OSHPC BARKI TOJIK

TECHNO-ECONOMIC ASSESSMENT STUDY FOR ROGUN HYDROELECTRIC CONSTRUCTION PROJECT

PHASE II: ECONOMIC ANALYSIS

P002378.T2-19

August 2014

COYNE ET BELLIER
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ELECTROCONSULT

IPA
Energy + Water Economics

TECHNO-ECONOMIC ASSESSMENT STUDY
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Chapter 1: Economic Analysis

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GLOSSARY

Abbreviation	Definition
1220_X or Ro1220_X	Project design option: 1220 masl and X MW installed capacity, where X = 2000, 2400 or 2800.
1255_Y or Ro1255_Y	Project design option: 1255 masl and Y MW installed capacity, where Y = 2400, 2800 or 3200.
1290_Z or Ro1290_Z	Project design option: 1290 masl and Z MW installed capacity, where Z = 2800, 3200 or 3600.
AAGR	Average Annual Growth Rate.
ACF	Annual Capacity Factor. A measure of the utilisation of a power plant. It is the ratio of the MWh actually delivered to the grid by a plant to the MWh that would have been generated had the plant been operated at maximum load throughout a year, usually expressed as a percentage.
ADB	Asian Development Bank.
AF	Afghanistan.
AGR	Annual Generation Requirement.
Ancillary services	Services necessary to balance energy supply and demand and to maintain reliable operations of the transmission system. Such services may include load regulation, spinning reserve, non-spinning reserve, replacement reserve, and voltage support.
ARA	Amsterdam-Rotterdam-Antwerp. A delivery point and trading hub basis for commodities.
Assignment	The TEAS of the Project.
Assumptions Book	The spreadsheet file *Assumptions Book for Rogun-2014-02-24.xlsm*.
Baseload	Operating regime in which the generator operates at or close to its full capacity most of the time.
Baseload plant	An electricity plant dedicated to the production of baseload supply. Baseload plants are the production facilities used to meet some or all of a given region's continuous energy demand, and produce energy at a reasonably constant rate, usually at a lower cost than other production facilities available to the system.
Baseload price	This is the simple arithmetic average of all hourly electricity shadow prices during the period in question and includes fuel, O&M and capacity cost components.
bbl	Barrel of oil.
BOO	Build-Operate-Own type of project concession.
BOT	Build-Operate-Transfer type of project concession
BTU	British Thermal Unit.
°C	Degrees Celsius.
CAGR	Compound Annual Growth Rate.
Capacity Demand	Demand for Dependable Capacity.
capex	Capital expenditure.
CAPS	Central Asian Power System.
CAPS-5	Central Asian Power System, including five countries as originally: southern Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan.
CAREC	Central Asia Regional Economic Cooperation.
CASA-1000	Central Asia South Asia Electricity Transmission and Trade Project
CCGT	Combined Cycle Gas Turbine.
cf	Cubic Feet.

Abbreviation	Definition
CF	Capacity Factor. A measure of the utilisation of a power plant over a given period. It is the ratio of the MWh actually delivered to the grid by a plant to the MWh that would have been generated had the plant been operated at maximum load throughout the given period, usually expressed as a percentage.
Client	Barki Tojik.
CME	Chicago Mercantile Exchange.
CO_2	Carbon dioxide.
COD	Commissioning Online Date. Date, usually year, on which equipment becomes operational.
Cogen	Cogeneration. Plants with ability to provide both power and steam.
Consortium	The consortium appointed by the Client and the World Bank comprising of Coyne et Bellier, ELC and IPA.
Coyne et Bellier	Consortium partners.
CY(s)	Calendar Year(s).
DABM	"Da Afghanistan Breshna Moassasa", Afghanistan's state-owned electricity utility.
DABS	"Da Afghanistan Breshna Sherkat", independent company operating and managing electric power generation, transmission, distribution and imports in Afghanistan.
Debt/equity ratio	The ratio of a project's capital, financed by loans and by equity.
Decommissioning	The closure of a plant and all processes associated with this.
Dependable Capacity	Calculated by subtracting own consumption, EFOR and Reserves, from the installed capacity. The Dependable Capacity of nuclear, Hydro and wind plants is derived from historical dispatch. Also expressed in percentage terms of installed capacity.
Disco(s)	Distribution Company(ies).
EBITDA	Earnings Before Interest, Tax, Depreciation and Amortisation.
ECLIPSE®	Emissions Constraints and Policy Interactions in Power System Economics. IPA's proprietary dispatch and capacity expansion power market model.
Economic New Build(s)	Type of new power plants that are additional and justified on economic merit alone.
EFOR	Equivalent Forced Outage Rate. The portion of time a unit is unavailable due to full or partial downtime.
EIA	Energy Information Administration. Part of the US Department of Energy.
EIRR	Economic Internal Rate of Return.
ELC	ELC-Electroconsult S.p.A.
Energy demand	The national requirement for energy including the network losses but excluding consumption for pumped storage, if applicable.
ENTSO-E	European Network of Transmission System Operators for Electricity.
EPC	Engineering, Procurement and Construction.
EPP	Electric Power Plant Company, in Kyrgyzstan.
ESIA	Environmental and Social Impact Assessment.
EUR	Euro.
Firm New Build	Type of new power plant entrants that are assumed to come online exogenously and on a firm basis.
FOB	Free On Board.
FOM	Fixed Operating and Maintenance Costs. Costs incurred that do not change with a plant's electricity generation.
Forecast Horizon	The period under study in this Report, 2013-2050.
G	Giga (10^9).
GDP	Gross Domestic Product.
Genco(s)	Generation Company(ies).
GT	Gas Turbine.

Abbreviation	Definition
GVA	Gross Value Added.
GW	Gigawatt. 10^9 Watt.
GWh	Gigawatt hour. Unit of electrical energy equal to one billion (10^9) watt hours, one thousand megawatt hours, 3.6 TJ, or 3.41 BBTU.
h	Hour.
HFO	Heavy Fuel Oil.
HHV	Higher Heating Value. Defined as the amount of heat released by a specified quantity (initially at 25 °C) once it is combusted and the products have returned to a temperature of 25 °C taking into account the latent heat of vaporization of water in the combustion products.
HPP(s)	Hydroelectric Power Plant(s).
HV	High Voltage.
HVDC	High Voltage Direct Current.
Hydro	Hydroelectric power.
i.c.	Installed Capacity. Production capacity of a plant given its rated (nameplate) capacity.
IC	Internal Combustion units.
ICE	Inter-Ministerial Commission for Energy (in Afghanistan).
IDC	Interest During Construction.
IJTPE	International Journal on Technical and Physical Problems of Engineering.
IMF	International Monetary Fund.
IN	India.
Installed Capacity	Maximum rated output that generating equipment can supply before taking into account own consumption measured in MW.
IPA	IPA Energy + Water Economics Limited.
IPP	Independent Power Producer.
IRA	IPA Reference Assumptions.
IROA	Islamic Republic of Afghanistan.
KESC	Karachi Electric Supply Company (Pakistan).
KG	Kyrgyzstan.
kW	Kilowatt. 10^3 Watt.
kWh	Kilowatt hour. Standard unit of electricity or consumption equal to 1,000 watts over one hour, and equivalent to 3,600 kJ or about 3,412 BTU.
kWy	Kilowatt year.
KZ	Kazakhstan.
Lignite	A soft brown fuel with characteristics that put it somewhere between coal and peat. It is considered the lowest rank of coal and sometimes referred as brown coal.
Load	Same as demand.
Load duration curve	Cumulative function plotting the hourly energy demand against the number of hours at which the demand was at least as high.
Load profile	A curve showing the power provided or consumed as a function of time.
Load shedding	Intentional cut-off of electricity supply for a certain time for a certain area.
LP	Linear Programme or Linear Programming.
LRAIC	Long Run Average Incremental Cost.
LRCCR	Levelised Real Capital Charge Rate. Minimum annual repayment on capital required for the investment to take place. It is measured as percentage of TIC.
LRMC	Long Run Marginal Cost. Average cost of providing an additional unit of electricity from an Economic New Build. This incorporates inputs on the SRMC, FOM, TIC, LRCCR and the ACF.
M	Mega (10^6).
masl	Metres above sea level.
Max ACF	Maximum ACF.

Abbreviation	Definition
MEW	Ministry of Energy and Water (of Afghanistan).
MMBTU	Million British Thermal Units.
mn	Million.
MW	Megawatt. Unit of power (10^6).
MWh	Megawatt hour. Standard unit of electricity or consumption equal to 1,000,000 watts over one hour, and equivalent to about 3,412,000 BTU.
N.A.	Not available.
NDRC	National Development and Reform Commission (of China).
NEA	National Energy Administration (of China).
NEPRA	National Electric Power Regulatory Authority (of Pakistan).
NEPS	North-East Power System – part of the power grid in Afghanistan.
NESK	National Electric System of Kyrgyzstan.
NESP	National Energy Supply Program (in Afghanistan).
Net generation	The electricity that is delivered to the grid by the power plant measured at the connection point of the power plant to the transmission grid and therefore after deducting own consumption.
Netback price	Electricity price calculated by subtracting all costs incurred to supply it to a market (wheeling charges, losses, etc.) from the sales revenue.
New Build(s)	New power plants, both Economic and Firm.
NoRogun	Scenario in which the Project is not built.
NOx	Nitrogen Oxides.
NPV	Net Present Value.
NTC	Net Transfer Capacity.
NTDC	National Transmission and Despatch Company (of Pakistan).
O&M	Operating and Maintenance.
OCGT	Open Cycle Gas Turbine. Also known as a Single Cycle Gas Turbine or GT for short.
OPEC	Organization of the Petroleum Exporting Countries.
Own consumption	Electricity consumed internally within the boundary of a power plant to run a power plant.
p.p.	Percentage point(s).
Peak demand	Maximum power requirement of an energy system, usually for the year, measured in MW.
PK	Pakistan.
Pmax	Maximum hourly generation, usually in the peak hours.
Pmin	Minimum hourly generation.
PPA	Power Purchase Agreement.
PPIB	Private Power and Infrastructure Board (Pakistan).
PPP	Purchasing Power Parity.
Project	Rogun Hydroelectric Power Project, located on the Vakhsh river in Tajikistan.
PV	Present Value.
Q1, Q2, Q3, Q4	First, second, third and fourth quarter of a year. Q1: January – March, Q2: April – June, Q3: July – September, Q4: October – December.
Ref	Refers to one of the ten reference cases.
Regional power market	The potential market for sale and purchase of electricity which is the subject of this Report, as defined in the Consultant's proposal.
Report	*Techno-Economic Assessment Study for Rogun Hydroelectric Construction Project – Phase II Economic Analysis.*
Results Summary	The spreadsheet files *IPA-Results Summary for Rogun(●)-2014-02-24.xlsm* for each Project design option and NoRogun case.
RFO	Recycled Fuel Oil.
RM	Reserve Margin. The system's sum of Dependable Capacity in excess of peak demand, expressed as a percentage of peak demand.

Abbreviation	Definition
RMC	Reserve Margin Contribution.
ROR	Run-Of-River.
RY(s)	Run Year(s). For power market modelling purposes, representative of a number of CYs.
SAARC	South Asian Association for Regional Cooperation.
SERC	State Electricity Regulatory Commission (of China).
Shadow Price	The marginal cost of meeting demand.
SO_2	Sulphur dioxide.
SOE	State Owned Enterprise.
SRMC	Short Run Marginal Cost. Cost of providing an additional unit to generate incorporating only expenses that vary with generation such as fuel and carbon costs as well as VOM.
ST	Steam Turbine.
Surplus energy	Energy generated by a power producer and not required by the domestic market.
T	Tera (10^{12}).
TALCO	Tajik Aluminium Company.
TEAS	Techno-Economic Assessment Study.
Technical Lifetime	Maximum operating lifetime that a power station can run before being subject to forced closure.
Thermal efficiency	The rate at which a power plant converts energy in the fuel into useable electricity. Unless otherwise stated, IPA defines this in terms of the HHV energy context of the fuel and the net generation of the power plant, hence "net HHV".
TIC	Total Investment Cost. TIC includes EPC, sponsor costs, IDC and all indirect costs at the time of commissioning.
TJ	Tajikistan.
TLSS	Transmission Line Sub Station.
TM	Turkmenistan.
TSC	Total System Cost.
TWA	Time-Weighted Average.
TWA All-in (electricity price)	This is the simple arithmetic average of all hourly electricity shadow prices during the period in question and includes fuel, O&M and capacity cost components. Also known as the baseload electricity shadow price.
TWEC	World Bank report (November 2012) "*Tajikistan's Winter Energy Crisis: Electricity Supply and Demand Alternatives*".
TWh	Terawatt hour.
UAP-EST	Uzbekistan-Afghanistan-Pakistan Electricity Supply and Trade Project.
UNECE	United Nations Economic Commission for Europe.
Unserved Demand	Demand for energy not met by power producers.
USD	United States Dollar.
USD/kWy	USD per kW per year.
UZ	Uzbekistan.
V	Volts. The standard unit of electric potential. It is defined as the amount of electrical potential between two points on a conductor carrying a current of one ampere while one watt of power is dissipated between the two points.
Vakhsh cascade	The HPPs that lie along the Vakhsh river.
VOLL	Value of Lost Load.
VOM	Variable Operating and Maintenance. Non-fuel cost component of operating a power plant that does varies with a plant's electricity generation.
W	Watt. Unit of power.
WACC	Weighted Average Cost of Capital.
WAPDA	Water and Power Development Authority (of Pakistan).
WEO	World Economic Outlook database published by the IMF.

Abbreviation	Definition
WEPP	The Platts UDI World Electric Power Plants Database. A global inventory of electric power generating units which contains design data for plants of all sizes and technologies operated by regulated utilities, private power companies, and industrial autoproducers (captive power).
Wheeling charges	The costs of delivering power to export markets.
y	Year.

EXECUTIVE SUMMARY

Barki Tojik (the “Client”) appointed a consortium comprising Coyne et Bellier, ELC-Electroconsult S.p.A. (“ELC”) and IPA Energy + Water Economics (“IPA”) (together the “Consortium”) to undertake a Techno-Economic Assessment Study (“TEAS” or the “Assignment”) of the Rogun Hydroelectric Power Project (the “Project” or “Rogun”), located on the Vakhsh river in Tajikistan. IPA was responsible for the economic and financial analysis (Volume 5: Economic and Financial Analysis) which, in the initial phase of the Assignment, consisted of the following tasks:

- (Chapter 1) T2-18: Initial assessment of potential export markets & calculation of indicative netback prices;
- (Chapter 2) T2-19: Economic Analysis; and,
- (Chapter 3) T2-20: Financial Analysis.

This report (the “Report”) summarises the methodology, assumptions and results of the economic analysis, considering nine possible design options for the Project, comprising combinations of three different dam heights each with three total installed generation capacities, and also an option excluding Rogun.

A regional power market modelling approach was used to quantify Total System Costs (“TSC”) in the interconnected Central Asian Power System (“CAPS”) and determine the economic return for each of the options. We have assessed the economic benefit of each option by evaluating the impact on the Present Value (“PV”) of TSC in Tajikistan. This impact is measured by calculating the difference in the PV of TSC over the lifetime of each option between a scenario in which the Project is built and a scenario in which it is not. TSC for Tajikistan is defined as the sum of annualised capital expenditure (“capex”) repayments, non-fuel Operating and Maintenance (“O&M”) costs, fuel costs, and flood protection benefits, less the net financial benefits from net exports. Note that the assessment of potential exports markets was initially submitted by IPA in November 2012. As this is an integral part of the economic analysis for Rogun, this Report includes an update of that analysis reflecting changes to the input data and assumptions which have been made since that initial submission.

We have also prepared stand-alone economic analyses for the different designs of the Project in terms of their Net Present Value (“NPV”) and Economic Internal Rate of Return (“EIRR”), based on the capital investment and dispatch profiles for the Project calculated by Coyne et Bellier and ELC.

The system cost savings and economic analyses were undertaken under a reference set of assumptions of demand growth, fuel prices, Total Investment Cost (“TIC”) of new build, and regional interconnector development (expressed in terms of Net Transfer Capacity (“NTC”)), with eight low and high sensitivities for these four parameters to this Reference case also examined. By assigning a likelihood of occurrence to each of these outcomes, we were able to calculate probability-weighted values for the TSC savings, and the economic NPV for each Rogun design option.

It should be noted that all monetary figures referred herein are in real terms with 2013 as the base year, and United States Dollars (“USD”) as the default currency, unless otherwise stated.

Table 1 below outlines the summary of the different Rogun design options and shows the total investment cost, the levelised cost, probability-weighted cost savings and the economic NPV for each design option.

Table 1: Summary of the results for different Rogun design options

Height (masl)[4]	Installed Capacity (MW)	Investment cost[1] (USD million)	All-in levelised cost (2013-2050)[2] @ 10% (USD/MWh)	Probability-weighted PV of TSC savings @ 10% (USD million)	Probability-weighted Economic NPV[3] @ 10% (USD million)
1290	3,600	5,211	57.60	1,453	795
	3,200	5,111	56.70	1,479	835
	2,800	5,040	56.35	1,437	825
1255	3,200	4,381	57.96	1,341	699
	2,800	4,310	57.32	1,314	722
	2,400	4,229	56.93	1,218	701
1220	2,800	3,467	50.02	1,174	618
	2,400	3,386	49.74	1,100	613
	2,000	3,313	50.64	1,022	575

Note: The colour coding is used to highlight the relative values for each parameter, not across all cases: red = worst (highest cost, lowest benefit), yellow = middle, green = best (lowest cost, highest benefit).

[1]: Investment cost is the simple sum of 1) Civil works, 2) Hydro-mechanical & electromechanical equipment, 3) Administration + engineering, and 4) Resettlement and infrastructure replacement (environmental costs). Interest During Construction ("IDC") is not included.

[2]: All-in levelised cost is the ratio of the PV of the investment cost to the PV of the generation in 2013-2050, using a discount rate of 10%.

[3]: The NPV is the present value sum of the economic benefits including downstream flood protection less all economic costs.

[4]: "masl" = metres above sea level.

Source: Coyne et Bellier; IPA analysis.

Our analysis establishes that the benefits of Rogun exceed those of other feasible Hydroelectric Power Projects ("HPPs") included in our analytical framework. Regardless of which design option is chosen, Rogun will significantly enhance security of supply in Tajikistan throughout the entire forecasted period, contributing an average of approximately 30% of electricity needed to meet demand between 2020 and 2050. There is even a short period after full operation of the Project when Tajikistan no longer needs net winter imports to meet demand,

From these results, and the outcome of the technical analyses, the Consortium recommends that the highest dam height alternative (1290 m.a.s.l.) should be taken forward for further detailed evaluation. The choice between capacity options within this specified dam height design is less clear cut, however, with limited apparent benefit from choosing the highest installed capacity. There may be value in maintaining the option of expanding capacity at a later stage, either in the event of stronger demand growth or as cover during maintenance periods, and it is suggested that these potential options be examined in detail in the next phase of the studies.

At this stage since the 3,200 MW intermediate installed capacity option shows both the highest overall TSC saving and economic NPV, further sensitivity and breakeven analysis (i.e. the extent to which a particular parameter would have to change from the Reference to reduce the benefit or value of the Project to zero) was undertaken on this design option. These included consideration of the following variables:

- Economic interconnector expansion only ("Modified Reference" case).
- Gas supply to Tajikistan for electricity generation and urban space heating.
- Delay in starting Rogun construction.
- Share reimbursement costs for NoRogun.
- Demand growth.
- Extension in Rogun construction timetable.
- Rogun TIC.
- Achieved Rogun sale prices both domestically and exports.
- Carbon dioxide ("CO_2") emissions abatement benefit versus NoRogun case.
- Delay in receiving export revenues.

The full range of results for these sensitivities on the TSC savings and economic NPV are summarised in Table 2 and Table 3 below, against the Reference case and eight market-level sensitivities examined as part of the selection of the preferred design option:

Table 2: Sensitivity of PV of TSC savings for Ro1290_3200 @ 10%

Case	PV of TSC savings @ 10%	Variation to Reference	
	(USD million)	(USD million)	(percentage)
Reference	**1,707**	-	-
High Demand	1,825	+118	+6.9%
Low Demand	679	-1,028	-60.2%
High Fuel	1,929	+222	+13.0%
Low Fuel	1,238	-469	-27.5%
High TIC	2,531	+824	+48.3%
Low TIC	560	-1,147	-67.2%
High NTC	1,072	-635	-37.2%
Low NTC	1,542	-165	-9.7%
Modified Reference	1,508	-199	-11.6%
Gas generation	775	-933	-54.6%
Gas generation + heating	684	-1,023	-59.9%
Rogun delay:			
2 years	1,770	+63	+3.7%
4 years	1,658	-49	-2.9%
6 years	1,301	-406	-23.8%
Share reimbursement	1,747	+40	+2.3%
Demand growth Ref -55%:			
full savings	389	-1,318	-77.2%
excluding externalities	56	-1,651	-96.7%

Source: IPA analysis.

Table 3: Sensitivity of Ro1290_3200 economic NPV @ 10%

Case	Economic NPV @ 10% (USD million)	Variation to Reference (USD million)	Variation to Reference (percentage)
Reference	**863**	-	-
High Demand	887	+23	+2.7%
Low Demand	765	-98	-11.4%
High Fuel	1,121	+258	+29.8%
Low Fuel	559	-304	-35.2%
High TIC	1,244	+380	+44.0%
Low TIC	420	-444	-51.4%
High NTC	808	-55	-6.4%
Low NTC	819	-45	-5.2%
Rogun delay 2 years	732	-132	-15.2%
Rogun construction extension	657	-207	-24.0%
Rogun TIC:			
-20%	1,417	+553	+64.1%
+20%	310	-553	-64.1%
+31.2%	0	-863	-100.0%
Rogun sale prices:			
domestic tariffs, export -50%	410	-454	-52.5%
only domestic -38.4%	0	-863	-100.0%
only exports -62.5%	0	-863	-100.0%
CO_2 abatement costs	801	-63	-7.3%
No export revenues until Q3 2032	-15	-879	-101.8%

Source: IPA analysis.

These results demonstrate the robustness of the benefits and value of this specific Rogun design option to a wide range of possible future outcomes, with very large movements necessary to alter the conclusions.

1. INTRODUCTION

Barki Tojik (the "Client") appointed a consortium comprising Coyne et Bellier, ELC-Electroconsult S.p.A. ("ELC") and IPA Energy + Water Economics ("IPA") (together the "Consortium") to undertake a Techno-Economic Assessment Study ("TEAS" or the "Assignment") of the Rogun Hydroelectric Power Project (the "Project" or "Rogun"), located on the Vakhsh river in Tajikistan. IPA was responsible for the economic and financial analysis (Volume 5: Economic and Financial Analysis) which, in the initial phase of the Assignment, consisted of the following tasks:

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This report (the "Report") summarises the methodology, assumptions and results of the economic analysis, considering nine possible Rogun design options, comprising combinations of three different dam heights each with three total installed generation capacities, and also an option excluding Rogun. Based on these results, and the outcome of the technical studies, one specific design option is recommended by the Consortium to be taken forward for detailed consideration, and additional analysis has been incorporated on economics of this recommended option.

A regional power market modelling approach was used to quantify Total System Costs ("TSC") in the interconnected Central Asian Power System ("CAPS") and determine the economic return for each of the options. We have assessed the economic benefit of each option by evaluating the impact on the Present Value ("PV") of TSC in Tajikistan. This impact is measured by calculating the difference in the PV of TSC over the lifetime of each option between a scenario in which the Project is built and a scenario in which it is not. TSC for Tajikistan is defined as the sum of annualised capital expenditure ("capex") repayments, non-fuel Operating and Maintenance ("O&M") costs, fuel costs, and flood protection benefits, less the net financial benefits from net exports. Note that the assessment of potential exports markets was initially submitted by IPA in November 2012. As this is an integral part of the economic analysis for Rogun, this Report includes an update of that analysis reflecting changes to the input data and assumptions which have been made since that initial submission.

We have also prepared stand-alone economic analyses for the different designs of the Project in terms of their Net Present Value ("NPV") and Economic Internal Rate Of Return ("EIRR"), based on the capital investment and dispatch profiles for the Project calculated by Coyne et Bellier and ELC.

It should be noted that all monetary figures referred herein are in real terms with 2013 as the base year, and United States Dollars ("USD") as the default currency, unless otherwise stated.

This Report is structured as follows:

- **Section 2** provides an overview of the electricity market in Tajikistan.
- **Section 3** summarises the methodology undertaken for the two phases of the economic analysis.
- **Section 4** presents the key modelling inputs under the IPA Reference Assumptions (“IRA”).
- **Section 5** sets out the market results for each Rogun design option under the IRA.
- **Section 6** provides a summary of the results for all sensitivities.
- **Section 7** presents the results of the economic analysis for the Project.
- **Section 8** provides details and further sensitivity analysis of the recommended preferred Rogun design option.
- **Section 9** presents the conclusions of the economic analysis.

In addition:

- **Annex A** presents electricity supply industry profiles for Uzbekistan, Kyrgyzstan, Turkmenistan, Pakistan, Afghanistan and Kazakhstan.
- **Annex B** provides a description of our proprietary market model, ECLIPSE®, used for the regional least-cost expansion planning.
- **Annex C** details our approach for forecasting Tajikistan electricity demand growth.
- **Annex D** sets out in more detail the key modelling assumptions for the various stages of the economic analysis.
- **Annex E** provides a comparison of the costs of building new power plants in different markets based on the reference assumptions.
- **Annex F** provides detailed least-cost expansion plan results for the different Rogun design options under the IRA.

The complete set of assumptions and results has also been provided separately in spreadsheet format:

- *IPA-Central Asia Assumptions Book for Rogun-2014-02-24.xlsm* (the “Assumptions Book”) presents all the modelling assumptions;
- *IPA-Results Summary for Rogun(●)-2014-02-24.xlsm* (the “Results Summary”) provides the results of the least-cost generation expansion plan for each Project design option and NoRogun case;
- *IPA-System Cost Savings-2014-03-06.xlsm* provides the system cost savings results; and,
- *IPA-Rogun Economic Model (Ref)-2014-02-24.xlsm* provides the calculations and results of the economic analysis.

2. TAJIKISTAN ELECTRICITY MARKET

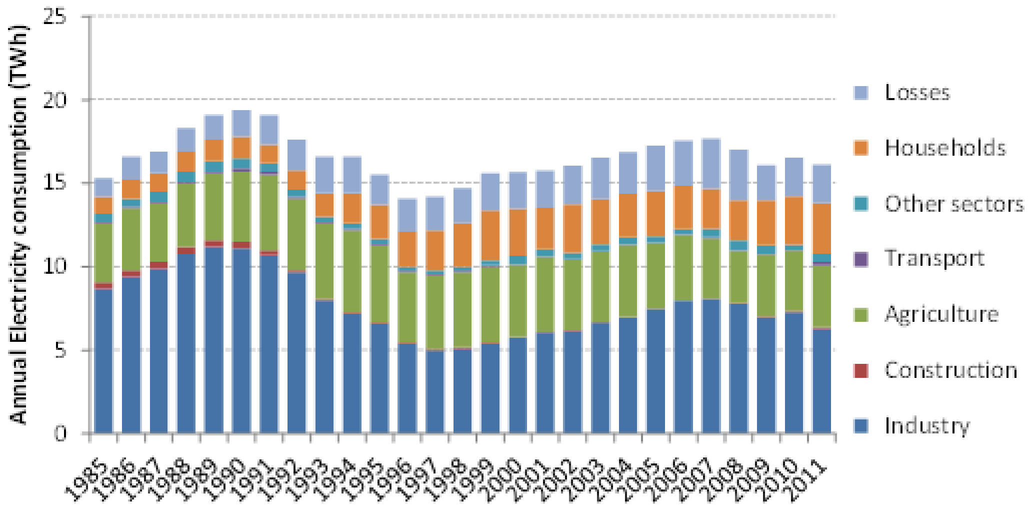
This Section 2 provides an overview of the demand and supply situation in Tajikistan as well as a summary of the profile of the Tajik energy balance throughout the year.

2.1. Demand overview

2.1.1. Historical electricity consumption

Over the last 25 years, growth in demand for power in Tajikistan has been slow and subject to downturns, as shown in Figure 1 below. After gaining independence in 1991, Tajikistan entered into a civil war which lasted until 1997. Over this period, electricity consumption dropped by around 5% per year. From 1997 until 2007, the economy was recovering, with electricity consumption growing at around 1% per year. However, since 2007, electricity consumption has stagnated. Officials explain that this was caused by a domestic financial crisis, interruptions in gas imports from Uzbekistan, and unusually cold winters which reduced the output of Hydroelectric Power Plants ("HPP(s)") which predominate in Tajikistan. Together, the latter led to increasing levels of unmet demand.

Figure 1: Annual electricity consumption in Tajikistan



Source: Tajikistan Statistics (http://www.stat.tj/en/database/real-sector/).

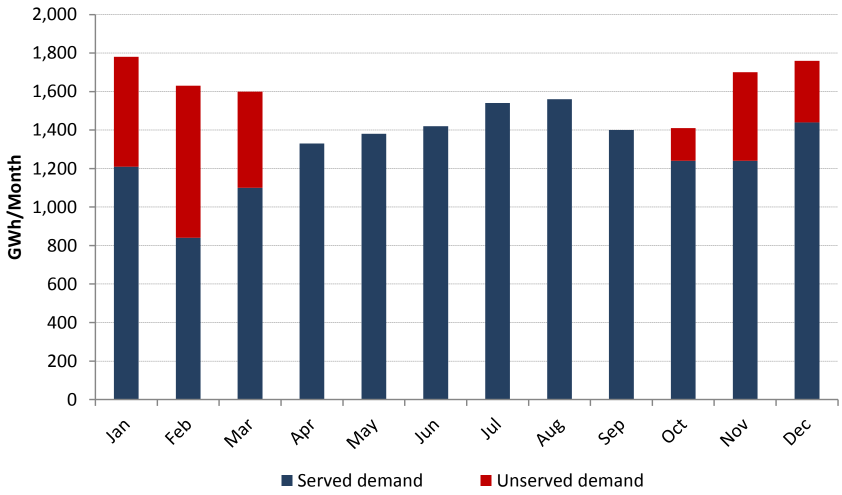
2.1.2. Unserved demand

Between December and January, Tajikistan experiences average temperatures of -8°C, making space heating essential. According to the World Bank (November 2012) *Tajikistan's Winter Energy Crisis: Electricity Supply and Demand Alternatives* ("TWEC") report, firewood and electricity are the major sources of energy for heating in

Tajikistan[1]. We would therefore expect electricity demand in Tajikistan to follow a seasonal cycle. However, generation from HPPs, which depends on glacial and snow melting, is constrained in the winter (October to March). Therefore, a significant amount of electricity demand is left unserved.

The severity of unserved winter demand in Tajikistan becomes particularly obvious when looking at the monthly electricity consumption data. Recent winters have seen up to 50% of demand remaining unserved in the worst affected months. The unserved part of demand is suppressed by means of load shedding, which translates into cutting off the supply to certain parts of the grid (mostly residential) for a certain period of time.

Figure 2: Monthly electricity demand in Tajikistan



Source: Fichtner (October 2012) Central Asia Regional Economic Cooperation ("CAREC") Power Sector Master Plan.

The true (unconstrained) demand cannot be directly observed. Unserved demand (also known as unmet demand) must be estimated and added to served demand (for which data is available) in order to estimate the true demand (unconstrained demand) in any given year. However, not all parts of the economy are equally affected by supply shortages with aluminium production and agriculture less affected by the phenomenon of unserved demand.

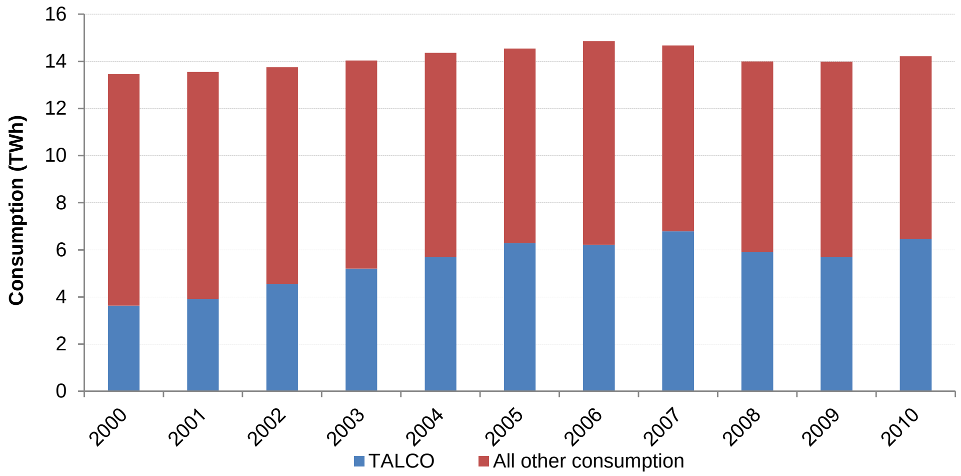
Aluminium production

The Tajik Aluminium Company ("TALCO", formerly known as "TadAZ") is the state-owned aluminium producer. Aluminium smelting is highly electricity intensive and this, coupled with TALCO's size, makes it the single largest electricity consumer in the country. Its consumption peaked at 6,789 GWh in 2007, which was 46% of the total electricity supplied that year[2]. TALCO's electricity demand as a percentage of Tajikistan's total annual electricity demand from 2001 to 2010 is illustrated in Figure 3

[1] World Bank (November 2012) *Tajikistan's Winter Energy Crisis: Electricity Supply and Demand Alternatives.*
[2] Tajikistan Statistics.

below. We believe that given its size and importance to the economy it will not be subject to power outages and that it will therefore have its electricity demand fully met. This assumption is consistent with other studies (SNC Lavalin[3] and Fichtner[4]).

Figure 3: TALCO consumption compared to all other consumption



Source: the Client, Tajikistan Statistics (http://www.stat.tj/en/database/real-sector/).

Agriculture

Supply of electricity is plentiful during the summer and, as the TWEC report[5] states, "the electricity demand of the agricultural sector is largely restricted to the summer months when water-intensive crops such as cotton require irrigation". The only period in which the agricultural sector may suffer from unserved electricity demand is in spring, which starts from March, when electricity is required for irrigation pumping stations and supply from HPPs is still constrained.

2.1.3. Unconstrained demand

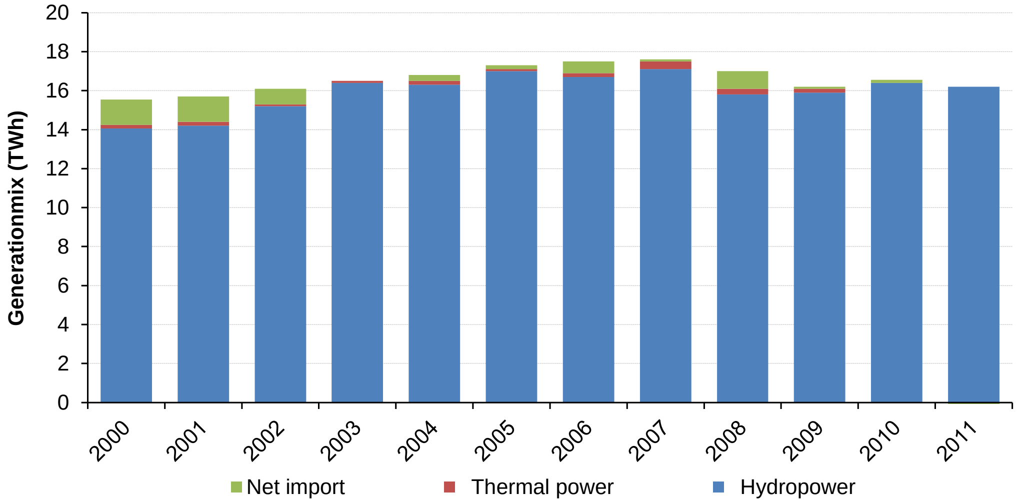
Since customers are not equally affected by supply shortages and the relevant data is not available, unconstrained demand is difficult to measure. We have conducted our own forecast of unconstrained electricity demand in Tajikistan, the methodology and results of which are summarised in subsection 4.5. Details of the methodology for our forecast are provided in the Annex C of this Report.

2.2. Generation profile

Tajikistan relies on HPPs to supply the majority of its electricity, as illustrated in Figure 4 below.

[3] SNC Lavalin, (August 2011) *Technical Memorandum #2: Tajikistan Power Supply Options Study*.
[4] Fichtner (October 2012) *CAREC Power Sector Regional Master Plan*.
[5] World Bank (November 2012) *Tajikistan's Winter Energy Crisis: Electricity Supply and Demand Alternatives*.

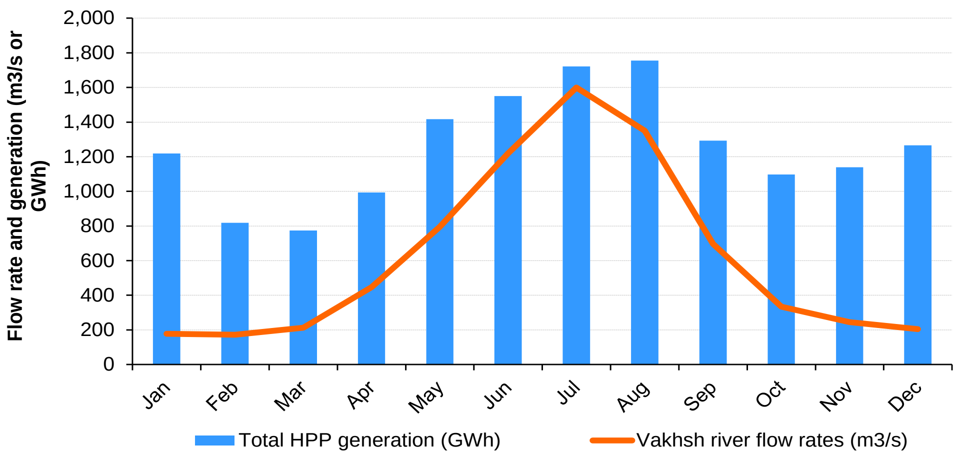
Figure 4: Tajikistan historical generation mix (2000-2011)



Source: Tajikistan Statistics (http://www.stat.tj/en/analytical-tables/real-sector/).

The majority of Tajikistan's HPP capacity, including the 3,000MW Nurek Dam, is located on the Vakhsh River, the flow of which is primarily driven by seasonal glacial and snow melting, at their highest in the summer (April to September). During the colder winter months, its flow rate falls significantly meaning that dispatch is much lower in the winter as illustrated in Figure 5 below.

Figure 5: Monthly Vakhsh average flow rate and HPP average generation (2007-2010)



Source: the Client, United Nations Economic Commission for Europe ("UNECE").

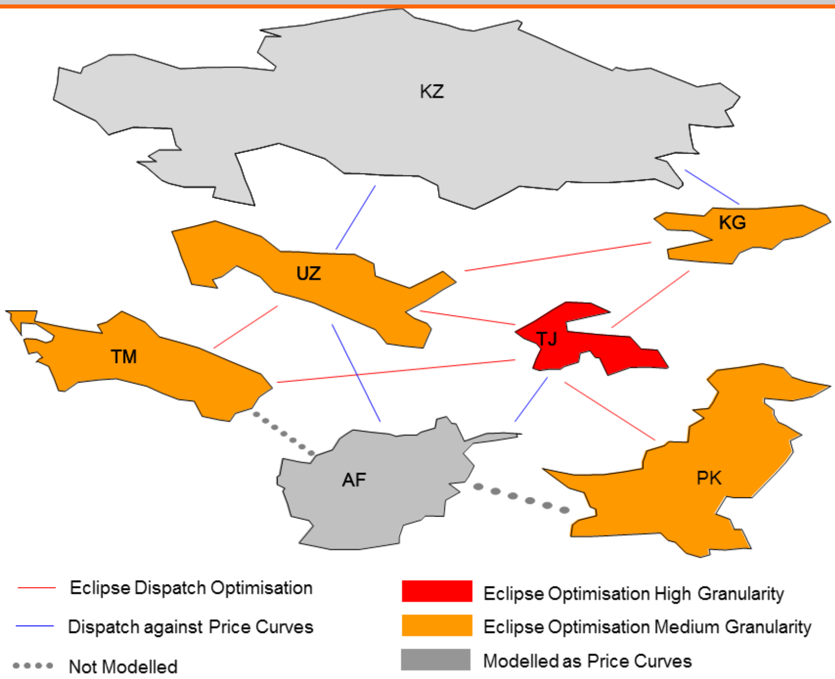
3. METHODOLOGY

This Section 3 describes the methodology used for the least-cost generation expansion plan to meet electricity demand in Tajikistan and for the economic analysis study to quantify the economic benefits of commissioning the Project.

3.1. Regional least-cost generation expansion plan

We prepared a regional least-cost generation expansion plan based on assumptions for Tajikistan and neighbouring countries using our proprietary power market model, ECLIPSE®, for the interconnected CAPS. A graphical representation of CAPS ECLIPSE® is shown in Figure 6 below.

Figure 6: Representation of CAPS ECLIPSE®



Note: This figure represents the interconnectors as modelled in the CAPS ECLIPSE® and not the full range of existing physical links. "TJ": Tajikistan, "UZ": Uzbekistan, "TM": Turkmenistan, "AF": Afghanistan, "PK": Pakistan, "KG": Kyrgyzstan, and "KZ": Kazakhstan.

Source: IPA.

CAPS ECLIPSE® builds capacity and dispatches power plants in Tajikistan and the neighbouring countries with the aim of minimising TSC for the interconnected region. The TSC includes annualised capex repayments, fixed and variable O&M costs, fuel costs and the cost of using interconnectors.

We define a country's minimum reserve margin as the minimum amount of dependable or "firm" capacity – i.e., the amount that can be relied upon in the peak demand hour – above the national annual peak hourly demand needed to ensure an adequate level of supply security. Up to 2019 we do not require any country to hold a reserve but after

2020 CAPS ECLIPSE® will target a minimum reserve margin of 10%. Note, however, that we never allow for the transfer of firm capacity (measured in kW/year) across interconnectors. Hence, a country can only meet its minimum reserve requirement by relying on domestic power plants.

CAPS ECLIPSE® does allow for electricity (measured in MWh) to be transferred between the interconnected countries based on the Net Transfer Capacity ("NTC") of the interconnection lines. The import-export flows will be determined by the difference between marginal generation costs in different jurisdictions and the supply-demand situation in each country. If the marginal cost of generation in a neighbouring country is high enough, it may be cheaper to build capacity in Tajikistan and export to the neighbouring country and vice versa. CAPS ECLIPSE® will calculate the trade-offs and determine the most viable transfer options. This can also include using some countries as transit routes if direct routes are not viable. In addition, ECLIPSE® can build additional interconnections on an economic basis to fully leverage the transfer of energy from low cost to high cost countries, if doing so would reduce the TSC for the whole region.

The results from the model calculate the potential volume of electricity imports to and exports from Tajikistan to each neighbouring market, identifying the potential export markets, and providing a measure of the realised price of these exports to each neighbouring market based on their opportunity cost of electricity generation.

3.2. Total System Cost saving comparison

The main focus of the Assignment is to establish whether the Project is economically viable. In order to assess the Project's value to the Tajikistan power system, we calculate the total system cost savings, from the year construction of the Project begins, by comparing the TSC under each of the following two scenarios:

- No Rogun ("NoRogun"): Perform a least-cost expansion plan analysis which excludes the Project to determine the benchmark capacity expansion plan and potential exports.
- With Rogun: Perform the same least-cost expansion plan analysis assuming that the Project will be built on a firm basis. The phases of construction, the costs and the generation characteristics of each of the Rogun design options were provided by our Consortium partners.

The option that provides the largest estimated cost saving is considered to be the least cost option for Tajikistan.

The construction of Rogun may also provide flood protection to the entire downstream Vakhsh cascade, depending on the design option selected. Since these benefits are inherent in the system costs for those designs, for a proper comparison, it was necessary to include the costs of providing similar flood protection benefits in the TSC for the No Rogun case and any of the Rogun design options which do not confer this benefit. To quantify this, we considered the avoided costs which would have to be incurred for an alternative method, namely constructing additional spillways at the Nurek HPP. This cost of building additional spillways was estimated by Coyne et Bellier.

There has been a considerable amount of preparatory work already undertaken at the Rogun site, and in the event that the Project does not proceed, the construction site would have to be decommissioned. The cost of doing so therefore has to be included in the TSC for the No Rogun case, and has been done based on information provided by the Client and Coyne et Bellier.

Total cost savings until 2050

The calculation of total cost savings derived from the Project until 2050 is illustrated in Table 4 below.

Table 4: Calculating the cost savings from the Project

	2013	2014	…	2050	Post-2050 value (2050)	Net PV
TSC without Rogun	X_1	X_2	…	X_{38}	X_{39}	$\sum X_i/(1+r)^{i-1}$
TSC with Rogun	Y_1	Y_2	…	Y_{38}	Y_{39}	$\sum Y_i/(1+r)^{i-1}$
Savings from Rogun	X_1-Y_1	X_2-Y_2	…	X_{38}-Y_{38}	X_{39}-Y_{39}	$\sum(X_i-Y_i)/(1+r)^{i-1}$

Notes: PV is calculated as of 2013, where i = 1 in 2013 and:

- Y_i and X_i are resulting annual TSC when the Project goes ahead and when it does not respectively in year *i*;
- TSC is defined A+B+C+D, where:
  - A = TIC × LRCCR i.e. capital repayment costs calculated as the product of Total Investment Cost (“TIC”) and the Levelised Real Capital Charge Rate (“LRCCR”)[6];
  - B = FOM + VOM, i.e. Fixed Operating and Maintenance (“FOM”) and Variable Operating and Maintenance (“VOM”) costs;
  - C = Fuel costs, and,
  - D = Net revenues from net exports.

Source: IPA.

Total cost savings post-2050

The technical lifetime of the Project depends on the time for the reservoir to fill with sediment and hence on the available reservoir capacity for each dam height option. The lifetime has been determined as 45 years for the smallest dam height (1,220 metres above sea level (“masl”)), 75 years for the medium dam height (1,255 masl) and 115 years for the largest (1,290 masl). The long project lifetime exceeds the timeframe of a meaningful least-cost planning analysis. Therefore, in order to reflect the long-run benefits of the Project, we have also performed a post-2050 value calculation.

[6] The LRCCR is the minimum annual repayment on capital required for the investment to take place, measured as the percentage of TIC. TIC includes EPC, sponsor costs, IDC and all indirect costs at the time of commissioning.

Table 5: Calculating the cost savings from the Project post-2050

	2051	2052	…	End of life	Post-2050 value (as of 2050)
Savings from Rogun	X_n-Y_n-d	X_n-Y_n-2d	…..	0	$\sum_t(X_n\text{-}Y_{n\text{-}}t\times d)$

Notes: X_n - Y_n is the savings of deploying the Project resulting from the least-cost analysis in year *n;* year *n* is the last year of the least-cost planning i.e. 2050; d is the depreciation factor.

Source: IPA.

The post-2050 value is calculated as the PV of the annual savings in the period after 2050 to the end of the projected technical lifetime of the option under consideration. We have not used the common run-out approach that the savings in the last modelled year continue to the end of the Project's life because this makes the implicit assumption that the costs of new build to meet demand growth and replace existing plant as they close are identical with or without the Project, and hence there are no net savings. However, because increasing sedimentation will tend to reduce the output from the Project, and hence its benefit, towards the end of its life, we have instead assumed that the annual savings in 2050 drop in a linear manner to zero at the end of the projected technical lifetime of the option under consideration. Since in reality the effect of sedimentation will be more gradual and significant only in the last few years of the Project's life, this provides a conservative estimate for the benefits of the Project options.

3.3. Economic analysis

The second assessment of the viability of Rogun was via an economic analysis consisting of a comparison of benefits versus costs for each Rogun design option. Economic costs are determined on the same basis as in the first stage analysis, with some refinements. The economic benefits should reflect how the economy of Tajikistan improves as a direct result of the increase in power and energy generation due to the implementation and operation of the selected Rogun option, and indirectly from other consequences of Rogun's implementation. This second stage analysis has thus taken into account both direct financial benefits accruing from the sale of electricity generated as well as wider societal economic benefits arising from its construction and operation, as described below.

3.3.1. Project benefits

The economic value of electricity generated by Rogun arise from both meeting domestic demand and exporting via interconnectors to neighbouring countries to meet their requirements. The value of these sales can be determined in one of two ways:

1. **Marginal cost**: The least-cost generation expansion plan determines the value of generation as the cost of production of the marginal plant required to meet demand in any period. The construction of Rogun may reduce this cost by avoiding the need for expensive alternative sources of generation, and hence, economically, its value is equivalent to this marginal (avoided) cost of generation.
2. **Tariffs**: An alternative method to estimate the value to Rogun relies on the amount which consumers would be able and/or willing to pay for the electricity generated.

In developing economies such as Tajikistan and its neighbours, this amount is likely to be less than the full cost of generation. We will therefore consider this as part of a sensitivity of the project economics for the preferred design option only, calculating potential tariffs for domestic and export sales as follows:

- Domestic: This inability/unwillingness to pay the full cost of electricity production by Tajik consumers is recognised in the fact that electricity tariffs are subsidised and currently stand at 2.25US¢/kWh. The level of subsidy may not be sustainable by 2020 if tariffs are not increased to better reflect the cost of new supply. We have therefore considered an increase to 9US¢/kWh (in real 2012 terms) between 2014 and 2025 (of which 1.5US¢/kWh is attributed to transmission and distribution costs) for the sensitivity analysis of the value of domestic sales of electricity from Rogun.
- Exports: In terms of export sales to neighbouring countries, rather than being willing to pay the full avoided cost, a compromise position could be to split the difference with the marginal cost of production, i.e. sales at 50% of the economic marginal cost described above.

The proportion of the total generation from Rogun attributed to each revenue stream (domestic and individual export destinations) has been calculated *pro rata* with the Rogun share of total generation in Tajikistan.

3.3.2. Other economic benefits

As described above, one of the main benefits of building Rogun is flood protection for the entire Vakhsh cascade. For the dam options which provide this benefit, we have therefore also incorporated the avoided costs of spillways at Nurek as additional Project benefits in the economic analysis for those design options which confer this downstream protection.

3.3.3. Project costs

The Project's costs include the costs for civil works, hydro-mechanical, electromechanical, and transmission line sub-station ("TLSS") equipment costs (including transmission), administration and engineering costs, resettlement and infrastructure replacement (environmental costs), O&M costs as provided by Coyne et Bellier and ELC, as well as the annual value of lost agricultural production from the land impacted by the reservoir as estimated in the Environmental and Social Impact Assessment ("ESIA") undertaken by Pöyry Energy[8].

Table 6 summarises the combination of the Project benefits and costs into the calculation of a Net Present Value ("NPV") and Economic Internal Rate of Return ("EIRR").

The post-2050 economic value of the Project has been calculated in a similar manner to that of the total system cost savings, with the net benefit in 2050 assumed to drop linearly to zero at the end of the projected technical lifetime of the option under consideration.

[8] Pöyry Energy (July 2013) *Environmental and Social Impact Assessment for Rogun Hydro Power Plant – Infrastructure Replacement and Resettlement Costs for Dam Alternatives*.

Table 6: Calculating the economic benefits of the Project

		Units	Formula	2013	2014	…	2050	Post-2050 value (2050)
Benefits								
1	Domestic sales	000 USD		d_1	d_2	…	d_n	d_{n+1}
2	Export sales	000 USD		e_1	e_2	…	e_n	e_{n+1}
3	Flood benefits	000 USD		f_1	f_2	…	f_n	f_{n+1}
4	Total benefits	000 USD	1+2+3	B_1	B_2	…	B_n	B_{n+1}
Costs								
5	Project costs	000 USD		p_1	p_2	…	p_n	p_{n+1}
6	O&M costs	000 USD		o_1	o_2	…	o_n	o_{n+1}
7	Agriculture loss	000 USD		a_1	a_2	…	a_n	a_{n+1}
8	Total costs	000 USD	5+6+7	C_1	C_2	…	C_n	C_{n+1}
Net benefits								
9	Net benefits	000 USD	4-8	B_1-C_1	B_2-C_2	…	B_n-C_n	B_{n+1}-C_{n+1}
10	NPV	000 USD	∑PV(9)					
11	EIRR	%	IRR(9)					

Note: "∑PV(9)" and "IRR(9)" represent the calculation of the sum of the PV and IRR of the net benefits in line 98 for all years of the analysis.

Source: IPA.

3.4. Probability-weighted sensitivity analysis

In order to account for the uncertainty around the inputs used for the least-cost expansion planning, sensitivities were used to assess the robustness of the estimated cost savings and the economic value of each Rogun design option to variations in economic and other conditions. The sensitivities considered in our analysis cover changes in four variables which we identified as likely to have a large impact on TSC:

1. Demand: electricity demand growth scenarios for Tajikistan.

2. Fuel costs: fuel price assumptions for Central Asia including Tajikistan.

3. Total Investment Costs ("TIC"): the TIC of the New Build options, presented later in 4.7.4, including the different candidate plants in Tajikistan and neighbouring countries whilst keeping inputs for the Project unaffected.

4. NTC: capacity of the interconnectors from Tajikistan to Pakistan, Kyrgyzstan and Uzbekistan.

The impact of changes to each of these variables was examined through sensitivities in which the inputs are identical to the IRA with the exception of one of the four variables listed above which was either higher or lower. Thereby, our sensitivities include a central (IRA), low or high case for each of these variables.

We assigned a probability-weighting to each of the three cases for all four variables. These probability-weightings were used to calculate the probability-weighted average of the cost savings. The weight assigned to each of the variables was 50% for the central case, and 25% for each of the low and high cases. The sensitivity-specific probability was calculated by multiplying the respective probability-weights of the central, low or high value assigned to each variable in the given sensitivity.

Figure 7 below illustrates our probability framework whereby we allocate probabilities to different levels of demand, fuel costs, TICs and NTCs, so that we can assess the probability-weighted savings of each Rogun design option.

In order to analyse the sensitivities on all ten options – nine Rogun design options and one NoRogun option – in an efficient computational time period, we have chosen to analyse the eight sensitivities with the highest raw probabilities as well as the Reference Case, for each of the ten options. These are summarised in Table 7 below. A description of the inputs used in the sensitivities highlighting the differences to the IRA is provided in Table 37 in subsection 4.10 au-dessous.

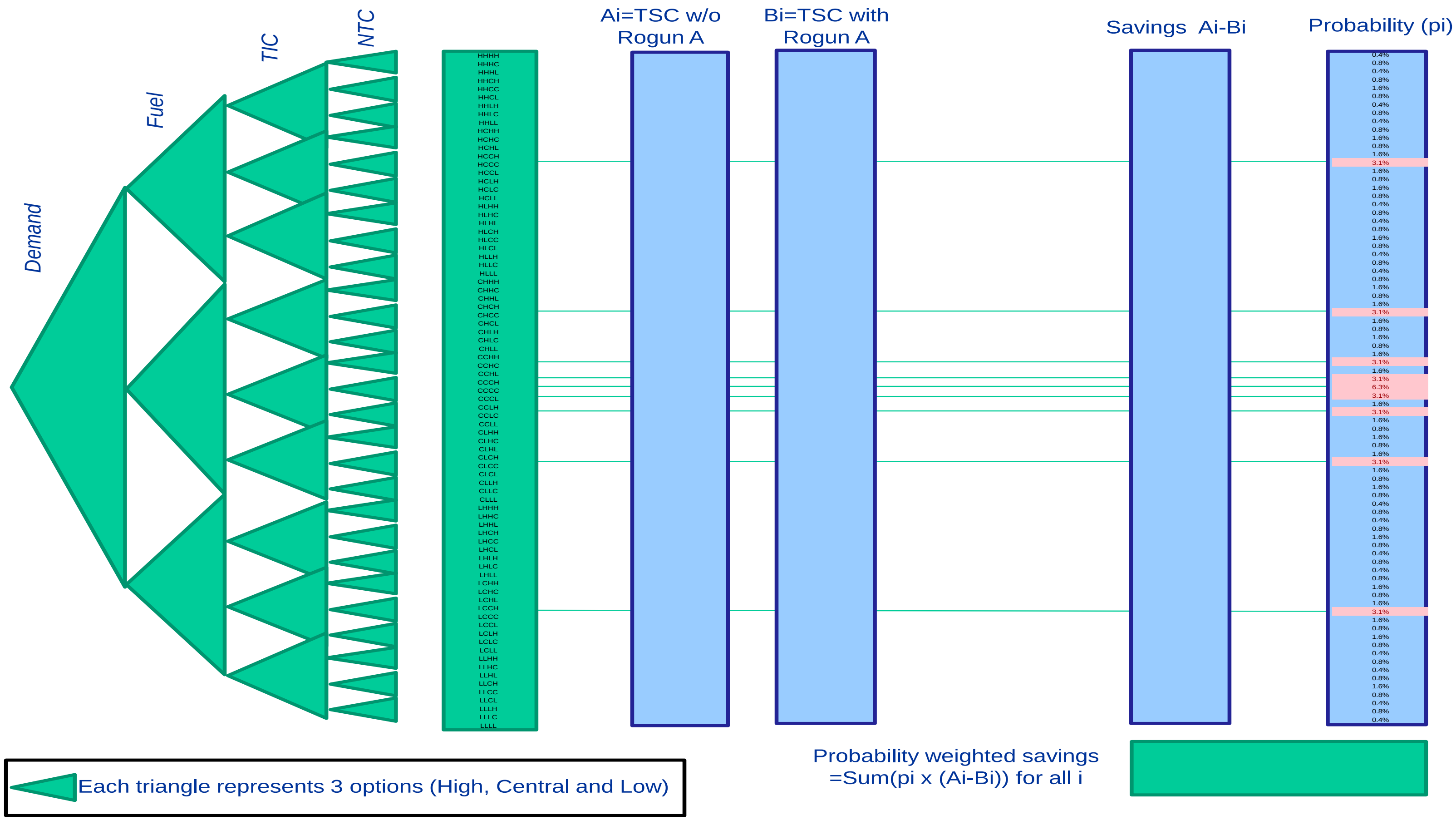
Table 7: Sensitivity analysis – selected sensitivities and their normalised probabilities

Sensitivity[1]	Raw probability	Normalised probability
Ref (C,C,C,C)	6.250%	20.0%
HiDem (H,C,C,C)	3.125%	10.0%
LoDem (L,C,C,C)	3.125%	10.0%
HiFuel (C,H,C,C)	3.125%	10.0%
LoFuel (C,L,C,C)	3.125%	10.0%
HiTIC (C,C,H,C)	3.125%	10.0%
LoTIC (C,C,L,C)	3.125%	10.0%
HiNTC (C,C,C,H)	3.125%	10.0%
LoNTC (C,C,C,L)	3.125%	10.0%
Sum of probabilities	**31.25%**	**100%**

[1]: Each sensitivity is initially identified by a short name. Within the subsequent brackets we define either C (Central), L (Low) or H (High) option for each of demand, fuel costs, TICs and NTCs parameters in this order. Therefore, Ref (C,C,C,C) represents the IRA where the central case is chosen for each parameter.

Source: IPA analysis.

Figure 7: Sensitivity analysis – defining the universe of sensitivities to assess system cost savings for Tajikistan



Source: IPA analysis.

