PD 0011 – TJK
May 31, 2017

PROJECT DOCUMENT

OF

THE ASIAN INFRASTRUCTURE INVESTMENT BANK

Republic of Tajikistan

Nurek Hydropower Rehabilitation Project
Phase I

CURRENCY EQUIVALENTS
(As of March 30, 2017)

Currency Unit	=	Tajikistan Somoni (diram)
TJS1.00	=	US$0.113382
US$1.00	=	TJS8.81978

FISCAL YEAR
January 1 – December 31

ABBREVIATIONS AND ACRONYMS

ACF	Average Capacity Factor
ADB	Asian Development Bank
AIIB	Asian Infrastructure Investment Bank
BoP	Balance of Plant
BT	Barki Tojik, National Power Company
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
EBRD	European Bank for Reconstruction and Development
EaDB	Eurasian Development Bank
EBITDA	Earnings Before Interest, Tax, Depreciation and Amortization
EIRR	Economic Internal Rate of Return
EPC	Engineering, Procurement, and Construction
EPP	Emergency Preparedness Plan
FIRR	Financial Internal Rate of Return
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GWh	Gigawatt-hour
HPP	Hydropower Plant
IDA	International Development Association
IFI	International Financial Institution
IFRS	International Financial Reporting Standards
IMF	International Monetary Fund
kV	Kilovolt
kWh	Kilowatt-hour
LC	Letter of Credit
MEWR	Ministry of Energy and Water Resources
MIV	Main Inlet Valve
MOEDT	Ministry of Economic Development and Trade
MOJ	Ministry of Justice
MOF	Ministry of Finance
MW	Megawatt
NPV	Net Present Value
OM	Operational Manual
O&M	Operation and Maintenance
OP	Operational Policy
PDSI	Plant Design, Supply and Installation
PMC	Project Management Consultant
PoE	Panel of Experts
PPA	Power Purchase Agreement
PRG	Project Realization Group
SCADA	Supervisory Control and Data Acquisition
TALCO	Tajik Aluminum Company
tCO_2e	Carbon Dioxide Equivalents (tonnes)
UNFCCC	UN Framework Convention on Climate Change
WB	World Bank

CONTENTS OF THE PROJECT DOCUMENT

1. PROJECT SUMMARY SHEET

Tajikistan
Nurek Hydropower Rehabilitation Project Phase I

Project No.	000018
Borrower(s) Implementation Agency	Republic of Tajikistan Barki Tojik (BT), Open Joint Stock Holding Company "Barki Tojik"
Sector(s) Subsector(s)	Energy/Water Hydropower
Project Objectives / Brief Project Description	The objectives of the Project are to rehabilitate and restore the generating capacity of three units of the Nurek hydropower plant, improve their efficiency, and strengthen the safety of the Nurek dam. Component 1: Power Plant Rehabilitation Component 2: Dam Safety Component 3: Technical Assistance
Project Implementation Period (Start Date and End Date)	Start Date: June 1, 2017 End Date: June 30, 2023
Expected Loan Closing Date	December 31, 2023
Project cost and Financing Plan	Total Project Cost (Phase I): US$350 million Financing plan: IDA US$225.7 million AIIB US$60 million (joint co-financing) EaDB US$40 million (parallel co-financing) Financing gap: US$24.3 million
AIIB Loan (Size and Terms)	US$60 million; 25-year term, including a 5-year grace period
Co-financing (If any) (Co-financier(s), Size and Terms)	IDA Scale-Up Facility – US$100 million (21-year term, 9-year grace period) IDA concessional credit – US$69.135 million (32-year term, 5-year grace period) IDA grant – US$56.565 million equivalent EaDB Loan – US$40 million, parallel financing
Environmental and Social Category	B
Project Risk (Low/Medium/High)	High
Conditions for Effectiveness and Disbursement (if any)	(i) The Subsidiary Agreement has been executed on behalf of the Borrower and the Project Implementing Entity; (ii) There is cross-effectiveness with the IDA loan agreement; and (iii) The Project Operational Manual has been adopted by the Project Implementing Entity. The Effectiveness Deadline is the date 180 days after the date of the Loan Agreement.

Key Covenants	• Average Electricity Tariff Increase: The Recipient shall gradually increase the average electricity tariff annually during the Project implementation period to reach cost-recovery tariff level by December 31, 2021. • Long-term Debt of BT: Except as the Bank and the Co-financier shall otherwise agree, not to incur any long-term debt unless a reasonable forecast of its revenues and expenditures shows that its estimated net revenues for each fiscal year during the term of the debt to be incurred shall be equal to at least the estimated long-term debt service requirements in such year on all debt of the Project Implementing Entity, including the debt to be incurred. • Short-term Debt of BT: Except as the Bank and the Co-financier shall otherwise agree, maintain the ratio of its operating cash flows to short-term debt service requirement at a level not less than 0.08 for the Borrower's fiscal year 2017; 0.15 for fiscal year 2018; 0.20 for fiscal year 2019; 0.25 for fiscal year 2020; 0.31 for fiscal year 2021; and 0.52 for fiscal year 2022.
Policy Assurance	The Vice President, Policy and Strategy, confirms an overall assurance that the Bank is in compliance with the policies applicable to the Project.

