtained from four generators each rated at 219.2 MW. The estimated average annual energy generation would be 3,213 GWh while the firm energy amounts to 2,656 GWh.

The feasibility study reviewed did not provide the plant's firm energy or the monthly distribution of energy. These values were estimated by correlating the total average energy to the equivalent values for Rogun. In order to arrive at the monthly firm and average energy values for Shurob, it was assumed that construction of the HPP would start in 2020 (after Rogun's first stage), the plant would be commissioned by 2031, at which time the Rogun dam would be completely filled, and the energy generation is highly correlated to that produced by Rogun. Table 5-6 presents the resulting estimates from the correlation with the monthly values for the Rogun energy. The plant's capacity factor under average conditions is 42.5% on an annual basis and 71% in the month of August and this seems to indicate that the plant has an over installation of capacity but the selection of this capacity is not apparent from the feasibility studies.

Table 5-6: Shurob HPP Monthly Average and Firm Energy

Hydro Condition	January	February	March	April	May	June	July	August	Septemb.	October	Novemb.	Decemb.	Annual
Average (GWh)	255.3	235.6	208.0	215.7	248.3	270.0	279.7	458.3	323.8	208.7	245.1	264.5	3,213
Firm (GWh)	236.7	179.5	183.4	183.1	248.7	271.3	280.6	273.4	232.4	145.8	191.5	229.7	2,656

Source: Corelation with TEAS Reservoir Operation Study - Appendices

The HPP's generation would be evacuated to the grid by 500 kV transmission lines some 20 km long tapping into the Rogun to Dushanbe transmission lines.

The capital cost was estimated as 6,395.157 million Somoni with a cost reference of the 2011 fourth quarter which is equivalent to US$ 1,343.52 million. However, the World Bank report entitled "Tajikistan's Winter Energy Crisis: Electricity Supply and Demand Alternatives" of November 2012 showed a project cost of US$ 1,565 million (early 2012) and in terms of 2015 values this is equivalent to US$ 1,710 million (escalation at 3% per year).

The annual capital disbursements were determined from the values shown in the project schedule presented in the feasibility study. Based on a total project cost of US$ 1,710 million the annual capital disbursements are shown in

Table 5-7.

Table 5-7: Shurob HPP Capital Disbursements

Year	Disbursement	
	(US$, million)	(%)
1	48.6	2.8
2	87.4	5.1
3	124.0	7.3
4	133.1	7.8
5	157.1	9.2
6	225.7	13.2
7	302.9	17.7
8	257.3	15.0
9	174.8	10.2
10	124.1	7.3
11	75.0	4.4
Total	**1,710.0**	**100.0**

Once the entire project is completed, the operation and maintenance cost (O&M) is taken as 1.25% of the project's capital cost or US$ 21.375 million per year which is equivalent to US$ 24.8/kW-year.

5.2.3 Candidate Hydroelectric Power Plants without Feasibility or Prefeasibility Study Reports

In addition to the above projects for which studies have been provided, Appendix C provides a list of candidate hydro projects that were mentioned in other reports but for which feasibility or pre-feasibility study reports were not available for MHI to review.

Since specific studies including location, size, hydrology and capital cost are not available, these HPPs were not considered as generation sources to be included in the PSDMP.

The list may include potentially important candidate projects which could be developed to form a part of the future development plan. A ranking of their potential should be carried out in order to define priorities for the preparation of detailed feasibility studies of the most likely options.

5.3 COAL FIRED GENERATION

The explored and proven coal reserves in the country amount to more than 4.5 billion tonnes distributed over 40 deposits. There are currently 16 enterprises actively involved in development of 13 coal deposits. Table 5-8 provides a summary of a few coal reserves at the principal mines in the country, which were posted on the MoEI's web site with information collected from the relevant study reports.

Table 5-8: Main Coal Resources

Mine	In Service Year	Type of Coal	Estimated Reserve (Million Ton)	Calorific Value (kcal/kg)	Sulfur (%)	Nitrogen (%)	Mercury (%)
Fon Yagnob	1983	Bituminous	800	7,936-8,463	0.1-1.96		

Mine	In Service Year	Type of Coal	Estimated Reserve (Million Ton)	Calorific Value (kcal/kg)	Sulfur (%)	Nitrogen (%)	Mercury (%)
Khakimi	1932	Anthracite	42	6,453-7,780	0.16-0.4		
Miyanadu		Anthracite	645	8373	1.25		
Nazar-Ailoq	1991	Anthracite	300	8,394	0.13-0.62	1.04-1.52	
Ravnou			179	7,576			
Saiyed		Anthracite	1	7,385			
Shurob	1939	Lignite	130	6,679	1.05		
Ziddy	1980	Anthracite	90	4,689-7,471	0.51-0.68		

As part of a recent feasibility study for phase 2 of the Dushanbe 2 CHP plant, a coal analysis was carried out. The analysis results showed an average heat content of 21.4 MJ/kg for the coal being supplied to the plant and this value is used in the present study.

Based on previous studies, there are at least three coal mines that could be used to supply fuel for power generation in the near future; Ziddy, Shurob and Fon Yagnob. These three mines have a total estimated proven reserve of around 1,020 million tonnes and could supply several new power plants with a total capacity greater than 5,000 MW.

The size of a coal fired generating units can range from 10 MW to over 1,000 MW. The typical service life of a coal fired generating unit could vary from 30 to 50 years. However in economic and financial analysis, an economic life of 20 to 30 years is normally used. Based on the potential electric load growth over the next 20 years, the unit size of between 150 MW and 350 MW could be suitable to the BT electric system.

The lead time to develop a 150 MW or 350 MW coal generating unit could be six to seven years if a standard (or off-the-shelf) technology is selected. Fast tracking could of course reduce the lead time.

A feasibility study for the Shurob thermal power plant was completed in May 2005 and the plant was to be located in the proximity of the Shurob coal field. The plant would use CFB boilers and have four generating units, each at 150 MW, which are to be connected to the BT system with 220 kV transmission lines.

For the PSDMP, the selected candidate coal-fired power units include 50 MW CHP, 150 MW CHP, 150 MW TPP and 350 MW TPP, all with CFB boilers as this technology fits well with the existing system conditions and requirements as well as system demand requirements in the planning horizon.

Table 5-9 shows the main technical and economic parameters of these three generation technologies.

Table 5-9: Coal Fired Generation Technologies

Generation Technology	CHP	CHP	TPP	TPP
Fuel	Coal			
Plant Gross Capacity (MW)	50	150	150	300
Plant Net Capacity (MW)	44	135	135	276
Number of Units	1	1	1	1
Economic Life (Year)	30	30	30	30
Lead Time (Year)	5-6	5-6	5-6	6-7
Earliest On-Line Year	2020/2021	2020/2021	2020/2021	2021/2022
Equivalent Availability (%)	85	85	85	85
Equivalent Forced Outage Rate (%)	7	7	7	7
Planed Outage Rate (%)	8	8	8	8
Production Profile (Daily)	Dispatched as per system requirements			
Production Profile (Seasonal)	Dispatched as per system requirements			
Net Heat Rate (KJ/kWh, HHV)	10,000	9,600	11,600	11,000
Primary Fuel Cost ($/GJ)	3.21	3.21	2.11	2.11
Overall Capitalized Cost ($M)	69.1	197.6	207.4	411.5
Plant EPC ($M)	52.5	150.0	157.5	300.0
Owner's Cost ($M)	5.3	15.0	15.8	30.0
Plant CAPEX Disbursement Flow (%)	30,40,30			20,25,30,25
Plant IDC ($M)	9.1	25.9	27.2	67.6
Financing Charges including Commitment ($M)	1.0	2.9	3.0	6.0
Decommissioning Cost ($M)	1.3	3.8	4.0	8.0
Overall Plant Capital Unit Capacity Cost ($/kW)	1,571	1,463	1,537	1,491
Fixed O&M Cost ($/kW-Year)	23.57	21.95	23.05	22.36
Variable O&M Cost ($/MWh)	10.72	10.24	11.01	10.52
Insurance Cost ($M/Year)	0.173	0.494	0.519	1.029
Interim Replacement Cost ($M/Year)	0.173	0.494	0.519	1.029

The following is a short description of some of the factors for the above candidates:

- The equivalent availability of a unit would be around 85%, which is based on the information available in the North American Electric Reliability Corporation (NERC) database
- The heat rate of CHP includes the compensation from heat and hot water sale
- Based on the feasibility studies and negotiations with foreign investors, the EPC costs for 50 MW CHP, 150 MW CHP, 150 MW TPP and 350 MW TPP technologies have been estimated at $1,050, $1,000, $1,050 and $1,000 per gross unit capacity (kW) respectively.
- Owner's cost has been estimated at 10% of the total EPC cost, 1.5% of the sum of EPC, owner's cost and IDC is assumed to be the financing charges including commitment fees, and 2% of the sum of EPC, owner's cost and IDC is assumed to be the decommissioning costs, which is allocated at the beginning of the unit's operation
- Fixed operation & maintenance (O&M) cost was calculated based on 1.5% of the unit's total capitalized cost and variable O&M cost was calculated based on 1.5% of the unit's total capitalized cost and 40% capacity factor and includes also offset allowance for GHG emissions estimated at $5/Tonne
- Annual insurance cost is assumed to be 0.25% of the total capitalized cost, annual fund contribution to the interim replacement cost is assumed to be 0.25% of the total capitalized cost.

5.4 Natural Gas Fuelled Generation

According to the information collected from the MoEI, the potential reserve of oil and gas in Tajikistan was estimated at some 1,330 million tonnes of oil equivalent of which oil reserves account for some 177 million tonnes. There are several companies active in the oil and gas exploration in Tajikistan.

Since as of yet there are no known, proved and commercially viable reserves of natural gas in Tajikistan for power generation, the natural gas fired generation technologies proposed in the PSDMP are based on gas imported from other countries.

For this study, the net sizes selected for CCGTs are 150 MW and 300 MW and the net sizes for GTs are 50 and 100 MW. In the case of a 300 MW unit, it is expected that there would be two GTs, each rated at some 100 MW and one steam turbine rated at 100 MW.

Table 5-10 presents the main technical and economical parameters for the 150 MW and 300 MW CCGT technologies as well as the 50 MW and 100 MW GT technologies fired by natural gas.

Table 5-10: Natural Gas Fuelled Generation Technologies

Generation Technology		CCGT	CCGT	GT	GT
Fuel		Imported Natural Gas			
Plant Gross Capacity (MW)		156	312	51	102
Plant Net Capacity (MW)		150	300	50	100
Number of Units		1	1	1	1
Economic Life (Year)		25	25	20	20
Lead Time (Year)		5-6	5-6	4-5	4-5
Earliest On-Line Year		2020/2021	2020/2021	2019/2020	2019/2020
Equivalent Availability (%)		88	88	91	91
Equivalent Forced Outage Rate (%)		6.0	6.0	5.0	5.0
Planed Outage Rate (%)		6.0	6.0	4.0	4.0
Production Profile (Daily)		Dispatched as per system requirements			
Production Profile (Seasonal)		Dispatched as per system requirements			
Net Heat Rate (KJ/kWh, HHV)		7,400	7,260	11,200	11,000
Primary Fuel Cost ($/GJ)		10	10	10	10
Overall Capitalized Cost ($M)		177.8	335.8	41.1	75.9
	Plant EPC ($M)	135.0	255.0	32.5	60.0
	Owner's Cost ($M)	13.5	25.5	3.3	6.0
	Plant CAPEX Disbursement Flow (%)	30,40,30		60,40	
	Plant IDC ($M)	23.3	44.0	4.0	7.4
	Financing Charges including Commitment ($M)	2.6	4.9	0.6	1.1
	Decommissioning Cost ($M)	3.4	6.5	0.8	1.5
Overall Plant Capital Unit Capacity Cost ($/kW)		1,185	1,119	823	759
Fixed O&M Cost ($/kW-Year)		17.78	16.79	12.34	11.39
Variable O&M Cost ($/MWh)		8.63	8.22	15.35	14.34
Insurance Cost ($M/Year)		0.445	0.840	0.103	0.190
Interim Replacement Cost ($M/Year)		0.445	0.840	0.103	0.190

The following is a short description of some of the factors for the selected CCGT and GT sizes:

- The CCGT and GT technologies for the selected size ranges are technically proven and commercially available and have been widely used in electric power generation applications around the world
- The CCGTs and GTs would be fuelled by the imported natural gas, supplied through the existing trunk pipe lines
- Based information from the NERC database, the equivalent availability of a plant would be from 88% to 91%
- The natural gas price is the delivered price to the power plants
- The EPC costs for CCGT 150 MW, CCGT 300 MW, GT 50 MW GT 100 MW have been estimated at $900, $850, $650 and $600 per net unit capacity (kW) respectively
- Owner's cost has been estimated at 10% of the total EPC cost, 1.5% of the sum of EPC, owner's cost and IDC is assumed to be the financing charges including commitment fees and 2% of the sum of EPC, owner's cost and IDC is assumed to be the decommissioning costs, which is allocated at the beginning of the unit's operation
- Fixed operation & maintenance (O&M) cost was calculated based on 1.5% of the unit's total capitalized cost, variable O&M cost was calculated based on 2% of the unit's total capitalized cost and 40% capacity factor for CCGTs and 15% capacity factor for GTs. The offset allowance for GHG emissions is also included in this component
- Annual insurance cost is assumed to be 0.25% of the total capitalized cost, annual fund contribution to the interim replacement cost is assumed to be 0.25% of the total capitalized cost.

5.5 Fuel Oil Fired Generation

For this study, the 20 MW medium speed diesel (MSD) generator set burning HFO has been considered as well as the LFO fuelled 150 MW and 300 MW CCGTs, and 50 MW and 100 MW GTs. MSD engines used to power large electrical generators run at approximately 400 to 800 rpm and the largest medium-speed engines in production are in sizes of up to approximately 20 MW.

The prices of the fuel oils used to fire these generation technologies are based on the crude oil prices and are presented in Section 4. Table 5-11 shows the technical and economic parameters for the selected fuel oil fired generation technologies.

The parameters presented in Table 5-11 for CCGT and GT technologies are similar to those given in Table 5-10, except for heat rate, fuel cost and emission factors. The following presents only the descriptions and explanations of the differences:

- The MSD, CCGT and GT technologies using fuel oil for the selected size ranges are technically proven and commercially available and have been widely used in electric power generation applications around the world
- It is expected that the equivalent availability of an MSD, CCGT and GT would be some 91%, 88% and 91% respectively based on the information from the NERC database
- The EPC costs for MSD 20 MW, CCGT 150 MW, CCGT 300 MW, GT 50 MW and GT 100 MW have been estimated at $1,000, $900, $850, $650 and $600 per net unit capacity (kW) respectively
- Variable O&M cost was calculated based on 2% of the unit's total capitalized cost and 40% capacity factor for MSDs and CCGTs and 15% capacity factor for GTs. It also includes the offset allowance for GHG emissions.

Table 5-11: Fuel Oil Fired Generation Technologies

Generation Technology	Diesel	CCGT	CCGT	GT	GT
Fuel	HFO	LFO			
Plant Gross Capacity (MW)	20.8	156	312	51	102
Plant Net Capacity (MW)	20	150	300	50	100
Number of Units	1	1	1	1	1
Economic Life (Year)	25	25	25	20	20
Lead Time (Year)	4-5	5-6	5-7	4-5	4-5
Earliest On-Line Year	2019/2020	2020/2021	2020/2022	2019/2020	2019/2020
Equivalent Availability (%)	91	88	88	91	91
Equivalent Forced Outage Rate (%)	5.0	6.0	6.0	5.0	5.0
Planed Outage Rate (%)	4.0	6.0	6.0	4.0	4.0
Production Profile (Daily)	Dispatch as per system requirements				
Production Profile (Seasonal)	Dispatch as per system requirements				
Net Heat Rate (KJ/kWh, HHV)	8,860	6,980	6,850	10,570	10,380
Primary Fuel Cost ($/GJ)	15.17	24.47	24.47	24.47	24.47
Overall Capitalized Cost ($M)	25.3	177.8	335.8	41.1	75.9
Plant EPC ($M)	20.0	135.0	255.0	32.5	60.0
Owner's Cost ($M)	2.0	13.5	25.5	3.3	6.0
Plant CAPEX Disbursement Flow (%)	60,40	30,40,30		60,40	
Plant IDC ($M)	2.5	23.3	44.0	4.0	7.4
Financing Charges including Commitment ($M)	0.4	2.6	4.9	0.6	1.1
Decommissioning Cost ($M)	0.5	3.4	6.5	0.8	1.5
Overall Plant Capital Unit Capacity Cost ($/kW)	1,266	1,185	1,119	823	759
Fixed O&M Cost ($/kW-Year)	18.99	17.78	16.79	12.34	11.39
Variable O&M Cost ($/MWh)	10.30	9.19	8.76	16.19	15.16
Insurance Cost ($M/Year)	0.063	0.445	0.840	0.103	0.190
Interim Replacement Cost ($M/Year)	0.063	0.445	0.840	0.103	0.190

5.6 NON – HYDRO RENEWABLE ENERGIES

5.6.1 Wind

Figure 5-2 shows the country's wind resource map prepared by 3TIER, which was collected from a document prepared for the European Bank for Reconstruction and Development (EBRD).

It can be seen from Figure 5-2, the most promising areas are the Pamirs northward of the Sarez Lake in GBD, the Turkmenistan ridge in the Zeravshan river headwater and the region from the Vakhsh ridge to the boundary with Afghanistan.

Given Tajikistan's endowment with hydro power and the location of the wind resources, wind power was not considered as a priority supply option to the power sector development master plan. Nevertheless, since wind power is technically feasible, a total of 50 MW are included in the master plan. Table 5-12 presents the main technical and economic parameters of the technology for two selected plant sizes, 10 MW and 50 MW.

The following is a short description of some of the factors for the two sizes of wind power plants:

- Wind power technologies have been widely used around the world over the last several years, and are mature both technically and commercially
- The expected annual capacity factor for wind power plants could range from 30% to 40% depending on the average wind speed. Availability of the wind power plant output is totally dependent upon the availability of wind
- The EPC costs are $1,500/kW and $1,400/kW for the 10 MW and 50 MW plants.
- Owner's cost has been estimated at 10% of the total EPC cost, 1.5% of the sum of EPC, owner's cost and IDC is assumed to be the financing charges including commitment fees and 2% of the sum of EPC, owner's cost and IDC is assumed to be the decommissioning costs, which is allocated at the beginning of the unit's operation
- Fixed operation & maintenance (O&M) cost was calculated based on 2.5% of the unit's total capitalized cost
- Annual insurance cost is assumed to be 0.25% of the total capitalized cost and annual fund contribution to the interim replacement cost is assumed to be 0.25% of the total capitalized cost.

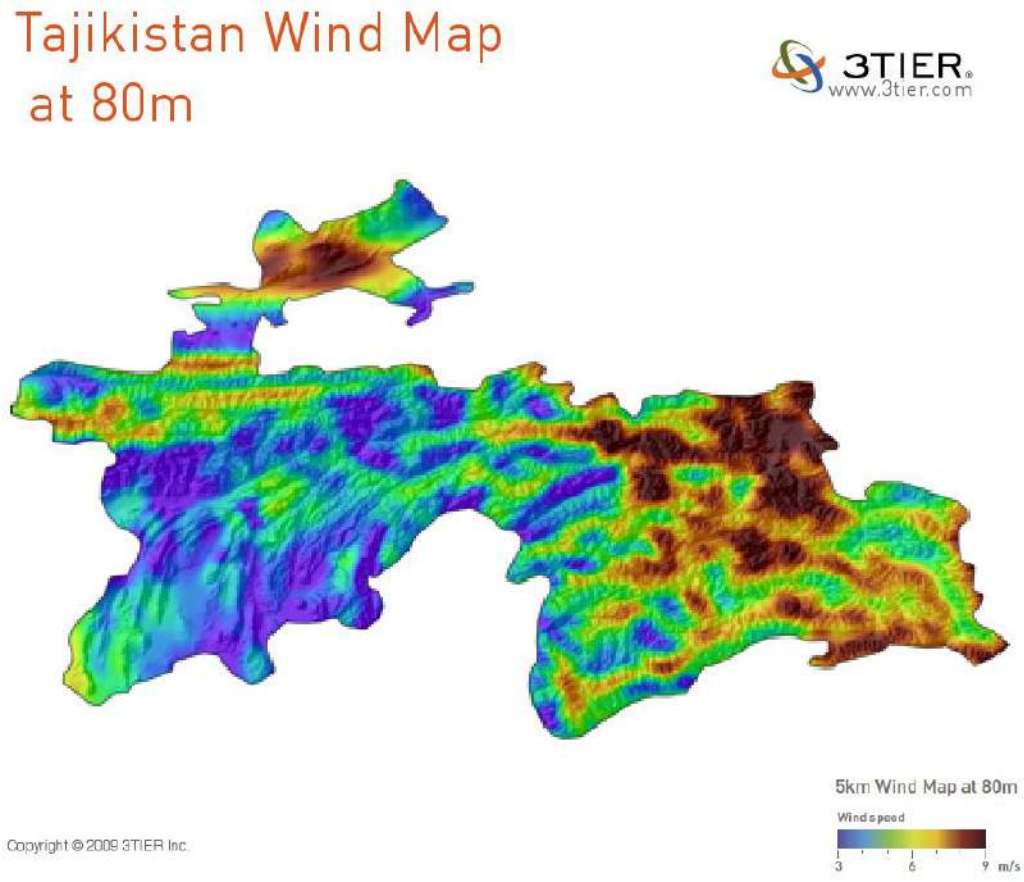

Figure 5-2: Wind Resource Map

Table 5-12: Wind Power Technologies

Wind Power Plant Name	Wind Power	Wind Power
Fuel	Wind	
Plant Gross Capacity (MW)	10.2	51
Plant Net Capacity (MW)	10	50
Number of Units	1	1
Expected Annual Energy Production (GWh)	26.3	131.4
Annual Capacity Factor (%)	30.0	30.0
Economic Life (Year)	20	20
Lead Time (Year)	4	4
Earliest On-Line Year	2019	2019
Equivalent Availability (%)		
Equivalent Forced Outage Rate (%)		
Planed Outage Rate (%)		
Production Profile (Daily)	Non-dispatchable	
Production Profile (Seasonal)	Non-dispatchable	
Overall Capitalized Cost ($M)	19.0	88.6
Plant EPC ($M)	15.0	70.0
Owner's Cost ($M)	1.5	7.0
Plant CAPEX Disbursement Flow (%)	60,40	
Plant IDC ($M)	1.8	8.6
Financing Charges including Commitment ($M)	0.3	1.3
Decommissioning Cost ($M)	0.4	1.7
Overall Plant Capital Unit Capacity Cost ($/kW)	1,899	1,772
Fixed O&M Cost ($/kW-Year)	47.46	44.30
Insurance Cost ($M/Year)	0.047	0.221
Interim Replacement Cost ($M/Year)	0.047	0.221

5.6.2 Solar

The climate conditions of Tajikistan are considered as favourable for using solar energy. The solar radiation is especially high in the mountainous regions. The theoretical potential of the country is estimated to be about 25 billion kWh/year.

Due to a wide variety of factors, solar power is most probably not a technology, which can solve the power supply problem of Tajikistan. Solar power is therefore not considered as a priority supply option to the PSDMP. However, since solar PV is technically feasible, a total of 50 MW is included in the master plan. Table 5-13 presents the main technical and economic parameters of the technology for two selected sizes, 10 MW and 50 MW.

Table 5-13: Solar Power Technologies

Solar Power Plant Name		Solar PV	Solar PV
Fuel		Sun Light	
Plant Gross Capacity (MW)		10.2	51
Plant Net Capacity (MW)		10	50
Number of Units		1	1
Expected Annual Energy Production (GWh)		15.4	77.0
Annual Capacity Factor (%)		17.6	17.6
Economic Life (Year)		20	20
Lead Time (Year)		4	4
Earliest On-Line Year		2019	2019
Equivalent Availability (%)			
Equivalent Forced Outage Rate (%)			
Planed Outage Rate (%)			
Production Profile (Daily)		Non-dispatchable	
Production Profile (Seasonal)		Non-dispatchable	
Overall Capitalized Cost ($M)		22.8	107.6
	Plant EPC ($M)	18.0	85.0
	Owner's Cost ($M)	1.8	8.5
	Plant CAPEX Disbursement Flow (%)	60,40	
	Plant IDC ($M)	2.2	10.4
	Financing Charges including Commitment ($M)	0.3	1.6
	Decommissioning Cost ($M)	0.4	2.1
Overall Plant Capital Unit Capacity Cost ($/kW)		2,278	2,152
Fixed O&M Cost ($/kW-Year)		56.96	53.79
Insurance Cost ($M/Year)		0.057	0.269
Interim Replacement Cost ($M/Year)		0.057	0.269

The following is a short description of the factors for the two sizes of solar PV power plants:

- Only solar PV technologies will be considered in this analysis and these are mature both technically and commercially
- The expected annual capacity factor for solar PV is taken as 17.6%
- Availability of the PV solar output is totally dependent upon the availability of sun light
- The EPC costs are $1,800/kW and $1,700/kW for the 10 MW and 50 MW plants.
- Owner's cost has been estimated at 10% of the total EPC cost, 1.5% of the sum of EPC, owner's cost and IDC is assumed to be the financing charges including commitment fees and 2% of the sum of EPC, owner's cost and IDC is assumed to be the decommissioning costs, which is allocated at the beginning of the unit's operation.
- Fixed operation & maintenance (O&M) cost was calculated based on 2.5% of the unit's total capitalized cost
- Annual insurance cost is assumed to be 0.25% of the total capitalized cost and annual fund contribution to the interim replacement cost is assumed to be 0.25% of the total capitalized cost.

5.6.3 Geothermal and Biomass

There is no information about geothermal potential in areas which are located near by the transmission network and can be used to develop geothermal power plants with a capacity of 10 MW or more.

In view of the geology specifics of the country, it may be considered to conduct the surface studies to identify prospective geothermal sites, which could support geothermal power plants. Hence geothermal energy is not considered as a source to contribute to the PSDMP.

There is no comprehensive assessment of the biomass potential of the country and for the purpose of this study, biomass is not considered as a generation expansion option.

5.7 Energy Efficiency

As part of the PSDMP, an energy efficiency and promotion plan report was prepared and issued in April 2014 and finalised in February 2015. The report identified some nine energy efficiency (EE) improvement measures, including CHP heating as potential EE improvement measures. Energy audits, pricing policy, building codes and energy policy in rural areas were not retained for further analysis for the reasons provided in the report.

Table 5-14 presents the summary of the potential savings that could be brought about by EE improvements. In some years more than 910 GWh could be saved by the implementation of these programs. By 2020, this amounts to 6.3% of the consumption without TALCO and Spot Loads.

The values contained in

Table 5-14 were incorporated into the demand forecast for the various regions along with the firm exports and the resulting demand forecast for the three growth scenarios is presented in Table 3-14.

Table 5-14: Potential Energy Savings Due to EE Improvements

Year	Public Awareness (GWh)	S&L [1] (GWh)	Water Pumping (GWh)	SHWH [2] (GWh)	CHP Heating (GWh)	Total (GWh)	Peak Demand (MW)
2015	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	50	100	100	20	32	302	74.2
2018	65	120	200	30	78	493	82.7
2019	75	140	300	40	110	665	132.2
2020	80	160	360	45	130	775	136.7
2021	80	184	436	55	157	912	141.2
2022	80	184	436	55	157	912	141.2
2023	80	184	436	55	157	912	141.2
2024	80	184	436	55	157	912	141.2
2025	80	184	436	55	157	912	141.2
2026	80	184	436	55	157	912	141.2
2027	65	160	436	55	157	873	133.8
2028	50	130	436	55	157	828	125.2
2029	-	-	436	55	157	648	91.0
2030	-	-	436	55	157	648	91.0
2031	-	-	436	55	157	648	91.0
2032	-	-	436	55	157	648	91.0
2033	-	-	436	55	157	648	91.0
2034	-	-	436	55	157	648	91.0
2035	-	-	436	55	157	648	91.0
2036	-	-	436	55	157	648	91.0
2037	-	-	436	55	157	648	91.0

Notes: [1] S&L Standards and Labellling [2] SHWH - Solar Hot Water Heaters

5.8 IMPORTS

There are in general three options for the potential imports: electricity imports directly from Uzbekistan, electricity imports from Turkmenistan through Uzbekistan and electricity imports from Turkmenistan through Afghanistan.

5.8.1 Electricity Imports Directly from Uzbekistan

It is recognized that with increasing domestic demand over the next few years, Uzbekistan is not expected to have surplus capacity in the winter. Nevertheless, some firm capacity could potentially be made available after new power plants are commissioned in Uzbekistan. Power could be available during low demand hours of the day which could save water in the Tajikistan reservoirs to be used during the peak hours to provide additional firm capacity. Moreover, it should be noted that electricity imports from Uzbekistan might be limited due to existing gas export contracts.

The potential imports from Uzbekistan could be modeled with the following parameters:

- Capacity: 300 MW
- Time: off-peak hours of Uzbekistan system during the winter season, i.e. about 12 hours a day for the six winter months, October to March
- Earliest available time: 2025
- Tariff: $40/MWh

5.8.2 Electricity Imports from Turkmenistan through Uzbekistan

Tapping Turkmenistan's extensive gas reserves for power generation and export would revitalize past efforts to contract Turkmenistan—Tajikistan energy trade through the existing transmission lines. Although transmission lines exist, they is no longer synchronized with the Central Asia grid.

The potential imports from Turkmenistan through Uzbekistan could be modeled with the following parameters:

- Firm power: 300 MW
- Time: any time during the six winter months, i.e. from October to March
- Earliest available time: 2025
- Tariff: $40/MWh

5.8.3 Electricity Imports from Turkmenistan through Afghanistan

The transmission line from 220kV Geran-2 SS to Afghanistan could provide an alternative or additional route for electricity imports to Tajikistan. This supply option depends on the timely availability of the transmission infrastructure in Afghanistan and the construction of one or more gas-fired plants in Turkmenistan specifically for electricity export.

The potential imports from Turkmenistan through Afghanistan could be modeled with the following parameters:

- Firm power: 150 MW for Stage 1 and 300 MW for Stage 2
- Time: any time during the six winter months, i.e. from October to March
- Earliest available time: 2020
- Tariff: $40/MWh

5.9 OTHER ENERGY RESOURCES

In international practice, nuclear power generation requires very large upfront capital investment and requires a good national technological base, a good regulatory framework and well trained human resources to run and maintain such power plants. However, Tajikistan has very large hydro power potential and has supply deficit only during the autumn/winter period, nuclear power generation is not considered to be an economically viable solution. For the purpose of this study, nuclear power will not be considered for the PSDMP.

There are no other technically viable generation options available to Tajikistan.

5.10 SCREENING OF THERMAL GENERATION RESOURCES

At this stage, a reasonable way to compare generation resources and technologies is to make a comparison of the unit cost of energy produced by each generation option including capital costs, operation and maintenance costs and fuel costs (if any).

Each of the generation categories has its own characteristics, drawbacks, costs and benefits when comparing the unit cost of energy including life of plant and operating characteristics. The unit cost of energy for each generation category presented in the following subsections harmonizes these parameters such that realistic comparisons can be made.

Energy efficiency was not considered at this stage since generation expansion plans are to be developed with and without this resource.

5.10.1 Cost of Generation Technologies (excluding HPPs)

The previous sections outlined the generation options available to meet the demand in Tajikistan for the next 25 years. The comparison of unit cost of energy is done by employing the so called screening curves where the unit cost of energy at different capacity factors is plotted and compared amongst the various generation resources. In lieu of unit cost energy, one can also have the unit cost of producing one kW per year at different capacity factors.

Figure 5-3 and Figure 5-4 show the unit cost of energy and total annual cost of the selected base load thermal generation technologies respectively. The similar information for the selected peak load thermal generation technologies is presented in Figure 5-5 and Figure 5-6.

For the selected base load thermal generation technologies, one could observe the following from Figure 5-3 and Figure 5-4:

- For the capacity factor range examined, from 10% to 90%, coal fired generation has the lowest cost (capacitor factors greater than 12%). The unit cost of energy varies from approximately $249/MWh at 10% capacity factor to $59/MWh at 90% capacity factor. The 350 MW unit size is slightly more economical than 150 MW unit size. This implies that 350 MW coal units should be constructed if there are no constraints due to demand, resources, transmission facilities, financing and other important aspects
- The next economical generation is the CCGT plant using imported natural gas. The unit cost of energy would be approximately $247/MWh at 10% capacity factor to $100/MWh at 90% capacity factor
- The most expensive generation option is the CCGT 300 MW plant fueled by LFO, which would have a unit cost of energy of some $343/MWh at 10% capacity factor and $195/MWh at 90% capacity factor
- The unit cost of energy of a 20 MW diesel unit using HFO varies from approximately $333/MWh at 10% capacity factor to $166/MWh at 90% capacity factor.

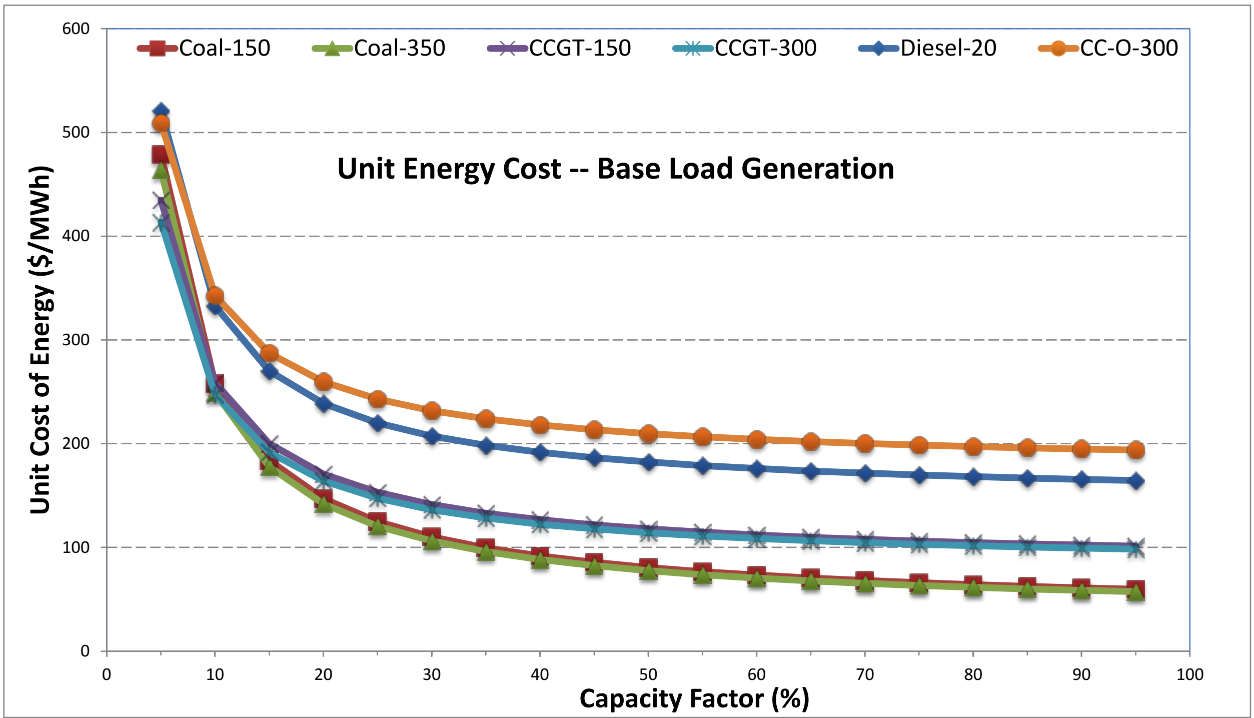

Figure 5-3: Unit Cost of Energy of Selected Base Load Generation

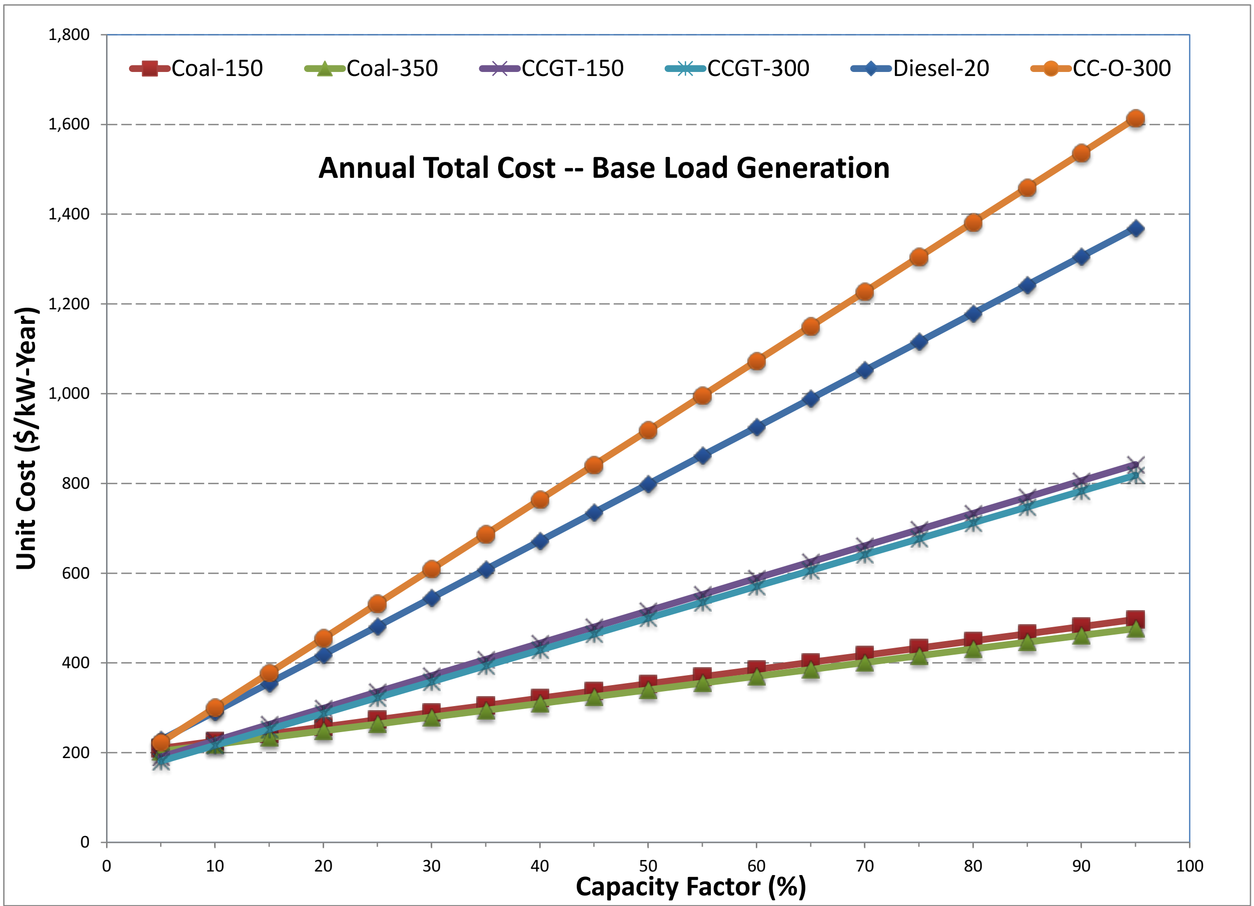

Figure 5-4: Total Annual Costs of Selected Base Load Generation

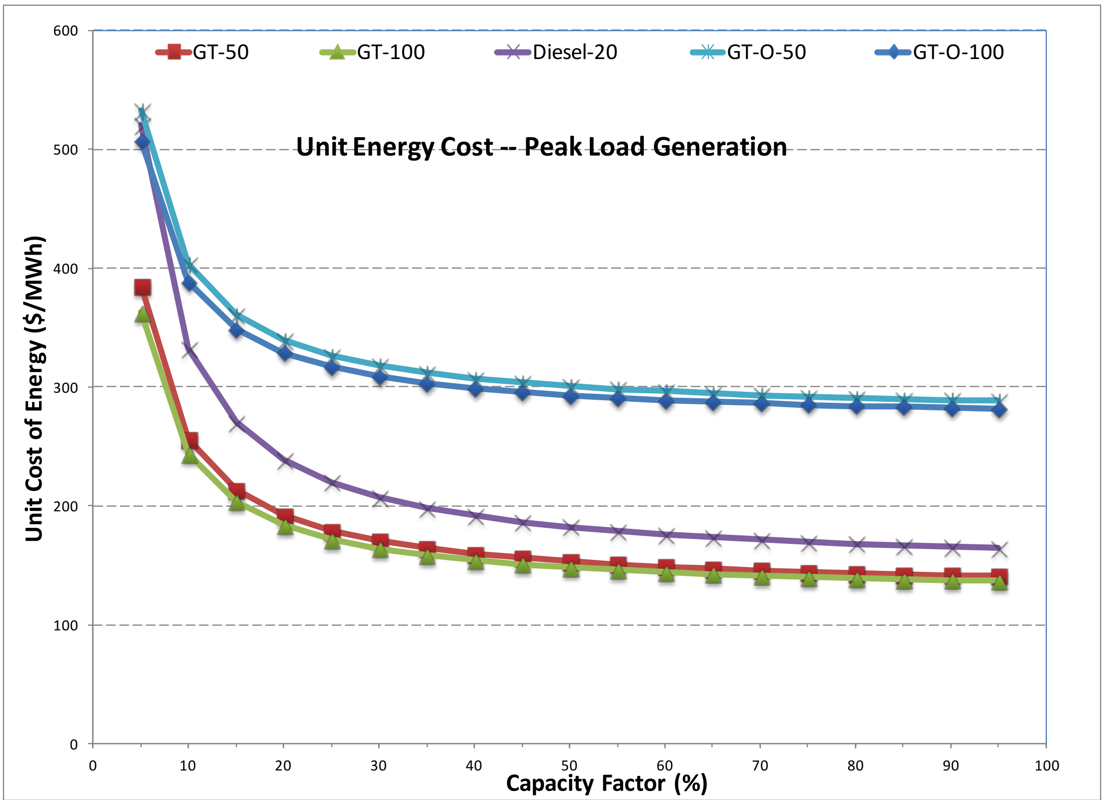

Figure 5-5: Unit Cost of Energy of Selected Peak Load Generation

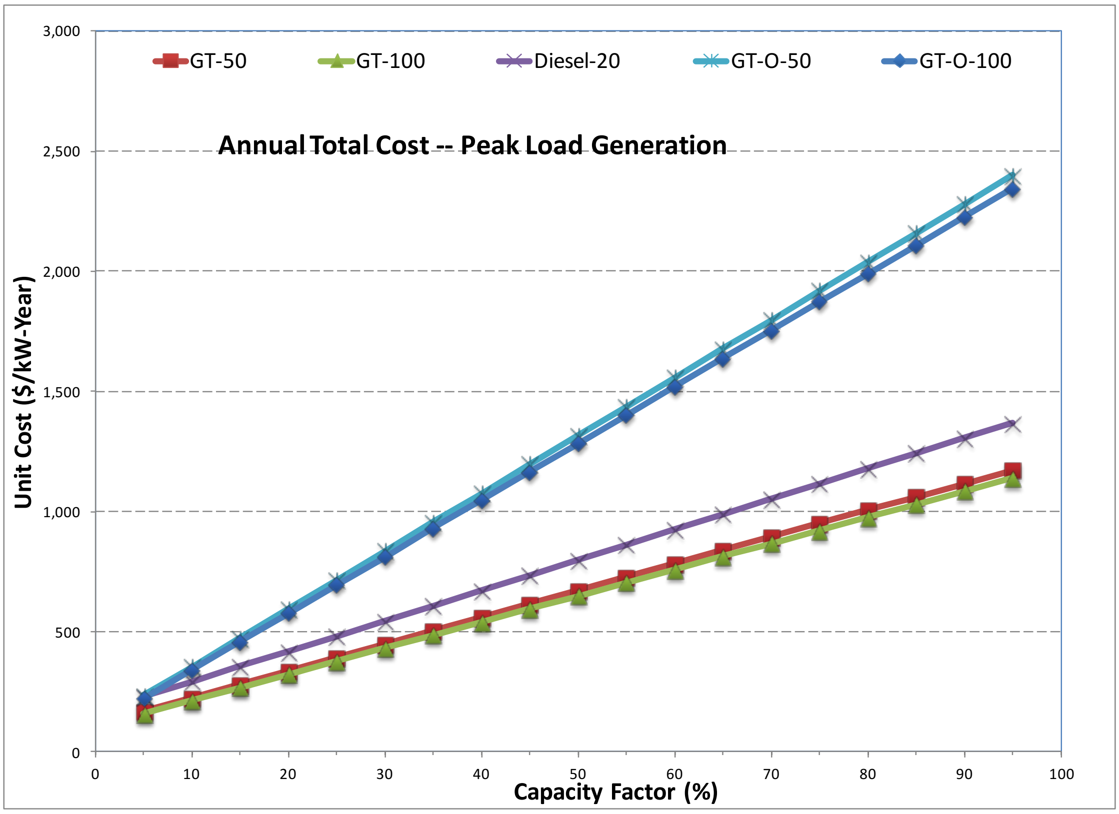

Figure 5-6: Total Annual Costs of Selected Peak Load Generation

Similarly, the following could be observed from Figure 5-5 and Figure 5-6 and for the selected peak load thermal generation technologies:

- Within the capacity factor range of 5% to 40%, the unit cost of energy of the gas turbines using imported natural gas is the lowest, i.e. $363/MWh at 5% capacity factor and $154/MWh at 40% capacity factor. The 100 MW gas turbine is slightly more cost effective than 50 MW gas turbine
- The next cost effective peak load generation is the 20 MW diesel unit using HFO (except for the cost at 5% capacity factor), which has a unit cost of energy of some $520/MWh at 5% capacity factor and $190/MWh at 40% capacity factor
- The most expensive peak load generation is the LFO fueled gas turbine, which has a unit cost of energy of some $510/MWh at 5% capacity factor and $300/MWh at 40% capacity factor. The 100 MW gas turbine is slightly more cost effective than 50 MW gas turbine.