4. KEY ASSUMPTIONS

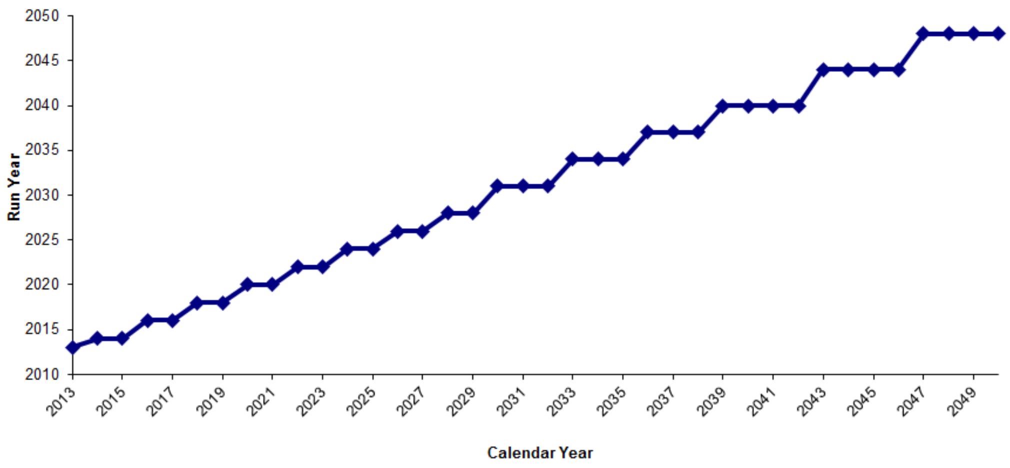
This Section 4 summarises the IRA. In subsection 4.1, we outline the Calendar Year ("CY") to Run Year ("RY") mapping, and in 4.2 specify the discount rate assumption used throughout the economic analysis. In subsection 4.3, we review the different Rogun design options for the Project. In subsection 4.4, we describe our assumptions regarding the impact of the Project on the power plants of the Vakhsh cascade. We then present our forecasts of electricity demand in Tajikistan and in neighbouring countries in subsections 4.5 and 4.6 respectively. In subsection 4.7 and 4.8, we discuss our assumptions regarding the electricity supply options in Tajikistan and interconnections with neighbouring markets respectively. We summarise our fuel price projections in subsection 4.9. Finally, subsection 4.10 provides an overview of the sensitivities.

Further details of these assumptions are given in Annexes C and D, and separately in the Assumptions Book (file "*Assumptions Book for Rogun-2013-12-06.xlsm*").

4.1. Model structure

The least-cost analysis for the Assignment extends from 2013 through to 2050 (the "Forecast Horizon") with ECLIPSE® seeking the least-cost solution that meets all constraints over this 38-year period. To efficiently capture power system developments, individual calendar years ("CY(s)") are grouped into a limited number of RYs. ECLIPSE® thus forecasts power system developments and prices at the RY level. For the Assignment, we aggregated the 38 CYs into 15 RYs, as shown in Figure 8 and Table 8 below, to capture the key milestones for the Project.

Figure 8: CY to RY mapping



Source: IPA assumptions.

Table 8: CY to RY mapping

RY	CY – start year	CY – end year
2013	2013	2013
2014	2014	2015
2016	2016	2017
2018	2018	2019
2020	2020	2021
2022	2022	2023
2024	2024	2025
2026	2026	2027
2028	2028	2029
2031	2030	2032
2034	2033	2035
2037	2036	2038
2040	2039	2042
2044	2043	2046
2048	2047	2050

Source: IPA assumptions.

4.2. Discount rate

A discount rate of 10% has been applied throughout the least-cost generation expansion modelling and economic analysis. (Unless otherwise stated, the discount rates referred to in this Report are real discount rates.) This is as per with the recommendation of the World Bank and in line with its general practice to reflect the opportunity cost of investment capital.

We have additionally undertaken sensitivity analyses of the TSC savings and economic NPV at discount rates of 8% and 12%. The former is believed by the Government of Tajikistan to more closely reflect its public cost of funds, while the latter reflects the fact that often a rate higher than 10% is used in assessing investment opportunities in emerging economies especially for very large projects.

4.3. Rogun design options

Coyne et Bellier has identified nine potential Rogun design options, each of which is evaluated in this Report. These comprise three different possible dam heights – 1,290, 1,255 and 1,220 metres above sea level ("masl") – with three different total installed generating capacities each from 2,000MW to 3,600MW. Table 9 below summarises the nine Rogun design options and their total capital and levelised costs. A breakdown of the costs and technical inputs is provided in Figure 9 and Table 10 below.

Table 9: Rogun design options cost summary

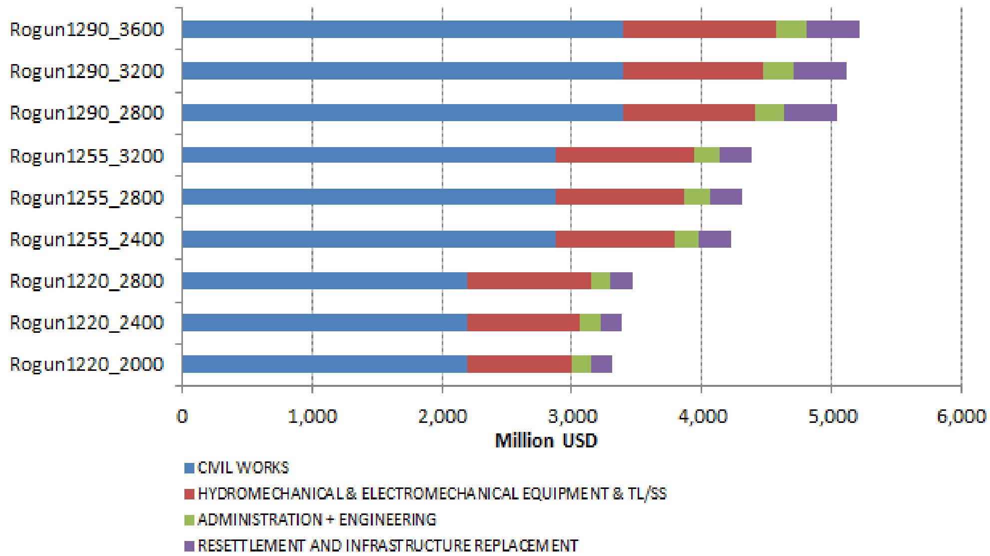
Dam height (masl)	Installed capacity (MW)	Investment cost[1] (USD million)	All-in levelised costs (2013-2050)[2] @ 10% (USD/MWh)
1,290	3,600	5,211	57.60
	3,200	5,111	56.70
	2,800	5,040	56.35
1,255	3,200	4,381	57.96
	2,800	4,310	57.32
	2,400	4,229	56.93
1,220	2,800	3,467	50.02
	2,400	3,386	49.74
	2,000	3,313	50.64

[1]: Investment cost is the simple sum of 1) Civil works, 2) Hydro-mechanical & electromechanical equipment & TL/SS equipment (includes transmission), 3) Administration + engineering, and 4) Resettlement and infrastructure replacement (environmental costs). Interest During Construction ("IDC") is not included.

[2]: All-in levelised cost is the ratio of the PV of the investment cost to the PV of the generation for the period 2013-2050, using a discount rate of 10%.

Source: Coyne et Bellier and IPA analysis.

Figure 9: Rogun design options investment cost breakdown



Source: Coyne et Bellier and IPA analysis.

Table 10: Rogun design options investment cost breakdown

USD million	Design option								
	1290_3600	**1290_3200**	**1290_2800**	**1255_3200**	**1255_2800**	**1255_2400**	**1220_2800**	**1220_2400**	**1220_2000**
Civil works	3,398	3,398	3,398	2,876	2,876	2,876	2,199	2,199	2,199
Hydro-mechanical and electromechanical equipment and TL/SS	1,176	1,081	1,013	1,060	993	916	945	868	798
Administration + engineering	229	224	221	197	193	190	157	153	150
Resettlement and infrastructure replacement	408	408	408	248	248	248	165	165	165
Total	**5,211**	**5,111**	**5,040**	**4,381**	**4,310**	**4,229**	**3,467**	**3,386**	**3,313**
PV @ 10%	2,820	2,767	2,728	2,545	2,506	2,462	2,126	2,081	2,041

Source: Coyne et Bellier, ELC and IPA analysis.

Table 11: Rogun design options technical and cost inputs

	Units	Design option								
		1290_3600	**1290_3200**	**1290_2800**	**1255_3200**	**1255_2800**	**1255_2400**	**1220_2800**	**1220_2400**	**1220_2000**
Installed capacity	MW	3,600	3,200	2,800	3,200	2,800	2,400	2,800	2,400	2,000
Equivalent Forced Outage Rate ("EFOR")	% generation	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Own consumption										
- During construction	% generation	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%
- During operation	% generation	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
Annual O&M costs[1]	USD million	23.26	22.36	21.79	22.02	21.42	20.62	16.24	15.69	15.18
Lost agriculture	USD million	5.79	5.79	5.79	2.44	2.44	2.44	1.69	1.69	1.69
Technical lifetime	Years	115	115	115	75	75	75	45	45	45

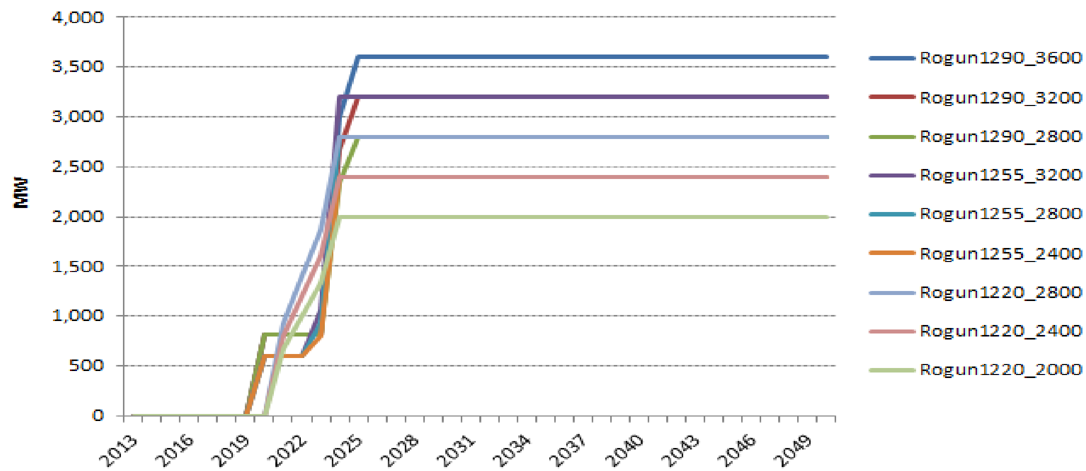
[1]: O&M costs increase over time – the figures shown are the long-term steady state assumption.

Source: Coyne et Bellier, ELC, Pöyry Energy and IPA analysis.

Expected capacity phasing

The expected build-up of capacity for each Rogun design option is shown in Figure 10 and Table 12 below.

Figure 10: Rogun design options capacity build-up

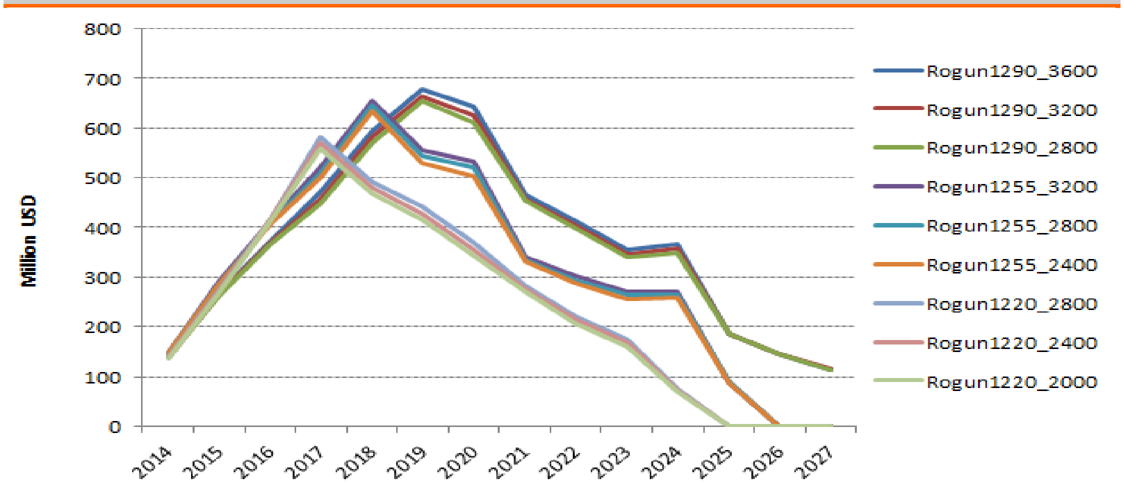


Source: Coyne et Bellier and IPA analysis.

Expected capex phasing

The capital expenditure phasing corresponding to these construction schedules is shown in Figure 11 and Table 13 below.

Figure 11: Rogun design options annual capital expenditure



Source: Coyne et Bellier and IPA analysis.

Table 12: Rogun design options capacity build-up

MW	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Ro1290_3600	-	-	-	-	-	-	-	812	812	812	812	3,000	3,600	3,600	3,600
Ro1290_3200	-	-	-	-	-	-	-	812	812	812	812	2,667	3,200	3,200	3,200
Ro1290_2800	-	-	-	-	-	-	-	812	812	812	812	2,333	2,800	2,800	2,800
Ro1255_3200	-	-	-	-	-	-	-	600	600	600	1,068	3,200	3,200	3,200	3,200
Ro1255_2800	-	-	-	-	-	-	-	600	600	600	933	2,800	2,800	2,800	2,800
Ro1255_2400	-	-	-	-	-	-	-	600	600	600	800	2,400	2,400	2,400	2,400
Ro1220_2800	-	-	-	-	-	-	-	-	934	1,401	1,868	2,800	2,800	2,800	2,800
Ro1220_2400	-	-	-	-	-	-	-	-	800	1,200	1,600	2,400	2,400	2,400	2,400
Ro1220_2000	-	-	-	-	-	-	-	-	667	1,000	1,333	2,000	2,000	2,000	2,000

Source: Coyne et Bellier and IPA analysis.

Table 13: Rogun design options annual capital expenditure

USD million	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Ro1290_3600	-	141	267	373	471	594	677	642	464	412	356	367	186	146	114
Ro1290_3200	-	140	265	370	457	581	663	624	458	404	346	357	186	146	115
Ro1290_2800	-	140	261	367	448	571	654	612	453	398	340	349	185	146	115
Ro1255_3200	-	147	290	413	520	655	555	532	340	301	271	271	87	0	0
Ro1255_2800	-	147	286	410	511	645	544	519	335	294	264	265	89	0	0
Ro1255_2400	-	147	284	408	500	635	530	503	331	288	257	259	88	0	0
Ro1220_2800	-	138	272	417	581	492	443	370	282	221	175	76	0	0	0
Ro1220_2400	-	138	270	415	570	480	429	355	275	214	168	71	0	0	0
Ro1220_2000	-	138	267	412	559	469	417	342	269	207	161	70	0	0	0

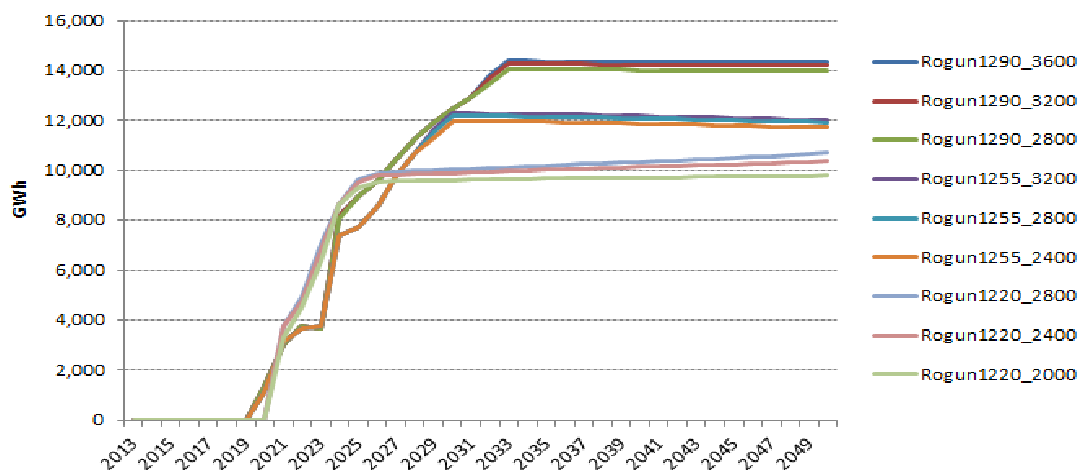
Source: Coyne et Bellier and IPA analysis.

Expected annual generation

The Project's annual generation is expected to vary between 10TWh for the smallest dam height option to 14TWh for the highest. Figure 12 below presents the expected annual generation profile for each Rogun design option. It should be noted that the total annual energy production is determined mainly by the dam height, i.e. the amount of water which can be stored, with the higher installed turbine capacity only providing marginally more output.

Over time, sediments are expected to fill the Rogun reservoir, impacting its regulation capacity. The operators of the Project will aim to store water in the summer and release this in the winter when demand is higher. However, a build-up of sediment will reduce the amount of water than can be stored for winter generation. Annual energy is therefore expected to increase over time because water discharges in the summer will have a higher head (and therefore higher energy) than water discharged in winter. This increase in annual energy is most noticeable for the lowest dam height option towards the end of the Forecast Horizon in Figure 12 below.

Figure 12: Rogun expected annual generation profiles

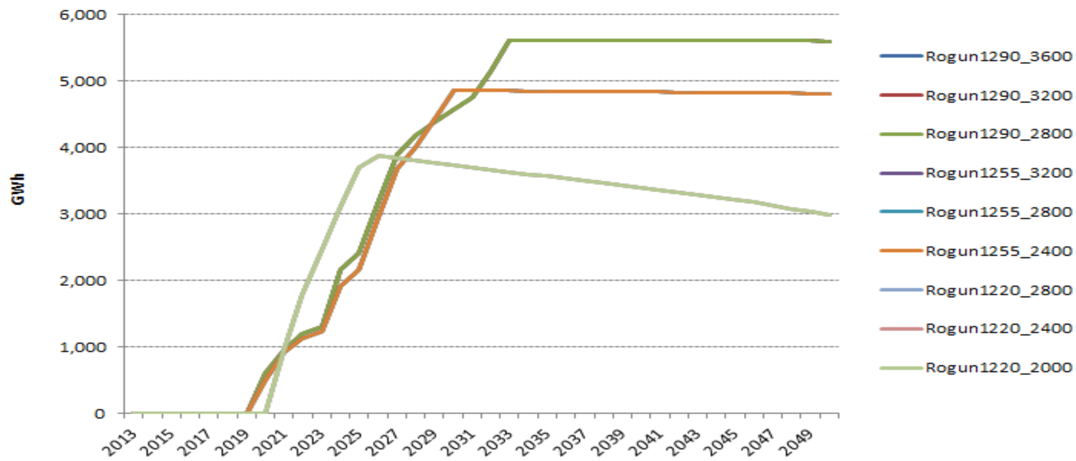


Source: Coyne et Bellier and IPA analysis.

Expected seasonal generation

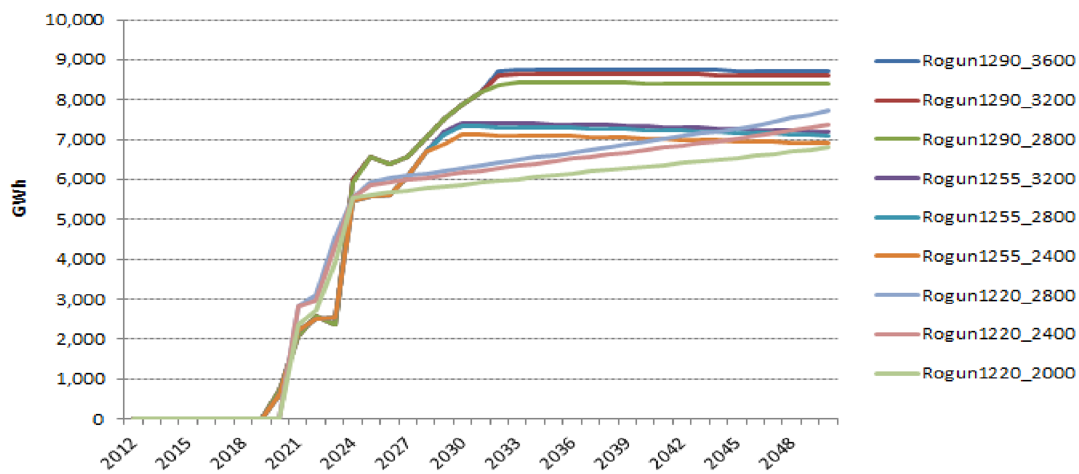
Monthly generation figures were provided by Coyne et Bellier and take the effect of sedimentation into account. Dispatch in winter, shown in Figure 13 below, is expected to be lower than dispatch in the summer, shown in Figure 14 further below. The difference in generation between the smallest and highest dam options is larger in the winter than in the summer. In the short-run, the difference in generation from the smallest and highest dam options is small. The value of surplus generation in summer, i.e. generation that exceeds domestic demand, can be measured by Tajikistan's ability to monetise this surplus electricity by exporting it to the neighbouring markets.

Figure 13: Rogun expected winter generation



Source: Coyne et Bellier and IPA analysis.

Figure 14: Rogun expected summer generation

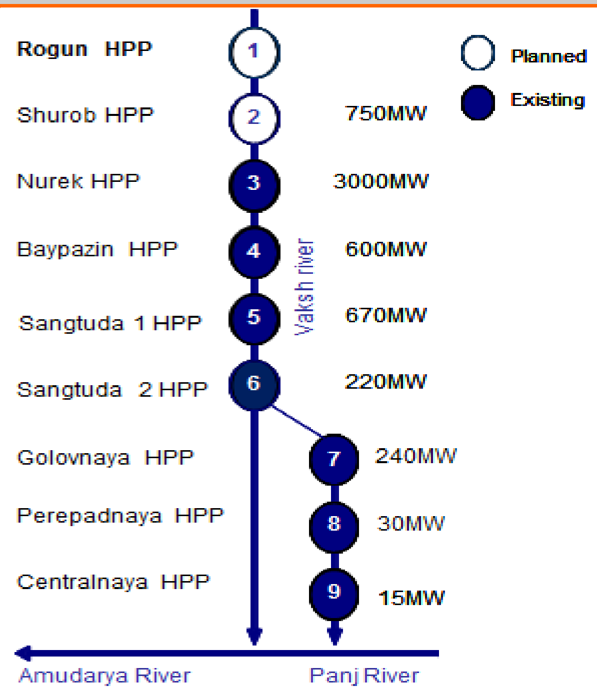


Source: Coyne et Bellier and IPA analysis.

4.4. Impact of Rogun on the Vakhsh cascade

The Vakhsh cascade includes eight existing and/or planned HPPs excluding Rogun: Shurob, Nurek, Baypazin, Sangtuda 1, Sangtuda 2, Goluvnaya, Centralnaya and Perepadnaya HPPs, as illustrated in Figure 15 below.

Figure 15: HPPs on the Vakhsh cascade



Note: Shurob is still in planning stage and is considered as one of the supply options in the Economic New Builds in Tajikistan, discussed in subsection 4.7.4.

Source: World Bank (2010) Terms of Reference – TEAS for Rogun HPP, *IPA analysis.*

An update of Coyne et Bellier's *Vakhsh Cascade Simulation Study – TEAS for Rogun HPP* study (September 2012) provided to IPA on 28 October 2013 presents the expected impact of the Project on downstream HPPs. The results of their analysis are summarised in Table 14 and Figure 16 below. The analysis suggests that, although it will be slightly reduced during the construction and reservoir fill period, total output from the Vakhsh cascade will be improved once the Project is fully operational.[9]

[9] IPA understands that the Project was simulated such as not to change the Nurek outflow condition.

Table 14: Expected annual generation of HPPs in the Vakhsh cascade (2033)[1]

GWh	Status	without Rogun	1,290 masl	1,255 masl	1,220 masl
Nurek	Existing	11,376	12,373	12,390	12,055
Baypazin	Existing	2,657	2,636	2,639	2,641
Sangtuda 1	Existing	2,980	2,955	2,959	2,961
Sangtuda 2	Existing	1,064	1,054	1,055	1,056
Goluvnaya	Existing	1,157	1,150	1,152	1,153
Perepadnaya/ Centralnaya[2]	Existing	203	200	203	203
Total downstream HPPs		**18,372**	**20,368**	**20,399**	**20,068**

[1]: The year 2033 was chosen for illustrative purposes as it is the year in which the largest Rogun option would be at full generation. However, note that the annual generation of the cascade varies over time, especially towards the end of the Forecast Horizon, as a result of sedimentation.

[2]: We consider Perepadnaya and Centralnaya as combined "Aggregated Hydro-Run Of River ("ROR")-Vakhsh" for all modelling purposes. The impact of the Project on Perepadnaya and Centralnaya was not assessed in detail in Coyne et Bellier's reservoir simulations. Therefore, for the purposes of the Assignment, we have assumed that the impact of the Project on the annual generation of these HPPs is in line with the impact observed on the downstream HPPs that were included in the study.

Source: Coyne et Bellier and IPA analysis.

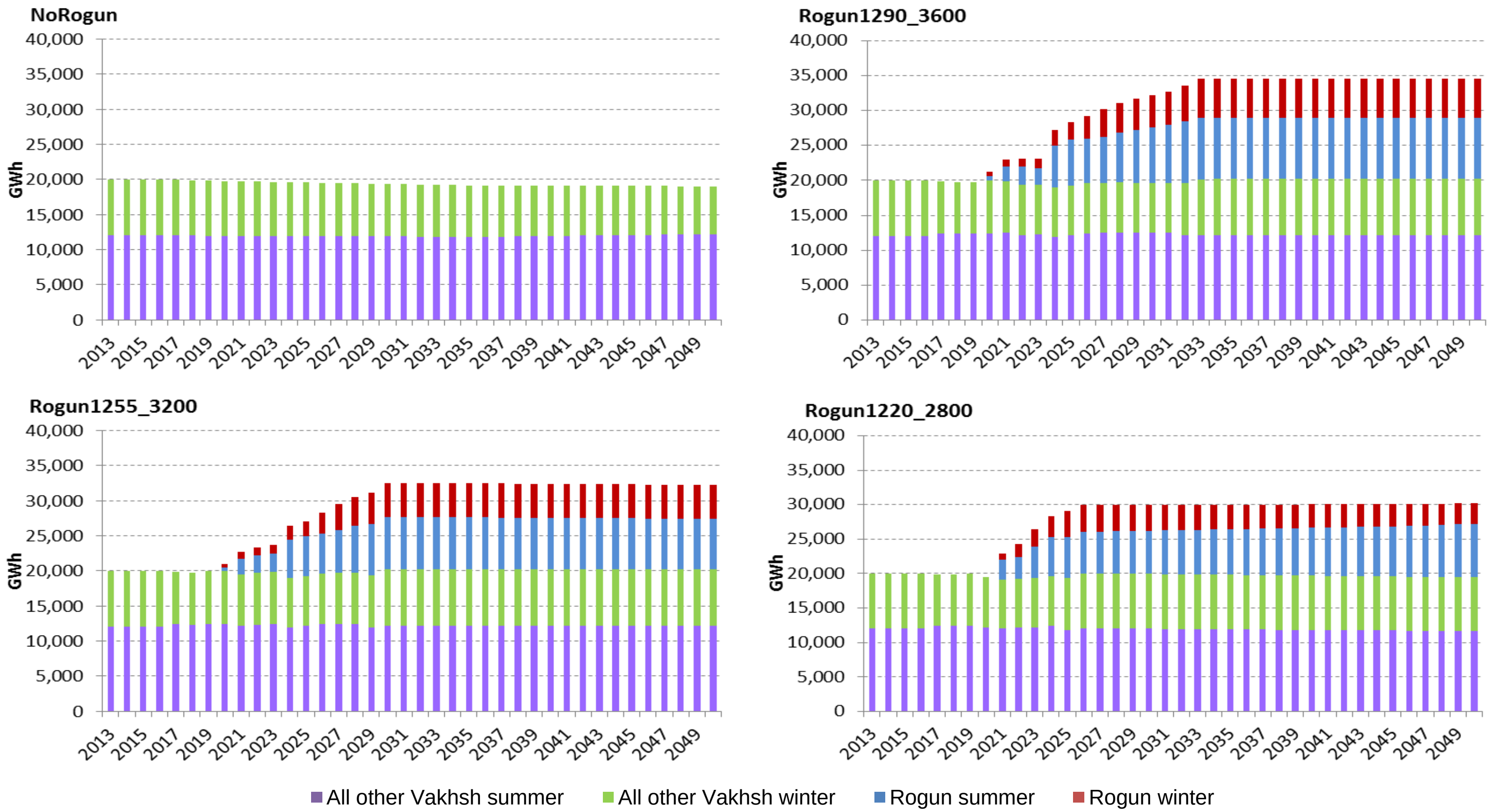
Flood protection benefits

The construction of some of the Rogun design options will provide additional benefits to the Vakhsh cascade in the form of protection from flooding. Analysis by Coyne et Bellier has identified that the two higher dam options (1,290 masl and 1,255 masl) will provide suitable protection but that the lowest option (1,220 masl) will not. Consequently, for an appropriate comparison, the additional costs of providing adequate flood protection should be added to the system costs incurred in the lowest and the No Rogun cases.

As a minimum, additional spillways would have to be constructed at the Nurek HPP. The cost of these spillways was estimated by Coyne et Bellier at USD318million, although estimates by the Government of Tajikistan suggest that the cost to protect the full cascade could be as much as USD945million. For the purposes of our system cost savings and economic analyses, we have chosen to use the more conservative figure, but it should be noted that the benefit provided by the two higher Rogun dam options could in fact be greater than expressed herein.

The value for the flood protection benefit is applied in both the system cost savings and economic analyses, albeit in opposite ways. For the former, it is added as an additional cost (assumed spread equally over four years to construct the spillways coincident with the completion of the 1,290 masl Rogun option) for the No Rogun and 1,220 masl design options to accrue the same benefit. For the latter, it is attributed as a specific benefit of the 1,290 and 1,255 masl design options (coincident with their respective completion dates).

Figure 16: Expected annual generation of HPPs in the Vakhsh cascade



Source: Coyne et Bellier and IPA analysis.

4.5. Demand forecast in Tajikistan

We conducted a detailed analysis on future electricity demand in Tajikistan. The full methodology is detailed in Annex C and a summary of the main results used in the least-cost modelling analysis are presented in this subsection 4.5 below.

4.5.1. Modelling annual demand

Our annual demand forecast is separated into two components: TALCO's demand, which is not expected to be as sensitive to Gross Domestic Product ("GDP") and tariff changes as the rest of the economy, and non-TALCO demand.

TALCO demand

For TALCO's demand, we assume that TALCO will follow the energy efficiency plan described by the World Bank and supported by the Government of Tajikistan in the TWEC report which foresees a drop in electricity use of 1,180GWh by 2018[5].

Non-TALCO demand

For the non-TALCO segments, our approach utilises two relationships to drive the electricity demand forecast:

1. The income elasticity of demand which gives the percentage change in demand that would result from a one percent (1.0%) increase in GDP

2. The price elasticity of demand which gives the percentage change in demand that would result from a one percent increase in electricity tariffs.

The product of the relevant elasticity with the GDP and tariff growth rate will give the effect of GDP and tariff changes on demand, and the sum of these two effects will give the total predicted growth rate of electricity demand in that year. The demand growth rate is then applied to a starting level of demand. Our starting demand is based on 2010 electricity consumption data from Tajikistan Statistics net of TALCO's consumption but including our estimate of unserved demand. The projected annual growth rate is then applied to this net demand before TALCO's consumption is then added back to give total demand. Total required electricity generation, as used in the least-cost generation expansion analysis, is equal to this electricity demand plus total losses.

4.5.2. Peak and annual demand forecasting results

In our modelling, electricity demand is defined as required generation, i.e. electricity consumption plus unserved demand and losses. Since losses are not trivial, required generation will be significantly higher than electricity consumption. IPA's central electricity generation requirement forecast is shown in Table 15 below. The range of demand forecasts is shown in Figure 17 below. The darker highlighted area indicates the range of forecasts that fall between the 25th and 75th percentiles, the lighter area is the outer range of our simulated forecast range. For comparison purposes only, we overlay the forecasts from other studies.

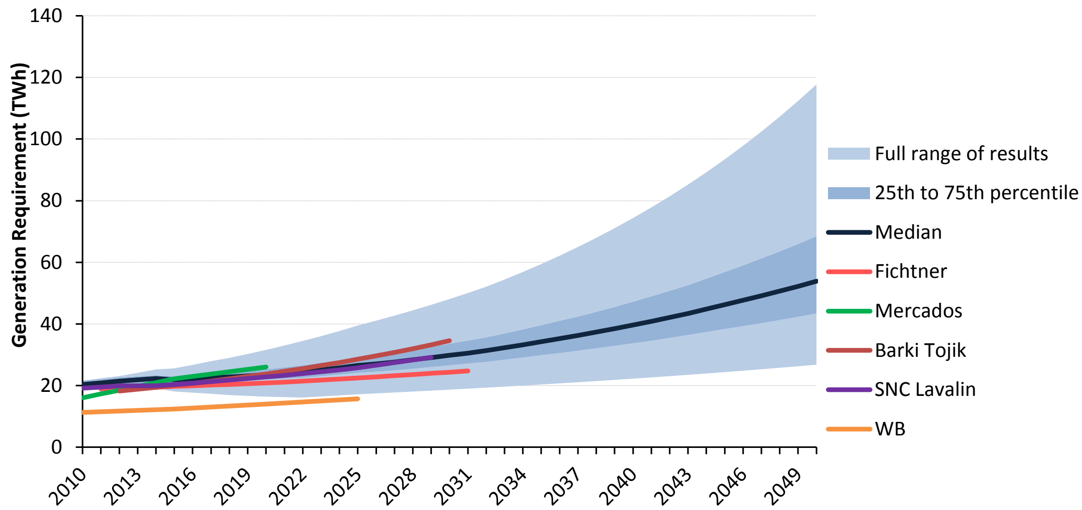
Table 15: IPA central peak and annual electricity generation requirement forecast

Year	Annual electricity generation requirement[1] (TWh)	Annual growth rate (%)	Annual peak demand (GW)	Annual growth rate (%)
2013	21.85	1.83%	4.17	1.83%
2014	22.27	1.91%	4.25	1.91%
2015	21.86	-1.86%	4.17	-1.86%
2016	22.19	1.50%	4.24	1.50%
2017	22.54	1.61%	4.30	1.61%
2018	22.78	1.05%	4.35	1.05%
2019	23.17	1.69%	4.42	1.69%
2020	23.58	1.77%	4.50	1.77%
2021	24.02	1.89%	4.59	1.89%
2022	24.51	2.05%	4.68	2.05%
2023	25.13	2.53%	4.80	2.53%
2024	25.77	2.54%	4.92	2.54%
2025	26.51	2.84%	5.06	2.84%
2026	27.07	2.13%	5.17	2.13%
2027	27.64	2.10%	5.28	2.10%
2028	28.39	2.72%	5.42	2.72%
2029	29.09	2.45%	5.55	2.45%
2030	29.80	2.47%	5.69	2.47%
2031	30.54	2.48%	5.83	2.48%
2032	31.35	2.65%	5.99	2.65%
2033	32.28	2.95%	6.16	2.95%
2034	33.27	3.07%	6.35	3.07%
2035	34.25	2.95%	6.54	2.95%
2036	35.23	2.86%	6.73	2.86%
2037	36.26	2.93%	6.92	2.93%
2038	37.37	3.05%	7.13	3.05%
2039	38.46	2.93%	7.34	2.93%
2040	39.65	3.08%	7.57	3.08%
2041	40.88	3.10%	7.80	3.10%
2042	42.10	3.00%	8.04	3.00%
2043	43.36	2.99%	8.28	2.99%
2044	44.80	3.32%	8.55	3.32%
2045	46.29	3.32%	8.84	3.32%
2046	47.70	3.04%	9.11	3.04%
2047	49.16	3.07%	9.39	3.07%
2048	50.68	3.08%	9.68	3.08%
2049	52.23	3.07%	9.97	3.07%
2050	53.90	3.19%	10.29	3.19%

[1]: Electricity generation requirement is domestic demand net of plant auxiliary consumption and industrial demand supplied by captive power generation facilities, gross of losses.

Source: IPA analysis.

Figure 17: Generation requirement forecast and comparison with other studies



Source: Fichtner (October 2012) CAREC Power Sector Regional Master Plan, *Mercados (October 2010)* Load Dispatch and System Operation Study for CAPS, *SNC Lavalin (August 2011)* Technical Memorandum #2: Tajikistan Power Supply Options Study, *World Bank (December 2004)* Regional Electricity Export Potential Study, *Client and IPA analysis.*

Five studies have reported what we have termed generation requirement (i.e. including losses). The Client has forecast a stronger growth in electricity generation requirement than us. Their forecast starts from a lower level than our forecast but ends up close to our 75th percentile, indicating a less conservative expectation of future demand. The Mercados (2010) report also has a lower starting level of required generation in 2010 than any of our forecasts, but predicts a rapid growth rate so that it is above our median by 2020. After this period, there appears to be an error in their calculation, as demand triples in two years. The forecast from this point onwards is therefore not shown in Figure 17 above. SNC Lavalin's (2011) and Fichtner's (October 2012) required generation forecasts have the same relative positions to the median as in the demand forecast, with SNC Lavalin's predictions very close to the median and Fichtner's outside the 25th percentile but within the range of our forecast. The World Bank's (2004) forecast is particularly low in comparison to ours. This is because it predicted that demand would have fallen to 11 TWh by 2010 in response to planned tariff increases by Barki Tojik that were never implemented.

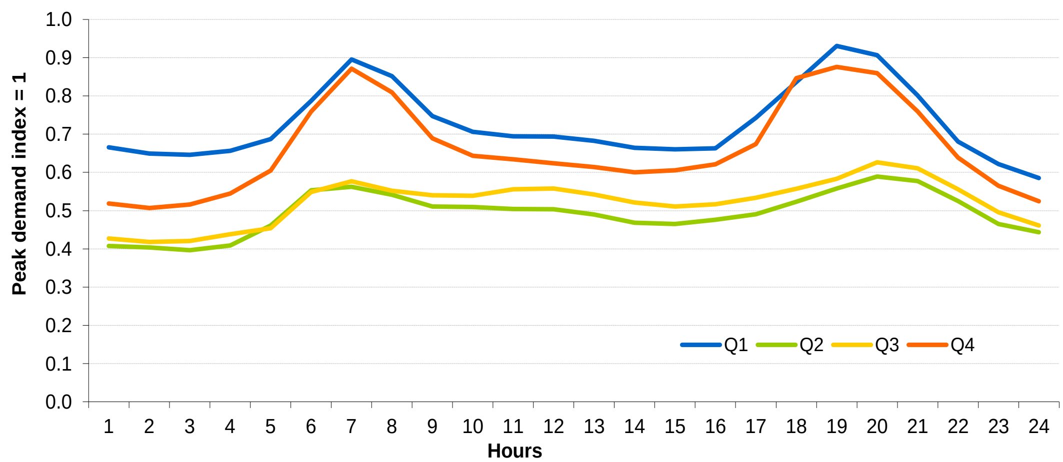
4.5.3. Hourly load profile

In order to capture the fluctuations in energy demand within a particular year, we have defined representative weekday and weekend demand profiles, one for each quarter.[10] Each day sub-divided into twenty four (24) segments to capture deviations in demand across peak, shoulder and off-peak periods. These curves were in turn calibrated so that, for every RY, the maximum hourly demand matches the peak energy demand forecast and the sum of the hourly energy demands equals the annual energy demand forecast. The resulting hourly load profiles

[10] First quarter ("Q1"): January-March, second quarter ("Q2"): April-June, third quarter ("Q3"): July-September, fourth quarter ("Q4"): October-December.

for each quarter are shown in Figure 18. The hourly load profiles are calculated based on historical average hourly demand data from 2005 to 2010 provided by the Client. The hourly load profiles are adjusted for unserved demand as estimated by IPA, and for future changes in the load profiles, provided in Fichtner *Central Asia Regional Economic Cooperation* ("CAREC") report (October 2012).

Figure 18: Tajikistan hourly load profile



Source: Client and IPA analysis.

4.5.4. Minimum reserve margin

We define a country's minimum reserve margin as the minimum amount of dependable capacity above the national annual peak hourly demand needed to ensure an adequate level of supply security. Up to 2019 we do not require Tajikistan to hold a reserve but after 2020 CAPS ECLIPSE® will target a minimum reserve margin of 10%.[11]

4.6. Demand forecast in neighbouring countries

This subsection 4.6 summarises our demand forecast assumptions for the neighbouring markets of Uzbekistan, Turkmenistan, Kyrgyzstan and Pakistan which are endogenously modelled in the CAPS ECLIPSE®.

[11] Note, however, that we never allow for the transfer of firm capacity (measured in kW/year) across interconnectors. Hence, a country can only meet its minimum reserve requirement by relying on domestic power plants.

4.6.1. Peak and annual generation requirement forecasts

Table 16: Peak and annual generation requirement in neighbouring countries

Year	Uzbekistan		Turkmenistan		Kyrgyzstan		Pakistan	
	Total annual (TWh)	Peak (GW)	Total annual (TWh)	Peak (GW)	Total annual (TWh)	Peak (GW)	Total annual (TWh)	Peak (GW)
2013	55.80	9.37	13.71	2.31	12.13	2.92	157.46	25.14
2014	57.78	9.77	13.97	2.35	12.26	2.92	169.53	27.14
2015	59.60	10.15	14.24	2.40	12.39	2.92	183.27	29.41
2016	61.00	10.47	14.51	2.44	12.41	2.89	199.61	32.33
2017	62.43	10.80	14.79	2.49	12.43	2.87	216.67	34.93
2018	63.89	11.14	15.07	2.54	12.44	2.84	235.27	38.01
2019	65.45	11.49	15.35	2.58	12.46	2.82	256.57	41.55
2020	67.06	11.78	15.64	2.63	12.52	2.80	279.65	45.40
2020	68.72	12.07	15.94	2.68	12.70	2.82	304.49	49.55
2022	70.89	12.45	16.24	2.73	12.91	2.83	330.81	53.97
2022	73.13	12.84	16.55	2.79	13.11	2.88	358.58	58.64
2024	75.76	13.31	16.87	2.84	13.32	2.92	387.73	63.57
2024	78.49	13.78	17.19	2.89	13.53	2.97	418.19	68.74
2026	81.32	14.28	17.51	2.95	13.74	3.02	449.74	74.11
2027	84.24	14.79	17.85	3.00	13.96	3.06	482.45	79.71
2028	87.28	15.33	18.19	3.06	14.18	3.11	516.02	85.47
2029	90.42	15.88	18.53	3.12	14.51	3.19	550.43	91.41
2030	93.67	16.45	18.88	3.18	14.80	3.25	585.69	97.52
2031	97.05	17.04	19.24	3.24	15.10	3.31	623.33	104.07
2032	100.54	17.66	19.61	3.30	15.36	3.36	663.24	111.04
2033	104.16	18.29	19.98	3.36	15.62	3.42	705.58	118.45
2034	107.91	18.95	20.36	3.43	15.89	3.47	750.64	126.37
2035	111.79	19.63	20.75	3.49	16.16	3.52	798.52	134.81
2036	115.82	20.34	21.14	3.56	16.44	3.58	834.45	140.88
2037	119.99	21.07	21.54	3.63	16.72	3.63	872.00	147.22
2038	124.31	21.83	21.95	3.70	17.01	3.69	911.24	153.85
2039	128.78	22.62	22.37	3.77	17.30	3.74	952.25	160.77
2040	133.42	23.43	22.79	3.84	17.60	3.80	985.57	166.40
2041	138.22	24.28	23.23	3.91	17.90	3.86	1,020.07	172.22
2042	143.20	25.15	23.67	3.99	18.21	3.92	1,055.77	178.25
2043	148.35	26.06	24.12	4.06	18.52	3.98	1,092.72	184.49
2044	153.69	27.00	24.58	4.14	18.84	4.04	1,130.97	190.94
2045	159.23	27.97	25.04	4.22	19.16	4.10	1,170.55	197.63
2046	164.96	28.98	25.52	4.30	19.49	4.17	1,211.52	204.54
2047	170.90	30.02	26.00	4.38	19.82	4.23	1,253.93	211.70
2048	177.05	31.10	26.50	4.46	20.16	4.30	1,297.81	219.11
2049	183.42	32.22	27.00	4.55	20.51	4.36	1,343.24	226.78
2050	190.03	33.38	27.52	4.63	20.86	4.43	1,390.25	234.72

[1]: Electricity generation requirement is domestic demand net of plant auxiliary consumption and industrial demand supplied by captive power generation facilities, gross of losses.

Source: Fichtner (October 2012); Mercados (October 2010); Asian Development Bank ("ADB") (October 2009) Energy Outlook for Central and West Asia*; National Transmission and Despatch Company ("NTDC") (September 2011)* National Power System Expansion Plan 2011-2030.

Peak and annual demand forecasts for each of the modelled neighbouring countries have been based on information from the following respective sources:

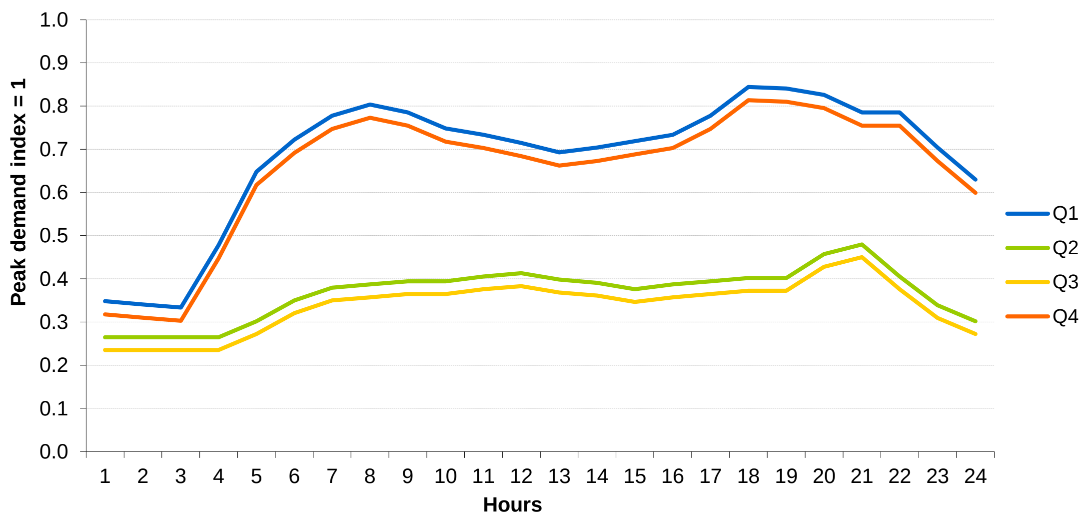
- Uzbekistan: peak demand growth rates reported in World Bank (June 2013) *Uzbekistan Energy Sector Issues Note*.
- Kyrgyzstan: peak demand growth rates reported in Fichtner (October 2012).
- Turkmenistan: the 2010 peak and annual demand figures provided in Mercados (October 2010) and the peak and annual demand growth rates provided in Asian Development Bank ("ADB") (October 2009) *Energy Outlook for Central and West Asia*.
- Pakistan: National Transmission and Despatch Company ("NTDC") (2011) *National Power System Expansion Plan 2011-2030*.

4.6.2. Hourly load profiles

Due to the unavailability of detailed hourly load profiles for Uzbekistan and Turkmenistan, and given their similarity with Tajikistan, we assume that the hourly load profiles for these two countries are the same as the hourly load profile estimated for Tajikistan. Their hourly load profiles are therefore the same as shown in Figure 18 above.

The hourly load profile for Kyrgyzstan, shown in Figure 19 below, is derived from the 2010 winter and summer twenty four (24) hour load curves and annual peak demand data provided in Fichtner (October 2012) *CAREC* report.

Figure 19: Kyrgyzstan hourly load profile

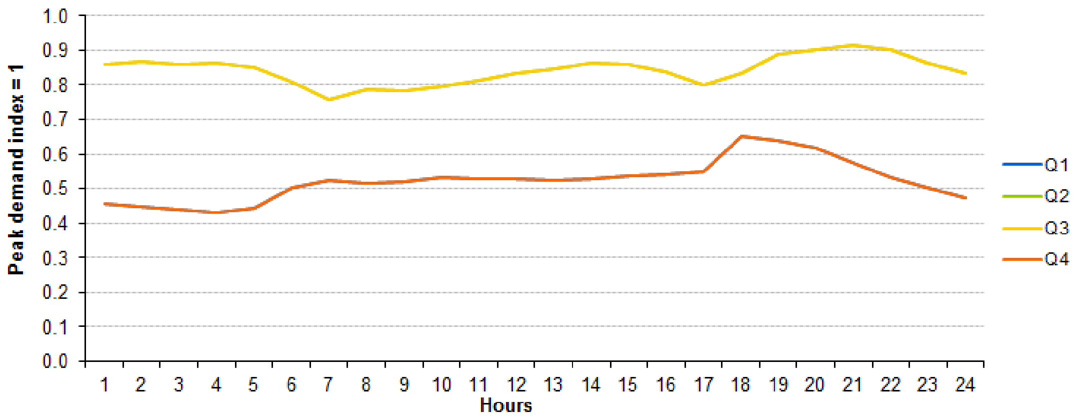


Source: Fichtner (October 2012).

The hourly load profile for Pakistan, shown in Figure 20 below, is derived from the 2010 hourly demand data for winter (mapped to Q1 and Q4) and summer (mapped to Q2 and Q3) from Pakistan's National Electric Power Regulatory Authority ("NEPRA") (2011) *State of Industry Report* and the 2011 annual peak demand data estimated in NTDC (February 2011)

Electricity Demand Forecast based on Multiple Regression Analysis. As can be seen by comparing Figure 20 below to Figure 18 above, Pakistan in a summer-peaking system whist Tajikistan is a winter-peaking system.

Figure 20: Pakistan hourly load profile



Note: The demand profiles for Q1 and Q4 overlap in the figure, as do those for Q2 and Q3.

Source: NEPRA (2011) State of Industry Report.

4.6.3. Minimum reserve margin

The minimum reserve margin applied to other countries is the same as for Tajikistan. Up to 2019 we do not require any country to hold a reserve but after 2020 CAPS ECLIPSE® will target a minimum reserve margin of 10%.[11]

4.7. Supply options in Tajikistan

4.7.1. Tajikistan resource endowment

Tajikistan has some coal deposits, mainly located in the Pyandzh and Leninabad region[12], and significant hydro potential. The majority of Tajikistan's HPPs are located on the Vakhsh River, which is the most important source of electricity generation in the country and is driven by seasonal glacial and snow melting. During the winter, the Vakhsh flow rate falls significantly. Although some water can be stored in reservoirs to power the HPPs during winter, the lower flow rate results in much lower generation levels. Table 17 below summarises the energy resource endowments in Tajikistan.

[12] USGS (2010) *Minerals Yearbook Tajikistan* (http://minerals.usgs.gov/minerals/pubs/country/2010/myb3-2010-ti.pdf).

Table 17: Tajikistan energy resource endowments

Natural resource	Unit	Quantity
Gas reserves[1]	cubic feet	modest/negligible
Coal reserves	tonnes	3.6 billion
Oil reserves[1]	bbl	modest/negligible
Hydro potential	MW	40,000

[1] USGS (2011) *Assessment of Undiscovered Oil and Gas Resources of the Amu Darya Basin and Afghan–Tajik Basin Provinces, Afghanistan, Iran, Tajikistan, Turkmenistan, and Uzbekistan* study suggests there are recoverable oil and gas reserves in Afghan–Tajik Basin Province. However, there has not been any information of the exploitation of these reserves, the size or earliest available date of these reserves.

Source: World Bank (June 2007) Potential and Prospects for Regional Energy Trade in the South Asia Region (http://siteresources.worldbank.org/SOUTHASIAEXT/Resources/223546-1192413140459/4281804-1192413178157/4281806-1194474073434/SAR_Energy_Trade_Nov_07.pdf).

4.7.2. Existing power plants in Tajikistan

As shown in Table 18 below, the existing installed capacity in Tajikistan is currently around 5,258MW, 94% of which is made up by HPPs.

Table 18: Existing generation options in Tajikistan

Power plant	Installed capacity (MW)	Technology	Fuel	COD	Expected retirement date
Hydro					
Nurek	3,000	Dam	Water	1974	-
Baypazin	600	ROR	Water	1986	-
Sangtuda 1	670	ROR	Water	2009	-
Goluvnaya	240	ROR	Water	1963	-
Kayrakkum	126	Dam	Water	1957	-
Pamir 1	14	ROR	Water	1994	-
Varzob 1	7.4	ROR	Water	1937	-
Varzob 2	14.4	ROR	Water	1949	-
Varzob 3	3.5	ROR	Water	1952	-
Perepadnaya	30	ROR	Water	1960	-
Centralnaya	15	ROR	Water	1964	-
Sangtuda 2	220	ROR	Water	2012	-
Thermal					
Dushanbe 1	198	Steam Gas	Natural Gas	1972	2017
Yavan	120	Steam Gas	Natural Gas	1969	2014

Note: "ROR" = Run-Of-River, "COD" = Commissioning Online Date.

Source: the Client, Platts (April 2011) WEPP, IPA research.

Some of the HPPs above were commissioned over 40 years ago and are therefore expected to undergo rehabilitations in the near future. The planned rehabilitations are listed in Table 19 below.

Table 19: Generation option rehabilitation

Power plant	Total capacity rehabilitated (MW)	Capacity rehabilitation per year (MW/year)	Cost (USD million)	Restoration period	
				Start year	End year
Nurek	3,000	500	450	2013	2020
Kayrakkum	126	42	129	2013	2016
Goluvnaya	240	70	120	2014	2017
Perepadnaya	30	10	30	2014	2017
Centralnaya	15	7.5	30	2015	2017
Varzob 1,2 & 3	27	15	30	2013	2015

Source: Client, Fichtner (April 2012) Interim Report Assessment of Tajikistan Power Supply Options and IPA calculations *prepared for the World Bank.*

4.7.3. Technical characteristics for existing power plants in Tajikistan

This subsection 4.7.3 summarises the technical characteristics and dispatch constraints associated with each existing power plant in Tajikistan, shown in Table 20 below.

Thermal efficiency

The thermal efficiency of a power plant reflects the rate at which it converts the energy contained in the fuel into the electricity delivered to the grid after allowing for own consumption ("net generation"). Thermal efficiency for HPPs is 100%. For thermal plants, it is based on the Higher Heating Value ("HHV") energy content of the fuel.

Own consumption, Equivalent Forced Outage Rate and Reserve Margin Contribution

Own consumption refers to the electricity consumed within the boundary of a power plant in order for it to run and generate electricity. The Equivalent Forced Outage Rate ("EFOR") is the portion of time for which a unit is unavailable due to full or partial, unplanned downtime.

To maintain a high level of reliability within the power system, a certain amount of capacity has to be made available during peak periods to compensate for potential forced outages of generators. A plant's Reserve Margin Contribution ("RMC") is our estimate of the dependable capacity which the system operator can rely on during peak periods. For thermal power plants, the RMC is measured as the percentage of a plant's installed capacity derated for its own consumption and EFOR. For Run-Of-River ("ROR") HPPs, RMC is set equal to their capacity factor in Q1 for all countries except Pakistan which is based on their capacity factor in Q2. For other Dam HPPs, we assume that they can be fully dispatched in the peak hour and only adjust downwards for own consumption and EFOR.

Maximum Annual Capacity Factor

The Maximum Annual Capacity Factor ("Max ACF") defines the maximum annual generation delivered to the grid as a percentage of the product of installed capacity and 8,760, the total number of hours in the year[13]. For thermal plants, this is the same as the RMC. For resource constrained power plants like HPPs and cogeneration facilities, we cap a plant's annual output based on historical data.

Maximum and minimum hourly dispatch

The maximum hourly dispatch for thermal power plants is its RMC. The maximum and minimum hourly dispatch for HPPs varies throughout the year with water flow in the rivers and is based on historical information.

Technical lifetimes

ECLIPSE® will retire power plants at the end of their technical lifetime. We assume that no HPP will retire in 2013-2050. All types of steam turbine power plants are assumed to have a technical lifetime of 45 years. Outside Tajikistan there are other types of power plants and their lifetimes vary with Open Cycle Gas Turbine ("OCGT"), Combined Cycle Gas Turbine ("CCGT") and Internal Combustion ("IC") engines capped at 35 years and nuclear plants at 50 years.

[13] Maximum annual generation will therefore be capped at the product of Max ACF, installed capacity and total number of hours in the year (8,760).

Table 20: Technical characteristics of existing plants in Tajikistan

Plant	Capacity type	Efficiency (net HHV) [1]	RMC [2,3] (% i.c.)[5]	Max ACF[3] (% i.c.)	Max hourly dispatch (% i.c.) [3]				Min hourly dispatch (% i.c.) [3]			
					Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Nurek	Hydro Dam	N.A.	99.9%	42.9%	99.9%	99.9%	99.9%	99.9%	15.1%	21.3%	32.8%	16.5%
Baypazin	Hydro ROR	N.A.	37.1%	50.0%	37.1%	54.2%	72.1%	36.5%	37.1%	54.2%	72.1%	36.5%
Sangtuda 1	Hydro ROR	N.A.	37.4%	50.3%	37.4%	54.3%	72.2%	36.9%	37.4%	54.3%	72.2%	36.9%
Goluvnaya	Hydro ROR	N.A.	41.5%	54.7%	41.5%	58.7%	77.6%	40.8%	41.5%	58.7%	77.6%	40.8%
Kayrakkum	Hydro Dam	N.A.	99.9%	49.9%	99.9%	99.9%	99.9%	99.9%	37.0%	23.1%	20.5%	19.4%
Pamir 1	Hydro ROR	N.A.	44.8%	53.4%	44.8%	55.9%	72.0%	40.6%	44.8%	55.9%	72.0%	40.6%
Aggregated Hydro ROR Varzob	Hydro ROR	N.A.	44.8%	53.4%	44.8%	55.9%	72.0%	40.6%	44.8%	55.9%	72.0%	40.6%
Aggregated Hydro ROR Vakhsh	Hydro ROR	N.A.	38.0%	50.9%	38.0%	55.0%	73.0%	37.3%	38.0%	55.0%	73.0%	37.3%
Dushanbe[4]	Steam Gas	16.0%	21.8%	14.5%	21.8%	7.3%	7.3%	21.8%	21.8%	7.3%	7.3%	21.8%
Yavan[4]	Steam Gas	16.0%	21.8%	14.5%	21.8%	7.3%	7.3%	21.8%	21.8%	7.3%	7.3%	21.8%

Note: Abbreviations are defined in the Glossary.

[1]: Thermal efficiency is defined on an all-fuel-to-power basis.

[2]: The RMC is set to be equal to the maximum hourly dispatch of Q1.

[3]: The RMC, Max ACF and hourly dispatch of downstream HPPs in the Vakhsh cascade will change when Rogun is brought online, figures shown are for 2050.

[4]: The dispatch of the Steam plants (Dushanbe and Yavan) is calibrated to match historical generation.

[5]: “i.c.” = Installed Capacity.

Source: the Client and IPA research.

O&M costs

Table 21 below provides a breakdown of non-fuel Variable O&M ("VOM") and Fixed O&M ("FOM")[14] costs by capacity type.

Table 21: O&M costs for existing power plants in Tajikistan

Plant	VOM (USD/MWh)	FOM (USD/kWy)	Total annual non-fuel O&M costs[1] (USD/MWh)	(USD/kWy)
Nurek	0.0	20.9	2.38	20.88
Baypazin	0.0	21.4	2.45	21.43
Sangtuda 1	0.0	21.4	2.45	21.43
Goluvnaya	0.0	21.4	2.45	21.43
Kayrakkum	0.0	20.9	4.78	20.88
Pamir 1	0.0	21.4	4.58	21.43
HydroROR-Varzob	0.0	21.4	4.58	21.43
HydroROR-Vakhsh	0.0	21.4	2.45	21.43
Dushanbe	2.7	31.3	27.36	34.73
Yavan	2.7	31.3	27.36	34.73

[1]: Representative figures assuming Max ACF.