President	Liqun Jin
Vice-President	D.J. Pandian
Director General, Operations	Supee Teravaninthorn
Manager, Operations	Ke Fang
Project Team Leader	Carmen de Castro, Operations Investment Specialist
Project Team Members	Baihui Sun, Assistant Chuanzhi Su, Senior Operations Investment Specialist Chongwu Sun, Senior Environment Specialist Henry Pitney, Senior Legal Consultant Ian Nightingale, Procurement Advisor Kishor Uprety, Senior Counsel Somnath Basu, Senior Social Development Specialist Yige Zhang, Assistant

2. STRATEGIC CONTEXT

A. Country Context

1. Tajikistan is located in southeast Central Asia and borders Uzbekistan to the west, Kyrgyz Republic to the north, China to the east and Afghanistan to the south. It is a landlocked country; 93% of its surface area is mountainous and 6% of the mountains are covered by glaciers. Endowed with abundant water resources, Tajikistan's hydropower potential, including for export, is substantial. With a population of 8.5 million and a Gross National Income per capita of US$1,240 in 2015, Tajikistan is one of the poorest countries in Central Asia. Following the end of the civil war in 1997, the economy grew strongly for 17 years, at 7.5% on average per year, driven by a rapid increase in remittances from Tajik migrant workers and a subsequent expansion of services, public investments, and construction. In 2015, real Gross Domestic Product (GDP) growth slowed to 6% from 6.7% due to weak global prices for key export commodities, and marginal expansion of the services and agriculture sectors. In 2016, economic growth recovered to 6.9%, supported by an increase in foreign-financed investments, mainly from China.

2. The recent global economic downturn affected Tajikistan negatively. Workers' remittances, the major source of foreign exchange income, dropped by over 50% (year-on-year) in US dollar terms through 2014–2016 and the currency depreciated by 11.2% in 2016. This translated into lower incomes for the population and subsequently, in lower domestic demand and slower economic growth. In the banking sector, the share of nonperforming loans increased dramatically and several systemic banks failed to meet obligations starting in the first half of 2016. The Government decided to bail out two of the largest banks for a total of about 6.0% of GDP in late 2016, while licenses for two smaller banks were revoked in early 2017.

3. Looking ahead, the Government of Tajikistan has set ambitious goals for 2020, including reducing poverty to 20% from 31% in 2015, expanding the middle class and doubling the GDP per capita by 2030. Such goals will be difficult to achieve given the country's weakening economic situation. The continued reduction in labor migration coupled with the expected return of many migrants, will increase the number of job seekers, putting additional pressure on local labor markets, poorer households in Tajikistan, and the country's social protection measures.

B. Sectoral and Institutional Context

4. The power sector is comprised of the vertically integrated energy company, Barki Tojik (BT), two independent power producers (IPPs), the Rogun Joint Stock Company, and a concession combining power generation and distribution. BT owns and operates most of the electricity generating plants and is also responsible for electricity transmission, dispatch, and distribution services. The two IPPs (Sangtuda-1 and Sangtuda-2 hydropower plants (HPPs)) were constructed with foreign direct investments from Russia and Iran, and supply electricity to BT under a 20-year Power Purchase Agreement (PPA) for Sangtuda 1 and a 12.5-year PPA for Sangtuda-2. The Government has started construction of the Rogun HPP through the incorporated Rogun Joint Stock Company, which is legally independent from BT. The Pamir Energy Company generates and supplies electricity to

around 30,000 consumers in the Gorno Badakhshan Autonomous Oblast, which is in the south-eastern part of the country.

5. The Government plans to complete the functional unbundling of generation, transmission, and distribution services by the end of 2017 and the legal separation of those entities by the end of 2018. BT has good technical skills among its staff but suffers from weak operational and financial management systems and a worsening financial position. This severely impacts on its ability to undertake its critical functions of planning, implementing, and supplying good quality and reliable power to the consumers of Tajikistan.

6. Tajikistan has an abundance of hydropower resources. The total installed capacity is 5,400MW and HPPs generate 95% of all electricity in the country. The Nurek HPP, with a seasonal reservoir, is the largest generating plant. With installed capacity of 3,000MW, it generates 70% of the total annual energy requirement and is also the balancing plant in the system.