5.10.2 Selection of Thermal Expansion Candidates

From the values presented in the previous subsection it can be concluded that coal fired units have the lowest cost for based load generation and the next lowest cost generation technology is a combined cycle plant using imported natural gas. For peak load generation, gas turbines using imported natural gas have the lowest cost. For ease of comparison, Figure 5-7 shows the unit cost of energy for six generation technologies, coal-fired 150 MW and 350 MW units, imported gas-fueled CCGT 150 MW and 300 MW units, and imported gas-fueled GT 50 MW and 100 MW units.

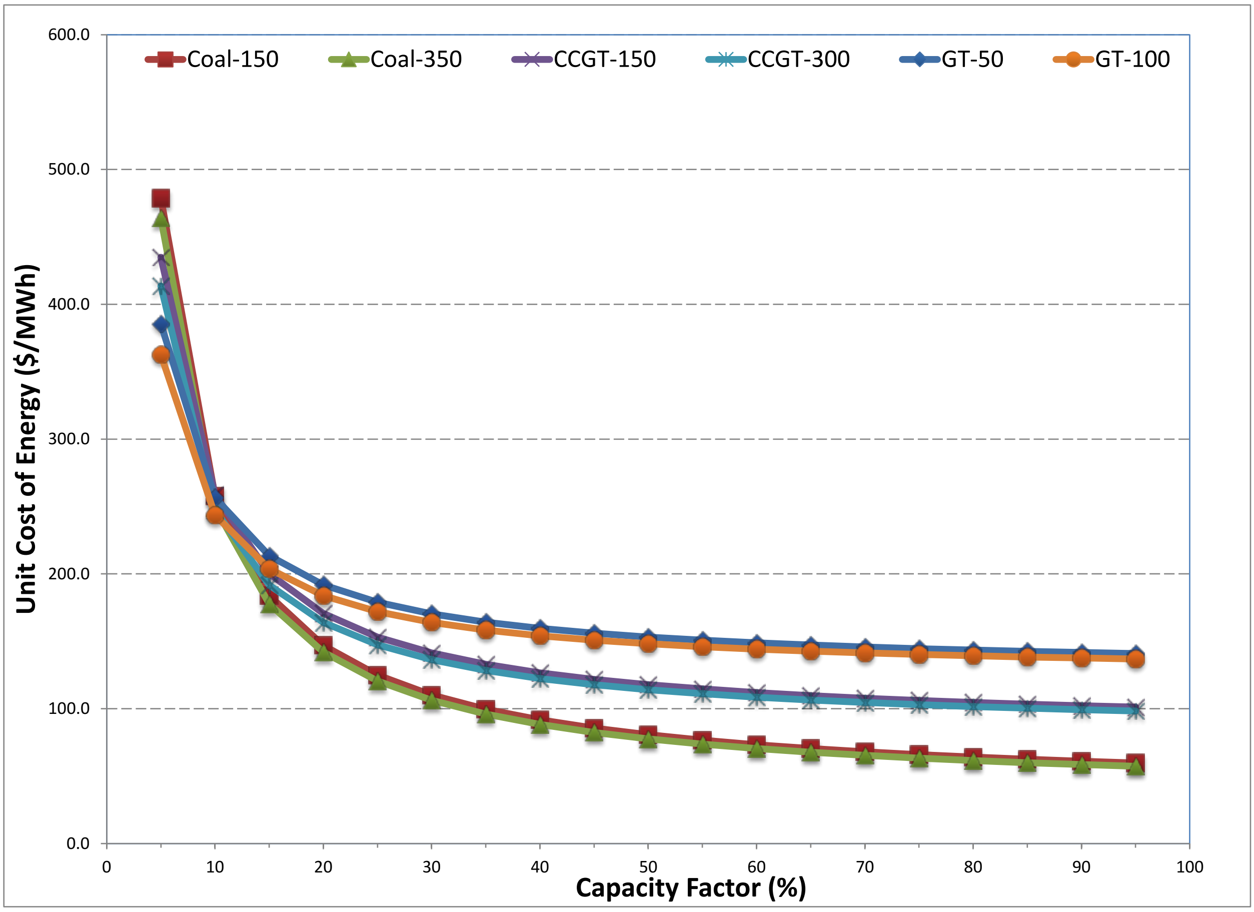

Figure 5-7: Comparison of Unit Cost of Energy of Selected Thermal Generation

With the six generation technologies plotted in the same graph, the following can be observed from Figure 5-7:

- For capacity factors higher than 12%, the unit cost of energy for coal 150 MW and 350 MW units is the lowest
- When the capacity factor is higher than 15%, the unit cost of energy for CCGT 150 MW and 300 MW is lower than that of GT 50 MW and GT100 MW units
- The unit cost of energy of GT 50 MW and 100 MW units is high

Based on these costs and the fact that the existing large hydro power plants have either large reservoirs or daily storage reservoir, and taking account of the fact that the winter month capacity factor of these hydro plants is low and should therefore act as peaking plants, it was determined that only base load thermal units should be considered further in formulation of generation expansion themes/scenarios in this study.

6. GENERATION EXPANSION PLANS

This section describes the principal decision factors used in the formulation and development of the generation expansion scenarios (for the Tajikistan national electricity grid) which were studied in preparing the PSDMP, presents the generation expansion scenarios along with their respective analysis and results, and selects the least cost generation expansion plans.

For ease of reference and clarity of the text, all tables associated with this section are shown at the end of the section.

6.1 PRINCIPAL DECISION FACTORS

In generation expansion planning, the principal decision factors for addition of generation units to a system include the forecast load demand, applicable energy policy, adopted reliability criteria, system cost and environmental and social impacts. A national energy policy may have already taken into account some of the key environmental and social impacts and the total system cost could include the offset allowance for the key environmental and social impacts. The reliability criteria used in generation planning are established based on system operation requirements. The planning work aims to simulate the real system operation as accurate as possible. Given a load demand forecast, the principal decision factors would be the established energy policy, the reliability planning criteria and cost. It is also important to note that over-building of generation capacity could sometimes be more cost effective, which means that the total generation cost could be lower if more new low cost generation units are added to the system even if the system without these new additions would meet the predefined reliability level.

In addition to other aspects, a national energy policy may provide directives on the requirements for electricity production and selection of generation types, technologies and locations (fuel diversification, renewable energy policy or renewable portfolio standard, domestic versus imports and/or locations within the country).

In this study, the adopted reliability criteria were not applied to the period from 2015 to 2020 due to the serious system deficit in power generation and the lead time required to bring new power plants on line. However, generation units would be added to the system in order to meet the LOLP criterion of 5 days per year for the study horizon from 2021 to 2039, which provides adequate time to achieve the specified reliability goal. In addition, a EUE criterion has been used as a companion criterion with EUE not to exceed a value of 1%.

6.2 FORMULATION OF GENERATION EXPANSION SCENARIOS

The energy efficiency programs, generation expansion plans were formulated and studied with the following three themes:

- Without Rogun HPP
- With Rogun HPP
- With Early Rogun Generation

The generation resources and technologies used in this PSDMP have been identified and analysed in the last section (Section 5 – Generation Resources and Technologies), and these include hydro, coal, natural gas, fuel oil and non-hydro renewable such as wind, solar, geothermal and biomass. Based on that analysis and generation cost, it was determined that each of the generation expansion plans under study would include a total of 20 MW of wind power (two 10 MW plants) and 50 MW of solar PV power which are evenly distributed among five years, i.e. from 2021 to 2025.

As per the screening curves results presented in Section 5 for the base load generation and peak load generation technologies as shown in Figure 5-3 to Figure 5-7, it was found that irrespective of the generation duty (base or peak load), diesel and fuel oil fired generation technologies are more expensive than coal and natural gas fired technologies and therefore they are not taken into account in the development of generation expansion plans. It is also noted that only those hydro plants with feasibility or prefeasibility studies reports were taken into account in this study and those without such studies were excluded. It thus implied that the generation expansion scenarios under each of the three themes are to be prepared using three main resources or combinations of resources, coal, natural gas and hydro, which include the following technologies:

- 350 MW coal-fired units
- 150 MW coal-fired units
- 300 MW natural gas-fired combined cycle plants
- Hydro generating power plant

Under the first two themes, the Shurob HPP is not considered since its construction is tied to Rogun and under the second theme its commissioning would be outside the simulation period.

6.3 Evaluation of the Formulated Expansion Scenarios

All formulated generation expansion scenarios presented in this section were modelled and simulated using the GENSIM generation planning software package. Selected generation units were added to the system to meet the predefined reliability planning criteria. The screening process on generation expansion scenarios does not include the analysis of the transmission system requirements for each scenario and is only included for the least cost power system expansion plan(s) as presented in Section 8.

Each generation expansion scenario includes two components of generation capacity additions, fixed and variable. The fixed component includes those common to all scenarios such as the refurbishment and retirement schedule of the existing generation fleet and the addition schedule of the committed generation projects. The variable component includes those additions, retirements and refurbishments schedules unique to each individual scenario. The following is a list of the assumptions made in setting up the fixed component for this study:

- All existing HPPs will continue to be operated over the planning horizon and there is no retirement schedule planned for any of them
- All planned rehabilitations for the existing HPPs will be completed by the end of 2027
- The existing mazout fired Dushanbe CPP units will be operated during the winter season only, i.e. from October to March
- The existing Yavan CHP will not be operated over the planning horizon, i.e. it is treated as retired
- Two 150 MW CHP units are to be added at Dushanbe-2 site, one in October of 2016 and the other in December of 2016. It was further assumed that 10% of the capacity is used for station services, i.e. the net output of each unit is 135 MW
- Two 150 MW coal fired units are to be added to the system to be located at Shurob. The net output of each unit is 135 MW
- Two 350 MW coal fired units are to be added to the system. These units are to be located near Ayni. The net output of each unit is 322 MW
- A 10 MW mini hydro power plants is to be added in 2022 and another in 2024
- A 10 MW wind power plant is to be added in 2021 and another in 2025
- 10 MW solar power plants are to be added in each year of 2021 to 2025.

For each of the formulated scenarios, the total cumulative present value (CPV) cost (to January 2015) related to generation expansion over the planning horizon (a total of 25 years, i.e. from 2015 to 2039) and end effect period (a total of 20 years, i.e. from 2040 to 2059) was calculated based on the following annual values:

- Fuel expenses
- O&M costs including GHG offset allowance for coal, natural gas, diesel and fuel oil fired generation
- Capital charges – amortized annual repayment of each new unit was calculated based on its capitalized capital cost at commissioning time, economic life and discount rate
- Cost for additional output which is produced for non-firm export
- EUE costs, i.e. customers' damage due to generation deficit (after 2021)
- Decommissioning costs for the existing Rogun HPP facilities (if applicable)

- Investment required to achieve the flood protection benefits provided by Rogun HPP (if applicable)
- Implementation cost of energy efficiency programs
- Revenue from firm exports
- Revenue from non-firm exports

All generation expansion scenarios have a certain amount of thermal generation added during the study period and a large proportion of this generation is not required to meet domestic demand or firm exports during the summer since the hydro power plants are expected to be generating at close to full capacity. The present study considers that this surplus energy could be exported to other markets (non-firm export) when interconnection transmission capacity is available. Since the export price is higher than the incremental cost of generation there would be a benefit to Tajikistan. The new connections in addition to CASA 1000 was assumed to be in place by 2025 to assist in exporting some of the surplus power during the summer. The total export capability was set to 900 MW (in addition to the capability of the 220 kV line to Afghanistan) prior to the commissioning of this connection and 1,900 MW once the connection comes in service.

6.4 Analysis of Generation Expansion Theme 1 – Expansion Plans Without the rogun hydro power plant

Under the first generation expansion theme – expansion with energy efficiency program and without Rogun HPP, a total of eight expansion scenarios were formulated and analysed. The main generation candidates used for each of these scenarios are as follows:

- 350 MW coal-fired units
- 150 MW coal-fired units
- 300 MW natural gas-fired combined cycle plants
- Five HPPs and 350 MW coal-fired units
- Four HPPs and 350 MW coal-fired units
- Three HPPs and 350 MW coal-fired units
- Two HPPs and 350 MW coal-fired units
- One HPP and 350 MW coal-fired units

6.4.1 Summary of the Expansion Scenarios Studied

Generation expansion sequences for the eight scenarios under Expansion Theme 1 are presented in Table 6-1. More details on these expansion scenarios are presented in Table D-1 to Table D-16 of Appendix D (each scenario has two tables), which include unit addition time and potential unit/plant location as well as annual information such as net generation capacity, peak demand, capacity reserve in both MW and %, expected LOLP in Days/Year and expected EUE in %. It is important to note that the cost information presented in the tables in Appendix D covers the planning horizon only. As mentioned previously, the costs in each year of the extended end effect period are same as those in the last simulation year, i.e. the last year of the planning horizon.

The following explanations and assumptions apply to the generation expansion plans and the resulting costs presented in this report:

- Due to the current generation deficiency, particularly the energy shortage over the winter season (from October to March), and the time and funds constraints on development of new generation projects, it was determined that the generation system should only meet the adopted LOLP criterion of five days per year and EUE criterion of 1% starting from 2021 onward. The two criteria are not be applied to the period from 2015 to 2020 and this period could be considered as transitional, during which significant efforts should be made to bring new generation project developments to the country
- For the last unit to be added to the expansion scenario, a portion of that unit could be sufficient to maintain the LOLP and EUE values within the predefined reliability levels. In this case, only partial

capacity of the last unit is modeled and simulated in the analysis, which is aimed to keep the system reliability within the similar magnitude of other scenarios and reduce the total system costs. It is noted that for a 150 MW or 350 MW unit, a step of 50 MW was used in this type of testing and analysis

- HPP candidates were added to the system according to their unit cost of energy, which was calculated based on the total capitalized capital, economic life, discount rate and expected annual energy production under the average hydrologic condition. The candidate with lower unit cost of energy is the one first added to the system.

The generation expansion scenarios for Theme – 1 are presented in Table 6-1. For the scenarios considering hydro plant additions the following abbreviations shown refer to specific plants:

- Hydro 100 MW refers to Nurek 2
- Hydro 125 MW refers to Sanobad
- Hydro 126 MW refers to Yavan
- Hydro 160 MW refers to Ayni
- Hydro 182.5MW refers to Fandarya

As can be seen from Table 6-1, in addition to the mini hydro, wind and solar power, Scenario 7 would need two hydro plants (one 100 MW and the other 125 MW – Nurek 2 and Sanobad), 2x150 MW coal fired CHP units, 2x150 MW coal fired units and 9x350 MW coal fired units (only 70% of the last 350 MW unit would be required in 2038) over the planning horizon, from 2015 to 2039. Comparing with Scenario 7, Scenario 1 does not have the two hydro plants but it needs an additional 150 MW of coal fired generation. The unit addition schedules for other scenarios presented in Table 6-1 are self-explanatory.

Table 6-2 presents the total system costs (in terms of cumulative present value to January 2015) for the eight scenarios formulated and includes two blocks of information, summary for generation and summary for thermal export. The CPV values on the "Net Total Cost" row are the total generation system costs used for scenario comparison while the values on the "Net Benefit" row show the net benefits generated by thermal units through non-firm sales of surplus energy that could be generated by those units. It is noted that the information shown for the later block is included in that shown in the first block. By examining Table 6-2 and Table 6-1, the following observations can be made:

- The generation expansion sequence developed with 350 MW coal-fired units (Scenario 1) results in lower system costs ($6,810.7 million) than those with either 150 MW coal-fired units (Scenario 2 -- $6,895.4 million) or 300 MW natural gas-fueled CCGT units (Scenario 3 -- $8,110.8 million)
- When hydro candidates are included, the expansion sequence with only two HPPs, Nurek-2 and Sanobad (Scenario 7), has the lowest total generation cost ($6,638.7 million) and other sequences with hydro plant(s) have a relatively higher cost
- Among all eight formulated scenarios, Scenario 7, i.e. the one with only Nurek-2 and Sanobad HPPs has the least total generation cost over the planning and end effect periods.

Based on these findings, it was decided that Scenarios 1 and 7 would be investigated further and the expansion scenarios for other two generation expansion themes would be prepared based on these two scenarios, i.e. one using 350 MW coal-fired units and the other using 350 MW coal-fired units and two hydro plants when applicable. It should be noted that even though Scenario 8 (one hydro plant) has the second lowest CPV it was not selected to be further investigated since the selected scenarios provide a wider potential for costs to be changed under the sensitivity analysis and in any event, the economic impact of having only one hydro plant is already included in the plan with two HPPs.

6.4.2 Comparison of the Selected Expansion Plans

The cost comparison for Scenarios 7 and 1 is presented in Table 6-3, which shows the costs for each of the two scenarios in three timeframes, planning horizon, end effect period and the sum of the two. In addition, the cost difference between Scenario 7 and 1 is also presented in this table. The following can be seen from this table:

- The net cost of Scenario 7 is approximately $6,638.7 million, which includes $5,516.41 million over the planning horizon and $1,122.36 over the end effect period

- The net cost of Scenario 1 is some $6,810.7 million, including $5,661.1 million over the planning time frame and $1,149.6 million over the end effect period
- Scenario 7 costs some $172 million less than Scenario 1
- Scenario 7, costs approximately $170 million less on fuel, $69 million less on O&M and $76 million less on additional generation for non-firm export
- Scenario 7 requires some $113 million more on capital investment (repayment) since it includes two capital intensive hydro projects
- Scenario 1 would have more thermal energy for non-firm export while Scenario 7 would have more hydro energy for non-firm export.

6.4.3 Benefits of Energy Efficiency Programs

To determine the economic viability of the EE program, generation expansion scenarios were developed without the changes in the demand brought about by the implementation of the EE programs. These expansion plans were carried out for Scenarios 1 and 7. The annual unit additions and total generation costs of these two scenarios are summarized in Table 6-4 and Table 6-5 respectively.

The following findings could be obtained from Table 6-4 and Table 6-5:

- The total generation additions by the end of the study period are the same as for the scenarios with EE since the effect of the EE programs are ended prior to the end of the study period. However, it should be noticed that the unit additions are advanced with the scenarios without EE when compared to the scenarios with EE
- The net cost of Scenario 7 is approximately $6,831 million, which includes $5,709 million over the planning horizon and $1,122 over the end effect period.
- The net cost of Scenario 1 is some $7,028 million, including $5,878 million over the planning time frame and $1,150 million over the end effect period
- Scenario 7 costs some $197 million less than Scenario 1
- Scenario 1 costs approximately $200 million more on fuel, $79 million more on O&M and $74 million more on additional generation for non-firm export
- Scenario 7 requires some $145 million more on capital investment than Scenario 1, since it includes two capital intensive hydro projects.

Table 6-6 presents the potential benefits arisen from the energy efficiency programs as described in Section 5.7, which are calculated based on the generation costs presented in Table 6-3 and Table 6-5. The following can be observed from Table 6-6:

- The proposed EE programs would reduce the energy requirement by approximately 5,110 GWh which is expressed in 2015 CPV
- Without implementation of the proposed EE programs, the generation expansion plan under Scenario 1 results in a total system cost of some $7,028 million. The total system cost is reduced to approximately $6,811 million if the estimated energy and capacity savings from the proposed EE programs could be fully materialized. This means that the EE programs could provide a net benefit of some $217 million. It is noted that the estimated cost for implementation of the proposed EE programs has been included in the total system cost
- The total generation costs of Scenario 7 is some $6,831 million if the EE programs are not implemented while it is reduced to some $6,639 million with the implementation of the EE programs, a net benefit of $192 million.

It is concluded that the proposed EE programs could provide net benefits to the generation system, i.e. reduce total system cost.

6.4.4 Expansion with Imports

From the generation expansion plans analysis it was observed that a coal unit during the first couple of years after its commissioning may only be required to produce a small amount of energy, i.e. it would have a low annual capacity factor. It is expected that this could be addressed through generation dispatch or operation arrangements. In this case, the system operator could dispatch the base load units in such a way that all base load units would have the same level of annual capacity factor.

Using peaking generation technologies could also appropriately address this but it would increase the total generation system cost due to their high incremental cost (including fuel cost and variable O&M). When the Tajikistan electricity grid system is interconnected with other electric systems which are able to provide energy support during the winter season, the interconnection support could be modeled appropriately and included in the simulation to displace some coal fired power units/plants while keeping the total system cost low.

The impact of imports on total generation cost was investigated for Scenario 7 under Expansion Theme 1. In the analysis, three imports (250 MW import from Turkmenistan via Afghanistan, 250 MW import directly from Uzbekistan and 250 MW import from Turkmenistan via Uzbekistan) were used to displace a two and half 350 MW coal-fired units.

The study results indicate that the two alternatives have the same level of total system cost. However, it is understood that these imports need much less capital investment from Tajikistan. As the main challenge faced by Tajikistan for winter power supply is the shortage of energy and as its large hydroelectric power plants have either large storage or daily operation storage, Tajikistan could import energy at low prices during off-peak hours, use that off-peak energy to meet its customer needs and save water for generation during mid-peak and peak hours. It is not expected that the Tajikistan system would experience capacity shortage during the winter period in the planning horizon if only a total of 750 MW off-peak import would be implemented.

6.4.5 Sensitivity Analysis

Sensitivity analysis is normally conducted to the selected least cost system expansion plan(s) to examine its robustness against variations in key parameters or assumptions. For this generation development theme, sensitivity studies were carried out for both Scenarios 1 and 7. The key parameters selected to examine the robustness of the study results that could reasonably be expected to occur, include load demand forecast, capital cost of new generation projects, fuel price of thermal units and discount rate.

6.4.5.1 Demand Forecast

In addition to the most likely load forecast, two additional load forecasts were prepared in this study, i.e. low and high demand growths as described in Section 3.3. In the development of generation expansion sequences for this sensitivity studies, the impacts of potential achievements of EE programs were treated equally in all three load forecasts.

It is understood that in the case of the high load growth, the generation system would need more generating units to supply the forecasted load, resulting in advanced commissioning of new generating units while in the case of low demand growth, the requirements for additions/enhancements of generation would be less, resulting in postponed commissioning of some units. Table 6-7 presents the generation addition and retirement schedules for Scenarios 1 and 7 under the low and high load forecasts while Table 6-8 presents their total generation system costs. More details on the two scenarios under the two different load forecasts are presented in Table D-17 to Table D-24 of Appendix D.

The following may be observed from Table 6-7 and Table 6-8:

- Under the low load demand forecast condition, Scenario 1, in addition to the micro hydro, wind and solar power, would need 2x150 MW CHP, 2x150 MW coal units and 8x350 MW coal units. Only 40% of the last 350 MW unit is required in 2038 in order to meet the system reliability requirements in 2039. The total system cost of this scenario is $5,810 million
- Comparing with Scenario 1, Scenario 7 under the low load forecast condition would need 200 MW less of coal power capacity - and 225 MW more of hydro power capacity. The total cost for Scenario 7 is $5,6270 million
- Under the low load forecast condition, Scenario 7 costs some $183 million less than Scenario 1 over the planning horizon and the extended end effect period

- Under the high load forecast condition, Scenario 1, in addition to the micro hydro, wind and solar power, would need 2x150 MW CHP, 2x150 MW coal units and 13x350 MW coal units, with a total system cost of some $8,296 million.
- Comparing with Scenario 1, Scenario 7 under the high load forecast condition would need 200 MW less of coal power capacity and 225 MW more of hydro power capacity. Scenario 7 has a total cost of some $8,152 million
- Under the high load forecast condition, Scenario 1 would cost some $144 million more than Scenario 7 over the planning horizon and the extended end effect period
- No matter what the load forecast, the generation expansion sequence with two HPPs and 350 MW coal units (Scenario 7) has the least total generation cost.

6.4.5.2 Capital Cost of New Power Projects

One of the important uncertain factors in the power sector development is the estimated capital cost of future new generation projects. Due to changing market conditions, specific site conditions and other factors such as estimate accuracy and EPC process, it is understood that the total capital cost for one project could be quite different from the amount required for another project, particularly for new technologies and projects whose construction cost is heavily dependent upon the site conditions.

The sensitivity analysis of the generation expansion plans to the capital cost uncertainty was carried out by reducing or increasing the estimated capital cost of new generation projects by 25%. It is important to note that for simplicity, the O&M cost of the new generation projects was kept unchanged although it is sometimes estimated as a proportion of their capital cost. Table 6-9 presents the study results.

The following could be seen or calculated from Table 6-9:

- With a 25% reduction in the capital cost of the new generation projects, the total generation cost of Scenario 1 would be reduced to some $6,096 million from $6,811 million, a net reduction of $714 million
- With a 25% increase in the capital cost of the new generation projects, the total generation cost of Scenario 1 would be increased to some $7,526 million from $6,811 million, a net increase of $7154 million
- It is noted that the small difference between the two cost differences above was caused by rounding. It could therefore be calculated that 1% change in the capital cost of Scenario 1 would result in a change of some $28.6 million in the total generation cost
- It could also be calculated that for Scenario 7, a change of 25% in the capital cost of new generation projects would result in a change of some $734 million in the total generation cost, which means that 1% change in the capital cost would have a change of some $29.4 million in the total generation cost
- Within the examined range of changes in the capital cost of new generation projects, Scenario 7 stands at the least cost position.

6.4.5.3 Fuel Price of Thermal Units

The sensitivity to fuel price variation of thermal units to the total generation cost was investigated by decreasing or increasing the fuel prices by 25% as per the values assumed in the base case. The fuels with changing price include mazout and coal as they are the only thermal fuels applicable to the selected scenarios. The sensitivity studies results to the fuel price are presented in Table 6-10. One could derive the following conclusions by observing or calculating the values presented in this table:

- With a 25% reduction in the fuel price of the thermal generating units, the total generation cost of Scenario 1 would be reduced to some $6,016 million from $6,811 million, a net reduction of $795 million
- With a 25% increase in the fuel price of the thermal generating units, the total generation cost of Scenario 1 would be increased to some $7,606 million from $6,811 million, a net increase of $795 million

- It is noted that the small difference between the two cost differences above was caused by rounding. It could therefore be calculated that 1% change in the fuel price of Scenario 1 would result in a change of some $31.8 million in the total generation cost
- It could also be calculated that for Scenario 7, a change of 25% in the fuel price results in a change of some $740 million in the total generation cost, which implies that 1% change in the fuel prices have a change of some $29.6 million in the total generation cost
- Within the examined range of changes in the fuel price of thermal generation projects, Scenario 7 stands at the least cost position.

6.4.5.4 Discount Rate

The sensitivity studies to discount rate variation were carried out for two different values, 8% and 12% which are minus 2% and plus 2% from the base discount rate of 10%. It is important to note that the two discount rates were also applied to all new generation projects to calculate their capitalized cost at the time of commissioning. The sensitivity study results to the discount rate are presented in Table 6-11. One could obtain the following conclusions by observing or calculating the values presented in this table:

- At a discount rate 8%, the total generation cost of Scenario 1 is some $8,478 million, increased by some $1,668 million from the total cost of $6,811 million calculated at the discount rate of 10%
- When the discount rate is reduced to 8% from 10%, the total generation cost of Scenario 7 would be increased to some $8,202 million from the amount of $6,639 million, i.e. a net increase of $1,563 million
- Scenario 1 has a total generation cost of some $5,675 million when a discount rate of 12% is applied, which is $1,135 million less than the cost of $6,811 million calculated at the discount rate of 10%
- The total cost of Scenario 7 is some $5,561 million when the discount rate of 12% is utilized, which is $1,078 million less than the amount of $6,639 million calculated at the discount rate of 10%
- Within the examined range of changes in discount rate, Scenario 7 stands at the least cost position.

6.4.6 Graphical Results Without Rogun

Figure 6-1 shows the annual installed capacity by type of resource for Scenario 1 (350 MW coal units). As can be seen, the hydro component is the largest of all resources and by the end of the study period accounts for 58% of the total net generation capacity and this is followed by coal which accounts for 43% of the total net capacity. The figure also indicates that, initially, the hydro component accounts for 95% of the net capacity which over the study period is increased by 483 MW as a result of the refurbishment of the existing units. Figure 6-2 shows the annual energy generation by type of resource for scenario 1. The figure indicates that by the end of the study period, the hydro power plants generate close to 50% of the total energy required by the system plus that for firm exports while the coal fired units generate 46% of the total energy and the remaining energy is generated by CHP plants and renewable energy plants (mini hydro, wind and solar plants). For the initial years of the study, Figure 6-2 shows a gap between the total energy generated and the demand with this being referred to as unserved or unsupplied energy which occurs mainly during the winter period. As can be observed, the gap is decreased as new units are brought into service starting in 2018 and 2019.

Figure 6-2 also shows the energy that was considered as additional non-firm exports from hydro resources and from the 350 MW coal units with these exports being more accentuated during June to September for the hydro plants since there is surplus hydro energy during those months and during other months for the 350 MW coal units. Since the system requires reserve installation and that is mainly obtained from the coal fired units, the reserve capacity could be generating energy for non-firm exports and thus obtaining a system benefit by selling that energy at a higher price than the marginal cost of energy produced by those units. As the system demand grows, the hydro surplus decreases as does the non-firm export for this resource and by the end of the study period the non-firm exports sales for hydro amount to 150 GWh and those for the coal units to 5,870 GWh. The costs and associated revenues of these non-firm sales have been quantified and are shown in Table 6-5.

Figure 6-3 shows the annual installed capacity by type of resource for Scenario 7 (2 HPPs and 350 MW coal units). As can be seen, the hydro component is the largest of all resources and by the end of the study period accounts for 60% of the total net generation capacity and this is followed by coal which accounts for 35% of the total net capacity. The figure also indicates that initially the hydro component accounts for 95% of the net capacity which over the study period is increased by 708 MW which is due to the refurbishment of the hydro existing units and the addition of Sanobad HPP and other HPPs.

Figure 6-4 shows the annual energy generation by type of resource for scenario 7. The figure indicates that by the end of the study period, the hydro power plants generate 53% of the total energy required by the system plus that for firm exports while the coal fired units generate 42% of the total energy and the remaining energy is generated by CHP plants and renewable energy plants (mini hydro, wind and solar plants). The unserved energy in the initial years is the same as that for Scenario 1. The non-firm exports for hydro and thermal generated energy are similar to those obtained for Scenario 1.

6.5 Analysis of Generation Expansion Theme 2 – Expansion Plans with the Rogun Hydro Power Plant

6.5.1 Summary of the Study Results

Based on the discussions presented in Section 5.2.1, it was assumed that the first two units of Rogun HPP would start their operation from January 1, 2025, the next two units from January 1, 2028 and the last two units from January 1, 2029. In the generation expansion tables, these additions are identified as "Rogun either 2x400 MW or 2x600 MW".

Two generation expansion scenarios were developed under Theme 2 – With Rogun HPP, one using 350 MW coal-fired units and the other using 350 MW coal-fired units and two HPPs, Nurek-2 and Sanobad. A generation expansion plan with the Shurob HPP is developed under the sensitivities studies.

The generation addition/retirement sequences for these two scenarios are presented in Table 6-12 and their costs are summarized in Table 6-13. The detailed unit additions and costs of these two scenarios are presented in Table D-25 to Table D-28 of Appendix D (each scenario has two tables).

The following can be observed from these tables:

- In addition to the Rogun HPP, mini hydro, wind and solar power projects, the Scenario 1 expansion sequence includes 2x150 MW CHP, 2x150 MW coal and 5x350 MW coal units
- The differences between Scenarios 7 and 1 is that Scenario 7 includes 200 MW less coal generation but 225 MW more of hydro generation. Partial 350 MW coal units were required towards the end in order to maintain the specified reliability levels
- The net cost of Scenario 7 is approximately $6,303 million, which includes $5,371 million over the planning horizon and $932 over the end effect period
- The net cost of Scenario 1 is some $6,505 million, including $5,541 million over the planning time frame and $964 million over the end effect period
- Scenario 7 costs some $202 million less than Scenario 1
- Scenario 1 costs approximately $149 million more on fuel, $74 million on O&M and $167 million on additional generation for non-firm exportScenario 7 requires some $43 million more on capital investment than Scenario 1.

6.5.2 Benefits/Costs of Rogun HPP

Table 6-14 presents the potential benefits/costs of the Rogun HPP, which are calculated based on the generation costs presented in Table 6-3 and Table 6-13. The following can be noted from Table 6-14:

- Without the Rogun HPP, the Scenario 1 total generation cost is some $6,811 million. This cost decreases to some $6,505 million when the Rogun HPP is included in the expansion sequence. The net benefit of the Rogun HPP is some $306 million
- Scenario 7 has a total generation cost of approximately $6,639 million when the Rogun HPP is not included in the expansion sequence. The cost is decreased to $6,303 million when Rogun HPP is included, which means that the net benefit of the Rogun HPP is some $336 million.

From the above comparisons it is clear that expansion scenarios considering the addition of the Rogun HPP present benefits when compared to those without that hydro plant at the base discount rate of 10%.

These benefits are of the order of 4 to 5% of the total scenario cost. Due to the late in-service date for the plant, a portion of the benefits occur beyond the planning horizon but this is expected since the full plant capability is only included in the planning period for a relatively short period.

Based on a cost comparison of the corresponding scenarios the benefits may appear to be relatively small and this may be caused by several factors. The methodology/approach used utilized the discounted cash flow method to bring to a common point in time all costs and benefits during the study period. With this method, expenses and benefits occurring in the medium and long term have less value than those which occurred in the short term. Thus when using a significant discount rate and the benefits start occurring in the long term their value can be less valuable but this can be investigated in the sensitivity studies by using lower discount rates.

It is also possible that the study may not be including some of the benefits associated with Rogun since decommissioning costs and the cost of the works required to provide protection against the PMF have been included in the expansion scenarios without the Rogun HPP. The study also included an environmental penalty against the coal fired units for CO2 emissions but did not take into account the effects on generation capability at Nurek of decreased generation due to sedimentation accumulation because this could probably occur outside the study period. However, since the decreased generation would likely occur so far into the future, once this is discounted at the base discount rate its value would be very small.

Another aspect maybe the economic life used for the generation resources. For thermal resources an economic life of 30 years was used while for hydro resources the economic life was 50 years. It is not uncommon for hydro power plants to last 75 years (the Varzob plants) and even 100 years but then refurbishment is required and then this would probably fall outside the study period.

In addition, it should be noted that under the studies considering the addition of Rogun, the total net capacity by the end of the study period is some 1,600 MW more than that under the sequences without Rogun and this is due to the fact that the energy generation capability of Rogun, with a capacity factor of 51%, is lower than that of coal fired units which can achieve capacity factors of 80% and higher, thus the generation expansion plans with Rogun would require more total net installed capacity than those without Rogun.

The methodology used is sound, has been used in many other power sector master plans and accepted by many international lending agencies with the above descriptions being an attempt to bring out some of the factors to light that might justify the results obtained.

6.5.3 Expansion with Imports

Similar to the summary described in Section6.4.4, the impact of imports on total generation costs was also investigated for Scenario 7 under Expansion Theme 2. In the analysis, three imports (250 MW import from Turkmenistan via Afghanistan, 250 MW import directly from Uzbekistan and 50 MW import from Turkmenistan via Uzbekistan) were used to displace the 350 MW coal-fired units required after 2021.

The study results indicate that using imports to displace the 350 MW units could reduce the total generation cost by approximately $100 million. It is noted that these imports need much less capital investment from Tajikistan although the import energy prices are relatively higher. As the main challenge faced by Tajikistan for winter power supply is the shortage of energy and as its large hydroelectric power plants have either large storage or daily operation storage, Tajikistan could import energy at low prices during off-peak hours, use the off-peak energy to meet its customer needs and save water for generation during mid-peak and peak hours.

6.5.4 Sensitivity Analysis

The sensitivity analysis carried out for the two scenarios under Expansion Theme 2 is similar to that presented in Section 6.4.5 for the two scenarios under Expansion Theme 1.

6.5.4.1 Demand Forecast

Table 6-15 presents the generation addition and retirement schedules for Scenarios 1 and 7 under the low and high load forecasts while Table 6-16 presents their total generation system costs. The detailed unit addition schedules and annual costs of the two scenarios under the two different load forecasts are presented in Table D-29 to Table D-36 of Appendix D.

The following could be observed or calculated from Table 6-15 and Table 6-16:

- Under the low load demand forecast condition, Scenario 1, in addition to the Rogun HPP, micro hydro, wind and solar power, needs 2x150 MW CHP, 2x150 MW coal units and 3x350 MW coal units. The total generation system cost of this scenario is some $5,497 million
- Scenario 7 under the low load forecast condition needs the same coal power capacity and 225 MW more hydro power capacity, it has a total generation cost of some $5,361 million
- Under the low load forecast condition, Scenario 7 costs some $136 million less than Scenario 1 over the planning horizon and the extended end effect period
- Under the high load forecast condition, Scenario 1, in addition to the Rogun HPP, micro hydro, wind and solar power, needs 2x150 MW CHP, 2x150 MW coal units and 8x350 MW coal units, with a total system cost of some $7,933 million.
- Scenario 7 under the high load forecast condition needs 150 MW less coal power capacity and 225 MW more hydro power capacity and has a total cost of some $7,795 million
- Under the high load forecast condition, Scenario 1 costs some $138 million more than Scenario 7 over the planning horizon and the extended end effect period
- No matter what the load forecast, the generation expansion sequence with two HPPs and 350 MW coal units (Scenario 7) has the least total generation cost.

6.5.4.2 Capital Cost of New Power Generation Projects

The sensitivity study results to the varying capital cost of new generation projects are presented in Table 6-17. The following can be seen or calculated from this table:

- With a 25% reduction in the capital cost of the new generation projects, the total generation cost of Scenario 1 is reduced to some $5,412 million from $6,505 million, a net reduction of $1,093 million
- With a 25% increase in the capital cost of the new generation projects, the total generation cost of Scenario 1 is increased to some $7,598 million from $6,505 million, a net increase of $1,093 million
- It can therefore be calculated that 1% change in the capital cost of Scenario 1 results in a change of some $43.7 million in the total generation cost
- It can also be calculated that for Scenario 7, a change of 25% in the capital cost of new generation projects would result in a change of some $1,092 million in the total generation cost, which means that 1% change in the capital cost would have a change of some $43.7 million in the total generation cost
- Within the examined range of changes in capital cost of new generation projects, Scenario 7 stands at the least cost position.

6.5.4.3 Fuel Price of Thermal Generation Projects

The sensitivity study results to the fuel price variation of thermal generation projects are presented in Table 6-18. The following conclusions can be drawn from the values presented in this table:

- With a 25% reduction in the fuel price of the thermal generating units, the total generation cost of Scenario 1 is reduced to some $5,909 million from $6,505 million, a net reduction of $596 million
- With a 25% increase in the fuel price of the thermal generating units, the total generation cost of Scenario 1 is increased to some $7,101 million from $6,505 million, a net increase of $596 million
- It can therefore be calculated that 1% change in the fuel price of thermal units in Scenario 1 results in a change of some $23.8 million in the total generation cost
- It can also be calculated that for Scenario 7, a change of 25% in the fuel prices would result in a change of some $531 million in the total generation cost, which means that 1% change in the fuel price has a change of some $21.2 million in the total generation cost
- Within the examined range of changes in fuel price of thermal generation projects, Scenario 7 stands at the least cost position.

6.5.4.4 Discount Rate

The sensitivity study results to the discount rate are presented in Table 6-19. The following conclusions can be made from the values presented in this table:

- At a discount rate 8%, the total generation cost of Scenario 1 is some $7,470 million, an increase of $965 million from the total cost of $6,505 million calculated for a discount rate of 10%
- When the discount rate is reduced to 8% from 10%, the total generation cost of Scenario 7 is increased to some $7,171 million from the amount of $6,303 million, i.e. a net increase of $868 million
- Scenario 1 has a total generation cost of some $5,746 million when a discount rate of 12% is applied, which is $759 million less than the cost of $6,505 million calculated at the discount rate of 10%
- The total cost of Scenario 7 is some $5,604 million when a discount rate of 12% is utilized, which is $699 million less than the amount of $6,303 million calculated at the discount rate of 10%
- Within the examined range of changes in discount rate, Scenario 7 stands at the least cost position.

6.5.4.5 Capital Disbursements

A sensitivity study was carried out for the capital disbursements outlined in the TEAS for the Rogun HPP versus those arrive at for the Early Rogun Generation theme. The results are presented in Table 6-20. The following conclusions can be drawn from the values presented in the Table:

- Using the cash disbursements for the Early Rogun theme, the total generation cost of Scenario 1 is some $6,331 million, a decrease of $174 million from the total cost of $6,505 million calculated for the TEAS disbursements
- Using the cash disbursements for the Early Rogun theme, the total generation cost of Scenario 2 is some $6,129 million, a decrease of $174 million from the total cost of $6,303 million calculated for the TEAS disbursements
- The decrease in the overall costs of scenario 1 and 2 is equal since the change was the same in both scenarios and only involved the amount of the annual capital disbursements while the overall total remained unchanged
- The decrease in overall scenario cost is due to the fact that under the Early Rogun disbursements the first disbursement occurs one year later so as to align the start of producing energy for the first phase in both cases
- The capital disbursements have an impact on the overall project economics and it is important to have a capital disbursement schedule as close to the actual disbursements as possible.

6.5.5 Graphical Results With Rogun

Figure 6-5 shows the annual installed capacity by type of resource for Scenario 1 (350 MW coal units). As can be seen, the hydro component is the largest of all resources and by the end of the study period accounts for 49% of the total net generation capacity, followed by Rogun at 31% and by coal units at 16% of the total net capacity. The figure also indicates that, initially, the hydro component accounts for 95% of the net capacity which over the study period is increased by 483 MW as a result of the refurbishment of the existing units. It should be noted that under Theme 2 studies, the total net capacity by the end of the study period is some 1,600 MW more than that under Theme 1 and this is due to the fact that the energy generation capability of Rogun, with a capacity factor of 51%, is lower than that of coal fired units which can achieve capacity factors of 80% and higher thus the generation expansion plans with Rogun would require more total net installed capacity than those without Rogun.