Source: the Client and IPA research.

4.7.4. New Build Options in Tajikistan

In this subsection 4.7.4, we review the list of Firm and Economic New Builds in Tajikistan. We distinguish between two types of new power plants ("New Builds") that we assume to come online on a firm basis ("Firm New Builds") and those that are endogenously determined by ECLIPSE® according to economic merit ("Economic New Builds"). To meet the demand and minimum RM requirements, ECLIPSE® takes into account Firm New Builds to establish the most cost-effective deployment of Economic New Builds.

Based on information from the Client, Fichtner (April 2012) and the Platts' WEPP database, we have developed a view on Firm and Economic New Builds summarised in Table 22 and Table 23 respectively below. Note that for Economic New Builds we define the earliest year in which CAPS ECLIPSE® can bring the option online. Generic ROR are a catch all for other ROR Dam projects that have yet to be identified. These are particularly important in the No Rogun cases since without this Generic ROR option, Tajikistan would suffer capacity shortages at the end of the Forecast Horizon.

Tajikistan has limited potential for other renewables such as wind, geothermal, waste-to-energy, and solar PV[15], and so these technologies have not been considered as significant capacity expansion options for the modelling.

[14] Since some FOM costs, such as major periodic maintenance, may not occur every year, the estimated FOM values represent an annualised average.
[15] World Bank (November 2012) *Tajikistan's Winter Energy Crisis: Electricity Supply and Demand Alternatives*.

Table 22: Firm New Builds in Tajikistan

Power plant	Installed capacity (MW)	Technology	COD	Status
Hydro				
Langar	0.06	ROR	2014	Under construction
Andarbak	0.25	ROR	2013	Under construction
Emts	0.1	ROR	2016	Under construction
Shkev	0.075	ROR	2015	Under construction
Yamchun	0.15	ROR	2015	Under construction
Pamir 2	14	ROR	2014	Under construction
Dastijum[1]	4,000	Dam	2030 / 2033	Under planning
Thermal				
Dushanbe 2	100	Coal	2015	Planned

[1]: Dashtijum is treated as a Firm New Build as the main new supply option when Rogun is not built with 800 MW coming online in 2030 and a further 3,200 in 2033.

Source: the Client, Fichtner (April 2012) and Platts (2011) WEPP.

Table 23: Economic New Builds in Tajikistan

Power plant	Installed capacity (MW)	Technology	Earliest COD	Status
Hydro				
Sangvor	400	Dam	2022	Feasibility
Sanobod	125	ROR	2020	Feasibility
Shtien	300	ROR	2026	Under planning
Urfatin	300	ROR	2024	Under planning
Nurabad 1	160	ROR	2020	Feasibility
Nurabad 2	120	ROR	2022	Feasibility
Sangiston	140	ROR	2020	Under planning
Ayni	160	ROR	2020	Feasibility
Zarafshon	160	ROR	2024	Feasibility
Darg	130	ROR	2025	Under planning
Shurob[1]	850	ROR	2029	Feasibility
Dupulin	90	ROR	2026	Feasibility
Fandarya	160	ROR	2020	Feasibility
Dashtijum[2]	400 per year, up to 4,000	Dam	2040	Under planning
Obburdan	120	Dam	2020	Under planning
Generic ROR	800 per year	ROR	2035	N/A

[1]: Shurob may only be built if Rogun is.

[2]: Dashtijum is considered as an Economic New Build only when Rogun is built, with an earliest COD of 2040 (to allow sufficient planning and construction time after the completion of Rogun) and a maximum build rate of 400 MW per year.

Source: the Client.

4.7.5. Assumptions for Economic New Builds in Tajikistan

This subsection 4.7.5 reviews our Economic New Build assumptions and then describes the assumptions that are common to both Firm and Economic New Builds in Tajikistan. The assumptions for Firm and Economic New Builds in Uzbekistan, Kyrgyzstan, Turkmenistan and Pakistan, i.e. the other endogenously modelled countries, are provided in Annex D.

Value of Lost Load

When demand cannot be met, i.e. when there is demand curtailment, the associated cost is reflected in our modelling by “Unserved Demand” with a relatively high cost to effectively represent the Value of Lost Load (“VOLL”). This has been set at 1,000USD/MWh.

TIC

Table 24 below summarises the assumptions regarding the investment cost of Economic New Builds in Tajikistan. The TIC includes Engineering, Procurement and Construction (“EPC”), sponsor costs, Interest During Construction (“IDC”) and all indirect costs at the time of commissioning.

Table 24: TIC and LRCCR of Economic New Builds in Tajikistan

Economic New Build	TIC (USD/kW)	LRCCR (%TIC/y)
Hydro		
Sangvor	2,769	11.02%
Sanobod	2,894	11.02%
Shtien	2,763	11.02%
Urfatin	2,763	11.02%
Nurabad-1	2,621	11.02%
Nurabad-2	2,856	11.02%
Sangiston	2,648	11.02%
Ayni	2,615	11.02%
Zarafshon	2,615	11.02%
Darg	2,648	11.02%
Shurob	2,421	11.02%
Dupulin	2,672	11.02%
Fandarya	2,590	11.02%
Dashtijum	3,011	11.02%
Obburdan	2,692	11.02%
Others		
New CCGT	1,400	11.02%
New OCGT	840	11.75%
New Coal	2,000	10.61%
New Lignite	1,400	11.02%

Source: World Bank supplementary data to TWEC report (2012); IPA analysis and assumptions.

Levelised Real Capital Charge Rate (“LRCCR”)

The LRCCR is the minimum annual repayment on capital required from the investment so that the equity investors achieve their targeted equity return, measured as a percentage of the TIC. The LRCCR is calculated using the assumptions for the book life of 20 years for that of

New OCGT, 25 years for that of New CCGT, 30 years for that of New Coal and New Lignite, and 10% as the discount rate for all technologies.[16]

Multiplying the LRCCR by the TIC gives the annualised minimum Earnings Before Interest, Tax, Depreciation and Amortisation ("EBITDA") required, i.e. the margin over fuel and running costs required to repay debt, taxes and meet the targeted equity return. IPA establishes the LRCCR using a separate cash flow model. Given their higher expected levels of utilisation, we assume that baseload plants will be able to raise more debt than peaking plant, and as such, the assumed debt to equity ratio is higher for baseload projects, such as New Coal or New CCGT, than it is for peaking plant, such as New OCGT.

Maximum annual build constraints

Table 25 below summarises the assumptions regarding maximum annual constraints applied in the modelling of Economic New Builds in Tajikistan. Taking fuel resources and availability in Tajikistan into account, we do not allow New OCGT, New CCGT or New Lignite plants to enter the market. New Coal can be deployed only from 2018 with an annual build limit of 350MW per year from 2018[17], up to a maximum of 1,170MW.

Table 25: Annual build limits for Economic New Builds in Tajikistan

Economic New Build	Maximum build constraint
New CCGT	Not allowed
New OCGT	Not allowed
New Coal	350MW per year from 2018, up to a maximum of 1,170MW
New Lignite	Not allowed

Source: the Client, IPA assumptions.

4.7.6. Generic assumptions for New Builds in Tajikistan

O&M costs

The O&M costs for all New Builds are presented in Table 26 below. Where applicable, we have aligned these costs with the O&M costs of existing power plants which are shown in Table 21 above in subsection 4.7.3. The representative annual O&M costs are shown in the rightmost column of Table 26 below.

Technical characteristics

Table 27 below summarises generic thermal efficiency figures, dispatch and availability characteristics for all New Builds. The assumptions regarding own consumption and EFOR for thermal plants and renewable technologies are in line with historical data and IPA's best estimates. The calculation of the RMC for New Builds follows the same methodology used for existing plants described in subsection 4.7.3 above.

[16] The time period which the investors will be willing to recoup their investment over is referred to as book or investment life. This can be a shorter period than the technical lifetime of the plant.

[17] In any year, the cumulative amount of New Coal that can be developed by ECLIPSE® is equal to (Current Year–2018) × 350MW up to a maximum of 1,170MW.

Table 26: O&M costs for New Builds in Tajikistan

New Build	VOM (USD/MWh)	FOM (USD/kWy)	Annual non-fuel O&M (USD/MWh)	Annual non-fuel O&M (USD/kWy)
Firm New Builds				
Langar	-	21.43	2.45	21.43
Andarbak	-	21.43	2.45	21.43
Emts	-	21.43	2.45	21.43
Shkev	-	21.43	2.45	21.43
Yamchun	-	21.43	2.45	21.43
Pamir 2	-	21.43	2.45	21.43
Dashtijum	-	19.58	4.96	19.58
Dushanbe 2	2.90	44.32	8.86	65.87
Economic New Builds				
Sangvor	-	21.83	3.78	21.83
Sanobod	-	22.82	4.33	22.82
Shtien	-	21.78	4.33	21.78
Urfatin	-	21.78	4.37	21.78
Nurabad 1	-	20.67	4.19	20.67
Nurabad 2	-	22.52	4.50	22.52
Sangiston	-	20.88	4.52	20.88
Ayni	-	20.61	4.52	20.61
Zarafshon	-	20.61	4.52	20.61
Darg	-	20.88	4.52	20.88
Shurob	-	18.41	4.12	18.41
Dupulin	-	21.07	5.94	21.07
Fandarya	-	20.42	6.57	20.42
Obburdan	-	21.23	4.94	21.23
New CCGT	1.40	19.55	3.94	30.34
New OCGT	1.40	11.73	2.92	22.52
New Coal	2.90	44.32	8.86	65.87
New Lignite	1.40	19.55	3.94	30.34

[1]: Representative figures assuming Max ACF.

Source: Fichtner (April 2012), IPA analysis.

Table 27: Technical characteristics for New Builds

Power plant	Main fuel	Efficiency (net HHV)	Own cons. (% i.c.)	EFOR (% i.c.)	RMC (% i.c.)	Sched. maint. [1] (% i.c.)	Max ACF (% i.c.)	Max hourly dispatch (% i.c.) Q1	Max hourly dispatch (% i.c.) Q2	Max hourly dispatch (% i.c.) Q3	Max hourly dispatch (% i.c.) Q4	Min hourly dispatch (% i.c.) Q1	Min hourly dispatch (% i.c.) Q2	Min hourly dispatch (% i.c.) Q3	Min hourly dispatch (% i.c.) Q4
Firm New Builds															
Langar	Water	N.A.	5.0%	3.5%	17.1%	N.A.	100.0%	17.1%	75.7%	92.0%	23.1%	17.1%	75.7%	92.0%	23.1%
Andarbak	Water	N.A.	5.0%	3.5%	17.1%	N.A.	100.0%	17.1%	75.7%	92.0%	23.1%	17.1%	75.7%	92.0%	23.1%
Emts	Water	N.A.	5.0%	3.5%	17.1%	N.A.	100.0%	17.1%	75.7%	92.0%	23.1%	17.1%	75.7%	92.0%	23.1%
Shkev	Water	N.A.	5.0%	3.5%	17.1%	N.A.	100.0%	17.1%	75.7%	92.0%	23.1%	17.1%	75.7%	92.0%	23.1%
Yamchun	Water	N.A.	5.0%	3.5%	17.1%	N.A.	100.0%	17.1%	75.7%	92.0%	23.1%	17.1%	75.7%	92.0%	23.1%
Pamir 2	Water	N.A.	5.0%	3.5%	17.1%	N.A.	100.0%	17.1%	75.7%	92.0%	23.1%	17.1%	75.7%	92.0%	23.1%
Dashtijum	Water	N.A.	N.A.	N.A.	99.9%	N.A.	45.0%	99.9%	99.9%	99.9%	99.9%	9.4%	29.7%	39.0%	11.8%
Dushanbe 2	Hard Coal	35.0%	5.0%	5.0%	90.3%	6.0%	84.8%	90.3%	90.3%	90.3%	90.3%	90.3%	90.3%	90.3%	90.3%
Economic New Builds															
Sangvor	Water	N.A.	N.A.	N.A.	99.9%	N.A.	65.9%	99.9%	99.9%	99.9%	99.9%	21.7%	46.5%	46.5%	17.0%
Sanobod	Water	N.A.	N.A.	N.A.	20.0%	N.A.	60.1%	20.0%	100.0%	100.0%	20.0%	20.0%	100.0%	100.0%	20.0%
Shtien	Water	N.A.	N.A.	N.A.	20.0%	N.A.	57.4%	20.0%	95.2%	94.1%	20.0%	20.0%	95.2%	94.1%	20.0%
Urfatin	Water	N.A.	N.A.	N.A.	20.0%	N.A.	56.9%	20.0%	94.0%	93.0%	20.0%	20.0%	94.0%	93.0%	20.0%
Nurabad 1	Water	N.A.	N.A.	N.A.	20.0%	N.A.	56.3%	20.0%	92.9%	91.9%	20.0%	20.0%	92.9%	91.9%	20.0%
Nurabad 2	Water	N.A.	N.A.	N.A.	20.0%	N.A.	57.1%	20.0%	87.9%	99.9%	20.0%	20.0%	87.9%	99.9%	20.0%
Sangiston	Water	N.A.	N.A.	N.A.	17.8%	N.A.	52.8%	17.8%	65.1%	96.4%	31.1%	17.8%	65.1%	96.4%	31.1%
Ayni	Water	N.A.	N.A.	N.A.	17.3%	N.A.	52.0%	17.3%	64.3%	95.7%	30.1%	17.3%	64.3%	95.7%	30.1%
Zarafshon	Water	N.A.	N.A.	N.A.	17.3%	N.A.	52.0%	17.3%	64.3%	95.7%	30.1%	17.3%	64.3%	95.7%	30.1%
Darg	Water	N.A.	N.A.	N.A.	17.8%	N.A.	52.8%	17.8%	65.1%	96.4%	31.1%	17.8%	65.1%	96.4%	31.1%
Shurob	Water	N.A.	N.A.	N.A.	43.4%	N.A.	51.1%	43.4%	53.6%	67.8%	39.3%	43.4%	53.6%	67.8%	39.3%
Dupulin	Water	N.A.	N.A.	N.A.	10.2%	N.A.	40.5%	10.2%	50.3%	83.1%	17.7%	10.2%	50.3%	83.1%	17.7%
Fandarya	Water	N.A.	N.A.	N.A.	8.2%	N.A.	35.5%	8.2%	53.5%	65.4%	14.4%	8.2%	53.5%	65.4%	14.4%
Obburdan	Water	N.A.	N.A.	N.A.	99.9%	N.A.	49.1%	99.9%	99.9%	99.9%	99.9%	7.7%	30.4%	46.3%	13.4%
New CCGT	Distillate	48.0%	5.0%	2.5%	92.6%	5.0%	88.0%	92.6%	92.6%	92.6%	92.6%	0.0%	0.0%	0.0%	0.0%
New OCGT	Distillate	30.0%	5.0%	2.5%	92.6%	5.0%	88.0%	92.6%	92.6%	92.6%	92.6%	0.0%	0.0%	0.0%	0.0%
New Coal	Hard coal	35.0%	5.0%	5.0%	90.3%	6.0%	84.8%	90.3%	90.3%	90.3%	90.3%	0.0%	0.0%	0.0%	0.0%
New Lignite	Lignite	48.0%	5.0%	5.0%	90.3%	6.0%	88.0%	92.6%	92.6%	92.6%	92.6%	0.0%	0.0%	0.0%	0.0%

[1]: Scheduled maintenance.

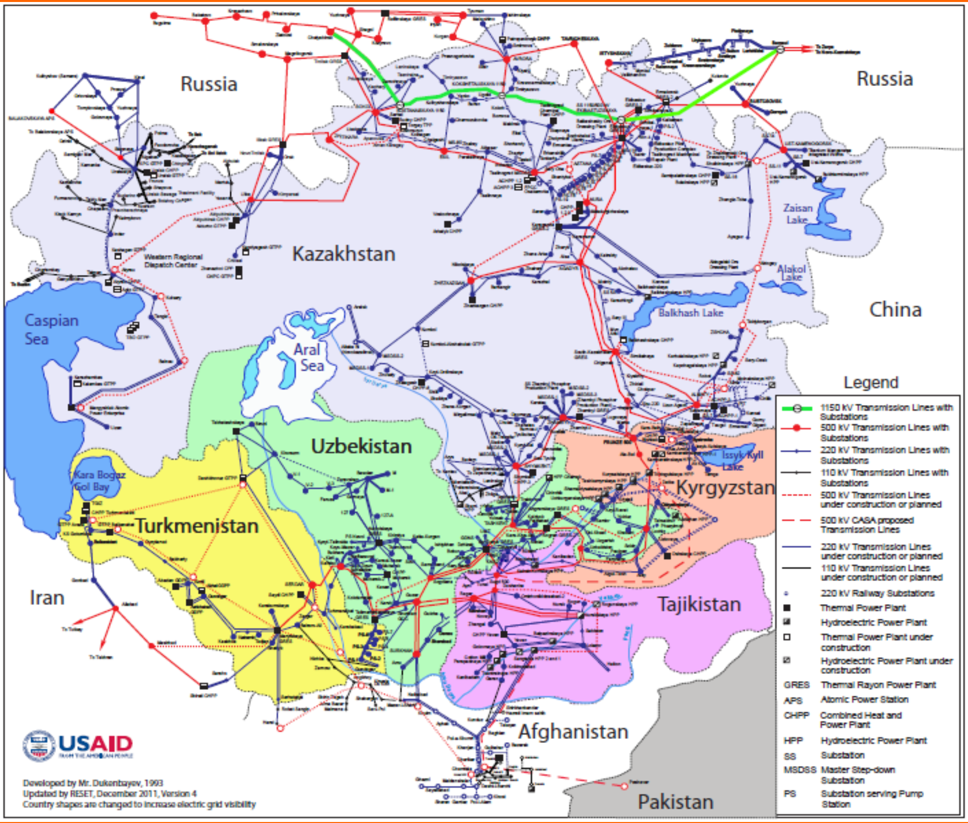
Source: the Client, Fichtner (April 2012), World Bank (November 2012) Tajikistan's Winter Energy Crisis: Electricity Supply and Demand Alternatives*, and IPA analysis.*

4.8. Interconnection with neighbouring markets

4.8.1. Central Asian Power System

The CAPS, developed under the Soviet Union, comprises the national grids of Tajikistan, southern Kazakhstan, Kyrgyzstan, Turkmenistan and Uzbekistan, as illustrated in Figure 21 below. The system was planned to function in an integrated model which allowed for exchange of power across these countries dependent on differences in their respective energy resources and seasonal demand and supply for electricity.

Figure 21: CAPS grid map



Source: USAID, Regional Energy Security, Efficiency and Trade Program (RESET). (http://www.ca-reset.org/PageFiles/Maps/CARE.php).

Although Tajikistan and Kyrgyzstan, the two upstream countries, have very little gas and oil reserves, the downstream countries, Uzbekistan and Turkmenistan, and Kazakhstan enjoy huge proven reserves of these fuels: 1.8 trillion, 7.5 trillion and 2.4 trillion cubic meters of natural gas and 594 million, 600 million and 30 billion bbl of oil respectively. On the other hand, Tajikistan and Kyrgyzstan benefit from substantial hydro potential

(317 billion and 99 billion kWh/year respectively[18]). Furthermore, summer water releases by the upstream countries are critical for irrigated agriculture in the downstream countries. As a result, in the winter, Tajikistan and Kyrgyzstan would rely on fuel and power imports from Uzbekistan, Turkmenistan and Kazakhstan, and in the summer they would release water and supply surplus hydropower to them.

Since the break-up of the Soviet Union and without a single coordinating political and economic ethos, competing national interests resulted in a shift towards uncontrolled outtakes of electricity from the regional grid[19], an emphasis on securing supply from national sources alone, and the eventual withdrawal from the CAPS of Turkmenistan in 2003 and Uzbekistan and Kazakhstan in 2009.

4.8.2. Existing and firm interconnections with Tajikistan

The assumptions used to model existing and known developments of interconnectors with Tajikistan are listed in Table 28 below.

Table 28: Tajikistan electricity interconnector assumptions

From	To	NTC (MW)	Earliest COD
Tajikistan	Uzbekistan	-	-
	Kyrgyzstan	1,000	2017
	Pakistan	1,000	2017
	Afghanistan	110	Existing
		300	2017
Uzbekistan	Tajikistan	-	-
Kyrgyzstan		1,000	2017
Pakistan		-	-
Afghanistan		-	-

Source: Fichtner (April 2012), SNC-Lavalin (February 2011), World Bank (November 2012), IPA research.

Uzbekistan

The interconnections between Tajikistan and Uzbekistan are the 500kV Surkhan-Regar and Guzar-Regar transmission lines. Uzbekistan is currently a net electricity exporter with surplus capacity and significant oil and gas reserves. However, the political situation between Uzbekistan and Tajikistan has resulted in an interruption of energy trade between the countries, highlighting security of supply issues. Although Uzbekistan re-joined CAPS in 2009, most of the transmission lines connecting Tajikistan and Uzbekistan remain disconnected and require rehabilitation for any future use. For our modelling we assume there is no interconnection between Tajikistan and Uzbekistan in the IRA.

[18] Eurasian Development Bank (September 2007) *Investment and Cooperation in Hydropower of Central Asia* (http://www.vinokurov.info/assets/files/hydroenergy%20CP2007%20Vinokurov%20.pdf).
[19] According to TWEC, withdrawals by Tajikistan were reported to be greater than 100 GWh.

Kyrgyzstan

According to SNC Lavalin (February 2011) *Central Asia-South Asia Electricity Transmission and Trade ("CASA-1000") Project Feasibility Study Update*, Kyrgyzstan could deliver up to 1,000MW at the Datka substation and from there, this level of power can be delivered to Tajikistan either through a 500kV line to Hojent or a direct 500kV line to Sangtuda. These transmission lines could allow electricity to be transferred between Tajikistan and Kyrgyzstan without having to transit through Uzbekistan[20]. We assume a potential power transfer between the two countries of 1,000MW from 2017.

Pakistan

At present, there are no transmission lines between Pakistan and Tajikistan. However, Tajikistan and Kyrgyzstan are planning the CASA-1000 transmission line which is expected to connect these two countries to Pakistan via Afghanistan by 2017 with a capacity of 1,000MW.

Pakistan experiences a capacity shortfall year round and imports power from Iran. As a result, Pakistan is likely to import power from Tajikistan in the near term, and we thus assume a firm NTC of 1,000MW between Tajikistan and Pakistan as of 2017. No flow from Pakistan to Tajikistan is allowed.

Afghanistan

There is an existing interconnection between Afghanistan and Tajikistan with an NTC of 110MW. The CASA-1000 project will significantly increase this capacity. The project is planned to allocate 300MW of transmission capacity to Afghanistan.

Afghanistan is experiencing a large capacity shortfall due to the major damages suffered by its generation, transmission and distribution infrastructure and therefore relies on imports from various countries including Tajikistan. Based on historical power transfers, we assume a NTC of 110MW from Tajikistan to Afghanistan until CASA-1000 is completed in 2017 when the assumed NTC increases by 300MW. We assume no electricity exports from Afghanistan to Tajikistan.

4.8.3. Existing interconnections between other countries within the CAPS

The assumptions regarding the interconnections between Tajikistan's neighbouring countries are summarised in Table 29 below.

Kyrgyzstan, Uzbekistan and South Kazakhstan are interconnected as part of the CAPS. We assume that the NTC is of 1,000MW between Kyrgyzstan and Uzbekistan, of 450MW from Kyrgyzstan to Kazakhstan, and of 450MW from Uzbekistan to Kazakhstan. We do not expect Kazakhstan to export any power and therefore assume an NTC of 0MW from Kazakhstan to both Kyrgyzstan and Uzbekistan.

As mentioned above, Afghanistan has a shortfall in capacity and therefore imports electricity from Tajikistan. It also relies on imports from Uzbekistan in order to meet

[20] Fichtner (October 2012).

domestic electricity demand. Based on our research, we assume a NTC of 250MW from Uzbekistan to Afghanistan and 0MW from Afghanistan to Uzbekistan.

We assume that there are no power transfers between Turkmenistan and the other endogenously modelled countries.

Table 29: Interconnections between Tajikistan's neighbouring countries

Imports		NTC (MW)	Earliest COD
From	To		
Kyrgyzstan	Uzbekistan	1,000	Existing
Uzbekistan	Kyrgyzstan	1,000	Existing
Kyrgyzstan	Kazakhstan	450	Existing
Uzbekistan		325	Existing
Kazakhstan	Kyrgyzstan	-	-
	Uzbekistan	-	-
Uzbekistan	Turkmenistan	-	-
Turkmenistan	Uzbekistan	-	-
Uzbekistan	Afghanistan	250	Existing
Afghanistan	Uzbekistan	-	-

Source: Fichtner (October 2012), SNC Lavalin (February 2011), Client and IPA analysis.

4.8.4. Assumptions for Economic New Interconnections

In addition to the existing and known planned interconnections, we also allow the potential for new interconnectors between Tajikistan, Kyrgyzstan and Pakistan to be built by CAPS ECLIPSE® on an economic basis, as detailed in Table 30 below.

Table 30: Economic New Interconnector assumptions

From	To	Annual Limit[1] (MW/y)	Cumulative Maximum[1] (MW)	Earliest COD
Tajikistan	Kyrgyzstan	350	3,000	2020
	Pakistan	350	3,000	2020
Kyrgyzstan	Tajikistan	350	3,000	2020
Pakistan		-	-	-

[1]: MW values are added to the NTCs already identified above.

Source: IPA assumptions.

These could be interpreted as an expansion of the CASA-1000 project in order to enable exports from future generation projects in Kyrgyzstan and Tajikistan to Pakistan. A TIC of 600USD/kW has been assumed for these based on the estimated cost of the Tajikistan-Pakistan portion of CASA-1000[21].

4.8.5. Modelling Afghanistan and Kazakhstan

For interconnections between the countries modelled explicitly and those which are not modelled in detail, namely Afghanistan and Kazakhstan, electricity exchanges are optimised based on an assumed hourly representative electricity price curve. The price curves for Afghanistan and Kazakhstan are calibrated to reflect the evolution of the all-in cost of the most economic baseload new entrant in each country, as identified and described in subsection 4.8.7 below.

4.8.6. Assessment of potential export markets

Table 31 below summarises the salient defining characteristics of each of the potential export markets and their relative attractiveness for the power generated by the Project. Country profiles, including the demand and supply outlook and the regulatory and market structure, are provided in Annex A.

[21] IPA analysis of data from SNC Lavalin (February 2011) *Central Asia - South Asia Electricity Transmission and Trade (CASA-1000) Project Feasibility Study Update*.

Table 31: Country comparison of the Potential Export Markets

	Uzbekistan	Kyrgyzstan	Turkmenistan	Pakistan	Afghanistan
Economic parameters					
Power shortfall during the summer	○	○	○	●	●
Existing tariffs	◐	○	○	●	◐
Cost of imports	◐	N.A.	N.A.	●	◐
Marginal cost of new build options	◐	◐	◐	●	◐
Size of the power market	◐	○	○	●	○
Energy resource scarcity	◐	◐	◐	●	●
Non-economic parameters					
Ease of doing business	○	◐	N.A.	◐	○
Credit/ payment collection issues	◐	◐	○	◐	○
Import/export regulatory framework	◐	●	◐	●	●
Existing export/import infrastructure	●	◐	●	○	◐
Current export/import with Tajikistan	○	◐	○	○	◐
Political cooperation with Tajikistan	○	◐	◐	●	●

Legend

● active ◐ Medium attractive ○ Least attractive N.A. Not available

Economic parameters	
Power shortfall during the summer:	Peak demand in the summer – Dependable capacity in the summer.
Existing tariffs:	Current tariff for the power producers.
Cost of imports:	Import prices from foreign countries.
Marginal cost of new build options:	Levelised cost (USD/MWh) of building new capacity.
Size of the power market:	Peak demand, MW.
Energy resource scarcity:	The scarcity of power generation resources: oil, gas, coal and hydro potential. Endowment relative to the size of the power market.
Non-economic parameters	
Ease of doing business:	The World Bank index reflecting the business-friendliness of the regulations.
Credit risk/payment collection issues:	Includes investment, breach of contract, expropriation and similar aspects of risk based on Euromoney Country Risk ratings and SACE Country Risk guide.
Import/Export regulatory framework:	Based on current import/export regime (whether the country is currently exchanging power with CAPS or is in negotiation for importing/exporting power with other countries).
Existing export/import infrastructure:	Existing transmission network with Tajikistan.
Current import/export with Tajikistan:	Current level of power exchange with Tajikistan.
Political cooperation with Tajikistan:	State-level partnership in developing bilateral and regional projects.

Attractive export markets

Pakistan is a relatively large power market, with maximum demand in the summer, currently experiencing capacity shortfall year round and imports from Iran. This shortfall could increase further in the near term as demand in Pakistan is expected to grow at a Compound Annual Growth Rate ("CAGR") of around 8%. Furthermore, the marginal cost of new build in Pakistan is high relative to that of its neighbours in the regional power market, with the latest upfront tariff for coal Independent Power Producers ("IPP(s)") in the range of 90-130USD/MWh. Although at present, there are no transmission lines between Pakistan and Tajikistan, the CASA-1000 project is expected to connect these two countries via Afghanistan by 2016. As a result of the significant year round capacity shortfall and high cost of generation in the country, Pakistan is a very likely export market for Tajikistan's hydro power.

Afghanistan has a very low electrification rate and currently experiences a large capacity shortfall and is therefore reliant on imports. Although the interconnection between Afghanistan and Tajikistan already exists, the CASA-1000 project will significantly increase its capacity. This, coupled with the fact that demand in the country is summer peaking, suggests that Afghanistan is a potential export market.

Potential export markets

Uzbekistan is currently a net electricity exporter with surplus capacity and significant oil and gas reserves. This, coupled with the current difficult political situation with Tajikistan, makes Uzbekistan an unlikely export market in the near term. However, since the majority of the generation in Uzbekistan comes from oil and gas-fired power plants, importing summer surplus hydro generation from Tajikistan is likely to prove economically attractive.

Kyrgyzstan has significant hydroelectric potential and it is estimated that the country has so far only exploited around 10% of its hydroelectric potential. Its power sector very much resembles that of Tajikistan, with very limited use of fossil fuels and most power generation coming from HPPs. Historically, Kyrgyzstan has been a net exporter of electricity. However, to ensure that sufficient electricity is available for export, load shedding was required in the past, particularly during dry years. Whilst it is less likely that Kyrgyzstan will have power shortage during summer months when hydro availability is higher, as in Tajikistan, its interconnections with Uzbekistan and Kazakhstan could provide alternative routes for power to be transmitted to and from these countries.

Unlikely export markets

Turkmenistan, which withdrew from the CAPS in 2003, is currently a net electricity exporter with surplus capacity and large gas and oil reserves. This, coupled with the lack of direct transmission lines with Tajikistan, makes Turkmenistan an unlikely export market for power generated by the Project.

4.8.7. Cost of supply in the key potential export markets

The value of exports from Tajikistan will depend on whether these can be provided on a firm or non-firm basis. Firm power is defined as power that can be guaranteed to be available for export. Non-firm power will only be supplied when there is available power at short notice.

Table 32 below compares the Long Run Marginal Cost (“LRMC”) – reflecting the cost of firm power – and the Short Run Marginal Cost (“SRMC”) – reflecting the cost of non-firm power – of the most cost-effective Economic New Build for baseload and peaking roles against current tariffs and cost of imports/exports for the four key export markets for Tajikistan. Details of the calculations for the SRMC and LRMC of the most cost-effective Economic New Builds in each of these markets are provided in Annex E.

We can use the all-in shadow price from CAPS ECLIPSE® (which includes the SRMC shadow price and the capacity premium) to value firm power as it includes a capacity premium component which reflects the avoided cost of building new standby capacity to meet demand when importing power from Tajikistan. We can use the SRMC shadow price as a proxy for the marginal cost of supply for the non-firm power.

Table 32: Cost of supply comparison

Prices in USD/MWh	LRMC (Firm power)		SRMC (Non-firm power)		Current tariffs and cost of imports/exports
	Peak[1]	Baseload[1]	Peak[1]	Baseload[1]	
Uzbekistan	New OCGT: 342.95	New CCGT: 79.89	New OCGT: 90.90	New CCGT: 57.34	Tariff: 50[22] Cost of imports: 33.8[23]
Kyrgyzstan	New OCGT: 342.95	New CCGT: 79.89	New OCGT: 90.90	New CCGT: 57.34	Set tariff: 40[24] Actual tariff:15[24] Cost of imports from Uzbekistan: 47[23] Cost of exports to Kazakhstan: 28-30 and to Tajikistan: 15[25]
Pakistan	New OCGT: 342.95	New Coal: 78.86	New OCGT: 90.90	New Coal: 44.35	Cost of imports from Iran: 70-100[26,27] Coal tariff: ~105-130 for local coal, 89-113 for imported[27] Current tariff of different technologies in Pakistan determined by NEPRA are: • 40 to 55USD/MWh for CCGT • 90USD/MWh for OCGT • 100 to 290USD/MWh for RFO[2] and Diesel plants
Afghanistan	N.A.	New CCGT: 79.89	N.A.	New CCGT: 57.34	Tariff for residential customers: ~73 Cost of imports from Uzbekistan: 75 from Tajikistan: 35, from Iran: 40 from Turkmenistan: 20
Kazakhstan	N.A.	New Coal: 77.36	N.A.	New Coal: 42.85	Cost of imports from Uzbekistan: 28-30[25] Ceiling tariff: 24[28]

[1]: Peaking ACF corresponds to 5% whilst baseload ACF corresponds to the Max ACF of the technology, 88% for coal and 85% for CCGT.
[2]: "RFO" = Recycled Fuel Oil.
Source: IPA analysis.

[22] ADB (August 2011) *Republic of Uzbekistan: Advanced Electricity Metering Project* (http://www2.adb.org/Documents/PAMs/UZB/41340-013-uzb-pam.pdf).
[23] CAREC (October 2010) *Energy Sector Progress Report and Work Plan (late 2010-2011).*
[24] Report commissioned by UNDP's Regional Bureau for Europe and CIS (Apr 2011) *Kyrgyzstan's Energy Sector* (http://km.undp.sk/uploads/public1/files/vulnerability/Senior%20Economist%20Web%20site/PSIA_Energy_Kyrgyzstan.pdf).
[25] Fichtner (October 2012) *CAREC Power Sector Master Plan*.
[26] NEPRA (2010) *State of Industry Report*.
[27] NEPRA (October 2011) *Mechanism and Assumptions for Upfront Tariff adjustments at COD and Indexations Applicable during Operations*.
[28] Kazakhmys power market overview (http://ara2011.kazakhmys.com/operating_and_financial_review/power/market_overview.html).

4.8.8. Wheeling charges

In order to establish the netback prices of the potential export markets for Tajikistan, we assessed the costs of delivering power from Tajikistan's national grid to each of the export markets. We used data on the cost and capacity of cross-border transmission projects, when available, in order to estimate the levelised cost of transmitting power between the interconnected states. The estimated wheeling charges are shown in Table 33 below.

Table 33: Wheeling charges

Country	Wheeling charge (USD/MWh)	Comments
Uzbekistan	7.00	Based on local transmission tariff
Kyrgyzstan	4.31	Based on levelised CASA-1000 cost
Afghanistan	7.23	Based on levelised CASA-1000 cost
Pakistan	8.35	Based on levelised CASA-1000 cost
Kazakhstan	7.00	Based on CAREC Master Plan

Source: Fichtner (October 2012) and SNC Lavalin (February 2012) CASA Electricity Transmission and Trade (CASA-1000) Project Feasibility Study Update.

For Kyrgyzstan, Afghanistan and Pakistan, the wheeling charges were estimated as the levelised cost of the planned CASA-1000 cross-border interconnector project, using projected cost and capacity data[29], together with a forecast utilisation rate.

Since an existing transmission line between Uzbekistan and Tajikistan existed but was no longer operational and there were no upcoming cross-border interconnection projects between these two countries, we use the estimated domestic transmission tariff of 7USD/MWh[30] as a proxy for the wheeling charge between these two countries.

For the avoidance of doubt, in IPA's least-cost modelling, the difference in the prices between low and high cost jurisdictions must exceed the wheeling charge between them if there are going to be any economic benefits arising from the trade of electricity.

4.9. Fuel price projections

This subsection 4.9 sets out the fuel prices defined in the IRA. The fuel price assumptions are summarised as follows:

- Crude oil prices are World Bank forecasts (July 2013) until 2025, 75.62USD/bbl (real 2013) thereafter.

[29] SNC Lavalin (February 2011) *Central Asia - South Asia Electricity Transmission and Trade (CASA-1000) Project Feasibility Study Update*.
[30] The domestic transmission tariff was assumed to be 15% of the domestic retail tariff of 48USD/MWh (in line with the assumption made in Fichtner (October 2012).

- Heavy Fuel Oil ("HFO") prices are linked to crude oil prices. We assume a HFO to crude oil price coefficient of 6.00 which is based on the relationship between forward Brent Spot Free on Board ("FOB") (USD/bbl) and European residual fuel oil prices (USD/t) from Chicago Mercantile Exchange ("CME") at the end of 2012.
- Distillate prices are linked to crude oil prices. We assume a distillate to crude oil price coefficient of 8.87 which is based on the relationship between forward Brent Spot FOB (USD/bbl) and European Gasoil (USD/t) prices from Bloomberg and CME at the end of 2012.
- Natural gas prices are World Bank forecasts (July 2013) until 2025, USD7.87/MMBTU (real 2013) thereafter.
- Hard coal prices are World Bank forecasts (July 2013) until 2025, USD78.69/tonne (real 2013) thereafter. A flat transportation fee of USD20.00/tonne (real 2013) and a surcharge of 10% of FOB price is also added to account for other costs.
- Lignite prices are assumed to be at a 75% discount of hard coal prices in a USD/tonne basis. Since lignite is assumed to have a calorific value of 7.1MMBTU/tonne (HHV) whilst hard coal is 25.06MMBTU/tonne (HHV) then this means that lignite is 34% less expensive than hard coal on an energy equivalent basis.

Table 34, Table 35 and Figure 22 below summarise these pricing assumptions in real 2013 prices.

Table 34: Central Asia fuel price forecasts (original units)

Year	Crude oil (USD/bbl)	HFO (USD/t)	Distillate (USD/t)	Natural gas (USD/ MMBTU)	Hard coal (USD/t)	Lignite (USD/t)
2013	100.70	604.20	893.21	12.00	119.00	22.50
2014	97.92	587.54	868.57	11.31	118.41	22.37
2015	95.44	572.66	846.59	10.62	115.54	21.71
2016	92.70	556.21	822.26	10.31	114.69	21.52
2017	89.97	539.81	798.01	10.00	113.57	21.27
2018	87.43	524.60	775.54	9.68	112.49	21.02
2019	85.25	511.53	756.21	9.39	111.54	20.80
2020	83.24	499.41	738.30	9.12	110.70	20.61
2021	81.65	489.93	724.27	8.86	109.88	20.43
2022	80.10	480.62	710.52	8.60	109.05	20.24
2023	78.58	471.49	697.02	8.35	108.22	20.05
2024	77.09	462.53	683.78	8.11	107.39	19.86
2025-2050	75.62	453.75	670.79	7.87	106.56	19.67

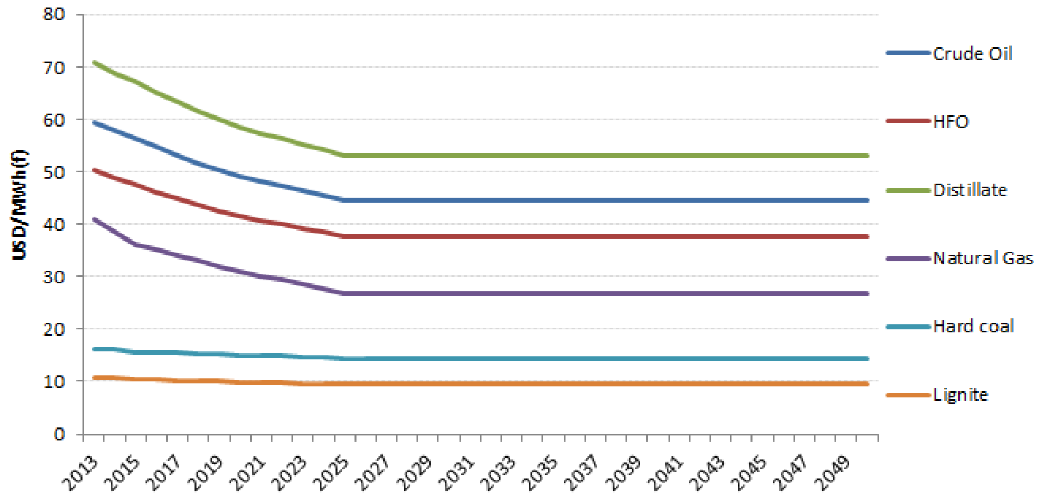
Source: Bloomberg, CME, Energy Information Administration ("EIA") Annual Energy Outlook (2011), World Bank forecasts and Spectrometer.

Table 35: Central Asia fuel price forecasts (USD/MWh(f))

Year	Crude oil	HFO	Distillate	Natural gas	Hard coal	Lignite
2013	59.53	50.23	70.83	40.95	16.20	10.81
2014	57.89	48.84	68.88	38.58	16.12	10.75
2015	56.42	47.60	67.13	36.22	15.73	10.43
2016	54.80	46.24	65.20	35.18	15.61	10.34
2017	53.18	44.87	63.28	34.11	15.46	10.22
2018	51.69	43.61	61.50	33.05	15.32	10.10
2019	50.40	42.52	59.97	32.05	15.18	10.00
2020	49.20	41.51	58.55	31.13	15.07	9.90
2021	48.27	40.73	57.43	30.23	14.96	9.81
2022	47.35	39.95	56.34	29.35	14.85	9.72
2023	46.45	39.19	55.27	28.49	14.73	9.63
2024	45.57	38.45	54.22	27.66	14.62	9.54
2025-2050	44.71	37.72	53.19	26.85	14.51	9.45

Source: Bloomberg, CME, Mercados (2010), EIA (2011), World Bank forecasts and Spectrometer.

Figure 22: Central Asia fuel price forecasts



Source: Bloomberg, CME, Mercados (2010), EIA (2011), World Bank forecasts and Spectrometer.

4.10. Rogun site decommissioning

There has been a considerable amount of preparatory work already undertaken at the Rogun site, and in the event that the Project does not proceed, the construction site would have to be safely decommissioned. The cost of doing so has been estimated as detailed in Table 36

Table 36: Costs for Rogun site decommissioning

Item	USD million
a. Liquidation activities of underground structures (concreting of plugs for tunnels – intake and outlet, backfilling of fault crossing areas, and stabilisation measures in all caverns)	80
b. Workmen's compensation of Contractors for three months	10
c. Workshops and warehouse area cleaning and dismantlement	70
d. Demobilization costs and termination of contracts with contractors / subcontractors	15
e. Penalties for equipment ordered, manufactured and not paid being in the factories	16
f. Resettlement and environmental costs	133
Sub-total	**324**
10% contingency	32.4
Total	**356.4**

Source: Client, Coyne et Bellier (February 2014)

These costs have been included in the TSC for the No Rogun case, split 25%:50%:25% between 2014, 2015 and 2016 respectively.

4.11. Overview of the sensitivities

As described in subsection 3.4, we also investigated eight sensitivities on four key parameters, as described in Table 37 below.

Table 37: Overview of sensitivities

Case	Demand	Fuel costs	TIC	NTC	Probability
IPA Reference Assumptions (“Ref”)	Median	World Bank forecast		CASA 2017; +3 GW TJ → PK	20%
High Demand (“HiDem”)	75th percentile				10%
Low Demand (“LoDem”)	25th percentile				10%
High Fuel Costs (“HiFuel”)		+20%			10%
Low Fuel Costs (“LoFuel”)		-20%			10%
High Cost of New Build (“HiTIC”)			+20%		10%
Low Cost of New Build (“LoTIC”)			-20%		10%
High Interconnection (“HiNTC”)				+5 GW TJ → PK, 1 GW TJ ↔ UZ	10%
Low Interconnection (“LoNTC”)				CASA 2020, +0	10%

Source: IPA analysis.

5. LEAST-COST EXPANSION RESULTS

This Section 5 presents our least-cost expansion results under the IRA for the NoRogun scenario ("NoRogun") and the highest possible capacity option for each of the proposed dam heights: 1290masl-3,600MW ("Ro1290_3600"), 1255masl-3,200MW ("Ro1255_3200"), and 1220masl-2,800MW ("Ro1220_2800"). We first describe the evolution of the Tajik capacity and generation mix over the Forecast Horizon in subsections 5.1 and 5.2 respectively. In subsection 5.3, we present the electricity (shadow) price forecasts under each of the four scenarios. Finally, we present the levels of electricity imports to and exports from Tajikistan under the different scenarios.

Tables detailing all the results presented and discussed in this section are given in Annex F. The generation expansion results for all the other Rogun design options are given in the respective Results Summary files ("*IPA-Results Summary for Rogun (●)-2014-02-24.xlsm*").

5.1. Capacity mix

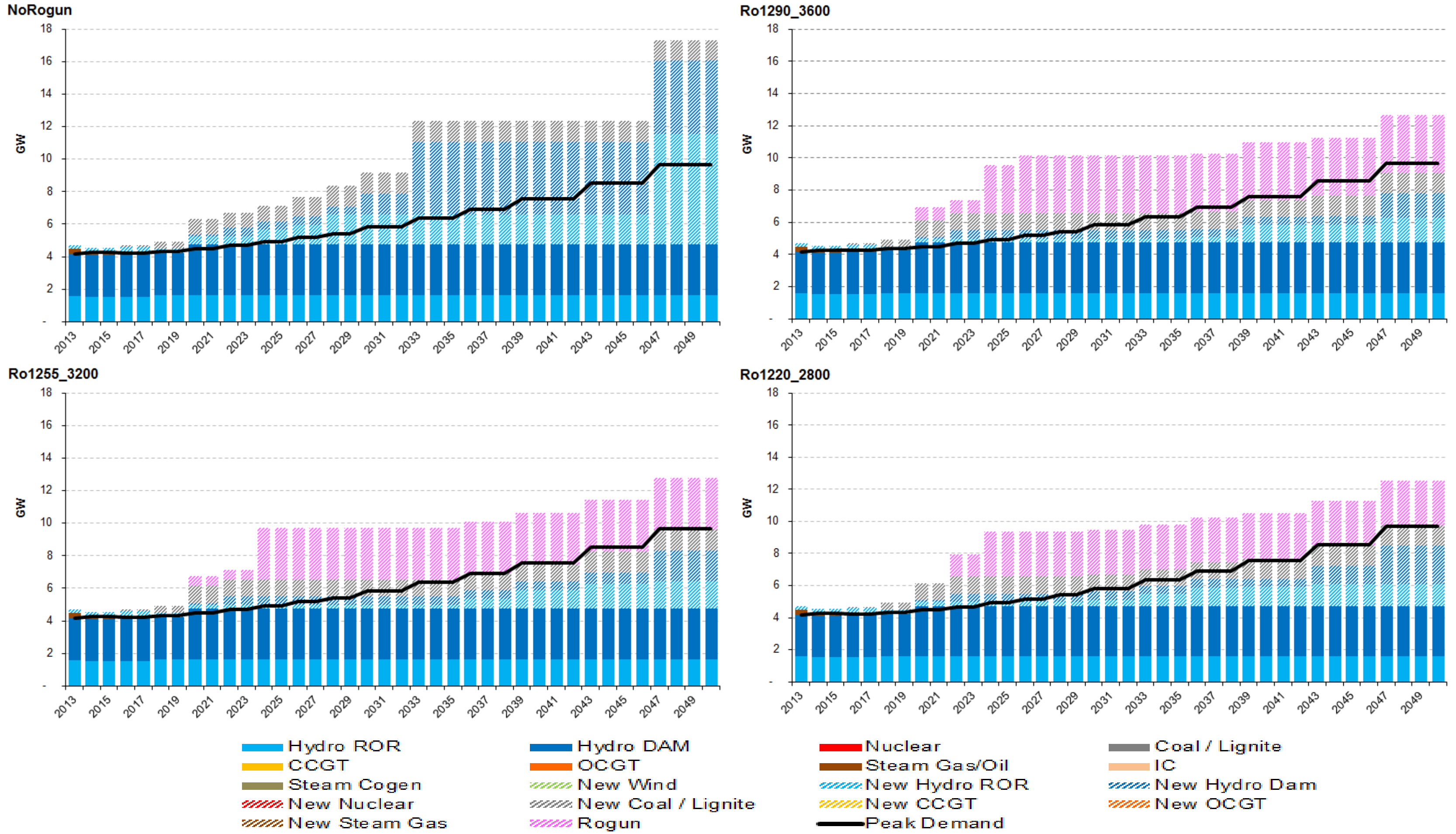
Figure 23 below provides the breakdown of the capacity mix over the Forecast Horizon under the NoRogun scenario and the three Rogun design options. The Tajikistan system starts with a total installed capacity of 4,481MW in 2013. The HPP capacity makes up 4,384MW (93.2%) of total installed capacity, with thermal capacity accounting for only 318MW (6.8%). However, the availability of the HPPs varies throughout the year due to varying water levels and can be very low in winter leading to a shortfall of supply.

In the NoRogun scenario, the firm construction of Dashtijum from 2030 signals the need for early deployment of Hydro ROR enabling a significant level of exports in the intermediate years of the forecast. In the final years, almost all the Economic New Builds identified in Table 23 and an additional 5GW of generic Hydro ROR is required to meet the peak demand, as shown in Figure 24. Note that the amount of Hydro ROR capacity is greater than that of the Project because of the very low availability of these ROR plants in winter.

The main differences between the capacity mixes under the three Rogun design options are the amounts of capacity and the timing of the deployment of other New Hydro. The lower capacity options clearly require more additional build earlier to meet demand. From 2033 once the reservoir of the Project is fully operational, the amount of Economic New Hydro on the system is lower under the 1290_3600 scenario than under the 1220_2800 scenario.

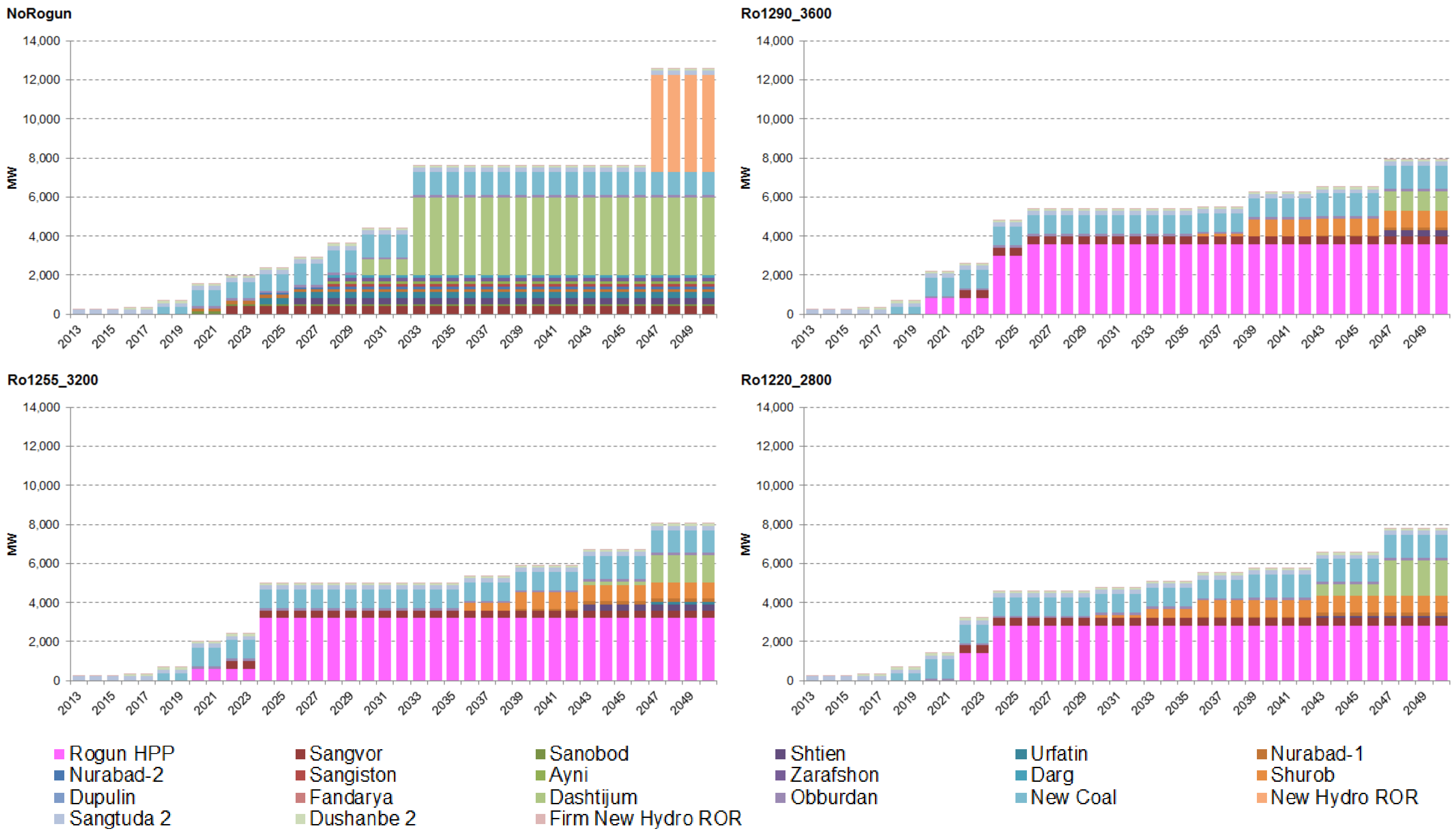
Interconnector expansions are shown in Figure 25 below. The results suggest that it would be economically beneficial for the system as a whole to expand the NTC of interconnections between Tajikistan and its neighbouring countries as this would allow Tajikistan to monetise its summer surplus. Economic expansion of the export interconnector to Pakistan is beneficial from 2020 onwards, both with and without Rogun. In the long term, the greater installed capacity of Dashtijum requires a greater total level of expansion of interconnectors in the NoRogun case than for Rogun to maximise the value to the region as a whole.

Figure 23: Tajikistan capacity mix by technology type under different Rogun design options



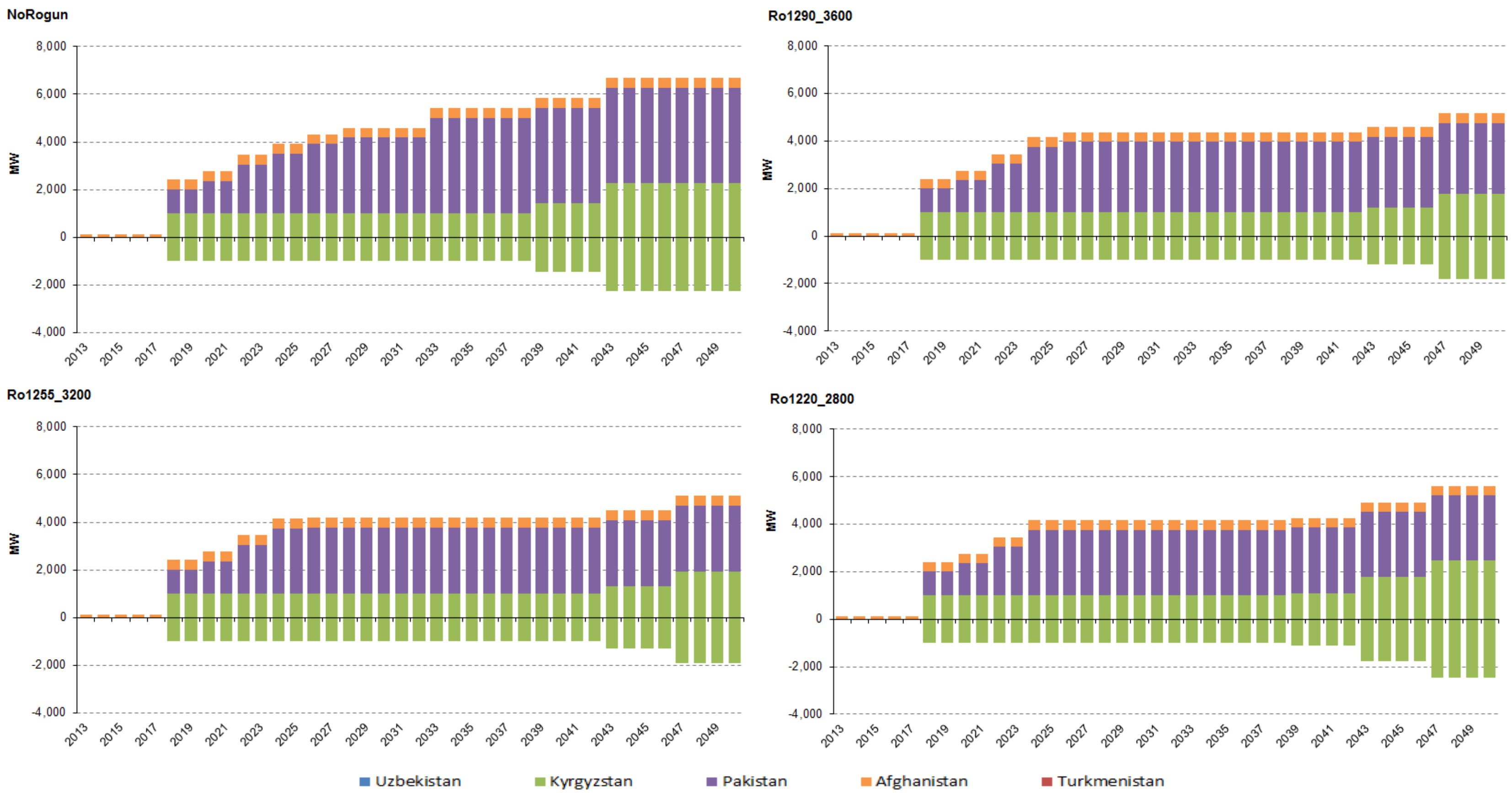
Source: IPA analysis. (Data in Table 82, Table 89, Table 103 and Table 110 in Annex F.)

Figure 24: Tajikistan New Builds under different Rogun design options



Source: IPA analysis. (Data in Table 83, Table 90, Table 104 and Table 111 in Annex F.)

Figure 25: Tajikistan interconnector capacity expansion under different Rogun design options



Source: IPA analysis. (Data in Table 84, Table 91, Table 105 and Table 112 in Annex F.)