Table 1: Large HPPs in Tajikistan

Plant	Installed Capacity (MW)
Nurek	3000
Sangtuda-1	670
Baipasinskaya	600
Golovnaya	240
Sangtuda-2	220
Kairakum	126

7. It is estimated that the effective available capacity of power generation facilities in Tajikistan as of 2012 was about 2,306 MW. The World Bank (WB) estimates that about 60% of HPPs need to be rehabilitated by 2020 and 80% of assets by 2030. Without this rehabilitation, the available capacity could drop from 2,100 MW to 760 MW by 2030.

8. Nurek is operating at 77% of installed capacity. One of the units is off-line due to a major failure of the transformer and the remaining units cannot operate at rated capacity due to dilapidation of key equipment and infrastructural components of the plant.

9. HPP power generation is very dependent on water flows in the country's major rivers, which decline sharply in cold winter months when water flow is low. On the other hand, the Tajik power system generates excess power in summer because of high water flows and while some power is exported to Afghanistan and the Kyrgyz Republic, water is frequently spilled from reservoirs.

10. The power system is interconnected with the neighboring countries, but there is limited electricity trade despite significant potential. Following independence in 1991, Tajikistan continued to be a member of the integrated Central Asia Power System, through which the five Central Asian countries optimized use of the fossil fuel and hydropower resources that are unevenly distributed among those countries. Tajikistan and the Kyrgyz Republic, as the upstream countries of the Amu Darya and Syr Darya river basins, have significant hydropower potential, whereas thermal resources are concentrated in the downstream countries of Uzbekistan, Turkmenistan and Kazakhstan. The coordinated

system operated successfully in the initial years of independence. However, differences in national priorities soon put pressure on these arrangements and some of the countries, including Tajikistan, desynchronized their systems. Parts of the transmission interconnections were dismantled.

11. Access to electricity is nearly universal in Tajikistan and electricity tariffs have been historically low as they were initially designed during the Soviet era when individual utilities did not have to be financially viable business units. Large cities have district heating systems. However, due to lack of maintenance and fuel, these systems are dysfunctional. The use of inefficient and polluting solid fuel stoves for heating and cooking is common and the World Health Organization lists Tajikistan among the 20 worst affected countries for diseases that result from indoor air pollution. The household use of solid fuels disproportionately affects women and children who collect the fuel, spend many hours each day near the stove, and are more susceptible to respiratory diseases.

12. The Ministry of Energy and Water Resources (MEWR) is responsible for policy-making in the power sector. The Anti-Monopoly Commission, under the Government, is responsible for review and approval of tariffs for all natural monopolies, including electricity tariffs.

13. The National Development Strategy for 2016–2030 prioritizes energy sector development as one of the strategic goals, which focuses on providing reliable, adequate, and affordable electricity in a socially, economically, and environmentally sustainable manner. The strategy aims to: (i) provide access to energy for all; (ii) maximize energy savings through efficient use of energy; (iii) improve sector performance by commercializing utility operations; (iv) attract private investments in the sector; (v) increase electricity exports; and (vi) undertake power sector reforms, including strengthening of the capacity and governance of the sector companies.

Power Sector Challenges

14. **Challenge #1: Winter electricity shortages.** Approximately 70% of the population suffers from extensive shortages of electricity during the winter. These shortages were estimated at about 2,700 GWh or 25% of winter demand in 2013.[1] The economic losses from those shortages were estimated at US$200 million or 3% of GDP. The electricity shortages are due to the lack of reliable generation capacity in winter and dilapidation of the Nurek HPP.

15. **Challenge #2: Financial distress.** The power sector is in financial distress due to tariffs lagging behind the cost-recovery level and to sub-optimal financial management of BT. The weighted average tariff is estimated to be 55% below the cost-recovery level (computed following the cash needs approach). Between 2012 and 2014, the Government increased the end-user tariffs by 46% in nominal terms. However, the tariff increases were not sufficient to allow BT to recover its cash costs, which have significantly increased due to inflation and increasing debt service needs. Over the period from 2012 to 2015, the cumulative inflation was 24.6% and the local currency depreciated by 47%, which

[1] Tajikistan's Winter Energy Crisis: Electricity Supply and Demand Alternatives, WB, 2012

exacerbated cash shortages given the need to service debt denominated primarily in US$. BT has not been able to pay in full for energy purchased from the IPPs, service its debts or finance the required capital repairs and maintenance. BT's total debt, including short-term, increased from US$450 million in 2012 to US$950 million in 2015. In addition, BT's management of receivables and inventory is inefficient, which results in a significant amount of cash being tied up for extended periods of time.