Figure 6-6 shows the annual energy generation by type of resource for scenario 1. The figure indicates that by the end of the study period, the hydro power plants generate close to 51% of the total energy required by the system plus that for firm exports, Rogun generates close to 32% while the coal fired units generate 12% of the total energy and the remaining energy is generated by CHP plants and renewable energy plants (mini hydro, wind and solar plants). As for the scenarios under Theme 1, Figure 6-6 shows the same gap between the total energy generated and the demand for the initial study years and this is decreased once new units are added to the system before Rogun is commissioned. Once Rogun starts to operate (in stages), the generation produced by the coal units added to the system prior to the commissioning of Rogun play a less significant role in meeting system demand and becomes available for non-firm export sales. Figure 6-6 shows this non-firm export as thermal and hydro exports with the non-firm exports from the hydro resources being more accentuated during June to September and during other months for the 350 MW coal units. In this case, by the end of the study period the non-firm sales are 1,900 GWh greater than those under Theme 1. The costs and associated revenues of these non-firm sales have been quantified and are shown in Table 6-13.

Figure 6-7 shows the annual installed capacity by type of resource for Scenario 7 (2 HPPs and 350 MW coal units). As can be seen the hydro component is the largest of all resources and by the end of the study period accounts for 51% of the total net generation capacity, Rogun for 31% and the coal for 14%. The figure also indicates that initially the hydro component accounts for 95% of the net capacity which over the study period is increased by 708 MW which is due to the refurbishment of the hydro existing units and the addition of Nurek – 2 and Sanobad HPPs.

Figure 6-8 shows the annual energy generation by type of resource for scenario 7. The figure indicates that by the end of the study period, the hydro power plants generate close to 55% of the total energy required by the system plus that for firm exports, Rogun generates close to 31% while the coal fired units generate 9% of the total energy and the remaining energy is generated by CHP plants and renewable energy plants (mini hydro, wind and solar plants). The unserved energy in the initial years is the same as that for Scenario 1. The non-firm exports for hydro and thermal generated energy are 180 GWh more than those obtained for Scenario 1.

6.6 Analysis of Generation Expansion Theme 3 – Expansion Plans with Early Rogun Generation

6.6.1 Summary of Study Results

Based on the discussions presented in Section 5.2.1 and Section 5.2.1.1, generation expansion plans with the Early Rogun HPP were developed. In this case, it was assumed that the first two units of Rogun HPP would start their operation from July 2019, the next two units from January 1, 2023 and the last two units from July 1, 2023. In the generation expansion tables, these additions are identified as "Rogun either 2x400 MW or 2x600 MW".

Two generation expansion scenarios were developed under Theme 3 – with the Early Rogun HPP, one using 350 MW coal-fired units and the other using 350 MW coal-fired units and two HPPs, Nurek-2 and Sanobad. The generation addition/retirement sequences for these two scenarios are presented in Table 6-21 and their costs are summarized in Table 6-22. The detailed unit additions and costs of these two scenarios are presented in Table D-37 to Table D-40 of Appendix D (each scenario has two tables).

The following can be observed from these tables:

- In addition to the Rogun HPP, mini hydro, wind and solar power projects, the Scenario 1 expansion sequence includes 2x150 MW CHP, 2x150 MW coal and 5x350 MW coal units (includes the partial unit in 2039). This is similar to the Theme 2 scenario requirements but with different timing for the additions
- The differences between Scenarios 7 and 1 is that Scenario 7 includes 200 MW less coal generation but 225 MW more of hydro generation. As for Theme 2 scenarios, partial 350 MW coal units were required towards the end in order to maintain the specified reliability levels.
- The net cost of Scenario 7 is approximately $6,256 million, which includes $5,351 million over the planning horizon and $905 over the end effect period
- The net cost of Scenario 1 is some $6,322 million, including $5,388 million over the planning time frame and $934 million over the end effect period
- Scenario 7 costs some $66 million less than Scenario 1
- Scenario 1 costs approximately $53 million more on fuel, $22 million on O&M and $45 million on additional generation for non-firm export
- Scenario 7 requires some $45 million more on capital investment than Scenario 1.

6.6.2 Benefits/Costs of Early Rogun HPP

Table 6-23 presents the potential benefits/costs of the Early Rogun HPP, which are calculated based on the generation costs presented in Table 6-21 and Table 6-22. The benefits/costs are determined in comparison with the scenarios under Theme 1. The following can be noted from Table 6-23:

- Without the Rogun HPP, the Scenario 1 total generation cost is some \$6,811 million. This cost decreases to some \$6,322 million when the Early Rogun HPP is included in the expansion sequence. The net benefit of the Early Rogun HPP is some \$489 million
- Scenario 7 has a total generation cost of approximately \$6,639 million when the Rogun HPP is not included in the expansion sequence. The cost is decreases to \$6,256 million when the Early Rogun HPP is included, which means that the net benefit of the Early Rogun HPP is some \$383 million
- Even though the Scenario 1 expansion plans provides larger benefits for the Early Rogun Theme (when compared to the corresponding Theme 1 scenario), the Scenario 7 overall cost is lower.

From the above comparisons it is clear that expansion scenarios considering the addition of the Early Rogun HPP present benefits when compared to those without that hydro plant at the base discount rate of 10%. These benefits are of the order of 6 to 7% of the total scenario cost. These benefits are greater than the Rogun HPP benefits and this is due to several factors. In the Early Rogun cases there is a significant reduction in the fuel cost (coal required to generate electricity in the absence of the HPP) since the hydro power plant in commissioned at a much earlier date, there is also a reduction in the O&M costs since the installation of other type of plants is reduced and the capital requirements (other than Rogun) are less since the investments are postponed. Another factor favoring the Early Rogun case is the increase in value and quantity of the non-firm exports due to the fact that the HPP starts generating at an earlier date.

On the cost side, the present worth of the plant's capital cost and O&M account for close to 50% of the overall cost and thus when all the different factors are taken into account, the Early Rogun scenarios present reasonable benefits when compared to the respective costs of the scenarios developed under Theme 1.

Cross comparison of the Theme 2 and Theme 3 results is relatively difficult since there is a difference in the cash disbursements for the Rogun HPP under the two themes which could skew the results obtained and influence the selection decision. The selected cash disbursements for the Early Rogun cases should be calculated with the same level of accuracy as those obtained from the TEAS for the studies undertaken for Rogun under Theme 2.

6.6.3 Sensitivity Analysis

The sensitivity analysis carried out for the two scenarios under Expansion Theme 3 is similar to that presented for the two scenarios under Expansion Theme 1 and Expansion Theme 2.

6.6.3.1 Demand Forecast

The generation addition and retirement schedules for Scenarios 1 and 7 under the low and high load forecasts are similar to those outlined for the demand forecast sensitivity under Theme 2. Table 6-24 presents their total generation system costs. The detailed unit addition schedules and annual costs of the two scenarios under the two different load forecasts are presented in Table D-41 to Table D-48 of Appendix D.

The following could be observed or calculated from the tables in Appendix D and Table 6-24:

- Under the low load demand forecast condition, Scenario 1, in addition to the Early Rogun HPP, micro hydro, wind and solar power, needs the same unit additions as the corresponding scenario for Theme 2. The total generation system cost of this scenario is some \$5,396 million
- Scenario 7 under the low load forecast condition, the additions are similar those of the Theme 2 scenario and it has a total generation cost of some \$5,352 million
- Under the low load forecast condition, Scenario 7 costs some \$44 million less than Scenario 1 over the planning horizon and the extended end effect period
- Under the high load forecast condition, Scenario 1, in addition to the Early Rogun HPP, micro hydro, wind and solar power, needs the same unit additions as the corresponding scenario for Theme 2, with a total system cost of some \$7,783 million.

- Scenario 7 under the high load forecast condition, the additions are similar those of the Theme 2 scenario and has a total cost of some $7,629 million
- Under the high load forecast condition, Scenario 1 costs some $154 million more than Scenario 7 over the planning horizon and the extended end effect period
- No matter what the load forecast, the generation expansion sequence with two HPPs and 350 MW coal units (Scenario 7) has the least total generation cost.

6.6.3.2 Capital Cost of New Power Generation Projects

The sensitivity study results to the varying capital cost of new generation projects are presented in Table 6-25. The following can be seen or calculated from this table:

- With a 25% reduction in the capital cost of the new generation projects, the total generation cost of Scenario 1 is reduced to some $5,066 million from $6,322 million, a net reduction of $1,256 million
- With a 25% increase in the capital cost of the new generation projects, the total generation cost of Scenario 1 is increased to some $7,578 million from $6,322 million, a net increase of $1,256 million
- It can therefore be calculated that 1% change in the capital cost of Scenario 1 results in a change of some $50.2 million in the total generation cost
- It can also be calculated that for Scenario 7, a change of 25% in the capital cost of new generation projects would result in a change of some $1,261 million in the total generation cost, which means that 1% change in the capital cost would have a change of some $50.5 million in the total generation cost
- Within the examined range of changes in capital cost of new generation projects, Scenario 7 stands at the least cost position.

6.6.3.3 Fuel Price of Thermal Generation Projects

The sensitivity study results to the fuel price variation of thermal generation projects are presented in Table 6-26. The following conclusions can be drawn from the values presented in this table:

- With a 25% reduction in the fuel price of the thermal generating units, the total generation cost of Scenario 1 is reduced to some $5,852 million from $6,322 million, a net reduction of $470 million
- With a 25% increase in the fuel price of the thermal generating units, the total generation cost of Scenario 1 is increased to some $6,792 million from $6,322 million, a net increase of $470 million
- It can therefore be calculated that 1% change in the fuel price of thermal units in Scenario 1 results in a change of some $18.8 million in the total generation cost
- It can also be calculated that for Scenario 7, a change of 25% in the fuel prices would result in a change of some $449 million in the total generation cost, which means that 1% change in the fuel price has a change of some $18.0 million in the total generation cost
- Within the examined range of changes in fuel price of thermal generation projects, Scenario 7 stands at the least cost position.

6.6.3.4 Discount Rate

The sensitivity study results to the discount rate are presented in Table 6-27. The following conclusions can be made from the values presented in this table:

- At a discount rate 8%, the total generation cost of Scenario 1 is some $7,015 million, an increase of $693 million from the total cost of $6,322 million calculated for a discount rate of 10%
- When the discount rate is reduced to 8% from 10%, the total generation cost of Scenario 7 is increased to some $76,893 million from the amount of $6,256 million, i.e. a net increase of $637 million
- Scenario 1 has a total generation cost of some $5,769 million when a discount rate of 12% is applied, which is $553 million less than the cost of $6,322 million calculated at the discount rate of 10%

- The total cost of Scenario 7 is some $5,733 million when a discount rate of 12% is utilized, which is $523 million less than the amount of $6,256 million calculated at the discount rate of 10%
- Within the examined range of changes in discount rate, Scenario 7 stands at the least cost position.

6.6.3.5 Shurob Hydro Power Plant

A sensitivity study was carried out considering the addition of the Shurob HPP to either of the generation expansion scenarios. The detailed unit addition schedules and annual costs of the two scenarios under the two expansion scenarios are presented in Table D-49 to Table D-52 of Appendix D. The Shurob HPP will be added after Rogun's Phase 1 is commissioned.

Table 6-28 presents the results of the studies considering the addition of the Shurob HPP. Under Scenario 1, the total cost amounts to $6,633 million or some $312 million more than the scenario without the Shurob HPP. Under Scenario 7, the total cost is $6,584 or some $328 million more than the scenario without the plant.

The above results are not surprising since the Shurob HPP has a capacity factor of 42.5% and has a unit cost of energy close to 99$/MWh (considering 10% discount rate and a 50 year life) whereas the unit cost of energy for the scenarios without Shurob HPP is of the order of 33 $/MWh.

6.6.4 Graphical Results With Early Rogun

Figure 6-9shows the annual installed capacity by type of resource for Scenario 1 (350 MW coal units). As can be seen, the hydro component is the largest of all resources and by the end of the study period accounts for 49% of the total net generation capacity, followed by Rogun at 31% and by coal units at 16% of the total net capacity. The figure also indicates that, initially, the hydro component accounts for 95% of the net capacity which over the study period is increased by 483 MW as a result of the refurbishment of the existing units. It should be noted that under Theme 3 studies, the total net capacity by the end of the study period is some 1,600 MW more than that under Theme 1 and this is due to the fact that the energy generation capability of Rogun, with a capacity factor of 51%, is lower than that of coal fired units which can achieve capacity factors of 80% and higher thus the generation expansion plans with Rogun would require more total net installed capacity than those without Rogun.

Figure 6-10 shows the annual energy generation by type of resource for scenario 1. The figure indicates that by the end of the study period, the hydro power plants generate close to 51% of the total energy required by the system plus that for firm exports, Rogun generates close to 32% while the coal fired units generate 12% of the total energy and the remaining energy is generated by CHP plants and renewable energy plants (mini hydro, wind and solar plants). As for the scenarios under Theme 1, Figure 6-6 shows the same gap between the total energy generated and the demand for the initial study years and this is decreased once new units are added to the system before Rogun is commissioned. Once Rogun starts to operate (in stages), the generation produced by the coal units added to the system prior to the commissioning of Rogun play a less significant role in meeting system demand and becomes available for non-firm export sales. Figure 6-10 shows this non-firm export as thermal and hydro exports with the non-firm exports from the hydro resources being more accentuated during June to September and during other months for the 350 MW coal units. In this case, by the end of the study period the non-firm sales are 1,900 GWh greater than those under Theme 1. The costs and associated revenues of these non-firm sales have been quantified and are shown in Table 6-22.

Figure 6-11 shows the annual installed capacity by type of resource for Scenario 7 (2 HPPs and 350 MW coal units). As can be seen the hydro component is the largest of all resources and by the end of the study period accounts for 51% of the total net generation capacity, Rogun for 31% and the coal for 14%. The figure also indicates that initially the hydro component accounts for 95% of the net capacity which over the study period is increased by 708 MW which is due to the refurbishment of the hydro existing units and the addition of Sanobad HPP and other HPPs.

Figure 6-12 shows the annual energy generation by type of resource for scenario 7. The figure indicates that by the end of the study period, the hydro power plants generate close to 55% of the total energy required by the system plus that for firm exports, Rogun generates close to 31% while the coal fired units generate 9% of the total energy and the remaining energy is generated by CHP plants and renewable energy plants (mini hydro, wind and solar plants). The unserved energy in the initial years is the same as that for Scenario 1. The non-firm exports for hydro and thermal generated energy are 180 GWh more than those obtained for Scenario 1.

It should be noted that by the end of the study period the results for Theme 3 are the same as those for Theme 2.

6.7 SELECTION OF THE LEAST COST PLANS

The benefits and costs of the Rogun HPP has been analysed in Section 6.5.2. and in Section 6.6.2. The total generation costs of the scenarios developed under Expansion Themes 2 and 3 have been presented in Table 6-14 and Table 6-23. It can be seen from these tables that the costs are as shown below for each of the expansion plans.

Theme	CPV ($, million)	
	Scenario 1	Scenario 7
1 – Without Rogun	6,811	6,639
2 – With Rogun	6,505	6,303
3 – With Early Rogun	6,322	6,256

From the above values, it can therefore be concluded that irrespective of the generation theme i.e. without, with the Rogun HPP or with Early Rogun, the expansion plans developed for Scenario 7 have lower cost than the expansion plans developed for Scenario 1.

Two least cost plans are selected for this study, one with the Rogun HPP and the other with the Early Rogun HPP. The annual unit addition and retirement schedules of these two plans are presented in Table 6-12 and Table 6-21 as well as detailed in Appendix D under tables D-27 and D-39.

6.8 SENSITIVITY ANALYSIS FOR THE SELECTED LEAST COST PLANS

The sensitivity study results for the two scenarios under Expansion Themes 1, 2 and 3 have been summarized in Sections 6.4.5, 6.5.4, and 6.6.3 respectively. This section presents the sensitivity study results for the selected two least cost plans plus the results for the corresponding plan Without the Rogun HPP.

6.8.1 Demand Forecast

The sensitivity study results of the two least cost plans to load variation are summarized in Table 6-29. The following can be seen from this table:

- Under the low load forecast, the least total generation cost is offered by the Early Rogun generation with a total cost of $5,352 million which is some $275 million less than the plan Without Rogun. The plan with Rogun is $10 million more than the plan with Early Rogun
- Under the most likely load forecast, the total generation cost of the plan with Early Rogun costs some $383 million less than the plan Without Rogun, The plan With Rogun is $47 million more than the plan with Early Rogun
- With the high load forecast, the plan with Early Rogun HPP has a cost of $7,629 million which is $524 million less than the plan Without Rogun. The plan With Rogun is $166 more than the plan with Early Rogun
- Under the three load forecast conditions, the plan with Early Rogun has the lower cost. However, the plan With Rogun has comparable costs for the low and most likely load forecast with the difference under the low load forecast being minimal.

6.8.2 Capital Cost of Plants

Table 6-30summarizes the sensitivity study results of the two least cost plans to capital cost variation. The following observations can be made from this table:

- Under the base case assumptions, the difference in total generation cost of the plan with Early Rogun and the plan With Rogun is only $47 million

- When the capital cost of new generation projects is reduced by 25%, the plan with Early Rogun costs $217 million less than the plan With
- If the capital cost of new generation projects is increased by 25%, the plan Without the Rogun HPP becomes the less expensive plan and the plan With Rogun becomes more attractive than the Early Rogun plan by some $123 million. The change in relative positions is due to the fact that Rogun is a capital intensive project and in the Early Rogun case the investment is made at an earlier date.

The results of this sensitivity analysis are shown graphically in Figure 6-13 and indicate that a capital increase of approximately 20% would bring the CPV of the generation expansion scenario Without Rogun lower than the other two Rogun plans. The figure also shows that a capital increase of 10% would make the With Rogun plan less expensive than the Early Rogun plan and this is due to the fact that the Early Rogun plan requires capital disbursements earlier than the other plan.

6.8.3 Fuel Price

The sensitivity study results of the two least cost plans to fuel price variation are summarized in Table 6-31. The following can be concluded from this table:

- Under the base case assumptions, the total generation cost of the Early Rogun plan is some $47 million less than the plan With Rogun
- When the fuel price is reduced by 25%, the cost difference between the two Rogun plans is $35 million in favor of the With Rogun plan. This reversal of positions between the plans is because the Early Rogun plan requires less fuel than the other plan and when the fuel is decreased there is a much lower impact on the plan’s cost than on the other plan
- When the fuel price is increased by 25%, the cost difference between the two Rogun plans increases to $129 million in favor of the Early Rogun plan.

The results of this sensitivity analysis are shown graphically in Figure 6-14 and indicate that a decrease in the fuel price of close to 35% would bring the CPV of the generation expansion scenario Without Rogun lower than that of the expansion plans With Rogun.

6.8.4 Discount Rate

Table 6-32 summarizes the sensitivity study results of the two least cost plans to discount rate variation. The following observations can be made from this table:

- Under the base case assumptions, the total generation cost of the Early Rogun plan is some $47 million less than the plan With Rogun
- When a discount rate of 12% is utilized, the plan without the Rogun HPP costs some $43 million less than the plan With the Rogun HPP
- When a discount rate of 8% is used, the plans with the Rogun HPP have a lower total costs than the plan Without Rogun. This is understandable as lower discount rate promotes capital intensive projects.

The results of this sensitivity analysis are shown graphically in Figure 6-15 and indicate that for discount rates of approximately 11.5%, the generation expansion scenario Without Rogun would have a lower CPV than the plans With Rogun.

6.8.5 Tariff of Export Energy

The tariff of export energy is another import parameter to the total generation system cost. In the base case assumptions, a tariff of US$ 68.2/MWh was used for non-firm export. The sensitivity study results to export tariff variation are summarized in Table 6-33. The following can be seen from this table:

- For the least cost plan without the Rogun HPP, every $10/MWh increase in the export energy tariff reduces the total generation system cost by some $333 million, i.e. an increase of $1/MWh in export tariff would reduce the system cost by $33.3 million
- For the least cost plan With Rogun HPP, every $10/MWh increase in the export energy tariff reduces the total generation system cost by some $399 million

- For the least cost plan with Early Rogun, every $10/MWh increase in the export energy tariff reduces the total generation system cost by some $452 million. The values of the non-firm exports are greater for the Early Rogun plan than for the With Rogun plan, thus when the export prices increase the total cost is reduced more for the Early Rogun plan than for the other plan.

The results of this sensitivity analysis are shown graphically in Figure 6-16 and indicate that for a non-firm export price of approximately $60/MWh, the generation expansion plans with Rogun would have the same cost. The figure also indicates the non-firm price would have to be reduced considerably before the Without Rogun plan becomes more cost effective than the plans with Rogun.

6.9 SUMMARY

The previous sections have described the analysis undertaken to arrive at a series of expansion plans that meet the electrical demand in Tajikistan with a certain degree of reliability at a minimum cost. This process is quite complex and analysed many different combinations of resources with different in service dates using a set of parameters and criteria that are common to all of the scenarios.

The results obtained are dependent upon many variables including the system demand, the reliability criteria, the fuel, capital and O&M costs, level and price of exports and discount rate. Should any one of these variables changes it is then possible that a different combination of resources and their respective in-service could result in a higher or lower overall cost depending upon the variable changed and its magnitude of change.

In order to arrive at a least cost of supply, many generation expansion scenarios were developed, and analysed following three main themes:

- Theme 1 – considered the system demand with without Rogun
- Theme 2 – considered the system demand with Rogun
- Theme 3 – considering the system demand with Early Rogun Generation

Eight generation expansion scenarios were developed under Theme 1 taking into account the different resources available and these consisted of 150 MW and 350 MW coal units, 300 MW combined cycle units and several hydroelectric power plants. The results of these generation expansion plans indicated that in the case of thermal unit additions only, the expansion scenarios with the 350 MW coal units resulted in lower costs than the ones with 150 MW coal units or 300 MW combined cycle units. The least cost generation expansion scenario under Theme 1 included 350 MW coal units and two hydro power plants. Based on the results for the Theme 1 generation expansion scenarios it was decided to analyse only two generation expansion scenarios under Theme 2 and Theme 3 and these would be the scenarios with the addition of only the 350 MW coal units (Scenario 1) and the one with the addition of 350 MW coal units and two HPPs (Scenario 7). At a discount rate of 10%, the cost difference between scenario 7 and scenario 1 amounted to $172 million and this is due to the fact that scenario 1 has a higher cost for fuel and O&M while scenario 7 has a higher cost for capital investment ($113 million).

It should be noted that even though the scenario with three hydro plants had the second lowest CPV it was not selected to be further investigated since the selected scenarios provide a wider potential for costs to be changed under the sensitivity analysis and the selected scenarios provide a wider use of the resources available.

To determine the economic viability of the EE programs, generation expansion scenarios were developed without the changes in the demand brought about by the implementation of the EE programs. The total generation additions by the end of the study period were the same since the EE programs are ended prior to the end of the study period. However it should be noted that the unit additions were advanced in the scenarios without EE when compared to the scenarios with EE. The comparison of results indicated that under scenario 1 the EE programs could provide a benefit of $217 million while under scenario 7 the benefit would be $192 million. The CPV of the energy saved under the EE programs is some 5,110 GWh which implies that there is a net saving of 4.25 ¢/kWh under Scenario 1 and 3.76 ¢/kWh under Scenario 7.

Table 6-34 presents the generation expansion sequences under consideration for Themes 2 and 3 so that a direct comparison between the themes and scenarios can be made.

The generation expansion scenarios under Theme 3 are somewhat similar to those under Theme 2 with the exception of the timing of the Rogun addition, the hydro plant and coal units additions. The total installation for each scenario in each theme is the same by the end of the study period.

Based on the retained generation expansion scenarios (1 and 7) of Theme 1, generation expansion sequences were developed under Theme 2 assuming that the first two units of Rogun would be commissioned in 2025, the next two in 2028 and the last two units in 2029 with the first two units being rated 400 MW each and the next four 600 MW each. The Rogun reservoir would only be completely filled by the end of 2036. Additional details on the timing of these additions are shown in Appendix C.

It should be noted that under Theme 2, the total net capacity by the end of the study period for the generation expansion scenarios analysed is some 1,600 MW more than that under Theme 1 since the energy generation capability of Rogun, with a capacity factor of 51%, is lower than that of coal fired units which can achieve capacity factors of 80% and higher thus the generation expansion plans with Rogun would require more total net installed capacity than those without Rogun. The annual capacity installation and annual energy generation for each of the retained scenarios under Theme 2 are presented in Figure 6-5 to Figure 6-8.

The generation expansion scenarios under Theme 3 considered that the first two units of Rogun HPP would start their operation from July 2019, the next two units from January 1, 2023 and the last two units from July 1, 2023. By the end of the study period the total generation additions under Theme 3 were the same as those under Theme 2 with the exception of their respective timing as several unit additions were delayed as Rogun was advanced. The annual capacity installation and annual energy generation for each scenario under Theme 3 are presented in Figure 6-9 to Figure 6-12.

By comparing the CPV of the generation expansion scenarios under Theme 2 and Theme 3 it is possible to determine the benefits or costs associated with Rogun. For the sequences with Rogun there would be a decrease in fuel and O&M costs, as well as the decommissioning and the flood protection cost and significant benefits due to the increase in revenue from non-firm exports. However, these benefits would be off-set by the capital and operating cost of Rogun. The resulting CPV at the base discount rate (10%) for the Themes 1, 2 and Theme 3 is shown below.

Theme	CPV ($, million)	
	Scenario 1	Scenario 7
1 – Without Rogun	6,811	6,639
2 – With Rogun	6,505	6,303
3 – Early Rogun	6,322	6,256

From the above values it is clear that expansion scenarios considering the addition of the Rogun HPP are more economic than those without at the base discount rate of 10%.

The benefits associated with each theme were determined against the results obtained for Theme 1 scenarios and are shown below.

Theme	Benefits[1] ($, million)	
	Scenario 1	Scenario 7
2 – With Rogun	306	336
3 – Early Rogun	489	383

Note:[1] Relative to Theme 1 – Without Rogun

From the values presented in the above table it can be observed that the Early Rogun scenarios provide greater benefits than those of the With Rogun scenarios.

The benefits for the With Rogun scenarios are of the order of 4 to 5% of the total scenario cost while the benefits for the Early Rogun scenarios are of the order of 6 to 7% of the total scenario cost. Both of these benefits may appear to be relatively small and this could be due to several factors such as the methodology/approach used, the relatively high discount rate used (the benefits are much larger at 8% discount rate), the economic life of plants and a variety of other factors. Also possible, but unlikely, that the study may not have included some of the benefits associated with Rogun since decommissioning costs and the cost of the works required to provide protection against the PMF have been accounted for. The study also included an environmental penalty against the coal fired units for CO2 emissions but did not take into account the effects on generation capability at Nurek of decreased generation due to sedimentation accumulation since this would occur outside the study period. However, since the decreased generation would likely occur so far into the future, once this is discounted at the base discount rate its value would be very small.

The benefits under Theme 3 are greater than those under Theme 2 due to several factors. In the Early Rogun cases there is a significant reduction in the fuel cost (coal required to generate electricity in the absence of the HPP) since the hydro power plant in commissioned at a much earlier date, there is also a reduction in the O&M costs since the installation of other type of plants is reduced and the capital requirements (for other plants) are less since the investments are postponed. Another factor favoring the Early Rogun case is the increase in value and quantity of the non-firm exports due to the fact that the HPP starts generating at an earlier date.

On the cost side, the present worth of the plant's capital cost and O&M account for close to 50% of the overall cost and thus when all the different factors are taken into account, the Early Rogun scenarios present reasonable benefits when compared to the respective costs of the scenarios developed under Theme 1.

Cross comparison of the Theme 2 and Theme 3 results is relatively difficult since there is a difference in the cash disbursements for the Rogun HPP under the two themes which could skew the results obtained and influence the selection decision. The selected cash disbursements for the Early Rogun cases should be calculated with the same level of accuracy as those obtained from the TEAS for the studies undertaken for Rogun under Theme 2.

. For both Theme 2 and Theme 3, the generation expansion sequence developed under Scenario 7 produced an overall lower CPV and was thus selected to be brought forward to determine the transmission requirements.

Sensitivity studies were carried out for both generation expansion scenarios 1 and 7 under Theme 2 and Theme 3 and are presented in the respective sections. The sensitivity studies were carried out to determine the sensitivity of the generation expansion sequences to changes in the economic parameters used in the analysis. Meaningful variations of these parameters were selected to demonstrate the robustness of the planning results under conditions that could reasonably be expected. Sensitivity was investigated to variations in the following parameters:

- Demand Forecast
- Capital cost of plants
- Fuel price
- Discount rate and
- Price of export energy

The results of the sensitivity analysis to the high and low growth rates indicate that the generation expansion scenarios are not overly sensitive to demand growth with the high growth demand presenting a decreased difference in the CPV between the cases without and with Rogun. For the other sensitivities, the results are presented in Figure 6-13 to Figure 6-16. In order for the generation expansion plans with Rogun to have the same CPV as the plan without Rogun, the following changes to individual parameters would be required.

Parameter	Base	Break Even Change
Capital Cost (%)	0	+20
Fuel Cost (%)	0	-40
Discount Rate (%)	10	11.5
Non-Firm Export Price ($/MWh)	68	<40

Table 6-1: Generation Addition Sequences – Expansion Theme 1

Year	Scenario							
	1	2	3	4	5	6	7	8
2015								
2016	CHP 2x150 MW							
2017								
2018								
2019	Coal 2x150 MW and Coal 350 MW							
2020	Coal 350 MW							
	10 MW Solar Power in Each of 2021 to 2025, 10 MW Wind in 2021 and 2025, 10 MW Mini Hydro in 2022 and 2024							
2021	CHP -128 MW and Coal 350 MW	CHP -128 MW and Coal 3x150 MW	CHP -128 MW and CCGT 300 MW	CHP -128 MW and Coal 350 MW	CHP -128 MW and Coal 350 MW	CHP -128 MW and Coal 350 MW	CHP -128 MW and Coal 350 MW	CHP -128 MW and Coal 350 MW
2022	Coal 350 MW		CCGT 300 MW	Hydro 100 MW	Hydro 100 MW	Hydro 100 MW	Hydro 100 MW	Hydro 100 MW
2023		Coal 150 MW		Hydro 125 MW	Hydro 125 MW	Hydro 125 MW	Hydro 125 MW	Coal 350 MW
2024								
2025		Coal 150 MW		Hydro 160 MW and Coal 350 MW	Hydro 160 MW and Coal 350 MW	Hydro 160 MW and Coal 350 MW	Coal 350 MW	
2026								
2027	Coal 350 MW	Coal 150 MW	CCGT 300 MW					
2028								Coal 350 MW
2029		Coal 150 MW	CCGT 300 MW	Hydro 182.5 MW and Coal 350 MW	Hydro 182.5 MW and Coal 350 MW	Coal 350 MW	Coal 350 MW	
2030	Coal 350 MW	Coal 150 MW						Coal 350 MW
2031		Coal 150 MW				Coal 350 MW	Coal 350 MW	
2032	Coal 350 MW	Coal 150 MW	CCGT 300 MW	Hydro 126 MW and Coal 350 MW	Coal 350 MW			
2033		Coal 150 MW						Coal 350 MW
2034		Coal 150 MW	CCGT 300 MW	Coal 350 MW	Coal 350 MW	Coal 350 MW	Coal 350 MW	
2035	Coal 350 MW	Coal 150 MW						Coal 350 MW
2036		Coal 150 MW					Coal 350 MW	
2037	Coal 350 MW	Coal 150 MW	CCGT 300 MW	Coal 350 MW	Coal 350 MW	Coal 350 MW		
2038		Coal 2x150 MW	CCGT 200 MW		Coal 350 MW	Coal 350 MW	Coal 250 MW	Coal 350 MW
2039	Coal 100 MW	Coal 50 MW		Coal 350 MW				

Table 6-2: Total Generation Costs – Expansion Theme 1

Item	Scenario							
	1	2	3	4	5	6	7	8
Summary for Generation								
Energy Demand (GWh)	274,710.0	274,710.0	274,710.0	274,710.0	274,710.0	274,710.0	274,710.0	274,710.0
Fuel Cost (M$)	2,529.7	2,583.8	3,800.4	2,283.4	2,297.5	2,320.8	2,359.7	2,468.7
O&M Cost (M$)	3,530.6	3,540.8	3,387.3	3,459.5	3,460.0	3,459.9	3,461.2	3,504.4
Capital Charge (M$)	2,437.6	2,402.8	2,183.4	2,836.9	2,780.3	2,687.8	2,551.0	2,470.0
Additional Cost (M$)	974.5	885.6	293.2	876.6	890.4	892.5	898.7	931.6
EUE Cost (M$)	29.6	29.4	31.6	32.5	31.4	31.7	32.0	33.9
Rogun Capital (M$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rogun O&M (M$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning Rogun Cost (M$)	131.0	131.0	131.0	131.0	131.0	131.0	131.0	131.0
Flood Protection Cost (M$)	189.7	189.7	189.7	189.7	189.7	189.7	189.7	189.7
Energy Efficiency Cost (M$)	41.1	41.1	41.1	41.1	41.1	41.1	41.1	41.1
Total Cost (M$)	**9,863.8**	**9,804.2**	**10,057.6**	**9,850.6**	**9,821.2**	**9,754.3**	**9,664.2**	**9,770.3**
Revenue from Firm Export (M$)	755.1	755.1	755.1	755.1	755.1	755.1	755.1	755.1
Revenue from Non-Firm Export (M$)	2,298.1	2,153.7	1,191.7	2,367.4	2,365.2	2,328.4	2,270.4	2,268.8
Net Total Cost (M$)	**6,810.7**	**6,895.4**	**8,110.8**	**6,728.2**	**6,701.0**	**6,670.8**	**6,638.7**	**6,746.4**
Summary for Thermal Export								
Thermal Energy Export (GWh)	23,202.9	21,086.4	6,980.6	20,872.1	21,199.5	21,249.1	21,396.7	22,181.0
Additional Cost for Export (M$)	974.5	885.6	293.2	876.6	890.4	892.5	898.7	931.6
Revenue from Export (M$)	1,582.4	1,438.1	476.1	1,423.5	1,445.8	1,449.2	1,459.3	1,512.7
Net Benefit (M$)	**607.9**	**552.5**	**182.9**	**546.8**	**555.4**	**556.7**	**560.6**	**581.1**

Table 6-3: Scenario Comparison – Expansion Theme 1

Item	Scenario						Difference Scenario 7 vs. Scenario 1		
	1			7					
	Planning Horizon	End Effect	All	Planning Horizon	End Effect	All	Planning Horizon	End Effect	All
Summary for Generation									
Energy Demand (GWh)	242,820.1	31,889.9	274,710.0	242,820.1	31,889.9	274,710.0	0.0	0.0	0.0
Fuel Cost (M$)	2,079.7	450.0	2,529.7	1,942.3	417.4	2,359.7	-137.4	-32.6	-170.0
O&M Cost (M$)	3,092.9	437.7	3,530.6	3,036.0	425.2	3,461.2	-56.9	-12.5	-69.4
Capital Charge (M$)	1,984.5	453.1	2,437.6	2,074.6	476.3	2,551.0	90.2	23.2	113.4
Additional Cost (M$)	780.8	193.7	974.5	710.1	188.5	898.7	-70.6	-5.2	-75.9
EUE Cost (M$)	20.4	9.2	29.6	23.0	9.0	32.0	2.6	-0.2	2.3
Rogun Capital (M$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rogun O&M (M$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning Rogun Cost (M$)	131.0	0.0	131.0	131.0	0.0	131.0	0.0	0.0	0.0
Flood Protection Cost (M$)	189.7	0.0	189.7	189.7	0.0	189.7	0.0	0.0	0.0
Energy Efficiency Cost (M$)	41.1	0.0	41.1	41.1	0.0	41.1	0.0	0.0	0.0
Total Cost (M$)	**8,320.1**	**1,543.8**	**9,863.8**	**8,147.9**	**1,516.4**	**9,664.2**	**-172.2**	**-27.4**	**-199.6**
Revenue from Firm Export (M$)	683.7	71.4	755.1	683.7	71.4	755.1	0.0	0.0	0.0
Revenue from Non-Firm Export (M$)	1,975.3	322.8	2,298.1	1,947.7	322.7	2,270.4	-27.5	-0.1	-27.6
Net Total Cost (M$)	**5,661.1**	**1,149.6**	**6,810.7**	**5,516.4**	**1,122.3**	**6,638.7**	**-144.7**	**-27.3**	**-172.0**
Summary for Thermal Export									
Thermal Energy Export (GWh)	18,590.2	4,612.8	23,202.9	16,908.2	4,488.5	21,396.7	-1,682.0	-124.3	-1,806.3
Additional Cost for Export (M$)	780.8	193.7	974.5	710.1	188.5	898.7	-70.6	-5.2	-75.9
Revenue from Export (M$)	1,267.8	314.6	1,582.4	1,153.1	306.1	1,459.3	-114.7	-8.5	-123.2
Net Benefit (M$)	**487.1**	**120.9**	**607.9**	**443.0**	**117.6**	**560.6**	**-44.1**	**-3.3**	**-47.3**

Table 6-4: Generation Addition Sequences –Without EE Programs

	Scenario	
	1	7
Year	Detailed Generation System Expansion Plan	
2015		
2016	CHP 2x150 MW	
2017		
2018		
2019	Coal 2x150 MW and Coal 350 MW	
2020	Coal 350 MW	
	10 MW Solar Power in Each of 2021 to 2025, 10 MW Wind in 2021 and 2025, 10 MW Mini Hydro	
2021	CHP -128 MW and Coal 2x350 MW	CHP -128 MW, Coal 350 MW, Hydro 100 MW and Hydro 125 MW
2022		
2023		Coal 350 MW
2024		
2025	Coal 350 MW	
2026		
2027		
2028		Coal 350 MW
2029	Coal 350 MW	
2030		
2031		Coal 350 MW
2032	Coal 350 MW	
2033		Coal 350 MW
2034	Coal 350 MW	
2035		
2036		Coal 350 MW
2037	Coal 350 MW	
2038		Coal 250 MW
2039	Coal 100 MW	

Table 6-5: Scenario Comparison Without EE Programs

Item	Scenario						Difference Scenario 7 vs. Scenario 1		
	1			7					
	Planning Horizon	End Effect	All	Planning Horizon	End Effect	All	Planning Horizon	End Effect	All
Summary for Generation									
Energy Demand (GWh)	247,929.8	31,889.9	279,819.7	247,929.8	31,889.9	279,819.7	0.0	0.0	0.0
Fuel Cost (M$)	2,179.1	450.0	2,629.1	2,011.8	417.4	2,429.2	-167.3	-32.6	-199.9
O&M Cost (M$)	3,144.5	437.7	3,582.1	3,077.6	425.2	3,502.7	-66.9	-12.5	-79.4
Capital Charge (M$)	2,064.4	453.1	2,517.6	2,185.8	476.3	2,662.2	121.4	23.2	144.6
Additional Cost (M$)	814.7	193.7	1,008.4	746.3	188.5	934.9	-68.3	-5.2	-73.6
EUE Cost (M$)	20.1	9.2	29.3	20.2	9.0	29.2	0.2	-0.2	-0.1
Rogun Capital (M$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rogun O&M (M$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning Rogun Cost (M$)	131.0	0.0	131.0	131.0	0.0	131.0	0.0	0.0	0.0
Flood Protection Cost (M$)	189.7	0.0	189.7	189.7	0.0	189.7	0.0	0.0	0.0
Energy Efficiency Cost (M$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Cost (M$)	**8,543.5**	**1,543.8**	**10,087.2**	**8,362.5**	**1,516.4**	**9,878.9**	**-181.0**	**-27.4**	**-208.4**
Revenue from Firm Export (M$)	683.7	71.4	755.1	683.7	71.4	755.1	0.0	0.0	0.0
Revenue from Non-Firm Export (M$)	1,981.3	322.8	2,304.2	1,970.3	322.7	2,293.0	-11.0	-0.1	-11.1
Net Total Cost (M$)	**5,878.4**	**1,149.6**	**7,028.0**	**5,708.5**	**1,122.3**	**6,830.8**	**-169.9**	**-27.3**	**-197.2**
Summary for Thermal Export									
Thermal Energy Export (GWh)	19,397.4	4,612.8	24,010.2	17,770.1	4,488.5	22,258.6	-1,627.3	-124.3	-1,751.6
Additional Cost for Export (M$)	814.7	193.7	1,008.4	746.3	188.5	934.9	-68.3	-5.2	-73.6
Revenue from Export (M$)	1,322.9	314.6	1,637.5	1,211.9	306.1	1,518.0	-111.0	-8.5	-119.5
Net Benefit (M$)	**508.2**	**120.9**	**629.1**	**465.6**	**117.6**	**583.2**	**-42.6**	**-3.3**	**-45.9**

Table 6-6: Benefits of EE Programs – Comparison of Costs With and Without EE Programs

Item	Scenario					
	1			7		
	Without EE	With EE	Benefits of EE	Without EE	With EE	Benefits of EE
Summary for Generation						
Energy Demand (GWh)	279,819.7	274,710.0	5,109.7	279,819.7	274,710.0	5,109.7
Fuel Cost (M$)	2,629.1	2,529.7	99.4	2,429.2	2,359.7	69.5
O&M Cost (M$)	3,582.1	3,530.6	51.5	3,502.7	3,461.2	41.5
Capital Charge (M$)	2,517.6	2,437.6	80.0	2,662.2	2,551.0	111.2
Additional Cost (M$)	1,008.4	974.5	33.9	934.9	898.7	36.2
EUE Cost (M$)	29.3	29.6	-0.4	29.2	32.0	-2.8
Rogun Capital (M$)	0.0	0.0	0.0	0.0	0.0	0.0
Rogun O&M (M$)	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning Rogun Cost (M$)	131.0	131.0	0.0	131.0	131.0	0.0
Flood Protection Cost (M$)	189.7	189.7	0.0	189.7	189.7	0.0
Energy Efficiency Cost (M$)	0.0	41.1	-41.1	0.0	41.1	-41.1
Total Cost (M$)	**10,087.2**	**9,863.8**	**223.4**	**9,878.9**	**9,664.2**	**214.6**
Revenue from Firm Export (M$)	755.1	755.1	0.0	755.1	755.1	0.0
Revenue from Non-Firm Export (M$)	2,304.2	2,298.1	6.1	2,293.0	2,270.4	22.6
			0.0			0.0
Net Total Cost (M$)	**7,028.0**	**6,810.7**	**217.3**	**6,830.8**	**6,638.7**	**192.1**

Table 6-7: Sensitivity Study Results – Expansion Sequences for Low and High Load Forecast – Expansion Theme 1

Load	Low Demand Forecast		High Demand Forecast	
Scenario	1	7	1	7
2015				
2016	CHP 2x150 MW			
2017				
2018				
2019	Coal 2x150 MW and Coal 350 MW			
2020	Coal 350 MW			
	10 MW Solar Power in Each of 2021 to 2025, 10 MW Wind in 2021 and 2025, 10 MW Mini Hydro in 2022 and 2024			
2021	CHP -128 MW and Coal 350 MW	CHP -128 MW, Hydro 100 MW and Hydro 125 MW	CHP -128 MW and Coal 2x350 MW	CHP -128 MW and Coal 2x350 MW
2022		Coal 350 MW		
2023				
2024			Coal 350 MW	Hydro 100 MW and Hydro 125 MW
2025				Coal 350 MW
2026	Coal 350 MW			
2027			Coal 350 MW	
2028				Coal 350 MW
2029		Coal 350 MW	Coal 350 MW	
2030	Coal 350 MW			Coal 350 MW
2031			Coal 350 MW	
2032		Coal 350 MW	Coal 350 MW	Coal 350 MW
2033	Coal 350 MW			Coal 350 MW
2034			Coal 350 MW	
2035		Coal 350 MW		Coal 350 MW
2036			Coal 350 MW	Coal 350 MW
2037	Coal 350 MW		Coal 350 MW	
2038		Coal 300 MW	Coal 350 MW	Coal 350 MW
2039	Coal 150 MW			Coal 200 MW

Table 6-8: Sensitivity Study Results – Changes in Load Forecast – Expansion Theme 1

Scenario		Changes in Load Forecast					
		Low		Most Likely		High	
No.	Descrption	25-Year	All	25-Year	All	25-Year	All
1	Coal 350 MW Units	4,875.5	5,809.5	5,661.1	6,810.7	6,689.5	8,295.5
7	Two Hydro Plants and Coal 350 MW Units	4,723.1	5,626.5	5,516.4	6,638.7	6,571.5	8,152.1

Table 6-9: Sensitivity Study Results – Changes in Capital Cost – Expansion Theme 1