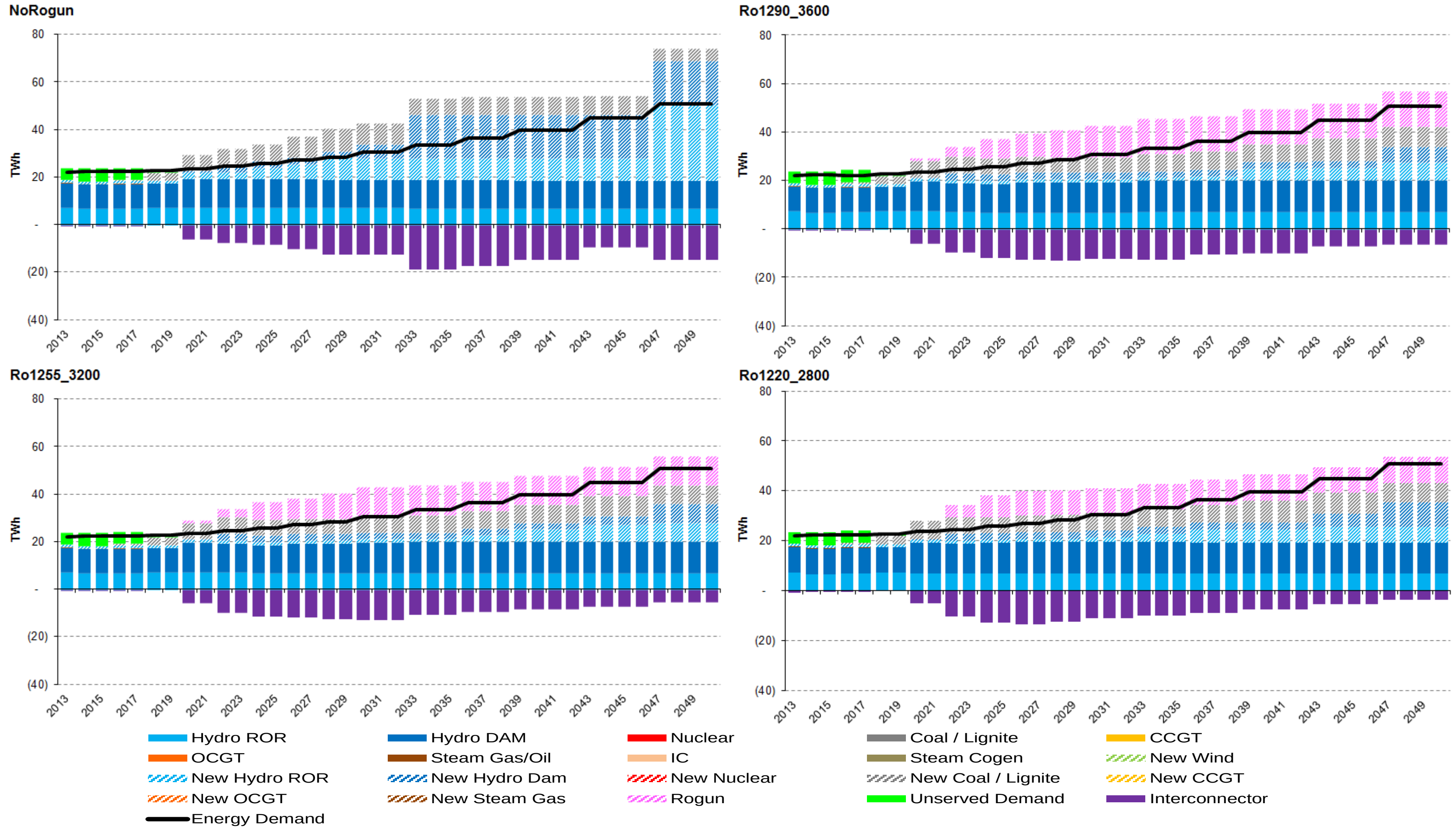
5.2. Generation mix

Figure 26 below provides the breakdown of the generation mix over the Forecast Horizon under the NoRogun scenario and the three Rogun design options in the IRA. The generation mix reflects the developments observed in the capacity mix forecast.

In all four cases, increases in demand are mainly met by new HPPs. This means that there will be a surplus of summer energy available for export, something we discuss in more detail in subsection 5.4 below. In 2013-2019 for all four scenarios, we identify unserved demand.

There are two key differences between the three Rogun design options and the NoRogun case. First, there is more generation from Hydro ROR plants under the NoRogun scenario. Second, the net exports from Tajikistan are higher under the NoRogun case because of the large amounts of generic Hydro ROR followed by Dashtijum combine to give a much greater level of surplus summer generation.

Figure 26: Tajikistan annual generation mix by technology under different Rogun design options



Source: IPA analysis. (Data in Table 85, Table 92, Table 106 and Table 113 in Annex F.)

5.3. Electricity (shadow) prices

IPA's Time Weighted Average ("TWA") all-in shadow price forecast combines the following components:

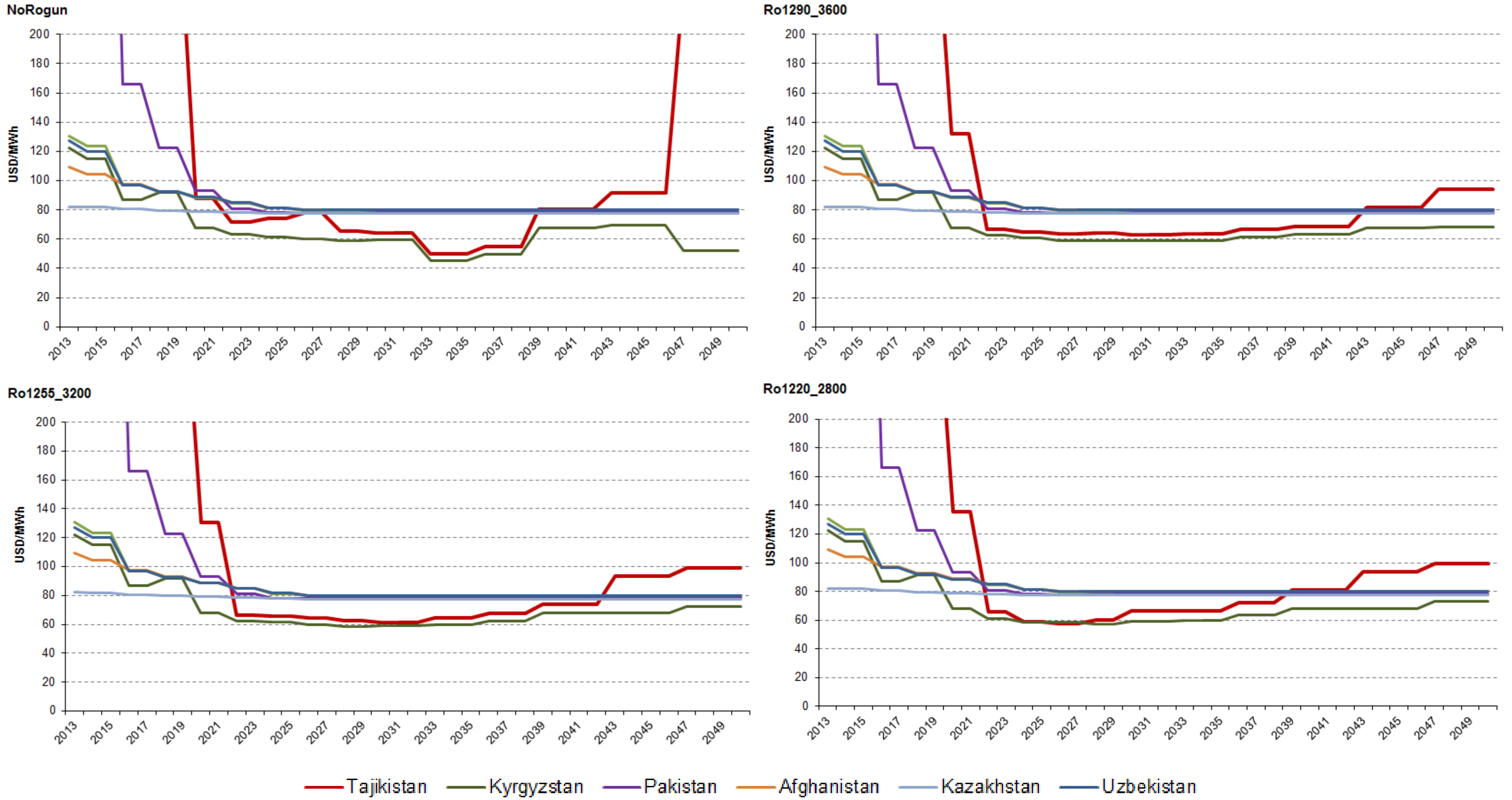
1. **SRMC shadow price**: The SRMC shadow price in each hour is calculated as the system marginal cost of meeting an incremental unit of demand in that hour. The TWA SRMC price is measured in USD/MWh.

2. **Capacity Premium**: After taking the hourly SRMC shadow prices into account, the Capacity Premium identifies the minimum annual payment required to allow the developers of the most cost-effective Economic New Build to break even (i.e. fully recover their fuel and O&M costs and achieve the required return on their invested capital). It is measured in USD/kWy and reflects the opportunity cost of firm capacity.

Figure 27 below shows the annual ECLIPSE® all-in TWA shadow prices in Tajikistan and in the potential export markets for Tajikistan's electricity under the four scenarios. Once the construction of the Project begins, the all-in shadow price tends to be lower under the three Rogun design options than under the NoRogun scenario, although the latter exhibits a short-term dip when Dashtijum comes online. The very high electricity prices during the initial years in all four cases reflect the VOLL to represent the unserved demand situation in the country. The high prices in the NoRogun scenario during the last years reflect the high costs of constructing a large number of ROR HPPs to meet the domestic demand and reserve margin requirement.

Towards the end of the Forecast Horizon, the annual all-in shadow prices in Pakistan, Afghanistan, Uzbekistan, Turkmenistan, and Kyrgyzstan are around 75-80USD/MWh. As we can see in Annex E, this is in line with the LRMC of the most economic technology in each of these countries. The annual all-in shadow price in Tajikistan under the three Rogun design options stands at just under 100USD/MWh reflecting the higher cost of ROR HPPs.

Figure 27: Central Asia annual shadow electricity price forecasts under different Rogun design options



Source: IPA analysis. (Data in Table 86, Table 93, Table 107 and Table 114.)

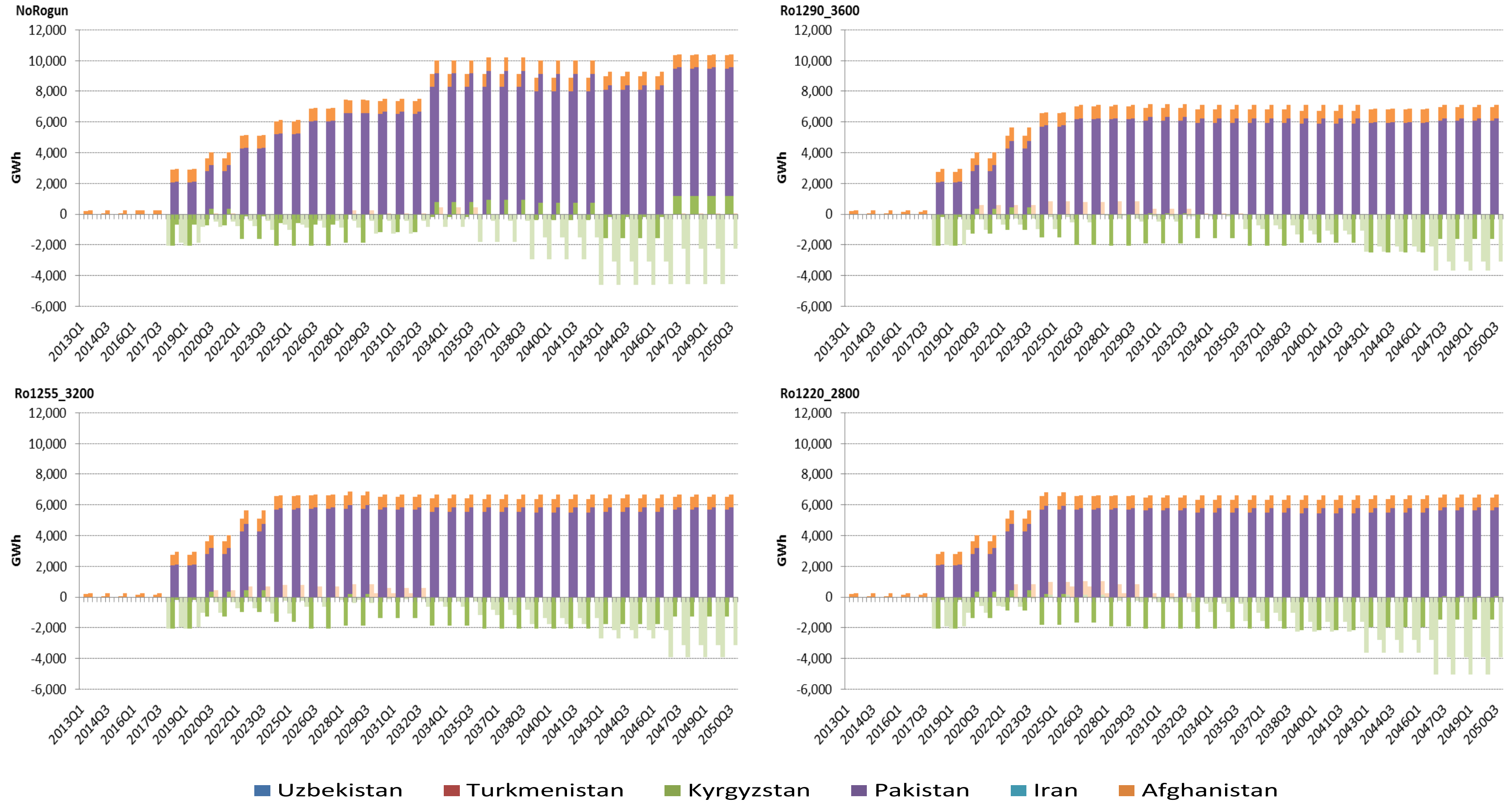
5.4. Electricity imports and exports

Electricity exchanges between countries are broadly similar in all four cases. As illustrated in Figure 28 below, Tajikistan is expected to export to Pakistan and Afghanistan during summer and to import from (and through) Kyrgyzstan in winter. There is a short period after the start of full operation of the large dam (Rogun or Dashtijum) when Tajikistan no longer needs net winter imports to meet demand. The length of this period is greater with the larger capacity dam options until demand grows further. The largest volume of exports is to Pakistan, with the export interconnectors almost fully utilised in the summer from 2017 onwards when electricity demand in Pakistan peaks and Tajikistan has surplus energy. By contrast, Tajikistan's other neighbours are winter-peaking which limits Tajikistan's opportunities for exporting to them in summer.

Tajikistan is expected to become a net exporter under all scenarios. In order to meet demand in the winter, when the Vakhsh river flow is low, Tajikistan is expected to rely on electricity imports from Kyrgyzstan, some of which is electricity in transit from Uzbekistan as this is the most economical way of meeting electricity demand. The imports are broadly similar with or without Rogun.

The annual realised export prices are shown in Figure 29 below. Pakistan has summer-peaking and offers the potential to be the largest market for exports of Tajik hydro-electricity as illustrated in Figure 28. From 2018, Pakistan is expected to import between 4,172GWh and 16,690GWh of power in the summer. Because of an assumed shortfall in Afghanistan, the latter is expected to import electricity from Tajikistan in the summer, even before the Project is completed. These imports increase further when the Project comes online and Tajikistan increases its export potential. Tajikistan is expected to import from Kyrgyzstan in the winter months, and export small volumes to Kyrgyzstan in the summer. These power exports to Kyrgyzstan are expected to then be exported onwards to Uzbekistan and Kazakhstan.

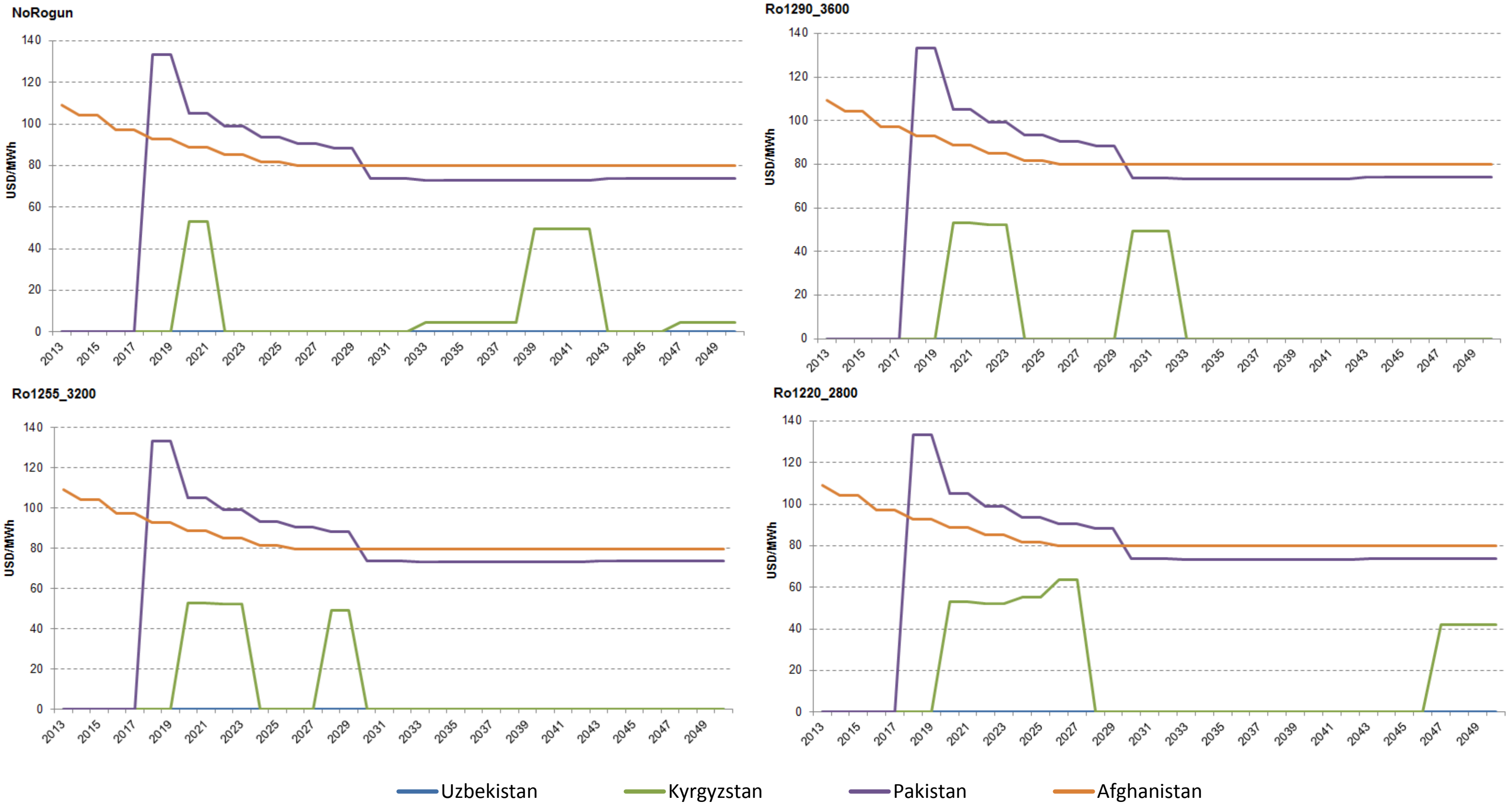
Figure 28: Tajikistan quarterly net exports under different Rogun design options



Note: Lighter bars are winter flows, darker bars are summer.

Source: IPA analysis. (Data in Table 87, Table 94, Table 108 and Table 115 in Annex F.)

Figure 29: Tajikistan annual realised export prices under different Rogun design options



Source: IPA analysis. (Data in Table 88, Table 95, Table 109 and Table 116 in Annex F.)

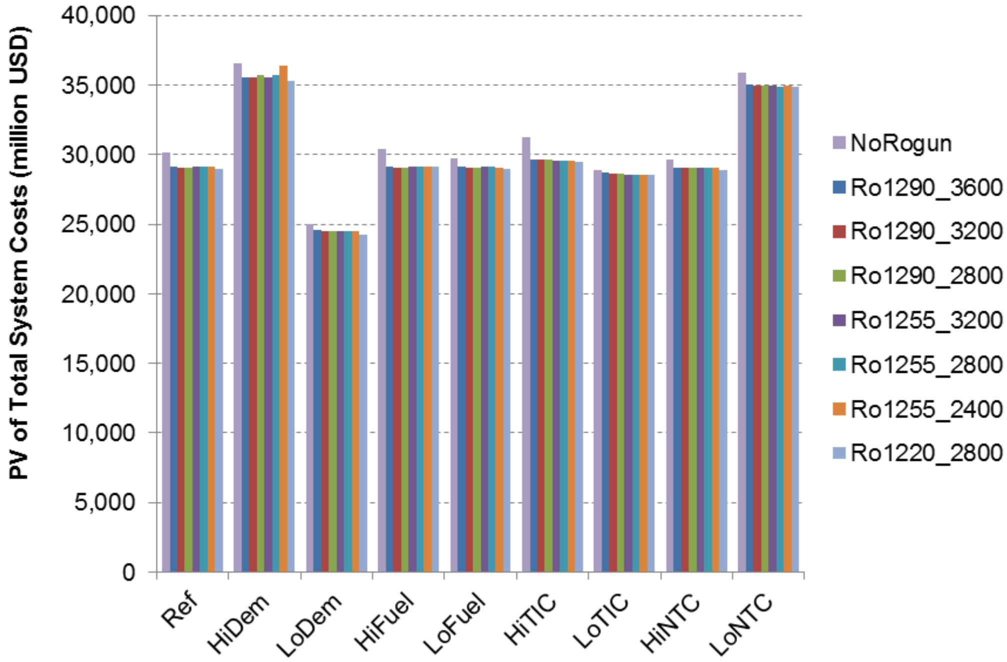
6. TOTAL SYSTEM COST SAVINGS ANALYSIS

In subsection 3.2 above we describe the methodology applied to calculate the total benefits of the different Rogun design options. We do this by combining the savings identified from the least-cost expansion analysis over the period 2013-2050 and add to this the savings for the period post-2050. In this Section 6, we provide the results of this analysis.

6.1. TSC savings until 2050

The PV of the TSC for Tajikistan over the Forecast Horizon at a discount rate of 10% is summarised in Figure 30 and Table 38 below for each of the nine Rogun design options and the NoRogun case under the IRA and eight sensitivities. These results come from the least-cost expansion analysis.

Figure 30: PV of Tajikistan TSC @ 10% (2013-50)



Source: IPA analysis.

These show the very small difference at a macro-level between the three Rogun design options for a given set of underlying conditions, and clearly identify the NoRogun option as significantly more costly.

The sensitivity results show that the rate of demand growth and the level of interconnection with neighbouring countries have the most influence on the overall cost of meeting demand. High demand growth or limited interconnector expansion would both significantly increase the costs of meeting domestic Tajik demand with large amounts of new Hydro ROR being required in either instance, especially given their limited generation capability during winter. Low demand growth has the opposite effect of requiring much less new build capacity.

Tajik system costs are relatively insensitive to fuel prices since, while they increase the cost of imports, there is a counterbalancing effect in that the value from exports also increases. The costs of new build (other than Rogun) also have a small but noticeable impact, and are clearly most significant in the NoRogun case when Dashtijum is built. Enabling greater interconnector expansion results in a small reduction in system costs – the potential for direct imports from Uzbekistan is realised in the Reference case by means of flows via Kyrgyzstan.

Table 38: PV of Tajikistan TSC @ 10% (2013-50)

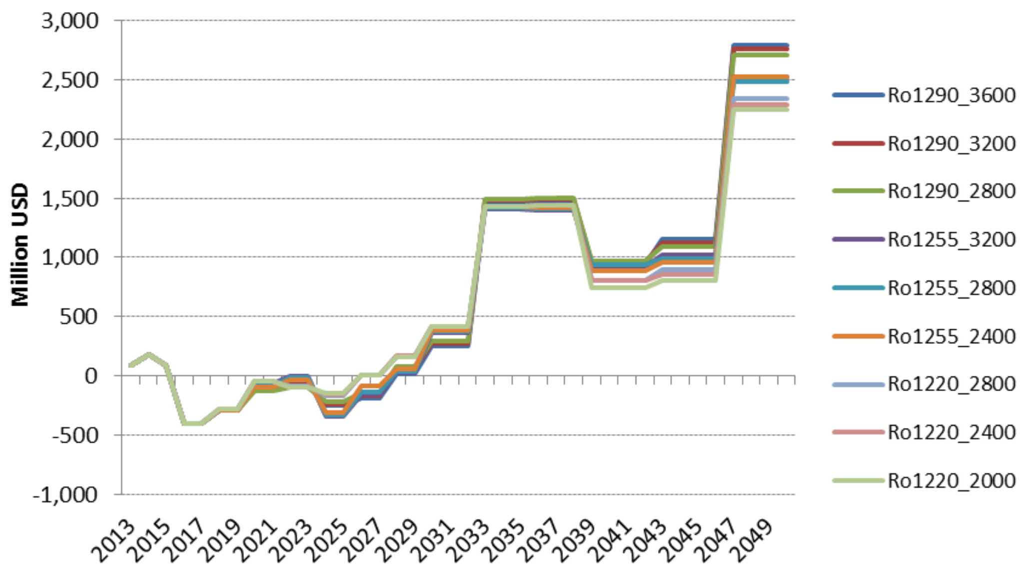
USD million \ Case	Ref	HiDem	LoDem	HiFuel	LoFuel	HiTIC	LoTIC	HiNTC	LoNTC
NoRogun	30,162	36,577	24,986	30,366	29,757	31,257	28,892	29,682	35,850
Ro1290_3600	29,104	35,551	24,550	29,134	29,125	29,648	28,678	29,088	35,036
Ro1290_3200	29,068	35,546	24,504	29,089	29,093	29,617	28,636	29,054	34,985
Ro1290_2800	29,061	35,734	24,484	29,091	29,068	29,615	28,629	29,045	34,979
Ro1255_3200	29,125	35,553	24,496	29,148	29,104	29,568	28,566	29,078	34,988
Ro1255_2800	29,114	35,723	24,472	29,135	29,096	29,557	28,564	29,076	34,908
Ro1255_2400	29,095	36,410	24,462	29,156	29,086	29,562	28,547	29,074	34,969
Ro1220_2800	28,925	35,317	24,261	29,152	28,925	29,471	28,570	28,849	34,841
Ro1220_2400	28,922	35,932	24,245	29,195	28,923	29,477	28,574	28,852	34,798
Ro1220_2000	28,962	36,534	24,264	29,163	28,963	29,525	28,493	28,908	34,726

Note: The colour coding is used to highlight the relative TSC of each sensitivity (column), not across all cases: red = highest cost, yellow = middle, green = lowest cost.

Source: IPA analysis.

The annual cost savings for the nine Rogun design options against the NoRogun case under the IRA are shown in Figure 31 below.

Figure 31: Annual system cost savings under IRA for different Rogun design options



Source: IPA analysis.

There is an immediate cost savings in all cases as a result of the assumed site decommissioning costs if Rogun is not built. During Rogun construction and the reservoir fill-in period, system costs increase resulting in negative savings (additional costs) relative to the NoRogun case. The lowest dam height option starts to achieve positive cost savings from 2026 whereas the higher ones do so only from 2029/30, because of their longer construction periods. The additional costs of achieving similar levels of flood protection do mitigate some of the relative advantage of the 1220 masl options. Once the 1290 masl and 1255 masl options reach their full generation capacity, they achieve higher cost savings than the smallest options due to their higher summer export potential and the reduced need to deploy additional capacity.

6.2. TSC savings post-2050

The technical lifetime of the Project depends on the design option. This is determined as 45 years for the 1,220_2800 option, 75 years for 1,250_3200 option and 115 years for 1,290_3600 option from river diversion. For this post-2050 value calculation, the annual savings from the final year of the ECLIPSE® modelling (2050) has been extrapolated with an equal year-on-year drop to reach zero at the end of the projected technical lifetime of the option under consideration.

6.3. Aggregate TSC savings

Table 39 below shows the annual system cost savings for the three Rogun design options at their highest capacity level under the different scenarios relative to the NoRogun case under the same scenario, including the post-2050 value. All of the Rogun options provide significant system cost savings in the later years predominantly as a result of the amount of ROR HPP build required in the NoRogun case.

Table 40 below shows the PV of TSC savings across the different sensitivities described in Table 37. (Note that the IRA are applied in what is defined as the Ref case.) To arrive at the probability-weighted savings we use the normalised probabilities summarised in Table 7 above.

This shows that, at the base discount rate of 10%, all the Rogun design options would have an overall beneficial impact on the Tajikistan electricity system across all sensitivities, from 69USD million for the smallest Rogun option with High Demand growth to over 2.5USD billion for the highest dam height options in the High TIC case. The highest dam option (1290 masl) generally shows the greatest benefit across all sensitivities, except in the Low Demand growth case when the lower need for capacity makes the smaller dam options more appropriate. In practice, if demand were forecast to grow less quickly, new build might be deferred or result in an adjustment in the implementation schedule of the Project.

Comparing the sensitivity results to the Reference case, we can note the following impacts:

1. **Demand**: The net benefit of all the Rogun options would be reduced if demand growth is lower than forecast, reflecting the unnecessarily early capital expenditure on new capacity. If demand growth is higher though, the lower capacity options also provide a smaller net benefit compared to the larger Dashtijum option in the NoRogun case because of the need for additional new build to meet the higher demand. The highest capacity options do provide an increased benefit because they contribute a significant level of generation earlier than the assumed firm start date for Dashtijum.

2. **Fuel costs**: Lower fuel costs for thermal generation alternatives would reduce the net benefit of all Rogun options, while higher costs increase the benefit from the two higher dam height options. The lowest dam height options actually show small reductions in cost savings because smaller export volumes displace more expensive thermal generation in neighbouring countries first. (As export volumes rise, the next tranche of foreign generation to be replaced would be less expensive than the previous one.)

3. **TIC**: Higher costs of alternative capacity options naturally increase the benefit from the Project, while lower costs reduce it.

4. **Interconnection**: Reducing the potential for exports by limiting interconnector expansion means that the benefit from exports to Tajikistan is reduced. However, the high interconnector case shows a similar reduction in cost savings because the interconnection with Uzbekistan and increased connection to Kyrgyzstan enable greater imports which reduce domestic Tajik shadow electricity prices and costs, and hence reduce the need for earlier generation from Rogun compared to Dashtijum.

Table 39: Annual system cost savings against the relevant NoRogun case

CYs / USD million	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-28	2039-42	2043-46	2047-50	Post-2050
Ro1290_3600														
Ref	-404.8	-289.4	-94.3	-57.4	-254.3	-192.9	18.8	247.7	1,458.3	1,474.5	940.4	1,155.4	2,789.6	24,109
HiDem	-532.3	-404.6	-347.5	-30.1	-190.2	-40.7	-176.8	294.5	1,405.3	938.6	1,445.5	3,037.2	3,608.2	31,184
LoDem	-393.7	-92.5	-126.1	-94.4	-255.2	-117.0	-53.8	-37.7	1,058.8	806.8	841.9	959.9	1,104.6	9,547
HiFuel	-405.2	-292.9	-260.9	50.2	-179.5	-49.6	69.5	192.2	1,526.5	1,530.1	1,172.7	1,173.4	2,905.9	25,115
LoFuel	-404.4	-287.0	-107.3	-66.3	-218.9	-136.2	-61.6	156.8	913.6	999.7	1,031.5	1,060.6	2,642.7	22,839
HiTIC	-404.3	-284.1	-119.2	-45.4	-196.7	-70.4	130.1	348.8	1,537.2	1,317.2	1,404.6	1,541.0	3,890.8	33,627
LoTIC	-405.3	-294.0	-283.8	12.7	-222.9	-197.9	-74.0	-46.5	1,108.1	1,039.5	784.9	878.6	1,689.6	14,602
HiNTC	-404.8	-289.4	-94.3	-57.4	-254.3	-192.9	-11.5	247.7	1,095.7	969.5	870.9	948.0	2,149.1	18,574
LoNTC	-404.8	-450.2	-277.3	-182.3	-395.6	-281.9	-253.1	117.9	1,242.5	1,360.6	2,128.7	2,726.3	2,986.4	25,810
Ro1255_3200														
Ref	-404.8	-289.1	-67.7	-3.2	-343.9	-162.1	22.5	361.0	1,408.8	1,395.2	922.8	1,024.2	2,524.6	18,609
HiDem	-532.3	-392.7	-315.1	-20.5	-262.8	31.6	-131.2	401.4	1,348.9	859.8	1,326.0	2,916.4	3,468.0	25,562
LoDem	-393.7	-91.4	-87.5	-40.9	-343.2	-105.7	-255.2	297.3	1,013.7	810.5	772.7	884.2	1,015.1	7,482
HiFuel	-405.2	-292.4	-234.9	106.5	-272.4	-8.3	-13.6	372.8	1,465.8	1,451.6	1,103.2	1,078.1	2,769.6	20,414
LoFuel	-404.4	-286.8	-78.2	-14.3	-302.7	-93.8	-17.4	292.5	883.6	942.6	971.0	851.4	2,486.5	18,328
HiTIC	-404.3	-284.0	-92.2	8.2	-198.8	53.4	155.5	392.5	1,602.3	1,258.3	1,317.6	1,304.2	3,683.5	27,151
LoTIC	-405.3	-293.5	-251.2	66.2	-310.8	-86.7	-117.1	183.8	1,067.4	997.1	731.7	814.7	1,588.1	11,706
HiNTC	-404.8	-289.1	-67.7	-3.2	-343.9	-174.3	22.5	361.0	1,046.1	900.4	864.0	830.5	1,998.7	14,733
LoNTC	-404.8	-435.7	-244.7	-133.1	-464.5	-244.0	-197.2	270.0	1,229.8	1,337.5	2,071.3	2,462.8	2,675.2	19,719
Ro1220_2800														
Ref	-404.8	-278.1	-45.7	-90.3	-170.0	1.9	160.8	412.3	1,431.3	1,440.3	803.7	901.2	2,338.2	8,195
HiDem	-532.3	-324.4	-25.0	-113.0	-108.9	177.5	13.3	431.7	1,341.3	766.1	1,060.7	2,503.9	2,524.7	8,849
LoDem	-393.7	-81.3	-65.7	-139.1	-257.3	-30.3	187.3	368.4	1,042.2	736.6	782.6	754.9	837.5	2,935
HiFuel	-405.2	-279.0	-23.7	-213.3	-255.0	112.5	199.0	358.8	1,419.0	1,382.3	1,007.8	932.6	2,488.2	8,721
LoFuel	-404.4	-278.4	-40.8	-103.9	-145.6	71.4	147.1	334.7	938.9	836.7	858.2	723.5	2,328.1	8,160
HiTIC	-404.3	-273.6	-73.2	-72.0	22.5	139.7	304.4	466.0	1,537.0	1,166.1	1,156.4	1,147.7	3,391.9	11,888
LoTIC	-405.3	-282.3	-34.2	-251.2	-322.1	0.7	91.1	200.9	1,062.1	939.2	643.6	724.2	1,193.9	4,184
HiNTC	-404.8	-278.1	-45.7	-90.3	-170.0	1.9	160.8	412.3	1,068.7	929.8	811.2	713.4	1,861.1	6,523
LoNTC	-404.8	-361.2	-45.6	-231.8	-293.3	-50.1	-20.7	277.9	1,212.0	1,260.7	1,803.0	1,757.5	1,849.0	6,481

Note: All Rogun design options exhibit savings of 89.1USDm, 178.2USDm, and 89.1USDm in 2014, 2015, and 2016 respectively compared to the NoRogun case in all scenarios to account for the cost of decommissioning the Rogun site if construction does not proceed. The figures shown are annual values and apply in each of the respective years indicated.

Source: IPA analysis.

Table 40: PV of TSC savings by sensitivity @ 10%

USD million / Case (prob.)	Ref 20%	HiDem 10%	LoDem 10%	HiFuel 10%	LoFuel 10%	HiTIC 10%	LoTIC 10%	HiNTC 10%	LoNTC 10%	Probability-weighted average
Ro1290_3600	1,678	1,854	628	1,881	1,215	2,509	554	1,051	1,485	**1,453**
Ro1290_3200	1,707	1,825	679	1,929	1,238	2,531	560	1,072	1,542	**1,479**
Ro1290_2800	1,701	1,452	688	1,897	1,248	2,522	538	1,071	1,552	**1,437**
Ro1255_3200	1,495	1,687	621	1,729	1,103	2,399	580	948	1,353	**1,341**
Ro1255_2800	1,497	1,344	648	1,739	1,099	2,410	529	944	1,436	**1,314**
Ro1255_2400	1,524	468	635	1,672	1,106	2,395	541	937	1,380	**1,218**
Ro1220_2800	1,389	1,432	723	1,381	983	2,047	356	936	1,111	**1,174**
Ro1220_2400	1,387	728	734	1,315	980	2,034	348	927	1,155	**1,100**
Ro1220_2000	1,342	69	710	1,329	933	1,980	424	866	1,228	**1,022**

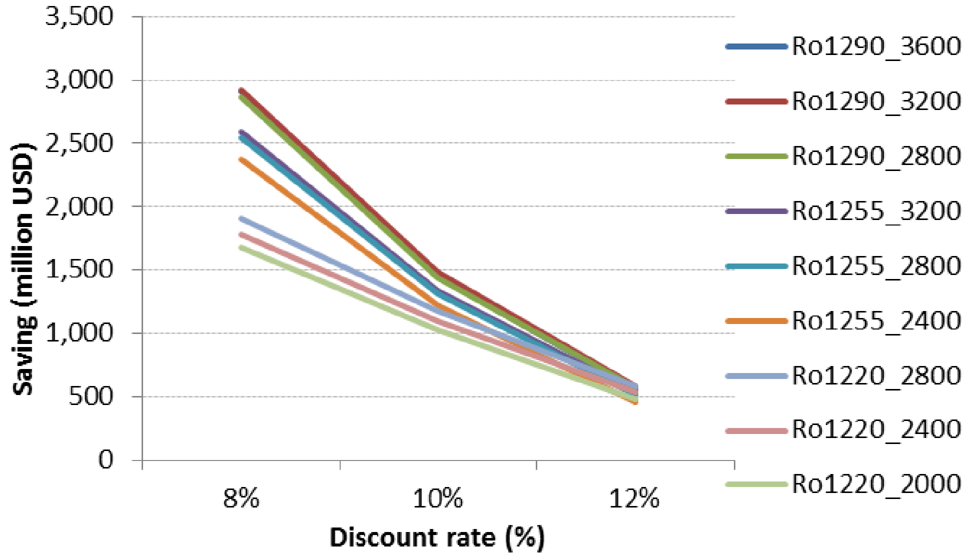
Note: The colour coding is used to highlight relative PV of TSC within each sensitivity (column) not across all cases: red = lowest, yellow = middle, green = highest.

Source: IPA analysis.

6.4. Sensitivity of TSC savings to discount rate

Figure 32 and Table 41 below show the probability-weighted PV of TSC savings in Tajikistan at 8% and 12% discount rates in addition to the base assumption of 10%. In all cases, Rogun provides a net benefit (costs savings) to the Tajik system, ranging from 2,919USD million for the Ro1290_3200 case at an 8% discount rate to 454USD million for the Ro1255_2400 case at a discount rate of 12%.

Figure 32: Probability-weighted PV of TSC savings in Tajikistan



Source: IPA analysis.

Table 41: Probability-weighted PV of TSC savings variation with discount rate

USD million	Real discount rate		
	8%	10%	12%
Ro1290_3600	2,905	1,453	564
Ro1290_3200	2,919	1,479	586
Ro1290_2800	2,862	1,437	572
Ro1255_3200	2,592	1,341	537
Ro1255_2800	2,545	1,314	520
Ro1255_2400	2,378	1,218	454
Ro1220_2800	1,908	1,174	582
Ro1220_2400	1,783	1,100	541
Ro1220_2000	1,681	1,022	476

Note: The colour coding is used to highlight relative probability-weighted PV of TSC savings within discount rate (column) not across all cases: red = lowest, yellow = middle, green = highest.

Source: IPA analysis.

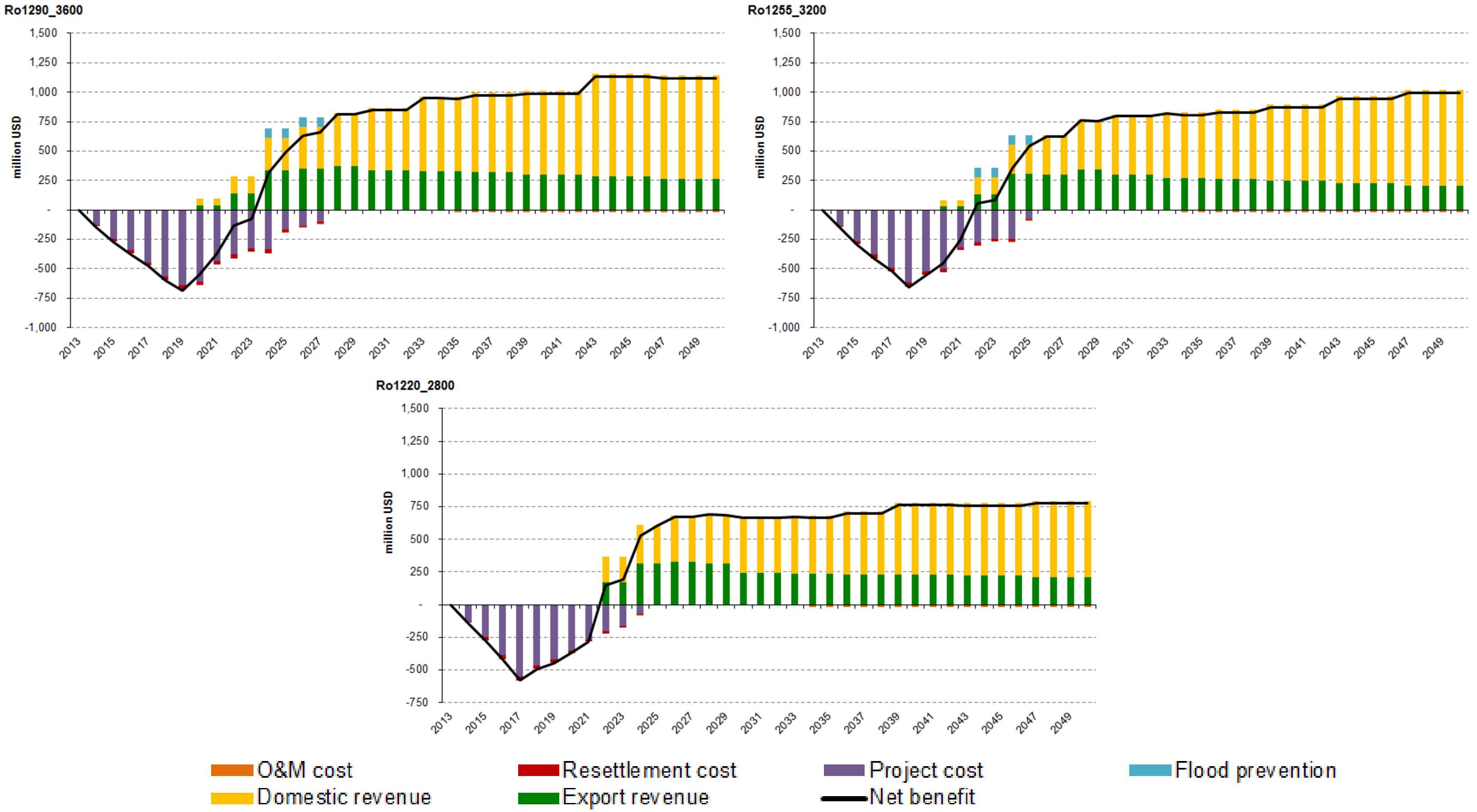
Higher discount rates reduce the overall PV savings attributed to the Project. The higher dam options tend to provide greater system cost savings than the smaller dam option at discount rates of 10% or less, with 12% near the switching point above which the larger capex requirements of the higher dam options start to outweigh the greater benefits because of the larger absolute costs incurred earlier in the investment cycle.

7. ECONOMIC ANALYSIS

This Section 7 presents the results of our economic analysis of the Project as outlined in subsection 3.3 above. Benefits of the Project consist of the value of Project's generation for domestic use and for exports, and the flood protection which the two higher dam heights provide for the downstream Vakhsh cascade. The costs include the costs for civil works, hydro-mechanical and electromechanical equipment, administration and engineering costs, resettlement, infrastructure replacement (environmental costs) and the O&M costs, as provided by Coyne et Bellier. We estimate the NPV and the EIRR for each of the proposed Rogun design options from the annual series of net benefits.

Figure 33 summarises the economic benefits and costs for the 1290_3600, 1255_3200 and 1220_2800 options in the IRA. A summary of the calculation of the NPV and the EIRR for these options is shown in Table 42/Table 43, Table 44/Table 45 and Table 46/Table 47. The higher initial costs of the higher dam options are outweighed by the future benefits including the external benefits of flood prevention.

Figure 33: Economic analysis of different Rogun design options under the IRA



Source: IPA analysis.

Table 42: Economic analysis of Ro1290_3600 under the IRA (2014-27)

	CYs / Units	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Benefits															
Domestic															
Generation	GWh	-	-	-	-	-	-	957	957	2,316	2,316	4,522	4,522	5,649	5,649
Average realised price	USD/MWh	-	-	-	-	-	-	66.77	66.77	65.31	65.31	61.12	61.12	63.00	63.00
Sales	000 USD	-	-	-	-	-	-	63,884	63,884	151,230	151,230	276,390	276,390	355,874	355,874
Exports															
Generation	GWh	-	-	-	-	-	-	363	363	1,437	1,437	3,645	3,645	3,939	3,939
Average realised price	USD/MWh	-	-	-	-	-	-	96.00	96.00	94.41	94.41	91.52	91.52	88.87	88.87
Sales	000 USD	-	-	-	-	-	-	34,829	34,829	135,702	135,702	333,529	333,529	350,056	350,056
Flood protection	000 USD	-	-	-	-	-	-	-	-	-	-	79,500	79,500	79,500	79,500
Total benefits	000 USD	-	-	-	-	-	-	98,714	98,714	286,932	286,932	689,419	689,419	785,429	785,429
Costs															
Annual project costs	000 USD	129,660	246,418	343,716	446,675	563,319	642,176	608,973	436,965	379,130	327,490	337,409	169,407	134,337	103,589
Resettlement costs	000 USD	10,969	20,847	29,078	24,501	30,899	35,225	33,404	27,397	32,968	28,477	29,340	16,550	11,682	10,245
O&M costs	000 USD	-	-	-	-	-	-	-	-	-	-	-	4,639	4,639	4,639
Loss of agricultural production	000 USD	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792
Total costs	000 USD	146,420	273,056	378,586	476,968	600,010	683,193	648,168	470,154	417,889	361,759	372,541	196,388	156,450	124,265
Net benefits															
Net benefits	000 USD	-146,420	-273,056	-378,586	-476,968	-600,010	-683,193	-549,455	-371,441	-130,958	-74,828	316,878	493,030	628,979	661,164

Note: The figures shown are annual values and apply in each of the respective years indicated.

Source: IPA analysis.

Table 43: Economic analysis of Ro1290_3600 under the IRA (continued 2028-50)

	CYs / Units	2028	2029	2030	2031	2032	2033	2034	2035	2036-38	2039-42	2043-46	2047-49	2050
Benefits														
Domestic														
Generation	GWh	6,971	6,971	8,317	8,317	8,317	9,794	9,794	9,794	9,931	10,186	10,431	10,743	10,743
Average realised price	USD/MWh	64.54	64.54	63.63	63.63	63.63	64.79	64.79	64.79	68.14	69.60	83.34	82.33	82.33
Sales	000 USD	449,872	449,872	529,220	529,220	529,220	634,590	634,590	634,590	676,700	708,971	869,312	884,458	884,458
Exports														
Generation	GWh	4,277	4,277	4,616	4,616	4,616	4,556	4,556	4,556	4,412	4,150	3,895	3,571	3,571
Average realised price	USD/MWh	86.40	86.40	72.33	72.33	72.33	72.44	72.44	72.44	72.71	72.74	73.36	72.79	72.79
Sales	000 USD	369,529	369,529	333,890	333,890	333,890	330,076	330,076	330,076	320,839	301,899	285,731	259,977	259,977
Flood protection	000 USD	-	-	-	-	-	-	-	-	-	-	-	-	-
Total benefits	000 USD	819,401	819,401	863,111	863,111	863,111	964,665	964,665	964,665	997,539	1,010,869	1,155,042	1,144,436	1,144,436
Costs														
Annual project costs	000 USD	-	-	-	-	-	-	-	-	-	-	-	-	-
Resettlement costs	000 USD	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M costs	000 USD	4,639	4,639	9,279	9,279	9,279	9,279	9,279	18,558	18,558	18,558	18,558	18,558	23,262
Loss of agricultural production	000 USD	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792
Total costs	000 USD	10,431	10,431	15,070	15,070	15,070	15,070	15,070	24,349	24,349	24,349	24,349	24,349	29,054
Net benefits														
Net benefits	000 USD	808,970	808,970	848,040	848,040	848,040	949,595	949,595	940,316	973,190	986,520	1,130,693	1,120,086	1,115,382
Post-2050 value as of 2050	000 USD													9,639,773
NPV @ 10%	000 USD	819,409												
EIRR		12.07%												

Note: The figures shown are annual values and apply in each of the respective years indicated.

Source: IPA analysis.

Table 44: Economic analysis of Ro1255_3200 under the IRA (2014-27)

	CYs / Units	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Benefits															
Domestic															
Generation	GWh	-	-	-	-	-	-	800	800	2,224	2,224	4,034	4,034	5,221	5,221
Average realised price	USD/MWh	-	-	-	-	-	-	66.88	66.88	65.27	65.27	61.82	61.82	63.68	63.68
Sales	000 USD	-	-	-	-	-	-	53,512	53,512	145,125	145,125	249,342	249,342	332,456	332,456
Exports															
Generation	GWh	-	-	-	-	-	-	292	292	1,408	1,408	3,321	3,321	3,366	3,366
Average realised price	USD/MWh	-	-	-	-	-	-	96.22	96.22	94.44	94.44	91.55	91.55	88.81	88.81
Sales	000 USD	-	-	-	-	-	-	28,103	28,103	132,941	132,941	304,093	304,093	298,957	298,957
Flood protection	000 USD	-	-	-	-	-	-	-	-	79,500	79,500	79,500	79,500	-	-
Total benefits	000 USD	-	-	-	-	-	-	81,615	81,615	357,566	357,566	632,935	632,935	631,413	631,413
Costs															
Annual project costs	000 USD	135,921	267,005	380,491	492,957	620,967	525,841	504,088	319,682	277,331	249,062	249,224	79,065	-	-
Resettlement costs	000 USD	11,499	22,588	32,189	27,040	34,062	28,844	27,650	20,044	24,116	21,658	21,672	7,724	-	-
O&M costs	000 USD	-	-	-	-	-	-	-	-	-	-	4,445	4,445	4,445	4,445
Loss of agricultural production	000 USD	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445
Total costs	000 USD	149,864	292,038	415,125	522,441	657,474	557,129	534,183	342,171	303,891	273,164	277,785	93,679	6,890	6,890
Net benefits															
Net benefits	000 USD	-149,864	-292,038	-415,125	-522,441	-657,474	-557,129	-452,567	-260,555	53,674	84,402	355,150	539,256	624,524	624,524

Note: The figures shown are annual values and apply in each of the respective years indicated.

Source: IPA analysis.

Table 45: Economic analysis of Ro1255_3200 under the IRA (continued 2028-50)

	CYs / Units	2028	2029	2030	2031	2032	2033	2034	2035	2036-38	2039-42	2043-46	2047-48	2049-50
Benefits														
Domestic														
Generation	GWh	6,745	6,745	8,142	8,142	8,142	8,474	8,474	8,474	8,609	8,769	8,998	9,210	9,210
Average realised price	USD/MWh	63.27	63.27	62.32	62.32	62.32	65.70	65.70	65.70	68.56	73.91	82.50	88.37	88.37
Sales	000 USD	426,722	426,722	507,403	507,403	507,403	556,761	556,761	556,761	590,279	648,149	742,403	813,970	813,970
Exports														
Generation	GWh	3,958	3,958	4,120	4,120	4,120	3,763	3,763	3,763	3,595	3,387	3,093	2,817	2,817
Average realised price	USD/MWh	85.89	85.89	72.75	72.75	72.75	72.19	72.19	72.19	72.21	72.35	72.10	71.82	71.82
Sales	000 USD	339,927	339,927	299,699	299,699	299,699	271,638	271,638	271,638	259,574	245,040	223,047	202,337	202,337
Flood protection	000 USD	-	-	-	-	-	-	-	-	-	-	-	-	-
Total benefits	000 USD	766,649	766,649	807,101	807,101	807,101	828,399	828,399	828,399	849,853	893,189	965,450	1,016,307	1,016,307
Costs														
Annual project costs	000 USD	-	-	-	-	-	-	-	-	-	-	-	-	-
Resettlement costs	000 USD	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M costs	000 USD	4,445	8,890	8,890	8,890	8,890	8,890	17,779	17,779	17,779	17,779	17,779	17,779	22,021
Loss of agricultural production	000 USD	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445
Total costs	000 USD	6,890	11,334	11,334	11,334	11,334	11,334	20,224	20,224	20,224	20,224	20,224	20,224	24,466
Net benefits														
Net benefits	000 USD	759,760	755,315	795,767	795,767	795,767	817,065	808,175	808,175	829,628	872,965	945,226	996,083	991,841
Post-2050 value as of 2050	000 USD													7,310,824
NPV @ 10%	000 USD	729,430												
EIRR		12.03%												

Note: The figures shown are annual values and apply in each of the respective years indicated.

Source: IPA analysis.

Table 46: Economic analysis of Ro1220_2800 under the IRA (2014-27)

	Units \ CYs	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Benefits															
Domestic															
Generation	GWh	-	-	-	-	-	-	-	-	3,098	3,098	5,193	5,193	6,137	6,137
Average realised price	USD/MWh	-	-	-	-	-	-	-	-	64.32	64.32	57.31	57.31	57.06	57.06
Sales	000 USD	-	-	-	-	-	-	-	-	199,271	199,271	297,640	297,640	350,215	350,215
Exports															
Generation	GWh	-	-	-	-	-	-	-	-	1,788	1,788	3,453	3,453	3,746	3,746
Average realised price	USD/MWh	-	-	-	-	-	-	-	-	93.94	93.94	90.46	90.46	88.09	88.09
Sales	000 USD	-	-	-	-	-	-	-	-	167,999	167,999	312,345	312,345	330,037	330,037
Flood protection	000 USD	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total benefits	000 USD	-	-	-	-	-	-	-	-	367,271	367,271	609,985	609,985	680,252	680,252
Costs															
Annual project costs	000 USD	127,555	250,788	384,712	550,402	466,162	420,394	350,977	265,205	203,445	160,921	69,808	-	-	-
Resettlement costs	000 USD	10,791	21,216	32,546	30,191	25,570	23,060	19,252	16,628	17,691	13,993	6,070	-	-	-
O&M costs	000 USD	-	-	-	-	-	-	-	-	-	-	4,061	4,061	4,061	4,061
Loss of agricultural production	000 USD	1,685	1,685	1,685	1,685	1,685	1,685	1,685	1,685	1,685	1,685	1,685	1,685	1,685	1,685
Total costs	000 USD	140,031	273,690	418,943	582,278	493,417	445,139	371,914	283,518	222,821	176,599	81,624	5,746	5,746	5,746
Net benefits															
Net benefits	000 USD	-140,031	-273,690	-418,943	-582,278	-493,417	-445,139	-371,914	-283,518	144,449	190,672	528,361	604,239	674,506	674,506

Note: The figures shown are annual values and apply in each of the respective years indicated.

Source: IPA analysis.

Table 47: Economic analysis of Ro1220_2800 under the IRA (continued 2028-50)

	Units \ CYs	2028	2029	2030	2031	2032	2033	2034	2035	2036-38	2039-42	2043-46	2047-49	2050
Benefits														
Domestic														
Generation	GWh	6,314	6,314	6,616	6,616	6,616	6,825	6,825	6,825	6,979	7,137	7,388	7,657	7,657
Average realised price	USD/MWh	60.21	60.21	65.14	65.14	65.14	65.22	65.22	65.22	69.57	77.41	75.50	75.63	75.63
Sales	000 USD	380,177	380,177	430,967	430,967	430,967	445,147	445,147	445,147	485,548	552,483	557,803	579,128	579,128
Exports														
Generation	GWh	3,633	3,633	3,426	3,426	3,426	3,312	3,312	3,312	3,253	3,188	3,063	2,951	2,951
Average realised price	USD/MWh	86.25	86.25	71.35	71.35	71.35	70.94	70.94	70.94	71.05	71.48	71.72	71.81	71.81
Sales	000 USD	313,377	313,377	244,485	244,485	244,485	234,940	234,940	234,940	231,126	227,894	219,638	211,893	211,893
Flood protection	000 USD	-	-	-	-	-	-	-	-	-	-	-	-	-
Total benefits	000 USD	693,554	693,554	675,451	675,451	675,451	680,087	680,087	680,087	716,674	780,377	777,441	791,021	791,021
Costs														
Annual project costs	000 USD	-	-	-	-	-	-	-	-	-	-	-	-	-
Resettlement costs	000 USD	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M costs	000 USD	4,061	8,122	8,122	8,122	8,122	8,122	16,244	16,244	16,244	16,244	16,244	16,244	16,244
Loss of agricultural prod.	000 USD	1,685	1,685	1,685	1,685	1,685	1,685	1,685	1,685	1,685	1,685	1,685	1,685	1,685
Total costs	000 USD	5,746	9,807	9,807	9,807	9,807	9,807	17,929	17,929	17,929	17,929	17,929	17,929	17,929
Net benefits														
Net benefits	000 USD	687,808	683,747	665,644	665,644	665,644	670,279	662,157	662,157	698,744	762,448	759,511	773,091	773,091
Post-2050 value as of 2050	000 USD													2,709,638
NPV @ 10%	000 USD	656,449												
EIRR		12.24%												

Note: The figures shown are annual values and apply in each of the respective years indicated.

Source: IPA analysis.

Table 48 and Table 49 below show the NPVs at a 10% discount rate and EIRRs for the different Rogun design options under all the different sensitivities. The EIRR corresponds to the hurdle rate of each investment option.

The highest dam height options have the greatest NPVs across all the sensitivities. Comparing the sensitivity results to the Reference case, we see a similar trend as with the TSC savings:

1. **Demand**: Lower demand growth reduces the value of all Rogun options because domestic prices are lower. The construction of additional ROR Hydro in the higher demand sensitivity increases realised prices.

2. **Fuel costs**: High fuel prices lead to higher costs in Tajikistan's thermal-based neighbours and thus increase the value of exports and the NPV of Rogun, with the opposite when fuel prices are lower.

3. **TIC**: Increasing the cost of non-Rogun new build options increases prices and the value of exports, and vice versa.

4. **Interconnection**: In the low interconnector sensitivity, the loss of exports to higher-priced Pakistan leads to a drop in export revenue and hence a lower NPV. NPVs are also reduced in the HiNTC sensitivity because of the downward impact on domestic prices of greater imports from Uzbekistan and Kyrgyzstan.

Table 48: NPV @ 10% of different Rogun design options across sensitivities

USD million	Ref	HiDem	LoDem	HiTIC	LoTIC	HiFuel	LoFuel	HiNTC	LoNTC
Ro1290_3600	819	852	720	1,080	523	1,222	366	766	780
Ro1290_3200	863	887	765	1,121	559	1,244	420	808	819
Ro1290_2800	878	792	769	1,132	561	1,251	405	820	767
Ro1255_3200	729	768	648	951	460	1,074	302	663	667
Ro1255_2800	758	715	678	973	471	1,102	331	690	747
Ro1255_2400	748	578	699	982	495	1,087	332	704	641
Ro1220_2800	656	656	640	887	402	943	312	629	398
Ro1220_2400	667	534	650	889	404	919	326	637	435
Ro1220_2000	635	431	614	848	389	874	286	601	435

Note: The colour coding is used to highlight relative NPV within each sensitivity (column) not across all cases: red = lowest, yellow = middle, green = highest.

Source: IPA analysis.

Table 49: EIRR of different Rogun design options across sensitivities

	Ref	HiDem	LoDem	HiTIC	LoTIC	HiFuel	LoFuel	HiNTC	LoNTC
Ro1290_3600	12.1%	12.1%	11.9%	12.6%	11.4%	13.0%	10.9%	12.0%	11.5%
Ro1290_3200	12.2%	12.2%	12.0%	12.7%	11.5%	13.1%	11.1%	12.1%	11.6%
Ro1290_2800	12.3%	12.1%	12.0%	12.8%	11.5%	13.1%	11.1%	12.2%	11.6%
Ro1255_3200	12.0%	12.1%	11.9%	12.5%	11.3%	12.9%	10.9%	11.9%	11.5%
Ro1255_2800	12.1%	12.0%	12.0%	12.6%	11.4%	13.0%	11.0%	12.0%	11.7%
Ro1255_2400	12.2%	11.8%	12.1%	12.7%	11.5%	13.0%	11.0%	12.1%	11.5%
Ro1220_2800	12.2%	12.3%	12.2%	12.9%	11.4%	13.1%	11.1%	12.2%	11.2%
Ro1220_2400	12.3%	12.0%	12.3%	12.9%	11.5%	13.1%	11.2%	12.2%	11.3%
Ro1220_2000	12.3%	11.7%	12.2%	12.9%	11.4%	13.0%	11.0%	12.2%	11.3%

Note: The colour coding is used to highlight relative EIRR within each sensitivity (column) not across all cases: red = lowest, yellow = middle, green = highest.