16. **Challenge #3: Gaps in BT's billing, accounting and financial reporting.** There is no unified billing system in place. There are donor-financed ongoing initiatives in regional distribution companies of BT. However, those systems will ultimately need to be integrated and rolled out to cover all consumers and regions. BT's existing system does not provide end-to-end data integrity, and its reliance on manual entry of all customer and consumption data at various dispersed entry points significantly increases the risk of error, manipulation and fraud in the critical metering and billing cycle.

17. **Challenge #4: Increasingly unaffordable electricity tariffs and inadequate social protection of vulnerable consumers.** The energy expenditure burden is high for the poorest parts of the population, especially in rural areas. This suggests that a large share of rural households cannot afford even a basic level of energy consumption. As of 2014, the bottom two quintiles of rural households were estimated to spend, respectively, 24% and 19% of their disposable income on energy during the winter heating season. This is substantially above the 10% benchmark, which is often used to define "energy poverty".

Measures Undertaken by Government to Address Existing Challenges

18. **Reduction of winter electricity deficit.** The Government has undertaken the following key steps to address the issue of winter electricity deficit:

- In 2014, BT completed the 100MW Phase I of the new Dushanbe-2 Combined Heat and Power (CHP) plant. The CHP's 300MW Phase II started operation in December 2016. This will increase winter supply by a total of 1,180GWh, which is 12% of total winter demand.
- The Government began construction of the 3,600MW Rogun HPP. The first two units are expected to start generating electricity in late 2018. This will increase winter supply by 612GWh, which is 6% of total winter demand.
- BT is also currently rehabilitating the Golovnaya and Kairakum HPPs, with support from the Asian Development Bank (ADB) and European Bank for Reconstruction and Development (EBRD), respectively.
- BT is also planning to rehabilitate the Nurek HPP to avoid loss of generation.

19. **Improvement of financial standing of BT.** During the last six months, BT and the Government, with the support of development partners, including the WB, EBRD and ADB, have been implementing a set of Key Short-term Measures to Improve Financial Condition of BT (Annex 5). The following measures (among others) have already been undertaken:

- MEWR prepared a Concept for New Electricity Tariff Policy to be approved in 2017.
- The Government increased the average electricity tariff by approximately 13% starting from November 1, 2016.
- BT will not be required to pay penalties on accumulated overdue tax payments to the Ministry of Finance (MOF).
- BT has taken steps to act on mutual settlement of debts with the Agency on Land Reclamation and Irrigation.
- BT's payable to Sangtuda-1 HPP was reduced by TJS12.5 million (President's Decree No. 42, dated January 25, 2017) in exchange for a reduction in the accrued tax liabilities of Sangtuda-1 IPP to the state budget.
- BT completed functional unbundling.
- The average collection rate for billed electricity increased to 83% in 2015. The number of days that receivables were outstanding was reduced to 91 days in 2015.

20. **Improvement of reliability of electricity supply.** BT has recently implemented a number of projects to improve the reliability of electricity supply in the country through the construction of new transmission lines (North-South 500kV transmission interconnection) and substations and the rehabilitation of existing obsolete and unreliable transmission and distribution infrastructure, such as the Ravshan and Regar substations, which are the backbone of the power transmission network.

21. **Reduction of electricity losses and improvement of billing.** There were 215,000 new meters installed for the Dushanbe Electricity Network,[2] which has the largest number of consumers in the country, reducing the unaccounted consumption of electricity in the city of Dushanbe from 19% in 2011 to 17.5% in 2014. BT is implementing a number of projects to introduce commercial billing systems.

22. **Elimination of gaps in accounting and financial management.** With support from ADB and EBRD technical assistance projects, BT strengthened its accounting capacity, introduced International Accounting Standards, improved financial management systems, and is planning to further strengthen corporate governance.

23. **BT has made significant progress since 2010 in strengthening its accounting and financial reporting functions.** The auditors of BT's 2014 and 2015 annual financial statements were able to express an opinion. It was a qualified opinion primarily due to the absence of appropriate procedures for recognition of revenues, accounts receivable and advances received for the electricity supply. However, the qualified audit opinion is a tangible achievement, given that auditors of annual financial statements for previous years issued only disclaimers.

24. **Social protection of vulnerable consumers.** The Ministry of Health and Social Policy and the MOF are working to develop social mitigation measures for tariff increases.

[2] WB financed Energy Loss Reduction Project

The WB is providing advisory and analytical support to the Government to further improve the coverage and targeting of existing benefit programs to deliver the subsidies. Additionally, the WB intends to provide support to review alternative mechanisms for protection of the poor such as lifeline subsidies.