Scenario		Changes in Capital					
		-25%		Base		+25%	
No.	Descrption	25-Year	All	25-Year	All	25-Year	All
1	Coal 350 MW Units	5,094.8	6,096.3	5,661.1	6,810.7	6,228.0	7,526.1
7	Two Hydro Plants and Coal 350 MW Units	4,935.6	5,905.5	5,516.4	6,638.7	6,097.8	7,372.7

Table 6-10: Sensitivity Study Results – Changes in Fuel Price – Expansion Theme 1

Scenario		Changes in Fuel Price					
		-25%		Base		+25%	
No.	Descrption	25-Year	All	25-Year	All	25-Year	All
1	Coal 350 MW Units	5,011.4	6,016.3	5,661.1	6,810.7	6,311.5	7,606.0
7	Two Hydro Plants and Coal 350 MW Units	4,912.8	5,899.4	5,516.4	6,638.7	6,120.6	7,378.8

Table 6-11: Sensitivity Study Results – Changes in Discount Rate – Expansion Theme 1

Scenario		Changes in Discount Rate					
		8%		10%		12%	
No.	Descrption	25-Year	All	25-Year	All	25-Year	All
1	Coal 350 MW Units	6,548.5	8,478.3	5,661.1	6,810.7	4,975.6	5,674.9
7	Two Hydro Plants and Coal 350 MW Units	6,331.5	8,202.0	5,516.4	6,638.7	4,874.5	5,560.8

Table 6-12: Generation Addition Sequences – Expansion Theme 2

	Scenario	
	1	7
Year	Detailed Generation System Expansion Plan	
2015		
2016	CHP 2x150 MW	
2017		
2018		
2019	Coal 2x150 MW and Coal 350 MW	
2020	Coal 350 MW	
	10 MW Solar Power in Each of 2021 to 2025, 10 MW Wind in 2021 and 2025, 10 MW Mini Hydro in 2022 and 2024	
2021	CHP -128 MW and Coal 350 MW	CHP -128 MW and Coal 350 MW
2022	Coal 350 MW	Hydro 100 MW
2023		Hydro 125 MW
2024		
2025	Rogun 2x400 MW	Rogun 2x400 MW
2026		
2027		
2028	Rogun 2x600 MW	Rogun 2x600 MW
2029	Rogun 2x600 MW	Rogun 2x600 MW
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		Coal 250 MW
2039	Coal 100 MW	

Table 6-13: Scenario Cost Comparison – Expansion Theme 2

Item	Scenario						Difference Scenario 7 vs. Scenario 1		
	1			7					
	Planning Horizon	End Effect	All	Planning Horizon	End Effect	All	Planning Horizon	End Effect	All
Summary for Generation									
Energy Demand (GWh)	242,820.1	31,889.9	274,710.0	242,820.1	31,889.9	274,710.0	0.0	0.0	0.0
Fuel Cost (M$)	1,528.5	146.7	1,675.2	1,407.1	119.2	1,526.3	-121.4	-27.5	-148.9
O&M Cost (M$)	2,815.2	276.9	3,092.1	2,751.5	266.5	3,018.0	-63.7	-10.4	-74.1
Capital Charge (M$)	1,696.2	253.0	1,949.3	1,716.2	276.2	1,992.5	20.0	23.2	43.2
Additional Cost (M$)	849.5	213.4	1,063.0	690.1	206.3	896.4	-159.4	-7.2	-166.6
EUE Cost (M$)	7.6	6.4	13.9	15.8	6.7	22.5	8.2	0.3	8.6
Rogun Capital (M$)	1,579.0	498.7	2,077.7	1,579.0	498.7	2,077.7	0.0	0.0	0.0
Rogun O&M (M$)	151.4	54.0	205.4	151.4	54.0	205.4	0.0	0.0	0.0
Decommissioning Rogun Cost (M$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Flood Protection Cost (M$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Energy Efficiency Cost (M$)	41.1	0.0	41.1	41.1	0.0	41.1	0.0	0.0	0.0
Total Cost (M$)	**8,668.5**	**1,449.2**	**10,117.7**	**8,352.2**	**1,427.6**	**9,779.8**	**-316.3**	**-21.6**	**-337.9**
Revenue from Firm Export (M$)	683.7	71.4	755.1	683.7	71.4	755.1	0.0	0.0	0.0
Revenue from Non-Firm Export (M$)	2,443.8	414.3	2,858.0	2,297.9	423.9	2,721.8	-145.9	9.6	-136.3
Net Total Cost (M$)	**5,541.0**	**963.6**	**6,504.6**	**5,370.6**	**932.4**	**6,303.0**	**-170.4**	**-31.2**	**-201.6**
Summary for Thermal Export									
Thermal Energy Export (GWh)	20,226.5	5,082.0	25,308.5	16,430.5	4,911.3	21,341.8	-3,796.0	-170.8	-3,966.7
Additional Cost for Export (M$)	849.5	213.4	1,063.0	690.1	206.3	896.4	-159.4	-7.2	-166.6
Revenue from Export (M$)	1,379.4	346.6	1,726.0	1,120.6	334.9	1,455.5	-258.9	-11.6	-270.5
Net Benefit (M$)	**529.9**	**133.1**	**663.1**	**430.5**	**128.7**	**559.2**	**-99.5**	**-4.5**	**-103.9**

Table 6-14: Benefits/Costs of Rogun HPP

Item	Scenario					
	1			7		
	Without Rogun	With Rogun	Benefits of Rogun	Without Rogun	With Rogun	Benefits of Rogun
Summary for Generation						
Energy Demand (GWh)	274,710.0	274,710.0	0.0	274,710.0	274,710.0	0.0
Fuel Cost (M$)	2,529.7	1,675.2	854.5	2,359.7	1,526.3	833.4
O&M Cost (M$)	3,530.6	3,092.1	438.5	3,461.2	3,018.0	443.2
Capital Charge (M$)	2,437.6	1,949.3	488.3	2,551.0	1,992.5	558.5
Additional Cost (M$)	974.5	1,063.0	-88.4	898.7	896.4	2.3
EUE Cost (M$)	29.6	13.9	15.7	32.0	22.5	9.5
Rogun Capital (M$)	0.0	2,077.7	-2,077.7	0.0	2,077.7	-2,077.7
Rogun O&M (M$)	0.0	205.4	-205.4	0.0	205.4	-205.4
Decommissioning Rogun Cost (M$)	131.0	0.0	131.0	131.0	0.0	131.0
Flood Protection Cost (M$)	189.7	0.0	189.7	189.7	0.0	189.7
Energy Efficiency Cost (M$)	41.1	41.1	0.0	41.1	41.1	0.0
Total Cost (M$)	**9,863.8**	**10,117.7**	**-253.9**	**9,664.2**	**9,779.8**	**-115.6**
Revenue from Firm Export (M$)	755.1	755.1	0.0	755.1	755.1	0.0
Revenue from Non-Firm Export (M$)	2,298.1	2,858.0	-560.0	2,270.4	2,721.8	-451.3
						0.0
Net Total Cost (M$)	**6,810.7**	**6,504.6**	**306.1**	**6,638.7**	**6,303.0**	**335.8**

Table 6-15: Sensitivity Study Results – Expansion Sequences for Low and High Load Forecast – Expansion Theme 2

Load	Low Demand Forecast		High Demand Forecast	
Scenario	1	7	1	7
2015				
2016	CHP 2x150 MW			
2018				
2019	Coal 2x150 MW and Coal 350 MW			
2020	Coal 350 MW			
	10 MW Solar Power in Each of 2021 to 2025, 10 MW Wind in 2021 and 2025, 10 MW Mini Hydro in 2022 and 2024			
2021	CHP -128 MW and Coal 350 MW	CHP -128 MW, Hydro 100 MW and Hydro 125 MW	CHP -128 MW and Coal 2x350 MW	CHP -128 MW and Coal 2x350 MW
2022		Coal 350 MW		
2023				
2024			Coal 350 MW	Hydro 100 MW and Hydro 125 MW
2025	Rogun 2x400 MW	Rogun 2x400 MW	Rogun 2x400 MW	Rogun 2x400 MW
2026				
2027				
2028	Rogun 2x600 MW	Rogun 2x600 MW	Rogun 2x600 MW	Rogun 2x600 MW
2029	Rogun 2x600 MW	Rogun 2x600 MW	Rogun 2x600 MW	Rogun 2x600 MW and Coal 350 MW
2030				
2031				
2032				
2033				
2034			Coal 350 MW	
2035				
2036			Coal 350 MW	Coal 350 MW
2037				
2038			Coal 350 MW	Coal 350 MW
2039				Coal 200 MW

Table 6-16: Sensitivity Study Results – Changes in Load Forecast – Expansion Theme 2

Scenario		Changes in Load Forecast					
		Low		Most Likely		High	
No.	Descrption	25-Year	All	25-Year	All	25-Year	All
1	Coal 350 MW Units	4,753.3	5,497.2	5,541.0	6,504.6	6,520.4	7,933.4
7	Two Hydro Plants and Coal 350 MW Units	4,648.5	5,361.2	5,370.6	6,303.0	6,409.0	7,794.9

Table 6-17: Sensitivity Study Results – Changes in Capital Cost – Expansion Theme 2

Scenario		Changes in Capital					
		-25%		Base		+25%	
No.	Descrption	25-Year	All	25-Year	All	25-Year	All
1	Coal 350 MW Units	4,658.5	5,412.1	5,541.0	6,504.6	6,424.0	7,597.7
7	Two Hydro Plants and Coal 350 MW Units	4,493.6	5,211.5	5,370.6	6,303.0	6,248.1	7,395.0

Table 6-18: Sensitivity Study Results – Changes in Fuel Prices – Expansion Theme 2

Scenario		Changes in Fuel Price					
		-25%		Base		+25%	
No.	Descrption	25-Year	All	25-Year	All	25-Year	All
1	Coal 350 MW Units	5,017.5	5,908.9	5,541.0	6,504.6	6,064.9	7,100.8
7	Two Hydro Plants and Coal 350 MW Units	4,904.0	5,772.2	5,370.6	6,303.0	5,837.6	6,834.1

Table 6-19: Sensitivity Study Results – Changes in Discount Rate – Expansion Theme 2

Scenario		Changes in Discount Rate					
		8%		10%		12%	
No.	Descrption	25-Year	All	25-Year	All	25-Year	All
1	Coal 350 MW Units	5,994.6	7,470.0	5,541.0	6,504.6	5,113.3	5,745.9
7	Two Hydro Plants and Coal 350 MW Units	5,762.5	7,171.4	5,370.6	6,303.0	4,985.7	5,603.9

Table 6-20: Sensitivity Study Results – Changes in Capital Disbursements – Expansion Theme 2

Scenario		Change in Capital Disbursement			
		Early Rogun		TEAS Rogun (base)	
No.	Descrption	25-Year	All	25-Year	All
1	Coal 350 MW Units	5,382.5	6,331.0	5,541.0	6,504.6
7	Two Hydro Plants and Coal 350 MW Units	5,212.1	6,129.4	5,370.6	6,303.0

Table 6-21: Generation Addition Sequences: Early Rogun – Expansion Theme 2

`	Scenario	
	1	7
Year	Detailed Generation System Expansion Plan	
2015		
2016	CHP 2x150 MW	
2017		
2018		
2019	Coal 2x150 MW, Coal 350 MW and Rogun 2x400 MW	
2020	Coal 350 MW	
	10 MW Solar Power in Each of 2021 to 2025, 10 MW Wind in 2021 and 2025, 10 MW Mini Hydro in 2022 and 2024	
2021	CHP -128 MW	CHP -128 MW
2022		
2023	Rogun 4x600 MW	Rogun 4x600 MW
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033	Coal 350 MW	Hydro 100 MW and 125 MW
2034		
2035		Coal 350 MW
2036	Coal 350 MW	
2037		
2038		Coal 250 MW
2039	Coal 100 MW	

Table 6-22: Scenario Cost Comparison: Early Rogun – Expansion Theme 3

Item	Scenario						Difference		
	1			7			Scenario 7 vs. Scenario 1		
	Planning Horizon	End Effect	All	Planning Horizon	End Effect	All	Planning Horizon	End Effect	All
Summary for Generation									
Energy Demand (GWh)	242,820.1	31,889.9	274,710.0	242,820.1	31,889.9	274,710.0	0.0	0.0	0.0
Fuel Cost (M$)	1,020.5	146.5	1,167.0	995.5	118.7	1,114.1	-25.0	-27.8	-52.9
O&M Cost (M$)	2,544.7	277.9	2,822.6	2,534.2	266.3	2,800.5	-10.5	-11.6	-22.2
Capital Charge (M$)	1,308.5	258.8	1,567.2	1,327.1	276.2	1,603.4	18.7	17.5	36.1
Additional Cost (M$)	846.3	223.0	1,069.2	817.0	206.9	1,024.0	-29.2	-16.1	-45.3
EUE Cost (M$)	9.5	2.9	12.4	10.3	6.7	17.0	0.8	3.8	4.6
Rogun Capital (M$)	2,649.0	471.3	3,120.3	2,649.0	471.3	3,120.3	0.0	0.0	0.0
Rogun O&M (M$)	317.2	54.0	371.2	317.2	54.0	371.2	0.0	0.0	0.0
Decommissioning Rogun Cost (M$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Flood Protection Cost (M$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Energy Efficiency Cost (M$)	41.1	0.0	41.1	41.1	0.0	41.1	0.0	0.0	0.0
Total Cost (M$)	**8,736.7**	**1,434.4**	**10,171.1**	**8,691.3**	**1,400.2**	**10,091.5**	**-45.3**	**-34.2**	**-79.5**
Revenue from Firm Export (M$)	683.7	71.4	755.1	683.7	71.4	755.1	0.0	0.0	0.0
Revenue from Non-Firm Export (M$)	2,665.2	429.2	3,094.4	2,656.4	424.2	3,080.6	-8.8	-5.0	-13.8
Net Total Cost (M$)	**5,387.7**	**933.8**	**6,321.6**	**5,351.2**	**904.6**	**6,255.8**	**-36.5**	**-29.2**	**-65.7**
Summary for Thermal Export									
	Planning Horizon	End Effect	All Periods	Planning Horizon	End Effect	All Periods	Planning Horizon	Planning Horizon	Planning Horizon
Thermal Energy Export (GWh)	20,148.9	5,308.9	25,457.9	19,453.3	4,926.7	24,380.0	-695.6	-382.3	-1,077.9
Additional Cost for Export (M$)	846.3	223.0	1,069.2	817.0	206.9	1,024.0	-29.2	-16.1	-45.3
Revenue from Export (M$)	1,374.2	362.1	1,736.2	1,326.7	336.0	1,662.7	-47.4	-26.1	-73.5
			0.0			0.0			
Net Benefit (M$)	**527.9**	**139.1**	**667.0**	**509.7**	**129.1**	**638.8**	**-18.2**	**-10.0**	**-28.2**

Table 6-23: Benefits/Costs of Early Rogun

Item	Scenario					
	1			7		
	Without Rogun	Early Rogun	Benefits of Early Rogun	Without Rogun	Early Rogun	Benefits of Early Rogun
Summary for Generation						
Energy Demand (GWh)	274,710.0	274,710.0	0.0	274,710.0	274,710.0	0.0
Fuel Cost (M$)	2,529.7	1,167.0	1,362.7	2,359.7	1,114.1	1,245.5
O&M Cost (M$)	3,530.6	2,822.6	708.0	3,461.2	2,800.5	660.8
Capital Charge (M$)	2,437.6	1,567.2	870.4	2,551.0	1,603.4	947.6
Additional Cost (M$)	974.5	1,069.2	-94.7	898.7	1,024.0	-125.3
EUE Cost (M$)	29.6	12.4	17.2	32.0	17.0	15.0
Rogun Capital (M$)	0.0	3,120.3	-3,120.3	0.0	3,120.3	-3,120.3
Rogun O&M (M$)	0.0	371.2	-371.2	0.0	371.2	-371.2
Decommissioning Rogun Cost (M$)	131.0	0.0	131.0	131.0	0.0	131.0
Flood Protection Cost (M$)	189.7	0.0	189.7	189.7	0.0	189.7
Energy Efficiency Cost (M$)	41.1	41.1	0.0	41.1	41.1	0.0
Total Cost (M$)	**9,863.8**	**10,171.1**	**-307.2**	**9,664.2**	**10,091.5**	**-427.3**
Revenue from Firm Export (M$)	755.1	755.1	0.0	755.1	755.1	0.0
Revenue from Non-Firm Export (M$)	2,298.1	3,094.4	-796.4	2,270.4	3,080.6	-810.2
Net Total Cost (M$)	**6,810.7**	**6,321.6**	**489.1**	**6,638.7**	**6,255.8**	**382.9**

Table 6-24: Sensitivity Study Results – Changes in Load Forecast – Expansion Theme 3

Scenario		Changes in Load Forecast					
		Low		Most Likely		High	
No.	Descrption	25-Year	All	25-Year	All	25-Year	All
1	Coal 350 MW Units	4,675.3	5,396.4	5,387.7	6,321.6	6,405.3	7,783.4
7	Two Hydro Plants and Coal 350 MW Units	4,667.0	5,351.8	5,351.2	6,255.8	6,279.5	7,628.6

Table 6-25: Sensitivity Study Results – Changes in Capital Cost – Expansion Theme 3

Scenario		Changes in Capital					
		-25%		Base		+25%	
No.	Descrption	25-Year	All	25-Year	All	25-Year	All
1	Coal 350 MW Units	4,337.1	5,066.1	5,387.7	6,321.6	6,438.8	7,577.5
7	Two Hydro Plants and Coal 350 MW Units	4,297.3	4,994.3	5,351.2	6,255.8	6,405.5	7,517.8

Table 6-26: Sensitivity Study Results – Changes in Fuel Prices – Expansion Theme 3

Scenario		Changes in Fuel Price					
		-25%		Base		+25%	
No.	Descrption	25-Year	All	25-Year	All	25-Year	All
1	Coal 350 MW Units	4,991.7	5,851.8	5,387.7	6,321.6	5,784.0	6,791.7
7	Two Hydro Plants and Coal 350 MW Units	4,966.3	5,806.8	5,351.2	6,255.8	5,736.4	6,705.2

Table 6-27: Sensitivity Study Results – Changes in Discount Rate – Expansion Theme 3

Scenario		Changes in Discount Rate					
		8%		10%		12%	
No.	Descrption	25-Year	All	25-Year	All	25-Year	All
1	Coal 350 MW Units	5,577.4	7,015.1	5,387.7	6,321.6	5,159.3	5,768.5
7	Two Hydro Plants and Coal 350 MW Units	5,516.5	6,893.4	5,351.2	6,255.8	5,137.7	5,733.0

Table 6-28: Sensitivity Study Results – Addition of Shurob – Expansion Theme 3

Scenario		Shurob Hydro Plant			
		With		Without	
No.	Descrption	25-Year	All	25-Year	All
1	Coal 350 MW Units	5,582.6	6,633.2	5,387.7	6,321.6
7	Two Hydro Plants and Coal 350 MW Units	5,566.4	6,583.7	5,351.2	6,255.8

Table 6-29: Sensitivity Study Results – Changes in Load Forecast – Least Cost Plan

Least Cost Plan	Changes in Load Forecast					
	Low		Most Likely		High	
	25-Year	All	25-Year	All	25-Year	All
Without Rogun HPP	4,723.1	5,626.5	5,516.4	6,638.7	6,571.5	8,152.1
With Rogun HPP	4,648.5	5,361.2	5,370.6	6,303.0	6,409.0	7,794.9
With EarlyRogun HPP	4,667.0	5,351.8	5,351.2	6,255.8	6,279.5	7,628.6

Table 6-30: Sensitivity Study Results – Changes in Capital Cost – Least Cost Plan

Least Cost Plan	Changes in Capital					
	-25%		Base		+25%	
	25-Year	All	25-Year	All	25-Year	All
Without Rogun HPP	4,935.6	5,905.5	5,516.4	6,638.7	6,097.8	7,372.7
With Rogun HPP	4,493.6	5,211.5	5,370.6	6,303.0	6,248.1	7,395.0
With EarlyRogun HPP	4,297.3	4,994.3	5,351.2	6,255.8	6,405.5	7,517.8

Table 6-31: Sensitivity Study Results – Changes in Fuel Prices – Least Cost Plan

Least Cost Plan	Changes in Fuel Price					
	-25%		Base		+25%	
	25-Year	All	25-Year	All	25-Year	All
Without Rogun HPP	4,912.8	5,899.4	5,516.4	6,638.7	6,120.6	7,378.8
With Rogun HPP	4,904.0	5,772.2	5,370.6	6,303.0	5,837.6	6,834.1
With EarlyRogun HPP	4,966.3	5,806.8	5,351.2	6,255.8	5,736.4	6,705.2

Table 6-32: Sensitivity Study Results – Changes in Discount Rate – Least Cost Plan

Least Cost Plan	Changes in Discount Rate					
	8%		10%		12%	
	25-Year	All	25-Year	All	25-Year	All
Without Rogun HPP	6,331.5	8,202.0	5,516.4	6,638.7	4,874.5	5,560.8
With Rogun HPP	5,762.5	7,171.4	5,370.6	6,303.0	4,985.7	5,603.9
With EarlyRogun HPP	5,516.5	6,893.4	5,351.2	6,255.8	5,137.7	5,733.0

Table 6-33: Sensitivity Study Results – Changes in Export Tariff – Least Cost Plan

Least Cost Plan	Changes in Export Tariff					
	$55/MWh		$68/MWh		$85/MWh	
	25-Year	All	25-Year	All	25-Year	All
Without Rogun HPP	5,893.4	7,078.1	5,516.4	6,638.7	5,036.6	6,079.4
With Rogun HPP	5,815.3	6,829.7	5,370.6	6,303.0	4,804.5	5,632.5
With EarlyRogun HPP	5,865.4	6,852.0	5,351.2	6,255.8	4,696.9	5,497.0

Table 6-34: Comparison of Generation Expansion Sequences under Theme 2 and Theme 3

	Theme 2		Theme 3	
	Scenario 1	Scenario 7	1	7
Year	Detailed Generation System Expansion Plan			
2015				
2016	CHP 2x150 MW		CHP 2x150 MW	
2017				
2018				
2019	Coal 2x150 MW and Coal 350 MW		Coal 2x150 MW, Coal 350 MW and Rogun 2x400 MW	
2020	Coal 350 MW		Coal 350 MW	
	10 MW Solar Power in Each of 2021 to 2025, 10 MW Wind in 2021 and 2025, 10 MW Mini Hydro in 2022 and 2024		10 MW Solar Power in Each of 2021 to 2025, 10 MW Wind in 2021 and 2025, 10 MW Mini Hydro in 2022 and 2024	
2021	CHP -128 MW and Coal 350	CHP -128 MW and Coal 350	CHP -128 MW	CHP -128 MW
2022	Coal 350 MW	Hydro 100 MW		
2023		Hydro 125 MW	Rogun 4x600 MW	Rogun 4x600 MW
2024				
2025	Rogun 2x400 MW	Rogun 2x400 MW		
2026				
2027				
2028	Rogun 2x600 MW	Rogun 2x600 MW		
2029	Rogun 2x600 MW	Rogun 2x600 MW		
2030				
2031				
2032				
2033			Coal 350 MW	Hydro 100 MW and 125 MW
2034				
2035				Coal 350 MW
2036			Coal 350 MW	
2037				
2038		Coal 250 MW		Coal 250 MW
2039	Coal 100 MW		Coal 100 MW	

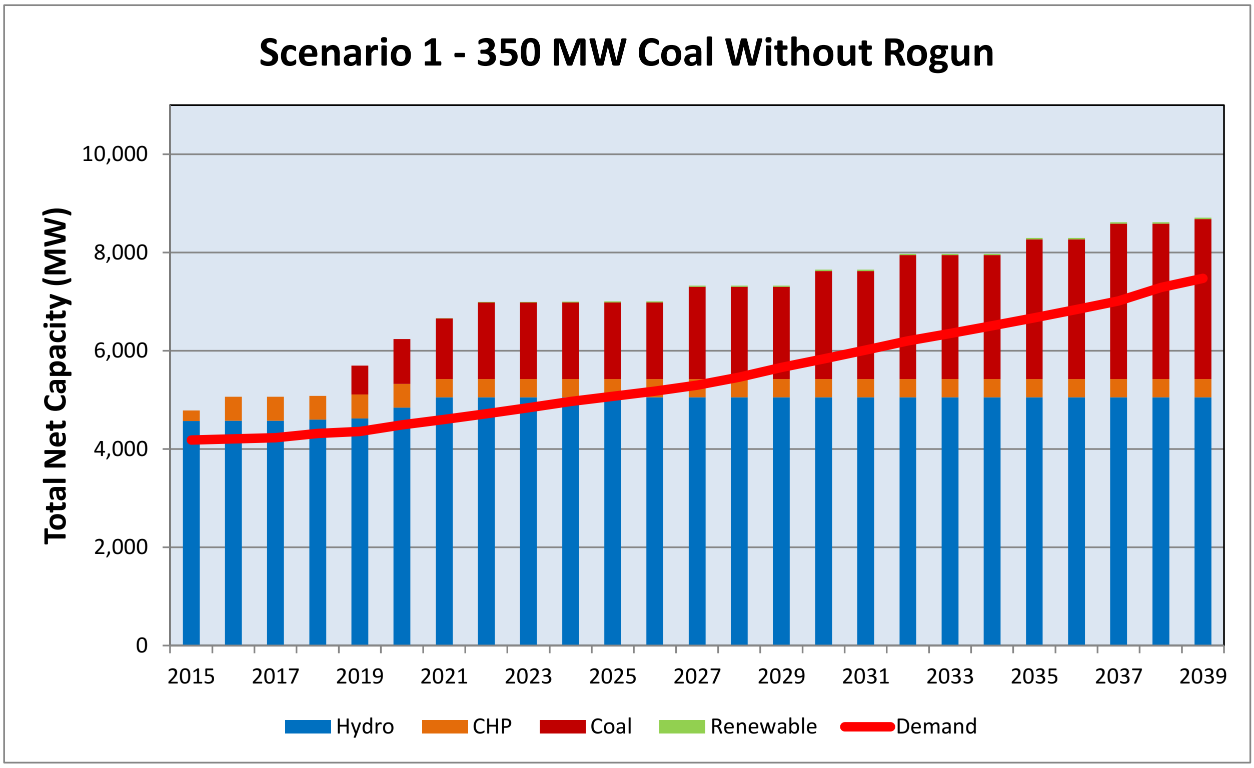

Figure 6-1: Theme 1, Scenario 1 – 350 MW Coal Units, Annual Capacity Installation

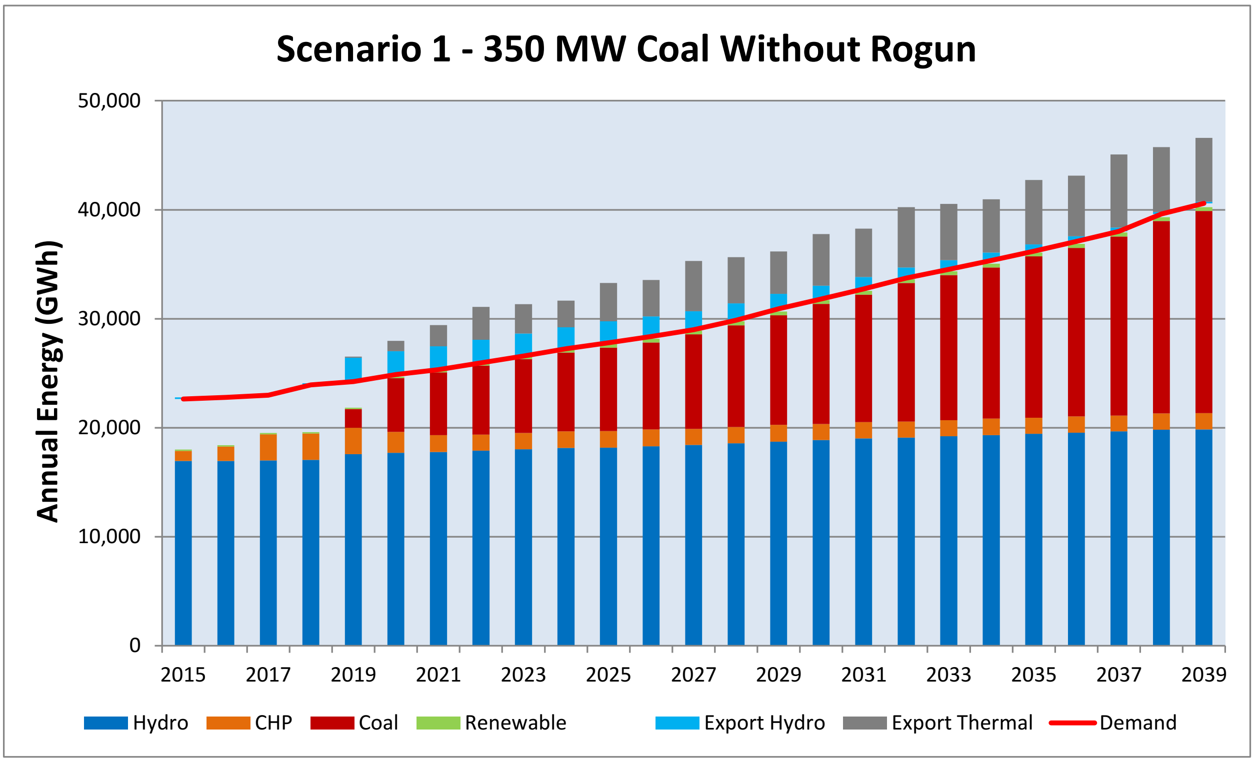

Figure 6-2: Theme 1, Scenario 1 – 350 MW Coal Units, Annual Energy Generation

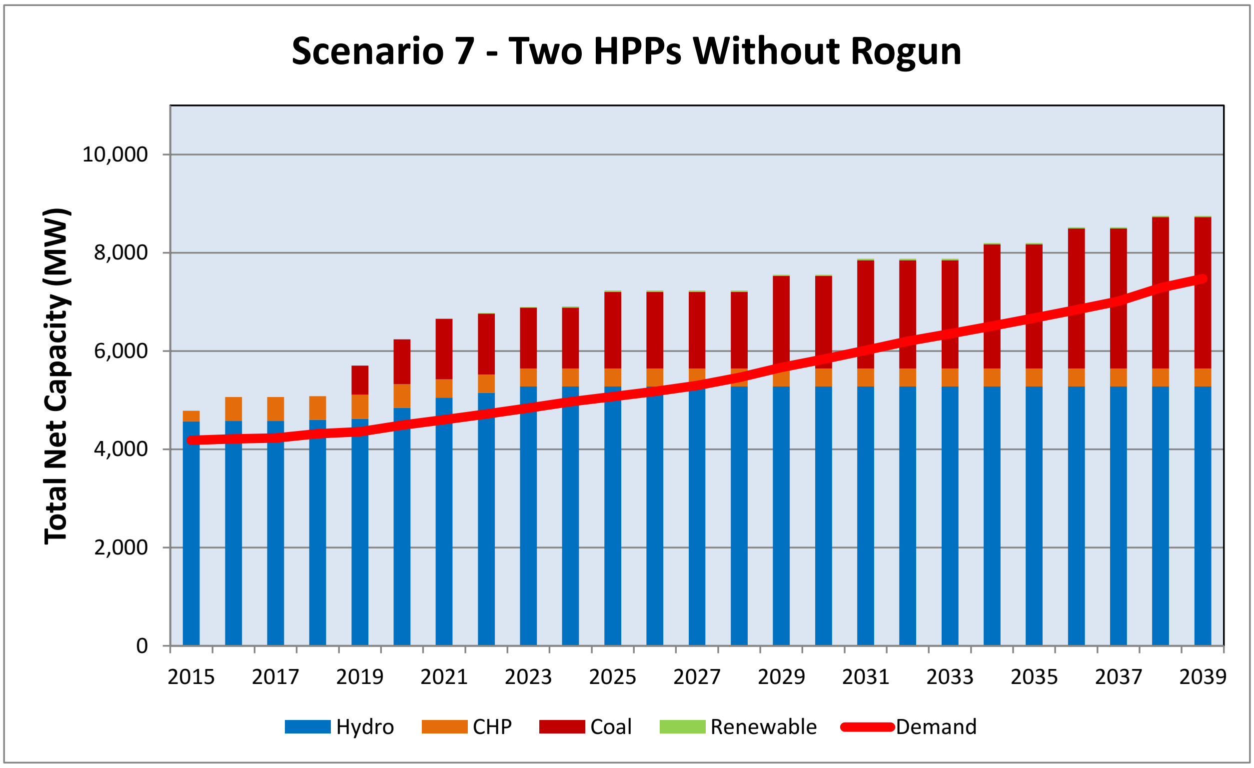

Figure 6-3: Theme 1, Scenario 7 – 2 HPPs and 350 MW Coal Units, Annual Capacity Installation

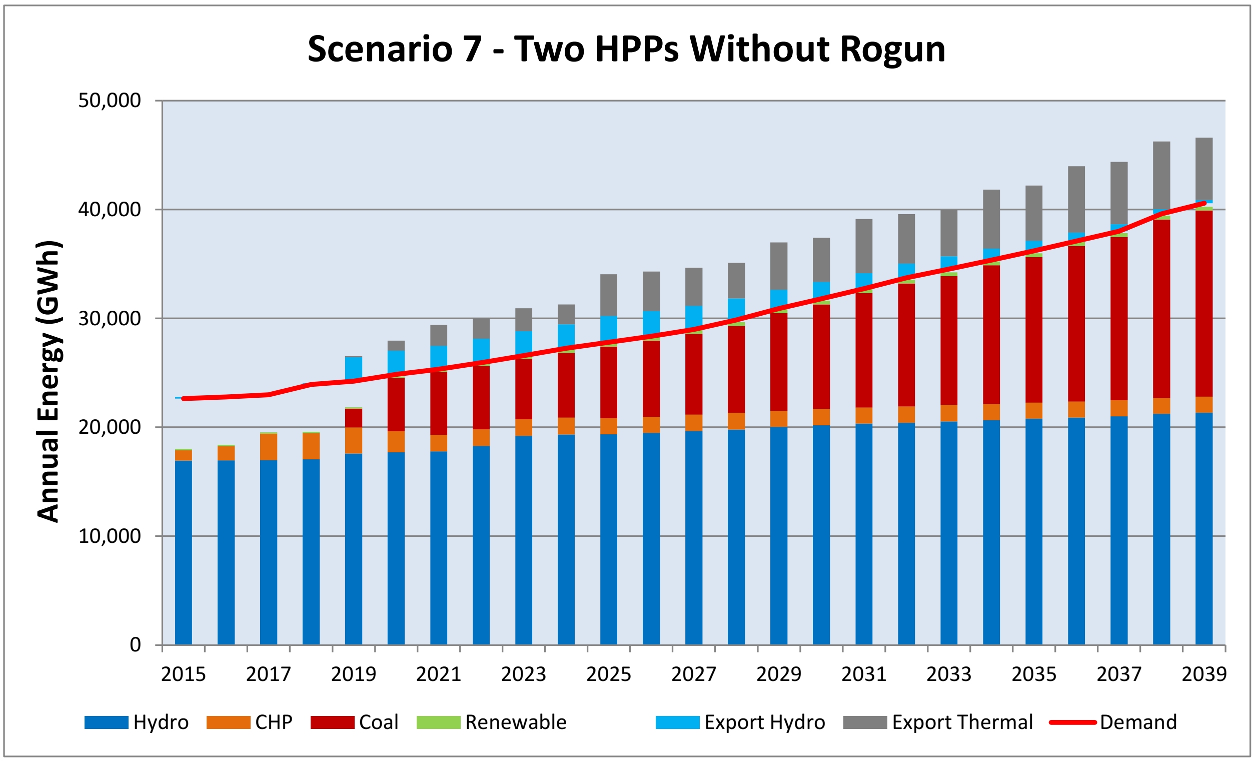

Figure 6-4: Theme 1, Scenario 7 – 2 HPPs and 350 MW Coal Units, Annual Energy Generation

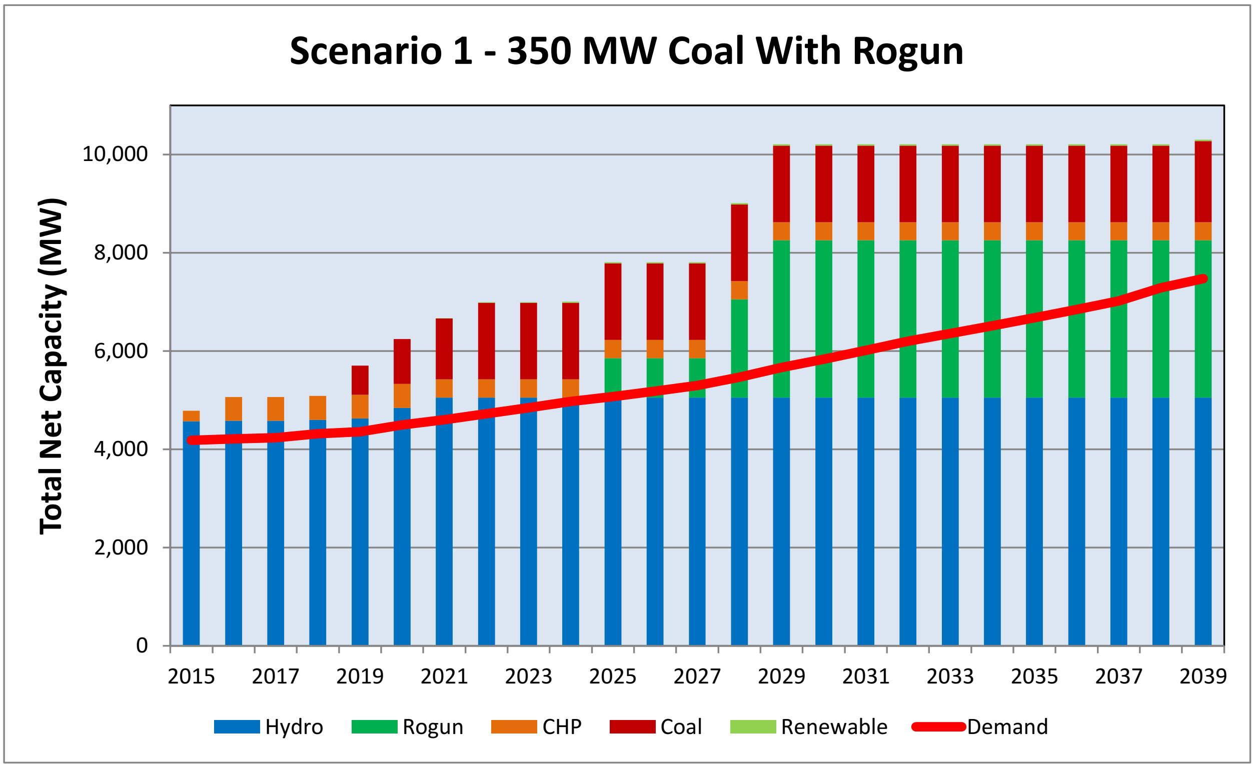

Figure 6-5: Theme 2, Scenario 1 - 350 MW Coal Units, Annual Capacity Installation

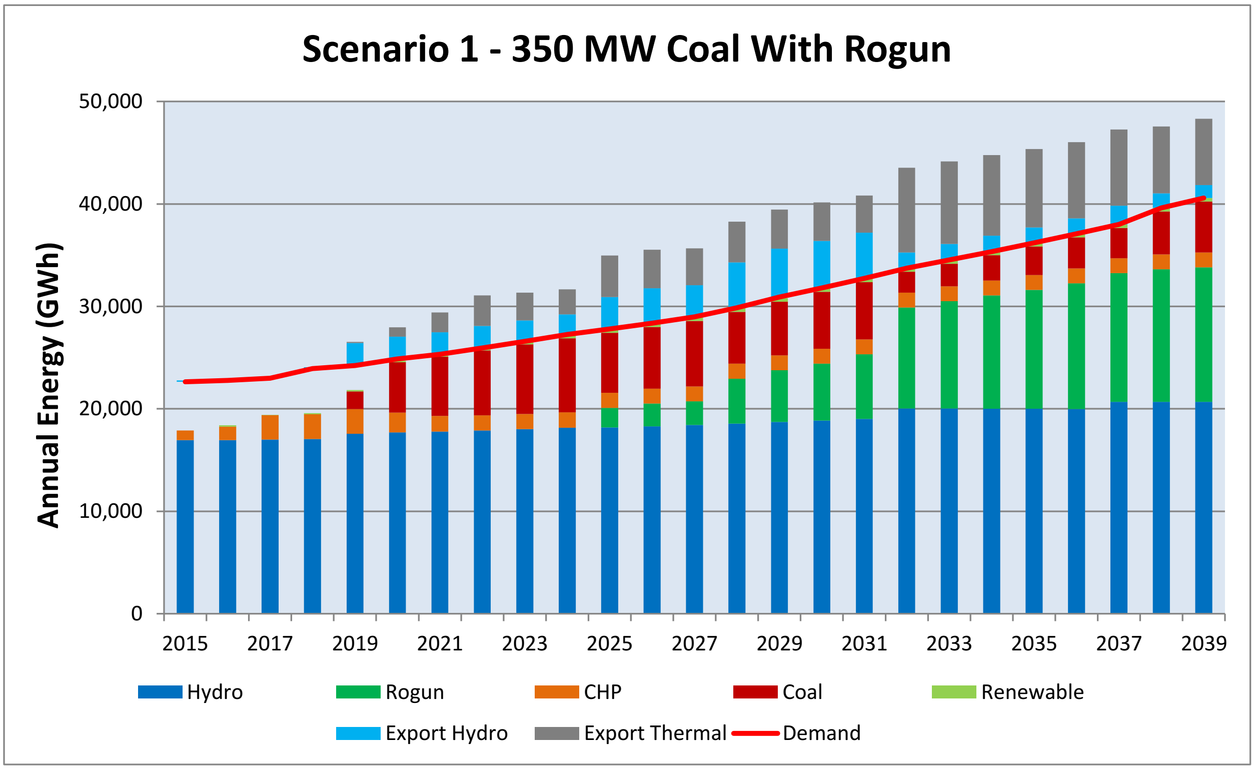

Figure 6-6: Theme 2, Scenario 1 - 350 MW Coal Units, Annual Energy Generation

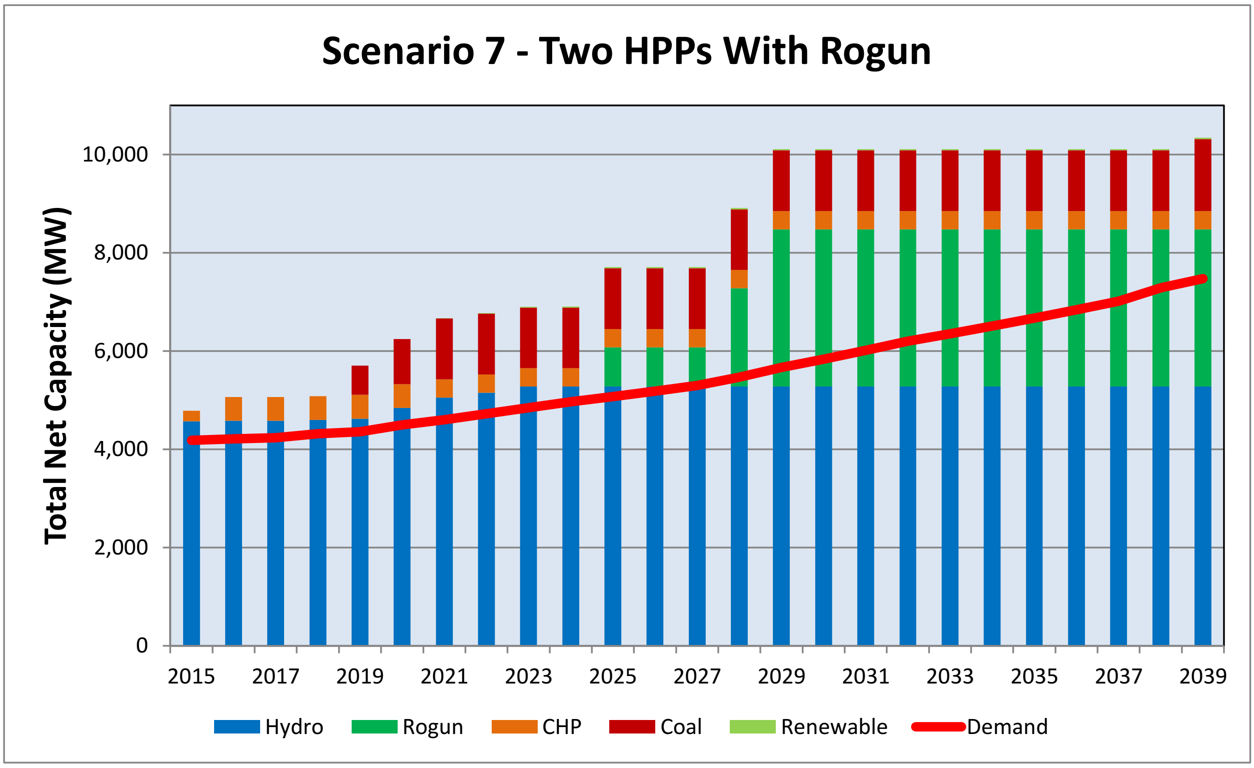

Figure 6-7: Theme 2, Scenario 7 - 2 HPPs and 350 MW Coal Units, Annual Capacity Installation