Source: IPA analysis.

The probability-weighted NPVs at a 10% discount rate for each Rogun design option across all scenarios are shown in Table 50 below. The variation of the probability-weighted NPV with discount rate is given in Table 51 below. As with the system cost savings, the higher dam options are more beneficial at lower discount rates, while all the options are fairly marginal at 12% (noting that this is approximately the EIRR).

Table 50: Probability-weighted NPV @ 10% of Rogun design options

Rogun Design	NPV @ 10% (USD million)	Rank
Ro1290_3600	795	3
Ro1290_3200	835	1
Ro1290_2800	825	2
Ro1255_3200	699	6
Ro1255_2800	722	4
Ro1255_2400	701	5
Ro1220_2800	618	7
Ro1220_2400	613	8
Ro1220_2000	575	9

Note: The colour coding is used to highlight relative probability-weighted NPV: red = lowest, yellow = middle, green = highest.

Source: IPA analysis.

Table 51: Sensitivity of probability-weighted NPV to discount rate

USD million	Real discount rate		
	8%	10%	12%
Ro1290_3600	2,337	795	-42
Ro1290_3200	2,371	835	-1
Ro1290_2800	2,330	825	5
Ro1255_3200	2,012	699	-42
Ro1255_2800	2,025	722	-16
Ro1255_2400	1,962	701	-15
Ro1220_2800	1,614	618	15
Ro1220_2400	1,589	613	21
Ro1220_2000	1,516	575	4

Note: The colour coding is used to highlight relative probability-weighted NPVs within discount rate (column) not across all cases: red = lowest, yellow = middle, green = highest.

Source: IPA analysis.

8. RECOMMENDED ROGUN DESIGN OPTION

Based on the results of the technical and economic analysis described herein, the Consortium recommends that the highest dam height alternative (1290 m.a.s.l.) should be taken forward for detailed consideration. The choice between capacity options within this specified dam height design is less clear cut, however, based on the analysis undertaken to date.

The regional least-cost expansion plan suggests that the incremental net benefit of adding capacity beyond a particular point is limited. The extra cost of installing the highest capacity level is not fully compensated since the total annual generation from the Project is primarily determined by dam height (and hence reservoir size) rather than installed capacity, and the benefit of additional peak capacity is limited by interconnector constraints and the level of achievable prices in Tajikistan and Pakistan (as the principle export market for Tajikistan).

However, maintaining the option of expanding installed capacity at a later stage by leaving one unit pit empty could be a viable option, for example, if demand grows more strongly than forecast. Alternatively, an additional unit could bring more flexibility in the generating system by allowing standby periods for maintenance without the loss of overall annual energy generation. The incremental cost would be recovered by the avoided loss of generation during maintenance. It is recommended that these potential options be examined in detail in the next phase of the studies.

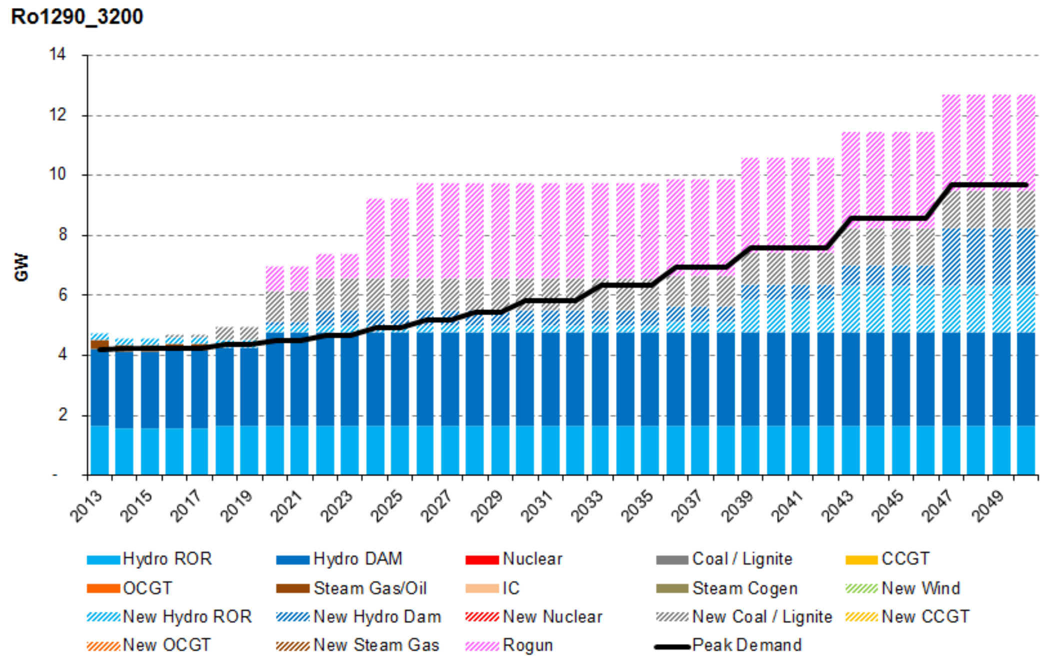
At this stage, however, since the 3,200 MW intermediate installed capacity option shows both the highest overall TSC saving and economic NPV, it has been agreed that further analysis should be undertaken on this recommended design option.

8.1. Reference case least-cost expansion plan

The least-cost expansion plan for this recommended design option Ro1290_3200 is broadly similar to that previously described in Section 5 above for the highest capacity option at the same dam height (Ro1290_3600).

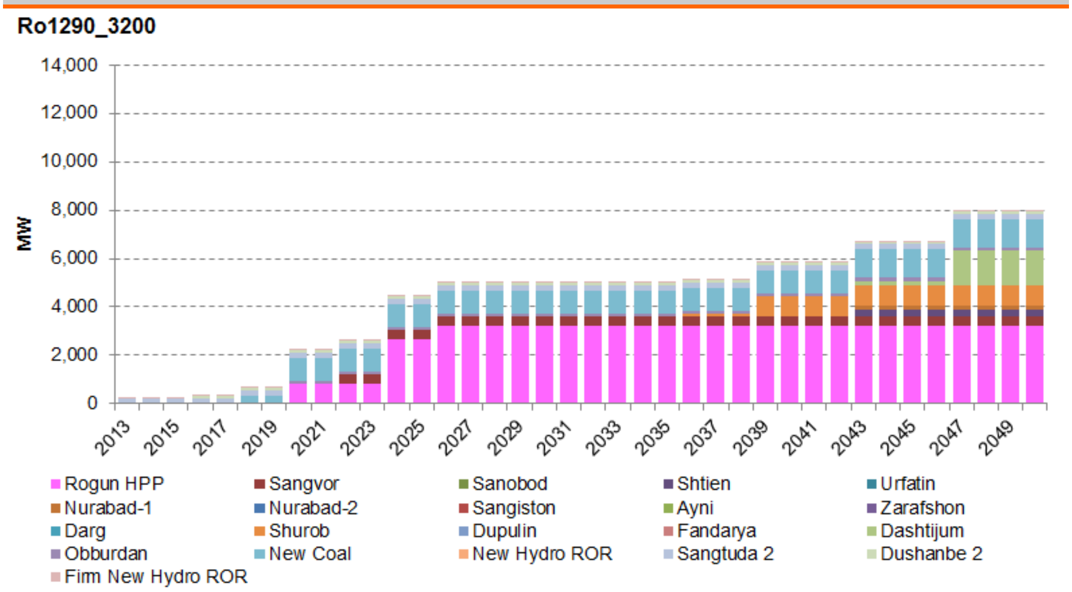
Capacity development in Tajikistan, shown in Figure 34, relies mainly on Rogun in the early years, with both ROR and Dam Hydro being built as peak demand increases above 7 GW from 2039 onwards (shown in more detail in Figure 35).

Figure 34: Tajikistan capacity mix by technology type – Ro1290_3200



Source: IPA analysis. (Data in Table 96 in Annex F.)

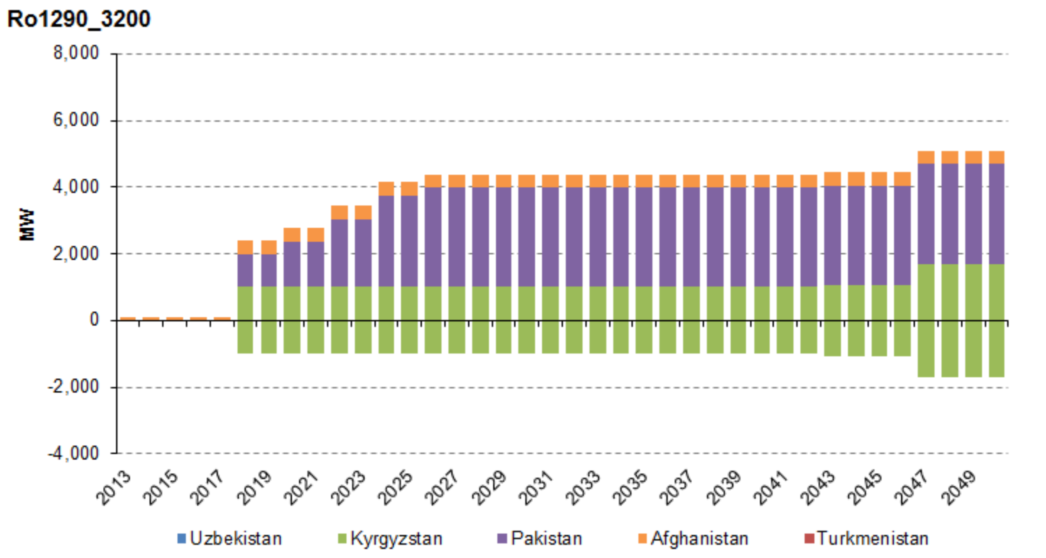
Figure 35: Tajikistan New Builds – Ro1290_3200



Source: IPA analysis. (Data in Table 97 in Annex F.)

As with all the other design options, interconnector expansion to Pakistan beyond the known Firm plans is required from 2020 when the Project first starts generating, as shown in Figure 36.

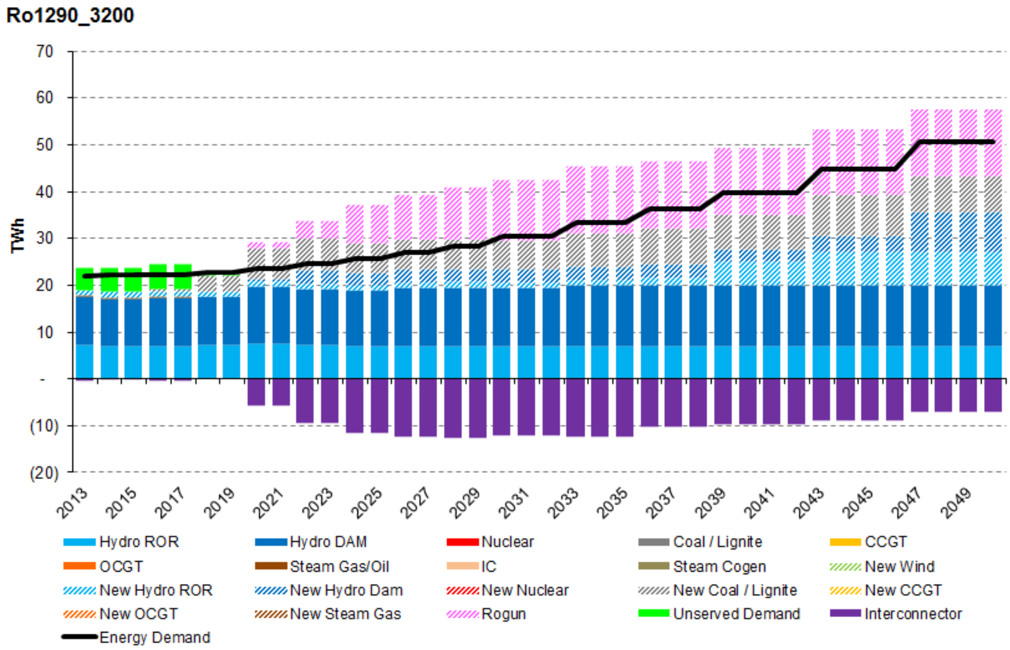
Figure 36: Tajikistan interconnector capacity expansion – Ro1290_3200



Source: IPA analysis. (Data in Table 98 in Annex F.)

The resulting generation mix for Tajikistan is shown in Figure 37. Net exports grow as the Project comes on line through the 2020s and then gradually decline as domestic demand rises.

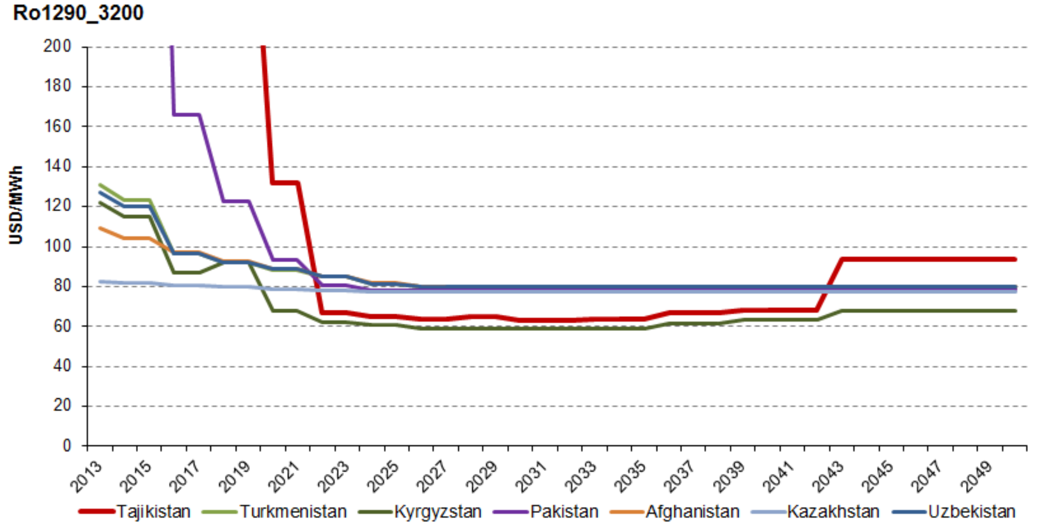
Figure 37: Tajikistan annual generation mix by technology – Ro1290_3200



Source: IPA analysis. (Data in Table 99 in Annex F.)

Figure 38 shows the forecast for shadow electricity prices in the region. As with the other Rogun cases, once the Project becomes operational and helps meet current levels of unmet demand, prices in Tajikistan fall to around 65USD/MWh. Only in the later years of the Forecast Horizon when New Build Hydro is required to meet the continually growing demand do prices rise significantly to cover the costs of this investment.

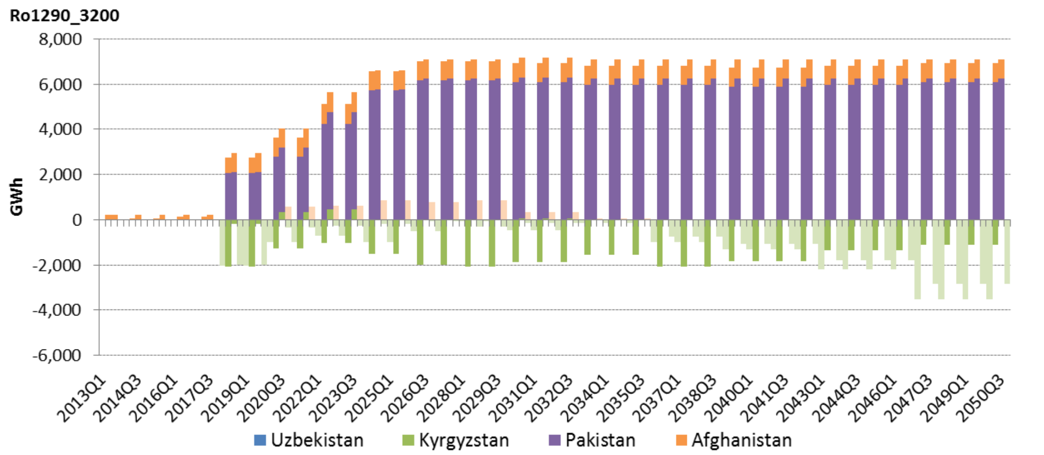
Figure 38: Central Asia annual shadow electricity price forecasts – Ro1290_3200



Source: IPA analysis. (Data in Table 100 in Annex F.)

The quarterly export pattern is exactly as seen for all the other cases, with imports from Kyrgyzstan during the winter and exports to Pakistan and Afghanistan in the summer, as shown in Figure 39. Again there is a period after Rogun reaches full operation in 2026 when Tajikistan does not need net winter imports, until demand grows further beyond 2033.

Figure 39: Tajikistan quarterly net exports – Ro1290_3200

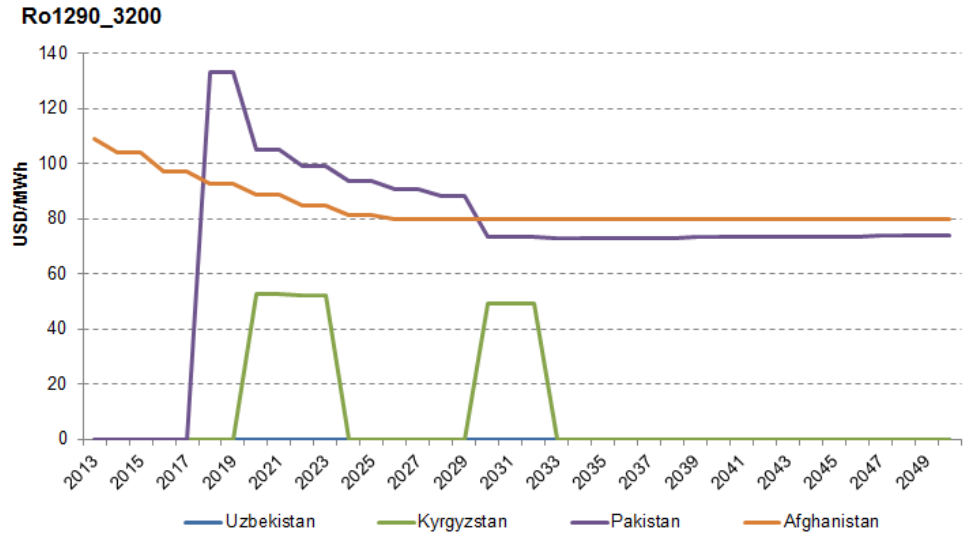


Note: Lighter bars are winter flows, darker bars are summer.

Source: IPA analysis. (Data in Table 101 in Annex F.)

Annual realised export prices shown in Figure 40 are also very similar with the higher capacity option shown previously.

Figure 40: Tajikistan annual realised export prices – Ro1290_3200



Source: IPA analysis. (Data in Table 102 in Annex F.)

8.2. System cost savings

Table 53 below shows the annual system cost savings for the recommended Rogun design option under the different scenarios relative to the NoRogun case under the same scenario, including the post-2050 value, and Table 52 summarises the resulting PV of these savings at discount rates of 8%, 10%, and 12% (as previously detailed in Section 6).

Table 52: PV of TSC savings for Ro1290_3200 across sensitivities

Case (probability)		PV (USD million)		
		8%	10%	12%
Ref	(20%)	3,262	**1,707**	541
HiDem	(10%)	4,080	**1,825**	966
LoDem	(10%)	1,618	**679**	262
HiTIC	(10%)	2,879	**1,929**	895
LoTIC	(10%)	2,955	**1,238**	405
HiFuel	(10%)	4,728	**2,531**	1,151
LoFuel	(10%)	1,070	**560**	165
HiNTC	(10%)	2,049	**1,072**	404
LoNTC	(10%)	3,284	**1,542**	536
Probability-weighted average		2,919	**1,479**	586

Source: IPA analysis.

Table 53: Annual system cost savings against the relevant NoRogun case – Ro1290_3200

CYs / USD million	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-28	2039-42	2043-46	2047-50	Post-2050
Ref	-404.8	-289.4	-109.0	-72.1	-235.0	-169.7	54.2	270.8	1,476.6	1,492.7	958.6	1,122.2	2,761.9	23,870
HiDem	-532.3	-404.6	-362.3	-44.8	-170.9	-17.5	-153.6	317.7	1,423.5	956.9	1,420.5	3,012.2	3,475.0	30,033
LoDem	-393.7	-92.5	-140.8	-109.2	-235.9	-93.8	-30.6	-14.6	1,077.1	825.0	860.1	978.0	1,122.8	9,704
HiFuel	-405.2	-292.9	-275.4	35.5	-160.2	-26.5	92.6	210.4	1,542.7	1,558.0	1,190.2	1,187.9	2,918.3	25,221
LoFuel	-404.4	-287.0	-122.0	-81.0	-199.6	-113.0	0.6	180.0	932.6	1,024.8	1,050.3	940.7	2,607.5	22,535
HiTIC	-404.3	-284.1	-134.0	-60.2	-177.4	-47.3	153.3	394.8	1,568.3	1,342.6	1,422.0	1,417.7	3,854.9	33,316
LoTIC	-405.3	-294.0	-298.5	-2.1	-203.6	-174.7	-48.4	-23.4	1,126.5	1,056.9	804.7	974.7	1,549.2	13,389
HiNTC	-404.8	-289.4	-109.0	-72.1	-235.0	-169.7	18.4	270.8	1,113.9	997.9	889.2	922.9	2,095.5	18,111
LoNTC	-404.8	-450.2	-292.0	-197.0	-376.3	-258.8	-229.9	141.1	1,265.1	1,383.2	2,149.2	2,742.9	3,009.5	26,010

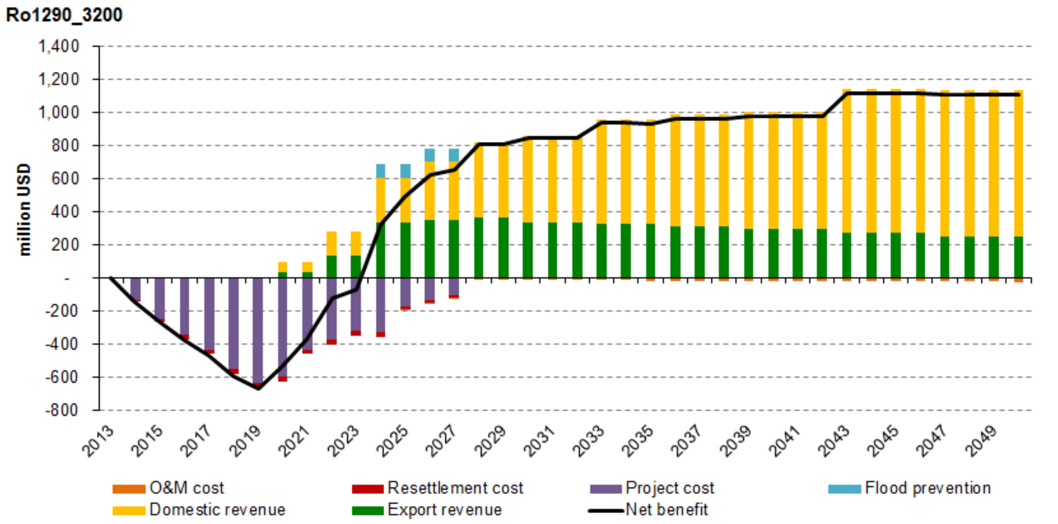
Note: There are cost savings of USD89.1m, USD178.2m, and USD89.1m in 2014, 2015, and 2016 respectively compared to the NoRogun case in all scenarios to account for the cost of decommissioning the Rogun site if construction does not proceed. The figures shown are annual values and apply in each of the respective years indicated.

Source: IPA analysis.

8.3. Economic analysis

Figure 41 summarises the economic benefits and costs for the recommended Rogun design option in the IRA, with the calculation of the NPV and the EIRR is shown in Table 54 and Table 55 below.

Figure 41: Economic analysis of Ro1290_3200 under the IRA



Source: IPA analysis

Table 54: Economic analysis of Ro1290_3200 under the IRA (2014-27)

	CYs / Units	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Benefits															
Domestic															
Generation	GWh	-	-	-	-	-	-	957	957	2,316	2,316	4,522	4,522	5,649	5,649
Average realised price	USD/MWh	-	-	-	-	-	-	66.77	66.77	65.31	65.31	61.12	61.12	63.00	63.00
Sales	000 USD	-	-	-	-	-	-	63,884	63,884	151,230	151,230	276,390	276,390	355,874	355,874
Exports															
Generation	GWh	-	-	-	-	-	-	363	363	1,437	1,437	3,645	3,645	3,939	3,939
Average realised price	USD/MWh	-	-	-	-	-	-	96.00	96.00	94.41	94.41	91.52	91.52	88.87	88.87
Sales	000 USD	-	-	-	-	-	-	34,829	34,829	135,702	135,702	333,529	333,529	350,056	350,056
Flood protection	000 USD	-	-	-	-	-	-	-	-	-	-	79,500	79,500	79,500	79,500
Total benefits	000 USD	-	-	-	-	-	-	98,714	98,714	286,932	286,932	689,419	689,419	785,429	785,429
Costs															
Annual project costs	000 USD	129,527	244,138	340,742	433,547	550,745	628,561	591,797	430,581	371,235	318,584	328,014	169,146	134,118	104,399
Resettlement costs	000 USD	10,958	20,654	28,826	23,781	30,210	34,478	32,461	26,997	32,281	27,703	28,523	16,525	11,662	10,325
O&M costs	000 USD	-	-	-	-	-	-	-	-	-	-	-	4,509	4,509	4,509
Loss of agricultural production	000 USD	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792
Total costs	000 USD	146,277	270,583	375,360	463,120	586,747	668,830	630,050	463,370	409,308	352,079	362,328	195,971	156,080	125,024
Net benefits															
Net benefits	000 USD	-146,277	-270,583	-375,360	-463,120	-586,747	-668,830	-531,336	-364,657	-122,376	-65,147	327,091	493,448	629,349	660,405

Note: The figures shown are annual values and apply in each of the respective years indicated.

Source: IPA analysis.

Table 55: Economic analysis of Ro1290_3200 under the IRA (continued 2028-50)

	CYs / Units	2028	2029	2030	2031	2032	2033	2034	2035	2036-38	2039-42	2043-46	2047-49	2050
Benefits														
Domestic														
Generation	GWh	6,971	6,971	8,317	8,317	8,317	9,739	9,739	9,739	9,875	10,126	10,453	10,726	10,726
Average realised price	USD/MWh	64.77	64.77	63.63	63.63	63.63	64.90	64.90	64.90	68.27	69.74	83.06	82.34	82.34
Sales	000 USD	451,446	451,446	529,220	529,220	529,220	632,034	632,034	632,034	674,145	706,235	868,250	883,199	883,199
Exports														
Generation	GWh	4,277	4,277	4,616	4,616	4,616	4,504	4,504	4,504	4,361	4,103	3,765	3,482	3,482
Average realised price	USD/MWh	86.40	86.40	72.33	72.33	72.33	72.56	72.56	72.56	72.82	72.86	72.73	72.68	72.68
Sales	000 USD	369,529	369,529	333,890	333,890	333,890	326,818	326,818	326,818	317,562	298,933	273,860	253,028	253,028
Flood protection	000 USD	-	-	-	-	-	-	-	-	-	-	-	-	-
Total benefits	000 USD	820,976	820,976	863,111	863,111	863,111	958,852	958,852	958,852	991,707	1,005,168	1,142,110	1,136,227	1,136,227
Costs														
Annual project costs	000 USD	-	-	-	-	-	-	-	-	-	-	-	-	-
Resettlement costs	000 USD	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M costs	000 USD	4,509	4,509	9,017	9,017	9,017	9,017	9,017	18,034	18,034	18,034	18,034	18,034	22,357
Loss of agricultural production	000 USD	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792
Total costs	000 USD	10,300	10,300	14,809	14,809	14,809	14,809	14,809	23,826	23,826	23,826	23,826	23,826	28,148
Net benefits														
Net benefits	000 USD	810,675	810,675	848,302	848,302	848,302	944,043	944,043	935,026	967,881	981,342	1,118,284	1,112,401	1,108,079
Post-2050 value as of 2050	000 USD													9,576,657
NPV @ 10%	000 USD	863,446												
EIRR		12.21%												

Note: The figures shown are annual values and apply in each of the respective years indicated.

Source: IPA analysis.

Table 56 below shows the NPV (calculated at discount rates of 8%, 10%, and 12%) and EIRR for the recommended Rogun design option under all the different sensitivities (as previously defined in Section 7).

Table 56: NPV and EIRR of Ro1290_3200 across sensitivities

Case (probability)		NPV (USD million)			EIRR
		8%	**10%**	**12%**	
Ref	(20%)	2,351	**863**	41	12.21%
HiDem	(10%)	2,417	**887**	43	12.21%
LoDem	(10%)	2,186	**765**	-20	12.00%
HiTIC	(10%)	2,794	**1,121**	198	12.72%
LoTIC	(10%)	1,879	**559**	-165	11.49%
HiFuel	(10%)	2,928	**1,244**	303	13.07%
LoFuel	(10%)	1,728	**420**	-285	11.09%
HiNTC	(10%)	2,239	**808**	12	12.11%
LoNTC	(10%)	2,837	**819**	-181	11.63%
Probability-weighted average		2,371	**835**	-1	-

Source: IPA analysis.

The value of the Ro1290_3200 option is thus robust against the full range of market sensitivities up to a discount rate of 11%.

8.4. Modified Reference case

As detailed in Section 4.8, we have assumed the CASA-1000 interconnector line between Kyrgyzstan, Tajikistan, Afghanistan and Pakistan as a Firm New Build in 2017 in the IRA. However, while the export value of the Project has been clearly demonstrated, there is a question as to what extent and how quickly interconnectors are actually required to maximise this potential.

In order to examine this, we have therefore considered a specific sensitivity on the Reference case in which the firm CASA-1000 lines are replaced by possible Economic New Interconnectors from 2018 determined endogenously by ECLIPSE. These Modified Reference assumptions for Economic Interconnector New Build between Tajikistan, Kyrgyzstan, Afghanistan and Pakistan are thus detailed in Table 30 below.

Table 57: Modified Reference Economic New Interconnector assumptions

From	To	Annual Limit (MW/y)	Cumulative Maximum (MW)	Earliest COD
Tajikistan	Kyrgyzstan	350	4,000	2018
	Afghanistan	350	350	2018
	Pakistan	350	4,000	2018
Kyrgyzstan	Tajikistan	350	4,000	2018
Afghanistan		-	-	-
Pakistan		-	-	-

Source: IPA assumptions.

For a full comparison, we have calculated the TSC savings compared to an equivalent NoRogun case for the medium capacity options for the other two dam heights, Ro1255_2800 and Ro1220_2400, in addition to the recommended design option Ro1290_3200.

As shown in Figure 42, the economic interconnector expansion is later than the firm CASA-1000 build. In the NoRogun case, the same total capacity to both Pakistan and Kyrgyzstan is built by 2033 and 2043 respectively but at a more gradual rate. With Rogun 1290_3200, about 400MW less is required to Pakistan than under the Reference case from 2026 when the Project is fully operational. About 600MW less is built to Kyrgyzstan from 2020 to 2040, after which there is a little bit more. Similar trends are also seen for the lower dam height options. In all cases, the full 350MW capacity to Afghanistan is built in 2018.

The PV of the TSC savings for the three medium capacity options for each of the dam heights is shown in Table 58, compared to the Reference case results.

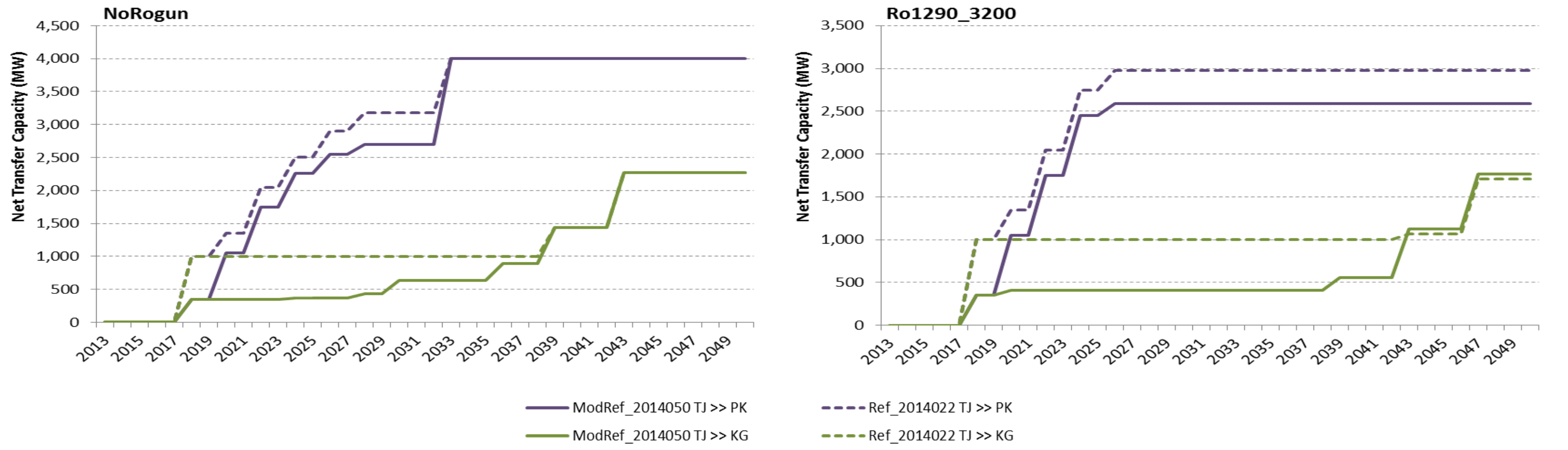
Table 58: PV of TSC savings @ 10% for Modified Reference vs. Reference case

Design Option	PV (USD million)	
	Modified Reference	Reference
Ro1290_3200	1,508	1,707
Ro1255_2800	1,315	1,497
Ro1220_2400	1,254	1,387

Source: IPA analysis.

The absolute savings are about USD130-200million lower with the removal of the Firm Build constraint, but there is the same clear trend of greater benefits from the highest dam options as from the other results. This thus demonstrates that the choice of the recommended Rogun option remains robust even in the absence of firm interconnections from 2017.

Figure 42: Tajikistan to Pakistan and Kyrgyzstan interconnector capacity expansion for Modified Reference vs. Reference case



Source: IPA analysis.

8.5. Additional sensitivity and breakeven analysis

In addition to the eight market-level sensitivities examined as part of the selection of the recommended design option, we also have investigated the robustness of the TSC savings and economic NPV of the Ro1290_3200 design option to a number of other variables. The following sensitivities and breakeven cases were examined for their impact on the least-cost expansion plans and consequent TSC savings versus a corresponding NoRogun case:

1. Gas supply to Tajikistan: Potential for CCGT and/or OCGT from 2025, and also for substitution of electricity for urban space heating.

2. Delay in starting Rogun construction: Delay of 2, 4 or 6 years (corresponding to 1, 2 and 3 Run Years respectively), maintaining specified implementation schedule thereafter.

3. Share reimbursement costs for NoRogun: Repayment of funds raised from investors which has already been spent.

4. Breakeven point for demand growth: The level of annual growth at which building Rogun in Ro1290_3200 would be less beneficial than building Dashtijum by 2033 in the NoRogun case.

5. Wet vs. average year generation: In wet years, the full summer surplus might not be able to be exported due to transmission constraints. To allow the full potential to be sold, additional interconnection capacity may have to be developed.

The results of these are shown in Table 59, along with the original eight sensitivities and the Modified Reference case for comparison, and described in more detail below:

Table 59: Sensitivity of PV of TSC savings for Ro1290_3200 @ 10% discount rate

Case	PV of TSC savings (USD million)	Variation to Reference (USD million)	Variation to Reference (percentage)
Reference	**1,707**	-	-
HiDem	1,825	+118	+6.9%
LoDem	679	-1,028	-60.2%
HiFuel	1,929	+222	+13.0%
LoFuel	1,238	-469	-27.5%
HiTIC	2,531	+824	+48.3%
LoTIC	560	-1,147	-67.2%
HiNTC	1,072	-635	-37.2%
LoNTC	1,542	-165	-9.7%
Modified Reference	1,508	-199	-11.6%
Gas generation	775	-933	-54.6%
Gas generation + heating	684	-1,023	-59.9%
Rogun delay:			
2 years	1,770	+63	+3.7%
4 years	1,658	-49	-2.9%
6 years	1,301	-406	-23.8%
Share reimbursement	1,747	+40	+2.3%
Demand growth Ref -55%:			
full savings	389	-1,318	-77.2%
excluding externalities	56	-1,651	-96.7%

Source: IPA analysis.

For the economic analysis, we have considered the following additional sensitivities and breakeven values:

1. Delay in starting Rogun construction: The two-year delay which showed an increase in TSC savings.

2. Extension in Rogun construction timetable: Assuming a two-year hiatus in construction after the first early capacity has been installed.

3. Rogun TIC: ± 20% on the estimated construction costs.

4. Achieved Rogun sale prices: Domestic sales priced assuming that tariffs are increased as recommended in the TWEC report, i.e. 75USD/MWh (real 2012) from 2023 onwards, and exports priced at 50% of the modelled realised values.

5. CO_2 abatement benefit versus NoRogun case: Applying the US Department of Energy's social cost of carbon to the change in CO_2 emissions in the modelled Central Asian region as a result of constructing Rogun.

6. Breakeven values: Calculated for the Rogun TIC, domestic and export sales prices (expressed as a percentage discount to the ECLIPSE forecast achieved price), and a delay in receiving export revenues from Pakistan and Afghanistan.

These results are summarised in Table 60 and described in further detail below.

Table 60: Sensitivity of Ro1290_3200 economic NPV @ 10% discount rate

Case	Economic NPV (USD million)	Variation to Reference (USD million)	Variation to Reference (percentage)
Reference	**863**	-	-
HiDem	887	+23	+2.7%
LoDem	765	-98	-11.4%
HiFuel	1,121	+258	+29.8%
LoFuel	559	-304	-35.2%
HiTIC	1,244	+380	+44.0%
LoTIC	420	-444	-51.4%
HiNTC	808	-55	-6.4%
LoNTC	819	-45	-5.2%
Rogun delay 2 years	732	-132	-15.2%
Rogun construction extension	657	-207	-24.0%
Rogun TIC:			
-20%	1,417	+553	+64.1%
+20%	310	-553	-64.1%
+31.2%	0	-863	-100.0%
Rogun sale prices:			
domestic tariffs, export -50%	410	-454	-52.5%
only domestic -38.4%	0	-863	-100.0%
only exports -62.5%	0	-863	-100.0%
CO_2 abatement costs	801	-63	-7.3%
No export revenues until Q3 2032	-15	-879	-101.8%

Source: IPA analysis.

Gas supply to Tajikistan

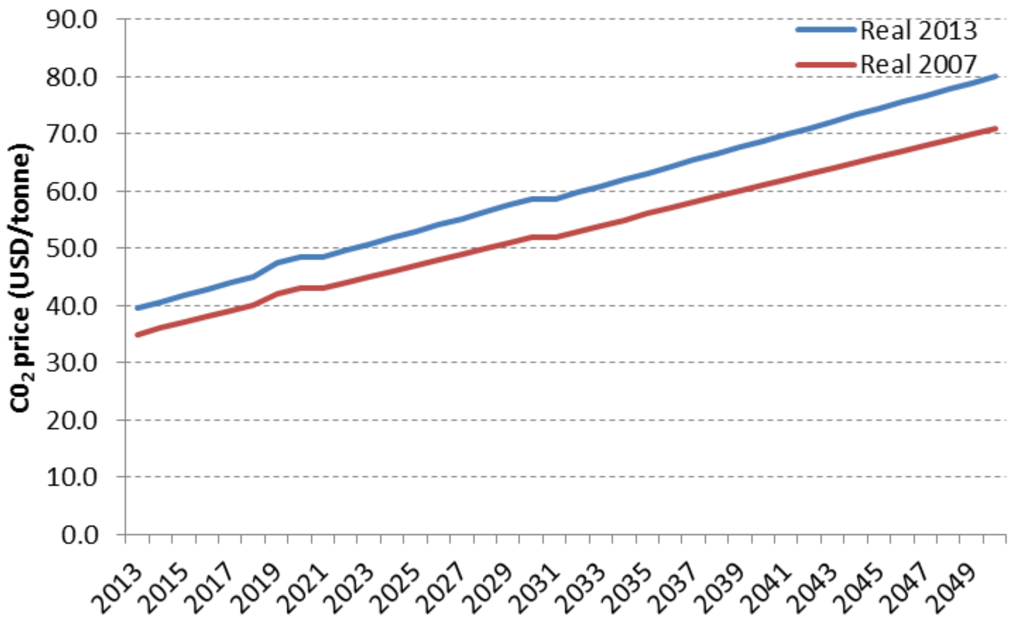
We examined the potential for gas-fired CCGT and/or OCGT generation capacity coming online from 2025 as an additional Economic New Build option.

Since Tajikistan has negligible known indigenous gas resources, as identified in subsection 4.7.1, it was assumed that a dedicated import pipeline from Turkmenistan would be required, with the following other inputs:

- CCGT and OCGT Economic New Build allowed from 2025, with no annual build limit or cumulative maximum.
- In the NoRogun case, Dashtijum switched from Firm to Economic from 2030 at an annual limit of 400MW/yr.

- Cost of a new pipeline added to the Total System Costs as an annual amortised charge from 2025: 600km × 2.5USD million per km[31] = 1.5USD billion, with an LRCCR of 10.6% based on a 30-year lifetime.
- Security of supply risk premium of 10EUR/MWh(e)[32] added to the annual gas price based on similar analyses undertaken by international financial institutions such as the World Bank.
- Gas price summer/winter seasonality of ±10% compared to the average annual price (similar to low storage markets such as the UK).
- CO_2 emissions in Tajikistan costed at the US Department of Energy's social cost of carbon forecast[33], which at a 3% discount rate increases from 35USD/tonne in 2013 to 71USD/tonne in 2050 (in real 2007 terms), as shown in Figure 43.

Figure 43: Social cost of carbon forecast



Source: US Department of Energy; IPA calculations.

[31] IPA research indicated a cost of 2.255-2.765USD million/km for four different pipelines, so an approximate average has been used as the estimated cost basis.
[32] World Bank note (email 15 April 2014) *Rogun Assessment Studies – Economic Analysis Sensitivity with Gas Availability*.
[33] United States Government (November 2013) *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866* (http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf).

As a second part of this sensitivity, we also considered the potential for some of the imported gas to be used for urban space heating, replacing corresponding electricity consumption. The specific additional inputs assumed for this were as follows:

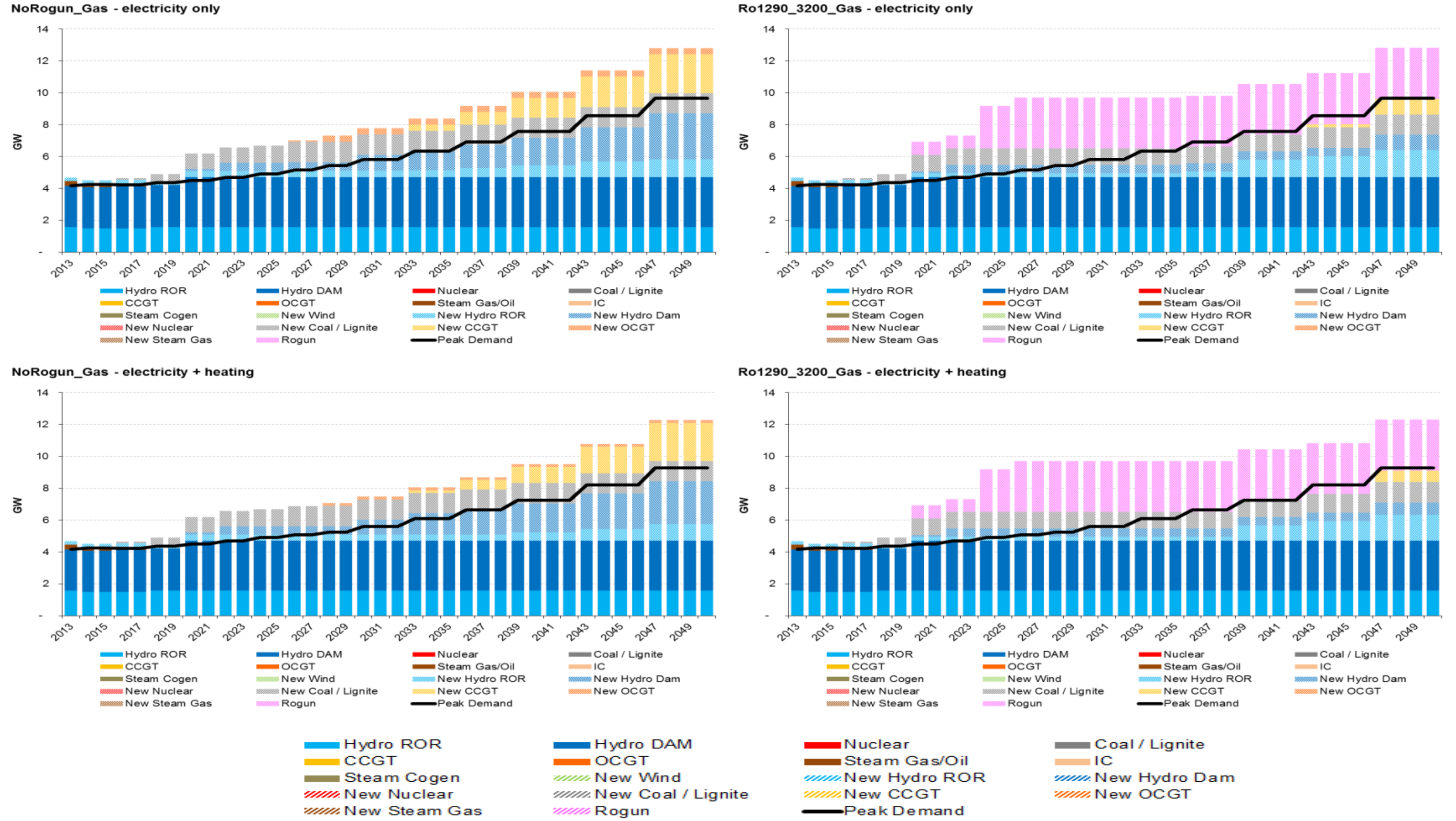
- Electricity demand reduction equivalent to 740 GWh in 2011 (assuming an annual household heating consumption of 2.4MWh based on 280,000 urban households switching to gas, with an additional 10% added to account for public buildings[34]), increased in line with the demand forecast.
- Generation requirement reduced according to the forecast implied losses.
- Penetration assumed to occur equally over five years 2025-29.
- Total gas consumption for heating calculated assuming that gas used for electricity generation can be switched directly to heating, and allowing for distribution losses of 1%.
- Cost of a new distribution network added equally over 2025-29 in TSC: 280,000 households × 1,750USD per household[35] + 10% = 539USD million.
- Tajikistan CO_2 emissions from both electricity generation and gas heating costed as previously.

With these assumptions, in the NoRogun case with gas for electricity generation only, OCGTs are initially built from 2025 partly replacing generic ROR hydro, with CCGTs coming online from 2033. As shown in Figure 44, by the end of the Forecast Horizon, a total of about 2.5GW of CCGTs and 400MW of OCGTs are built, with only about half of Dashtijum (2.3GW) required. The CCGTs generate at near full load in the winter with the OCGTs contributing a little in Q1 only, and there is no generation in the summer with needs being met by hydro output. In the Rogun case, nearly 1GW of new CCGTs are built but only from 2043. These run baseload in winter only. No OCGTs are deployed.

The electricity least-cost expansion results when gas is also used for space heating are similar with slightly smaller capacities deployed reflecting the small reduction in electricity requirements from 2030.

[34] World Bank note (email 15 April 2014) *Rogun Assessment Studies – Economic Analysis Sensitivity with Gas Availability*.
[35] World Bank analysis indicated a cost range of 1,500-2,000USD per household, so the average has been assumed.

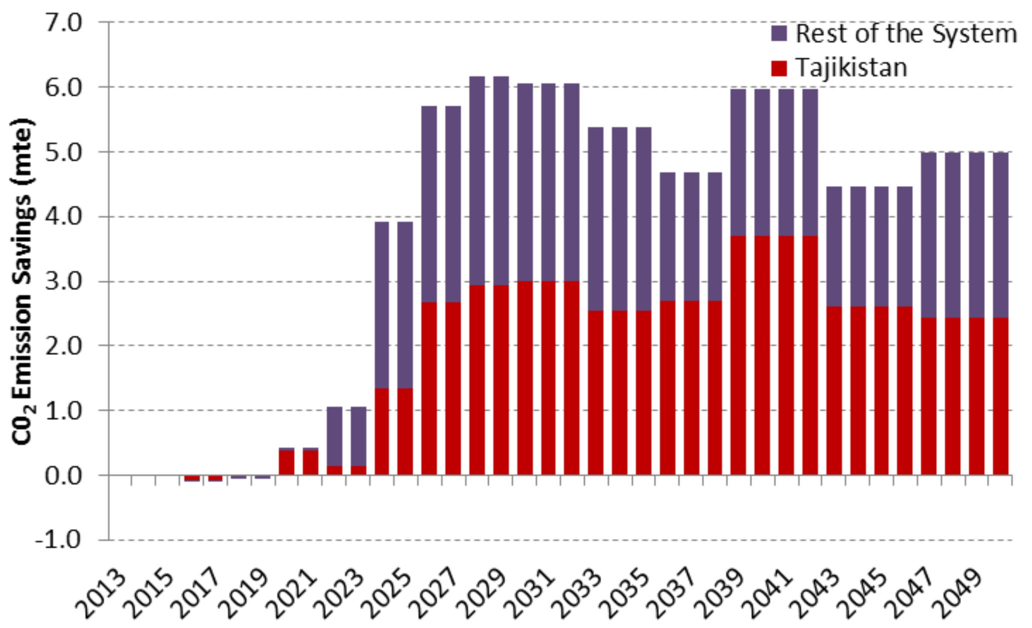
Figure 44: Tajikistan capacity mix by technology type – gas sensitivities



Source: IPA analysis.

With the larger amount of total gas generation in Tajikistan in the NoRogun case compared to the Rogun case (about 10GWh/y against 4 GWh/y by the end of the Forecast Horizon), there is a commensurately higher level of CO_2 emissions – or savings of 2.5-3 million tonnes per year as a result of building Rogun – as shown in Figure 45.

Figure 45: Annual CO_2 emissions savings of Ro1290_3200 vs. NoRogun in gas sensitivity



Source: IPA analysis.

Rogun thus remains the overall economic least-cost option for the Tajik system even if gas were to become available in the future. It should also be noted that in the cost savings presented in Table 59 above we have only accounted for Tajik CO_2 emissions, but as seen in Figure 45 there are significant emissions savings in the neighbouring countries, particularly Pakistan, because with Rogun exports nearly double thereby reducing fossil fuel use there as well. If these reductions were also included, there would be an additional 700USD million worth of benefit.

The analysis shows that Rogun remains the overall economic least-cost option for the Tajik system even if gas were to become available in the future.

Delay in Rogun construction

Pushing Rogun back by two years results in a slight increase in TSC savings compared to the Reference case through a combination in the delay of expenditure and the generation not necessarily being required earlier to meet forecast demand growth. Further delays though – while still considerably better than the NoRogun case – are worse from a TSC perspective because the benefits from the Project are not realised sufficiently quickly.

Looking at the standalone economic NPV, though, shows a decline against the Reference case, because although costs are reduced in present value terms, the much more significant benefits – particularly in alleviating unserved demand in Tajikistan – are as well.

Share reimbursement costs

In the event that Rogun is not constructed, in addition to the site decommissioning work required, the Government of Tajikistan would have to repay funds which it raised through a share issue to Tajik investors. The Government estimates that approximately USD60million out of a total amount raised of USD186million has been spent on the works so far at the site, and this amount would thus have to be found from general funds if Rogun did not proceed and should thus be considered as an additional cost in the NoRogun case.

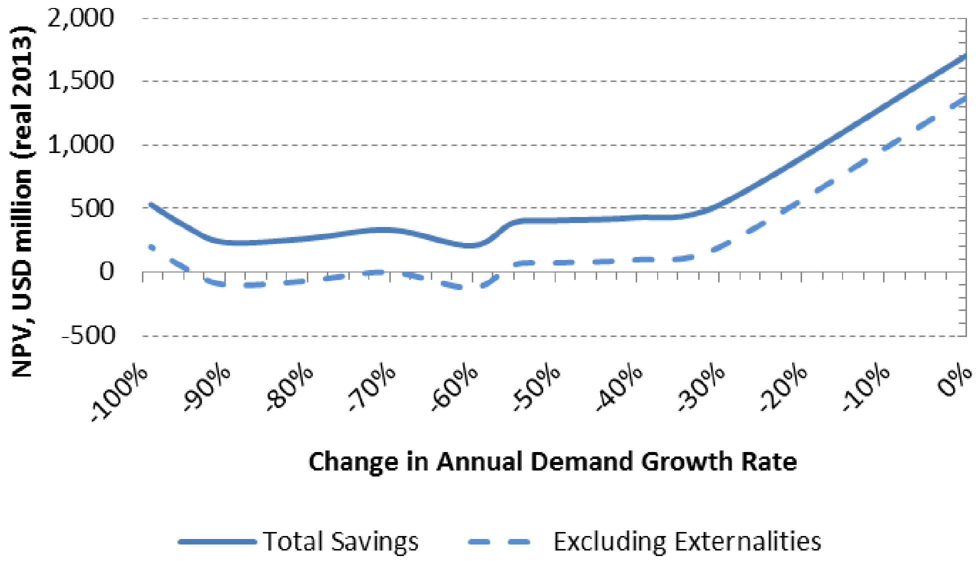
This adds about 40USD million to the PV of the TSC savings from Rogun.

Demand growth

As demand growth declines, the advantage of Rogun versus Dashtijum built later is gradually reduced. However, because of the Vakhsh flood protection benefits conferred by Rogun which would otherwise have to be achieved by additional measures downstream, and the upfront site decommissioning costs, the PV of the TSC savings including these externalities doesn't fall to zero even when there is no growth in demand. We have therefore examined the cost savings for the electricity system alone in determining this demand breakeven point.

On this basis, parity is achieved when the annual rate of growth is around 55% below that in the IRA (the median of our demand forecast), as shown in Figure 46. (For comparison, the Low demand forecast is around 20% below the Reference.) Down to around 90% below the median growth, the choice between the two options is very marginal, but then if there were no growth at all, the higher cost of Dashtijum would outweigh the present value benefits of waiting to build – essentially neither large dam is required to meet such low levels of demand growth.

Figure 46: Sensitivity of PV of TSC savings for Ro1290_3200 @ 10% to demand growth



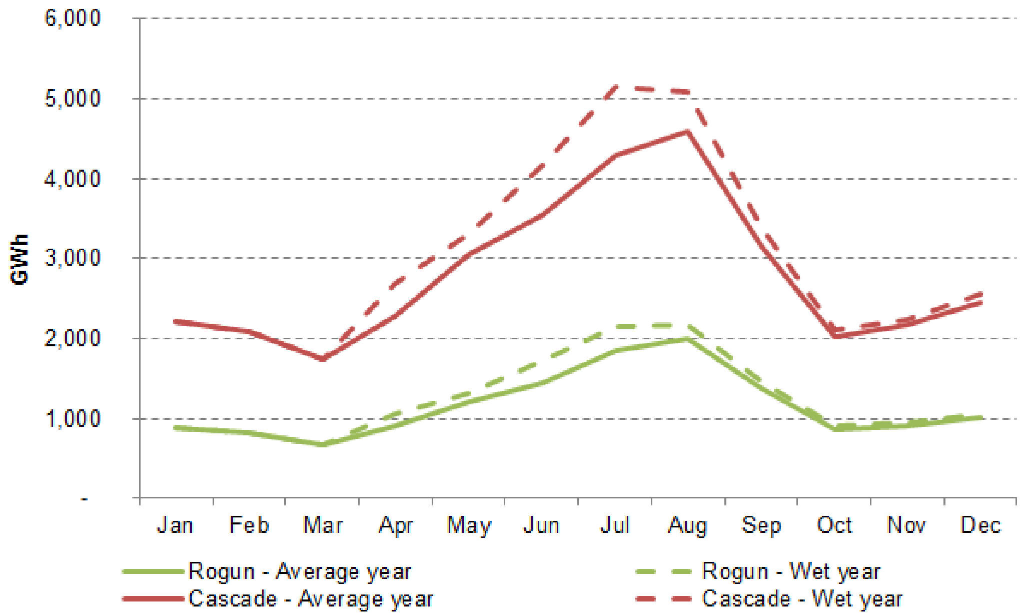
Source: IPA analysis.

Once the costs of developing alternative flood protection measures for the Vakhsh cascade and decommissioning the Rogun site are factored in, building Rogun remains the recommended alternative irrespective of the level of demand growth.

Wet vs. average year generation

The economic analysis has so far been based on the average expected electricity generation from the Project calculated from historic average annual rain/snowfall levels. However, this encompasses a range of annual generation levels which will vary from dry to wet years. (Furthermore, because of the constraint of maintaining downstream river flows, it is assumed that there is no storage of water between years as would typically be the case for large dam hydro projects). Figure 47 below shows the difference in the assumed monthly generation profile of the Project and the Vakhsh cascade as a whole between the average and a wet year, as calculated by Coyne et Bellier. This is broadly constant from 2032 when the reservoir is full and the Project is operational.

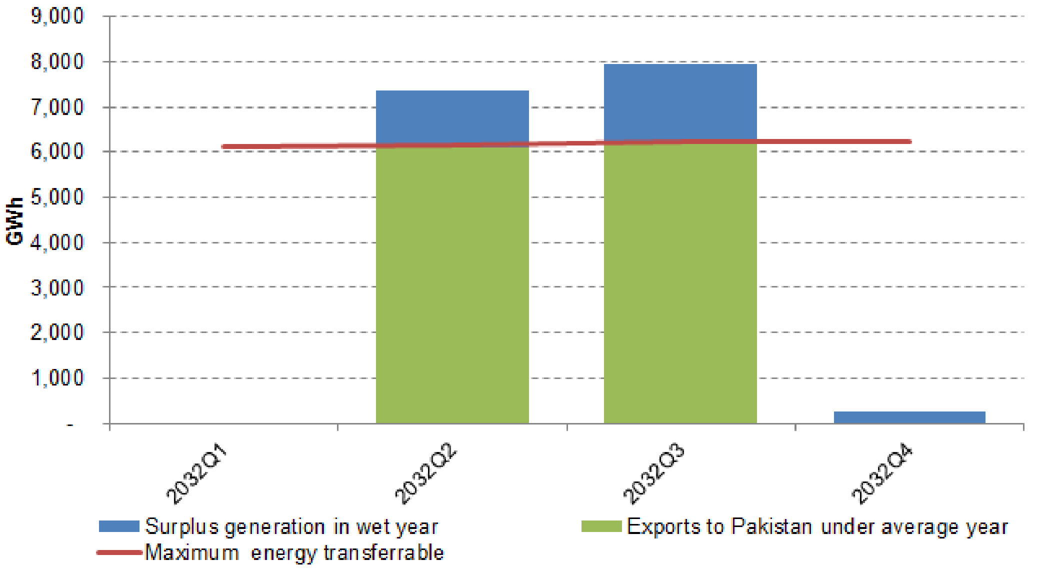
Figure 47: Comparison of generation in the Vakhsh cascade under an average and wet year



Source: Coyne et Bellier.