25. The Working Group of the Development Coordination Council[3] is a coordination platform which enables all development partners of the Government to better coordinate their efforts in helping the Government address the power sector challenges.

3. THE PROJECT

A. Rationale

26. The Project is in line with the Bank's draft Energy Sector Strategy, which proposes to actively support upgrading of generation capacity and rehabilitation of existing hydropower infrastructure to improve efficiency, dam safety and reliability of the electricity supply.

27. The Nurek HPP remains the key power generation facility of the country, providing more than 70% of the total generation in Tajikistan. The technical soundness of this engineering achievement, constructed 40 years ago, has been confirmed by international technical experts. Due to ageing and lack of maintenance, however, its energy generation capacity will continue to drop and will collapse completely unless urgent pre-emptive actions are taken, such as proposed under this Project.

28. WB's International Development Association (IDA) credit concession offers the Bank the opportunity to play an important role in such a top priority project for the country. The Project will benefit from the value-added of the Bank's involvement, encouraging the Government to resolve the financial health of the implementation agency.

29. The inability of Nurek to maintain the current levels of generation would lead to an increase in the cost of electricity supply for all consumers because it would need to be replaced by a new thermal power plant with higher electricity costs. The cost of generation from the Nurek HPP is negligible, given that it requires no fuel or other large operational expenses. Rehabilitation of the plant will increase the cost of electricity by only U$0.005/kWh. This is substantially below the cost of electricity from a new gas-fired thermal power plant, which is estimated at US$0.089/kWh (see Annex 3).

30. As green infrastructure, the Project will reduce Tajikistan's overall Greenhouse Gas (GHG) emissions and contribute to Tajikistan's international commitment under the United Nations Framework Convention on Climate Change (UNFCCC, ratified in 1992) and its Kyoto Protocol (ratified in 2008). The Project will lead to 29 million tCO_2e reduction in

[3] ADB, Aga Khan Development Network, European Union, EBRD, European Investment Bank, Islamic Development Bank, KfW Development Bank, United Nations Development Programme, United States Agency for International Development, and WB.

emissions[4] (after rehabilitation of 3 generating units) and 68 million tCO_2e reduction in emissions (after rehabilitation of 9 generating units). The installation of a new thermal plant would increase GHG emissions.

31. **Impact of climate change.** The Project will improve dam safety and flood prevention. Tajikistan is the country in Central Asia most vulnerable to the impacts of climate change. As detailed in Tajikistan's Second National Communication to the UNFCCC, the country's HPPs are highly vulnerable to the projected impacts of climate change as they depend upon river basins fed by glacial and snow melt. Many climate models predict significant changes in the dynamics of Tajik glaciers, snow melt, and precipitation as the climate warms. The International Commission on Large Dams (ICOLD) has already emphasized the urgent need to adapt older dams to cope with the new climate conditions. This improvement of Nurek's flood handling capacity will help both Tajikistan and the downstream countries to cope with the higher expected incidence of flooding in the future.

32. The rehabilitation of the Nurek HPP will ensure that Tajikistan is capable of expanding its electricity exports to the Kyrgyz Republic, Afghanistan and Pakistan, and the country will benefit from the increase of summer export revenues.

B. Objective

33. The Project objectives are to rehabilitate and restore the generating capacity of three power generating units of the Nurek HPP, improve their efficiency, and strengthen the safety of the Nurek dam.

Project Beneficiaries

34. The beneficiaries of the Project are all electricity consumers in the country and BT.

35. **Electricity consumers.** The project will contribute to the ongoing efforts of the Government in ensuring adequate and reliable electricity supply. In particular, the project will preclude loss of electricity supply from Nurek HPP, which accounts for 70 percent of winter generation during the time period of October-March when demand is the highest. Thus, the entire 8.5 million population of the country (including 4.2 million females) will benefit from the project. Moreover, 53,680 legal entities connected to the electricity network will also benefit because the project will help to meet their demand in a reliable manner.

36. **BT.** Rehabilitation of Nurek will allow BT to reduce revenue loss due to equipment failures caused by dilapidation and obsolescence. Those equipment failures lead to electricity under-supply from the power plant, which creates financial loss for BT. In case of disconnection of Nurek HPP from the power supply network due to failure of equipment or infrastructural components, the power plant does not supply electricity until the technical issues are fixed.

[4] The CO_2 emission reduction benefits from the Project were evaluated by the WB following the WB's Guidance Note on Greenhouse Gas Accounting for Energy Investment Operations (June 2013).