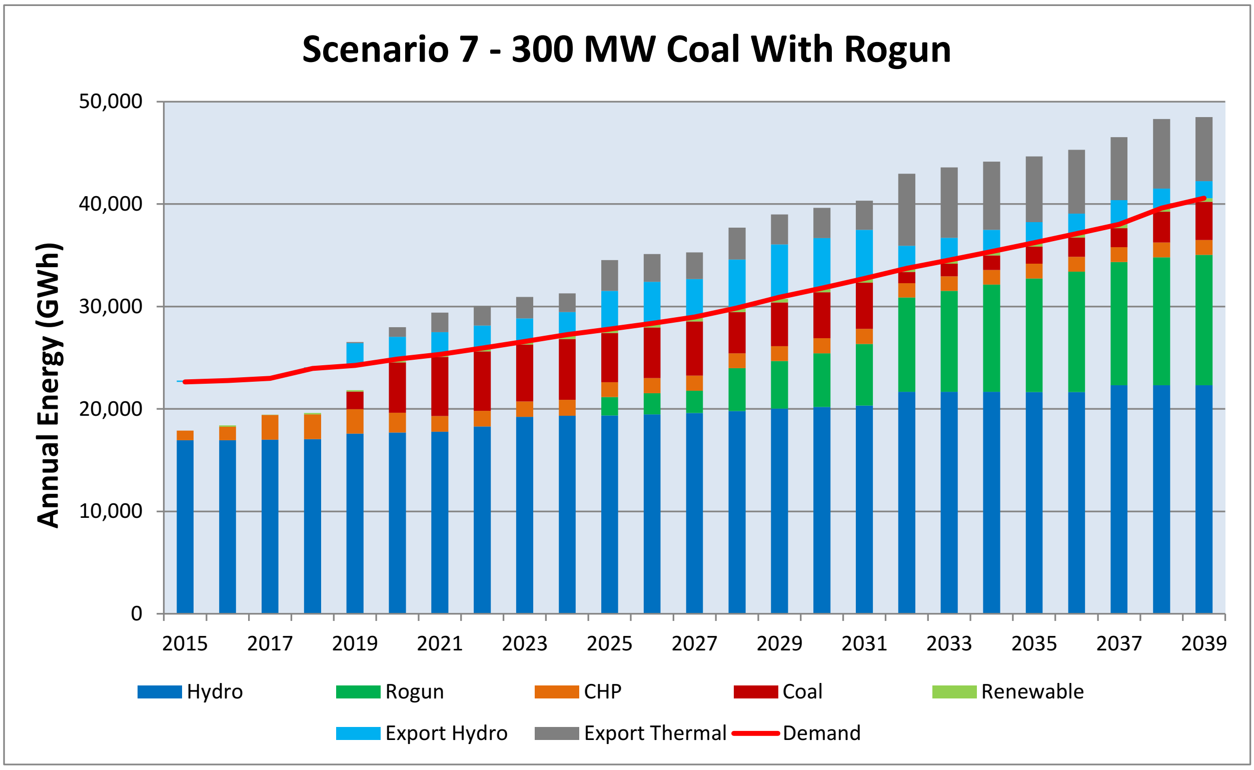

Figure 6-8: Theme 2, Scenario 7 – 2 HPPs and 350 MW Coal Units, Annual Energy Generation

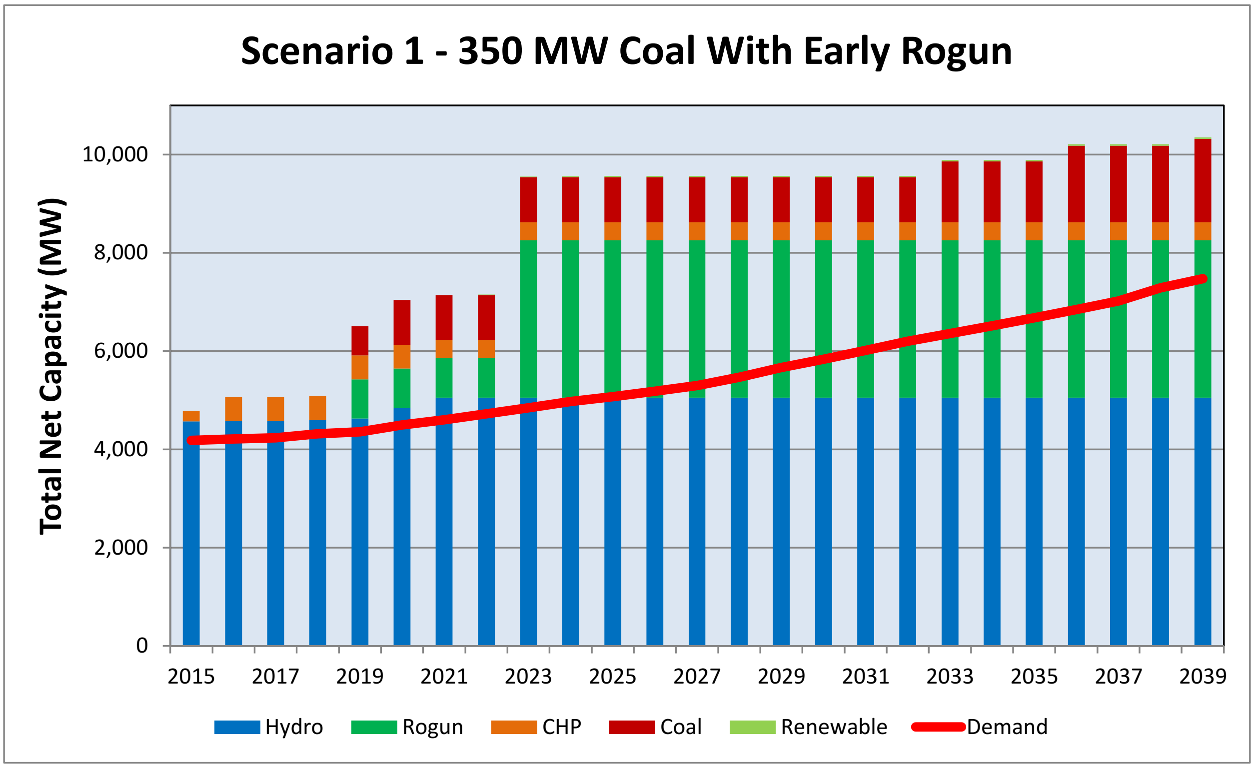

Figure 6-9: Theme 3, Scenario 1 - 350 MW Coal Units, Annual Capacity Installation

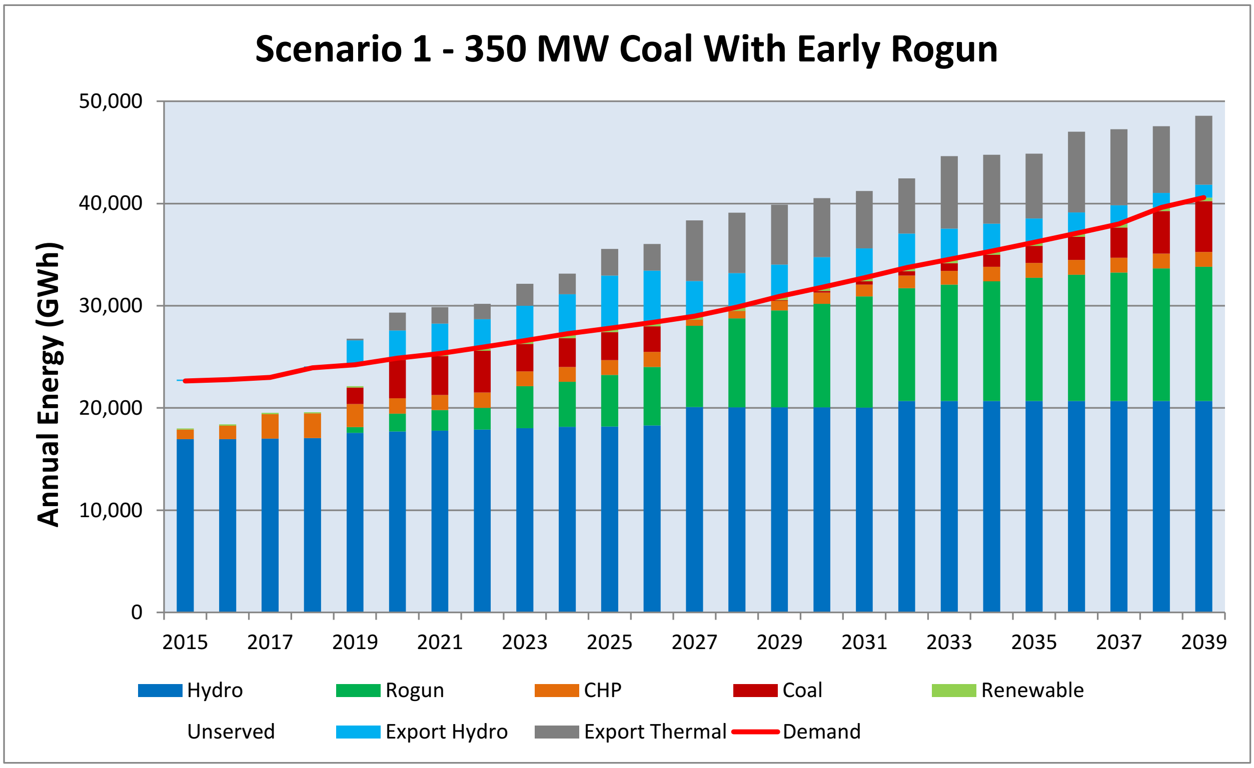

Figure 6-10: Theme 3, Scenario 1 – 350 MW Coal Units, Annual Energy Generation

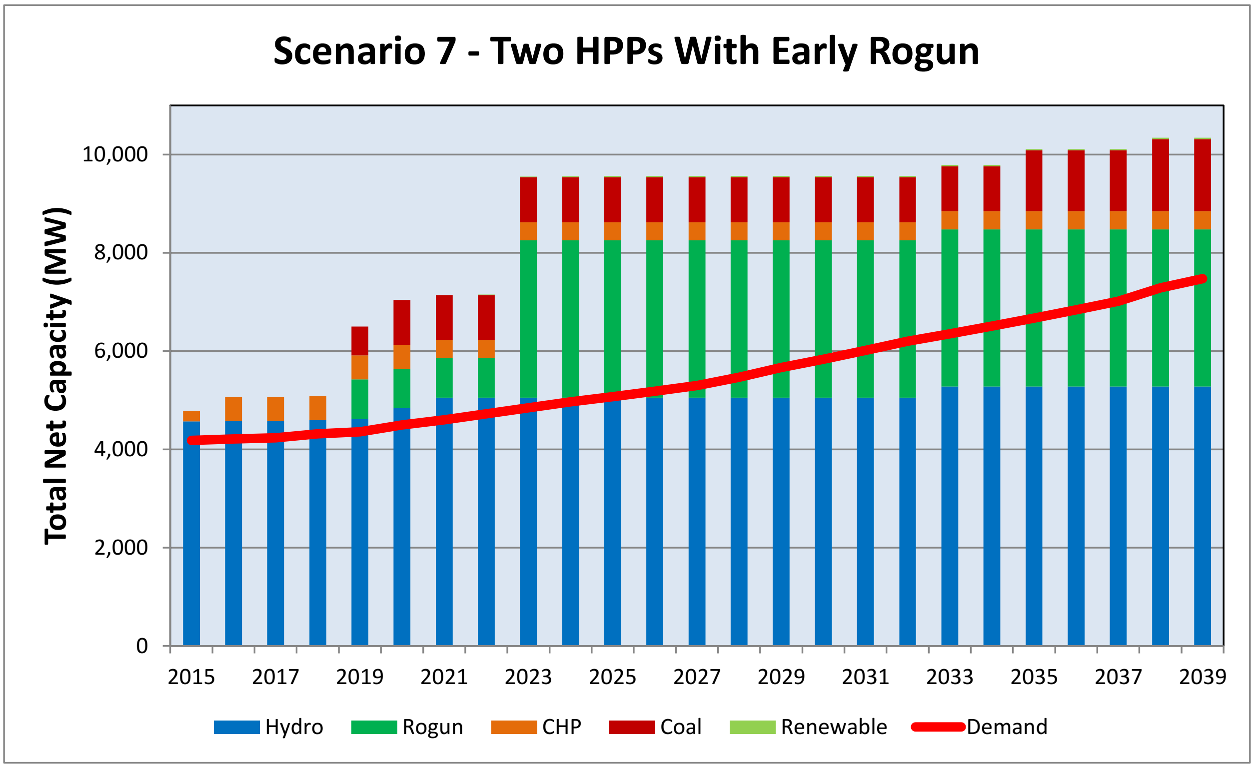

Figure 6-11: Theme 3, Scenario 7 - 2 HPPs and 350 MW Coal Units, Annual Capacity Installation

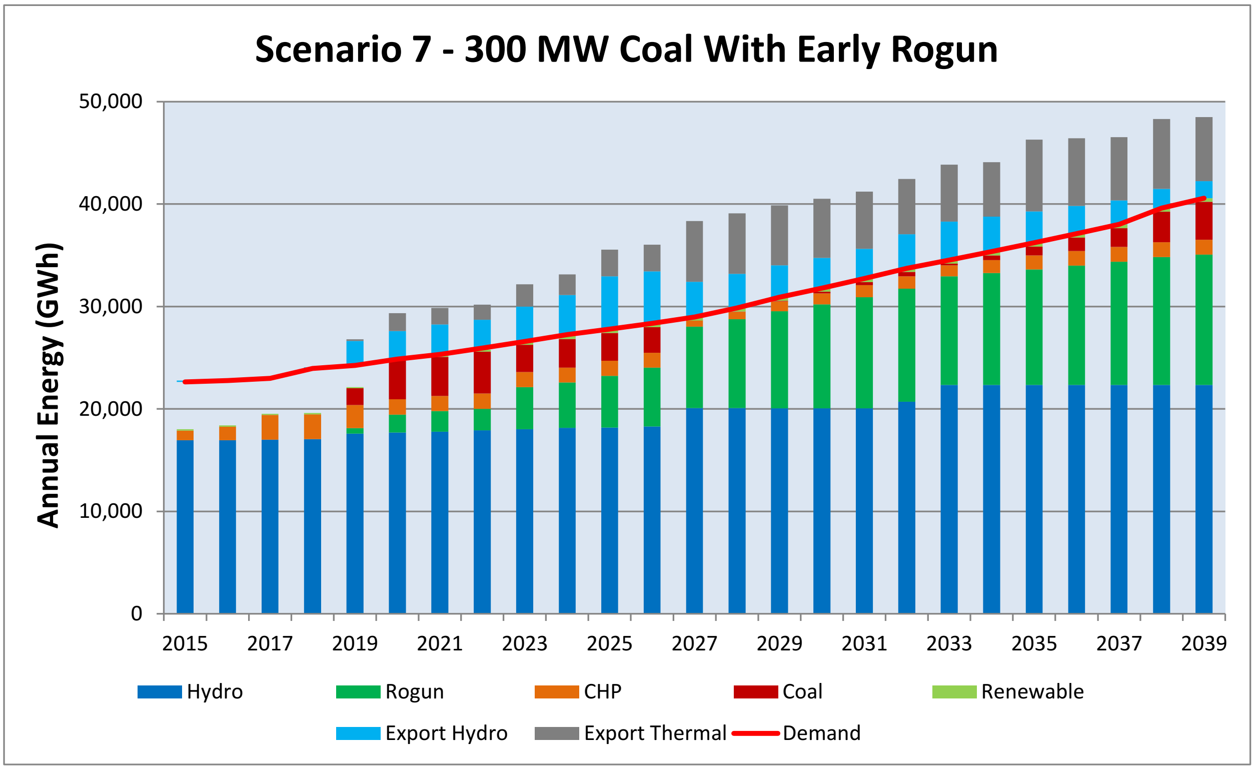

Figure 6-12: Theme 3, Scenario 7 – 2 HPPs and 350 MW Coal Units, Annual Energy Generation

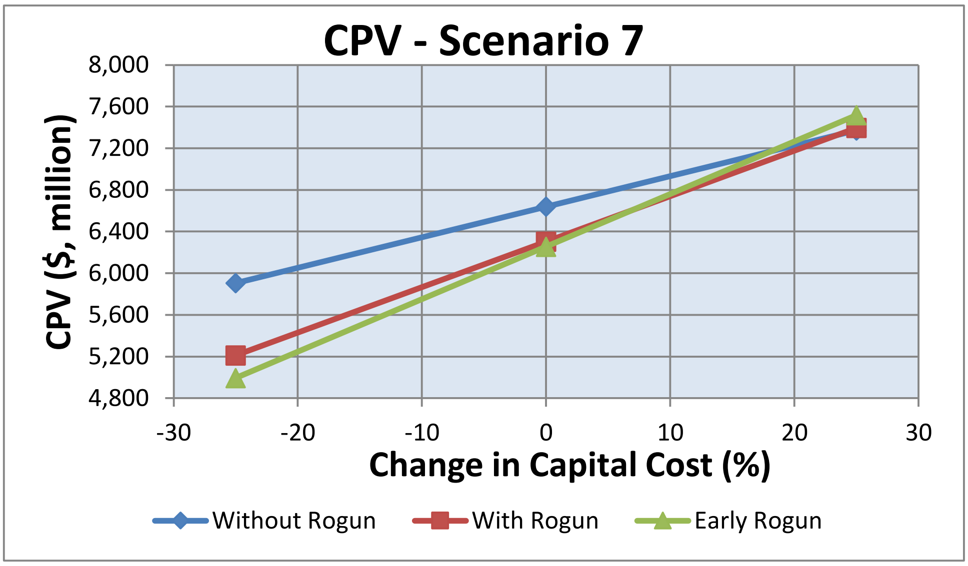

Figure 6-13: Change in Capital Costs – Least Cost Plans

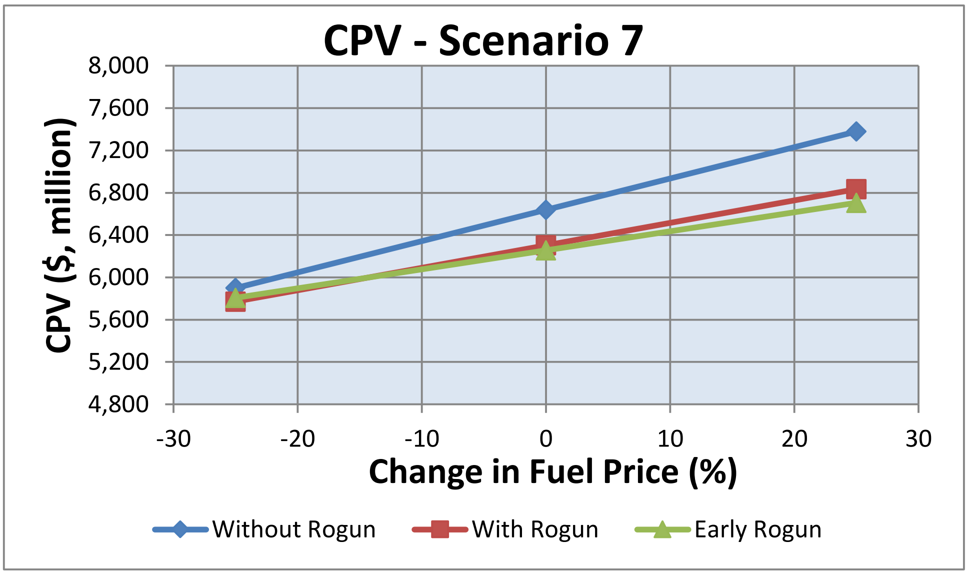

Figure 6-14: Change in Fuel Price – Least Cost Plans

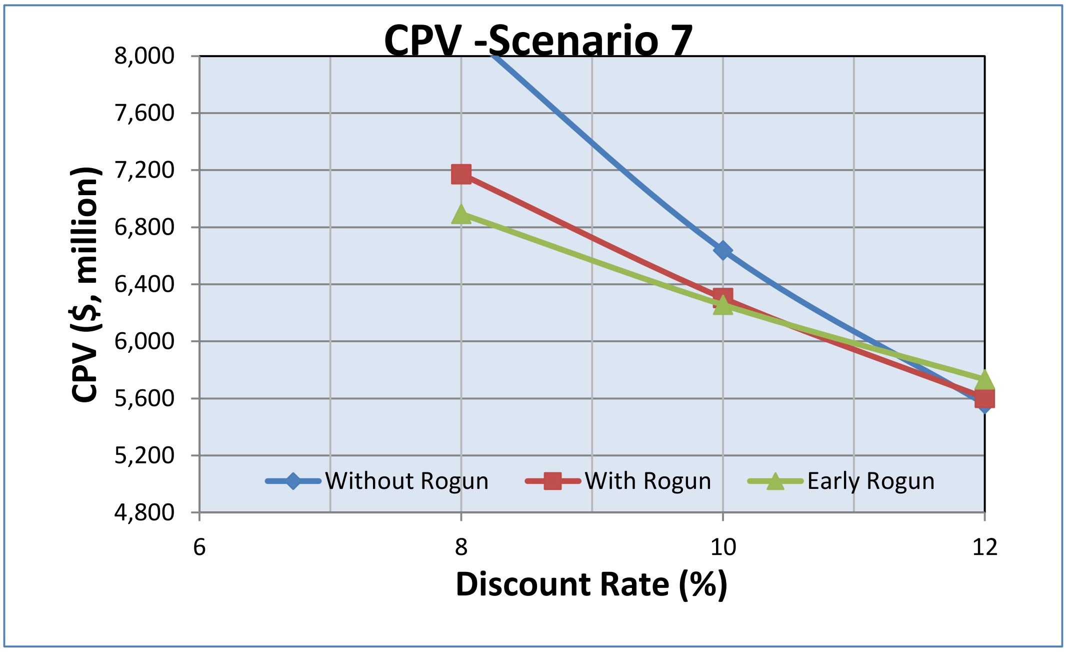

Figure 6-15: Change in Discount Rate – Least Cost Plans

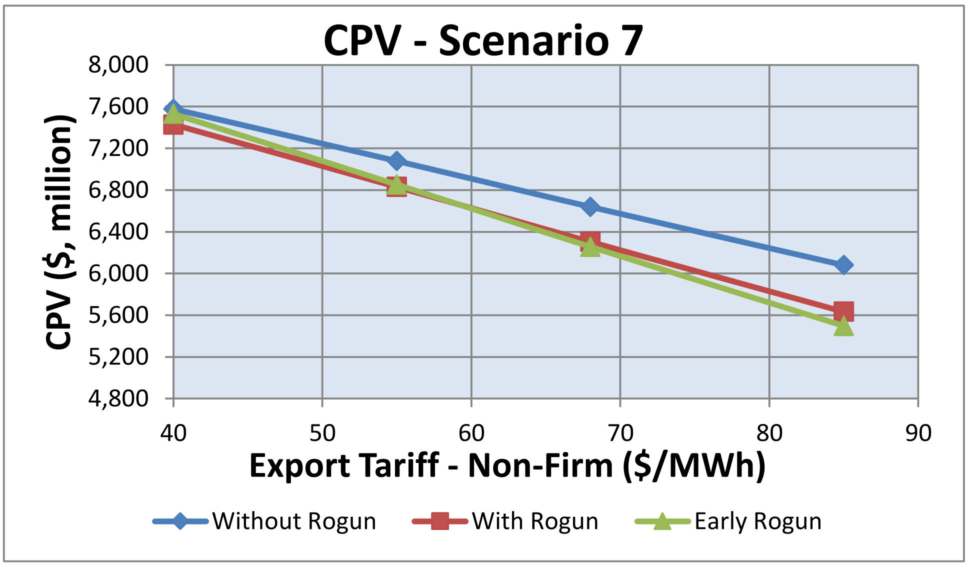

Figure 6-16: Changes to Non-Firm Export Tariff – Least Cost Plans

7. TRANSMISSION EXPANSION PLANS FOR THE SELECTED SCENARIOS

7.1 INTRODUCTION

This section presents the summary of the studies carried out to determine the transmission facilities required to deliver the generation output to the load centres for the three two selected generation expansion plans and calculates the associated costs for the required transmission facilities between 2015 and 2039.

The detailed studies are presented in Appendix E.

The two selected plans were:

- The generation expansion without Rogun (Theme 1, scenario 7)
- The generation expansion plan with Rogun (Theme 2, scenario 7)
- The generation expansion plan with Early Rogun Generation (Theme 3, scenario 7)

The study initially evaluates the Barki Tojik system and determines the facilities required to meet basic power delivery standards and it then develops the transmission expansion plan for each of the selected generation expansion plan. In each case, the facilities required to supply the load within Tajikistan are also determined and are very similar for each of the plans

The generation expansion plan associated with each of the three selected plans are shown in Table 6-1 and Table 6-34 for the without and the with Rogun generation expansion plans respectively.

7.2 APPROACH TO THE STUDY

The approach to this study consisted in taking the data provided by BT and developing transmission expansion plans that could be used to supply the demand and evacuate the generation under each of the selected generation expansion plans. The expansion plans were then compared on a cost basis.

The data that was provided include the following:

- Two base power flows in PSSE format: summer and winter loading conditions
- Existing expansion plans for the near future
- Background documentation on the Barki Tojik system.

The conclusions and recommendations on transmission facilities required to meet load serving and generation evacuation requirements are based on steady state powerflow analysis.

The data required to perform system dynamic response analysis was not available and hence dynamic studies were not carried out. The dynamic study is normally a confirmatory analysis while the load flow analysis is the investigative part of the study. As such, this is not likely to have major impacts on the overall conclusions, however, BT is encouraged to perform confirmatory studies when dynamic data is available.

This study was done in conjunction with the proposed CASA 1000 project and other export commitments.

An analysis of the existing system (2014/15) was carried out to determine the transmission facilities required to meet system intact and N-1 criteria. System upgrades required to meet the N-1 criteria were identified. This case was developed based on the 2012 model provided by BT.

The transmission expansion plan provided is for the 25-year period from 2015 to 2039. The required studies were carried out for five representative years: 2020, 2025, 2030, 2035 and 2039.

Study models (PSSE power flow cases) for each of these representative years were created from the base case based on the generation expansion plans and the forecasted load growth. The transmission facilities for evacuating power were chosen such that they would also accommodate load requirements for the study horizon. N-0 analysis was done on each of the models to identify system intact violations. Contingency analysis was performed to verify N-1 compliance and additional transmission facilities required to meet the N-1 compliance were identified. The recommendation includes new transmission lines, shunt capacitors and line upgrades.

The facilities that are recommended were chosen to reflect the development of the system to date.

Automatically switched capacitors at various 110kV busses were included to resolve a considerable number of low voltage issues. The recommendation for the addition of VArs is directly dependant on the loading and power factor at the individual 110kV substations. Thus, the bus loads at the 110 kV level are an important study input and a significant effort was made to convert the station loading that was provided into actual bus loading at the 110kV substations. Actual substation loading needs to be verified periodically and compared to the modelled substation load. As much as possible in this study, the recommendations for capacitor additions were tied to area loading to assist with the planning for capacitor additions.

In increasing the capacity of the 110 kV lines, the recommended solution is to re-conductor the existing lines. Manitoba Hydro's experience is that the cost to re-conductor transmission lines is 20% to 30% of the cost of building a new line even if high capacity composite conductors are used. Choosing a conductor with similar size and weight will eliminate the need to upgrade to tower strength.

Both generation plans included modest amounts of Wind, Solar, and Micro Hydro generation. This generation was deemed to be scattered across the country and was netted out (subtracted from) with system load.

7.2.1 CASA 1000

A major component of Tajikistan's future power development is the establishment of a 500kV line from Datka to Sughd and an HVdc link between Sangtuda and Nowshera.

The project consists of:

- The construction of a 500 kV transmission line from Datka in Kyrgyzstan to Khujand some 477 km long
- The construction of a 500 kV transmission line from Regar to Sangtuda some 115 km long and a 500/220 kV autotransformer at Sangtuda area
- The construction of an HVDC convertor at Sangtuda area with a capability of 1,300 MW and
- The construction of a 800 km long HVDC transmission line Sangtuda –Nowshera via Afghanistan
- The construction of a HVDC convertor station with a capacity of 1,300 MW in Nowshera, Pakistan.

The CASA 1000 project is now expected to be commissioned in 2021. The general agreement and the power purchase agreement were signed in April 2015 by the intergovernmental council and in November of the same year the agreements between the operating entities were signed.

7.2.2 Other Exports

A 720 km long line between Rogun and Peshawar is considered. Similar to the CASA 1000 line to Pakistan, this line runs through Tajikistan, Afghanistan and Pakistan. This line is assumed to export 1000 MW from Tajikistan to Pakistan during summer months. This line is intended to be in service by 2025 and both AC and DC options are being considered.

The final design for the line was not made available at the time of the study and as such the link was represented by a 1000 MW load at Lolazor. It is assumed that the necessary line compensation will be considered when designing the line. This assumption will not impact on the facilities recommended in this study.

A 550 km long line between Xinjiang, China and Rogun is considered. The line is assumed to have a transfer capability of 900 MW and will be operational during the summer months. This link was represented as a load at Rogun. It is assumed that necessary line compensation to maintain bus voltage will be provided as part of this project. This assumption will have no impact of the facilities recommended in this study.

7.3 NETWORK DATA AND RELEVANT INFORMATION

7.3.1 Base Power Flow

Two base power flow cases were provided by BT in PSS™E format. One case was representative of summer operation while the other was representative of winter operation. The data in this file had a fair representation of the generation and transmission facilities. The powerflow included transmission facilities between 110 kV and 500 kV with the facilities to Uzbekistan in place.

These powerflows had Rogun implemented with a high Tajikistan load. The loads in the files had some issues that are described in Appendix E. To develop a better load representation, a request was made and fulfilled for the loading on all the 110:35 kV transformers.

The corrected load data was added to the model and summer and winter cases were established. Since the load data provided was for 2012-2013 in order to represent the 2014-15 system, the network load was scaled to match the load data. The summer load is considered to be 80% of the peak load and the load distribution between summer and winter scenarios was maintained. The difference in power factors and relative loading in the winter and summer data that was presented in the two original load files was maintained in these cases and for all the representative year cases used in this study.

In developing a transmission expansion plan, the load data is a quintessential portion of the original data. The load profile in the base powerflow is essential for developing a plan that will stand a reasonable length of time. As with every transmission plan, the assumptions need to be periodically tested to ensure that the rest of the plan remains valid. Reviewing the loading assumptions used in this plan should be done fairly soon, e.g. 2 to 3 years after the implementation of the plan, to ensure that the loading assumptions are still valid. So the load analysis performed in the PSDMP must be reviewed periodically, and the results update in the study models to ensure that the results in the transmission plan remain valid.

7.4 Analysis of the Existing System

This section evaluates the 2014/15 BT system and determines the facilities that are required to meet basic power delivery standards. AC contingency analysis was performed on the 2014/15 network to identify existing problems in the network. Remedial actions to mitigate the pre and post contingency voltage and thermal violations are also listed in this section.

7.4.1 Modelling of the 2014 Network

A planning model for the year 2014/15 was developed and used as the starting point for further planning studies until 2039. The 2012 network model was updated to include any ongoing and committed transmission projects. Two cases representing the summer and winter loads and generation for the year 2014/15 were then analysed. Several system adjustments and modifications were made to develop a converged 2014/15 network.

The system load was scaled up to the 2014/15 load forecast. The total load in the system for the two cases studies was assumed to be 4,075 MW for the winter and 3,033 MW for the summer.

The generation pattern for each of the season is modified according to the data provided in Table 2-2 in Section 2.3 of the main report. All plants that are currently available in the system were included in the model.

7.4.2 N-0 (system intact)

The load for the 2014/15 network results in low voltages during the steady state operation. Additional shunt reactive power devices were added to obtain an acceptable system intact voltage profile. Depending on the summer or winter load, the reactive power requirement varies between the North and South regions. During summer, steady state voltage violations are predominantly observed in the Sughd region, while in winter, the voltage violations were observed in the Southern part of the country. A list of capacitors necessary to provide voltage support under system intact condition in each sector is provided in Table 7-1.

Table 7-1: Capacitors in the Northern Region

Substations (110 kV)_	Capacitors (MVAr)
KNS	20
Uzlovaya	100
Protletarskaya	60

Leninabad	20
Kanibadam	30
Asht	40
Ayni	30
Rudaki	20
Total	290

To support the projected 2014/15 load, an additional 290 MVAr of capacitors are required in the northern region. As capacitor additions are more economic at lower voltage buses, it is recommended to place as many of these capacitors on the 35.8 kV feeders at the substations listed above. The costs that are detailed in this report are based on automatically switched shunts controlling the 110 kV bus. The reason for recommending switched shunt capacitors is due to the poor visibility at the lower voltage buses.

Under the peak winter load condition, low voltages are observed in the southern region of the country (Dushanbe, Khatlon, and RRS). This is predominantly due to the increase in heating load during the winter. Capacitors are recommended at the Jangal substation, Hissar Steel plant and Tutak substation to provide voltage support. Table 7-2 lists the capacitors needed in this sector

Table 7-2: Capacitors in the Southern Region

Substations	Size (MVAr)
Jangal	60
Hissar	30
Tutak	60

7.4.3 Transmission lines

Under system intact conditions it was observed that some transmission lines were loaded above their emergency rating (110%). The list of transmission lines that are overloaded and the percentage overload is shown in the tables below. Table 7-3 shows the list of 220 kV lines that are overloaded, and

Table 7-4 shows the list of 110 kV lines that are overloaded.

Table 7-3: Overloaded 220 kV Lines (system intact)

220 kV Lines				
From Substation Bus	To Substation Bus	Loading (MVA)	Line Rating (MVA)	Percent
Nurek	Orjinikidzeabad (segment1)	418.8	267	156.8
Nurek	Orjinikidzeabad (segment 2)	366.7	276	132.8

Table 7-4: Overloaded 110 kV Lines (system intact)

From Substation Bus	To Substation Bus	Loading (MVA)	Line Rating (MVA)	Percent	Recommended Rating (MVA)
Jangal	Gissar	90.1	75	120.1	125
Shursai (double cct)	Orjinikidzeabad (double cct)	83.7	75	111.7	125
Golovnaya	Lomonosova	87.6	75	116.8	125
Prydilnaya	Kurgan-Tube	137.1	75	182.8	125
Kurgan-tube	Chapeva	123.9	75	165.2	125
Kulyab	Khatlon (double cct)	96.2	75	128.2	125
Khatlon (double cct)	Somoni (double cct)	87.7	75	116.9	125
Bohtar	Somoni	95	75	126.6	125
Kayrakkum (double cct)	Leninabad(double cct)	126.6	75	168.8	125

7.4.4 N-1 Contingency Analysis

Contingency analysis was performed on the 2014/15 network to verify N-1 compliance and to identify thermal and voltage violations as outlined in the planning criteria. Contingencies studied include single line trip, loss of transformer and loss of generation.

There are two contingencies that resulted in non-converged solution. The outage of the 500 kV line from Regar to Dushanbe and the outage of the 500 kV line from Dushanbe to Sughd result in non-convergence. The primary reason for non-converged solution is due to the fact that both these contingencies presently split Tajikistan electrically into two areas and there is insufficient generation in the North to maintain reliable operation. The recommended mitigation measures are detailed in Appendix E and basically consist of the addition of a second line from Dushanbe to Sughd.

Voltage violations (below 0.9 pu) are observed for some N-1 contingencies. Whenever a violation was found, suitable mitigation measures were identified from system adjustments such as transformer/shunt adjustments.

Two main contingencies that result in voltage violation at several buses are discussed below.

Rogun is currently supplied by the 220 kV line from Nurek. There are a couple of 110 kV connections from Orjinikidzeabad. With the loss of the 220 kV line severe under voltage problem is observed in the area. To mitigate the voltage violation, and future thermal overloads, it is recommended to have a second 220 kV line between Nurek and Rogun.

The 110 kV line from Pryadilnaya to Kurgan-Tyube with a tap to Chapaev is overloaded in the system intact condition. In addition, the loss of this line also results in voltage violation at the Ay-Kamar, Lyaur buses. Upgrading the conductor will mitigate the system intact overloading of the line. To mitigate this overload and post contingency voltage, a second line between Pryadilnaya and Kurgan-Tyube is recommended.

Under N-1 conditions there are some line and transformers that are over loaded. The 500/220 kV transformer in Sughd (Hojent) and the 220/110 kV transformer in Jangal, Khatlon, Geran and Orjinikidzeabad are loaded to their maximum under system intact condition. Table 7-5 provides the list of recommended transformers additions. In most cases transformers with the same rating as the existing transformer have been recommended.

Table 7-5: List of Recommended Transformer Additions

From Bus	To Bus	Id	Voltage Rating (kV)	Winding MVA Base
Sughd 220	Sughd 220	1	500/220	500
Orjinikidzeabad 220	Orjinikidzeabad 110	3	220/110	250
Jangal 220	Jangal 110	3	220/110	200
Rudaki 220	Rudaki 110	3	220/110	63
Khatlon 220	Khatlon 110	3	220/110	125
Buston 220	Buston 110	3	220/110	150
Geran 220	Geran 110	3	220/110	63

7.5 TRANSMISSION REQUIREMENTS FOR EXPANSION “WITHOUT” ROGUN

This section provides the transmission and substation upgrades necessary to support the projected load and generation growth until the year 2039. The proposed network is designed to meet N-1 requirements. A powerflow case representing each of the 5 representative years was developed based on the generation expansion plan and the load forecast. The generation expansion plan used in this section is predominantly based on the development of thermal power plants located primarily in the Sughd region.

Two cases representing the winter and summer load scenario were developed for each of the representative years. In addition, the following import and exports were also considered:

- Power import from Kyrgyzstan (455 MW)
- Power export (1300 MW) to Peshawar (Pakistan)
- 900 MW power export to Xinjiang, China
- 1,000 MW power export from Rogun to Peshawar.

Based on the season, the availability of generation varies; in the winter months, when there is less hydro generation and heavy loading due to heating requirements there is not as much power to evacuate to other systems as there is in the summer. As such the exports are significantly reduced. However, the transmission system is designed considering maximum generation under maximum load and maximum export, this places the most stress on the transmission network.

Transmission facilities needed to evaluate power from the new power plants were identified. N-0 and N-1 studies were performed on each of the cases to identify violations and transmission upgrades/ resources needed to maintain the system intact and N-1 compliance and the required additions are recommended. Sensitivity studies were also performed assuming maximum generation in the south and minimum in the north and vice versa. The transmission expansion plan is designed to cater to a number of different dispatch scenarios.

Figure 7-1 shows the transmission lines (500 kV and 220 kV) that are recommended under the Without Rogun generation expansion plan.

All new transmission lines are recommended to have a rating of 346 MVA for the 220 kV level and 125 MVA for 110 kV level. New lines are only proposed if they are necessary for evacuation of power from new power plants and when the violations cannot be mitigated by transmission upgrades.

All the new 220 kV and 110 kV substations are designed with as a single bus, double breaker substation, and the 500 kV substation is designed as a breaker and a half substation. This is consistent with the current practices in Barki Tojik. For substation upgrades, bus configuration as in the existing substation is used. Figure 7-2 is an example of the proposed design for new 220 kV and 500 kV substations.

Figure 7-1: Recommended 500 kV and 220 kV Transmission Lines for the Without Rogun Expansion Plan (2014-2039)

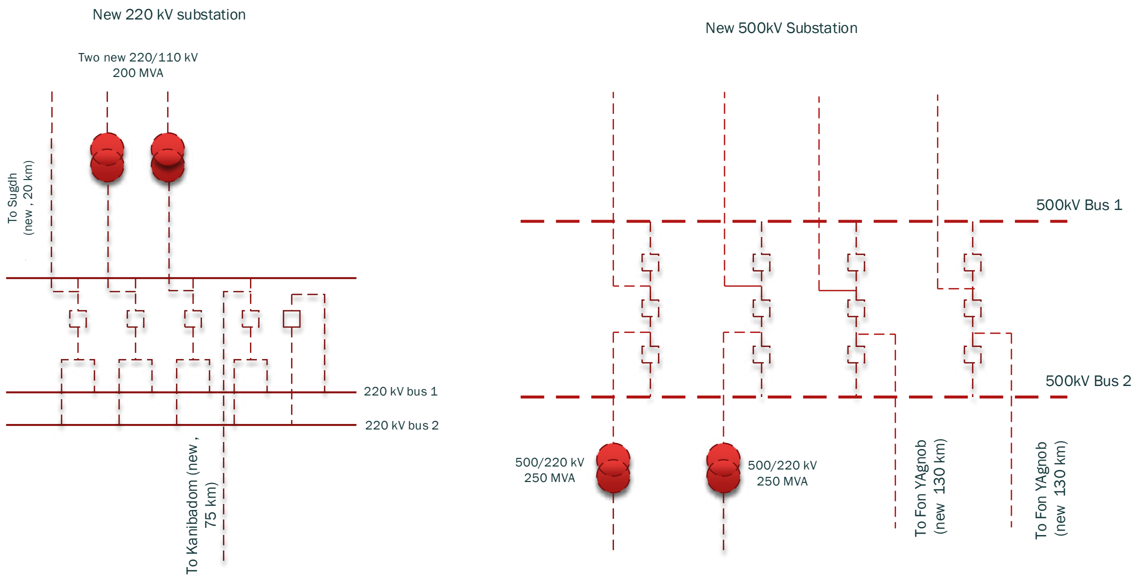

Figure 7-2: New 220 kV and 500 kV Substations Layout

7.5.1 Line Upgrades

Table 7-6 presents the list of the lines to be upgraded during the study period. The justification of each of these additions is provided in Appendix E.

Table 7-6: List of Lines Requiring Upgrading

From Bus 110 kV	To Bus 110 kV	Current Rating (MVA)	Recommended Rating
2020			
Buston	Zavodskaya	75	125
Novaya	Dtec (Double Cct)	75	125
Novaya	Promish (Double Cct)	75	125
Novaya	Shahri (Double Cct)	75	125
2025			
Jangal	Sovetskaya (Double Cct1)	75	125
Bohtar	Dangana	75	125
2030			
Severnaya	Vostochnaya (Double Cct)	75	125
Orjinikidzeabad	Kuz	75	125
Novaya	Severnaya (Double Cct)	75	125
2035			
Nurek	Sebestion	276	346
Sebestion	Lolazar	276	346
Nurek	Yavan	276	346
2039			
Dangana	Amirshoeu	75	125
Amirshoeu	Hovaling	75	125
Ayni B2	Ayni A2	75	125

7.5.2 *Transmission Lines*

This section outlines the transmission and substation facilities necessary to support the system during the study period. The justification for the addition of each line is provided in Appendix E.

The list of all the lines required up to 2039 is shown in Table 7-7.