In a wet year, this additional generation would need to be exported to countries such as Pakistan in order to secure the full benefit. However, exports of the additional generation in a wet year might be constrained by the transfer capacity of the interconnectors. The expected level of quarterly electricity exports from Tajikistan to Pakistan in a wet year is shown in Figure 48 below for a representative year (2032) against the maximum possible export capability of the interconnector.

Figure 48: Quarterly electricity exports to Pakistan in a wet year (2032)



Source: IPA analysis.

As can be seen, the transfer capacity of the interconnector between the two countries is insufficient to allow for all of the extra summer generation in a wet year to be exported to Pakistan, with a total of 1,204GWh in Q2 and 1,697GWh in Q3 constrained by the available transfer capacity. In order to fully realise the export potential and achieve the forecast economic value of the Project, the interconnector would have to be 810MW larger than the expansion calculated by the least-cost modelling, as shown in Table 61 below.

Based on the assumed TIC of new interconnectors of 600USD/kW (as specified in subsection 4.8.4), this would thus incur an additional cost to Tajikistan of 486USD million, with a present value increase to the TSC of around 100USD million. This is a very small additional percentage on the TSC (as shown in Table 38), and much less than the TSC savings conferred by the Project.

(It should also be noted that the same principle applies to Dashtijum and other Hydro ROR in the NoRogun case, so that the TSC would be similarly higher in this case than calculated for the average expected generation.)

Table 61: Additional transfer capacity needed for export in a wet year (2032)

Parameter	Calculation	Units	Q1	Q2	Q3	Q4
Exports to PK in average year	a	GWh	-	6,086	6,238	-
Surplus generation in wet year	b	GWh	-	1,289	1,697	256
Exports to PK in wet year	c = a + b	GWh	-	7,374	7,935	256
Transfer capacity available[1]	d	MW	2,825			
Maximum transferrable energy	e = d × (number of hours in Qi) ÷ 1,000	GWh	6,103	6,170	6,238	6,238
Constrained exports	f = a – e	GWh	-	1,204	1,697	-
Additional transfer capacity needed	g = 1,000 × f (number of hours in Qi) ÷ 95%	GWh	-	580	809	-
TIC of interconnector	h	USD/kW	600			
Cost of additional transfer capacity needed	i = max(g) × h	USD million	485.5			

[1]: Calculated as interconnector capacity (2,974MW) multiplied by the maximum availability (95% of installed capacity).

Source: IPA analysis.

As seen in Figure 48, there is considerable spare export capacity available during the winter. Thus if production could be optimised across the year by allowing storage of the additional water specifically in wet years rather than maintaining the same seasonal profile as on average, then additional interconnector capacity would not be needed and this extra cost could be saved. The sales value of exports would not be as high in winter as in summer but the difference would be less than the additional cost.

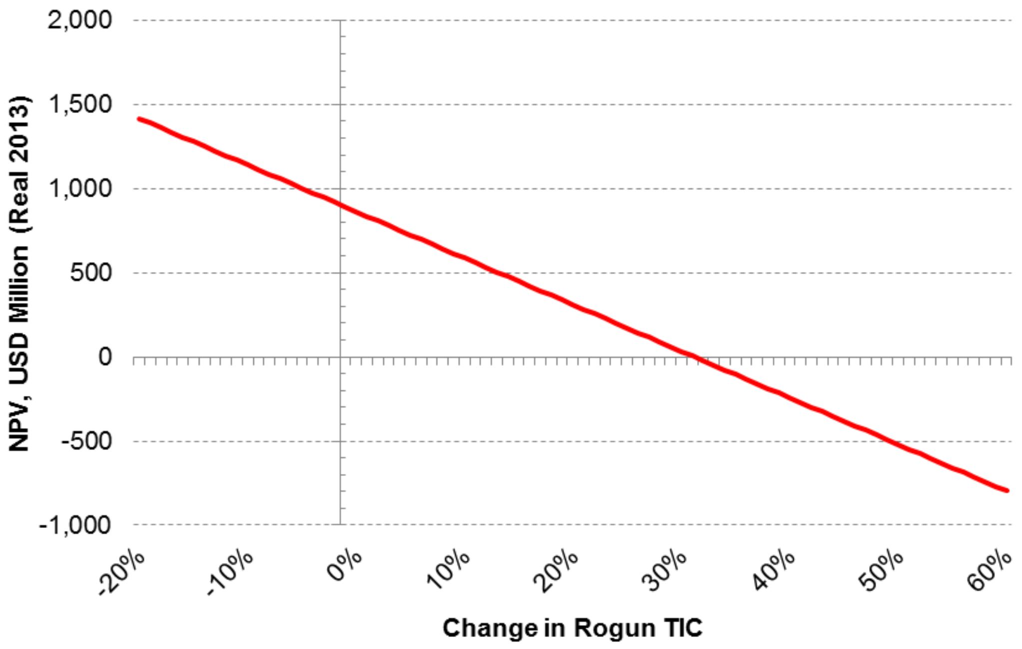
Extension in Rogun construction timetable

We examined the effect of an unexpected delay in the construction of Rogun assuming that the full capacity installation was delayed by two years with capital expenditure slowed from 2023 to 2027. Although there is thus a cost savings, the lost benefits from the full generation are also more significant, and there is thus a reduction in the NPV of the Project by about a quarter.

Rogun TIC

The NPV of Rogun will be strongly affected by the actual cost of construction. If costs were to be 31.2% higher than estimated, the NPV would be zero (under the Reference assumptions for market development), as shown in Figure 49 below.

Figure 49: Sensitivity of Ro1290_3200 economic NPV @ 10% to TIC



Source: IPA analysis.

It should be noted that a major cause of cost overruns is unexpected geological problems, and in the case of Rogun a major part of the underground works have already been undertaken.

Achieved Rogun sale prices

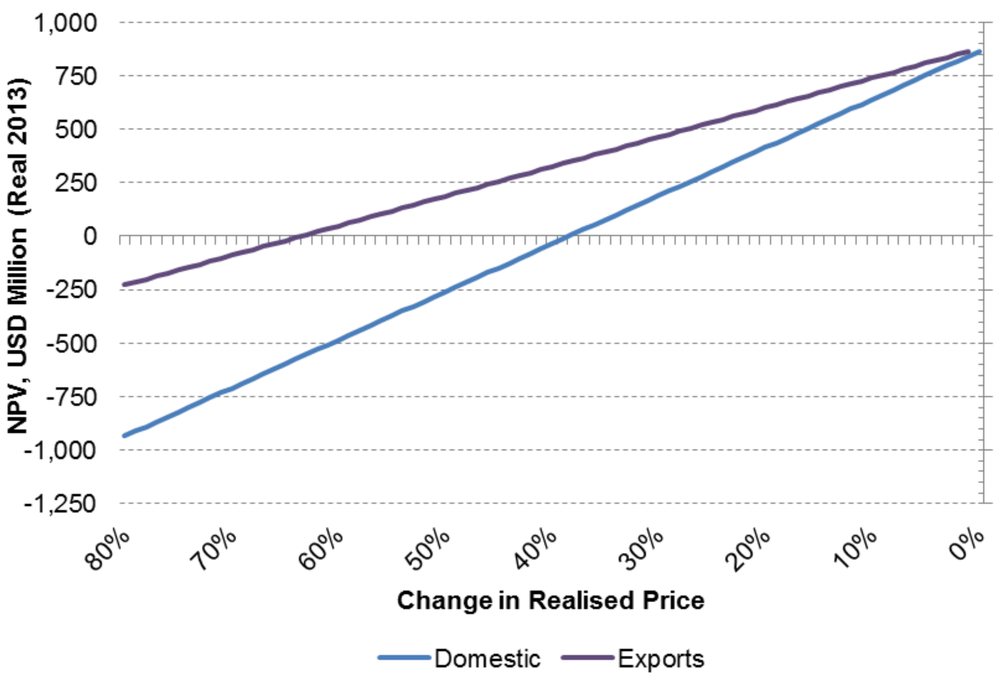
While the main economic analysis has been based on the marginal cost of generation for the value of Rogun's generation, in practice the Project revenue will likely be determined by actual electricity tariffs and negotiated contract prices. We have therefore assessed the economic NPV assuming that:

- Domestic sales are priced at 75USD/MWh (real 2012) from 2023 onwards, reflecting and increased tariff level of ¢9/kWh less estimated transmission and distribution costs of ¢1.5/kWh (with a linear rise to that level from 2014).
- Exports sales are priced at a negotiated compromise position of 50% of the economic marginal cost of those exports.

This specified domestic tariff level is between 5 and 15USD/MWh higher than the forecast marginal cost in 2023-2042, but then 7-8USD/MWh lower. This therefore partly offsets the loss of half the export revenues, such that the total reduction in NPV is only 52.5% from the Reference case.

As shown in Figure 50 below, domestic prices would have to be almost 40% below the forecast marginal costs throughout the life of the Project to reduce the NPV to zero (with export prices at the Reference marginal costs), on average around 43USD/MWh compared to 70USD/MWh; and export prices would have to be over 60% lower than the respective realised price in each market (on average just under 30USD/MWh against almost 80USD/MWh).

Figure 50: Sensitivity of Ro1290_3200 economic NPV @ 10% to achieved sale prices

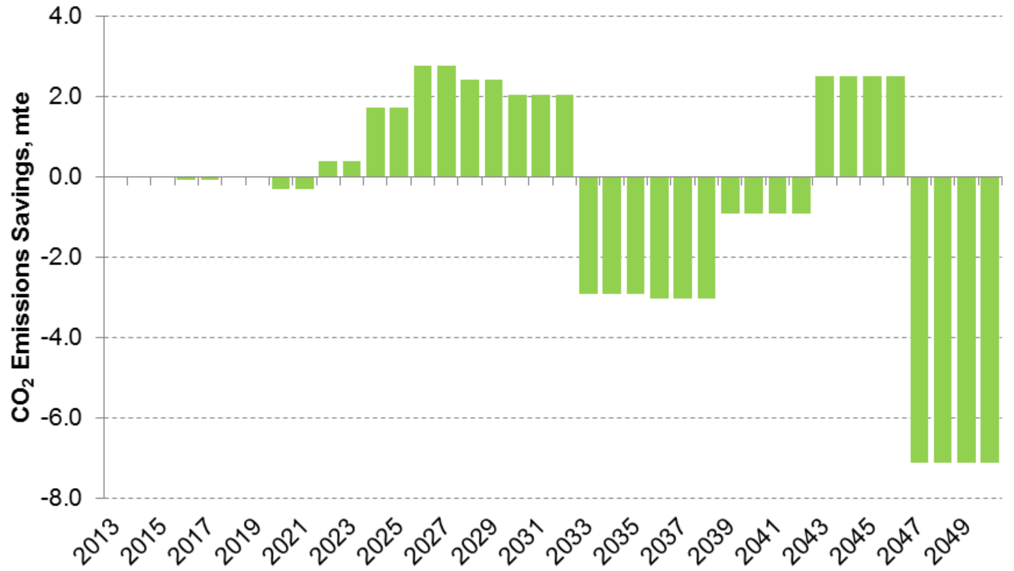


Source: IPA analysis.

CO_2 abatement benefit

Since the comparator NoRogun case also includes a large dam hydro Firm Build in Dashtijum, with corresponding large exports displacing thermal generation in the neighbouring countries, the benefit from Rogun in terms of CO_2 emissions reductions across the region is solely a matter of timing. As shown in Figure 51, since Rogun comes online a decade earlier than assumed for Dashtijum, regional emissions are forecast to be lower (and giving rise to positive savings) through the 2020s. However, once the larger Dashtijum dam is built, it provides greater reductions except for a brief period in the early-2040s.

Figure 51: Annual Central Asia CO_2 emissions savings of Ro1290_3200 vs. NoRogun



Source: IPA analysis.

Applying the US Department of Energy's social cost of carbon forecast as shown in Figure 43, produces a negative net benefit from Rogun compared to NoRogun as the long post-2050 value to the end of life outweighs the lower early years' savings.

Delay in export revenues

If export revenues from Pakistan and Afghanistan could not be realised for any reason – for example, due to an interconnector outage or contractual dispute – the situation would need to persist until the summer of 2032 before the NPV of the Project falls to zero.

9. CONCLUSIONS

IPA's economic analysis demonstrates the economic viability of all the Rogun design options under a range of assumptions. Table 62 below summarises the estimated costs of each Rogun design option as well as the probability-weighted system costs savings for Tajikistan together and the NPVs of the different Rogun design options. The Project is forecast to provide a probability-weighted system costs savings for Tajikistan of between 1.0 and 1.5USD billion and generate an NPV of 575-835USD million depending on the combination of dam height and installed capacity. This benefit largely derives from the controllable nature of generation from the Project which means that generation can be better matched to demand and also provide considerable levels of exports than the ROR alternatives in Tajikistan.

Table 62: Summary of the results for different Rogun design options

Height (masl)	Installed Capacity (MW)	Investment cost[1] (USD million)	All-in levelised cost (2013-2050)[2] @ 10% (USD/MWh)	Probability-weighted PV of TSC savings @ 10% (USD million)	Probability-weighted Economic NPV[3] @ 10% (USD million)
1290	3,600	5,211	57.60	1,453	795
	3,200	5,111	56.70	1,479	835
	2,800	5,040	56.35	1,437	825
1255	3,200	4,381	57.96	1,341	699
	2,800	4,310	57.32	1,314	722
	2,400	4,229	56.93	1,218	701
1220	2,800	3,467	50.02	1,174	618
	2,400	3,386	49.74	1,100	613
	2,000	3,313	50.64	1,022	575

Note: The colour coding is used to highlight the relative values for each parameter, not across all cases: red = worst (highest cost, lowest benefit), yellow = middle, green = best (lowest cost, highest benefit).

[1]: Investment cost is the simple sum of 1) Civil works, 2) Hydro-mechanical & electromechanical equipment, 3) Administration + engineering, and 4) Resettlement and infrastructure replacement (environmental costs). IDC is not included.

[2]: All-in levelised cost is the ratio of the PV of the investment cost to the PV of the generation over the Forecast Horizon, using a discount rate of 10%.

[3]: The NPV is the present value sum of the economic benefits (including downstream flood protection) less all economic costs.

Source: Coyne et Bellier; IPA analysis.

The higher dam options generally provide greater aggregate benefits than the lower ones due to the greater volumes of generation. Within dam heights, though, installing the highest capacity level is not always optimal, as the majority of the value of a hydroelectric dam is in the volume of water (energy) stored rather than in providing extra peak production.

The 1290 m.a.s.l. 3,200 MW design option exhibits both the highest overall TSC saving and economic NPV, and its economics are robust to a wide range of different outcomes. The sensitivity and breakeven analysis shows that very significant individual variations from the Reference assumptions would be needed for the NPV of the Project to fall below zero. Combinations of some of these adverse factors – particularly Low Demand and Low NTC – could have a greater negative impact, although the probability of such combinations is realtively low. Considering the results for the various individual parameter sensitivities which have been examined and the probability of multiple combinations occurring, we estimate that there is an overall greater than 90% likelihood that the economic NPV of this design option would be positive at a 10% discount rate, especially as we have adopted conservative assumptions is assessing various benefits (particularly the cost of providing full flood protection for the Vakhsh cascade).

It is therefore recommended that this dam height option is taken forward for detailed consideration and that additional analysis is undertaken to optimise the installed generation capacity.

ANNEX A: PROFILES OF POTENTIAL EXPORT COUNTRIES

This Annex A provides descriptions of the electricity supply industry, including the demand and supply outlook and the regulatory and market structure, in the potential export markets of Uzbekistan, Kyrgyzstan, Turkmenistan, Pakistan, Afghanistan and Kazakhstan.

Uzbekistan

Key statistics

Table 63: Key statistics – Uzbekistan (2013)

	Units	Value
Macroeconomic profile		
Population[1]		29.80 million
Access to electricity[2]	%	94.4
Electricity intensity*	kWh/USD	1.01
Gross Domestic Product ("GDP")[1]	USD	55.18 billion
Average GDP growth (2008-2012)[1]	%	8.27
Ease of doing business index[3]		154
Demand growth		
Peak demand 2013[4]	MW	9,367
Expected peak demand 2020[4]	MW	11,777
CAGR[4]	%	3.32
Dependable capacity development* **		
Existing capacity[4]	MW	10,678
Firm new capacity (2020)[4,5]	MW	1,209
Expected retirement (2020) [4,5]	MW	3,038
Capacity demand (2020)**	MW	12,955
Capacity shortfall (2020)	MW	4,106
Resource endowment[6]		
Gas reserves	cf	66.2 trillion
Coal reserves	tons	4 billion
Oil reserves	Bbl	594 million
Hydro potential	MW	Modest

Notes: *Electricity intensity calculated using 2013 energy demand[4] divided by 2013 GDP[1].
** Capacity demand calculated as expected peak demand plus an assumed reserve margin requirement of 10% from 2020.
***Dependable capacity (as percentage of its installed capacity) for different technologies is assumed as: 92.63% for CCGT ; 92.63% for OCGT; 90.25% for Coal; 92.63% for Lignite; 92.63% for Steam Gas; 90.25for Steam Oil; 92.63% for Steam Cogen Gas; 92.63% for Steam Cogen Coal; 92.15% for Steam Cogen Oil; 99.89% for Hydro Dam and 43.00% for Hydro ROR.

Sources:
[1]*: International Monetary Fund ("IMF") (Oct 2012) World Economic Outlook.*
[2]*: IPA research, https://energypedia.info/wiki/Uzbekistan_Energy_Situation*
[3]*: World Bank (Oct 2013) Development Indicators & Global Development Finance*
(*http://databank.worldbank.org/ddp/home.do?Step=1&id=4*). Ranking of 1-185, with 1 being the most business-friendly regulation.

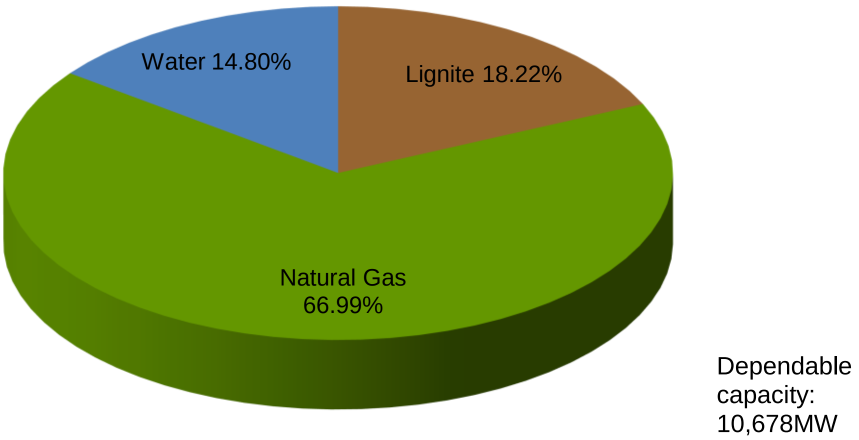
[4]: *World Bank (June 2013) Uzbekistan Energy Sector Issues Note, IPA research, IPA analysis.*
[5]: *Platts (June 2011) World Electric Power Plants ("WEPP") Database, IPA research.*
[6]: *World Bank (June 2007) Potential and Prospects for Regional Energy Trade In the South Asia Region.*

Current dependable capacity mix

Unlike Tajikistan, the majority of the existing dependable capacity in Uzbekistan comes from thermal plants using either natural gas (69.20%) or lignite (16.99%) as primary fuels. Hydro power plants make up the remaining 13.80% of dependable capacity in the country. This is illustrated in Figure 52 below.

At current international market prices of fossil fuels, there are potential economic benefits to be gained by Uzbekistan importing Tajik's surplus hydro generation in the summer rather than running its own thermal plants even if there is no capacity shortfall in the country.

Figure 52: Dependable capacity mix – Uzbekistan (2013)

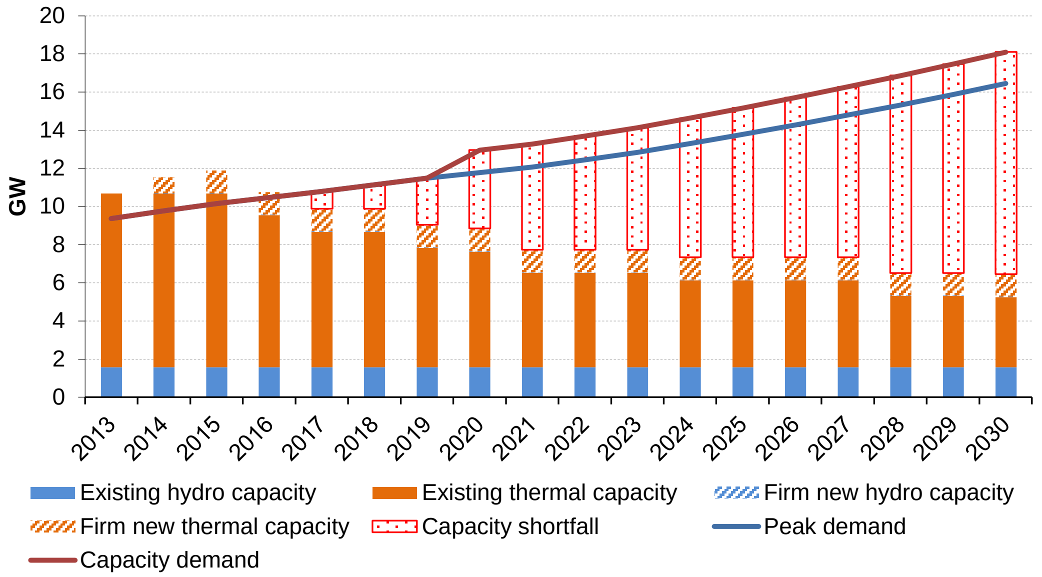


Source: World Bank (June 2013) Uzbekistan Energy Sector Issues Note, Platts (June 2011) WEPP, IPA research.

Supply and demand outlook

Currently, there is a capacity surplus in Uzbekistan, and 1,209MW of dependable new capacity is expected to come online by 2020. Nonetheless, given the 3,038MW of existing dependable capacity expected to retire between 2013 and 2020, as well as the increasing capacity demand, we anticipate a capacity shortfall in Uzbekistan from 2017 onwards.

Figure 53: Supply and demand outlook (dependable capacity) – Uzbekistan (2013-2030)

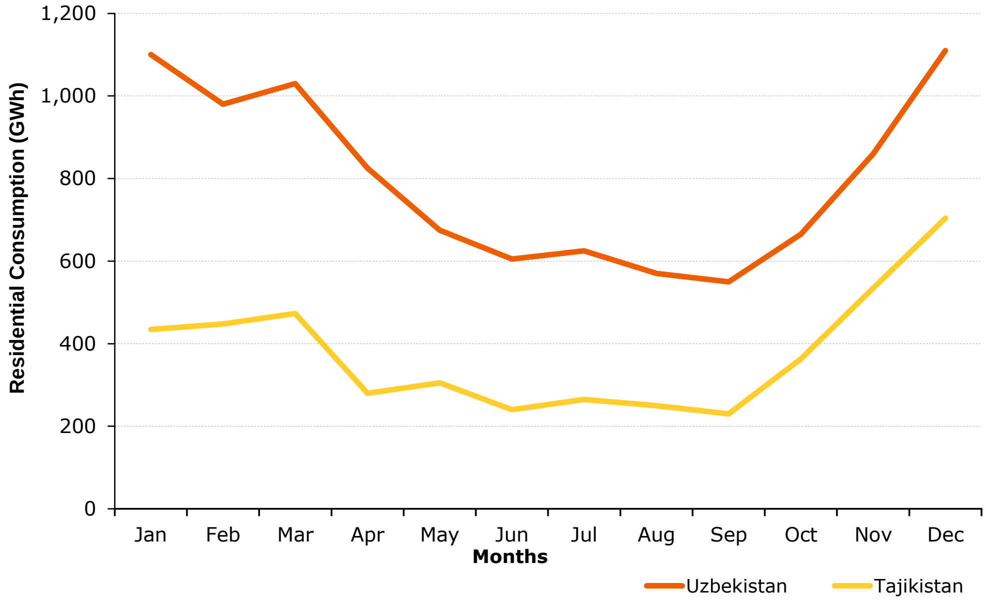


Source: World Bank (June 2013) Uzbekistan Energy Sector Issues Note, Platts (June 2011) WEPP, IPA research.

Demand profile

Residential consumption of electricity is extremely seasonal in Uzbekistan, unlike industrial and commercial electricity consumption. Uzbekistan's monthly residential consumption profile illustrated in Figure 54 below suggests that total electricity consumption is higher in the winter (reaching a maximum of 1,100MW) and lower in the summer (reaching a minimum of 550MW).

Figure 54: Monthly residential consumption – Uzbekistan



Note: Tajikistan residential load is estimated based on monthly consumption figures net of TALCO, Governmental, Industrial and Agricultural consumption.

Source: Fichtner (October 2012) Central Asia Regional Economic Cooperation ("CAREC") Power Sector Master Plan and IPA analysis.

As illustrated in Figure 54, monthly residential demand in Uzbekistan and Tajikistan follows a similar pattern.

Market structure and recent regulatory developments

Table 64: Market structure and recent regulatory developments – Uzbekistan

	Description
Market structure	The electricity market in Uzbekistan is a vertically integrated monopoly. Electricity generation, transmission and distribution assets are managed by the State Joint-Stock Company "Uzbekenergo" which currently encompasses almost all generation, transmission, distribution and supply companies.[36]
Interconnection	Although Uzbekistan maintains synchronous operation with Kazakhstan and Kyrgyzstan (members of the CAPS), as well as with Afghanistan and Russia (through Kazakhstan), it is currently disconnected from Tajikistan and Turkmenistan. Uzbekistan is currently the only country feeding into Afghanistan's grid. An agreement has been signed for power export from Uzbekistan to Afghanistan of up to 300MW starting in 2010[37]. As demand in Afghanistan increases, the power export is also expected to increase. Uzbekistan also exports electricity to Kazakhstan and Kyrgyzstan during the summer (Tajikistan stopped buying Uzbekistan's electricity early 2011). These electricity exports could fall if Kyrgyzstan, Tajikistan, Afghanistan and Pakistan succeed with the CASA-1000 project as Kyrgyzstan and Tajikistan will become competitors for electricity exports to Afghanistan and Pakistan (at prices as little as half those charged by "Uzbekenergo").[38] Uzbekistan is also looking into exporting power to Pakistan with an economic, financial and technical assessment for Uzbekistan-Afghanistan-Pakistan electricity supply and trade project (UAP-EST).[39] Uzbekistan imports electricity from Kyrgyzstan – "Uzbekenergo" signed an agreement with the Kyrgyz company "Elektricheskiestantsii" in November 2011 under which it will import 500GWh of electricity annually[38]. There are two 500 kV lines running from the Project into Uzbekistan that service the south, and one running from Syrdarya that services the north. When the 500 kV Datka – Khojent line is completed, Tajikistan will be reconnected to the CAPS and therefore to Uzbekistan.[40]
Power offtaker(s)	Access to transmission and distribution grids is under the control of Uzbekenergo via its subsidiary Energosotish. Energosotish is the buyer and sole supplier of electricity. It concludes agreements with generating companies regarding electricity purchase, with territorial distribution companies regarding electricity sales and with the grid company regarding

[36] EBRD (accessed 20 November 2012) *Uzbekistan Country Profile* (http://www.ebrd.com/downloads/legal/irc/countries/uzbekistan.pdf).
[37] Fichtner (October 2012) *CAREC Power Sector Master Plan*.
[38] Uznews.net (November 2011) (http://www.uznews.net/news_single.php?lng=en&sub=&cid=2&nid=18476).
[39] CAREC (October 2010) *Energy Sector Progress Report and Work Plan (late 2010-2011)*.
[40] USAID (April 2012) *Potential for Adding Russian or Turkmenistan's Power to Casa 1000's Throughput during Winter Months* (http://www.ca-reset.org/library/CASAApr/Eng/day1/PotentialforRusTurkmInCASA1000.pdf).

Table 64: Market structure and recent regulatory developments – Uzbekistan

	Description
	electricity transmission from generating companies to territorial distribution companies.[36]
Cost of supply	In Uzbekistan, setting cost-reflective energy prices is an issue as the power industry is subject to tremendous fluctuations in the world prices for oil and natural gas, the country's primary power generating fuels. Uzbekistan has implemented multi-year tariff reform programs aimed at closing the gap between cost and price of electricity by raising tariffs and lowering costs simultaneously.[41] The Uzbek government has been adjusting tariffs twice a year given the high annual inflation rates (about 10% in the past). The tariffs are however still relatively low with the average around 50USD/MWh in 2011. The government adjusts tariff for Uzbekenergo to ensure long-term sustainability, and to cover market risks including inflation, foreign exchange and interest risks. [42] The Ministry of Finance is authorised to approve tariffs for end customers, which are developed either on its own initiative or by the government's instruction. In general, Uzbekistan is in the process of a gradual increase of electricity tariffs[36,] with the current average tariff reaching around 54USD/MWh.[43] Afghanistan pays 75USD/MWh for electricity it imports from Uzbekistan whilst Kazakhstan and Kyrgyzstan pay 47USD/MWh. Uzbekistan intends to export electricity to Pakistan at a cost of 75USD/MWh. Kyrgyzstan and Tajikistan, on the other hand, have agreed to charge Pakistan just 35USD/MWh (but the latter will only able to sell relatively small amounts of power (several thousand MWh).[38] The electricity that Uzbekistan imports from its neighbours cost Uzbekistan's energy suppliers around 33.8USD/MWh, Uzbekenergo disclosed.[38] The long-run marginal cost of a CCGT in Uzbekistan was estimated at 109.56USD/MWh[44].
Political and regulatory development	Given the withdrawal of Turkmenistan and Uzbekistan from CAPS and Kazakhstan's intentions to end their participation, it can be expected that providing electricity to the population reliably throughout the year will become more difficult for Uzbekistan. Lack of cooperation within the region is also problematic for the provision of reliable electricity supply. Such disputes include Uzbekistan interrupting electricity deliveries to Tajikistan, illustrating the broader dispute between these two countries regarding territory, energy, water and the likely impact of the Project dam on Uzbekistan's riparian rights.

[41] World Energy Council (July 2007) *Electricity in Central Asia – Market and Investment Opportunity Report* (http://www.worldenergy.org/documents/central_asia_raoca_study.pdf).
[42] Asian Development Bank (August 2011) *Republic of Uzbekistan: Advanced Electricity Metering Project* (http://www2.adb.org/Documents/PAMs/UZB/41340-013-uzb-pam.pdf).
[43] World Bank (June 2013) *Uzbekistan Energy Sector Issues Note*.
[44] IPA analysis based on data from World Bank (June 2013) *Uzbekistan Energy Sector Issues Note*.

Table 64: Market structure and recent regulatory developments – Uzbekistan

	Description
	As illustrated in Table 63 and Figure 52 Uzbekistan is rich in hydrocarbons and relies majorly on thermal power but requires water for agriculture in the summer. Tajikistan, on the other hand, has large water resources and relies heavily on hydro power therefore needing to import electricity in the winter when demand is high and dependable capacity is low. Uzbekistan is undergoing a sector restructuring with the subsequent unbundling of monopolistic activities (dispatching and transmission) from competitive ones (supply and generation), An introduction of further market-related elements in the electricity sector is also planned. Sale of state assets has also taken place in a number of stock companies dealing with electricity distribution and supply, as well as in those generating heat and electricity. The process of privatisation of the country's electricity companies has been practically completed.[36] The Law on Electric Power (2009) was intended to create a better integrated framework for electricity sector regulation. It set out provisions to allow for on-site generation without a license and to allow on-site generators to sell electricity back to the grid. It also established requirements for independent distribution system operators.[45]

[45] World Bank (June 2013) *Uzbekistan Energy Sector Issues Note*.

Kyrgyzstan

Key statistics

Table 65: Key statistics – Kyrgyzstan (2013)

	Units	Value
Macroeconomic profile		
Population[1]		5.64 million
Access to electricity	%	N.A.
Electricity intensity*	kWh/USD	1.68
GDP[1]	USD	7.23 billion
Average GDP growth (2008-2012)[1]	%	1.84
Ease of doing business index[2]		70
Demand growth		
Peak demand 2013[3]	MW	2,915
Expected peak demand 2020[3]	MW	2,802
CAGR[3]	%	-0.56
Dependable capacity development* **		
Existing capacity[4]	MW	3,693
Firm new capacity (2020) [4]	MW	1,853
Expected retirement (2020) [4]	MW	N.A.
Capacity demand (2020)**	MW	3,082
Capacity shortfall (2020)	MW	N.A.
Resource endowment[5]		
Gas reserves	cf	modest/negligible
Coal reserves	tons	0.8 billion
Oil reserves	bbl	modest/negligible
Hydro potential	MW	26,000

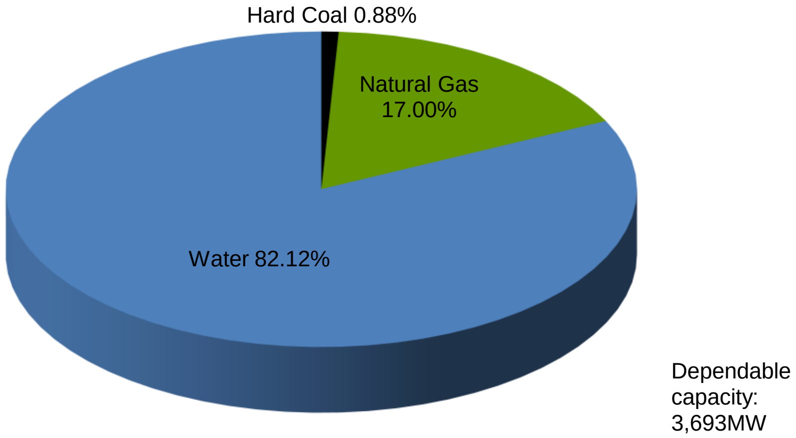
Notes: *Electricity intensity calculated using 2013 energy demand[3] divided by 2013[1].
** Capacity demand calculated as expected peak demand plus an assumed reserve margin requirement of 10% from 2020.
***Dependable capacity (as percentage of its installed capacity) for different technologies is assumed as: 92.63% for CCGT; 92.63% for OCGT; 90.25% for Coal; 92.63% for Lignite; 92.63% for Steam Gas; 90.25% for Steam Oil; 92.63% for Steam Cogen Gas; 92.63% for Steam Cogen Coal; 92.15% for Steam Cogen Oil; 99.89% for Hydro Dam and 51.69% for Hydro ROR.

Sources:
[1]: IMF (October 2013) World Economic Outlook.
[2]: World Bank (October 2013) Development Indicators & Global Development Finance (http://databank.worldbank.org/ddp/home.do?Step=1&id=4).
[3]: Fichtner (October 2012) CAREC Power Sector Master Plan, IPA analysis.
[4]: Platts (June 2011) WEPP Database, IPA research.
[5]: World Bank (June 2007) Potential and Prospects for Regional Energy Trade in the South Asia Region.

Current dependable capacity mix

Like Tajikistan, the majority of dependable capacity in Kyrgyzstan is made up by hydro plants (82.12%). The remainder of dependable capacity in the country comes from thermal plants using either natural gas (17.00%) or coal (0.88%) as their primary fuel. This is illustrated in Figure 55 below.

Figure 55: Dependable capacity mix – Kyrgyzstan (2013)



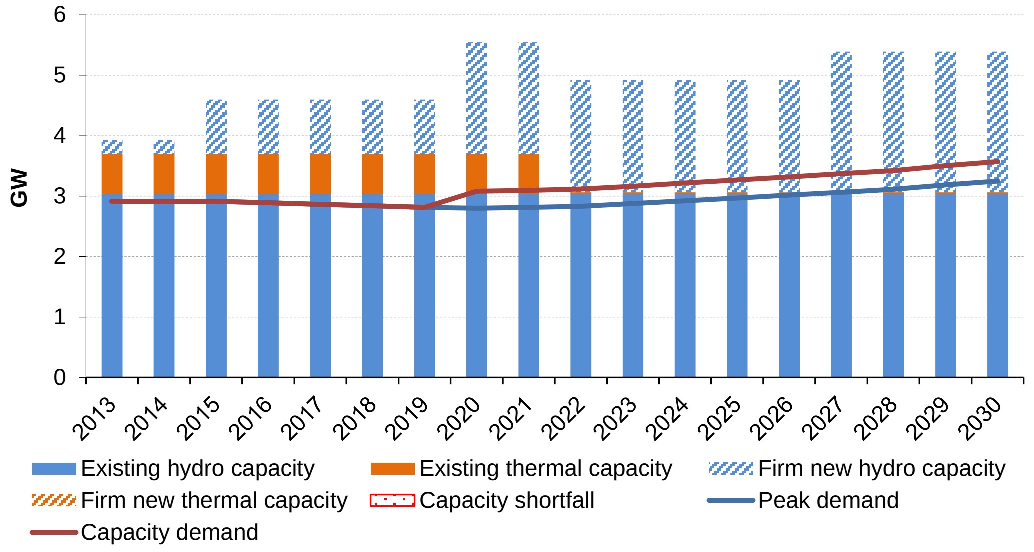
Source: Platts (June 2011) WEPP, IPA research.

Supply and demand outlook

As illustrated in Figure 56 below, there is currently a capacity shortfall in Kyrgyzstan. Although 628MW of dependable capacity are expected to retire by 2025, 1,853MW of dependable new hydro capacity is expected to come online over the same period. Furthermore, we project that demand will fall slightly between 2015 and 2020 before increasing again. This demand profile is based on the assumption that technical and commercial losses in Kyrgyzstan can be reduced from 39% to 21% by 2020.[46] As a result, capacity supply is expected to become sufficient to cover domestic capacity throughout the Forecast Horizon.

[46] Fichtner (October 2012) *CAREC Power Sector Master Plan*.

Figure 56: Supply and demand outlook – Kyrgyzstan (2013-2030)

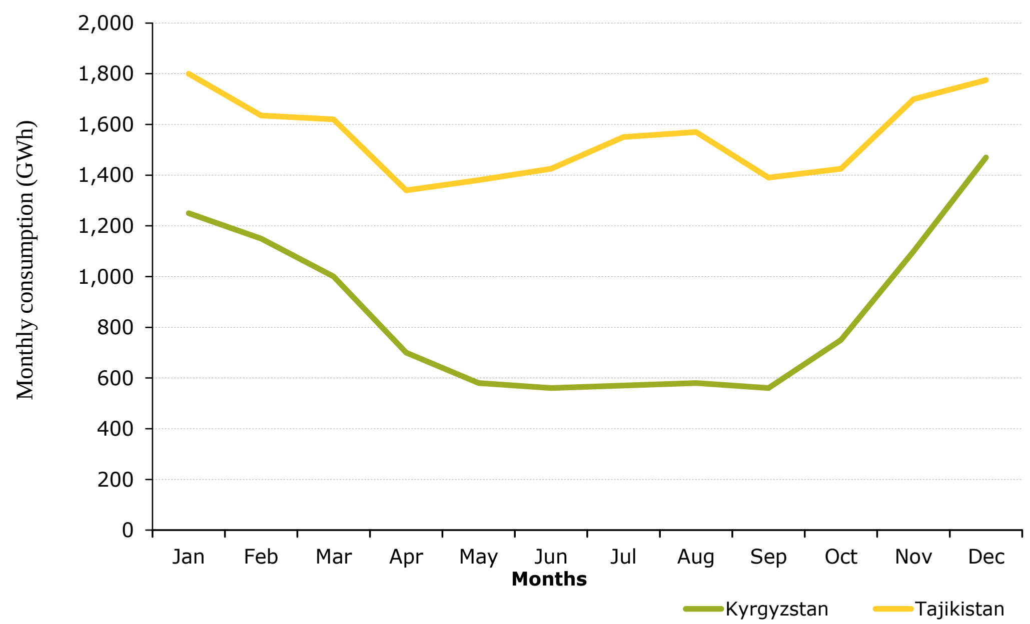


Source: Platts (June 2011) WEPP, Fichtner (October 2012), IPA research.

Demand profile

As we can see in Figure 57 below, electricity consumption in Kyrgyzstan is high in the winter and considerably lower in the summer. Kyrgyzstan therefore registers maximum demand for electricity at the same time as Tajikistan, i.e. during the winter period.

Figure 57: Monthly electricity consumption – Kyrgyzstan



Source: Fichtner (October 2012) CAREC Power Sector Master Plan and IPA analysis.

Market structure and recent regulatory developments

Table 66: Market structure and recent regulatory developments – Kyrgyzstan

	Description
Market structure	The Government of Kyrgyzstan restructured and unbundled "Kyrgyzenergo", the former state-owned vertically integrated electricity company, in 2001, creating the "Electric Power Plant Company" ("EPP", the generating company), the "National Electric System of Kyrgyzstan" ("NESK", the transmission company), and four distribution companies (Discos): "Severelectro", "Oshelectro", "Jalalabatelectro" and "Vostokelectro". 80% of each of these entities is owned by the state, with the remaining 20% in the hands of the national Social Fund and private entities (13% and 7% respectively).[47] Thus far, the restructuring of the energy sector has not resulted in creation of a competitive wholesale market. Virtually the entire volume of electricity (about 98%) is produced and sold by one generating company "Electric Plants OJSC".[48]
Interconnection	The NESK transmission system is integrated into the CAPS and is thereby physically interconnected with Turkmenistan, Tajikistan, Kazakhstan and Uzbekistan. However, these countries, Uzbekistan in particular, have been taking steps toward electricity self-sufficiency, thus compromising the integrity of the CAPS and threatening the ability of Kyrgyzstan to reliably serve its domestic customers.[49] Kyrgyzstan, along with Tajikistan, has a larger potential for excess supply than its neighbours but is less open to foreign investment due to legal hurdles and restrictive legislation.[50] It should also be noted that Kyrgyzstan suffers from major issues with its grid, including inefficient distribution, illegal diversions and leakages.[51] Despite the grid problems, Kyrgyzstan remains a net exporter of power, primarily to Kazakhstan.[38] If the CASA-1000 project succeeds, Kyrgyzstan is expected to supply Pakistan and Afghanistan with electricity. The CASA-1000 Project is planned with a capacity of 1,300MW (1,000MW for Pakistan and 300MW to Afghanistan).[52] Kyrgyzstan experiences annual winter shortages from low water flow. Therefore, it must import electricity during the winter season, mainly from Kazakhstan and Uzbekistan.[50]
Large customers	The Discos buy wholesale power from "JSC EPP", and resell to their own customers.[53]

[47] USAID (March 2011) *Management Diagnostic of the National Electricity System of Kyrgyzstan* (http://www.ca-reset.org/library/Reports/NESKPhase1ReportEng.pdf).
[48] EBRD (accessed 20 November 2012) *Kyrgyz Republic Country profile* (http://www.reegle.info/countries/kyrgyzstan-energy-profile/KG#competition).
[49] USAID (March 2011) *Management Diagnostic of the National Electricity System of Kyrgyzstan* (http://www.ca-reset.org/library/Reports/NESKPhase1ReportEng.pdf).
[50] Uznews.net (November 2011) (http://www.uznews.net/news_single.php?lng=en&sub=&cid=2&nid=18476).
[51] World Energy Council (July 2007) *Electricity in Central Asia – Market and Investment Opportunity Report* (http://www.worldenergy.org/documents/central_asia_raoca_study.pdf).
[52] Fichtner (October 2012) C*AREC Power Sector Master Plan*.
[53] USAID (June 2012) *Overview of Competitive Power Market Models*

Table 66: Market structure and recent regulatory developments – Kyrgyzstan

	Description
Cost of supply	Tariffs are set by the government and have been regulated unpredictably. The government doubled the electricity tariffs from 1 January 2010 in one step to bring them in line with the cost recovery levels but these were brought back to their previous levels by the new government due to social tension and political instability.[54] The average household tariff in 2011, as set by the Government Resolution No 699[55], was 40USD/MWh, but the actual tariffs have remained low at around 15USD/MWh.[56] The long-run marginal cost of a hydro power plant in Kyrgyzstan is estimated at 70.9-89.1USD/MWh.[57] The price at which Kyrgyzstan exports electricity to Kazakhstan is estimated at 28-30USD/MWh in 2011.[57] The price of Kyrgyz electricity exports to Tajikistan is 15USD/MWh according to the "Agreement on unplanned electricity exchange" between the companies "Elektrostanzia" and "Barki Tojik" signed on 1 October 2009.
Political and regulatory development	The Ministry of Energy includes the State Department for Regulating the Fuel and Energy Sector. Its main task is setting energy tariffs. This structure is a relatively new one, having been formed in 2007. In practice, the regulator is not independent of the Ministry of Energy, so that this Ministry in fact implements both managerial and regulatory functions. The regulator is therefore often guided by conflicting political and economic interests, which can generate inconsistencies in tariff setting and in other dimensions of energy policy. The regulatory framework is set by the 30 October 1996 law "On Energy" (N 56), which allowed "enterprises in the fuel and energy sector to have any organizational-legal form of operation and any form of ownership (public, municipal and private)". The market principles for energy sector operations were established in the 28 January 1997 law "On Electric Power" (N 8), which called for "creating a competitive environment and the formation of an energy market", as well as "encouraging development of the private sector and attracting investments".

(http://www.ca-reset.org/library/presentations/Power%20Markets%202012%20ENG.pdf).
[54] Asian Development Bank (October 2010) *Energy Demand/Supply Balance and Infrastructure Constraints Diagnostics Study* (http://www.carecprogram.org/uploads/events/2010/SOM-Oct/Diagnostic-Study-CAREC-Energy-Strategy-Pillar1-Full-Report.pdf).
[55] The medium term tariff policy of Kyrgyz Republic on electricity and thermal energy for 2010-2012 (November 2009).
[56] Report commissioned by UNDP's Regional Bureau for Europe and CIS (April 2011) *Kyrgyzstan's Energy Sector* (http://km.undp.sk/uploads/public1/files/vulnerability/Senior%20Economist%20Web%20site/PSIA_Energy_Kyrgyzstan.pdf).
[57] IPA analysis based on data from Fichtner (October 2012) *CAREC Power Sector Master Plan*.

Turkmenistan

Key statistics

Table 67: Key statistics – Turkmenistan (2013)

	Units	Value
Macroeconomic profile		
Population[1]		5.70 million
Access to electricity[2]	%	99.6
Electricity intensity*	kWh/USD	0.34
GDP[1]	USD	40.56 billion
Average GDP growth (2008-2012)[1]	%	10.24
Ease of doing business index[3]		N.A.
Demand growth		
Peak demand 2013[4]	MW	2,309
Expected peak demand 2020[4]	MW	2,634
CAGR[4]	%	1.90
Dependable capacity development* **		
Existing capacity[5]	MW	3,617
Firm new capacity (2020)[5]	MW	N.A.
Expected retirement (2020)[5]	MW	N.A.
Capacity demand (2020)**	MW	2,897
Capacity shortfall (2020)	MW	N.A.
Resource endowment[6]		
Gas reserves	cf	71 trillion
Coal reserves	tons	modest/negligible
Oil reserves	bbl	546 million
Hydro potential	MW	modest

Notes: *Electricity intensity calculated using 2013 electricity demand[4] divided by 2013 GDP[1].
** Capacity demand calculated as expected peak demand plus an assumed reserve margin requirement of 10% from 2020.
***Dependable capacity (as percentage of its installed capacity) for different technologies is assumed as: 92.63% for CCGT; 92.63% for OCGT; 90.25% for Coal; 92.63% for Lignite; 92.63% for Steam Gas; 90.25% for Steam Oil; 92.63% for Steam Cogen Gas; 92.63% for Steam Cogen Coal; 92.15% for Steam Cogen Oil; 99.89% for Hydro Dam and 20.00% for Hydro ROR.

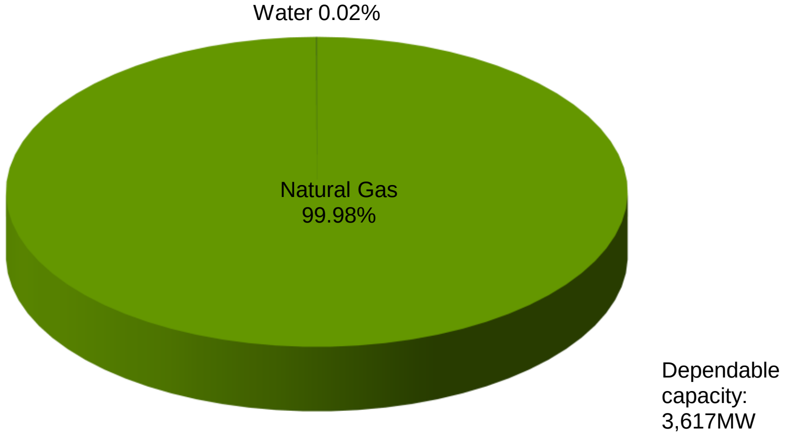
Sources:
[1]: *IMF (October 2013)* World Economic Outlook.
[2]: *IPA research, https://energypedia.info/wiki/Turkmenistan_Energy_Situation*.
[3]: *World Bank (October 2013)* Development Indicators & Global Development Finance (*http://databank.worldbank.org/ddp/home.do?Step=1&id=4*).
[4]: *Mercados (October 2010)* Load Dispatch and System Operation Study for CAPS, *Asian Development Bank (October 2009)* Energy Outlook for Central and West Asia, *IPA analysis.*
[5]: *Platts (June 2011)* WEPP Database, *IPA research.*
[6]: *World Bank (June 2007)* Potential and Prospects for Regional Energy Trade In the South Asia Region.

Current Dependable Capacity Mix

Unlike Tajikistan, the vast majority of dependable capacity in Turkmenistan comes from thermal plants running on natural gas (99.98%). Two run of river power plants make up the remaining 0.02% of dependable capacity in the country. This is illustrated in Figure 58 below.

Turkmenistan's power generation comes almost entirely from thermal power plants. As a result, Turkmenistan could, on economic grounds and if it experiences capacity surplus during the winter period, export power to Tajikistan, when the latter's demand for power is at its highest and generation is at its lowest.

Figure 58: Dependable capacity mix – Turkmenistan (2013)

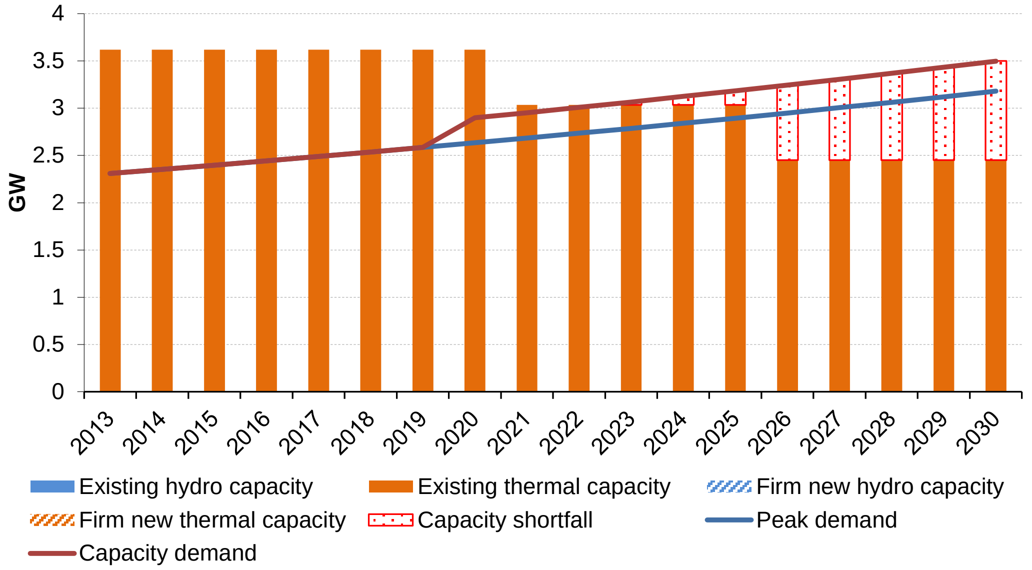


Source: Platts (June 2011) WEPP, *IPA research.*

Supply and demand outlook

As illustrated in Figure 59 below, there is currently a capacity surplus in Turkmenistan. 584MWof existing dependable capacity is expected to retire before 2025, and we anticipate a capacity shortfall in Turkmenistan from 2023 onwards if no new capacity is built in the country.

Figure 59: Supply and demand outlook – Turkmenistan (2013-2030)



Source: Platts (June 2011) WEPP, *Mercados (October 2010)* Load Dispatch and System Operation Study for CAPS, *Asian Development Bank (October 2009)* Energy Outlook for Central and West Asia, *IPA analysis.*

Market structure and recent regulatory developments

Table 68: Market structure and recent regulatory developments – Turkmenistan

	Description
Market structure	The electricity market in Turkmenistan is represented by a vertically integrated monopoly, namely "Turkmenenergo State Corporation" managed by the Ministry of Energy and Industry. At present, the "Turkmenenergo" system includes 6 territorial vertically integrated companies – electricity producers and 1 electric networks enterprise.
Interconnection	Turkmenistan was part of the CAPS but withdrew[58] and is therefore currently disconnected from Kyrgyzstan, Tajikistan, Kazakhstan and Uzbekistan. Turkmenistan was exporting electricity to Tajikistan up until 2009 but this is no longer possible because the 500 kV lines between Uzbekistan and Tajikistan are not available.[37] Turkmenistan exports power to Afghanistan both in winter and in summer via two transmission lines with a combined transfer capacity of 80MW[59]. Several foreign investment projects were aimed at increasing Turkmenistan's electricity exports, with Turkey and Iran as the primary beneficiaries for the power exports. Studies are underway, examining the feasibility of constructing new or expanding existing transmission lines between Turkmenistan and Iran.[60] When the CASA-1000 Project is completed, Turkmenistan may export electricity to Pakistan via Afghanistan. The CASA-1000 Project is based on the assumption that Tajikistan and Kyrgyzstan can only export electricity in the summer meaning that only 30–40% of the annual transmission capacity of the line to Pakistan is used. There are therefore opportunities for other countries such as Turkmenistan to use the line for power export to Pakistan if the countries cooperate.[37] On the other hand, the increasing industrial and residential demand in Turkmenistan suggests that the country may be unable to export significant amounts of electric power to fill the CASA-1000 line to capacity during winter times.[40]
Cost of supply	The Ministry of Finance handles tariff methodology matters, sets basic tariffs for transmission and shapes a tariff policy in the national economy. During the period between October 2003 to December 2010, Turkmenistan was exporting electricity to Afghanistan at 20USD/MWh according to the Power Purchase Agreement ("PPA") signed by the Ministry of Power Engineering and Industry of Turkmenistan and the Ministry of Water and Power of Afghanistan.

[58] Fichtner (October 2012) *CAREC Power Sector Master Plan*.
[59] USAID (April 2012) *Potential for Adding Russian or Turkmenistan's Power to Casa 1000's Throughput during Winter Months* (http://www.ca-reset.org/library/CASAApr/Eng/day1/PotentialforRusTurkmInCASA1000.pdf).
[60] World Energy Council (July 2007) *Electricity in Central Asia – Market and Investment Opportunity Report* (http://www.worldenergy.org/documents/central_asia_raoca_study.pdf).

Pakistan

Key statistics

Table 69: Key statistics – Pakistan (2013)

	Units	Value
Macroeconomic profile		
Population[1]		182.59 million
Access to electricity[2]	%	70
Electricity intensity*	kWh/USD	0.67
GDP[1]	USD	236.52 billion
Average GDP growth (2008-2012)[1]	%	2.73
Ease of doing business index[3]		107
Demand growth		
Peak demand 2013[2]	MW	25,142
Expected peak demand 2020[2]	MW	45,398
CAGR[2]	%	8.81
Dependable capacity development* **		
Existing capacity[4]	MW	21,108
Firm new capacity (2020)[4]	MW	5,841
Expected retirement (2020)[4]	MW	1,920
Capacity demand (2020)**	MW	49,938
Capacity shortfall (2020)	MW	24,909
Resource endowment[5]		
Gas reserves	cf	33 trillion
Coal reserves	tons	17.55 billion
Oil reserves	bbl	324 million
Hydro potential	MW	45,000

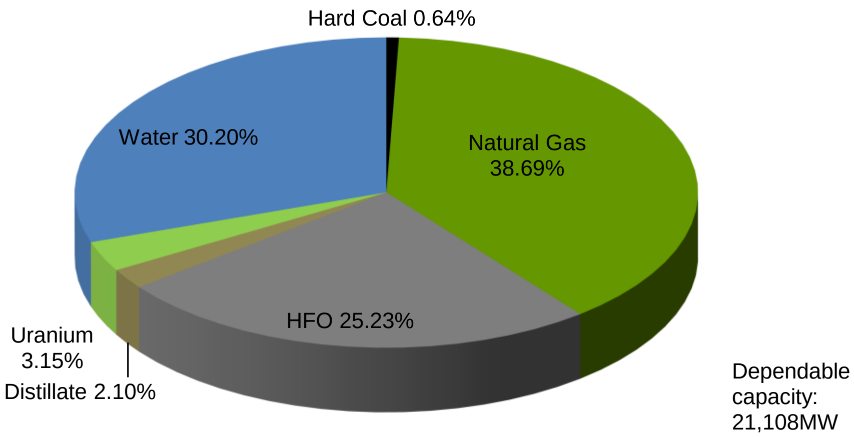
Notes: *Electricity intensity calculated using 2013 energy demand[2] divided by GDP[1].
** Capacity demand calculated as expected peak demand plus an assumed reserve margin requirement of 10% from 2020.
***Dependable capacity (as percentage of its installed capacity) for different technologies is assumed as: 92.63% for CCGT; 92.63% for OCGT; 90.25% for Coal; 92.63% for Lignite; 92.63% for Steam Gas; 90.25% for Steam Oil; 92.63% for Steam Cogen Gas; 92.63% for Steam Cogen Coal; 92.15% for Steam Cogen Oil; 99.89% for Hydro Dam and 63.98% for Hydro ROR.

Sources:
[1]: IMF (Oct 2013) World Economic Outlook, IPA analysis.
[2]: NTDC (2011) National Power System Expansion Plan 2011-2030, IPA analysis.
[3]: World Bank (Sept 2012) Development Indicators & Global Development Finance (http://databank.worldbank.org/ddp/home.do?Step=1&id=4).
[4]: Platts (June 2011) WEPP Database, NEPRA (2012) State of Industry Report 2011, IPA research.
[5]: South Asian Association for Regional Cooperation ("SAARC") (March 2010) Regional Energy Trade Study (http://www.sasec.asia/pdf/reports-and-publications/SRETS_Final.pdf).

Current dependable capacity mix

The majority of existing dependable capacity in Pakistan comes from thermal plants running on natural gas (38.69%), HFO (25.23%), distillate (2.10%) or coal (0.64%). The remainder of dependable capacity in the country is made up of hydro power plants (30.20%) and nuclear plants (3.15%). This is illustrated in Figure 60 below.