Results Indicators

37. The key outcome indicators include:

- **Indicator One:** Generation capacity of energy constructed or rehabilitated under the Project (MW). This indicator measures the capacity of hydropower constructed or rehabilitated under the Project.
- **Indicator Two:** Estimated annual electricity generation of three units included in the scope of the Project (GWh). This indicator measures the amount of electricity supplied by the rehabilitated units of the Nurek HPP to the power transmission network.
- **Indicator Three:** Estimated increase of winter electricity generation of rehabilitated units due to efficiency improvements (GWh). This indicator measures the increase in winter generation of rehabilitated units during the time period of October-March due to minimum weighted average efficiency increase of 2%.
- **Indicator Four:** Improved dam safety against hydrological and geological risks (Yes/No). This indicator measures the improvement of dam safety as a result of introduction of an advanced flood forecasting system and reservoir management rules; rehabilitation of the spillway tunnels, gates and hoisting system; and works to make both sides of the concrete gallery of the dam impermeable.
- **Indicator Five:** People provided with improved electricity service (Number). The indicator measures the number of people that have received improved electricity service due to the Project.

C. Project Description and Components

38. Given the significant cost of the total rehabilitation requirements and limited initial financing that would likely be available for the Project, the Project will be implemented in two phases.

39. The components of the first phase (Phase I) are as follows (see Annex 2 for more detail):

- **Component 1: Rehabilitation of the three generating units, the key infrastructural components of the plant and replacement of auto-transformers (US$310 million).**
    - Sub-component 1.1: Replacement and refurbishment of mechanical, electrical, and electromechanical equipment and civil works:
        - (a) Rehabilitation of 3 power generating units (generators, turbines, main inlet valves, transformers), auxiliary systems and key balance of plant (BoP); and
        - (b) Providing spare parts, and operation and maintenance (O&M) equipment.
    - Sub-component 1.2: Replacement of six auto-transformers.
- **Component 2: Enhancement of Dam Safety (US$30 million).** This component will finance activities to improve operational safety of the Nurek HPP:

(a) Rehabilitation of spillway tunnels;
(b) Measures to enhance safety against seismic hazards;
(c) Introduction of an advanced flood forecasting/warning system and preparing optimized reservoir operating rules to enhance the flood-handling capacity of the dam;
(d) Refurbishment and upgrade of monitoring instruments; and
(e) Update of the Emergency Preparedness Plan (EPP), O&M Plan, and the Instrumentation Plan.

- **Component 3: Technical Assistance (US$10 million).** This component will support implementation of the Project and strengthen the institutional capacity of BT.

40. The components of the second phase (Phase II) will comprise the rehabilitation of the remaining six generation units and the remaining components of the BoP.

D. Cost and Financing

41. The total current cost estimate for the rehabilitation of the Nurek HPP is US$700 million. Phase I will be implemented in 6 years and the estimated cost is US$350 million. The cost estimate is based on the detailed techno-economic study conducted by a reputable international firm. The cost estimate includes 5% physical contingency and 5% price contingency built into the estimates for Components 1 and 2.

42. The sources of financing for the Project are presented below.

- US$60 million from the Bank;
- US$225.7 million from IDA, which includes US$100 million from the IDA Scale-Up Facility, US$69.135 million IDA concessional credit, and US$56.565 million equivalent IDA grant; and
- US$40 million from the Eurasian Development Bank (EaDB).

43. Currently, the total financing available for Phase I of the Project is US$325.7 million, based on the above. Thus, Phase I of the Project has a financing gap of US$24.3 million. WB is considering providing additional financing from IDA18 funds.

44. The Bank and IDA will co-finance the Project and EaDB will provide parallel financing. Specifically, the Bank and IDA will co-finance the main contracts for rehabilitation of power plant equipment, dam safety measures, and technical assistance. EaDB will provide parallel financing only for the replacement of the six auto-transformers. The execution of financing from IDA will be a condition for disbursement of the Bank funds.

45. The financing from the Bank will be linked to Sub-component 1.1 and Component 2. Under Sub-component 1.1, the Engineering, Procurement, and Construction (EPC) contract will include payments for design and model testing of turbines, manufacturing and supply of goods, and installation. As per WB's standard bidding documents for Plant Design, Supply and Installation (PDSI) contracts, BT will be required to issue a confirmed

and irrevocable letter of credit (LC) for the value of goods to be supplied under the contract. It is not possible to link the LC for this large contract with two sources of financing (WB and AIIB), especially considering that the contract will require use of the WB's Special Commitment for the LC. Thus, the Bank will finance the design and model testing and installation costs under the EPC contract, which is estimated at US$45 million. The Bank will also co-finance US$15 million of the total cost of the civil works contracts under Component 2 of the Project.