Table 7-7: List of Lines to Support Generation and Load

From Bus	To Bus	Id	Rating (MVA)	(km)	Ccts
2020					
Dushanbe 500 kV	FonYagnob 500 kV	1	2000	180	1
Sughd 500 kV	Fon Yagnob 500 kV	1	2000	130	1
Kayrakkum 220 kV	Shurob 220 kV	1	346	20	1
Kanibadam 220 kV	Shurob 220 kV	1	346	20	1
Kayrakkum 220 kV	Leninabad 220 kV	1	346	20	1
Sughd 220 kV	Leninabad 220 kV	1	346	50	1
Bahoriston 220 kV	Ayni 220 kV	1	346	100	1
Ayni 220 kV	Rudaki 220 kV	1	346	90	1
Buston 110 kV	Zavodskaya 110 kV	1	125	6	1
Kurgan-Tube 110 kV	Pryadilnaya_110 kV	1	125	2	1
Chapaeva 110 kV	Kurgan-Tube 110 kV	1	125	20	1
2025					
Dushanbe 500 kV	Lolazar 500 kV	1	2000	85	1
Lolazar 500 kV	Sangtuda 500 kV	1	2000	20	1
Dushanbae 220 kV	Zavodskaya_220 kV	1	346	20	2
Khatlon 220 kV	Sanobad 220 kV	1	346	250	1
Kayrakkum 220 kV	Shurob 220 kV	2	346	80	2
Kayrakkum 220 kV	Shurob 220 kV	3	346	80	
Novaya 220 kV	Dushanbe 220 kV	1	346	25	1
Nurek New 220 kV	Nurek 220 kV	1	346	25	1
Buston 110 kV	Zavodskaya 110 kV	1	125	6	1
Dehmoy 110 kV	Khujand 110 kV	1	125	13	1
Jangal 110 kV	Severnaya 110 kV	1	125	25	1
Proletarsk_110 kV	Dehmoy_110 kV	1	125	12	1
2030					
Dushanbe 220 kV	Zavodskaya_220 kV	2	346	20	2
Dushanbae 220 kV	Zavodskaya_220 kV	1	346	20	
Bohtar 110 kV	Dagana 110 kV	1	125	15	1
Bohtar 110 kV	Somoni 110 kV	1	125	3	1
Gissar 110 kV	Hissar Stl 110 kV	1	125	12	1
Jangal 110 kV	Hissar Stl 110 kV	1	125	14	1
Novaya 110 kV	Severnaya 110 kV	1	125	8	1
2035					
Nurekg2 220 kV	Ordzh- Abad_220 kV	1	346	47	1

From Bus	To Bus	Id	Rating (MVA)	(km)	Ccts
2039					
Ayni 220 kV	Ziddy 220 kV	1	346	5	1
Rudaki 220 kV	Ziddy 220 kV	1	346	5	1

7.5.3 New Transformers

This section outlines the transformer additions necessary to support the system during the study period. The justification for the addition of these transformers is provided in Appendix E.

The list of all the transformers required up to 2039 is shown in Table 7-8.

Table 7-8: List of New Load Serving Transformers

From Bus	To Bus	Id	Voltage Rating (kV)	Winding MVA Base
2020				
Sangtuda 500*	Sangtuda 220	1	500/220	500
Sughd 500	Sughd 220	3	500/220	500
Orjinikidzeabad 220	Orjinikidzeabad 110	3	220/110	250
Novaya 220	Novaya 110	3	220/110	200
Jangal 220	Jangal 110	3	220/110	200
Geran 220	Geran 110	3	220/110	63
Khatlon 220	Khatlon 110	3	220/110	125
Buston 220	Buston 110	1	220/110	150
Rudaki 220	Rudaki 110	3	220/110	63
Leninabad 220	Leninab 110	1	220/110	200
Leninabad 220	Leninab 110	2	220/110	200
2025				
Lolazar 500	Lolazar 220	1	500/220	200
Geran2 220	Geran5 110	4	220/110	63
Khujand2 220	khujand5 110	3	220/110	125
Zavo_220 220	Zavods5 110	1	220/110	200
Zavo_220 220	Zavods5 110	2	220/110	200
2030				
Ordz-Abad 220	Ordz-Abad 110	3	220/110	250
Khatlon 220	Khatlon 110	4	220/110	125
Ayni 220	Ayni-B2 110	3	220/110	63
Zavodskaya 220	Zavodskaya 110	3	220/110	200
2035				
Dushanbe 500	Dushanbe 220	3	500/220	501
Rogun 220	Rogun 110	3	220/110	125
Uzlovaya 220	Uzlovaya 110	3	220/110	125
Kanibadam 220.00	Kanibadam 110	3	220/110	125

From Bus	To Bus	Id	Voltage Rating (kV)	Winding MVA Base
2039				
Novaya 220	Novaya 110	4	220/110	200
Jangal 220	Jangal 110	4	220/110	200
Kanibadam 220	Kanibadam 110	3	220/110	125
Buston 220	Buston 110	2	220/110	150

7.5.4 Capacitor Additions

When the network was developed some system intact voltage violations were observed and additional violations were observed following some contingencies. To mitigate the voltage violations and to meet the N-1 requirements, switched capacitors are recommended. The list of capacitors that are required is presented in Table 7-9.

Table 7-9: List of Voltage Support Capacitors

Bus (110 kV)	Size (MVAR)
2020	
Dzerhinskaya	140
Gissar	60
Sovetskaya	40
Lomonosova	100
Ay-Kanar	30
Jrumi5	40
Shugun	20
Oktyagr	20
2025	
Gissar	80
Sovetskaya	10
Ay-Kanar	10
Novaya	60
Vose	20
Dagana	40
2030	
Leninabad	50
Ay-Kanar	10
Shugun5	10
Oktyagr	10
Novaya	30
Vose	30
Dagana	30
2035	

Bus (110 kV)	Size (MVAR)
Sovetskaya	20
Rumi	40
Oktyagp	10
Novaya	30
Orjinikidzeabad	20
2039	
Leninabad	50
Sovetskaya	10
Rumi5	40
Oktyagr	20
Novaya	120
Kzyl-Su	30
Dzizhukrut	10
Khatlon 220.00	20
Jangal	20
Vostochnaya	100

7.6 TRANSMISSION REQUIREMENTS FOR EXPANSION "WITH" ROGUN

This section provides the transmission and substation upgrades necessary to support the projected load and generation growth until the year 2039 for the generation expansion with Rogun. The planning horizon is divided into 5 representative years 2020, 2025, 2030, 2035 and 2039. The transmission facility needed to support the system by each of the representative years is provided below. The proposed network was designed to meet N-1 requirements.

Powerflow cases representing each of the 5 representative years were developed based on the generation expansion plan and the load forecast. The generation expansion plan used in this section is based on the development of a hydro power plant at Rogun and some thermal generation in the Sughd region. Rogun is a large hydro project with a capacity of 3, 200 MW once completed.

Two cases representing the winter and summer load scenario were developed for each of the representative years. In addition, the following import and exports were also considered:

- Power import from Kyrgyzstan (455 MW)
- Power export (1300 MW) to Peshawar (Pakistan)
- 900 MW power export to Xinjiang, China
- 1,000 MW power export from Rogun HPP to Peshawar.

Based on the season, the availability of generation varies, in the winter months where there is less hydro generation and heavy loading due to heating requirements there is not as much power to evacuate to other systems as there is in the summer. As such the exports significantly reduced. However, the transmission system is designed considering maximum generation under maximum load and maximum export, this places the most stress on the transmission network.

Figure 7-3 shows the transmission lines (500kV and 220V) that are recommended under the Rogun generation expansion plan.

Figure 7-3: Recommended 500 kV and 220 kV Transmission Lines for the With Rogun Plan

Transmission facilities needed to evaluate power from the new power plants were identified. N-0 and N-1 studies were performed on each of the cases to identify violations and transmission upgrades/ resources needed to maintain the system intact and N-1 compliance and the required additions are recommended. Sensitivity studies were also performed assuming maximum generation in the south and minimum in the north and vice versa. The transmission expansion plan is designed to cater to a number of different dispatch scenarios.

All new transmission lines are recommended to have a rating of 346 MVA for the 220 kV level and 125 MVA for the 110 kV level. New lines are only proposed if they are necessary for evacuation of power from the new power plants and when the violations cannot be mitigated by transmission upgrades.

All the new 220 kV and 110 kV substations are designed with as a single bus, double breaker substation and the 500 kV substation is designed as breaker and a half substation. This is consistent with the current practices in Barki Tojik. For substation upgrades, bus configuration as in the existing substation is used. Figure 7-4 is an example of the proposed design for new 220 kV and 500 kV substations.

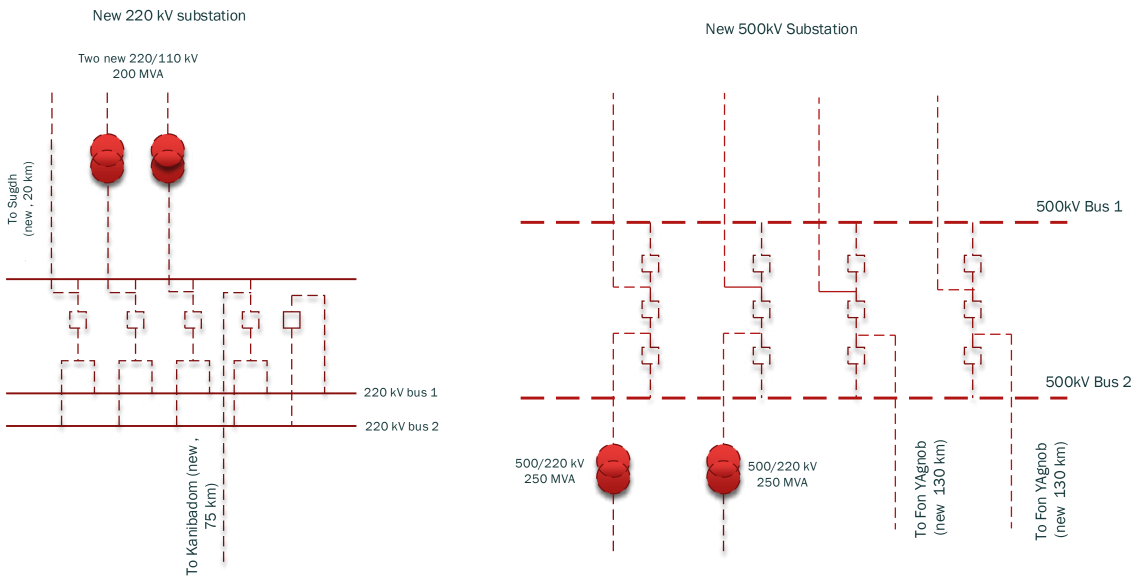

Figure 7-4: New 220 kV and 500 kV Substations Layout

7.6.1 Line Upgrades

Table 7-10 presents the list of the lines to be upgraded during the study period. The justification of each of these additions is provided in Appendix E.

Table 7-10: List of Lines Requiring Upgrading

From Bus (110 kV)	To Bus (110 kV)	Current Rating (MVA)	Recommended Rating (MVA)
2020			
Buston	Zavodskaya	75	125
Novaya	Dtec (Double Cct)	75	125
Novaya	Promish (Double Cct)	75	125
Novaya	Shahri (Double Cct)	75	125
2025			
Jangal	Sovetskaya (Double Cct1)	75	125
Bohtar	Dangana	75	125

From Bus (110 kV)	To Bus (110 kV)	Current Rating (MVA)	Recommended Rating (MVA)
2030			
Severnaya	Vostochnaya (Double Cct)	75	125
Orjinikidzeabad	Kuz	75	125
Novaya	Severnaya (Double Cct)	75	125
2035			
Nurek	Sebestion	276	346
Sebestion	Lolazar	276	346
Nurek	Yavan	276	346
2039			
Dangana	Amirshoeu	75	125
Amirshoeu	Hovaling	75	125
Ayni B2	Ayni A2	75	125

7.6.2 Transmission Lines

This section outlines the transmission lines and substations facilities necessary to support the system during the study period. The justification for the addition of each line is provided in Appendix E.

The list of all the lies required up to 2039 is shown in Table 7-11.

Table 7-11: List of Lines to Support Generation and Load

From Bus	To Bus	Id	Rating (MVA)	(km)	Ccts
2020					
Dushanbe 500 kV	Fon-Yagnob 500 kV	1	2000	180	1
Fon-Yagnob 500 kV	Sughd 500 kV	2	2000	130	1
Kayrakkum 220 kV	Leninabad 220 kV	1	346	20	1
Kanibadom 220 kV	Shurob 220 kV	1	346	20	1
Kayrakkum 220 kV	Shurob 220 kV	2	346	20	2
Sughd 220 kV	Leninabad 220 kV	1	346	50	1
Bahoriston 220 kV	Ayni 220 kV	1	346	100	1
Ayni 220 kV	Rudaki 220 kV	1	346	90	1
Buston 110 kV	Zavodskaya 110 kV	1	125	6	1
Kurgan-Tube 110 kV	Pryadilnaya 110 kV	1	125	2	1
Ochapaeva 110 kV	Kurgan-Tube 110 kV	1	125	20	1
2025					
Rogung 500 kV	Dushanbe 500 kV	1	2000	100	2
Rogung 500 kV	Dushanbe 500 kV	2	2000	100	
Rogun 500 KV	Lolazar 500kV	1	2000	100	1
Lolazar 500 kV	Sangtuda 500 kV	1	2000	20	1

From Bus	To Bus	Id	Rating (MVA)	(km)	Ccts
Kayrakkum 220 kV	Shurob 220 kV	2	346	80	2
Kayrakkum 220 kV	Shurob 220 kV	3	346	80	
Dushanbe 220 kV	Novaya 220 kV	1	346	25	1
Dushanbe 220 kV	Zavodskaya 220 kV	1	346	20	1
Rogun 220 kV	Rogun 220 kV	1	346	5	2
Rogun 220 kV	Rogun 220 kV	2	346	5	
Bustn2 110 kV	Zavodskaya 110 kV	1	125	6	1
Jangal 1100 kV	Severnaya 110 kV	1	125	25	1
Dehmoy 110 kV	Khujand_110 kV	1	125	12.6	1
Proletarsk_110 kV	Dehmoy_110 kV	1	125	12	1
Nurek New 220 kV	Nurek 220 kV	1	346	25	1
Khatlon_220 kV	Sanobad_220 kV	1	346	250	1
2030					
Dushanbe_220 kV	Zavodskaya_220 kV	2	346	20	2
Dushanbe_220 kV	Zavodskaya_220 kV	2	346	20	
Bohtar_110 kV	Dagana_110 kV	1	125	15.1	1
Bohtar_110 kV	Somoni_110 kV	1	125	3	1
Jangal_110 kV*	Hissar Stl_110 kV	1	125	14	1
Gissar_110 kV*	Hissar Stl_110 kV	1	125	11.5	1
Novaya_110 kV	Severnaya_110 kV	1	125	7.5	1
2035					
Nurekg_220 kV	Ordzh- Abad_220 kV	1	346	47	1

7.6.3 New Transformers

This section outlines the transformer additions necessary to support the system during the study period. The justification for the addition of these transformers is provided in Appendix E.

The list of all transformers required up to 2039 is shown in Table 7-12.

Table 7-12: List of New Load Serving Transformers

From Bus Name	To Bus Name	Id	Voltage Rating (kV)	Winding MVA Base
2020 Load Serving Transformers				
Sangtuda 500	Sangtuda 220	1	500/220	500
Sughd 500	Sughd 220	3	500/220	500
Orjinikidzeabad 220	Orjinikidzeabad 110	3	220/110	250
Novaya 220	Novaya 110	3	220/110	200
Jangal 220	Jangal 110	3	220/110	200
Geran 220	Geran 110	3	220/110	63
Khatlon 220	Khatlon 110	3	220/110	125

From Bus Name	To Bus Name	Id	Voltage Rating (kV)	Winding MVA Base
Buston 220	Buston 110	1	220/110	150
Rudaki 220	Rudaki 110	3	220/110	63
Leninabad 220	Leninabad 110	1	220/110	200
Leninabad 220	Leninabad 110	2	220/110	200
2025				
Rogun 500	Rogun 220	1	500/220	250
Rogun 500	Rogun 220	2	500/220	250
Lolazar 500	Lolazar 220	1	500/220	250
Geran 220	Geran 110	4	220/110	63
Khujand 220	Khujand 110	3	220/110	125
Zavodskaya 220	Zavodskaya 110	1	220/110	200
Zavodskaya 220	Zavodskaya 1100	2	220/110	200
2030				
Ordz-Abad 220	Ordz-Abad 110	3	220/110	250
Khatlon 220	Khatlon 110	4	220/110	125
Ayni 220	Ayni-B2 110	3	220/110	63
Zavodskaya 220	Zavodskaya 110	3	220/110	200
2035				
Dushanbe 500	Dushanbe 220	3	500/220	501
Rogun 220	Rogun 110	3	220/110	125
Uzlovaya 220	Uzlovaya 110	3	220/110	125
Kanibadam 220.00	Kanibadam 110	3	220/110	125
2039				
Novaya 220	Novaya 110	P	220/110	200
Jangal 220	Jangal 110	P1	220/110	200
Buston 220	Buston 110	P1	220/110	150

7.6.4 Capacitor Additions

When the network was developed some system intact voltage violations were observed and additional violations were observed following some contingencies. To mitigate the voltage violations and to meet the N-1 requirements, switched capacitors are recommended. The list of capacitors that are required is presented in Table 7-13.

Table 7-13: List of Voltage Support Capacitors

Bus (110 kV)	Size (MVAR)
2020	
Novaya	30
Dzerzhinskaya	140
Gissar	100
Sovetskaya	30
Vose	30
Lomonosova	20

Bus (110 kV)	Size (MVAR)
Ay-Kanar	50
Rumi	80
Shugnu	20
Nov	20
Prolets	20
Leninabad	60
Oktyabp	40
Kzyl-Su	10
2025	
Lomonosova	80
2030	
Novaya	70
Sovetskaya	20
Shugnu	10
Oktyabp	10
Dangana	10
2035	
Novaya	20
Sovetskaya	10
Vose	10
Oktyabp	30
Kzyl-Su	10
Dangana	10
Orjinikidzeabad	20
2039	
Novaya	30
Gissar	40
Sovetskaya	20
Vose	10
Rumi	40
Kzyl-Su	10
Dangana	10
Orjinikidzeabad	20
Jangal	20

7.7 TRANSMISSION REQUIREMENTS FOR EXPANSION WITH EARLY ROGUN GENERATION

This section provides the transmission and substation upgrades necessary to support the projected load and generation growth until the year 2039 for the generation expansion with Early Rogun Generation. The planning horizon is divided into 5 representative years 2020, 2025, 2030, 2035 and 2039. The transmission facility needed to support the system by each of the representative years is provided below. The proposed network was designed to meet N-1 requirements.

Powerflow cases representing each of the 5 representative years were developed based on the generation expansion plan and the load forecast. The generation expansion plan used in this section is based on the development of a hydro power plant at Rogun and some thermal generation in the Sughd region. Rogun is a large hydro project with a capacity of 3, 200 MW once completed.

Two cases representing the winter and summer load scenario were developed for each of the representative years. In addition, the following import and exports were also considered:

- Power import from Kyrgyzstan (455 MW)
- Power export (1300 MW) to Peshawar (Pakistan)
- 900 MW power export to Xinjiang, China
- 1,000 MW power export from Rogun HPP to Peshawar.

Based on the season, the availability of generation varies, in the winter months where there is less hydro generation and heavy loading due to heating requirements there is not as much power to evacuate to other systems as there is in the summer. As such the exports significantly reduced. However, the transmission system is designed considering maximum generation under maximum load and maximum export, this places the most stress on the transmission network.

Transmission facilities needed to evaluate power from the new power plants were identified. N-0 and N-1 studies were performed on each of the cases to identify violations and transmission upgrades/ resources needed to maintain the system intact and N-1 compliance and the required additions are recommended. Sensitivity studies were also performed assuming maximum generation in the south and minimum in the north and vice versa. The transmission expansion plan is designed to cater to a number of different dispatch scenarios. Figure 7-5 shows the transmission lines (500kV and 220V) that are recommended under the Rogun generation expansion plan.

All new transmission lines are recommended to have a rating of 346 MVA for the 220 kV level and 125 MVA for the 110 kV level. New lines are only proposed if they are necessary for evacuation of power from the new power plants and when the violations cannot be mitigated by transmission upgrades.

All the new 220 kV and 110 kV substations are designed with as a single bus, double breaker substation and the 500 kV substation is designed as breaker and a half substation. This is consistent with the current practices in Barki Tojik. For substation upgrades, bus configuration as in the existing substation is used. Figure 7-2 is an example of the proposed design for new 220 kV and 500 kV substations.

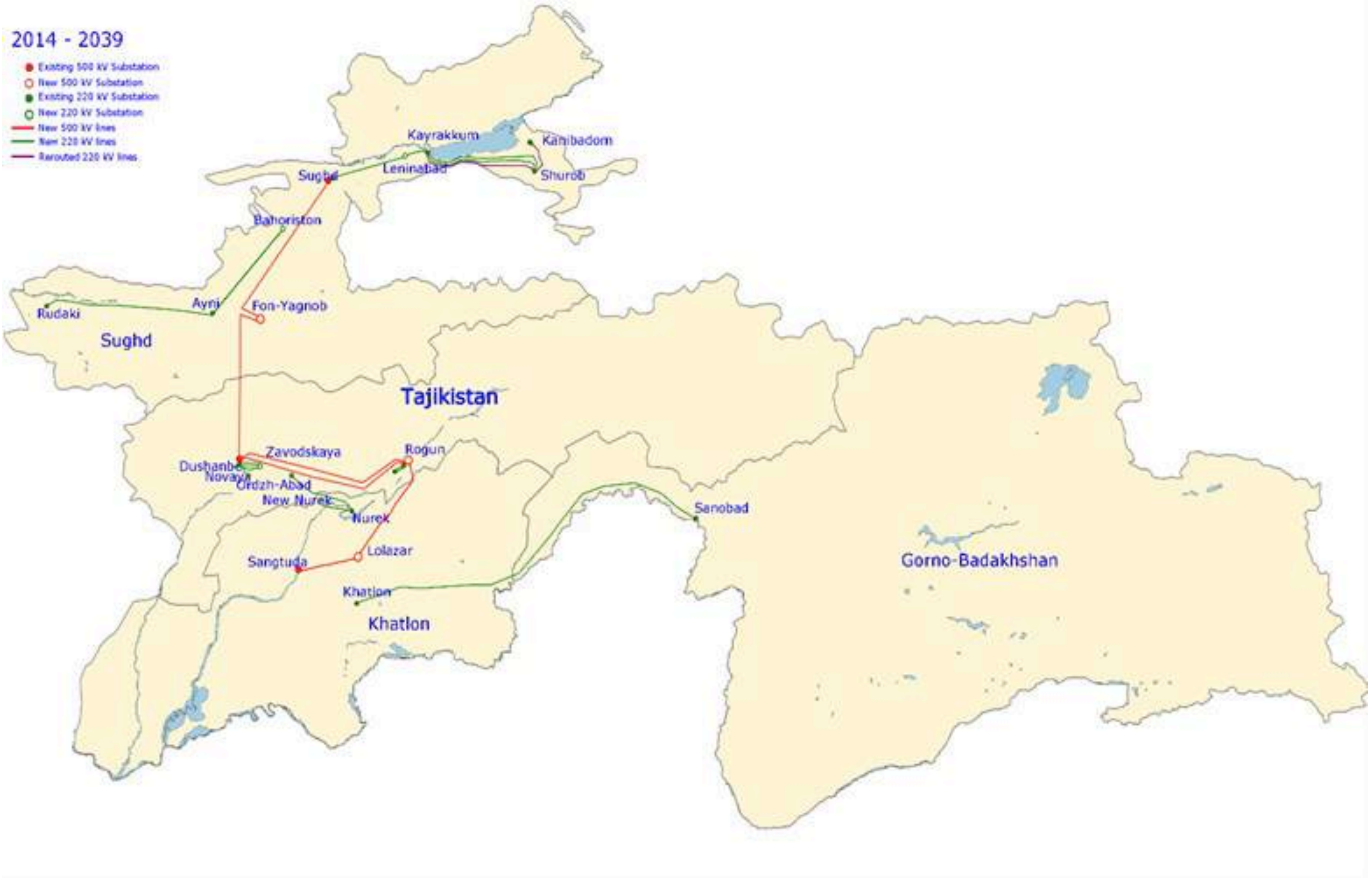

Figure 7-5: Recommended 500 kV and 220 kV Transmission Lines for the with Early Rogun Generation Plan

7.7.1 Line Upgrades

Table 7-14 presents the list of the lines to be upgraded during the study period. The justification of each of these additions is provided in Appendix E.

Table 7-14: List of Lines Requiring Upgrading

From Bus (110 kV)	To Bus (110 kV)	Current Rating (MVA)	Recommended Rating (MVA)
2020			
Buston	Zavodskaya	75	125
Novaya	Dtec (Double Cct)	75	125
Novaya	Promish (Double Cct)	75	125
Novaya	Shahri (Double Cct)	75	125
2025			
Jangal	Sovetskaya (Double Cct1)	75	125
Bohtar	Dangana	75	125
2030			
Severnaya	Vostochnaya (Double Cct)	75	125
Orjinikidzeabad	Kuz	75	125
Novaya	Severnaya (Double Cct)	75	125
2035			
Nurek	Sebestion	276	346
Sebestion	Lolazar	276	346
Nurek	Yavan	276	346
2039			
Dangana	Amirshoeu	75	125
Amirshoeu	Hovaling	75	125
Ayni B2	Ayni A2	75	125

7.7.2 Transmission Lines

This section outlines the transmission lines and substations facilities necessary to support the system during the study period. The justification for the addition of each line is provided in Appendix E.

The list of all the lies required up to 2039 is shown in Table 7-15.

Table 7-15: List of Lines to Support Generation and Load

From Bus	To Bus	Id	Rating (MVA)	(km)	Ccts
2020					
Dushanbe 500 kV	Fon-Yagnob 500 kV	1	2000	180	1
Fon-Yagnob 500 kV	Sughd 500 kV	2	2000	130	1
Rogung 500 kV	Dushanbe 500 kV	1	2000	100	2
Rogung 500 kV	Dushanbe 500 kV	2	2000	100	
Kayrakkum 220 kV	Leninabad 220 kV	1	346	20	1

From Bus	To Bus	Id	Rating (MVA)	(km)	Ccts
Kanibadom 220 kV	Shurob 220 kV	1	346	20	1
Kayrakkum 220 kV	Shurob 220 kV	2	346	20	2
Sughd 220 kV	Leninabad 220 kV	1	346	50	1
Bahoriston 220 kV	Ayni 220 kV	1	346	100	1
Ayni 220 kV	Rudaki 220 kV	1	346	90	1
Rogun 220 kV	Rogun 220 kV	1	346	5	2
Rogun 220 kV	Rogun 220 kV	2	346	5	
Buston 110kV	Zavodskaya 110 kV	1	125	6	1
Kurgan-Tube 110 kV	Pryadilnaya 110 kV	1	125	2	1
Ochapaeva 110 kV	Kurgan-Tube 110 kV	1	125	20	1
2025					
Rogun 500 kV	Lolazar 500 kV	1	2000	100	1
Lolazar 500 kV	Sangtuda 500 kV	1	2000	20	1
Dushanbe 220 kV	Novaya 220 kV	1	346	25	1
Dushanbe 220 kV	Zavodskaya 220 kV	1	346	20	1
Buston 110 kV	Zavodskaya 110 kV	1	125	6	1
Jangal 1100 kV	Severnaya 110 kV	1	125	25	1
Dehmoy 110 kV	Khujand 110 kV	1	125	13	1
Proletarsk 110 kV	Dehmoy 110 kV	1	125	12	1
2030					
Dushanbe_220 kV	Zavodskaya_220 kV	2	346	20	2
Dushanbe_220 kV	Zavodskaya_220 kV	2	346	20	
Bohtar_110 kV	Dagana_110 kV	1	125	15	1
Bohtar_110 kV	Somoni_110 kV	1	125	3	1
Jangal_110 kV*	Hissar Stl_110 kV	1	125	14	1
Gissar_110 kV*	Hissar Stl_110 kV	1	125	12	1
Novaya_110 kV	Severnaya_110 kV	1	125	8	1
2035					
Kayrakkum 220 kV	Shurob 220 kV	2	346	80	2
Kayrakkum 220 kV	Shurob 220 kV	3	346	80	
Nurek New 220 kV	Nurek 220 kV	1	346	25	1
Khatlon_220 kV	Sanobad_220 kV	1	346	250	1
Nurekg_220 kV	Ordzh- Abad_220 kV	1	346	47.1	1

7.7.3 New Transformers

This section outlines the transformer additions necessary to support the system during the study period. The justification for the addition of these transformers is provided in Appendix E.

The list of all transformers required up to 2039 is shown in Table 7-16.

Table 7-16: List of New Load Serving Transformers

From Bus Name	To Bus Name	Id	Voltage Rating (kV)	Winding MVA Base
2020 Load Serving Transformers				
Sangtuda 500	Sangtuda 220	1	500/220	500
Sughd 500	Sughd 220	3	500/220	500
Orjinikidzeabad 220	Orjinikidzeabad 110	3	220/110	250
Novaya 220	Novaya 110	3	220/110	200
Jangal 220	Jangal 110	3	220/110	200
Geran 220	Geran 110	3	220/110	63
Khatlon 220	Khatlon 110	3	220/110	125
Buston 220	Buston 110	1	220/110	150
Rudaki 220	Rudaki 110	3	220/110	63
Leninabad 220	Leninabad 110	1	220/110	200
Leninabad 220	Leninabad 110	2	220/110	200
2025				
Rogun 500	Rogun 220	1	500/220	250
Rogun 500	Rogun 220	2	500/220	250
Lolazar 500	Lolazar 220	1	500/220	250
Geran 220	Geran 110	4	220/110	63
Khujand 220	Khujand 110	3	220/110	125
Zavodskaya 220	Zavodskaya 110	1	220/110	200
Zavodskaya 220	Zavodskaya 1100	2	220/110	200
2030				
Ordz-Abad 220	Ordz-Abad 110	3	220/110	250
Khatlon 220	Khatlon 110	4	220/110	125
Ayni 220	Ayni-B2 110	3	220/110	63
Zavodskaya 220	Zavodskaya 110	3	220/110	200
2035				
Dushanbe 500	Dushanbe 220	3	500/220	501
Rogun 220	Rogun 110	3	220/110	125
Uzlovaya 220	Uzlovaya 110	3	220/110	125
Kanibadam 220.00	Kanibadam 110	3	220/110	125
2039				
Novaya 220	Novaya 110	P	220/110	200
Jangal 220	Jangal 110	P1	220/110	200
Buston 220	Buston 110	P1	220/110	150

7.7.4 Capacitor Additions

When the network was developed some system intact voltage violations were observed and additional violations were observed following some contingencies. To mitigate the voltage violations and to meet the N-1 requirements, switched capacitors are recommended. The list of capacitors that are required is presented in Table 7-17.

Table 7-17: List of Voltage Support Capacitors

Bus (110 kV)	Size (MVAR)
2020	
Novaya	30
Dzerzhinskaya	140
Gissar	100
Sovetskaya	30
Vose	30
Lomonosova	20
Ay-Kanar	50
Rumi	80
Shugnu	20
Nov	20
Prolets	20
Leninabad	60
Oktyabp	40
Kzyl-Su	10
2025	
Lomonosova	80
2030	
Novaya	70
Sovetskaya	20
Shugnu	10
Oktyabp	10
Dangana	10
2035	
Novaya	20
Sovetskaya	10
Vose	10
Oktyabp	30
Kzyl-Su	10
Dangana	10
Orjinikidzeabad	20
2039	
Novaya	30
Gissar	40
Sovetskaya	20
Vose	10
Rumi	40
Kzyl-Su	10
Dangana	10
Orjinikidzeabad	20
Jangal	20

7.8 COMPARISON OF TRANSMISSION REQUIREMENTS

This section compares and highlights the difference between the two transmission expansion plans presented in the previous sections. The transmission facilities recommended for each generation theme are categorised into facilities that are needed to evacuate power from the generating stations and those that are required to supply the load. The transmission facilities for the evacuation of power are different in both plans due to the difference in geographic location of the power plants in both generation expansion plans. However, the facilities recommended to support the load growth and meet the N-1 requirements are mostly the same in both options. This is because the load pattern used in both options is the same.

There are some lines that are unique to each option. These lines are added as specific contingency support for each option. This can be attributed to the difference in power transfer due to the different geographic distribution of generation in each plan. The following are the lines that are unique to each option.

7.8.1 Dushanbe- Sangtuda 500 and Rogun- Sangtuda 500 kV line

The Dushanbe-Sangtuda 500 kV line is recommended for the Without Rogun theme and the Rogun-Sangtuda line is recommended for the with Rogun theme.

In the without Rogun theme/plan, the new power plants are concentrated in the Sughd province. As the load increases from 2015 to 2039 the power flow between the two main regions changes direction with the predominant flow being from North to South. The power from the Sughd region is transferred to the Dushanbe area through the 500 kV link between the two areas, which is then distributed within Dushanbe and the excess power is transferred to Sangtuda for export.

With the generation expansion (without Rogun plan) concentrated in the north, the Dushanbe – Regar and Regar-Sangtuda 500 kV lines becomes a critical path for power transfer. The loss of either line especially during low load conditions causes instability in the Tajikistan network. A second line is essential to provide contingency support. The Dushanbe- Sangtuda 500 kV line is recommended as it provides contingency support for the loss of either of the two lines (Regar-Sangtuda or Regar-Dushanbe). Figure 7-6 shows the recommended 500 kV network for the without Rogun theme.

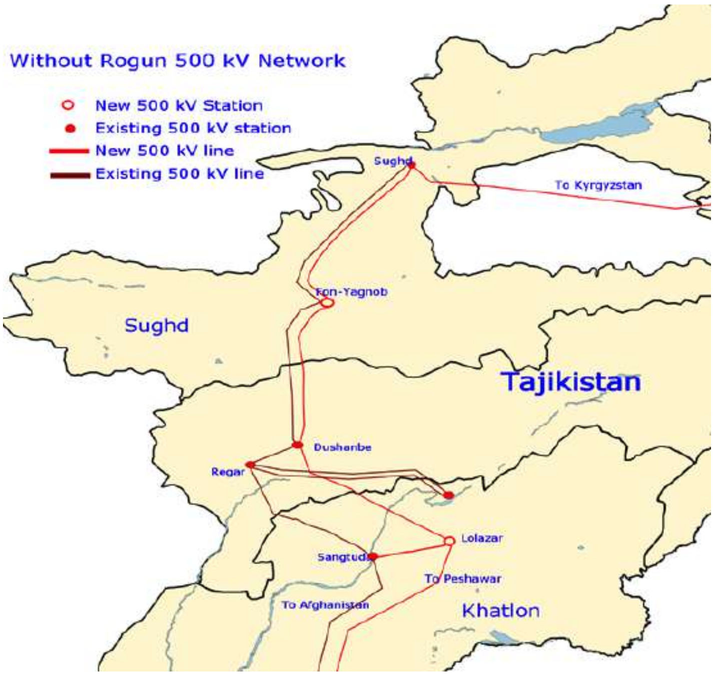

Figure 7-6: 500 kV Network Without Rogun Plan

In the with Rogun plan, the generation is predominantly concentrated in the south and the power transfer is predominantly from South to North. With the establishment of the Rogun power plant it becomes the main source of power for export and well as local supply. To facilitate power export a direct link between Rogun and Sangtuda is recommended. This line would also provide contingency support following the loss of the

Regar- Sangtuda and Regar-Dushanbe line. The Dushanbe- Sangtuda line is not needed in this option. Figure 7-7 shows the recommended 500 kV network for the with Rogun plan.

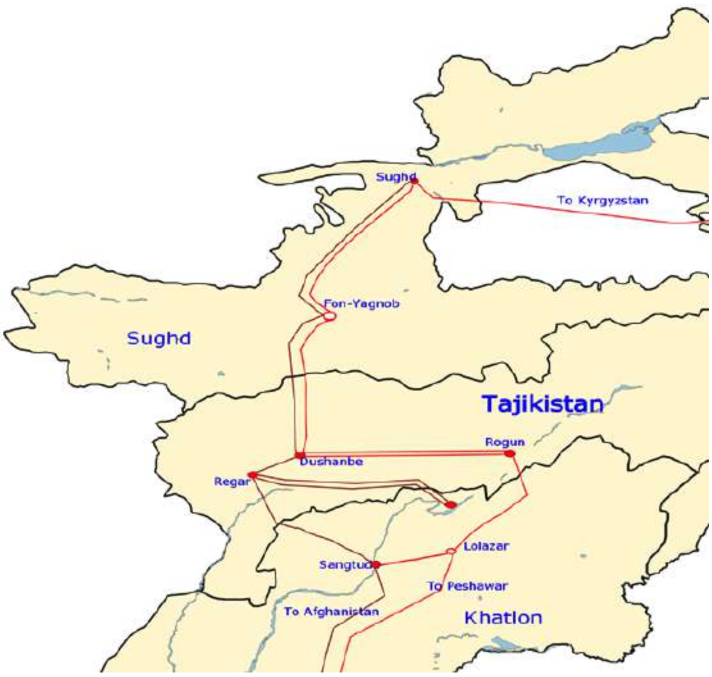

Figure 7-7: 500 kV Network With Rogun Plan

7.8.2 Losses

The transmission losses were determined for the peak load cases with maximum generation and maximum export. This represents the worst case for transmission losses. The total transmission loss in both cases is 3-4%. The transmission losses for both plans without Rogun and with Rogun are provided in Table 7-18.

Table 7-18: Transmission Losses (MW)

Plan	Year				
	2020	2025	2031	2035	2039
Without Rogun	142.2	149.5	189.9	228.7	276.2
With Rogun	146.2	134.3	194.4	276.5	326.4
Early Rogun	140.8	148.4	202.6	270.1	326.7

Table 7-19 presents the value of the transmission losses for each generation plan. These values were determined using the values for capacity and energy outlined in Section 4.2.10.

Table 7-19: Value of Transmission Losses

Year	Without Rogun			With Rogun			Early Rogun		
	Losses		Value of Losses ($, million)	Losses		Value of Losses ($, million)	Losses		Value of Losses ($, million)
	Capacity (MW)	Energy (GWh)		Capacity (MW)	Energy (GWh)		Capacity (MW)	Energy (GWh)	
2020	142.2	537.5	44.65	146.2	552.7	45.91	140.8	532.2	44.21
2021	143.7	543.1	45.11	143.8	543.7	45.16	142.3	538.0	44.69
2022	145.1	548.6	45.57	141.4	534.7	44.41	143.8	543.7	45.17
2023	146.6	554.1	46.03	139.1	525.7	43.67	145.4	549.5	45.64
2024	148.0	559.6	46.49	136.7	516.7	42.92	146.9	555.2	46.12
2025	149.5	565.1	46.94	134.3	507.7	42.17	148.4	561.0	46.60
2026	157.6	595.7	49.48	146.3	553.1	45.95	159.2	601.9	50.00
2027	165.7	626.2	52.02	158.3	598.5	49.72	170.1	642.9	53.41
2028	173.7	656.8	54.56	170.4	644.0	53.49	180.9	683.9	56.81
2029	181.8	687.3	57.09	182.4	689.4	57.27	191.8	724.9	60.21
2030	189.9	717.8	59.63	194.4	734.9	61.04	202.6	765.9	63.62
2031	197.7	747.2	62.07	210.2	794.7	66.01	216.1	816.9	67.86
2032	205.4	776.5	64.50	226.0	854.5	70.98	229.6	867.9	72.10
2033	213.2	805.8	66.94	241.9	914.3	75.95	243.1	918.9	76.33
2034	220.9	835.2	69.38	257.7	974.1	80.91	256.6	970.0	80.57
2035	228.7	864.5	71.81	273.5	1033.9	85.88	270.1	1021.0	84.81
2036	240.6	909.4	75.54	286.7	1083.9	90.03	284.3	1074.5	89.26
2037	252.5	954.3	79.27	300.0	1133.8	94.19	298.4	1128.0	93.70
2038	264.3	999.2	83.00	313.2	1183.8	98.34	312.6	1181.5	98.14
2039	276.2	1044.1	86.73	326.4	1233.8	102.49	326.7	1235.0	102.59

7.9 Cost of Network Additions

This section summarizes all the transmission upgrades proposed for the without Rogun plan and the with Rogun plan and provides an estimated cost associated with each component. The cost of upgrades are categorised into:

- Cost of transmission lines
- Cost of substations
- Cost of shunt compensation
- Cost for restringing lines

7.9.1 Unit Costs of Transmission Facilities

7.9.1.1 Transmission Lines

The cost of transmission lines were estimated by assuming that the conductor type is similar to that currently used in Tajikistan. The cost of building the lines varies depending on the terrain. Since there is no information about the right of way and the nature of the terrain through which these lines run it was assumed that 25 % of each line runs through mountains and the remaining 75% runs through valleys. The length of lines that were not known was obtained by measuring the distance between the two point using google maps. The new lines are assumed to have the same MVA as that of the highest rating available for lines in each voltage level in the current system. Typical costing ratio for a new line supply and construction is listed in Table 7-20.

Table 7-20: Typical Cost Ratios for New Transmission Line

Costing ratios for new line supply & construction (CIGRE WG 22.09 -Overall Design)						
Materials	Construction	Approximate Components of Material Costs				
		Towers	Conductor	Foundation	Insulators	Shield Wire
64%	**36%**	36%	33%	19%	8%	3%

The unit cost for transmission lines at various voltage levels are given in Table 7-22

Table 7-21: Unit Cost of Transmission Lines

Terrain	Capital Cost of Transmission Lines (US$/km)			
	500 kV	220 kV 2Ccts	220 kV 1Cct	110 kV 1Cct
Mountain	$750K	$405K	$300K	$225K
Valley	$570K	$300K	$225K	$165K

7.9.1.2 Cost of Substations

The cost of each substation was estimated by considering a single breaker double bus arrangement for all the 110 kV and 220 kV substations. This is consistent with the existing substations in Tajikistan. For all the 500 kV substations the cost was calculated based on 3 breaker bay (breaker and a half) arrangement.

Table 7-22 provides the estimated equipment price for the substation. The single breaker bay consists of the cost of foundation, steel, conductors and insulators. Each breaker arrangement is considered to have 3 CT`s and two disconnects. The element termination consists of the estimated price for three VT`s and one disconnect or isolator.

Table 7-22: Estimated Substation Equipment Price

Estimated Equipment Prices			
Items	500 kV	220 kV	110 kV
Single Breaker Bay	$ 200,000	$ 100,000	$ 75,000
Breaker+ CTs+ Disconnects	$ 950,000	$ 490,000	$ 225,000
Element termination (MOD + VTs)	$ 225,000	$ 120,000	$ 95,000
Labour and Engineering	$ 618,750	$ 319,500	$ 177,750

The estimated transformer cost used in determining the substation cost is listed in Table 7-23.

Table 7-23: Transformer Costs

Transformers Size	Cost
500 MVA	$ 4,000,000
250 MVA	$ 2,000,000
200 MVA	$ 1,500,000
150 MVA	$ 1,125,000
63 MVA	$ 472,500

7.9.1.3 Other Costs

The capacitors recommended are switched capacitors and the cost was estimated at about $14 per kVAr at the 13.8 kV level

For the present study, it is assumed that the annual operation and maintenance charges would be equal to 1.5% per year of the total capital investment for each item of equipment. It is recognized that transmission lines require a lower percentage for operation and maintenance but substation equipment requires a higher percentage thus the selected value represents an average value for all transmission equipment.

7.9.2 Cost of Network Additions for Expansion Without Rogun and With Rogun

Appendix E presents the detailed cost for each transmission line addition, each substation and the capacitor banks added to the system between 2015 and 2039.

Table 7-24 presents the summary of the costs for the transmission additions required to evacuate the generation and supply the demand under the generation plan without Rogun and with Rogun.

Table 7-24: Summary of Transmission Costs

Item	Without Rogun (US$, million)	With Rogun (US$, million)	Early Rogun (US$, million)
Cost of Transmission	478.56	588.60	588.60
Cost of Substations	213.47	224.86	224.86
Cost of Capacitors	25.90	22.40	22.40
Cost of Line Upgrades	17.80	17.80	17.80
Total Cost	**735.73**	**853.66**	**853.66**

The main difference in the cost between the two options can be attributed to the difference in the generation pattern in the two plans. The cost of the with Rogun plan is higher due to the fact that it has more 500 kV lines compared to the without Rogun plan.