Figure 60: Dependable capacity mix – Pakistan (2013)



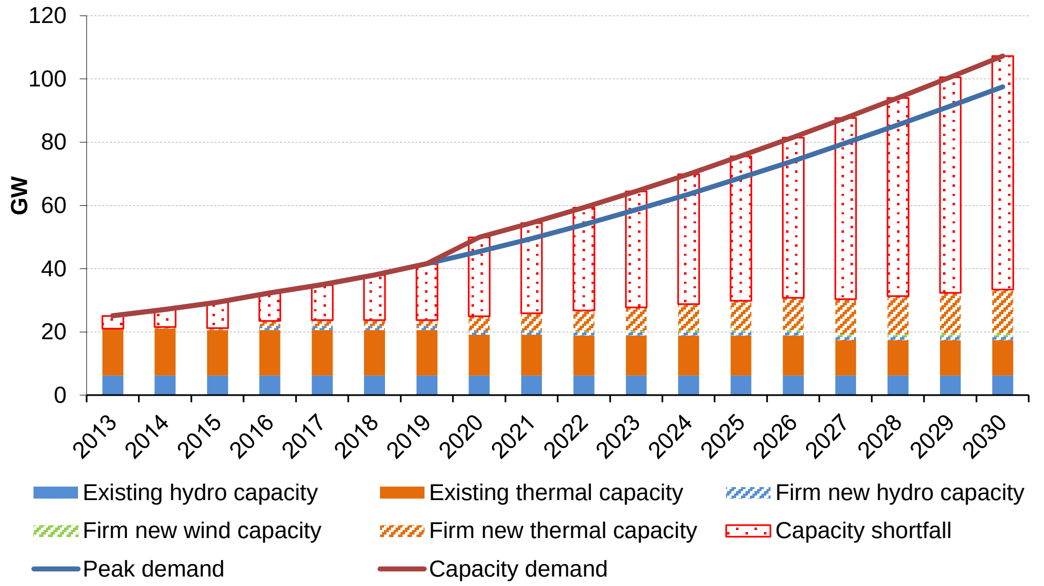
Source: Platts (June 2011) WEPP database, NEPRA (2012) State of Industry Report 2011, IPA research.

Supply and demand outlook

As illustrated Figure 61 below, there is currently a capacity shortfall in Pakistan. By 2025, 10,923 MW of new dependable capacity under construction is expected to come online whilst over 2,125MW of existing dependable capacity is expected to retire. Demand is anticipated to increase rapidly and we anticipate that the current shortfall in capacity supply, estimated at 2,995MW in October 2012[61], will increase significantly if no additional new capacity is built in Pakistan.

[61] Ministry of Power and Water (October 2012) (http://202.83.164.28/mowp/frmDetails.aspx?id=49&opt=newsevents).

Figure 61: Supply and demand outlook – Pakistan (2013-2030)

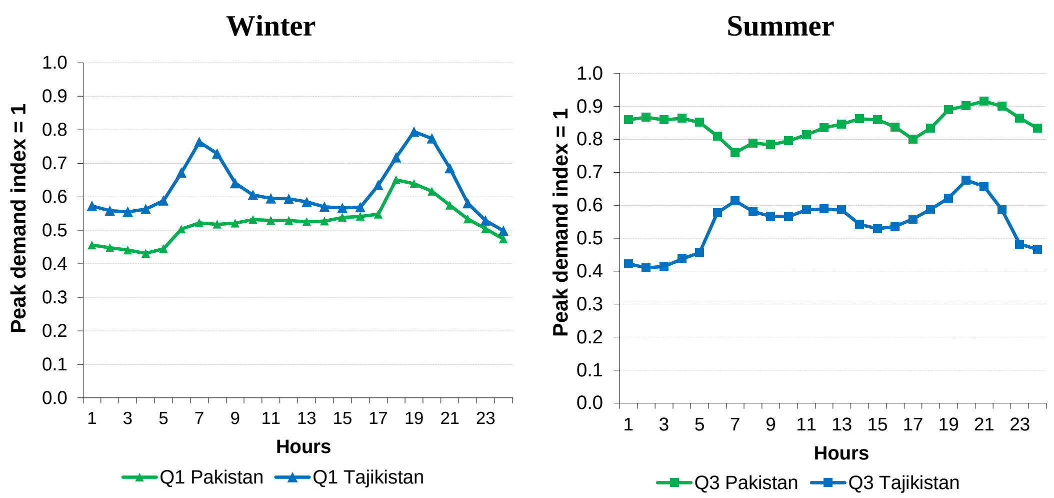


Source: Platts (June 2011) WEPP, NEPRA (2012) State of Industry Report 2011, NTDC (2011) National Power System Expansion Plan 2011-2030, IPA research.

Demand profile

In both the winter and the summer periods, illustrated by the hourly load profiles for the first quarter ("Q1") and the third quarter ("Q3") respectively in Figure 62 below, demand in Pakistan peaks when demand in Tajikistan is low and vice-versa.

Figure 62: Demand profile – Pakistan



Source: NEPRA (2012) State of the Industry Report 2011, *IPA analysis.*

Market structure and recent regulatory developments

Table 70: Market structure and recent regulatory developments – Pakistan

	Description
Market structure	Karachi Electric Supply Company ("KESC") and Water and Power Development Authority ("WAPDA") are vertically integrated public sector utilities responsible for the generation, transmission and distribution in Karachi and the rest of Pakistan respectively. At present, there are also 27 independent power producers in the Pakistani market.[62]
Interconnection	Currently, Pakistan imports electricity from Iran. In February 2012, Iran doubled power supply to Pakistan to 70MW following the installation of new transmission lines between the two countries. Furthermore, Iran and Pakistan have recently reached an agreement to increase imports from Iran to 1,000MW once a new 230 kV transmission line between Iran's south-eastern city of Zahedan and Pakistan's Quetta is established.[63] However, the countries have not agreed on a tariff, which is expected to be in the range of 70-110USD/MWh There are currently four on-going cross-border interconnection projects[64]: 1) Import of 100MW from Pak, Iran to Gwadar, Pakistan via a 220kV D/C T/L, with expected completion in June 2013; 2) Import of 1,000MW from Zahedan, Iran to Quetta, Pakistan via a 500 kV High Voltage Direct Current ("HVDC") bipolar with expected completion in 2015-2016; 3) Import of 1,000MW from Sangtuda, Tajikistan via Kabul, Afghanistan to Peshawar, Pakistan via a 500 kV HVDC 3-terminal bipolar with expected completion in 2015-2016; 4) Import of 200-500MW from India which World Bank has offered to sponsor pre-feasibility study for the project. If the CASA-1000 project succeeds, Pakistan would begin to import electricity from either Kyrgyzstan, Tajikistan, Uzbekistan or even Turkmenistan.[65,66] Uzbekistan wants to export electricity to Pakistan at a cost of 75USD/MWh. Kyrgyzstan and Tajikistan, on the other hand, have agreed to charge Pakistan just 35USD/MWh.[38]
Wholesale electricity purchaser	Currently, the National Transmission and Despatch Company ("NTDC") procures power from GENCOs, Hydel and IPPs on behalf of the nine distribution companies.

[62] Private Power and Infrastructure Board (accessed 20 November 2012) (http://www.ppib.gov.pk/index.htm).
[63] NEPRA (August 2011) *Decision of the Authority with respect to Import of Power from Iran First Amended Restated Contract (Draft) with "Tavanir"* (http://www.nepra.org.pk/Tariff/Import%20of%20Power/TRF-100%20IPI%20TAVANIR%2022-08-2011%207590-7592.PDF).
[64] NTDC (September 2012) *Monthly report on NTDC Development Projects* (http://www.ntdc.com.pk/Files/monthly_sept2012.pdf).
[65] Fichtner (October 2012) *CAREC Power Sector Master Plan*.
[66] Uznews.net (November 2011) (http://www.uznews.net/news_single.php?lng=en&sub=&cid=2&nid=18476).

Table 70: Market structure and recent regulatory developments – Pakistan

	Description
Cost of supply	The National Electric Power Regulatory Authority ("NEPRA") is responsible for the determination of tariffs.[67] In order to maintain economic efficiency and service quality, the tariff, in most cases under long term PPAs, is determined on "cost plus" basis (i.e., upfront tariff). The distribution companies are given a multi-year performance tariff and the transmission tariff is determined on an annual "cost plus" basis.[67, 68] The tariff for the imports from Iran is determined by NTDC and approved by NEPRA. It is calculated as an upfront tariff on a portion of the Organization of the Petroleum Exporting Countries ("OPEC") basket crude oil monthly average price. The tariff is set between 70 and 100USD/MWh and valid until December 2013. [67, 68] The current tariffs of different technologies in Pakistan determined by NEPRA are: • 40 to 55USD/MWh for a CCGT; • 90USD/MWh for an OCGT; • 100 to 290USD/MWh for RFO and Diesel plants.[69] The coal upfront tariff is determined at: • 105.4 to 129.6USD/MWh for local coal; • 89.4 to 112.9USD/MWh for imported coal.[70]
Political and regulatory development	In 1992, the Government of Pakistan approved WAPDAs Strategic Plan for the Privatization of the Pakistan Power Sector. NEPRA was created in 1997 and its major regulatory functions include the transmission and distribution, the determination of electricity tariff rates, both with regard to remuneration of producers (NTDC purchase price) and consumer pricing and the approval of tariffs negotiated in connection with bilateral agreements between individual power producers and the NTDC, distribution companies and major customer. The Private Power & Infrastructure Board ("PPIB") was created in 1994 with the objective of improving investment incentives and facilitating private investors in Pakistan's power sector. The major function of PPIB is to negotiate the implementation of agreements and to provide support in negotiating fuel supply agreements and PPAs. [71,72]

[67] NEPRA (accessed 20 November 2012) (http://www.nepra.org.pk/tariff.htm).
[68] Ministry of Water & Power (November 2005) *Guidelines for Determination of Tariff for IPPs*. (http://202.83.164.28/mowp/userfiles1/file/policies/tarrif_final.pdf).
[69] NEPRA (2010) *State of Industry Report*.
[70] NEPRA (October 2011) *Mechanism and Assumptions for Upfront Tariff adjustments at COD and Indexations Applicable during Operations*.
[71] Nishat Chunian Power Ltd (accessed 20 November 2012) (http://www.nishat.net/ncpl/structure-59).
[72] Private Power and Infrastructure Board (accessed 20 November 2012) (http://www.ppib.gov.pk/N_ppib2.htm).

Afghanistan

Key statistics

Table 71: Key statistics – Afghanistan (2013)

	Units	**Value**
Macroeconomic profile		
Population[1]		32.98 million
Access to electricity (2008)[2]	%	42.4
Electricity intensity*	kWh/USD	0.16
GDP[1]	USD	20.65 billion
Average GDP growth (2008-2012)[1]	%	11.87
Ease of doing business index[3]		168
Demand and dependable capacity**		
Existing capacity (2013)[5]	MW	461
Firm new capacity (2020)[5]	MW	51
Expected retirement (2020)[5]	MW	132
Peak demand (2010)[6]	MW	670
Resource endowment[7]		
Gas reserves	cf	15 trillion
Coal reserves	tons	440 million
Oil reserves	bbl	Negligible
Hydro potential	MW	25,000

Notes: *Electricity intensity calculated using 2010 energy consumption[4] divided by 2010 GDP[1].
**Dependable capacity (as percentage of its installed capacity) for different technologies is assumed as: 92.63% for CCGT; 92.63% for OCGT; 90.25% for Coal; 92.63% for Lignite; 92.63% for Steam Gas; 90.25% for Steam Oil; 92.63% for Steam Cogen Gas; 92.63% for Steam Cogen Coal; 92.15% for Steam Cogen Oil; 99.89% for Hydro Dam and 51.69% for Hydro ROR.

Sources:
[1]: IMF (Oct 2013) World Economic Outlook.
[2]: Icon-Institute commissioned by the European Union (Oct 2009) National Risk and Vulnerability Assessment 2007/8 (http://ec.europa.eu/europeaid/where/asia/documents/afgh_nrva_2007-08_full_report_en.pdf).
[3]: World Bank (Sept 2012) Development Indicators & Global Development Finance (http://databank.worldbank.org/ddp/home.do?Step=1&id=4).
[4]: EIA (Oct 2012) Country Analysis Brief- Afghanistan, IPA analysis.
[5]: Platts (June 2011) WEPP Database, IPA research.
[6]: Projection from USAID (2005) Afghanistan Electricity Demand Forecast.
[7]: SAARC Secretariat (Mar 2010) SAARC Regional Energy Trade Study SRETS (http://www.sasec.asia/pdf/reports-and-publications/SRETS_Final.pdf).

Kazakhstan

Key statistics

Table 72: Key statistics – Kazakhstan (2013)

		Value
Macroeconomic profile		
Population[1]		17.23 million
Access to electricity	%	N.A.
Electricity intensity*	kWh/USD	0.43
GDP[1]	USD	224 billion
Average GDP growth (2008-2012)[1]	%	5.15
Ease of doing business index[2]		49
Demand growth		
Peak demand 2013[4]	MW	15,173
Peak demand 2020[4]	MW	20,002
CAGR[4]	%	4.03
Dependable capacity development* **		
Existing capacity (2013)[3]	MW	12,791
Firm new capacity (2020)[3]	MW	482
Expected retirement (2020)[3]	MW	11,792
Capacity demand 2020[4]	MW	20,002
Capacity shortfall (2020)**	MW	18,522
Resource endowment[5]		
Gas reserves	cf	65-70 trillion
Coal reserves	tons	37.5 billion
Oil reserves	bbl	29 billion
Hydro potential	MW	20,000

Notes: *Electricity intensity calculated using 2013 energy consumption[6] divided by 2013 GDP[1].
**Capacity demand is equal to peak demand.
***Dependable capacity (as percentage of its installed capacity) for different technologies is assumed as: 92.63% for CCGT; 92.63% for OCGT; 90.25% for Coal; 92.63% for Lignite; 92.63% for Steam Gas; 90.25% for Steam Oil; 92.63% for Steam Cogen Gas; 92.63% for Steam Cogen Coal; 92.15% for Steam Cogen Oil; 99.89% for Hydro Dam and 51.69% for Hydro ROR.

Sources:
[1]: IMF (Oct 2013) World Economic Outlook.
[2]: World Bank (Sept 2012) Development Indicators & Global Development Finance (http://databank.worldbank.org/ddp/home.do?Step=1&id=4).
[3]: Platts (June 2011) WEPP Database, IPA research.
[4]: Mercados (Oct 2010) Load Dispatch and System Operation Study in CAPS.
[5]: SAARC Secretariat (Mar 2010) SAARC Regional Energy Trade Study SRETS

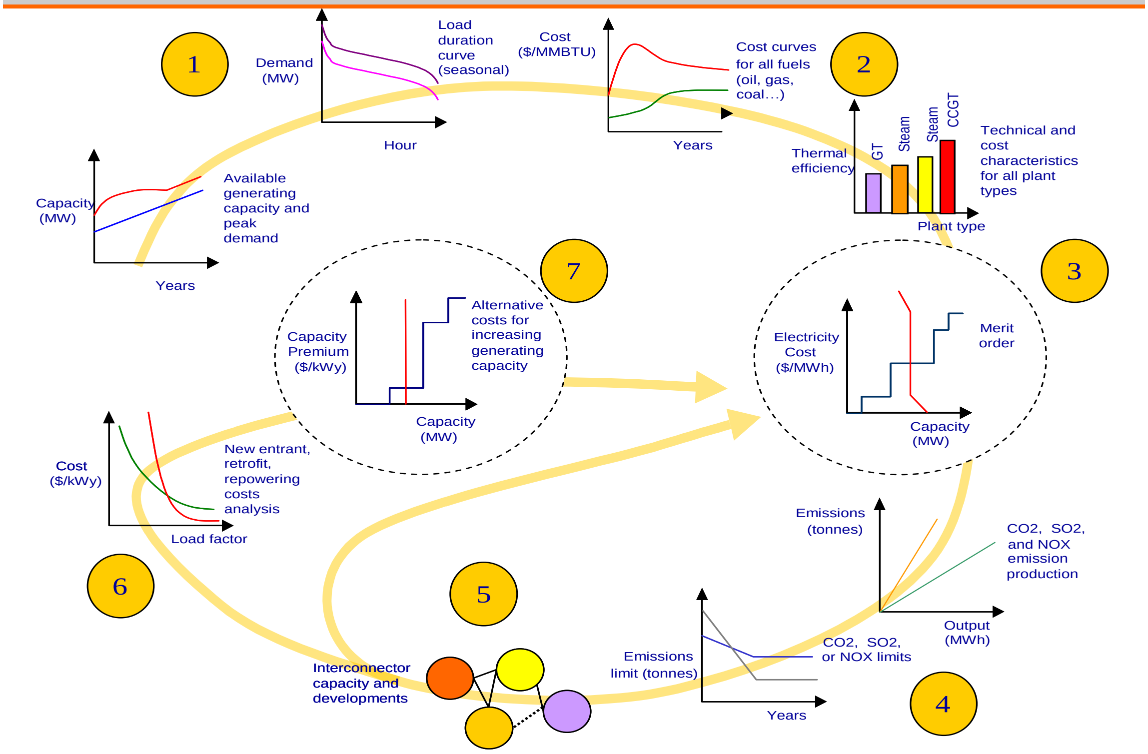
(http://www.sasec.asia/pdf/reports-and-publications/SRETS_Final.pdf).

ANNEX B: ECLIPSE® OVERVIEW

ECLIPSE® is based on a deterministic dynamic linear programming ("LP") approach with the objective of minimising the present value of fuel, other maintenance costs, and capital investment costs across the forecast horizon for both power generation and desalinated water production. Resulting prices, dispatch, fuel use and capacity expansion are optimal for each set of input parameters. Our models are developed as bespoke applications in Excel with a compatible LP optimiser (What'sBest! from LINDO Systems) and designed for fast turnaround to enable consideration of multiple scenarios.

Conceptually, it is possible to think of the model carrying out a series of discrete tasks as illustrated in Figure 63 and described further below.

Figure 63: ECLIPSE® conceptual overview



Source: IPA.

1. *Extracting current capacity and demand*

Detailed information of the characteristics of demand and of the existing generating capacity is required. Demand for electricity can be subdivided into two key components: hourly demand and total annual demand. The hourly demand, or load profile, is the demand for electrical energy on an hour-by-hour basis across the whole year.

In addition to this demand being met, an adequate safety margin needs to be maintained in the form of non-generating capacity in case of any sudden plant failures. This capacity reserve margin is measured as a percentage of the highest demand in the year ("peak demand").

Each power plant can provide both electricity and firm capacity to satisfy the hourly demand and capacity reserve margin respectively. The former will be a function of resource availability and maintenance. The contribution each power plant makes to the reserve margin will be determined by its availability in the peak. The unreliability of certain sources, including intermittent renewables, will be reflected by derating their reserve margin contribution.

2. *Identifying generation-specific operational costs*

When determining how to generate electricity and produce water to meet a certain level of demand at minimum cost, available power plants need to be ranked according to their generation/production-specific operating costs. This includes fuel and non-fuel operating and maintenance costs. Information is needed on fuel options, fuel prices and detailed information on the technical characteristics of the existing power plants. The marginal fuel cost will take into account the fuel price and the technology-specific fuel-to-electricity conversion factor ("thermal efficiency").

3. *Initial dispatching of resources to meet demand*

Once the costs per unit have been defined, the model dispatches as many resources as required. Notwithstanding other constraints described below, the lowest cost resources will be dispatched first. Dispatch can be optimised to take into account any requirements to meet ancillary services.

4. *Applying environmental, fuel and cogeneration constraints*

The relative cost of production of different power plants can also be affected by the application of environmental constraints. For example, if a power plant has to pay for allowances to cover its emissions of CO_2, this additional cost must be added to their costs of production. ECLIPSE® takes these types of constraints into account whether these are defined in terms of allowance prices (measured in USD per tonne of pollutant emitted) or emission limits (measured as weight limits or rate caps). Fuel supply - quantity caps ("DCQ") and floors ("TOP") – can apply at a national, portfolio or individual units level and will affect both dispatch and pricing decisions. The production of steam to supply industry or desalination processes will also impose operational constraints on power plants. There are various alternatives for modelling their impact. We can accommodate all these options.

5. *Applying network constraints*

Electricity travels from power plants to consumers via high and low voltage transmission and distribution networks. Due to constraints and bottlenecks on this network, both within countries as well as between them, the most cost-effective solution to meeting a certain electrical demand may in fact not be technically feasible. Despite the robustness incorporated into a lot of electrical equipment, certain events must be avoided. Therefore, in order to limit the possibility of damaging sensitive equipment, more expensive electricity from a power plant that has unhindered access to consumers may be used instead of a cheaper power plant at the wrong side of a bottleneck. Transmission constraints are accommodated by defining different dispatch zones. Dispatch across zones is optimised to take account of user-defined available transfer capacities.

6. Applying entry and exit constraints

In order to meet demand and maintain an adequate security standard in the future, new power plants can be built, and existing ones closed, refurbished or repowered. Similar to existing plants, the technical, availability and fuel supply characteristics for all new entrants must be defined. But unlike existing plants, we also define the annualised investment cost for each taking a view on various financing parameters. The model will then weigh up the benefits from all options offered.

7. Intelligent dispatch and capacity expansion

Plants' online or retire dates and dispatch profiles can be hard-wired but we can also allow the model to make this decision endogenously. Having defined the constraints and options above, the model assesses alternative dispatch and capacity expansion patterns and selects the schedule that minimises the present value of operating and investment costs over the forecast horizon

ANNEX C: DEMAND FORECAST

This Annex C describes our methodology and the inputs used for forecasting electricity demand in Tajikistan. We have used 2010 as the starting point, being the latest year for which all the necessary data were available, and forecast demand up to 2050. This section explains the relationships incorporated into our demand model to calculate future demand, the inputs, and the rationale behind the probabilistic approach that we have used.

Modelling annual demand

Our annual demand forecast is separated into two components: TALCO's demand, which is not expected to be as sensitive to GDP and tariff changes as the rest of the economy, and non-TALCO demand.

For TALCO's demand, we assume that TALCO will follow the energy efficiency plan described by the World Bank in the TWEC report. This will see its energy usage fall by 1,180 GWh by 2018[73]. This assumption is also in line with the Government of Tajikistan's intention to begin implementing energy efficiency measures in TALCO[74].

For non-TALCO demand, our approach utilises two relationships to drive the electricity demand forecast: the income elasticity of demand and the price elasticity of demand. The former gives the percentage change in demand that would result from a one percent (1.0%) increase in GDP whilst the latter gives the percentage change in demand that would result from a one percent increase in electricity tariffs. The product of the relevant elasticity with the GDP or tariff growth rate will give the effect of GDP and tariff changes on demand, and the sum of these two effects will give the total predicted growth rate of electricity demand in that year. This relationship is illustrated by the equation below, where d_t is the growth rate of non-TALCO demand in year t, g_t is the growth rate of GDP in year t, p_t is the growth rate of tariffs in year t, ϵ_{income} is the income elasticity of demand and ϵ_p is the price elasticity of demand.

$$d_t = \epsilon_{income} g_t + \epsilon_p p_t$$

The demand growth rate is then applied to a starting level of demand. Our starting demand is based on 2010 electricity consumption data from Tajikistan Statistics net of TALCO's consumption but including our estimate of unserved demand. The projected annual growth rate is then applied to this net demand before TALCO's consumption is then added back to give total demand. The demand equation is given below, where D_t is total demand in year t, TC_t is TALCO's consumption in year t, C_{2010} is observed consumption in 2010, and U_{2010} is unserved demand in 2010. ϵ_{income}, ϵ_p, g_t, and p_t have the same meaning as before.

For 2011: $$D_{2011} = (C_{2010} - TC_{2010} + U_{2010})(1 + \epsilon_{income} g_t + \epsilon_p p_t) + TC_{2011}$$

For all years (t) after 2011: $$D_t = (D_{t-1} - TC_{t-1})(1 + \epsilon_{income} g_t + \epsilon_p p_t) + TC_t$$

[73] World Bank (November 2012) *Tajikistan's Winter Energy Crisis: Electricity Supply and Demand Alternatives*.
[74] *Ibid.*

Total required electricity generation, as used in the least-cost generation expansion analysis, is equal to this electricity demand plus total losses. This is expressed below, where G_t represents total generation requirement in year t, and L_t represents total losses in year t.

$$G_t = D_t + L_t$$

Forecasting annual demand

Twelve input parameters are used to prepare our forecast. Four of these are fixed values while the others are variable to allow for the uncertainty in their evolution over the next 40 year. The inputs used are summarised in turn below.

1. Fixed inputs

The four fixed inputs are held constant.

- The **starting level of transmission and distribution losses**[75] and the **initial level of tariffs** for the economy are taken from the TWEC report.
- The **2010 constrained starting level of consumption** based on historical data from Tajikistan Statistics to which unserved demand will be added.
- **TALCO's consumption** which is matches levels projected in the TWEC report.

2. Variable inputs

Variable inputs are used where there is a strong argument for a parameter to lie between an upper and lower range. The most important of these are the price and income elasticities of demand and the level of unserved demand in 2010.

- We estimate that the level of **unserved demand in 2010** lies somewhere between 2.1 and 3.8 TWh per year as described in subsection 4 below. We therefore concluded that a suitable set of unserved demand values for 2010 were 2.0, 3.0 and 4.0 TWh.
- The **GDP growth rate** for Tajikistan was taken from the International Monetary Fund ("IMF") World Economic Outlook (October 2012) which predicts Tajikistan GDP growth up to and including 2017. After this date we have assumed an annual growth rate of 5%, falling to 4% from 2026. Although it is challenging to accurately predict economic growth, historically, if unimpeded, developing countries can enjoy rapid growth rates as they "catch up" with more industrialised nations. Therefore, we feel that this level of growth is achievable. To account for the uncertainty implicit in any prediction of the future we also allow the growth rate to be at +/-1 percentage point of the central estimate.
- We calculated two primary values of **income elasticity**, namely 0.78 and 1.0. This calculation is described in subsection 3.2. We therefore believe that a suitable set

[75] Starting T&D losses, excluding losses on supply to TALCO, are set at 18% whilst TALCO's starting level of losses is set at 3.5% based on the transmission losses figures given in "*Tajik electric supply and consumption basic indicators for 2009-2011*" which was provided to IPA by the World Bank on 12 February 2013.

of elasticities is 0.8, 0.9 and 1.0. For the forecast itself, each elasticity is applied using a top down approach (i.e. they are applied to a single growth rate for the entire economy, with TALCO excluded).

- For the **price elasticity**, a set of three possibilities is used, namely -0.1, -0.2 and -0.3. They were chosen based on a review of economic literature as applied to developing countries, as described in subsection 3.2 below. Price elasticities are applied using a top down approach, with TALCO again excluded.
- The **final level of the average tariff**, the **time taken to reach the final tariff**, the **total savings in transmission and distribution losses** (for the economy excluding TALCO[76]) and the **time taken for the savings in T&D losses to occur** are based on schedules suggested in the TWEC report. Since these parameters are liable to be influenced by political as well as economic decisions we believe that they can be treated as variable inputs. The full set of values that we allow them to hold, as well as the values for all other inputs, is summarised in Table 73 below.

[76] The change in the losses for TALCO's electricity consumption is assumed to follow the same Compound Annual Growth Rate ("CAGR") as transmission and distribution losses for the rest of the economy. The CAGR is a function of the total savings in transmission and distribution losses and the time taken for these losses to occur.

Table 73: Electricity demand forecast model inputs

Input	*Sources*	Low	Middle	High
2010 starting level of constrained consumption (TWh)	*Tajikistan Statistics*	14.22		
2010 unserved demand (TWh)	*IPA calculation*	2.00	3.00	4.00
TALCO consumption (TWh)	*Client, TWEC report*	2010: 6.46 2011 onwards: falls according to schedule suggested in the TWEC report		
Income elasticity (percentage change in demand per 1% increase in GDP)	*IPA calculation*	0.80	0.90	1.00
Adjustment to GDP growth rate (%)	*2010-17: IMF WEO 2018 onwards: IPA assumptions*	-1.00	0.00	1.00
Price elasticity (percentage change in demand per 1% increase in tariffs)	*IPA assumptions*	-0.30	-0.20	-0.10
Starting tariff value (in 2012 US cents/kWh)	*TWEC report*	2.25		
Final tariff value (in 2012 US cents/kWh)	*TWEC report*	5.00	7.00	9.00
Time taken to reach final tariff (years)	*TWEC report*	10	15	20
Starting size of T&D losses (%)	*TWEC report*	18.00		
Final size of T&D losses (percentage point ("p.p."))	*IPA assumptions*	8.00	12.00	16.00
Time taken for savings in technical losses to occur (years)	*TWEC report*	8	10	12

3. Income and price elasticities of demand

Ideally, the price and income elasticities of demand would be estimated by using a time series regression to determine the historical relationship between price and GDP and demand in Tajikistan. However, the presence of unserved demand makes estimating such a relationship using historical figures impractical. We have therefore defined the Tajik parameters by examining this relationship in other countries that can be used as comparators to Tajikistan. Note that we assume that the elasticities are fully independent of each other so that any value of the price elasticity may be combined with any value of the income elasticity.

To estimate income elasticity, two sets of countries were chosen as comparators. The first set was composed of countries that had similar levels of GDP per capita to Tajikistan, as well as a relatively similar mix of sectors. The second set was composed of countries which were most similar to Tajikistan in terms of electricity intensity.

- The first comparator group was chosen because GDP per capita can be used as a proxy for a country's level of development, and it is expected that countries at similar stages of development will have similar income elasticities. Developed nations can be expected to have low elasticities due to the implementation of energy efficiency measures and a move from energy intensive industries towards services. Countries which are developing and industrialising can be expected to have higher elasticities as their citizens begin to afford more electrical goods, infrastructure improvements make access to electricity easier, and as the economy moves away from a dependence on agriculture and develops its manufacturing base. This comparator group comprises 12 countries: Bangladesh, Cameroon, India, Kenya, the Kyrgyz Republic, Nicaragua, Pakistan, Senegal, Uganda, Uzbekistan, Vietnam and Zambia.
- The second comparator group was chosen because Tajikistan has unusually high electricity intensity[77] – the highest in the world in 2010, even with TALCO removed. This group is composed of 15 countries: Bosnia and Herzegovina, Georgia, Vietnam, Zambia, Iceland, Former Yugoslav Republic of Macedonia, Bulgaria, Uzbekistan, Moldova, Bhutan, Kazakhstan, Mongolia, the Russian Federation, Ukraine and the Kyrgyz Republic.

For each of these groups, we prepared data covering the period 2000-2010 inclusive, and performed fixed-effect panel regressions of the log of electricity consumption on the log of GDP. These analyses produced income elasticities of 1.0 and 0.78 respectively.

A second set of income elasticities was also estimated, this time determining three different elasticities for different economic sectors. Sector-specific electricity consumption data was only available for 2009 so the analysis was limited to a cross-section of countries in that one year. Countries were again selected by GDP per capita and sector mix. Data for Uganda was not available so only 11 countries were included in the assessment. This analysis suggested elasticities well within the range of our primary income elasticities, with values of 0.91, 0.90 and 0.91 for industry, residential consumers and service sectors respectively.

Since both results were compatible, we defined the probable range for the GDP elasticity of demand as 0.8, 0.9 or 1.0.

For the price elasticity, we were unable to obtain sufficient pricing data to undertake any meaningful analysis so we replied on the economic literature. A literature review revealed possible elasticities for countries at Tajikistan's level of development around -0.1 to -0.3[78]. Therefore, we allow the price elasticity to take a value of either -0.1, -0.2 or -0.3. The impact of price on electricity demand is related to the availability of substitute goods (e.g. fuel switching). The higher absolute elasticity, i.e. -0.3, would be likely to occur if there were alternative fuels available that can be used to meet energy demand after a tariff increase.

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[77] IPA calculations – Electricity intensity is calculated by dividing electricity consumption figures from the EIA with real GDP figures from the World Bank.

[78] Amarawickrama and Hunt (October 2007) *Electricity Demand for Sri Lanka: A Time Series Analysis*, De Vita, Endresen and Hunt (July 2005) *An Empirical Analysis of Energy Demand in Namibia*, Hope and Singh (March 1995) *Energy Price Increases in Developing Countries*.

We assume that our elasticities are equally likely to be any value in their set.

4. Unserved demand

Subsection 2.1.2 introduced the concept of unserved demand, the difference between *ex ante* demand and what is actually consumed due to constrained supply. Our demand forecast relies on establishing a reasonable estimate of unserved demand in 2010. This is then been added to consumption to determine the total 2010 demand value, to which we apply our demand growth rates.

We begin the process of calculating unserved demand in 2010 by selecting a base year in which unserved demand was expected to be limited. We do not believe that there has been a year with absolutely no unserved demand in Tajikistan since the civil war, which ended in 1997. This war, together with the dissolution of the USSR, devastated the country and caused both GDP and electricity consumption to collapse. Presidential elections were held at the end of 1999, and from 2000 onwards GDP growth increased substantially. This appears to indicate that from 2000 a semblance of stability had returned to the country and normal economic relationships will have begun to apply. Therefore, the year 2000 is chosen as the base year for our model in order to avoid any of the atypical economic relationships existing in the years immediately following the war. We expect unserved demand to have been small.[79]

The 2000 consumption levels of sectors which are considered to suffer from unserved demand were grown using an estimated growth rate, which aims to reflect the path that demand from that sector would have taken had there been no supply constraints. This growth rate is applied up to 2010. As noted in subsection 2.1.2 TALCO and the agricultural sector[80] are considered to be special cases and so their actual historical levels of consumption were used. Once the 2010 level of demand in the other sectors has been estimated, this was added to the observed consumption levels of agriculture and TALCO in 2010 to give the estimated total demand in that year. The difference between this estimated demand and observed consumption was defined as our estimate of unserved demand.

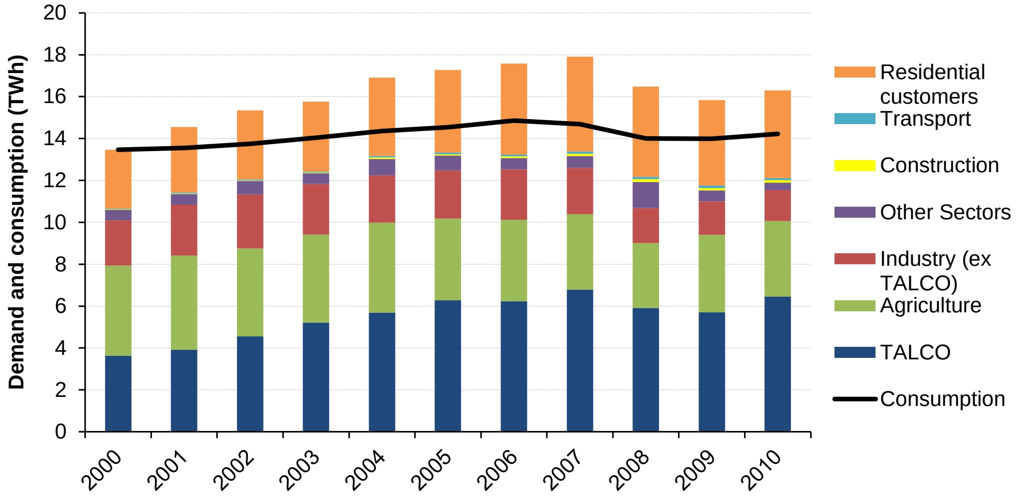
The demand growth rate for this period is calculated in the same manner as that for the forecast. Demand growth is driven by the income and tariff elasticities multiplied by the GDP and tariff growth rates and, since there is data for GDP growth available at a sector level over this period, each sector's electricity demand can be grown in line with its own output/income growth rate.

The full combination of the price and income elasticities listed in Table 73 above gives a range of unmet demand in 2010 of 2.1-3.8 TWh. The high and low case of demand compared to consumption are displayed in Figure 64 and Figure 65 below.

[79] The Client confirmed that the "year 2000 is considered as the starting period for GDP growth in the Republic of Tajikistan" and "the shortage of electricity has been reduced to a minimum".

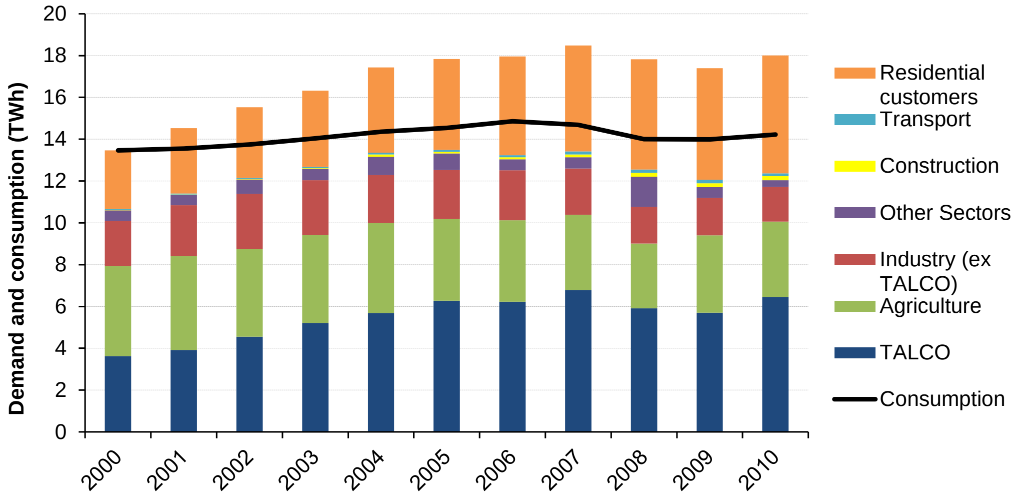
[80] As pointed out by the Client, there may be some constrained supply to the agricultural sector during spring period. However, the percentage of total demand that this represents is not expected to be great and so we have assumed no unmet demand for the agricultural sector in our calculation.

Figure 64: Low estimated total demand vs. historical consumption



Source: IPA calculations and Tajikistan Statistics.

Figure 65: High estimated total demand vs. historical consumption



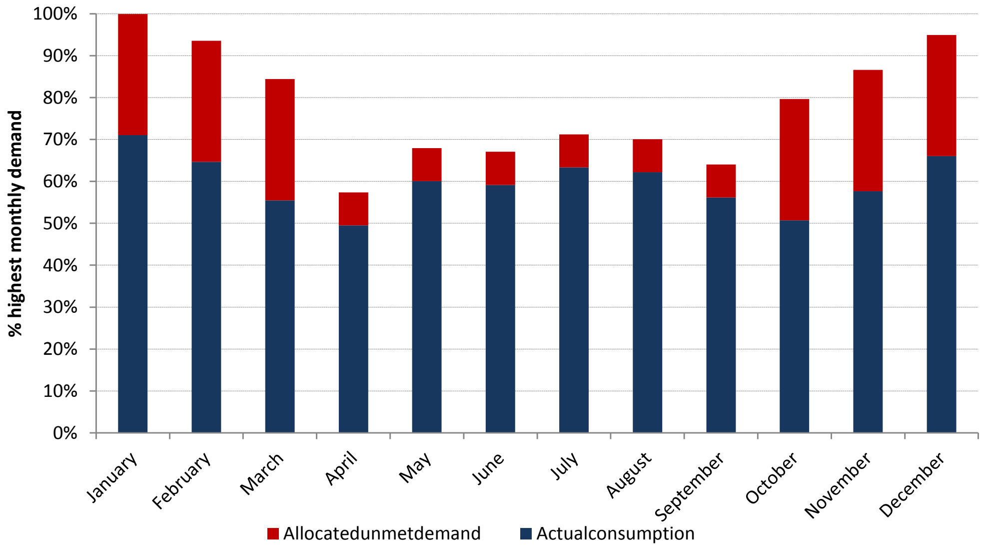
Source: IPA calculations and Tajikistan Statistics.

The total winter consumption reported by the Client (excluding TALCO) came to 3.7 TWh in 2010[81]. Our highest estimate for unmet demand in 2010 is approximately equal to this level of winter electricity consumption and our lowest estimate is still 50% of it.

[81] Data provided by the Client.

We believe that unmet demand will be concentrated in the winter months and that TALCO will not be affected by this. Figure 66 below shows how unmet demand will be distributed across the year, by comparing the generation requirement estimated by IPA to the actual consumption levels for 2011.[82]

Figure 66: Split between met and unmet demand (2011)

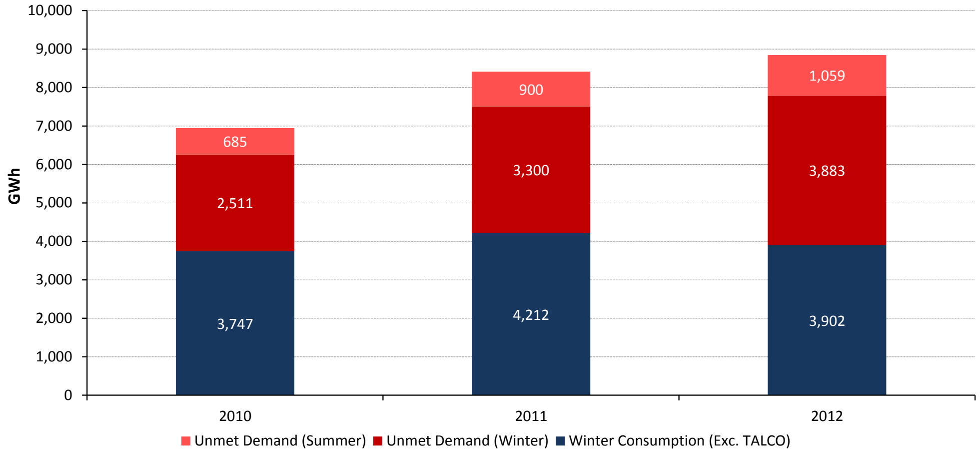


Source: the Client, IPA calculations.

The difference between our forecast of electricity demand and actual consumption provides an indication of the total notional demand. If we exclude the consumption of TALCO from consumption figures provided by the Client for 2010-2012 in the winter months (October-March), we can compare IPA's estimate of unmet demand to the actual winter consumption. Figure 67 below shows that unmet demand may be as large as winter demand net of TALCO's contribution.

[82] We developed a monthly distribution profile by calibrating the monthly profile given in the Client's demand forecast and the actual historical consumption. We consider it is reasonable to use this distribution to allocate the unserved demand estimated by IPA across different months. As a result, we allocate the majority of the unmet demand in winter (80%) and the rest in summer (20%).

Figure 67: Comparison of historical winter consumption and estimated unmet demand



Note: IPA's methodology adds 3TWh to the 2010 consumption data from Tajikistan Statistics. This differs slightly from data subsequently received from the Client by 196MW.

Source: the Client, IPA calculations.

Forecasting peak demand

Due to unserved demand, the hourly peak demand in any year is not directly observable either. In order to estimate this, we used an estimate of the grid load factor and the forecasted average demand to calculate the peak demand using the following equation:

$$Grid\ Load\ Factor = \frac{Average\ Load}{Peak\ Load}$$

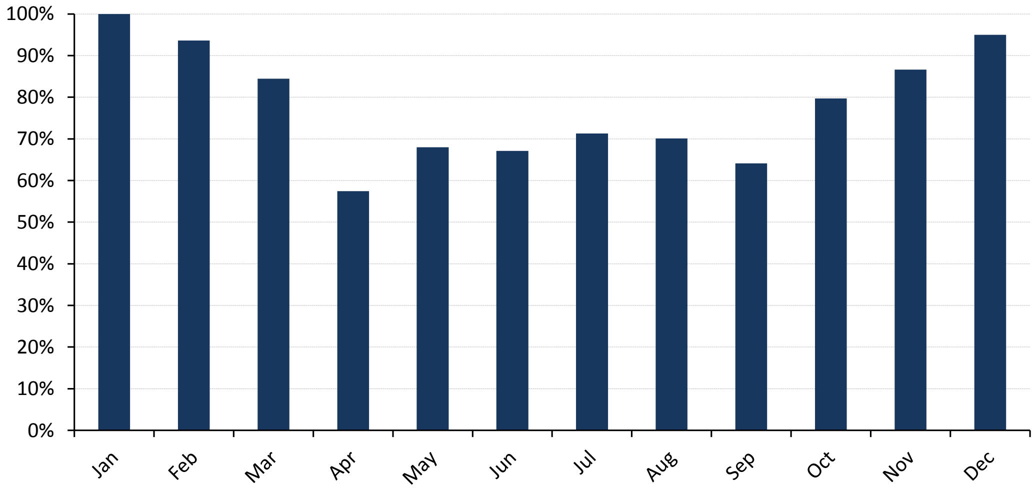
Using the fact that the number of hours in a year is 8,760, this can be rewritten as:

$$Grid\ Load\ Factor = \frac{Total\ Annual\ Energy/8{,}760}{Peak\ Load}$$

Tajikistan's grid load factor is not known so we assume that countries which share a similar monthly distribution of demand will share a similar relationship between peak demand and average demand. This allows us to estimate a grid load factor for Tajikistan. IPA's distribution of monthly demand was based on the Client's demand forecast for 2011[83]. In this distribution, demand in the winter is much higher than in the summer. Figure 68 below illustrates this distribution with demand in each month scaled as a percentage of the month with the highest demand.

[83] Client *Operation condition of HPP Cascade on the Vakhsh River*.

Figure 68: Assumed monthly distribution of demand in Tajikistan

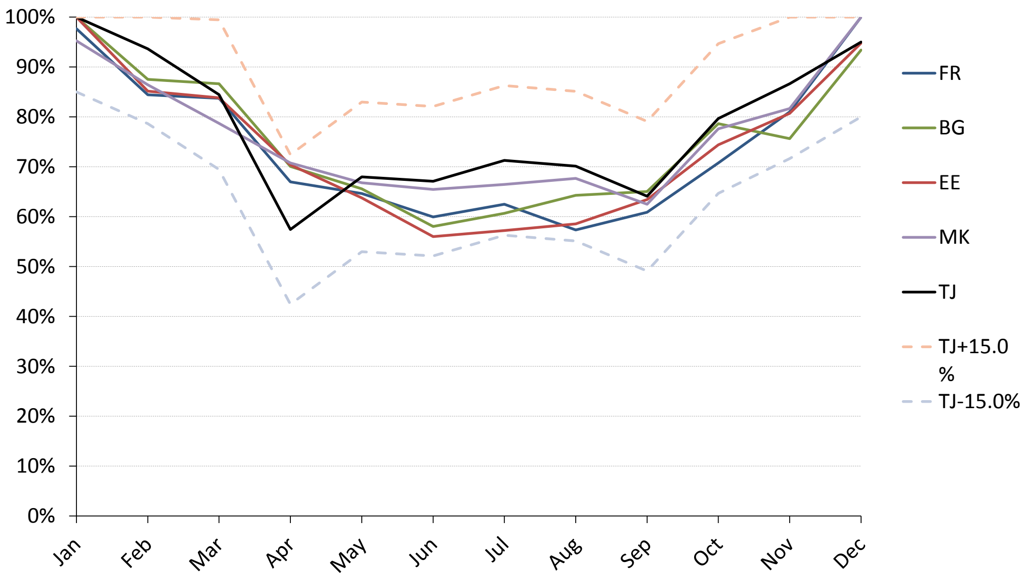


Source: IPA calculations, based on data from the Client for 2011.

For our comparator group, we chose four European countries whose distribution of demand had the closest fit to the monthly profile above[84]. These consist of France ("FR"), Bulgaria ("BG"), Estonia ("EE") and the Former Yugoslav Republic of Macedonia ("MK"). These countries' demand distributions, along with that of Tajikistan, are displayed in Figure 69. These countries' grid load factors range from 50.0% to 71.0%. We used the simple average, 59.8%, as the expected grid load factor for Tajikistan. This grid load factor is used to calculate peak demand using the equation shown above. For example, in 2012 our median peak demand forecast was 3,545 MW and the median peak required generation forecast was 4,098 MW. The grid load factor was held constant throughout the Forecast Horizon.

[84] For all ENTSO-E countries, we calculated the aggregate monthly consumption as a proportion of the highest monthly demand in 2010. We do the same for Tajikistan based on the adjusted profile. Comparator countries had to have a deviation of less than 15 percentage points from the equivalent monthly figures for Tajikistan in all 12 months.

Figure 69: Comparison of monthly distributions of demand



Source: ENTSO-E and IPA calculations.

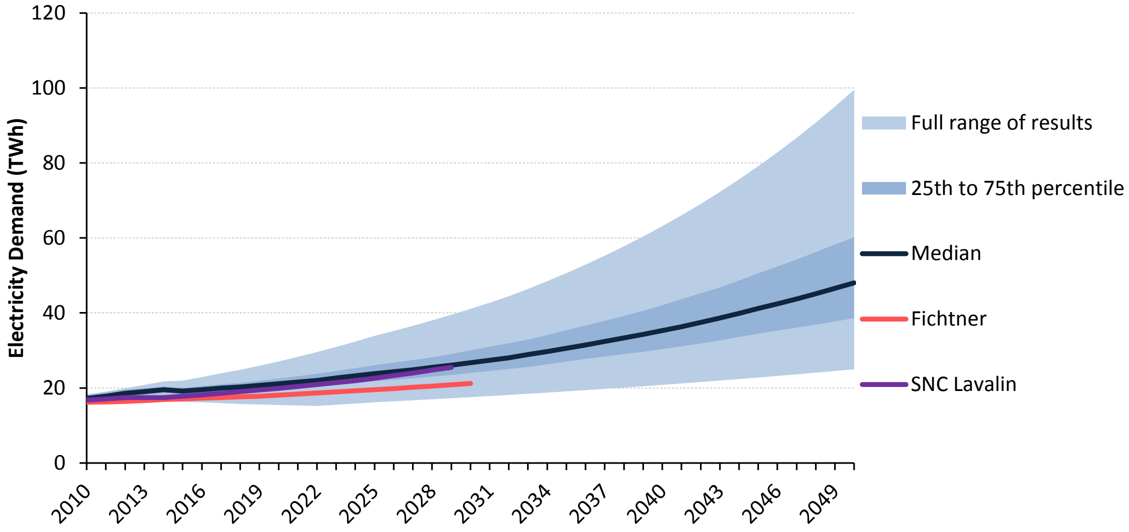
Demand Forecast Results

The results of the forecast electricity demand and required generation are displayed in Table 74 and Table 75 below and illustrated in Figure 70 and Figure 73 below.

The highest density of forecasts falls between the 25th and 75th percentile (indicated by the darker shaded band). This area is made up largely of results where demand management measures are implemented as scheduled, the forecasted growth of GDP is as predicted by the IMF, or the price and income elasticities are at their middle values. Our median forecast for demand is 27.4 TWh in 2030 and 48.1 TWh in 2050, while the median starting level of demand (with 3 TWh of unserved demand) is 17.2 TWh. This represents a median CAGR of 2.6%, although it must be remembered that the set of assumptions that generates the median demand changes as the forecast progresses. The 25th-75th percentile range of 38.6-60.2 TWh in 2050 represents a CAGR of 2.0-3.6%.

Because growth is compounded, the higher growth rates cause a greater absolute divergence from the median than the lower growth rates. As a result, at the extremes, forecast demand in 2050 ranges from a low point of 25.0 TWh to a high point of 99.6 TWh. Figure 71 below shows the distribution of results in a single year 2030. The graph shows the probability of a result falling at different levels of electricity demand. The distribution is skewed to the right, with the right-hand tail being less dense and falling over a greater range. As noted above, this is a result of the compounding nature of demand growth.

Figure 70: Demand forecast and comparison with other studies

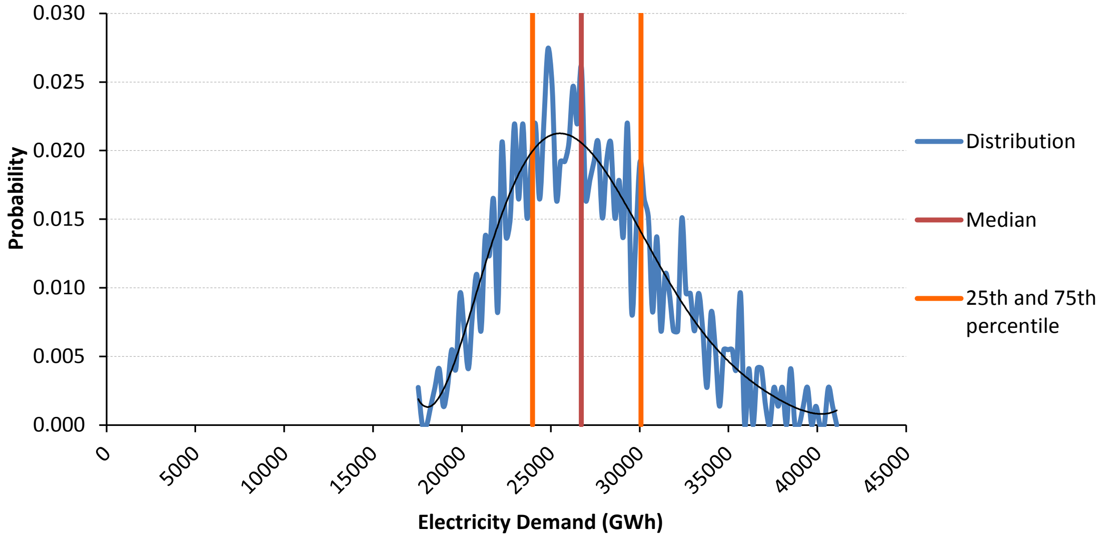


Note: For comparison purposes we include other forecasts prepared by third parties:

- SNC Lavalin (August 2011) *Technical Memorandum #2: Tajikistan Power Supply Options Study.*
- Fichtner (October 2012) *CAREC Power Sector Regional Master Plan.*

Source: IPA calculations.

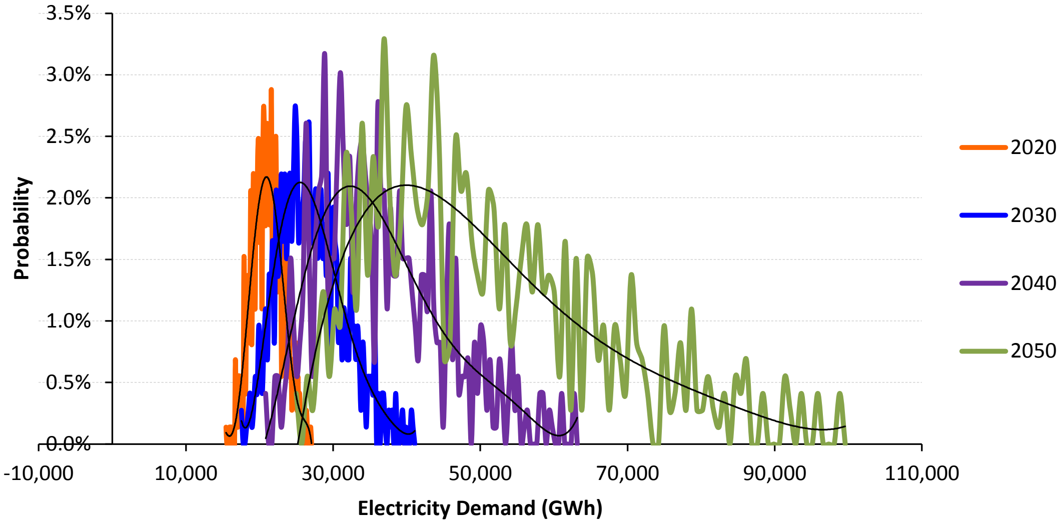
Figure 71: Distribution of demand (2030)



Source: IPA calculations.

Figure 72 below shows how results become more dispersed over time. In each year, the probability of a result falling into the central region is much greater than the probabilities in the extremes so that by 2050, the probability of a result falling in most of the right-hand tale is negligible.

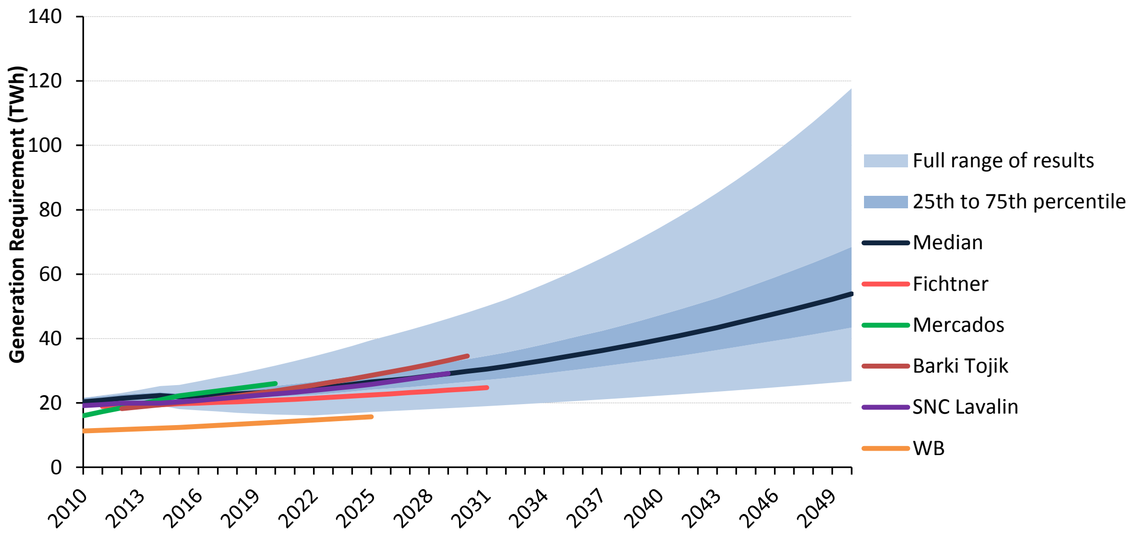
Figure 72: Evolution of the distribution of demand over time



Source: IPA calculations.

We have compared the Client's electricity consumption reports for 2011 and 2012 with our demand forecasts for those years in order to gain some idea of how much total demand has been diverging from consumption. Recorded consumption for both 2011 and 2012 was 13.6 TWh, whereas our median forecast puts demand at 17.8 TWh in 2011 and 18.6 TWh in 2012. This median forecast therefore implies an unmet demand of 4.2 TWh in 2011 and 4.9 TWh in 2012.

Figure 73: Generation requirement forecast and comparison with other studies



Note: For comparison purposes we include other forecasts prepared by third parties:

- Client (2012) monthly and annual projections provided by email.
- SNC Lavalin (August 2011) *Technical Memorandum #2: Tajikistan Power Supply Options Study.*
- Fichtner (October 2012) *CAREC Power Sector Regional Master Plan.*

- Mercados (October 2010) *Load Dispatch and System Operation Study for Central Asian Power System.*
- World Bank (December 2004) *Regional Electricity Export Potential Study*.

Source: IPA calculations.

The addition of losses means that generation requirements are significantly higher than demand but follow a similar pattern. For instance, our median forecast for required generation is 20.3 TWh in 2010, 29.8 TWh in 2030 and 53.9 TWh in 2050.

Where possible we have compared both the demand and generation requirement predictions of other studies to our own. However, only SNC Lavalin and Fichtner report separate results for forecast demand and generation requirements[85,86]. As can be seen in Figure 70 above, SNC Lavalin's demand predictions fall close to the median of our forecasts, while Fichtner's are within the range of our forecast, but outside our 25th percentile. The divergence of Fichtner's results from our median is largely due to them having used a lower income elasticity.

Three other studies report what we have termed generation requirement (i.e. they include losses) without a separate report of demand. The Client has forecast a stronger growth in electricity generation requirement than us. Their forecast starts from a lower level than our forecast but ends up close to our 75th percentile, indicating a less conservative expectation of future demand. The Mercados report[87] also has a lower starting level of required generation in 2010 than any of our forecasts, but predicts a rapid growth rate so that it is above our median by 2020. After this period, there appears to be an error in their calculation, as demand triples in two years. The forecast from this point onwards is therefore not shown in Figure 73.

SNC Lavalin's and Fichtner's required generation forecasts have the same relative positions to the median as in the demand forecast, with SNC Lavalin's predictions very close to the median and Fichtner's outside the 25th percentile but within the range of our forecast. The World Bank (2004) forecast[88] was particularly low in comparison to ours. This is because it predicted that demand would have fallen to 11 TWh by 2010 in response to planned tariff increases by Barki Tojik that never materialised.

[85] SNC Lavalin (August 2011) *Technical Memorandum #2: Tajikistan Power Supply Options Study*.
[86] Fichtner (October 2012) *CAREC Power Sector Regional Master Plan*.
[87] Mercados (October 2010) *Load Dispatch and System Operation Study for Central Asian Power System.*
[88] World Bank (December 2004) *Regional Electricity Export Potential Study*.