Table 2. Project Cost and Financing Plan

Project Cost (US$ million)		Financing Plan (US$ million, rounded)				
Components	**Cost**	**Financing Gap**	**AIIB**	**IDA**	**EaDB**	**% AIIB**
Component 1: Power Plant Rehabilitation	**310**	**24**	**45**	**201**	**0**	**15%**
- Sub-component 1.1: Three generation units	270	24	45	201	0	17%
- Sub-component 1.2: Six auto-transformers	40	0	0	0	40	0%
Component 2: Dam Safety	**30**	**0**	**15**	**15**	**0**	**50%**
Component 3: Technical Assistance	**10**	**0**	**0**	**10**	**0**	**0%**
Total	**350**	**24**	**60**	**226**	**40**	**17%**
			326			

46. The financing package for Phase II will depend on progress in implementation of BT's financial recovery and other factors such as public debt sustainability. If financing for Phase II does not materialize, it will not have any financial implications on the PDSI contract for the three units under Phase I and sustainability of the rehabilitated units and the dam safety.

E. Implementation Arrangement

47. The Borrower will be the MOF on behalf of the Republic of Tajikistan. The MOF will on-lend the credits from the International Financial Institutions (IFIs) to BT under Subsidiary Agreements, under the same terms that it received from the respective IFIs. The Grant portion of the financing will be transferred to BT on grant terms.

48. BT will be responsible for the implementation of the Project. The Project's implementation arrangements were developed considering the experience of BT with implementation of IFI-financed projects (WB and EBRD).

49. The Supervisory Board of BT will be responsible for overall Project oversight. BT will establish a Working Group, which will be responsible for (i) review and acceptance of works of the contractors and outputs of the consultants under the Project; and (ii) review of justifications for changes in the scope of contracts under the Project, including variation orders under construction contracts. The Technical Council of BT will be responsible for review and approval of the technical specifications of the bidding documents for all main contracts under the Project. The Project Realization Group (PRG) at BT will be responsible for procurement, contract administration, and financial management under the Project.

50. A Panel of Experts (PoE), which has already been selected, includes an experienced dam safety specialist, geologist, and an electro-mechanical expert. The PoE will provide independent review and expert advice on dam safety issues. A Project Management Consultant (PMC) will assist BT with the design, procurement and implementation supervision. BT, with the support of the PMC, will be responsible for ensuring compliance of construction works with Project environmental and social requirements (see Section 4.D below). BT will be responsible for monitoring and evaluation during implementation, and submitting semi-annual implementation progress reports.

51. The Project implementation schedule foresees completion by December 2023. According to the schedule, the bid documents for the Project's largest component, the power plant rehabilitation, will be issued in 2017, with contract award in early 2018. The activity with the longest lead time is rehabilitation of the generating units, which is expected to take 60 months, including the time required for contractor mobilization, detailed design, manufacture, transportation, installation and commissioning.

52. The financiers of the Project will coordinate during implementation. A Project Co-Lenders' Agreement will be signed by the Bank and the WB.

4. PROJECT ASSESSMENT

A. Technical

53. The proposed approach to rehabilitation of the power plant and the dam safety measures are based on comprehensive and robust technical and economic assessments, including detailed cost estimates.

54. **Dam safety.** The design of the dam safety measures is based on the assessment of the condition of the Nurek dam and associated structures, including a possible failure mode analysis. The ongoing advanced flood forecasting study, ongoing seismic hazard assessment and stability analyses of the Nurek dam; and an assessment of the geological structure of the left bank to check the slope stability will be used to finalize the scope of the safety measures to be included in the Project. See Annex 2 for more detail.

55. **Sedimentation study.** In addition to the dam safety issues, Project preparation has addressed the issue of sedimentation in the Nurek reservoir. The Vakhsh River carries a heavy sediment load. A sedimentation study was undertaken by HR Wallingford Consultants in 2015 to predict future sedimentation in the reservoir under different conditions. The study found that a 33% reduction in Nurek's reservoir capacity has taken place over 43 years. The study predicted the storage volume would reduce by 4% every 5 years in the absence of new upstream storage. Thus, by 2035, storage volume would be half of the original volume. However, the start of construction of the Rogun dam upstream of Nurek affects the deposition of sediment in the Nurek reservoir. The study showed that once the Rogun dam is built, storage loss will be in the Nurek reservoir will slow significantly. These findings have been taken into account in the calculation of the energy generated from Nurek.

56. **Survey of tailrace channel.** The possibility of reducing the tailrace water level in order to increase the head to improve electricity generation is being investigated. The reduction could be possibly achieved by removing the remnants of a cofferdam that have existed since the dam was built. A bathymetric survey of the tailrace channel will be carried out and the results will be used for the design specifications of the new turbines to be procured and installed under the Project.