8. OVERALL COST AND INVESTMENT PLAN

8.1 GENERAL

The economic analysis for the generation expansion plans is presented in Section 6 and the costs associated with the transmission requirements for the selected expansion plans are shown in Section 7. This section presents the economic analysis for the combined generation and transmission system expansion plans in terms of CPV for the two components (generation and transmission). The CPV for the generation expansion plans was determined based on the output from the GENSIM software while the CPV for the transmission additions (lines and substations) associated with the selected generation expansion sequence was obtained from spreadsheet calculations taking into account the timing of the transmission additions and includes capital investment, operation and maintenance costs and the value of losses.

The CPV of the transmission cost is approximately 13% of the total cost for both generation themes; without Rogun and with Rogun and it should be noted that the total transmission CPV is similar for both generation themes.

This section also presents the investment plan in both economic and financial terms for generation and transmission system expansion for the two selected least cost plans, without and with the Rogun HPP. The capital expenditures are shown for the combined generation and transmission equipment of each year.

8.2 COMBINED COST OF POWER SYSTEM EXPANSION PLANS

The two selected least cost generation system expansion plans and their associated costs have been discussed in Section 6 and the corresponding transmission system expansion plans and their costs have been described in Section 7. Table 8-1 shows the entire system cumulative present value in terms of 2015 dollars, i.e. combination of generation and transmission costs. For ease of reference and comparison, the cost for generation and transmission is tabled for three timeframes, planning horizon (a 25 year period from 2015 to 2039), end effect period (a 20 year period from 2040 to 2059) and the study period (a 45 year period from 2015 to 2059).

Table 8-1: Total System Cost

Component	Timeframe	Cumulative Present Value ($, million)		
		Case		
		Without Rogun	With Rogun	Early Rogun
Generation	Planning Horizon	5,516.4	5,370.6	5,351.2
	End Effect	1,122.3	932.4	904.6
	Subtotal	6,638.7	6,303.0	6,255.8
Transmission	Planning Horizon	729.2	809.1	805.9
	End Effect	141.6	153.3	153.3
	Subtotal	870.8	962.4	959.2
Combined System	Planning Horizon	6,245.6	6,179.7	6,157.1
	End Effect	1,263.9	1,085.7	1,057.9
	Total	7,509.5	7,265.4	7,215.0

From Table 8-1 it can be observed that the CPV for the selected system expansion plan without the Rogun HPP is some $7,509 million whereas it is $7,265.4 million for the plan with the Rogun HPP and $7,215 million for the plan with Early Rogun Generation, a difference of approximately $2448 million and $294 million for the with Rogun and Early Rogun Generation with reference to the Without Rogun plan respectively. It is also noted that the transmission costs are higher for the plans with Rogun by about $90 million or about 10% more than the cost for the plan Without Rogun. It can thus be concluded that the arguments / discussions presented in Section 6 for the generation system are also valid for the entire system and that the addition of the transmission expansion plans costs do not influence the results of the generation expansion themes.

8.3 Approach and Assumptions for the Investment Plans

It was assumed that all investments on capital projects, either generation or transmission facility were to be made prior to commissioning of the equipment.

In calculating the annual investment requirements, the total capital investment of the generation facilities was converted into annual cash flows based on the capital disbursement schedules presented in

Table 4-1 (for thermal and hydro plants except for the Rogun HPP) and Table 5-2 and Table 5-3 (for the Rogun HPP and Early Rogun respectively). It is noted that the total capital cost includes the EPC cost, owner's costs, financing charges including commitment fees and decommissioning costs. These cash flows are considered reasonable and follow industry standards.

The capital investment of the transmission facilities shown in Section 7 was converted into annual cash flows. Except for a couple of transmission lines, the capital investment of a transmission facility (lines, substations or capacitors) was assumed to be disbursed in the year prior to commissioning. For transmission lines longer than 100 km, it was assumed that the capital investment would be evenly distributed over two years.

The annual disbursement requirements, in terms of economic constant costs, were determined by adding each project's annual investment requirements and thus obtaining a stream of annual costs. These were then converted into financial requirements by applying a series of factors related to financial analysis. These factors were taken as follows:

- As described in Section 4.5, hydro power facilities were exempt from custom duties and VAT
- An inflation rate of 3% per year was assumed over the entire study period.

It should be noted that this provides an amount of money needed each year during the study period for each project and in order to determine how much each project costs in financial terms, the interest during construction on the loans taken to finance the projects has to be added to determine a particular project total cost.

8.4 Economic Investment Requirements of Selected expansion plans

The annual capital expenditures for each of the new generation and transmission facilities were added during the study period and are presented in this section. These are expressed in economic costs and are similar to those used in the analysis described in Sections 6 and 7.

8.4.1 Plan "Without" Rogun"

Table 8-2 presents the annual investment requirements in economic term for the expansion plan without the Rogun HPP. The following can be seen from this table:

- The total investment requirements over the study period are approximately $6,822 million, with $6,086 million for generation, $496 million for transmission and 240 million for substations. This means that the new generation facilities would use approximately 89% of the total system investment requirements
- The capital requirements until 2025 amount to $3,905 million or 57% of the total requirement over 25 years
- The annual cash requirements for generation vary from $0.0 in 2038 to $492 million in 2018. Every year, except for the last study year of 2039, has capital requirements. This analysis does not take into account the new facilities required after the study horizon
- The annual cash requirements for transmission including lines and substations vary from 0 to $ 195 million in 2018
- The maximum combined annual capital requirement is $703 million in 2017, followed by $6365 million in 2018.

8.4.2 Plan "With" Rogun

The annual investment requirements in economic term for the expansion plan with the Rogun HPP are presented in Table 8-3. The following can be seen from this table:

- The total investment requirements over the study period are approximately $9,233 million, $8,380 million for generation, $606 million for transmission and $247 for substations. This means that new generation facilities would use 90% of the total system investment requirements
- The capital requirements until 2025 amount to $6,811 million or 73% of the total requirement over 25 years
- The annual cash requirements for generation vary from 0 to some $768 million in 2024, one year before commissioning of the two first units at the Rogun HPP
- The annual cash requirements for transmission vary from 0 to approximately $192 million in 2017
- The maximum combined annual capital requirement is $942 million in 2024 followed by $782 million in 2023.

8.4.3 Plan with Early Rogun Generation

The annual investment requirements in economic term for the expansion plan with the Rogun HPP are presented in Table 8-4. The following can be seen from this table:

- The total investment requirements over the study period are approximately $9,233 million, $8,380 million for generation, $606 million for transmission and $247 for substations. This means that new generation facilities would use 90% of the total system investment requirements
- The capital requirements until 2025 amount to $7,54 million or 82% of the total requirement over 25 years
- The annual cash requirements for generation vary from 0 to some $792 million in 2019, the year of commissioning the first two units at the Rogun HPP
- The annual cash requirements for transmission vary from 0 to approximately $244 million in 2017
- The maximum combined annual capital requirement is $1,017 million in 2017 followed by $963 million in 2018.

8.5 FINANCIAL REQUIREMENTS OF THE SELECTED GENERATION AND TRANSMISSION EXPANSION PLANS

The annual capital expenditures in terms of financial costs for each of the generation and transmission facilities were added during the study period and are presented in this section. The financial costs were obtained from the economic costs by applying the factors listed in Section 8.3.

8.5.1 Plan "Without" Rogun

Table 8-5 shows the annual investment requirements in financial term for the expansion plan without the Rogun HPP. The following can be seen from this table:

- The total investment requirements over the study period are approximately $10,387 million, $9,350 million for generation, $675 million for transmission and $362 for substations. This means that new generation facilities would need over 90% of the total system investment requirements
- The capital requirements until 2025 amount to $4,932 million or approximately 47% of the total requirement over 25 years
- The annual cash requirements for generation vary from $0.0 million in 2038 to $613 million in 2017
- The annual cash requirements for transmission vary from 0 to $238 million in 2017
- The maximum combined annual capital requirement is $851 million in 2017 followed by $793 million in 2018.

8.5.2 Plan "With" Rogun

The annual investment requirements in financial term for the expansion plan with the Rogun HPP are presented in Table 8-6. The following can be seen from this table:

- The total investment requirements over the study period would be approximately $12,501 million, $11,314 million for generation, $826 million for transmission and $361 million for substations. The new generation facilities cost amounts to some 90% of the total system investment requirements
- The capital requirements until 2025 amount to $8,658 million or over 69% of the total requirement over 25 years
- The annual cash requirements for generation vary from 0 to $1,025 million in 2024
- The annual cash requirements for transmission vary from 0 to $234 million in 2017
- The maximum combined annual capital requirement is $1,286 million in 2024, followed by $1,280 million in 2023.

8.5.3 Plan with Early Rogun Generation

The annual investment requirements in financial term for the expansion plan with the Rogun HPP are presented in Table 8-7. The following can be seen from this table:

- The total investment requirements over the study period would be approximately $12,145 million, $11,929 million for generation, $856 million for transmission and $359 million for substations. The new generation facilities cost amounts to some 90% of the total system investment requirements
- The capital requirements until 2025 amount to $9,167 million or over 75% of the total requirement over 25 years
- The annual cash requirements for generation vary from 0 to $928 million in 2019
- The annual cash requirements for transmission vary from 0 to $298 million in 2017
- The maximum combined annual capital requirement is $1,188 million in 2017, followed by $1,155 million in 2018.

8.6 COMPARISON OF POWER SYSTEM INVESTMENT COSTS

The annual capital investment disbursements in terms of economic and financial costs for the three selected expansion plans have been presented in Table 8-2 to Table 8-7. The values in these Tables are shown graphically in Figure 8-1 and Figure 8-2. The first figure presents the annual capital investment disbursements while the second shows the cumulative capital investments.

The values shown in Figure 8-1 to Figure 8-4indicate that the expansion plan without the Rogun HPP requires a lower capital investment. However it is noted that this plan would result in higher O&M costs and fuel costs than the plans with the Rogun HPP.

In economic terms, the plans with the Rogun HPP requires $2,411 million more in capital investment than the plan without the Rogun HPP whereas the comparable value under financial terms is $2,113 million.

8.7 CAPITAL WORKS PROGRAM

Table 8-5 to Table 8-7 present the list of projects under the three selected system expansion plans (without, with Rogun and Early Rogun). The tables also present the expected duration for each project since it was assumed that a project would be on line following the last year that it required capital investments.

All of the selected expansion plans included two mini hydro power plants. No capital requirements were included for these two plants since costs for these plants are site specific and they were not provided to the study team and in addition, the costs tend to be small and many times are part of grants provided by bilateral aid.

For the expansion scenarios without Rogun there are a total of 25 generation additions. However, of these one considers the energy efficiency program, the other the decommissioning of Rogun, and the third the construction of facilities to provide protection against the PMF. In the first 10 years of the plan, there is a need for the completion of the rehabilitation of all the existing hydro power plants and to add the following generating facilities:

- Two 150 MW CHP coal fired units
- Two new hydro power plants
- 2 wind plants
- 5 solar plants
- 2, 150 MW coal fired units and
- 3, 350 MW coal fired units

For the expansion scenarios without Rogun, there are a total of 31 transmission line projects and 45 substation projects required over the study period. Of these, 22 transmission line projects and 37 substation projects are required during the first 10 years (until 2025).

For the expansion scenarios with Rogun there are a total of 19 generation with one considering the energy efficiency program. In the first 10 years of the plan there is a need for the completion of the rehabilitation of all the existing hydro power plants and to add the following generating facilities:

- Two 150 MW CHP coal fired units
- Two new hydro power plants
- 2 wind plants
- 5 solar plants
- 2, 150 MW coal fired units and
- 2, 350 MW coal fired units

In addition, it should be noted that the first two units of Rogun were assumed to start generating in 2025. There is a feasibility study available for Rogun on the World Bank web site issued in August, 2014.

For the expansion scenarios with Early Rogun Generation there are a total of 19 generation with one considering the energy efficiency program. In the first 10 years of the plan there is a need for the completion of the rehabilitation of all the existing hydro power plants and to add the following generating facilities:

- Two 150 MW CHP coal fired units
- Rogun 2 x 400 MW and 4 x 600 MW
- 2 wind plants
- 5 solar plants
- 2, 150 MW coal fired units and
- 2, 350 MW coal fired units

There is a feasibility study for the two 150 MW CHP coal fired units in Chinese and Russian. There is also a prefeasibility study for Sanobad and Nurek -2. The wind plants and solar plants considered in the PSDMP are of the generic type and studies have to be carried out in order to define the basic parameters.

The PSDMP assigned the location for the coal fired units based on the existing coal mines in Tajikistan and no specific studies have been carried out to determine the best location for these plants. Mine mouth locations were assumed to be at Shurob, Fon Yagnob and Ziddy.

For the expansion scenarios with Early Rogun Generation, there are a total of 31 transmission line projects and 45 substation projects required over the study period.

The transmission line Appendix provides details on the requirements for the transmission lines and substations.

Table 8-2: Economic Investment Requirements – Expansion Plan Without Rogun

Generation Projects

Project		Online	Capital	Capital Disbursement in Year																									
No.	Name	Year	Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
1	Energy Efficiency	2015	54.3		6.8	14.5	12.5	12.5	8.0																				
2	CHP 150 MW	2016	171.7	51.5	68.7	51.5																							
3	CHP 150 MW	2016	171.7	51.5	68.7	51.5																							
4	Coal 150 MW	2019	180.2			54.1	72.1	54.1																					
5	Coal 150 MW	2019	180.2			54.1	72.1	54.1																					
6	Coal 350 MW	2019	401.3		80.3	100.3	120.4	100.3																					
7	Coal 350 MW	2020	401.3			80.3	100.3	120.4	100.3																				
8	Coal 350 MW	2021	401.3				80.3	100.3	120.4	100.3																			
9	Decommissioning Rogun	2021	200.0				50.0	50.0	50.0	50.0																			
10	Solar 10 MW	2021	20.6						12.4	8.2																			
11	Wind 10 MW	2021	17.2						10.3	6.9																			
12	Solar 10 MW	2022	20.6							12.4	8.2																		
13	Nurek-2 100 MW	2022	170.0						51.0	68.0	51.0																		
14	Solar 10 MW	2023	20.6								12.4	8.2																	
15	Sanobad 125 MW	2023	323.6						64.7	80.9	113.3	64.7																	
16	Solar 10 MW	2024	20.6									12.4	8.2																
17	Coal 350 MW	2025	401.3								80.3	100.3	120.4	100.3															
18	Solar 10 MW	2025	20.6										12.4	8.2															
19	Wind 10 MW	2025	17.2										10.3	6.9															
20	Coal 350 MW	2029	401.3												80.3	100.3	120.4	100.3											
21	Coal 350 MW	2031	401.3														80.3	100.3	120.4	100.3									
22	Coal 350 MW	2034	401.3																	80.3	100.3	120.4	100.3						
23	Flood Protection Control	2034	1,000.0																	250.0	250.0	250.0	250.0						
24	Coal 350 MW	2036	401.3																			80.3	100.3	120.4	100.3				
25	Coal 350 MW	2038	286.6																					57.3	71.7	86.0	71.7		
Subtotal			**6,086.1**	**103.0**	**224.4**	**406.2**	**507.6**	**491.7**	**417.1**	**326.7**	**265.1**	**185.6**	**151.3**	**115.4**	**80.3**	**100.3**	**200.7**	**200.7**	**120.4**	**430.6**	**350.3**	**450.7**	**450.7**	**177.7**	**172.0**	**86.0**	**71.7**	**0.0**	**0.0**

(Table 8-2 Continued)

Transmission Lines

Project		Online	Capital	Capital Disbursement in Year																									
No.	Name	Year	Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
1	Dushanbe TO FonYagnob	2019	110.7				55.4	55.4																					
2	Sughd TO Fon Yagnob	2019	80.0				40.0	40.0																					
3	Kayrakkum TO Shurob	2019	4.9					4.9																					
4	Kanibadam TO Shurob	2019	4.9					4.9																					
5	Kayrakkum TO Leninabad	2018	4.9				4.9																						
6	Sughd TO Leninabad	2018	12.2				12.2																						
7	Bahoriston TO Ayni	2018	24.4			12.2	12.2																						
8	Ayni TO Rudaki	2018	21.9				21.9																						
9	Buston TO Zavodskaya 110 kV	2020	1.1						1.1																				
10	Kurgan-Tube TO Pryadilnaya	2020	0.3						0.3																				
11	Chapaeva TO Kurgan-Tube	2020	3.8						3.8																				
12	Dushanbe TO Lolazar	2025	52.3											52.3															
13	Lolazar TO Sangtuda	2025	12.3											12.3															
14	Dushanbae TO Zavodskaya	2025	4.9											4.9															
15	Khatlon TO Sanobad	2023	60.9								30.5	30.5																	
16	Kayrakkum TO Shurob	2025	26.1											26.1															
17	Novaya TO Dushanbe	2025	6.1											6.1															
18	Nurek New TO Nurek	2022	6.1								6.1																		
19	Buston TO Zavodskaya	2025	1.1											1.1															
20	Dehmoy TO Khujand	2025	2.4											2.4															
21	Jangal TO Severnaya	2023	4.8									4.8																	
22	Proletarsk TO Dehmoy	2023	2.3									2.3																	
23	Dushanbe TO Zavodskaya	2028	6.5														6.5												
24	Bohtar TO Dagana	2027	2.9													2.9													
25	Bohtar TO Somoni	2027	0.6													0.6													
26	Gissar TO Hissar Stl	2029	2.2															2.2											
27	Jangal TO Hissar Stl	2029	2.7															2.7											
28	Novaya TO Severnaya	2029	1.4															1.4											
29	Nurekg2 TO Ordzh- Abad	2035	11.5																					11.5					
30	Ayni TO Ziddy	2038	1.2																								1.2		
31	Rudaki TO Ziddy	2038	1.2																								1.2		
	LINES UPGRADE		17.8				6.1	1.5	2.6				1.5					2.5					2.8				0.8		
Subtotal			**496.3**	**0.0**	**0.0**	**12.2**	**152.6**	**106.6**	**7.9**	**0.0**	**36.6**	**37.5**	**1.5**	**105.2**	**0.0**	**3.5**	**6.5**	**8.8**	**0.0**	**0.0**	**0.0**	**0.0**	**2.8**	**11.5**	**0.0**	**0.0**	**3.2**	**0.0**	**0.0**

(Table 8-2 Continued)

Substations

Project		Online	Capital	Capital Disbursement in Year																									
No.	Name	Year	Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
1	Shurab generating station		8.3					3.1						5.2															
2	Kaiyrakum		5.3					2.1						3.2															
3	Kanibadom		5.2					2.6																		2.6			
4	Fon Yagnob generating station		30.2					10.1										5.0					10.1		5.0				
5	Ayni		2.6						1.3									1.3											
6	Ziddy		4.3																								4.3		
7	Rudaki		1.8				1.8																						
8	Sugdh		4.9					4.9																					
9	Sugdh		2.1					2.1																					
10	Leninbad 220		8.9				8.9																						
11	Leninbad		0.9				0.9																						
12	Dehmoy		2.2											2.2															
13	Hodzent		3.2									3.2																	
14	Buston		3.3										3.3																
15	Proletarsk		2.6										2.6																
16	Dushanbe		14.0					6.6						6.6								0.7							
17	Dushanbe		3.7											0.9			1.9					0.9							
18	Novaya		6.9				2.3							2.3													2.3		
19	Novaya		1.6				0.5										0.5										0.5		
20	Zavodskaya		11.5											7.7			3.8												
21	Zavodskaya		2.8											2.3			0.6												
22	Jangal		5.9				3.0																			3.0			
23	Jangal		2.3				0.6					0.6						0.6								0.6			
24	Geran		7.1				5.9						1.2																
25	Geran110		1.1									1.1																	
26	Ordzh-abad`		10.4				5.2									2.6								2.6					
27	Ordzh-abad`		0.6				0.2									0.4													
28	Severnaya		1.2									0.6						0.6											
29	Nurekskaya generating station		5.5								5.5																		
30	Nurek		0.9								0.3											0.6							
31	Prydilnaya		0.6					0.6																					
32	Kurgan-tube		1.7					1.7																					
33	Rogun		2.8																			2.8							
34	Rogun110		0.6																			0.6							
35	Khatlon		6.1					2.0				2.0					2.0												
36	Khatlon		2.2					1.1									1.1												
37	Bohtar		2.2													2.2													
38	Sangtuda		19.9				5.0							14.9															
39	Sangtuda		1.0				1.0																						
40	Gissar		1.4															1.4											
41	Dangana		0.5													0.5													
42	Somoni		0.5													0.5													
43	Lolazar		10.8											10.8															
44	Bahoriston		0.9					0.9																					
45	Lolazar		0.9											0.9															
	Capacitors		25.9				7.2		9.6					1.6					2.2					2.0				3.3	
	Subtotal		**239.4**	**0.0**	**0.0**	**0.0**	**42.4**	**37.9**	**10.9**	**0.0**	**5.8**	**7.6**	**7.1**	**58.7**	**0.0**	**6.2**	**10.0**	**8.9**	**2.2**	**0.0**	**0.0**	**5.6**	**10.1**	**4.6**	**5.0**	**6.1**	**7.1**	**3.3**	**0.0**
	Total (G+T+S)		**6,821.9**	**103.0**	**224.4**	**418.4**	**702.6**	**636.1**	**435.9**	**326.7**	**307.5**	**230.7**	**159.9**	**279.3**	**80.3**	**110.0**	**217.1**	**218.4**	**122.6**	**430.6**	**350.3**	**456.2**	**463.5**	**193.8**	**177.0**	**92.1**	**82.0**	**3.3**	**0.0**

Table 8-3: Economic Investment Requirements – Expansion Plan With Rogun

Generation Projects

Project		Online	Capital	Capital Disbursement in Year																									
No.	Name	Year	Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
1	Energy Efficiency	2015	54.3		6.8	14.5	12.5	12.5	8.0																				
2	CHP 150 MW	2016	171.7	51.5	68.7	51.5																							
3	CHP 150 MW	2016	171.7	51.5	68.7	51.5																							
4	Coal 150 MW	2019	180.2			54.1	72.1	54.1																					
5	Coal 150 MW	2019	180.2			54.1	72.1	54.1																					
6	Coal 350 MW	2019	401.3		80.3	100.3	120.4	100.3																					
7	Coal 350 MW	2020	401.3			80.3	100.3	120.4	100.3																				
8	Coal 350 MW	2021	401.3				80.3	100.3	120.4	100.3																			
9	Solar 10 MW	2021	20.6						12.4	8.2																			
10	Wind 10 MW	2021	17.2						10.3	6.9																			
11	Solar 10 MW	2022	20.6							12.4	8.2																		
12	Nurek-2 100 MW	2022	170.0						51.0	68.0	51.0																		
13	Solar 10 MW	2023	20.6								12.4	8.2																	
14	Sanobad 125 MW	2023	323.6						64.7	80.9	113.3	64.7																	
15	Solar 10 MW	2024	20.6									12.4	8.2																
16	Rogun 2x400 MW and 4x600 MW	2025	5,500.0						103.7	276.1	394.6	531.6	661.9	752.7	738.9	490.3	416.1	392.9	419.4	146.6	100.1	75.1							
17	Solar 10 MW	2025	20.6										12.4	8.2															
18	Wind 10 MW	2025	17.2										10.3	6.9															
19	Coal 350 MW	2038	286.6																					57.3	71.7	86.0	71.7		
Subtotal			**8,379.6**	**103.0**	**224.4**	**406.2**	**457.6**	**441.7**	**470.8**	**552.8**	**579.5**	**616.9**	**692.8**	**767.8**	**738.9**	**490.3**	**416.1**	**392.9**	**419.4**	**146.6**	**100.1**	**75.1**	**0.0**	**57.3**	**71.7**	**86.0**	**71.7**	**0.0**	**0.0**

(

Table 8-3 Continued)

Transmission Lines

Project		Online	Capital	Capital Disbursement in Year																									
No.	Name	Year	Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
1	Dushanbe TO Fon-Yagnob	2019	110.7				55.4	55.4																					
2	Fon-Yagnob TO Sughd	2019	80.0				40.0	40.0																					
3	Kayrakkum TO Leninabad	2019	4.9					4.9																					
4	Kanibadom TO Shurob	2019	4.9					4.9																					
5	Kayrakkum TO Shurob	2018	4.9				4.9																						
6	Sughd TO Leninabad	2018	12.2				12.2																						
7	Bahoriston TO Ayni	2018	24.4			12.2	12.2																						
8	Ayni TO Rudaki	2018	21.9				21.9																						
9	Buston TO Zavodskaya	2020	1.1						1.1																				
10	Kurgan-Tube TO Pryadilnaya	2020	0.3						0.3																				
11	Ochapaeva TO Kurgan-Tube	2020	3.8						3.8																				
12	Rogung TO Dushanbe	2025	101.6										50.8	50.8															
13	Rogun TO Lolazar 500kV	2025	61.5										30.8	30.8															
14	Lolazar TO Sangtuda	2025	12.3											12.3															
15	Kayrakkum TO Shurob	2021	26.1							26.1																			
16	Dushanbe TO Novaya	2025	6.1											6.1															
17	Dushanbe TO Zavodskaya	2025	4.9											4.9															
18	Rogun TO Rogun	2025	1.6											1.6															
19	Bustn2 TO Zavodskaya	2025	1.1											1.1															
20	Jangal TO Severnaya	2023	4.8									4.8																	
21	Dehmoy TO Khujand	2025	2.4											2.4															
22	Proletarsk TO Dehmoy	2023	2.3									2.3																	
23	Nurek New TO Nurek	2022	6.1								6.1																		
24	Khatlon TO Sanobad	2021	60.9						30.5	30.5																			
25	Dushanbe TO Zavodskaya	2028	6.5														6.5												
26	Bohtar TO Dagana	2027	2.9													2.9													
27	Bohtar TO Somoni	2027	0.6													0.6													
28	Jangal* TO Hissar Stl	2029	2.7															2.7											
29	Gissar* TO Hissar Stl	2029	2.2															2.2											
30	Novaya TO Severnaya	2029	1.4															1.4											
31	Nurekg TO Ordzh- Abad	2035	11.5																					11.5					
	LINES UPGRADE		17.8				6.1	1.5	2.6				1.5					2.5					2.8				0.8		
Subtotal			**606.4**	**0.0**	**0.0**	**12.2**	**152.6**	**106.6**	**38.3**	**56.6**	**6.1**	**7.1**	**83.1**	**110.0**	**0.0**	**3.5**	**6.5**	**8.8**	**0.0**	**0.0**	**0.0**	**0.0**	**2.8**	**11.5**	**0.0**	**0.0**	**0.8**	**0.0**	**0.0**

(

Table 8-3 Continued)

Substations

Project		Online	Capital	Capital Disbursement in Year																									
No.	Name	Year	Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
1	Shurab generating station	2019	7.9					4.0		3.0																	1.0		
2	Kaiyrakum	2019	5.6					3.4		2.2																			
3	Kanibadom	2019	2.8					2.8																					
4	Fon Yagnob generating station	2019	13.1					13.1																					
5	Ayni	2018	2.8				2.8																						
6	Rudaki	2018	1.8				1.8																						
7	Sugdh	2019	4.9					4.9																					
8	Sugdh	2019	2.0					2.0																					
9	Leninbad 220	2018	8.9				8.9																						
10	Leninbad	2018	0.9				0.9																						
11	Dehmoy	2025	2.2											2.2															
12	Hodzent	2023	3.2									3.2																	
13	Buston	2024	3.3										3.3																
14	Proletarsk	2024	2.6										2.6																
15	Rogun 1	2025	5.1											2.6			2.6												
16	Rogun	2025	32.2											10.7			21.5												
17	Rogun	2028	0.6														0.6												
18	Dushanbe	2019	14.6					7.3						7.3															
19	Dushanbe	2025	3.7											0.9			1.9					0.9							
20	Novaya	2018	6.9				2.3							2.3													2.3		
21	Novaya	2018	1.6				0.5										0.5										0.5		
22	Zavodskaya	2025	11.5											7.7			3.8												
23	Zavodskaya	2025	2.8											2.3			0.6												
24	Jangal	2018	5.9				3.0																				3.0		
25	Jangal	2018	2.3				0.6						0.6					0.6									0.6		
26	Geran	2020	7.1						5.9			1.2																	
27	Geran 110	2023	1.1									1.1																	
28	Ordzh-abad`	2018	10.4				5.2									2.6								2.6					
29	Ordzh-abad`	2018	0.6				0.2											0.4											
30	Severnaya	2023	1.2									0.6				0.6													
31	Nurekskaya New generating statio	2022	5.5								5.5																		
32	Nurekskaya N	2022	0.9								0.3											0.6							
33	Prydilnaya	2019	0.6					0.6																					
34	Kurgan-tube	2019	1.7					1.7																					
35	Khatlon	2019	6.1					2.0				2.0					2.0												
36	Khatlon	2019	2.2					1.1									1.1												
37	Bohtar	2027	2.2													2.2													
38	Sangtuda	2018	19.9				5.0							14.9															
39	Sangtuda	2018	1.0				1.0																						
40	Gissar	2029	1.4															1.4											
41	Dangana	2027	0.5													0.5													
42	Somoni	2027	0.5													0.5													
43	Lolazar	2025	10.8											10.8															
44	Lolazar	2025	0.9											0.9															
45	Bahoriston	2018	0.9				0.9																						
Capacitors			22.4				6.2		9.1					1.1					1.7					1.5				2.8	
Subtotal			**247.3**	**0.0**	**0.0**	**0.0**	**39.2**	**42.8**	**15.0**	**5.2**	**5.8**	**8.2**	**6.5**	**63.7**	**0.0**	**6.4**	**34.6**	**2.4**	**1.7**	**0.0**	**0.0**	**1.6**	**0.0**	**4.1**	**0.0**	**0.0**	**7.3**	**2.8**	**0.0**
Total (G+T+S)			**9,233.3**	**103.0**	**224.4**	**418.4**	**649.5**	**591.1**	**524.2**	**614.6**	**591.3**	**632.2**	**782.4**	**941.5**	**738.9**	**500.2**	**457.2**	**404.1**	**421.1**	**146.6**	**100.1**	**76.7**	**2.8**	**73.0**	**71.7**	**86.0**	**79.8**	**2.8**	**0.0**

Table 8-4: Economic Investment Requirements - Expansion Plan with Early Rogun

Generation Projects

Project		Online	Capital	Capital Disbursement in Year																									
No.	Name	Year	Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
1	Energy Efficiency	2015	54.3		6.8	14.5	12.5	12.5	8.0																				
2	CHP 150 MW	2016	171.7	51.5	68.7	51.5																							
3	CHP 150 MW	2016	171.7	51.5	68.7	51.5																							
4	Coal 150 MW	2019	180.2			54.1	72.1	54.1																					
5	Coal 150 MW	2019	180.2			54.1	72.1	54.1																					
6	Coal 350 MW	2019	401.3		80.3	100.3	120.4	100.3																					
7	Rogun 2x400 MW and 4x600 MW	2019	5,500.0		196.0	313.7	396.0	401.5	660.7	752.7	738.9	490.3	416.1	392.9	419.4	246.7	75.1												
8	Coal 350 MW	2020	401.3			80.3	100.3	120.4	100.3																				
9	Solar 10 MW	2021	20.6						12.4	8.2																			
10	Wind 10 MW	2021	17.2						10.3	6.9																			
11	Solar 10 MW	2022	20.6							12.4	8.2																		
12	Solar 10 MW	2023	20.6								12.4	8.2																	
13	Solar 10 MW	2024	20.6									12.4	8.2																
14	Solar 10 MW	2025	20.6										12.4	8.2															
15	Wind 10 MW	2025	17.2										10.3	6.9															
16	Nurek-2 100 MW	2033	170.0																	51.0	68.0	51.0							
17	Sanobad 125 MW	2033	323.6																64.7	80.9	113.3	64.7							
18	Coal 350 MW	2035	401.3																		80.3	100.3	120.4	100.3					
19	Coal 350 MW	2038	286.6																					57.3	71.7	86.0	71.7		
Subtotal			**8,379.6**	**103.0**	**420.4**	**719.9**	**773.4**	**742.8**	**791.7**	**780.2**	**759.5**	**510.9**	**447.0**	**408.0**	**419.4**	**246.7**	**75.1**	**0.0**	**64.7**	**131.9**	**261.5**	**216.0**	**120.4**	**157.7**	**71.7**	**86.0**	**71.7**	**0.0**	**0.0**

(Table 8-4 Continued)

Transmission Lines

Project		Online	Capital	Capital Disbursement in Year																									
No.	Name	Year	Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
1	Dushanbe TO Fon-Yagnob	2019	110.7				55.4	55.4																					
2	Fon-Yagnob TO Sughd	2019	80.0				40.0	40.0																					
3	Rogung TO Dushanbe	2019	101.6				50.8	50.8																					
4	Kayrakkum TO Leninabad	2019	4.9					4.9																					
5	Kanibadom TO Shurob	2019	4.9					4.9																					
6	Kayrakkum TO Shurob	2019	4.9					4.9																					
7	Sughd TO Leninabad	2018	12.2				12.2																						
8	Bahoriston TO Ayni	2018	24.4			12.2	12.2																						
9	Ayni TO Rudaki	2018	21.9				21.9																						
10	Rogun TO Rogun	2019	1.6					1.6																					
11	Buston 110kV TO Zavodskaya	2020	1.1						1.1																				
12	Kurgan-Tube TO Pryadilnaya	2020	0.3						0.3																				
13	Ochapaeva TO Kurgan-Tube	2020	3.8						3.8																				
14	Rogun TO Lolazar	2025	61.5										30.8	30.8															
15	Lolazar TO Sangtuda	2025	12.3											12.3															
16	Dushanbe TO Novaya	2025	6.1											6.1															
17	Dushanbe TO Zavodskaya	2025	4.9											4.9															
18	Buston TO Zavodskaya	2025	1.1											1.1															
19	Jangal 1100 kV TO Severnaya	2023	4.8									4.8																	
20	Dehmoy TO Khujand	2025	2.4											2.4															
21	Proletarsk TO Dehmoy	2023	2.3									2.3																	
22	Dushanbe TO Zavodskaya	2028	6.5														6.5												
23	Bohtar TO Dagana	2027	2.9													2.9													
24	Bohtar TO Somoni	2027	0.6													0.6													
25	Jangal* TO Hissar Stl	2029	2.7															2.7											
26	Gissar* TO Hissar Stl	2029	2.2															2.2											
27	Novaya TO Severnaya	2029	1.4															1.4											
28	Kayrakkum TO Shurob	2035	26.1																					26.1					
29	Nurek New TO Nurek	2033	6.1																			6.1							
30	Khatlon TO Sanobad	2033	60.9																		30.5	30.5							
31	Nurekg TO Ordzh- Abad	2035	11.5																					11.5					
	LINES UPGRADE		17.8				6.1	1.5	2.6				1.5					2.5					2.8				0.8		
Subtotal			**606.4**	**0.0**	**0.0**	**12.2**	**198.6**	**163.9**	**7.9**	**0.0**	**0.0**	**7.1**	**32.3**	**57.6**	**0.0**	**3.5**	**6.5**	**8.8**	**0.0**	**0.0**	**30.5**	**36.6**	**2.8**	**37.6**	**0.0**	**0.0**	**0.8**	**0.0**	**0.0**

(Table 8-4 Continued)

Substations

Project		Online	Capital	Capital Disbursement in Year																									
No.	Name	Year	Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
1	Shurab generating station	2019	7.9					4.0																3.0			1.0		
2	Kaiyrakum	2019	5.6					3.4																2.2					
3	Kanibadom	2019	2.8					2.8																					
4	Fon Yagnob generating station	2019	13.1					13.1																					
5	Ayni	2018	2.8				2.8																						
6	Rudaki	2018	1.8				1.8																						
7	Sugdh	2019	4.9					4.9																					
8	Sugdh	2019	2.0					2.0																					
9	Leninbad 220	2018	8.9				8.9																						
10	Leninbad	2018	0.9				0.9																						
11	Dehmoy	2025	2.2											2.2															
12	Hodzent	2023	3.2									3.2																	
13	Buston	2024	3.3										3.3																
14	Proletarsk	2024	2.6										2.6																
15	Rogun 1	2019	5.1					2.6						2.6															
16	Rogun	2019	32.2					10.7						21.5															
17	Rogun	2026	0.6												0.6														
18	Dushanbe	2019	14.6					7.3						7.3															
19	Dushanbe	2025	3.7											0.9			1.9					0.9							
20	Novaya	2018	6.9				2.3							2.3													2.3		
21	Novaya	2018	1.6				0.5										0.5										0.5		
22	Zavodskaya	2025	11.5											7.7			3.8												
23	Zavodskaya	2025	2.8											2.3			0.6												
24	Jangal	2018	5.9				3.0																			3.0			
25	Jangal	2018	2.3				0.6					0.6						0.6								0.6			
26	Geran	2018	7.1				5.9					1.2																	
27	Geran 110	2023	1.1									1.1																	
28	Ordzh-abad`	2018	10.4				5.2									2.6								2.6					
29	Ordzh-abad`	2018	0.6				0.2									0.4													
30	Severnaya	2023	1.2									0.6						0.6											
31	Nurekskaya New generating statior	2028	5.5														5.5												
32	Nurekskaya N	2028	0.9														0.3					0.6							
33	Prydilnaya	2019	0.6					0.6																					
34	Kurgan-tube	2019	1.7					1.7																					
35	Khatlon	2019	6.1					2.0									4.1												
36	Khatlon	2019	2.2					1.1									1.1												
37	Bohtar	2027	2.2													2.2													
38	Sangtuda	2018	19.9				5.0							14.9															
39	Sangtuda	2018	1.0				1.0																						
40	Gissar	2029	1.4															1.4											
41	Dangana	2027	0.5													0.5													
42	Somoni	2027	0.5													0.5													
43	Lolazar	2025	10.8											10.8															
44	Lolazar	2025	0.9											0.9															
45	Bahoriston	2018	0.9				0.9																						
	Capacitors		22.4				6.2		9.1					1.1					1.7					1.5				2.8	
	Subtotal		**247.3**	**0.0**	**0.0**	**0.0**	**45.1**	**56.1**	**9.1**	**0.0**	**0.0**	**6.7**	**5.9**	**74.4**	**0.6**	**6.2**	**17.8**	**2.6**	**1.7**	**0.0**	**0.0**	**1.6**	**0.0**	**9.4**	**0.0**	**3.5**	**3.8**	**2.8**	**0.0**
	Total (G+T+S)		**9,233.3**	**103.0**	**420.4**	**732.1**	**1,017.0**	**962.9**	**808.7**	**780.2**	**759.5**	**524.7**	**485.2**	**540.0**	**420.0**	**256.4**	**99.4**	**11.4**	**66.4**	**131.9**	**292.0**	**254.2**	**123.2**	**204.6**	**71.7**	**89.5**	**76.3**	**2.8**	**0.0**

Table 8-5: Financial Investment Requirements – Expansion Plan Without Rogun

Generation Projects

Project Name	Online Year	Capital Cost	Capital Disbursement in Year 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Energy Efficiency	2015	66.4		7.8	17.2	15.3	15.7	10.4																				
CHP 150 MW	2016	197.7	57.6	79.1	61.1																							
CHP 150 MW	2016	197.7	57.6	79.1	61.1																							
Coal 150 MW	2019	220.2			64.1	88.0	68.0																					
Coal 150 MW	2019	220.2			64.1	88.0	68.0																					
Coal 350 MW	2019	484.6		92.4	119.0	147.0	126.2																					
Coal 350 MW	2020	499.2			95.2	122.5	151.5	130.0																				
Coal 350 MW	2021	514.1				98.0	126.2	156.0	133.9																			
Decommissioning Rogun	2021	227.1				54.3	55.9	57.6	59.3																			
Solar 10 MW	2021	24.0						14.2	9.8																			
Wind 10 MW	2021	20.0						11.9	8.2																			
Solar 10 MW	2022	24.7							14.7	10.1																		
Nurek-2 100 MW	2022	201.7						58.7	80.7	62.3																		
Solar 10 MW	2023	25.5								15.1	10.4																	
Sanobad 125 MW	2023	390.4						74.5	96.0	138.4	81.5																	
Solar 10 MW	2024	26.2									15.6	10.7																
Coal 350 MW	2025	578.7								110.3	142.1	175.6	150.7															
Solar 10 MW	2025	27.0										16.0	11.0															
Wind 10 MW	2025	22.6										13.4	9.2															
Coal 350 MW	2029	651.3												124.2	159.9	197.6	169.6											
Coal 350 MW	2031	691.0														131.7	169.6	209.7	180.0									
Coal 350 MW	2034	755.0																	144.0	185.3	229.1	196.6						
Flood Protection Control	2034	1,876.0																	448.4	461.9	475.7	490.0						
Coal 350 MW	2036	801.0																			152.7	196.6	243.0	208.6				
Coal 350 MW	2038	607.0																					115.7	149.0	184.2	158.1		
total		**9,349.5**	**115.2**	**258.4**	**481.7**	**613.2**	**611.5**	**513.4**	**402.5**	**336.2**	**249.4**	**215.7**	**170.9**	**124.2**	**159.9**	**329.4**	**339.2**	**209.7**	**772.3**	**647.2**	**857.5**	**883.3**	**358.8**	**357.6**	**184.2**	**158.1**	**0.0**	**0.0**

(Table 8-5 Continued)

Transmission Lines

Project		Online	Capital	Capital Disbursement in Year																									
No.	Name	Year	Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
1	Dushanbe TO FonYagnob	2019	137.2				67.6	69.6																					
2	Sughd TO Fon Yagnob	2019	99.1				48.8	50.3																					
3	Kayrakkum TO Shurob	2019	6.1					6.1																					
4	Kanibadam TO Shurob	2019	6.1					6.1																					
5	Kayrakkum TO Leninabad	2018	6.0				6.0																						
6	Sughd TO Leninabad	2018	14.9				14.9																						
7	Bahoriston TO Ayni	2018	29.3			14.5	14.9																						
8	Ayni TO Rudaki	2018	26.8				26.8																						
9	Buston TO Zavodskaya 110 kV	2020	1.5						1.5																				
10	Kurgan-Tube TO Pryadilnaya	2020	0.4						0.4																				
11	Chapaeva TO Kurgan-Tube	2020	5.0						5.0																				
12	Dushanbe TO Lolazar	2025	78.5											78.5															
13	Lolazar TO Sangtuda	2025	18.5											18.5															
14	Dushanbae TO Zavodskaya	2025	7.3											7.3															
15	Khatlon TO Sanobad	2023	85.0								41.9	43.1																	
16	Kayrakkum TO Shurob	2025	39.2											39.2															
17	Novaya TO Dushanbe	2025	9.2											9.2															
18	Nurek New TO Nurek	2022	8.4								8.4																		
19	Buston TO Zavodskaya	2025	1.7											1.7															
20	Dehmoy TO Khujand	2025	3.6											3.6															
21	Jangal TO Severnaya	2023	6.8									6.8																	
22	Proletarsk TO Dehmoy	2023	3.2									3.2																	
23	Dushanbe TO Zavodskaya	2028	10.7														10.7												
24	Bohtar TO Dagana	2027	4.6													4.6													
25	Bohtar TO Somoni	2027	0.9													0.9													
26	Gissar TO Hissar Stl	2029	3.7															3.7											
27	Jangal TO Hissar Stl	2029	4.5															4.5											
28	Novaya TO Severnaya	2029	2.4															2.4											
29	Nurekg2 TO Ordzh- Abad	2035	23.2																					23.2					
30	Ayni TO Ziddy	2038	2.7																								2.7		
31	Rudaki TO Ziddy	2038	2.7																								2.7		
	LINES UPGRADE		26.3				7.5	1.9	3.4				2.2					4.2					5.4				1.8		
Subtotal			**675.6**	**0.0**	**0.0**	**14.5**	**186.4**	**134.1**	**10.2**	**0.0**	**50.3**	**53.2**	**2.2**	**158.0**	**0.0**	**5.5**	**10.7**	**14.9**	**0.0**	**0.0**	**0.0**	**0.0**	**5.4**	**23.2**	**0.0**	**0.0**	**7.2**	**0.0**	**0.0**

(Table 8-5 Continued)