Table 74: Tajikistan annual demand forecast

GWh	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030	2035	2040	2045	2050
Min.	16,220	16,634	17,266	17,216	17,166	16,315	16,139	15,963	15,703	15,571	15,441	16,169	17,541	19,085	20,824	22,782	24,987
25th	16,220	16,816	17,560	18,031	18,543	18,224	18,552	18,845	19,059	19,376	19,722	21,784	23,974	26,991	30,307	34,415	38,567
Median	**17,220**	**17,816**	**18,570**	**19,020**	**19,492**	**19,162**	**19,536**	**19,943**	**20,240**	**20,664**	**21,096**	**23,842**	**26,717**	**30,575**	**35,283**	**41,217**	**48,052**
75th	18,220	18,805	19,557	19,987	20,400	20,096	20,589	21,029	21,412	21,985	22,566	26,147	30,075	35,472	42,125	50,646	60,265
Max.	18,220	19,025	19,912	20,799	21,744	21,950	22,898	23,916	24,824	25,918	27,073	33,889	41,093	50,635	63,168	79,163	99,577

Table 75:Tajikistan peak demand forecast

MW	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030	2035	2040	2045	2050
Min.	3,097	3,176	3,296	3,287	3,277	3,115	3,081	3,048	2,998	2,973	2,948	3,087	3,349	3,644	3,976	4,350	4,771
25th	3,097	3,211	3,353	3,443	3,540	3,479	3,542	3,598	3,639	3,699	3,765	4,159	4,577	5,153	5,786	6,571	7,363
Median	**3,288**	**3,402**	**3,545**	**3,631**	**3,722**	**3,659**	**3,730**	**3,808**	**3,864**	**3,945**	**4,028**	**4,552**	**5,101**	**5,838**	**6,736**	**7,869**	**9,174**
75th	3,479	3,590	3,734	3,816	3,895	3,837	3,931	4,015	4,088	4,198	4,308	4,992	5,742	6,772	8,043	9,670	11,506
Max.	3,479	3,632	3,802	3,971	4,152	4,191	4,372	4,566	4,740	4,948	5,169	6,470	7,846	9,667	12,060	15,114	19,012

Table 76: Tajikistan annual generation requirement forecast

GWh	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030	2035	2040	2045	2050
Min.	19,059	19,396	19,873	19,517	19,201	18,097	17,718	17,364	16,938	16,664	16,409	17,200	18,691	20,370	22,260	24,388	26,784
25th	19,059	19,624	20,231	20,664	21,139	20,742	21,018	21,279	21,397	21,661	21,933	24,141	26,579	29,850	33,728	38,356	43,411
Median	**20,320**	**20,873**	**21,463**	**21,855**	**22,272**	**21,859**	**22,186**	**22,543**	**22,780**	**23,166**	**23,576**	**26,506**	**29,803**	**34,250**	**39,649**	**46,289**	**53,901**
75th	21,581	22,108	22,667	23,014	23,361	23,010	23,422	23,895	24,248	24,763	25,312	29,149	33,603	39,623	47,251	56,857	68,478
Max.	21,581	22,382	23,100	24,142	25,251	25,601	26,726	27,932	29,001	30,266	31,601	39,510	48,085	59,445	74,365	93,407	117,709

Table 77: Tajikistan peak generation requirement forecast

MW	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030	2035	2040	2045	2050
Min.	3,639	3,703	3,794	3,726	3,666	3,455	3,383	3,315	3,234	3,182	3,133	3,284	3,569	3,889	4,250	4,656	5,114
25th	3,639	3,747	3,863	3,945	4,036	3,960	4,013	4,063	4,085	4,136	4,188	4,609	5,075	5,699	6,440	7,323	8,288
Median	**3,880**	**3,985**	**4,098**	**4,173**	**4,252**	**4,173**	**4,236**	**4,304**	**4,349**	**4,423**	**4,501**	**5,061**	**5,690**	**6,539**	**7,570**	**8,838**	**10,291**
75th	4,120	4,221	4,328	4,394	4,460	4,393	4,472	4,562	4,629	4,728	4,833	5,565	6,416	7,565	9,021	10,855	13,074
Max.	4,120	4,273	4,410	4,609	4,821	4,888	5,103	5,333	5,537	5,779	6,033	7,543	9,181	11,349	14,198	17,834	22,474

ANNEX D: MODELLING ASSUMPTIONS

Table 78: IPA Reference Assumptions

Macro-economic		
Discount rate	10%	World Bank recommendation (December 2013).
Demand		
Demand growth assumptions		
Tajikistan		
Peak generation requirement (2013)	4.17GW	50th percentile from IPA Tajikistan Demand Model.
Average growth 2013-2020	1.19%	
Average growth 2021-2030	2.37%	
Average growth 2031-2050	3.01%	
Annual generation requirement(“AGR”) (2013)	21.86TWh	
Average growth 2013-2020	1.19%	
Average growth 2021-2030	2.37%	
Average growth 2031-2050	3.01%	
Uzbekistan		
Peak generation requirement (2013)	9.37GW	World Bank (June 2013) *Uzbekistan Energy Sector Issues Note* until 2030. Thereafter assume a long-term growth rate of 3.60% based on 2029 data.
Average growth 2013-2020	3.33%	
Average growth 2021-2030	3.40%	
Average growth 2031-2050	3.60%	
Annual generation requirement (2013)	55.80TWh	
Average growth 2013-2020	2.77%	
Average growth 2021-2030	3.40%	
Average growth 2031-2050	3.60%	
Kyrgyzstan		
Peak generation requirement (2013)	2.92GW	Fichtner (October 2012) base case scenario in Annex 4.2.1-1 until 2031. Thereafter assume a long-term peak growth rate of 1.54% and energy growth rate of 1.72% based on 2021-2031 averages.
Average growth 2013-2020	-0.49%	
Average growth 2021-2030	1.49%	
Average growth 2031-2050	1.56%	

Table 78: IPA Reference Assumptions

Annual generation requirement (2013)	12.13TWh	
Average growth 2013-2020	0.53%	
Average growth 2021-2030	1.69%	
Average growth 2031-2050	1.73%	
Turkmenistan		
Peak generation requirement (2013)	2.31GW	ADB (2009) *Energy Outlook for Asia and the Pacific*, p.116-120 until 2030. Thereafter assume the same rate of 1.90 as long-term growth rate.
Average growth 2013-2020	1.90%	
Average growth 2021-2030	1.90%	
Average growth 2031-2050	1.90%	
Annual generation requirement (2013)	13.71TWh	
Average growth 2013-2020	1.90%	
Average growth 2021-2030	1.90%	
Average growth 2031-2050	1.90%	
Pakistan		
Peak generation requirement (2013)	25.14GW	NTDC (2011) *National Power System Expansion Plan 2011 - 2030* until 2035. For 2036 to 2039 we assume that the Average Annual Growth Rate ("AAGR") falls to 4.5% and from 2040 onward to 3.5%, as the economy matures.
Average growth 2013-2020	8.67%	
Average growth 2021-2030	7.95%	
Average growth 2031-2050	4.50%	
Annual generation requirement (2013)	157.46TWh	
Average growth 2013-2020	8.41%	
Average growth 2021-2030	7.68%	
Average growth 2031-2050	4.42%	
Hourly load profile		
Tajikistan		Based on Client 2005-2010 average weekday and weekend load profile and adjusted for monthly unserved energy demand estimated by IPA and for future changes in the hourly load profiles, based on Fichtner (October 2012)
Uzbekistan		Tajikistan profile assumed. Calibrated to be consistent with the annual growth rate of peak demand and with the annual demand.
Turkmenistan		Tajikistan profile assumed. Calibrated to be consistent with the annual growth rate of peak demand and with the annual demand.

Table 78: IPA Reference Assumptions

Kyrgyzstan		Fichtner (October 2012) Fig. 3.5-2 for 2010 winter/summer load curve and Fig. 3.5-3 for monthly consumption profile.
Pakistan		NEPRA (2012) *State of Industry Report 2011* based on summer/winter load profile.
Minimum reserve margin requirement		
Tajikistan	0% 2013-19; 10% thereafter	IPA assumption. Percentage Dependable Capacity over peak demand.
Uzbekistan		
Turkmenistan		
Kyrgyzstan		
Pakistan		
Supply[89]		
Existing plants (installed capacity)		
Tajikistan		
Hydro	4,940MW	Client, Platts (June 2011) WEPP Database.
Coal	0MW	
Gas	318MW	
Total	**5,258MW**	
Uzbekistan		
Hydro	1,748MW	World Bank's Uzbekistan Energy Issues Note (June 2013), Platts (June 2011) WEPP Database.
Coal	0MW	
Gas	8,076MW	
Lignite	2,584MW	
Total	**12,408**	
Kyrgyzstan		
Hydro	2,959MW	Platts (June 2011) WEPP Database, IPA research.
Coal	35MW	

[89] Note: for modelling purposes we include operating plants as separate units for every country, instead of using aggregate measures as provided in the summary under "Existing plants".

Table 78: IPA Reference Assumptions

Gas	728MW	
Total	**3,722MW**	
Turkmenistan		
Hydro	4MW	Platts (June 2011) WEPP Database, IPA research.
Coal	0MW	
Gas	3,702MW	
Total	**3,716MW**	
Pakistan		
Hydro	6,974MW	NEPRA (2012) *State of Industry Report 2011*, NTDC Expansion plan (2011), IPA research.
Coal	150MW	
Gas	8,242MW	
Oil	6,096MW	
Nuclear	737MW	
Distillate	490MW	
Total	**22,689MW**	
Firm New Build		
Tajikistan		
Langar (Afghanistan Border)	0.06MW, COD 2014	Platts (June 2011) WEPP Database, Client, IPA research.
Andarbak	0.25MW, COD 2013	
Emts	0.10MW, COD 2016	
Shkev	0.075MW, COD 2015	
Yamchun	0.15MW, COD 2015	
Pamir 2	14MW, COD 2014	
Dushanbe Heat stations 2	100MW, COD 2015	
Total	**115MW**	

Table 78: IPA Reference Assumptions

Uzbekistan		
Andijan	12MW, COD 2014	Platts (June 2011) WEPP Database, Fichtner (October 2012), World Bank (June 2013) *Uzbekistan Energy Issues Note*, IPA research.
Talimardjan Thermal Power Plant	900MW, COD 2014	
Navoi Thermal Power Plant	476MW, COD 2012	
Tashkent Thermal Power Plant	370MW, COD 2015	
Angren Thermal Power Plant	140MW, COD 2015	
Sokh	14MW, COD 2014	
Akhangaran Reservoir	21MW, COD 2014	
Tupolang	30MW, COD 2014	
Total	**1,963MW**	
Kyrgyzstan		
Kambarata 1 project unit 1	120MW, COD 2011	Platts (June 2011) WEPP Database, CAREC Program (2008) *National Energy Plan of the Kyrgyz Republic for 2008-2010 and the fuel and energy complex development until 2025*, Fichtner (October 2012), IPA research.
Kambarata 1 project unit 2,3	240MW, COD 2013	
Kambarata 2 project P1	475MW, COD 2015	
Kambarata 2 project P2	475MW, COD 2020	
Kambarata 2 project P3	475MW, COD 2020	
Kambarata 2 project P4	475MW, COD 2027	
Upper Naryn Cascade HPP	190MW, COD 2015	
Total	**2,450MW**	
Turkmenistan		
Seydi	80MW, COD 2009	Platts (June 2011) WEPP Database, IPA research.
Dashoguz Velayat GT	254MW, COD 2010	
Total	**334MW**	
Pakistan		
Bhikki (Halmore) Power Project	209MW, COD 2011	WAPDA, NEPRA (2012) *State of Industry Report 2011*, NTDC (2011) *National Power System Expansion Plan 2011 - 2030*, KESC, IPA research.
Neelum Jhelum	969MW, COD 2016	
Kurram Tangi	83MW, COD 2014	
New Bong Escape	84MW, COD 2014	

Table 78: IPA Reference Assumptions

Nandipur Power Project	425MW, COD 2014	
UAE GT Faisalabad	320MW, COD 2016	
Guddu CC	750MW, COD 2016	
Bin Qasim CC	560MW, COD 2012	
Kaigah Hydropower Project	548MW, COD 2017	
Chasnupp 3	340MW, COD 2016	
Chasnupp 4	340MW, COD 2017	
Chasnupp 5	1000MW, COD 2020	
Kanupp 2	1000MW, COD 2020	
Kanupp 3	1000MW, COD 2020	
Total	**7,628MW**	
Economic New Build options		
Tajikistan		IPA assumptions, Client, Platts (June 2011) WEPP Database capacities under construction/planned, Fichtner (October 2012) 2020 capacity mix results and national oil/gas/coal resource data provided by Oil and Gas Journal (2011) and World Bank (2008) *Potential and Prospects for Regional Energy Trade in the South Asia Region Formal Report 334/08*.
New Coal	up to 1,170MW	
New Hydro ROR	uncapped	
Uzbekistan		
New OCGT	uncapped	
New CCGT	uncapped	
Kyrgyzstan		
New OCGT	uncapped	
New CCGT	uncapped	
New Lignite	up to 1,000MW	
Turkmenistan		
New OCGT	uncapped	
New CCGT	uncapped	

Table 78: IPA Reference Assumptions

Pakistan		
New OCGT	uncapped	
New CCGT	up to 40,000MW	
New Coal	up to 80,000MW	
New Hydro Dam	uncapped	
New Hydro ROR	uncapped	
Economic New Build parameters		
New build TIC (all-in investment cost including IDC):		
New CCGT	1,400USD/kW	IPA assumptions.
New OCGT	840USD/kW	
New Coal	2,000USD/kW	
New Lignite	2,200USD/kW	
New Hydro Dam	2,700USD/kW	
New Hydro ROR	2,700USD/kW	
New Interconnector: TJ → PK, TJ ↔ KG	600USD/kW	IPA assumption based on analysis of data from SNC Lavalin (February 2011) *Central Asia – South Asia Electricity Transmission and Trade (CASA-1000) Project Feasibility Study Update*.
Interconnector TJ ↔ UZ	300USD/kW	Refurbishment cost estimated by the Client (August 2013).
New build thermal efficiencies (net HHV):		
New CCGT	48.0%	IPA assumptions.
New OCGT	30.0%	
New Coal	35.0%	
New Lignite	34.5%	
New Hydro Dam	100.0%	
New Hydro ROR	100.0%	
Plant operating constraints		
Hydro		
Tajikistan		

Table 78: IPA Reference Assumptions

Hydro DAM (Vakhsh river)		
	CF specific to each HPP	Coyne et Bellier.
	Pmax = 99.9%	IPA assumption.
	CF specific to each HPP	IPA assumption.
Hydro DAM (non-Vakhsh)		
	CF Q1/2/3/4 = 74/46/41/39%	SNC Lavalin (February 2011) *Central Asia – South Asia Electricity Transmission and Trade (CASA-1000) Project Feasibility Study Update* based on historical data from 2007-2010.
	Pmax = 99.9%	IPA assumption.
	Pmin Q1/2/3/4 = 37/23/21/19%	IPA assumption.
Hydro ROR		
	CF Q1/2/3/4 = 45/56/72/41%	Coyne et Bellier.
	Pmax = quarterly CF	IPA assumption.
	Pmin = quarterly CF	IPA assumption.
Uzbekistan		
Hydro DAM		
	CF = 43%	Fichtner (October 2012) based on annual generation data.
	Pmax = 99.9%	IPA assumption.
	Pmin = 22%	IPA assumption.
Hydro ROR		
	CF = 43%	Fichtner (October 2012) based on annual generation data.
	Pmax = CF = 43%	IPA assumption.
	Pmin = CF = 43%	IPA assumption.
Turkmenistan		
Hydro DAM		
	CF = 20%	IPA assumption.
	Pmax = 99.9%	IPA assumption.
	Pmin=10%	IPA assumption.

Table 78: IPA Reference Assumptions

Hydro ROR		
	CF = 20%	IPA assumption.
	Pmax = CF = 20%	IPA assumption.
	Pmin = CF = 20%	IPA assumption.
Kyrgyzstan		
Hydro DAM		
	CF = 55%	SNC Lavalin (February 2011) *Central Asia – South Asia Electricity Transmission and Trade (CASA-1000) Project Feasibility Study Update* based on monthly hydro generation profile.
	Pmax = 99.9%	IPA assumption.
	Pmin = 27%	IPA assumption.
Hydro ROR		
	CF = 39%	SNC Lavalin (February 2011) *Central Asia – South Asia Electricity Transmission and Trade (CASA-1000) Project Feasibility Study Update* based on monthly hydro generation profile.
	Pmax = quarterly CF	IPA assumption.
	Pmin = quarterly CF	IPA assumption.
Pakistan		
Hydro DAM		
	CF Q1/2/3/4 = 40/50/64/56%	IPA assumption based on historical annual generation data from 2006-2011 calibrated to match monthly Pmax profile.
	Pmax = 99.9%	NEPRA (2011) *State of Industry Report 2010* monthly Pmax data in Table 32.
	Pmin = 20%	IPA assumption.
Hydro ROR		
	CF Q1/2/3/4 = 40/50/64/56%	IPA assumption based on historical annual generation data from 2006-2011 calibrated to match monthly Pmax profile.
	Pmax = quarterly CF	NEPRA (2011) *State of Industry Report 2010* monthly Pmax data in Table 32.
	Pmin = quarterly CF	IPA assumption.
Thermal (efficiency - net HHV)		
Coal	33.0%	IPA assumptions.
Lignite	32.0%	

Table 78: IPA Reference Assumptions

Steam Gas	32.0%	
Steam Oil	33.0%	
Steam Cogen Coal	32.0%	
Steam Cogen Gas	32.0%	
Steam Cogen Oil	30.2%	
OCGT	25.0%	
CCGT	47.7%	
Hydro Dam	100.0%	
Hydro ROR	100.0%	
Nuclear	Plant specific	
IC	32.0%	
Technical life assumptions		
Coal	45 years	Fichtner (October 2012) Annex 3.3.1.2-2. Same for steam cogen coal / gas / oil.
Lignite	45 years	
Steam Gas	45 years	
Steam Oil	45 years	
Steam Cogen	45 years	
OCGT	35 years	IPA assumption.
CCGT	35 years	
Hydro Dam	99 years	
Hydro ROR	99 years	
IC	50 years	
Nuclear	35 years	
Fuel prices		
Central Asia long term forecast (2025 onwards):		
Crude oil	75.62USD/bbl	World Bank (July 2013), IPA assumptions.
HFO	453.75USD/t	Linked to crude price based on relationship between forward Brent Spot FOB (USD/bbl) and European residual fuel oil (USD/t) prices from CME Group (2012).
Diesel	670.79USD/t	Linked to crude price based on relationship between forward Brent Spot FOB (USD/bbl) and European Gasoil (USD/t) prices from Bloomberg and CME Group (2012).
Coal	106.56USD/t	World Bank (July 2013), IPA assumptions.

Table 78: IPA Reference Assumptions

Gas	7.87USD/MMBTU	World Bank (July 2013), IPA assumptions.
Lignite	19.67USD/t	Assuming 75% discount to coal price in USD/t results into a lignite price of 2.77USD/MMBTU (energy conversion rate for lignite is 6.75 MMBTU/t).
Uranium	1.60USD/MMBTU	IPA assumption.

Table 79: IPA Reference Assumptions for interconnections in Central Asia

From \ To	Tajikistan	Uzbekistan	Turkmenistan	Kyrgyzstan	Pakistan	Afghanistan	Kazakhstan
Tajikistan		-	-	1,000MW 2017; + up to 3,000MW @ 350MW/y from 2020	1000MW 2017 + up to 3,000MW @ 350MW/y from 2020	110MW existing; 300MW 2017	-
Uzbekistan	-		-	1000MW existing	-	250MW existing	325MWexisting
Turkmenistan	-	-		N.A.	-	N.A.	N.A.
Kyrgyzstan	1,000MW 2017 + up to 3,000MW @ 350MW/y from 2020	-	-		-	-	450MW existing
Pakistan	-	-	-	-		N.A.	-
Afghanistan	N.A.	-	N.A.	-	N.A.		-
Kazakhstan	-	N.A.	N.A.	N.A.	-	-	

Sources: Fichtner (October 2012), SNC Lavalin (February 2011) CASA Electricity Transmission and Trade (CASA-1000) Project Feasibility Study Update.

Notes: N.A. = not modelled.

Table 80: Assumptions for sensitivities

Tajikistan Demand Growth		
High		
Peak generation requirement (2013)	4.39GW	75th percentile from IPA Tajikistan Demand Model. • 2020 AGR = 25.31TWh and peak = 4.83GW. • 2030 AGR = 33.60TWh and peak = 6.42GW. • 2050 AGR = 68.48TWh and peak = 13.07GW.
Annual generation requirement (2013)	23.01TWh	
Average growth 2013-2020	1.40%	
Average growth 2021-2030	2.87%	
Average growth 2031-2050	3.62%	
Low		
Peak generation requirement (2013)	3.95GW	25th percentile from IPA Tajikistan Demand Model. • 2020 AGR = 21.93TWh and peak = 4.19GW. • 2030 AGR = 26.58TWh and peak = 5.08GW. • 2050 AGR = 43.41TWh and peak = 8.29GW.
Annual generation requirement (2013)	20.66TWh	
Average growth 2013-2020	1.02%	
Average growth 2021-2030	1.94%	
Average growth 2031-2050	2.46%	
Fuel prices		
High	+20% to IRA.	
Low	-20% to IRA.	
Economic New Build TIC		
High	+20% to IRA.	No change to Rogun TIC.
Low	-20% to IRA.	
Interconnector NTC		
High	1000MW TJ↔UZ in 2017, additional 2000MW TJ↔KZ, additional 2000MW TJ→PK.	
Low	1000MW TJ→PK, 1GW TJ↔KG, 300MW TJ→AF, and 1000MW PK→TJ are delayed to 2020 (from 2017). No economic expansion of interconnectors.	

ANNEX E: COMPARISON OF NEW BUILD COSTS

The cost of new build in each potential export market is determined by the LRMC of the most Economic New Build option for baseload and peaking plants in that country.

By looking at the resource endowments and the supply-demand outlook in each of the potential markets, we can establish which technology will be the most likely new build option to satisfy baseload and peaking requirements.

Uzbekistan has an abundance of gas reserves and thermal power plants make up nearly 90% of capacity supply in the country. Hence, our calculations suggest that the economically optimal new build options in Uzbekistan are CCGTs for baseload and OCGTs for peaking. On the other hand, Kyrgyzstan has little gas and oil reserves and its power sector is dominated by HPPs. Therefore, we do not expect thermal plants to come online as baseload. Pakistan has very large coal and gas reserves. Our calculations show that the most Economic New Build options in Pakistan will be coal plants for baseload and OCGTs for peaking. Finally, given the significant gas reserves in Afghanistan, the most Economic New Build options in the country can be expected to be baseload new CCGT plants.

The resulting LRMCs are presented in Table 81 below.

Table 81: Cost of New Build comparison

	Unit	Uzbekistan		Kyrgyzstan		Pakistan		Afghanistan		Kazakhstan	
		Baseload	Peaking	Baseload	Peaking	Baseload	Peaking	Baseload	Peaking	Baseload	Peaking
		New CCGT	New OCGT	New CCGT	New OCGT	New Coal	New OCGT	New CCGT	-	New Coal	-
Technical Parameters											
Technical life	Years	35.00	35.00	35.00	35.00	45.00	35.00	35.00	-	45.00	-
Thermal efficiency	Net HHV	48.00%	30.00%	48.00%	30.00%	35.00%	30.00%	48.00%	-	35.00%	-
Annual Capacity factor	%	87.99%	87.99%	87.99%	87.99%	84.84%	87.99%	87.99%	-	84.84%	-
Capital costs and FOM											
TIC	USD/kW	1400	840	1400	840	2000	840	1400	-	2000	-
Discount rate	%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	-	10.00%	-
LRCCR*	% of TIC	11.02%	11.75%	11.02%	11.75%	10.61%	11.75%	11.02%	-	10.61%	-
Annualised TIC	USD/kWy	154.24	98.67	154.24	98.67	212.16	98.67	154.24	-	212.16	-
FOM	USD/kWy	19.55	11.73	19.55	11.73	44.32	11.73	19.55	-	44.32	-
Total annual fixed cost	USD/kWy	30.34	22.52	30.34	22.52	65.87	22.52	30.34	-	65.87	-
Variable costs											
VOM	USD/MWh	1.40	1.40	1.40	1.40	2.90	1.40	1.40	-	2.90	-
Fuel cost (2040)	USD/MWh	55.94	89.50	55.94	89.50	41.45	89.50	55.94	-	41.45	-
Total SRMC	USD/MWh	57.34	90.90	57.34	90.90	44.35	90.90	57.34	-	44.35	-
Long Run Marginal Cost											
LRMC	USD/MWh	**79.89**	**105.23**	**79.89**	**105.23**	**78.86**	**105.23**	**79.89**	-	**78.86**	-

Source: IPA analysis

.

ANNEX F: LEAST-COST GENERATION EXPANSION RESULTS

NoRogun Reference Case

Table 82: Tajikistan forecast capacity expansion – NoRogun_Ref

MW \ CYs	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Steam Gas/Oil	318	198	198	-	-	-	-	-	-	-	-	-	-	-	-
Hydro DAM	2,584	2,584	2,626	2,626	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126
Hydro ROR	1,579	1,499	1,507	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594
New Coal / Lignite	-	-	100	450	932	932	932	1,177	1,270	1,270	1,270	1,270	1,270	1,270	1,270
New Hydro Dam	-	-	-	-	120	520	520	520	520	1,320	4,520	4,520	4,520	4,520	4,520
New Hydro ROR	220	234	235	235	520	520	917	1,217	1,830	1,830	1,830	1,830	1,830	1,830	6,800
Import Interconnector	-	-	-	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,438	2,268	2,268
Rogun	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Installed	5,878	5,813	5,824	5,405	6,292	6,692	7,089	7,634	8,434	9,140	12,340	12,340	12,340	12,340	17,311
Total Dependable	4,642	4,700	4,697	4,349	4,951	5,342	5,413	5,685	5,962	6,654	9,838	9,826	9,816	9,804	10,643
Peak Demand	4,173	4,252	4,236	4,349	4,501	4,680	4,921	5,169	5,420	5,831	6,352	6,923	7,570	8,554	9,675

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 83: Tajikistan forecast New Build expansion – NoRogun_Ref

CYs MW	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Rogun HPP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sangvor	-	-	-	-	-	400	400	400	400	400	400	400	400	400	400
Sanobod	-	-	-	-	125	125	125	125	125	125	125	125	125	125	125
Shtien	-	-	-	-	-	-	-	300	300	300	300	300	300	300	300
Urfatin	-	-	-	-	-	-	300	300	300	300	300	300	300	300	300
Nurabad-1	-	-	-	-	160	160	160	160	160	160	160	160	160	160	160
Nurabad-2	-	-	-	-	-	-	97	97	120	120	120	120	120	120	120
Sangiston	-	-	-	-	-	-	-	-	140	140	140	140	140	140	140
Ayni	-	-	-	-	-	-	-	-	160	160	160	160	160	160	160
Zarafshon	-	-	-	-	-	-	-	-	160	160	160	160	160	160	160
Darg	-	-	-	-	-	-	-	-	130	130	130	130	130	130	130
Shurob	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dupulin	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fandarya	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dashtijum	-	-	-	-	-	-	-	-	-	800	4,000	4,000	4,000	4,000	4,000
Obburdan	-	-	-	-	120	120	120	120	120	120	120	120	120	120	120
New Coal	-	-	-	350	832	832	832	1,077	1,170	1,170	1,170	1,170	1,170	1,170	1,170
New Hydro ROR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,971
Sangtuda 2	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
Firm New Hydro ROR	0	14	15	15	15	15	15	15	15	15	15	15	15	15	15
Dushanbe 2	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 84: Tajikistan forecast interconnector expansion – NoRogun_Ref

MW \ CYs		2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Import capacity	Uzbekistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Kyrgyzstan	-	-	-	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,438	2,268	2,268
	Pakistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Afghanistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Export capacity	Uzbekistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Kyrgyzstan	-	-	-	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,438	2,268	2,268
	Pakistan	-	-	-	1,000	1,350	2,050	2,508	2,906	3,177	3,177	4,000	4,000	4,000	4,000	4,000
	Afghanistan	110	110	110	410	410	410	410	410	410	410	410	410	410	410	410

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 85: Tajikistan forecast generation mix – NoRogun_Ref

GWh \ CYs	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Steam Gas/Oil	404	251	251	-	-	-	-	-	-	-	-	-	-	-	-
Hydro DAM	10,177	10,177	10,360	10,334	12,242	12,194	12,145	12,096	12,048	11,975	11,902	11,853	11,852	11,850	11,849
Hydro ROR	7,383	6,986	7,021	7,432	7,399	7,365	7,332	7,298	7,264	7,214	7,164	7,126	7,115	7,099	7,084
New Coal / Lignite	-	-	514	3,344	6,549	6,924	6,924	8,747	9,438	8,633	6,629	7,416	7,510	7,582	5,006
New Hydro Dam	-	-	-	-	516	2,824	2,824	2,824	2,824	5,980	18,606	18,606	18,606	18,606	18,606
New Hydro ROR	1,103	1,167	1,169	1,166	2,609	2,604	4,580	6,084	8,898	8,891	8,884	8,879	8,878	8,877	31,565
Oversupply	1,551	1,336	1,406	-	-	-	-	-	-	-	1,282	478	-	-	9,119
Net Imports	-454	-269	-459	437	-5,739	-7,397	-8,031	-9,978	-12,083	-12,151	-18,633	-17,140	-14,311	-9,211	-14,314
Unserved Demand	4,794	5,297	4,735	67	-	-	-	-	-	-	-	-	-	-	-
Rogun	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Demand	21,855	22,272	22,186	22,780	23,576	24,513	25,773	27,071	28,389	30,542	33,269	36,262	39,649	44,803	50,677

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 86: Central Asia annual shadow electricity price forecasts – NoRogun_Ref

CYs / USD/MWh	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Tajikistan	524.06	522.83	510.48	298.15	88.16	71.43	74.33	78.1	65.33	64.33	49.87	54.74	80.65	91.65	232.07
Uzbekistan	127.09	119.9	96.62	92.28	88.6	85.05	81.53	79.84	79.84	79.84	79.84	79.84	79.84	79.84	79.84
Turkmenistan	130.69	123.41	96.65	92.29	88.37	84.74	81.3	79.65	79.65	79.65	79.55	79.4	79.84	79.84	79.84
Kyrgyzstan	122.23	115.15	86.79	91.66	67.84	63.55	61.68	59.89	58.9	59.77	45.53	49.77	67.79	69.39	52.28
Pakistan	578.76	579.01	166.17	122.45	93.31	80.91	78.11	77.85	77.88	78.46	78.49	78.49	78.49	78.46	78.44
Afghanistan	109.25	104.32	97.24	92.79	88.8	85.09	81.58	79.89	79.89	79.89	79.89	79.89	79.89	79.89	79.89
Kazakhstan	82.2	81.97	80.52	79.67	78.97	78.33	77.69	77.36	77.36	77.36	77.36	77.36	77.36	77.36	77.36

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 87: Forecast annual net exports from Tajikistan – NoRogun_Ref

CYs / GWh	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Uzbekistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Kyrgyzstan	-	-	-	-6,646	-1,708	-3,018	-4,360	-4,040	-3,181	-2,892	-268	-1,376	-4,045	-9,481	-4,492
Pakistan	-	-	-	4,172	5,633	8,553	10,463	12,105	13,160	13,186	16,690	16,690	16,405	16,508	16,690
Afghanistan	454	269	459	1,704	1,712	1,711	1,711	1,711	1,945	1,712	2,160	1,711	1,711	1,711	1,775

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 88: Forecast annual average realised export prices – NoRogun_Ref

CYs / USD/MWh	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Uzbekistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Kyrgyzstan	-	-	-	-	52.91	-	-	-	-	-	4.54	4.54	49.47	-	4.54
Pakistan	-	-	-	133.29	105.16	99.18	93.58	90.75	88.47	73.74	72.92	72.92	73.15	73.61	73.63
Afghanistan	109.25	104.32	97.24	92.79	88.8	85.09	81.58	79.89	79.89	79.89	79.89	79.89	79.89	79.89	79.89

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Rogun 1290_3600 Reference Case

Table 89: Tajikistan forecast capacity expansion – Ro1290_3600_Ref

CYs / MW	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Steam Gas/Oil	318	198	198	-	-	-	-	-	-	-	-	-	-	-	-
Hydro DAM	2,584	2,584	2,626	2,626	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126
Hydro ROR	1,579	1,499	1,507	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594
New Coal / Lignite	-	-	100	450	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,270	1,270
New Hydro Dam	-	-	-	-	120	520	520	520	520	520	520	520	520	520	1,521
New Hydro ROR	220	234	235	235	235	235	235	235	235	235	235	336	1,085	1,127	1,545
Import Interconnector	-	-	-	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,198	1,792
Rogun	-	-	-	-	812	812	3,000	3,600	3,600	3,600	3,600	3,600	3,600	3,600	3,600
Total Installed	5,878	5,813	5,983	5,472	6,937	7,337	9,525	10,125	10,125	10,125	10,125	10,227	10,975	11,237	12,656
Total Dependable	4,642	4,700	4,786	4,349	4,951	5,482	8,294	8,885	8,893	8,885	8,982	9,027	9,352	9,559	10,643
Peak Demand	4,173	4,252	4,236	4,349	4,501	4,680	4,921	5,169	5,420	5,831	6,352	6,923	7,570	8,554	9,675

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 90: Tajikistan forecast New Build expansion – Ro1290_3600_Ref

CYs / MW	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Rogun HPP	-	-	-	-	812	812	3,000	3,600	3,600	3,600	3,600	3,600	3,600	3,600	3,600
Sangvor	-	-	-	-	-	400	400	400	400	400	400	400	400	400	400
Sanobod	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Shtien	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300
Urfatin	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nurabad-1	-	-	-	-	-	-	-	-	-	-	-	-	-	42	160
Nurabad-2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sangiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ayni	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Zarafshon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darg	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Shurob	-	-	-	-	-	-	-	-	-	-	-	101	850	850	850
Dupulin	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fandarya	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dashtijum	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,001
Obburdan	-	-	-	-	120	120	120	120	120	120	120	120	120	120	120
New Coal	-	-	-	350	950	950	950	950	950	950	950	950	950	1,170	1,170
New Hydro ROR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sangtuda 2	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
Firm New Hydro ROR	0	14	15	15	15	15	15	15	15	15	15	15	15	15	15
Dushanbe 2	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 91: Tajikistan forecast interconnector expansion – Ro1290_3600_Ref

MW / CYs		2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Import capacity	Uzbekistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Kyrgyzstan	-	-	-	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,198	1,792
	Pakistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Afghanistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Export capacity	Uzbekistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Kyrgyzstan	-	-	-	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,198	1,792
	Pakistan	-	-	-	1,000	1,350	2,050	2,750	2,974	2,974	2,974	2,974	2,974	2,974	2,974	2,974
	Afghanistan	110	110	110	410	410	410	410	410	410	410	410	410	410	410	410

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 92: Tajikistan forecast generation mix – Ro1290_3600_Ref

GWh / CYs	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Steam Gas/Oil	404	251	251	-	-	-	-	-	-	-	-	-	-	-	-
Hydro DAM	10,177	10,177	10,344	10,280	12,330	12,005	11,845	12,493	12,614	12,588	12,927	12,936	12,945	12,948	12,948
Hydro ROR	7,383	6,986	7,014	7,404	7,473	7,254	7,009	6,986	7,001	6,986	7,128	7,133	7,138	7,139	7,139
New Coal / Lignite	-	-	591	3,344	6,566	6,986	6,338	6,542	6,260	6,209	7,220	7,716	7,331	9,438	8,376
New Hydro Dam	-	-	-	-	516	2,824	2,824	2,824	2,824	2,824	2,824	2,824	2,824	2,824	6,774
New Hydro ROR	1,103	1,167	1,146	1,144	1,150	1,121	1,100	1,097	1,099	1,097	1,121	1,576	4,924	5,132	7,223
Oversupply	1,551	1,336	1,940	-	-	-	-	-	-	-	-	-	-	-	-
Net Imports	-454	-269	-359	245	-5,780	-9,429	-11,509	-12,457	-12,656	-12,094	-12,301	-10,266	-9,849	-7,003	-6,098
Unserved Demand	4,794	5,297	5,137	363	-	-	-	-	-	-	-	-	-	-	-
Rogun	-	-	-	-	1,320	3,753	8,166	9,588	11,247	12,933	14,351	14,344	14,336	14,326	14,314
Energy Demand	21,855	22,272	22,186	22,780	23,576	24,513	25,773	27,071	28,389	30,542	33,269	36,262	39,649	44,803	50,677

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 93: Central Asia annual shadow electricity price forecasts – Ro1290_3600_Ref

CYs / USD/MWh	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Tajikistan	524.06	522.83	521.07	309.89	131.96	66.61	65.11	63.51	64.33	63.09	63.51	66.98	68.38	81.61	93.79
Uzbekistan	127.09	119.9	96.62	92.26	88.61	85.05	81.53	79.84	79.84	79.84	79.84	79.84	79.84	79.84	79.84
Turkmenistan	130.69	123.41	96.65	92.29	88.37	84.74	81.3	79.65	79.65	79.65	79.55	79.4	79.84	79.84	79.84
Kyrgyzstan	122.23	115.15	86.79	91.79	67.65	62.37	60.81	58.96	58.71	58.96	59.19	61.46	63.49	67.79	68.01
Pakistan	578.76	579.01	166.14	122.45	93.31	80.91	78.11	77.85	77.88	78.46	78.49	78.49	78.48	78.45	78.43
Afghanistan	109.25	104.32	97.24	92.79	88.8	85.09	81.58	79.89	79.89	79.89	79.89	79.89	79.89	79.89	79.89
Kazakhstan	82.2	81.97	80.52	79.67	78.97	78.33	77.69	77.36	77.36	77.36	77.36	77.36	77.36	77.36	77.36

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 94: Forecast annual net exports from Tajikistan – Ro1290_3600_Ref

CYs / GWh	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Uzbekistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Kyrgyzstan	-	-	-	-6,285	-2,279	-1,543	-2,669	-2,563	-2,445	-2,422	-1,714	-3,821	-4,207	-7,017	-8,366
Pakistan	-	-	-	4,172	5,633	8,553	11,474	12,408	12,408	12,324	12,190	12,185	12,135	11,959	12,335
Afghanistan	454	269	359	1,553	2,295	2,318	2,571	2,484	2,571	2,068	1,739	1,711	1,711	1,711	1,711

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 95: Forecast annual average realised export prices – Ro1290_3600_Ref

CYs / USD/MWh	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Uzbekistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Kyrgyzstan	-	-	-	-	52.91	52.24	-	-	-	49.47	-	-	-	-	-
Pakistan	-	-	-	133.29	105.16	99.18	93.58	90.66	88.19	73.78	73.14	73.2	73.45	74.05	73.93
Afghanistan	109.25	104.32	97.24	92.79	88.80	85.09	81.58	79.89	79.89	79.89	79.89	79.89	79.89	79.89	79.89

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Rogun 1290_3200 Reference Case

Table 96: Tajikistan forecast capacity expansion – Ro1290_3200_Ref

CYs / MW	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Steam Gas/Oil	318	198	198	-	-	-	-	-	-	-	-	-	-	-	-
Hydro DAM	2,584	2,584	2,626	2,626	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126
Hydro ROR	1,579	1,499	1,507	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594
New Coal / Lignite	-	-	100	450	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,270	1,270
New Hydro Dam	-	-	-	-	120	520	520	520	520	520	520	520	520	686	1,921
New Hydro ROR	220	234	235	235	235	235	235	235	235	235	235	347	1,085	1,545	1,545
Import Interconnector	-	-	-	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,071	1,709
Rogun	-	-	-	-	812	812	2,667	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200
Total Installed	5,878	5,813	5,983	5,472	6,937	7,337	9,192	9,725	9,725	9,725	9,725	9,836	10,575	11,421	12,656
Total Dependable	4,642	4,700	4,786	4,349	4,951	5,482	7,961	8,485	8,493	8,485	8,583	8,632	8,953	9,409	10,643
Peak Demand	4,173	4,252	4,236	4,349	4,501	4,680	4,921	5,169	5,420	5,831	6,352	6,923	7,570	8,554	9,675

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 97: Tajikistan forecast New Build expansion – Ro1290_3200_Ref

CYs / MW	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Rogun HPP	-	-	-	-	812	812	2,667	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200
Sangvor	-	-	-	-	-	400	400	400	400	400	400	400	400	400	400
Sanobod	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Shtien	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
Urfatin	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nurabad-1	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
Nurabad-2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sangiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ayni	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Zarafshon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darg	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Shurob	-	-	-	-	-	-	-	-	-	-	-	111	850	850	850
Dupulin	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fandarya	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dashtijum	-	-	-	-	-	-	-	-	-	-	-	-	-	166	1,401
Obburdan	-	-	-	-	120	120	120	120	120	120	120	120	120	120	120
New Coal	-	-	-	350	950	950	950	950	950	950	950	950	950	1,170	1,170
New Hydro ROR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sangtuda 2	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
Firm New Hydro ROR	0	14	15	15	15	15	15	15	15	15	15	15	15	15	15
Dushanbe 2	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 98: Tajikistan forecast interconnector expansion – Ro1290_3200_Ref

MW \ CYs		2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Import capacity	**Uzbekistan**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Kyrgyzstan	-	-	-	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,071	1,709
	Pakistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Afghanistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Export capacity	**Uzbekistan**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Kyrgyzstan	-	-	-	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,071	1,709
	Pakistan	-	-	-	1,000	1,350	2,050	2,750	2,974	2,974	2,974	2,974	2,974	2,974	2,974	2,974
	Afghanistan	110	110	110	410	410	410	410	410	410	410	410	410	410	410	410

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 99: Tajikistan forecast generation mix – Ro1290_3200_Ref

GWh \ CYs	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Steam Gas/Oil	404	251	251	-	-	-	-	-	-	-	-	-	-	-	-
Hydro DAM	10,177	10,177	10,344	10,280	12,330	12,005	11,845	12,493	12,614	12,588	12,927	12,936	12,945	12,948	12,948
Hydro ROR	7,383	6,986	7,014	7,404	7,473	7,254	7,009	6,986	7,001	6,986	7,128	7,133	7,138	7,139	7,139
New Coal / Lignite	-	-	591	3,344	6,566	6,986	6,338	6,542	6,260	6,209	7,317	7,799	7,427	8,621	7,782
New Hydro Dam	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New Hydro ROR	1,103	1,167	1,146	1,144	1,150	1,121	1,100	1,097	1,099	1,097	1,121	1,122	1,122	1,123	1,123
Oversupply	1,551	1,336	1,940	-	-	-	-	-	-	-	-	-	-	-	-
Net Imports	-454	-269	-359	245	-5,780	-9,429	-11,509	-12,457	-12,656	-12,094	-12,290	-10,283	-9,838	-8,827	-6,976
Unserved Demand	4,794	5,297	5,137	363	-	-	-	-	-	-	-	-	-	-	-
Rogun	-	-	-	-	1,320	3,753	8,166	9,588	11,247	12,933	14,243	14,236	14,229	14,219	14,208
Energy Demand	21,855	22,272	22,186	22,780	23,576	24,513	25,773	27,071	28,389	30,542	33,269	36,262	39,649	44,803	50,677

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 100: Central Asia annual shadow electricity price forecasts – Ro1290_3200_Ref

CYs / USD/MWh	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Tajikistan	524.06	522.83	521.07	309.89	131.75	66.61	65.11	63.51	64.76	63.09	63.51	66.98	68.38	93.60	93.74
Uzbekistan	127.09	119.90	96.62	92.26	88.61	85.05	81.53	79.84	79.84	79.84	79.84	79.84	79.84	79.84	79.84
Turkmenistan	130.69	123.41	96.65	92.29	88.37	84.74	81.30	79.65	79.65	79.65	79.55	79.40	79.84	79.84	79.84
Kyrgyzstan	122.23	115.15	86.79	91.79	67.65	62.37	60.81	58.96	58.71	58.96	59.19	61.46	63.49	67.79	67.76
Pakistan	578.76	579.01	166.14	122.45	93.31	80.91	78.11	77.85	77.88	78.46	78.49	78.49	78.48	78.45	78.43
Afghanistan	109.25	104.32	97.24	92.79	88.80	85.09	81.58	79.89	79.89	79.89	79.89	79.89	79.89	79.89	79.89
Kazakhstan	82.20	81.97	80.52	79.67	78.97	78.33	77.69	77.36	77.36	77.36	77.36	77.36	77.36	77.36	77.36

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 101: Forecast annual net exports from Tajikistan – Ro1290_3200_Ref

CYs / GWh	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Uzbekistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Kyrgyzstan	0	0	0	-6,285	-2,279	-1,543	-2,669	-2,563	-2,445	-2,422	-1,726	-3,803	-4,219	-5,346	-7,442
Pakistan	0	0	0	4,172	5,633	8,553	11,474	12,408	12,408	12,324	12,190	12,185	12,135	12,196	12,335
Afghanistan	454	269	359	1,553	2,295	2,318	2,571	2,484	2,571	2,068	1,739	1,711	1,711	1,711	1,711

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 102: Forecast annual average realised export prices – Ro1290_3200_Ref

CYs / USD/MWh	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Uzbekistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Kyrgyzstan	-	-	-	-	52.91	52.24	-	-	-	49.47	-	-	-	-	-
Pakistan	-	-	-	133.29	105.16	99.18	93.58	90.66	88.19	73.78	73.14	73.20	73.45	73.72	73.93
Afghanistan	109.25	104.32	97.24	92.79	88.80	85.09	81.58	79.89	79.89	79.89	79.89	79.89	79.89	79.89	79.89

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Rogun 1255_3200 Reference Case

Table 103: Tajikistan forecast capacity expansion – Ro1255_3200_Ref

CYs / MW	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Steam Gas/Oil	318	198	198	-	-	-	-	-	-	-	-	-	-	-	-
Hydro DAM	2,584	2,584	2,626	2,626	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126
Hydro ROR	1,579	1,499	1,507	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594
New Coal / Lignite	-	-	100	450	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,270	1,270
New Hydro Dam	-	-	-	-	120	520	520	520	520	520	520	520	520	686	1,894
New Hydro ROR	220	234	235	235	235	235	235	235	235	235	235	609	1,147	1,545	1,681
Import Interconnector	-	-	-	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,301	1,919
Rogun	-	-	-	-	600	600	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200
Total Installed	5,878	5,813	5,983	5,472	6,725	7,125	9,725	9,725	9,725	9,725	9,725	10,100	10,638	11,421	12,766
Total Dependable	4,642	4,700	4,786	4,349	4,951	5,481	8,493	8,485	8,493	8,583	8,584	8,746	8,965	9,409	10,643
Peak Demand	4,173	4,252	4,236	4,349	4,501	4,680	4,921	5,169	5,420	5,831	6,352	6,923	7,570	8,554	9,675

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 104: Tajikistan forecast New Build expansion – Ro1255_3200_Ref

CYs / MW	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Rogun HPP	-	-	-	-	600	600	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200
Sangvor	-	-	-	-	-	400	400	400	400	400	400	400	400	400	400
Sanobod	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Shtien	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
Urfatin	-	-	-	-	-	-	-	-	-	-	-	-	-	-	137
Nurabad-1	-	-	-	-	-	-	-	-	-	-	-	-	63	160	160
Nurabad-2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sangiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ayni	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Zarafshon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darg	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Shurob	-	-	-	-	-	-	-	-	-	-	-	375	850	850	850
Dupulin	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fandarya	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dashtijum	-	-	-	-	-	-	-	-	-	-	-	-	-	166	1,374
Obburdan	-	-	-	-	120	120	120	120	120	120	120	120	120	120	120
New Coal	-	-	-	350	950	950	950	950	950	950	950	950	950	1,170	1,170
New Hydro ROR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sangtuda 2	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
Firm New Hydro ROR	0	14	15	15	15	15	15	15	15	15	15	15	15	15	15
Dushanbe 2	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 105: Tajikistan forecast interconnector expansion – Ro1255_3200_Ref

MW \ CYs		2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Import capacity	Uzbekistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Kyrgyzstan	-	-	-	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,301	1,919
	Pakistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Afghanistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Export capacity	Uzbekistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Kyrgyzstan	-	-	-	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,301	1,919
	Pakistan	-	-	-	1,000	1,350	2,050	2,750	2,777	2,777	2,777	2,777	2,777	2,777	2,777	2,777
	Afghanistan	110	110	110	410	410	410	410	410	410	410	410	410	410	410	410

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 106: Tajikistan forecast generation mix – Ro1255_3200_Ref

GWh \ CYs	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Steam Gas/Oil	404	251	251	-	-	-	-	-	-	-	-	-	-	-	-
Hydro DAM	10,177	10,177	10,344	10,281	12,318	12,183	11,836	12,501	12,614	12,936	12,943	12,948	12,947	12,947	12,947
Hydro ROR	7,383	6,986	7,014	7,403	7,466	7,373	7,001	6,986	7,001	7,133	7,137	7,139	7,139	7,139	7,139
New Coal / Lignite	-	-	591	3,344	6,684	6,912	6,807	6,407	6,209	6,868	7,462	7,556	7,463	8,791	7,722
New Hydro Dam	-	-	-	-	516	2,824	2,824	2,824	2,824	2,824	2,824	2,824	2,824	3,480	8,244
New Hydro ROR	1,103	1,167	1,146	1,141	1,151	1,140	1,099	1,097	1,099	1,122	1,122	2,798	5,234	7,223	7,904
Oversupply	1,551	1,336	1,940	-	-	-	-	-	-	-	-	-	-	-	-
Net Imports	-454	-269	-359	248	-5,652	-9,549	-11,149	-11,330	-12,060	-12,602	-10,455	-9,207	-8,115	-6,870	-5,308
Unserved Demand	**4,794**	**5,297**	**5,137**	**363**	-	-	-	-	-	-	-	-	-	-	-
Rogun	-	-	-	-	1,092	3,631	7,355	8,587	10,703	12,262	12,237	12,204	12,156	12,092	12,028
Energy Demand	21,855	22,272	22,186	22,780	23,576	24,513	25,773	27,071	28,389	30,542	33,269	36,262	39,649	44,803	50,677

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 107: Central Asia annual shadow electricity price forecasts – Ro1255_3200_Ref

CYs / USD/MWh	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Tajikistan	524.06	522.83	521.07	309.89	130.3	66.61	65.7	64.65	62.83	61.52	64.45	67.25	73.78	93.6	99.01
Uzbekistan	127.09	119.9	96.62	92.26	88.61	85.05	81.53	79.84	79.84	79.84	79.84	79.84	79.84	79.84	79.84
Turkmenistan	130.69	123.41	96.65	92.29	88.37	84.74	81.3	79.65	79.65	79.65	79.55	79.4	79.84	79.84	79.84
Kyrgyzstan	122.23	115.15	86.79	91.79	67.65	62.37	61.37	59.61	58.71	58.88	59.83	62.44	67.79	67.79	72.23
Pakistan	578.76	579.01	166.18	122.45	93.31	80.91	78.11	77.85	77.88	78.46	78.49	78.49	78.47	78.45	78.43
Afghanistan	109.25	104.32	97.24	92.79	88.8	85.09	81.58	79.89	79.89	79.89	79.89	79.89	79.89	79.89	79.89
Kazakhstan	82.2	81.97	80.52	79.67	78.97	78.33	77.69	77.36	77.36	77.36	77.36	77.36	77.36	77.36	77.36

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 108: Forecast annual net exports from Tajikistan – Ro1255_3200_Ref

GWh \ CYs	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Uzbekistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Kyrgyzstan	-	-	-	-6,285	-2,279	-1,518	-2,968	-2,793	-2,219	-1,508	-2,777	-4,088	-5,195	-6,559	-8,340
Pakistan	-	-	-	4,172	5,633	8,553	11,474	11,589	11,589	11,514	11,383	11,380	11,339	11,390	11,520
Afghanistan	454	269	359	1,550	2,166	2,415	2,494	2,395	2,571	2,521	1,711	1,711	1,711	1,711	1,711

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 109: Forecast annual average realised export prices – Ro1255_3200_Ref

USD/MWh \ CYs	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Uzbekistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Kyrgyzstan	-	-	-	-	52.91	52.24	-	-	49.47	-	-	-	-	-	-
Pakistan	-	-	-	133.29	105.16	99.18	93.58	90.68	88.36	73.77	73.2	73.21	73.55	73.72	73.93
Afghanistan	109.25	104.32	97.24	92.79	88.8	85.09	81.58	79.89	79.89	79.89	79.89	79.89	79.89	79.89	79.89

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Rogun 1220_2800 Reference Case

Table 110: Tajikistan forecast capacity expansion – Ro1220_2800_Ref

CYs / MW	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Steam Gas/Oil	318	198	198	-	-	-	-	-	-	-	-	-	-	-	-
Hydro DAM	2,584	2,584	2,626	2,626	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126
Hydro ROR	1,579	1,499	1,507	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594	1,594
New Coal / Lignite	-	-	100	450	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,270	1,270	1,270
New Hydro Dam	-	-	-	-	120	520	520	520	520	520	520	520	520	1,121	2,356
New Hydro ROR	220	234	235	235	235	235	235	235	235	385	716	1,140	1,167	1,371	1,371
Import Interconnector	-	-	-	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,102	1,767	2,462
Rogun	-	-	-	-	-	1,401	2,800	2,800	2,800	2,800	2,800	2,800	2,800	2,800	2,800
Total Installed	5,878	5,813	5,983	5,472	6,131	7,932	9,331	9,331	9,331	9,481	9,812	10,236	10,477	11,282	12,517
Total Dependable	4,642	4,700	4,786	4,349	4,951	6,704	8,099	8,190	8,190	8,255	8,399	8,569	8,768	9,409	10,643
Peak Demand	4,173	4,252	4,236	4,349	4,501	4,680	4,921	5,169	5,420	5,831	6,352	6,923	7,570	8,554	9,675

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 111: Tajikistan forecast New Build expansion – Ro1220_2800_Ref

CYs / MW	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Rogun HPP	-	-	-	-	-	1,401	2,800	2,800	2,800	2,800	2,800	2,800	2,800	2,800	2,800
Sangvor	-	-	-	-	-	400	400	400	400	400	400	400	400	400	400
Sanobod	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Shtien	-	-	-	-	-	-	-	-	-	-	-	-	-	126	126
Urfatin	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nurabad-1	-	-	-	-	-	-	-	-	-	-	-	55	82	160	160
Nurabad-2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sangiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ayni	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Zarafshon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darg	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Shurob	-	-	-	-	-	-	-	-	-	150	481	850	850	850	850
Dupulin	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fandarya	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dashtijum	-	-	-	-	-	-	-	-	-	-	-	-	-	601	1,836
Obburdan	-	-	-	-	120	120	120	120	120	120	120	120	120	120	120
New Coal	-	-	-	350	956	956	956	956	956	956	956	956	1,170	1,170	1,170
New Hydro ROR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sangtuda 2	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
Firm New Hydro ROR	0	14	15	15	15	15	15	15	15	15	15	15	15	15	15
Dushanbe 2	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 112: Tajikistan forecast interconnector expansion – Ro1220_2800_Ref

MW / CYs		2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Import capacity	Uzbekistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Kyrgyzstan	-	-	-	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,102	1,767	2,462
	Pakistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Afghanistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Export capacity	Uzbekistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Kyrgyzstan	-	-	-	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,102	1,767	2,462
	Pakistan	-	-	-	1,000	1,350	2,050	2,750	2,750	2,750	2,750	2,750	2,750	2,750	2,750	2,750
	Afghanistan	110	110	110	410	410	410	410	410	410	410	410	410	410	410	410

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 113: Tajikistan forecast generation mix – Ro1220_2800_Ref

GWh / CYs	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Steam Gas/Oil	404	251	251	-	-	-	-	-	-	-	-	-	-	-	-
Hydro DAM	10,177	10,177	10,344	10,335	12,050	12,095	12,559	12,786	12,735	12,657	12,579	12,503	12,429	12,332	12,247
Hydro ROR	7,383	6,986	7,014	7,438	7,296	7,093	7,001	7,140	7,140	7,140	7,140	7,140	7,140	7,141	7,141
New Coal / Lignite	-	-	591	3,344	7,448	6,580	6,243	6,607	6,837	6,996	7,010	6,920	8,805	8,385	7,510
New Hydro Dam	-	-	-	-	516	2,824	2,824	2,824	2,824	2,824	2,824	2,824	2,824	5,195	10,068
New Hydro ROR	1,103	1,167	1,146	1,145	1,126	1,109	1,099	1,123	1,123	1,796	3,276	5,198	5,330	6,349	6,349
Oversupply	1,551	1,336	1,940	-	-	-	-	-	-	-	-	-	-	-	-
Net Imports	-454	-269	-359	154	-4,860	-10,074	-12,599	-13,292	-12,216	-10,912	-9,697	-8,555	-7,205	-5,049	-3,245
Unserved Demand	4,794	5,297	5,137	363	-	-	-	-	-	-	-	-	-	-	-
Rogun	-	-	-	-	-	4,886	8,646	9,884	9,947	10,042	10,137	10,232	10,325	10,450	10,608
Energy Demand	21,855	22,272	22,186	22,780	23,576	24,513	25,773	27,071	28,389	30,542	33,269	36,262	39,649	44,803	50,677

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 114: Central Asia annual shadow electricity price forecasts – Ro1220_2800_Ref

USD/MWh \ CYs	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Tajikistan	524.06	522.83	521.07	309.86	135.52	65.53	59.1	57.38	60.17	66.42	66.62	72.1	81.17	93.64	99.18
Uzbekistan	127.09	119.9	96.62	92.27	88.6	85.05	81.53	79.84	79.84	79.84	79.84	79.84	79.84	79.84	79.84
Turkmenistan	130.69	123.41	96.65	92.29	88.37	84.74	81.3	79.65	79.65	79.65	79.55	79.4	79.84	79.84	79.84
Kyrgyzstan	122.23	115.15	86.79	91.76	67.85	61.34	58.61	58.5	57.55	58.96	59.83	63.67	67.79	67.79	72.97
Pakistan	578.76	579.01	166.19	122.45	93.31	80.91	78.11	77.85	77.88	78.46	78.49	78.49	78.47	78.45	78.43
Afghanistan	109.25	104.32	97.24	92.79	88.8	85.09	81.58	79.89	79.89	79.89	79.89	79.89	79.89	79.89	79.89
Kazakhstan	82.2	81.97	80.52	79.67	78.97	78.33	77.69	77.36	77.36	77.36	77.36	77.36	77.36	77.36	77.36

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 115: Forecast annual net exports from Tajikistan – Ro1220_2800_Ref

CYs / GWh	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Uzbekistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Kyrgyzstan	-	-	-	-6,203	-2,632	-1,130	-1,540	-1,504	-2,167	-2,553	-3,456	-4,656	-6,036	-8,358	-10,394
Pakistan	-	-	-	4,172	5,633	8,553	11,474	11,474	11,474	11,400	11,270	11,267	11,228	11,278	11,406
Afghanistan	454	269	359	1,567	1,711	2,571	2,571	3,238	2,801	1,938	1,711	1,711	1,711	1,711	1,711

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.

Table 116: Forecast annual average realised export prices – Ro1220_2800_Ref

CYs / USD/MWh	2013	2014-15	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-32	2033-35	2036-38	2039-42	2043-46	2047-50
Uzbekistan	-	-	-	-	52.91	52.24	55.39	63.74	-	-	-	-	-	-	42.17
Kyrgyzstan	-	-	-	133.29	105.16	99.18	93.58	90.68	88.36	73.84	73.2	73.2	73.48	73.72	73.93
Pakistan	109.25	104.32	97.24	92.79	88.8	85.09	81.58	79.89	79.89	79.89	79.89	79.89	79.89	79.89	79.89
Afghanistan	-	-	-	-	52.91	52.24	55.39	63.74	-	-	-	-	-	-	42.17

Note: The figures shown apply in each of the respective years indicated.

Source: IPA analysis.