Substations

Project		Online	Capital	Capital Disbursement in Year																									
No.	Name	Year	Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
1	Shurab generating station	0	11.8					3.9						7.8															
2	Kaiyrakum	0	7.5					2.7						4.8															
3	Kanibadom	0	8.8					3.3																		5.5			
4	Fon Yagnob generating station	0	51.3					12.6										8.5					19.7		10.4				
5	Ayni	0	3.9						1.7									2.2											
6	Ziddy	0	9.4																								9.4		
7	Rudaki	0	2.2				2.2																						
8	Sugdh	0	6.2					6.2																					
9	Sugdh	0	2.7					2.7																					
10	Leninbad 220	0	10.9				10.9																						
11	Leninbad	0	1.1				1.1																						
12	Dehmoy	0	3.4											3.4															
13	Hodzent	0	4.6									4.6																	
14	Buston	0	4.8										4.8																
15	Proletarsk	0	3.8										3.8																
16	Dushanbe	0	19.7					8.3						10.0								1.4							
17	Dushanbe	0	6.3											1.4			3.1					1.8							
18	Novaya	0	11.3				2.8							3.4													5.1		
19	Novaya	0	2.7				0.6										0.9										1.2		
20	Zavodskaya	0	17.8											11.5			6.3												
21	Zavodskaya	0	4.4											3.4			0.9												
22	Jangal	0	9.9				3.6																			6.3			
23	Jangal	0	3.8				0.7					0.8						1.0								1.2			
24	Geran	0	8.9				7.2						1.7																
25	Geran110	0	1.6									1.6																	
26	Ordzh-abad`	0	15.8				6.4									4.2								5.3					
27	Ordzh-abad`	0	0.8				0.2									0.6													
28	Severnaya	0	1.8									0.8						1.0											
29	Nurekskaya generating station	0	7.5								7.5																		
30	Nurek	0	1.6								0.4											1.2							
31	Prydilnaya	0	0.7					0.7																					
32	Kurgan-tube	0	2.1					2.1																					
33	Rogun	0	5.2																			5.2							
34	Rogun110	0	1.1																			1.1							
35	Khatlon	0	8.8					2.6				2.9					3.4												
36	Khatlon	0	3.2					1.4									1.8												
37	Bohtar	0	3.5													3.5													
38	Sangtuda	0	28.4				6.1							22.4															
39	Sangtuda	0	1.2				1.2																						
40	Gissar	0	2.4															2.4											
41	Dangana	0	0.8													0.8													
42	Somoni	0	0.8													0.8													
43	Lolazar	0	16.2											16.2															
44	Bahoriston	0	1.2					1.2																					
45	Lolazar	0	1.4											1.4															
	Capacitors		39.0				8.7		12.4					2.4					3.8					4.1				7.5	
Subtotal			**362.2**	**0.0**	**0.0**	**0.0**	**51.7**	**47.7**	**14.1**	**0.0**	**8.0**	**10.7**	**10.3**	**88.1**	**0.0**	**9.9**	**16.4**	**15.1**	**3.8**	**0.0**	**0.0**	**10.6**	**19.7**	**9.4**	**10.4**	**13.1**	**15.6**	**7.5**	**0.0**
Total			**10,387.3**	**115.2**	**258.4**	**496.2**	**851.4**	**793.3**	**537.7**	**402.5**	**394.5**	**313.3**	**228.2**	**417.0**	**124.2**	**175.3**	**356.4**	**369.2**	**213.4**	**772.3**	**647.2**	**868.2**	**908.4**	**391.3**	**368.1**	**197.3**	**180.9**	**7.5**	**0.0**

Table 8-6: Financial Investment Requirements – Expansion Plan With Rogun

Generation Projects

No.	Project Name	Online Year	Capital Cost	Capital Disbursement in Year 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
1	Energy Efficiency	2015	66.4		7.8	17.2	15.3	15.7	10.4																				
2	CHP 150 MW	2016	197.7	57.6	79.1	61.1																							
3	CHP 150 MW	2016	197.7	57.6	79.1	61.1																							
4	Coal 150 MW	2019	220.2			64.1	88.0	68.0																					
5	Coal 150 MW	2019	220.2			64.1	88.0	68.0																					
6	Coal 350 MW	2019	484.6		92.4	119.0	147.0	126.2																					
7	Coal 350 MW	2020	499.2			95.2	122.5	151.5	130.0																				
8	Coal 350 MW	2021	514.1				98.0	126.2	156.0	133.9																			
9	Solar 10 MW	2021	24.0						14.2	9.8																			
10	Wind 10 MW	2021	20.0						11.9	8.2																			
11	Solar 10 MW	2022	24.7							14.7	10.1																		
12	Nurek-2 100 MW	2022	201.7						58.7	80.7	62.3																		
13	Solar 10 MW	2023	25.5								15.1	10.4																	
14	Sanobad 125 MW	2023	390.4						74.5	96.0	138.4	81.5																	
15	Solar 10 MW	2024	26.2									15.6	10.7																
16	Rogun 2x400 MW and 4x600 MW	2025	7,544.4						119.4	327.6	482.2	669.1	858.1	1005.1	1016.3	694.6	607.1	590.5	649.2	233.7	164.4	127.0							
17	Solar 10 MW	2025	27.0										16.0	11.0															
18	Wind 10 MW	2025	22.6										13.4	9.2															
19	Coal 350 MW	2038	607.0																					115.7	149.0	184.2	158.1		
Subtotal			**11,313.8**	**115.2**	**258.4**	**481.7**	**559.0**	**555.6**	**575.2**	**670.7**	**708.1**	**776.5**	**898.2**	**1025.3**	**1016.3**	**694.6**	**607.1**	**590.5**	**649.2**	**233.7**	**164.4**	**127.0**	**0.0**	**115.7**	**149.0**	**184.2**	**158.1**	**0.0**	**0.0**

(Table 8-6 Continued)

Transmission Lines

Project		Online	Capital	Capital Disbursement in Year																									
No.	Name	Year	Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
1	Dushanbe TO Fon-Yagnob	2019	137.2				67.6	69.6																					
2	Fon-Yagnob TO Sughd	2019	99.1				48.8	50.3																					
3	Kayrakkum TO Leninabad	2019	6.1					6.1																					
4	Kanibadom TO Shurob	2019	6.1					6.1																					
5	Kayrakkum TO Shurob	2018	6.0				6.0																						
6	Sughd TO Leninabad	2018	14.9				14.9																						
7	Bahoriston TO Ayni	2018	29.3			14.5	14.9																						
8	Ayni TO Rudaki	2018	26.8				26.8																						
9	Buston TO Zavodskaya	2020	1.5						1.5																				
10	Kurgan-Tube TO Pryadilnaya	2020	0.4						0.4																				
11	Ochapaeva TO Kurgan-Tube	2020	5.0						5.0																				
12	Rogung TO Dushanbe	2025	150.4										74.1	76.3															
13	Rogun TO Lolazar 500kV	2025	91.0										44.8	46.2															
14	Lolazar TO Sangtuda	2025	18.5											18.5															
15	Kayrakkum TO Shurob	2021	34.8							34.8																			
16	Dushanbe TO Novaya	2025	9.2											9.2															
17	Dushanbe TO Zavodskaya	2025	7.3											7.3															
18	Rogun TO Rogun	2025	2.5											2.5															
19	Bustn2 TO Zavodskaya	2025	1.7											1.7															
20	Jangal TO Severnaya	2023	6.8									6.8																	
21	Dehmoy TO Khujand	2025	3.6											3.6															
22	Proletarsk TO Dehmoy	2023	3.2									3.2																	
23	Nurek New TO Nurek	2022	8.4								8.4																		
24	Khatlon TO Sanobad	2021	80.1						39.5	40.7																			
25	Dushanbe TO Zavodskaya	2028	10.7														10.7												
26	Bohtar TO Dagana	2027	4.6													4.6													
27	Bohtar TO Somoni	2027	0.9													0.9													
28	Jangal* TO Hissar Stl	2029	4.5															4.5											
29	Gissar* TO Hissar Stl	2029	3.7															3.7											
30	Novaya TO Severnaya	2029	2.4															2.4											
31	Nurekg TO Ordzh- Abad	2035	23.2																					23.2					
	LINES UPGRADE		26.3				7.5	1.9	3.4				2.2					4.2					5.4				1.8		
Subtotal			**826.4**	**0.0**	**0.0**	**14.5**	**186.4**	**134.1**	**49.7**	**75.5**	**8.4**	**10.0**	**121.1**	**165.3**	**0.0**	**5.5**	**10.7**	**14.9**	**0.0**	**0.0**	**0.0**	**0.0**	**5.4**	**23.2**	**0.0**	**0.0**	**1.8**	**0.0**	**0.0**

(Table 8-6 Continued)

Substations

Project		Online	Capital	Capital Disbursement in Year																									
No.	Name	Year	Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
1	Shurab generating station	2019	11.2					5.0		4.0																	2.2		
2	Kaiyrakum	2019	7.2					4.2		3.0																			
3	Kanibadom	2019	3.6					3.6																					
4	Fon Yagnob generating station	2019	16.4					16.4																					
5	Ayni	2018	3.4				3.4																						
6	Rudaki	2018	2.2				2.2																						
7	Sugdh	2019	6.2					6.2																					
8	Sugdh	2019	2.6					2.6																					
9	Leninbad 220	2018	10.9				10.9																						
10	Leninbad	2018	1.1				1.1																						
11	Dehmoy	2025	3.4											3.4															
12	Hodzent	2023	4.6									4.6																	
13	Buston	2024	4.8										4.8																
14	Proletarsk	2024	3.8										3.8																
15	Rogun 1	2025	8.1											3.9			4.2												
16	Rogun	2025	51.4											16.1			35.2												
17	Rogun	2028	0.9														0.9												
18	Dushanbe	2019	20.1					9.2						10.9															
19	Dushanbe	2025	6.3											1.4			3.1					1.8							
20	Novaya	2018	11.3				2.8							3.4													5.1		
21	Novaya	2018	2.7				0.6										0.9										1.2		
22	Zavodskaya	2025	17.8											11.5			6.3												
23	Zavodskaya	2025	4.4											3.4			0.9												
24	Jangal	2018	10.1				3.6																				6.5		
25	Jangal	2018	3.8				0.7						0.9					1.0									1.3		
26	Geran	2020	9.3						7.7			1.7																	
27	Geran 110	2023	1.6									1.6																	
28	Ordzh-abad`	2018	15.8				6.4									4.2								5.3					
29	Ordzh-abad`	2018	0.9				0.2											0.6											
30	Severnaya	2023	1.8									0.8				0.9													
31	Nurekskaya New generating statio	2022	7.5								7.5																		
32	Nurekskaya N	2022	1.6								0.4											1.2							
33	Prydilnaya	2019	0.7					0.7																					
34	Kurgan-tube	2019	2.1					2.1																					
35	Khatlon	2019	8.8					2.6				2.9					3.4												
36	Khatlon	2019	3.2					1.4									1.8												
37	Bohtar	2027	3.5													3.5													
38	Sangtuda	2018	28.4				6.1							22.4															
39	Sangtuda	2018	1.2				1.2																						
40	Gissar	2029	2.4															2.4											
41	Dangana	2027	0.8													0.8													
42	Somoni	2027	0.8													0.8													
43	Lolazar	2025	16.2											16.2															
44	Lolazar	2025	1.4											1.4															
45	Bahoriston	2018	1.1				1.1																						
	Capacitors		33.4				7.5		11.8					1.7					2.9					3.1				6.4	
Subtotal			**360.6**	**0.0**	**0.0**	**0.0**	**47.9**	**53.9**	**19.5**	**7.0**	**8.0**	**11.5**	**9.5**	**95.7**	**0.0**	**10.3**	**56.7**	**4.0**	**2.9**	**0.0**	**0.0**	**3.0**	**0.0**	**8.4**	**0.0**	**0.0**	**16.2**	**6.4**	**0.0**
Total			**12,500.8**	**115.2**	**258.4**	**496.2**	**793.2**	**743.6**	**644.4**	**753.2**	**724.4**	**798.1**	**1028.8**	**1286.2**	**1016.3**	**710.4**	**674.6**	**609.4**	**652.2**	**233.7**	**164.4**	**130.0**	**5.4**	**147.3**	**149.0**	**184.2**	**176.1**	**6.4**	**0.0**

Table 8-7: Financial Investment Requirements – Expansion Plan with Early Rogun

Generation Projects

Project		Online	Capital	Capital Disbursement in Year																									
No.	Name	Year	Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
1	Energy Efficiency	2015	66.4		7.8	17.2	15.3	15.7	10.4																				
2	CHP 150 MW	2016	197.7	57.6	79.1	61.1																							
3	CHP 150 MW	2016	197.7	57.6	79.1	61.1																							
4	Coal 150 MW	2019	220.2			64.1	88.0	68.0																					
5	Coal 150 MW	2019	220.2			64.1	88.0	68.0																					
6	Coal 350 MW	2019	484.6		92.4	119.0	147.0	126.2																					
7	Rogun 2x400 MW and 4x600 MW	2019	6,684.3		200.6	330.7	430.0	449.0	761.0	893.0	902.9	617.1	539.4	524.6	576.8	349.5	109.6												
8	Coal 350 MW	2020	499.2			95.2	122.5	151.5	130.0																				
9	Solar 10 MW	2021	24.0						14.2	9.8																			
10	Wind 10 MW	2021	20.0						11.9	8.2																			
11	Solar 10 MW	2022	24.7							14.7	10.1																		
12	Solar 10 MW	2023	25.5								15.1	10.4																	
13	Solar 10 MW	2024	26.2									15.6	10.7																
14	Solar 10 MW	2025	27.0										16.0	11.0															
15	Wind 10 MW	2025	22.6										13.4	9.2															
16	Nurek-2 100 MW	2033	279.3																	81.3	111.7	86.3							
17	Sanobad 125 MW	2033	524.7																100.2	129.0	186.0	109.5							
18	Coal 350 MW	2035	777.7																		148.3	190.9	236.0	202.5					
19	Coal 350 MW	2038	607.0																					115.7	149.0	184.2	158.1		
Subtotal			**10,929.0**	**115.2**	**459.0**	**812.4**	**890.9**	**878.4**	**927.5**	**925.6**	**928.1**	**643.1**	**579.5**	**544.8**	**576.8**	**349.5**	**109.6**	**0.0**	**100.2**	**210.3**	**446.0**	**386.7**	**236.0**	**318.3**	**149.0**	**184.2**	**158.1**	**0.0**	**0.0**

(Table 8-7 Continued)

Transmission Lines

Project		Online	Capital	Capital Disbursement in Year																									
No.	Name	Year	Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
1	Dushanbe TO Fon-Yagnob	2019	137.2				67.6	69.6																					
2	Fon-Yagnob TO Sughd	2019	99.1				48.8	50.3																					
3	Rogung TO Dushanbe	2019	126.0				62.1	63.9																					
5	Kanibadom TO Shurob	2019	6.1					6.1																					
6	Kayrakkum TO Shurob	2019	6.1					6.1																					
8	Bahoriston TO Ayni	2018	29.3			14.5	14.9																						
9	Ayni TO Rudaki	2018	26.8				26.8																						
10	Rogun TO Rogun	2019	2.1					2.1																					
11	Buston 110kV TO Zavodskaya	2020	1.5						1.5																				
12	Kurgan-Tube TO Pryadilnaya	2020	0.4						0.4																				
13	Ochapaeva TO Kurgan-Tube	2020	5.0						5.0																				
14	Rogun TO Lolazar	2025	91.0										44.8	46.2															
15	Lolazar TO Sangtuda	2025	18.5											18.5															
16	Dushanbe TO Novaya	2025	9.2											9.2															
18	Buston TO Zavodskaya	2025	1.7											1.7															
20	Dehmoy TO Khujand	2025	3.6											3.6															
21	Proletarsk TO Dehmoy	2023	3.2									3.2																	
22	Dushanbe TO Zavodskaya	2028	10.7														10.7												
23	Bohtar TO Dagana	2027	4.6													4.6													
24	Bohtar TO Somoni	2027	0.9													0.9													
26	Gissar* TO Hissar Stl	2029	3.7															3.7											
27	Novaya TO Severnaya	2029	2.4															2.4											
28	Kayrakkum TO Shurob	2035	52.7																					52.7					
29	Nurek New TO Nurek	2033	11.6																			11.6							
30	Khatlon TO Sanobad	2033	114.3																		56.3	58.0							
31	Nurekg TO Ordzh- Abad	2035	23.2																					23.2					
	LINES UPGRADE		26.3				7.5	1.9	3.4				2.2					4.2					5.4				1.8		
Subtotal			**856.9**	**0.0**	**0.0**	**14.5**	**242.5**	**206.2**	**10.2**	**0.0**	**0.0**	**10.0**	**47.0**	**86.5**	**0.0**	**5.5**	**10.7**	**14.9**	**0.0**	**0.0**	**56.3**	**69.6**	**5.4**	**75.9**	**0.0**	**0.0**	**1.8**	**0.0**	**0.0**

(Table 8-7 Continued)

Substations

Project		Online	Capital	Capital Disbursement in Year																									
No.	Name	Year	Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
1	Shurab generating station	2019	13.2					5.0																6.0			2.2		
2	Kaiyrakum	2019	8.7					4.2																4.5					
3	Kanibadom	2019	3.6					3.6																					
4	Fon Yagnob generating station	2019	16.4					16.4																					
5	Ayni	2018	3.4				3.4																						
6	Rudaki	2018	2.2				2.2																						
7	Sugdh	2019	6.2					6.2																					
8	Sugdh	2019	2.6					2.6																					
9	Leninbad 220	2018	10.9				10.9																						
10	Leninbad	2018	1.1				1.1																						
11	Dehmoy	2025	3.4											3.4															
12	Hodzent	2023	4.6									4.6																	
13	Buston	2024	4.8										4.8																
14	Proletarsk	2024	3.8										3.8																
15	Rogun 1	2019	7.1					3.2						3.9															
16	Rogun	2019	45.8					13.5						32.3															
17	Rogun	2026	0.9												0.9														
18	Dushanbe	2019	20.1					9.2						10.9															
19	Dushanbe	2025	6.3											1.4			3.1					1.8							
20	Novaya	2018	11.3				2.8							3.4													5.1		
21	Novaya	2018	2.7				0.6										0.9										1.2		
22	Zavodskaya	2025	17.8											11.5			6.3												
23	Zavodskaya	2025	4.4											3.4			0.9												
24	Jangal	2018	9.9				3.6																			6.3			
25	Jangal	2018	3.8				0.7					0.8						1.0								1.2			
26	Geran	2018	8.9				7.2					1.7																	
27	Geran 110	2023	1.6									1.6																	
28	Ordzh-abad`	2018	15.8				6.4									4.2								5.3					
29	Ordzh-abad`	2018	0.8				0.2									0.6													
30	Severnaya	2023	1.8									0.8						1.0											
31	Nurekskaya New generating statio	2028	9.0														9.0												
32	Nurekskaya N	2028	1.7														0.5					1.2							
33	Prydilnaya	2019	0.7					0.7																					
34	Kurgan-tube	2019	2.1					2.1																					
35	Khatlon	2019	9.3					2.6									6.7												
36	Khatlon	2019	3.2					1.4									1.8												
37	Bohtar	2027	3.5													3.5													
38	Sangtuda	2018	28.4				6.1							22.4															
39	Sangtuda	2018	1.2				1.2																						
40	Gissar	2029	2.4															2.4											
41	Dangana	2027	0.8													0.8													
42	Somoni	2027	0.8													0.8													
43	Lolazar	2025	16.2											16.2															
44	Lolazar	2025	1.4											1.4															
45	Bahoriston	2018	1.1				1.1																						
	Capacitors		33.4				7.5		11.8					1.7					2.9					3.1				6.4	
Subtotal			**358.9**	**0.0**	**0.0**	**0.0**	**55.1**	**70.6**	**11.8**	**0.0**	**0.0**	**9.5**	**8.6**	**111.8**	**0.9**	**9.9**	**29.2**	**4.4**	**2.9**	**0.0**	**0.0**	**3.0**	**0.0**	**18.9**	**0.0**	**7.6**	**8.4**	**6.4**	**0.0**
Total			**12,144.8**	**115.2**	**459.0**	**826.8**	**1188.5**	**1155.2**	**949.5**	**925.6**	**928.1**	**662.6**	**635.2**	**743.1**	**577.7**	**364.9**	**149.5**	**19.3**	**103.1**	**210.3**	**502.2**	**459.2**	**241.4**	**413.0**	**149.0**	**191.7**	**168.3**	**6.4**	**0.0**

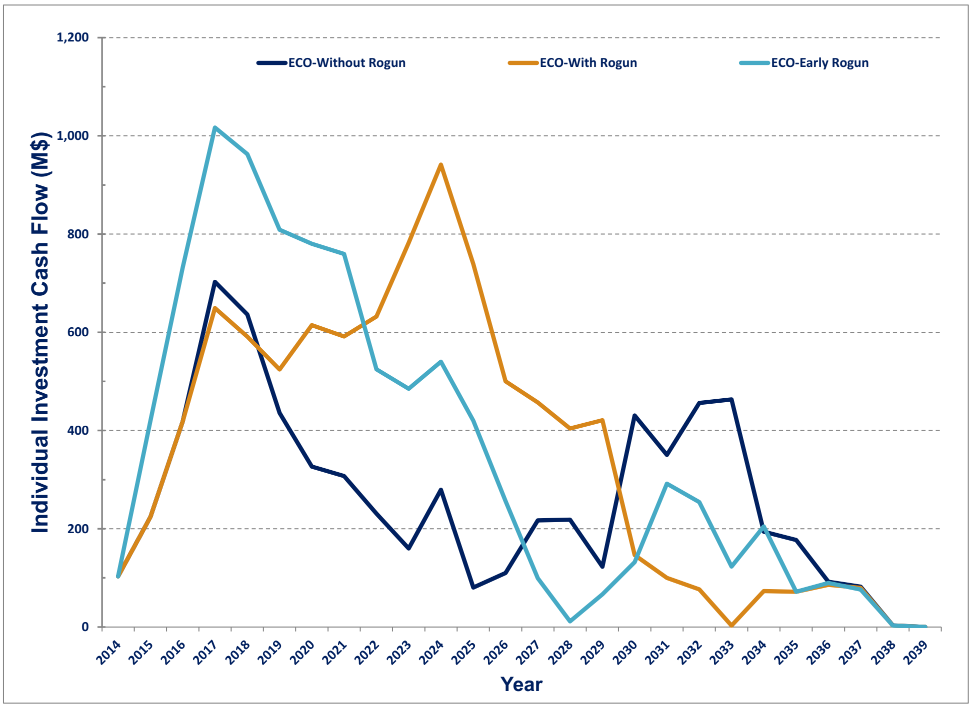

Figure 8-1: Comparison of Annual Economic Capital Requirement

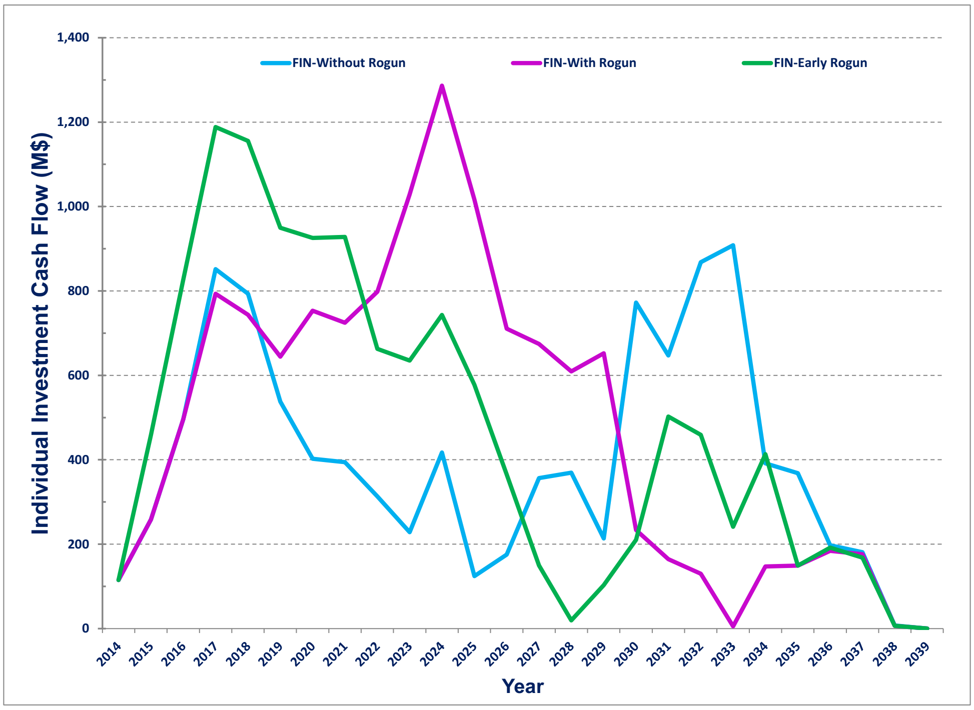

Figure 8-2: Comparison of Annual Financial Capital Requirements

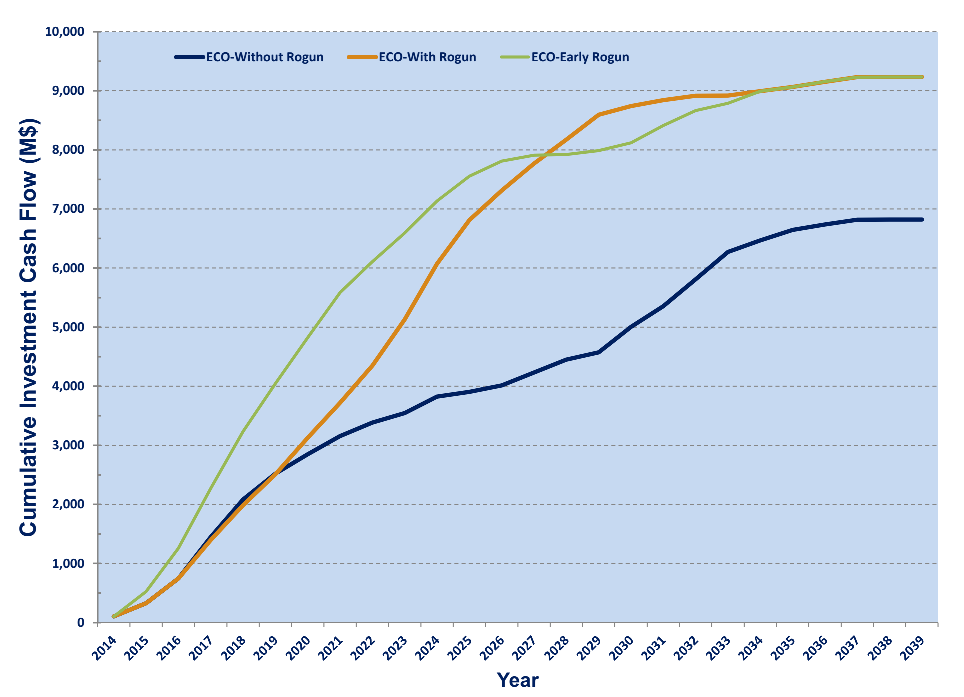

Figure 8-3: Cumulative Economic Capital Requirements

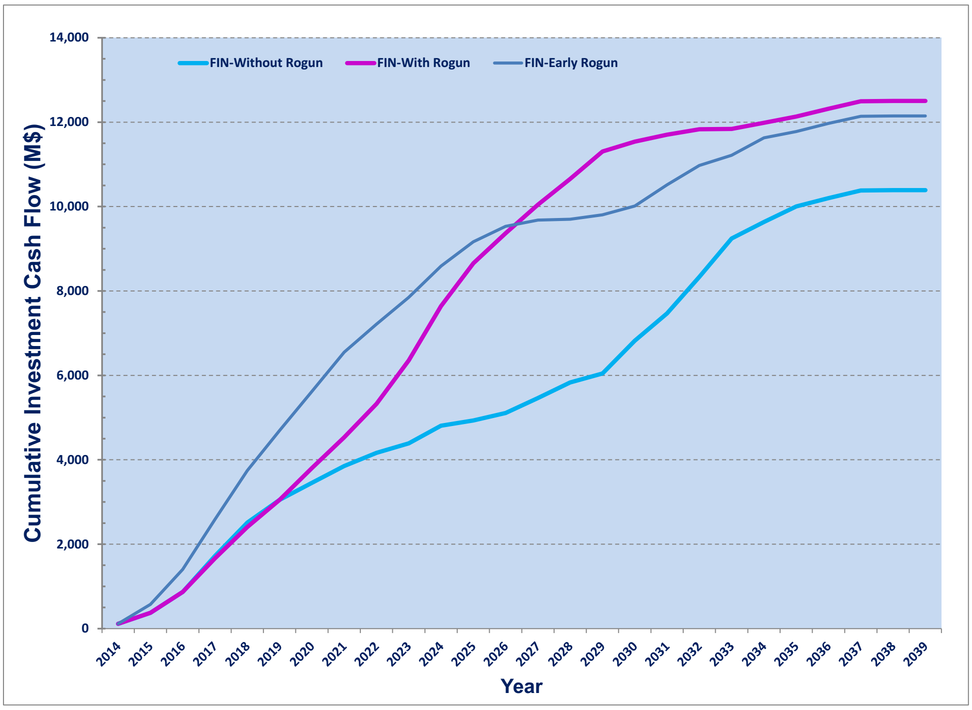

Figure 8-4: Cumulative Financial Capital Requirements

9. KEY FINDINGS

The main findings arising from the work carried out and reported in the previous sections can be summarized as:

- In Tajikistan, the Ministry of Energy and Water Resources (MoEWR) is responsible for the entire energy sector, which comprises the electricity sector as well as oil and gas. The MoEWR is responsible for the energy policy and the development of standards
- The power sector in Tajikistan is dominated by Barki Tojik (BT) which is responsible for most generation, transmission and generation. The electricity customers for the Gorno Badakhshan autonomous region are supplied by Pamir Energy
- Regulation of the energy sector is the responsibility of the Antimonopoly Service (AMS) under the Government of the Republic of Tajikistan. The AMS is responsible for the tariff methodology, tariff level proposals, service quality, consumer complaints and anti-competitive behavior. MoEWR is responsible for licensing, approval of investment plans and technical and safety standards.
- The total installed capacity in the BT grid amounts to 5,346 MW. The hydro capacity amounts to 4,928 MW (92%). There are two build, own, operate and transfer (BOOT) hydro plants (Sangtuda 1 and 2) with a total installation of 990 MW and three CHP plants
- The currently available capacity is 4,785 MW. The study considered that all existing hydro plants would be refurbished by 2020 thus increasing the available capacity to 5,269 MW
- On average, the hydro plants can generate a total of 19,492 GWh per year (45% capacity factor) but the generation is greatly reduced over the late autumn/winter period due to reduced hydrological flows thus seriously affecting the system's capability to meet the demand
- While a few units have gone through rehabilitation, most of the BT hydro plants are over 30 years old and in need of rehabilitation. There are plans to rehabilitate several of the existing HPPs including Nurek, Golovnaya and Kayrakkum
- BT has two power purchase agreements (PPAs) with Afghanistan and one with Kyrgyzstan for 600 GWh which is renewed on an annual basis. All other PPAs have been terminated. The contracted energy is 1,007.6 GWh per year with a minimum guaranteed energy of 650.8 GWh to be delivered between April and October. For the CASA 1000 project, Tajikistan and Kyrgyzstan are expected to start exports to Pakistan in 2019. The Tajikistan's share of the firm exports amounts to 1,331.5 GWh per year but additional quantities may be exported if available (up to 4,000 GWh)
- Over the last years there has been a significant amount of unmet or unserved /unsupplied energy with several studies stating the estimated amount of unsupplied energy and these ranges from 2,650 GWh to 3,789 GWh per season (October to the end of March). Available information from BT and an UNDP report on Sustainable Energy provide values for unsupplied energy ranging from 2,139 to 2,430 GWh. The present study assumes an annual unmet demand of 2,430 GWh
- TALCO is the largest consumer of electricity in Tajikistan accounting for a large portion of total electricity consumption. TALCO's demand has varied from 5,360 GWh to 7,229 GWh per year representing 40% to 50% of the total demand. For the present study it is assumed that a value of the order of 6,500 GWh could be more representative of TALCO's future demand
- The BT's grid system consists of transmission lines at three different voltage levels, 500 kV, 220 kV and 110 kV. At present, it includes approximately 489 km of 500 kV lines, 1,960 km of 220 kV lines and 4,327 km of 110 kV lines. The 500 kV transmission lines include a double circuit between the Nurek HPP and Regar substation, a single circuit between the Regar and Dushanbe substations as well as a single circuit between the Dushanbe and the Sughd substations
- The BT's grid system used to be interconnected to the Uzbek network at 500 kV and 220 kV. Presently, there are only three main interconnections between Tajikistan and other systems: a 220 kV, 53 km long, transmission line that connects the Kanibadan substation in Tajikistan to the Aigul-Tash 220 kV substation in Kyrgyzstan, a 220 kV double-circuit transmission line between Geran-2 SS (Tajikistan) and Pul-e-Khumri (Afghanistan) and a 110 kV, 63 km long single circuit line from Tajikistan to Kunduz in Afghanistan. There is also a connection from the Geran 230/110/35 kV substation and the 35/10 kV Lower Pyanj substation

- In addition, the CASA 1000 interconnection is expected to be in service by early 2021 and requires the construction of a 500 kV transmission line from Kyrgyzstan to the Sughd 500 kV substation (477 km), the construction of a 1300 MW DC converter station at Sangtuda area and an HVDC transmission line ± 500 kV from Sangtuda area to Pakistan (800 km) with a 1,300 MW capability.
- Currently there are several regional interconnection projects under consideration. For the present study the construction of a transmission line to Pakistan from the Rogun substation in Tajikistan to the Peshawar substation in Pakistan either at 500 kV AC or 500 kV DC and the construction of a 550 km, 500 kV transmission line to Xinjiang Uyghur Autonomous Region on China are considered.
- The electrical demand in Tajikistan is of the order or 4,100 MW and 21,000 GWh
- By the end of the study period, 2039, under the medium growth demand, the system demand is expected to increase to close to 7,475 MW and 40,600 GWh (62% load factor). This represents an average load growth of 2.45% for both capacity and energy
- The capacity and energy balance studies carried out indicates that the system has the capability to meet the peak demand but lacks energy capability to meet the winter energy requirements. In order to eliminate the expected unsupplied energy, new base load generation of the order of 500 MW or more (in addition to the committed projects) would need to be commissioned
- Tajikistan possesses vast amounts of hydropower resources that could be developed to generate electrical energy but only a limited amount is being used. The country's hydropower resources are in the order of 527 TWh per year, of which only 4% is currently being used
- For the selected alternative in the TEAS for Rogun (1,290 MASL and 3,200 MW) it is assumed that the capital cost to complete the Rogun hydroelectric power plant would be of the order of US$ 5,500 million to be disbursed over 14 years. The total capital cost of US$ 5,500 million is an overnight capital cost and includes owner's costs, financial charges (excluding interest) and decommissioning costs
- Recognizing that work has been on-going at the Rogun site for many years it is assumedthat the first two units at Rogun could be in service by mid 2019 with the next two units to be commissioned by January 2023 and the last two units by July 2023. As an alternative to the dates identified in the TEAS, it was decided to consider this alternative in-service date for Rogun and thus denominate it as Early Rogun Generation
- Six other hydro projects for which studies were made available were considered in the study as candidate generation resources. However, some of the studies lacked detailed capital cost estimates and some of the values had to be assumed
- There are many other hydroelectric power plants projects in Tajikistan but specific studies for these were not made available. These may include potentially important candidate projects which could be developed to form a part of the future development plan. A ranking of their potential should be carried out in order to define priorities for the preparation of detailed feasibility studies of the most likely options
- In addition to the hydro power reserves, Tajikistan also has large amounts of explored and proven coal reserves which could be used to develop coal fired power generation projects. Although the nation has only limited oil and natural gas reserves, it might import fuel oils and natural gas from other countries for power generation
- Several generation technologies based on the use of fossil fuels were analysed to meet the growing demand in Tajikistan and based on a screening approach, the selected generation resources included only 150 MW and 350 MW coal fired units and 150 MW and 300 MW combined cycle units using imported oil
- Other options include the long term power purchase/sale agreements with neighbouring countries for purchasing power during the winter season and selling surplus power during the summer season and in addition to these options, other non-hydro renewable resources as well as energy efficiency programs were considered
- In order to arrive at a least cost of supply, many generation expansion scenarios were developed, and analysed following three main themes:

- Theme 1 – considered the system demand with the EE programs and without Rogun
- Theme 2 – considered the system demand with the EE programs and with Rogun
- Theme 3 – considered the system demand with EE programs and with Early Rogun Generation

- The results of the Theme 1 scenarios indicated that that in the case of thermal unit additions only, the expansion scenarios with the 350 MW coal units resulted in lower costs than the ones with 150 MW coal units or 300 MW combined cycle units. The least cost generation expansion scenario under Theme 1 included 350 MW coal units and two hydro power plants
- Based on the results for the Theme 1 generation expansion scenarios it was decided to analyse only two generation expansion scenarios under Theme 2 and Theme 3 and these were to be the scenarios with the addition of only the 350 MW coal units (Scenario 1) and the one with the addition of 350 MW coal units and two HPPs (Scenario 7). At a discount rate of 10%, the cost difference between scenario 7 and scenario 1 amounted to $172 million and this is due to the fact that scenario 1 has a higher cost for fuel and O&M while scenario 7 has a higher cost for capital investment ($113 million)
- By comparing the CPV of the generation expansion scenarios for Theme 1 with and without the EE programs it is possible to determine the net benefits of these programs which under Scenario 1 amount to $217 million and those under Scenario 7 amount to $192 million
- Under Theme 3, generation expansion sequences were developed assuming that the Early Rogun Generation would be available by mid 2019 (from the two 400 MW units) with the remaining units being brought in service by January 2023 (2 x 600 MW units) and by July 2023 (another 2 x 600 MW units)
- The resulting CPV at the base discount rate (10%) for Themes 1, 2 and 3 is shown below. From the values shown it is clear that the generation expansion sequences considering the addition of the Rogun HPP are more economic that those without at the base discount rate of 10%

Theme	CPV ($, million)	
	Scenario 1	Scenario 7
1 – Without Rogun	6,811	6,639
2 – With Rogun	6,505	6,303
3 - Early Rogunt	6,322	6,256

- By comparing the CPV of the generation expansion scenarios under Theme 2 and Theme 3 with those of Theme 1, it is possible to determine the benefits or costs associated with Rogun. The resulting CPV of benefits at the base discount rate (10%) for the Theme 2 and Theme 3 is shown below. From the table it can be observed that the Early Rogun Generation sequence provide greater benefits than those of the With Rogun sequences

Theme	Benefits [1[CPV ($, million)	
	Scenario 1	Scenario 7
2 – Without Rogun	306	336
3- With Early Rogun	489	383

Note:[1] Relative to Theme 1 – Without Rogun

- The benefits for the With Rogun scenarios are of the order of 4 to 5% of the total scenario cost while the benefits for the Early Rogun scenarios are of the order of 6 to 7% of the total scenario cost. Both of these benefits may appear to be relatively small and this may be caused by several factors including a high discount rate, the omission of some benefits such as protection against the PMF, decommissioning cost of existing Rogun facilities, in the case of no Rogun, and lack of CO2 credits. However, all of these factors were considered in the analysis
- The analysis did not take into account the effects of decreased generation capability at Nurek due to sedimentation accumulation since this would occur outside the study period. However, since the decreased generation would likely occur so far into the future, once this is discounted at the base discount rate its value would be very small
- Cross comparison of the Theme 2 and Theme 3 results is relatively difficult since there is a difference in the cash disbursements for the Rogun HPP under the two themes which could skew the results obtained and influence the selection decision. The selected cash disbursements for the Early Rogun cases should be calculated with the same level of accuracy as those obtained from the TEAS for the studies undertaken for Rogun under Theme 2.
- For both Theme 2 and Theme 3, the generation expansion sequence developed under Scenario 7 produced an overall lower CPV and was thus selected to be brought forward to determine the transmission requirements
- The results of the sensitivity analysis to the high and low growth rates indicate that the generation expansion scenarios are not overly sensitive to demand growth with the high growth demand presenting an increased difference in the CPV between the cases without and with Rogun. In order for the generation expansion plan with Rogun to have the same CPV as the plan without Rogun, the following changes to individual parameters would be required

Parameter	Base	Break Even Change
Capital Cost (%)	0	20
Fuel Cost (%)	0	-40
Discount Rate (%)	10	11.5
Non-Firm Export Price ($/MWh)	40	<40

- Information for the transmission system was provided by BT. The data required to perform system dynamic response analysis for the BT system was not available and hence, dynamic studies were not carried out. The dynamic studies are normally a confirmatory analysis while the load flow analysis is the investigative part of the study. As such, this is not likely to have major impacts on the overall conclusions. However, BT is encouraged to perform confirmatory studies when dynamic data is available
- The results for the existing system studies showed low voltages during steady state operation with the need for additional shunt reactive power. Depending on the summer or the winter, the reactive power requirements vary. During the summer they are required in the northern region while in the winter these are required in the southern part of the country
- The transmission studies recommend the restringing of several transmission lines to increase their thermal limit in order to meet the increasing demand. In addition, several transformers are required to be added so as for the system to meet the N-1 requirements
- There are some lines that are unique to each generation plan. These lines are added as specific contingency support for each option. This can be attributed to the difference in power transfer due to the different geographic distribution of generation in each plan.

- The system additions for the generation plans consist of transmission lines at 500 kV and 220 kV, new substations and several capacitor banks.
- The transmission losses were calculated for each transmission expansion plan (without Rogun and With Rogun). The total transmission system losses are of the order of 3% to 4%. The losses were valued using the prices established in the present study and their annual value ranges from US$ 44 million to US$ 102 million.
- The transmission facilities required to be added over the study period were costed using unit cost of equipment adapted for Tajikistan. The following total capital costs were obtained:

Component	Capital Cost ($, million)		
	Without Rogun	With Rogun	
New Lines	478.6	588.6	588.6
Substations	213.4	224.9	224.9
Line Upgrades	17.8	17.8	17.8
Capacitors	25.9	22.4	22.4
Total	735.7	853.7	853.7

- The combined CPV for the system expansion plan is shown below. It can be seen that the plan without Rogun has a total cost of $7,510 million while the plan With Rogun has a total cost of $7,265 million and the Early Rogun plan has a cost of $7,215 million. As can be seen from the table the transmission CPV is approximately 13% of the total cost in both plans

Component	CPV ($, million)		
	Without Rogun	With Rogun	Early Rogun
Generation	6,638.7	6303.0	6255.8
Transmission	870.8	962.4	959.2
Total	7,509.5	7,265.4	7,215.0

- The difference in the cost between the Rogun plans and the Without Rogun plan is $244 million (With Rogun) and $295 million (Early Rogun). The addition of the transmission costs do not influence the results of the generation expansion themes
- The capital requirements were made on both economic (no escalation, no taxes) and financial terms and are presented below:

Condition	Capital Requirement ($, million)		
	Without Rogun	With Rogun	Early Rogun
Economic	6,822	9,233	9,233
Financial	10,387	12,501	12,145

- For the plans without Rogun, the generation component requires 87% of the capital while for the plans with Rogun, the generation component requires 90% of the capital. The plans with Rogun require larger amounts of capital under both the economic and financial terms. In financial terms, the plan with Rogun requires $2,111 million more in capital requirements than the plan without Rogun and in economic terms the difference is $2,411 million

- Under financial terms the maximum combined (generation and transmission) annual capital requirement is $1,286 million in 2024, followed by $1,280 million in 2023 for the plan with Rogun. Moreover, the capital requirements up to 2025 of the plan With Rogun represent 69% of the total requirements over 25 years while those for the plan with Early Rogun represent 75% and those for without Rogun represent 47% of the total
- The benefits under Theme 3 are greater than those under Theme 2 due to several factors. In the Early Rogun cases there is a significant reduction in the fuel cost since the hydro power plant in commissioned at a much earlier date as well as a reduction in the O&M costs. Another factor favoring the Early Rogun case is the increase in value and quantity of the non-firm exports due to the fact that the HPP starts generating at an earlier date. On the cost side, the present worth of the plant's capital cost and O&M account for close to 50% of the overall cost and thus when all the different factors are taken into account, the Early Rogun scenarios present reasonable benefits when compared to the respective costs of the scenarios developed under Theme 1

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