B. Economic and Financial

57. **Economic analysis.** Based on the incremental benefits and costs, the economic analysis of the entire Project yielded an economic Net Present Value (NPV) of US$1,615 million and Economic Internal Rate of Return (EIRR) of 36%, exclusive of the social cost of avoided CO_2 emission. Inclusive of the social cost of avoided CO_2 emissions, the economic NPV was US$2,077 million and the EIRR 40%. For Phase 1 alone, the economic analysis yielded an economic NPV of US$713 million and EIRR of 33%, exclusive of the social cost of avoided GHG emissions, and an economic NPV of US$905 million and EIRR of 37% inclusive of the social cost of avoided GHG emissions. See Annex 3 for details.

58. **Financial analysis.** The average billed tariff is assumed to increase at an annual rate of 15 percent from 2017 to 2021. Starting in 2022, the nominal tariff increase is assumed to be 6% per year to compensate for cost inflation. Assuming this tariff increase is implemented, the financial analysis of the entire Project yielded a financial NPV of US$25,156 million and Financial Internal Rate of Return (FIRR) of 23%. This result suggests that the Project will have a significant impact on BT's financial viability. Without the Project, BT's revenues will be much lower, exacerbating its financial difficulties. For Phase 1, the financial analysis yielded a financial NPV of US$25,979 million and FIRR of 23%. See Annex 3 for details.

Assessment of Financial Standing of BT

59. The financial condition of BT continued to deteriorate in the period from 2013 to 2015, due to: (i) unsustainable and increasing debt levels, (ii) low cash collections, and (iii) below cost recovery end-user electricity tariffs.

60. As of the end of 2015, BT's total liabilities exceeded its total assets. Operating losses persisted in the period of 2013–2015, leading to complete erosion of equity. The issue of debt service is particularly acute because BT's total debt, including short-term, increased from US$450 million in 2012 to US$950 million in 2015. Out of the total debt, US$800 million are long-term loans from IFIs and bilaterals for specific investment projects. An additional fee of 6% was charged by the MOF when this long-term debt was granted. The remaining US$150 million are short-term and expensive dollar denominated loans from a local commercial bank (Orienbank) which cost the company about TJS253 million (US$36 million) per year in interest expense (average interest rate 22.5%). Those loans were taken to make up for the shortfall of working capital due to lack of cash.

61. Unfortunately, BT rolls over the short-term commercial loans as it is not able to repay them. It is not able to service the long-term loans either and the MOF repays the principal and interest due to lenders (e.g., IFIs and bilaterals) from the state budget.

62. End-user electricity tariffs remain below the cost-recovery levels, which do not allow the company to finance even the required recurrent expenditures. The expected average end-user tariff for 2016 (12.89 diram/kWh, US$0.016/kWh) is estimated at 55% below the cost-recovery level.

63. In 2015, BT earned TJS1548 million (US$252 million) from sales of electricity. It supplied 12,817 GWh of electricity to domestic consumers and exported 1,340 GWh to Afghanistan and the Kyrgyz Republic. The weighted average export tariff was US$0.035/kWh.

64. The collection rate for billed electricity at 83% in 2015 (87% in 2016) remains below the industry average. BT's receivables were outstanding 104 days in 2013 (91 in 2015 and 85 in 2016). The aluminum producer, Tajik Aluminum Company (TALCO), is the largest debtor to BT, with a total debt of TJS412 million (US$59 million).

65. **Refinancing of the very high interest short-term commercial debt** (US$150 million debt to Orienbank). The best way forward would be to restructure or refinance this high interest short-term debt. It seems unrealistic to expect other local commercial banks to refinance this debt due to BT's difficult financial situation and the vulnerabilities of the banking sector. Additionally, no IFI is open to lend money to BT to repay this debt.

66. In February 2016, the International Monetary Fund (IMF) published the Financial System Stability Assessment of Tajikistan. The banking sector in Tajikistan remains small compared to other Caucasus and Central Asian countries and is concentrated. It reports assets of less than 30% and loans of 15% of GDP, and consists of 17 commercial banks, including one fully state-owned, one majority state-owned, and seven majority foreign-owned institutions. The six largest banks account for 81% of total bank assets, and majority foreign-owned banks account for 10.5%. One large bank is insolvent and another fails to meet all prudential requirements, jointly accounting for 41% of total bank assets.

67. Nonperforming loans have grown rapidly, especially in large banks. A large share of the increase in nonperforming loans came from Orienbank (with loans to TALCO, BT, and other State Owned Enterprises), and Agroinvestmentbank (with loans to State Material Reserve agency and connected companies).

68. Interest rates remain high, reflecting the poor business environment and elevated credit risk. By the time Orienbank loans were taken by BT (2006–2007) the average bank interest rate for foreign exchange (FX) loans was higher than 22.5% (see Figure 1 below). The situation has not improved and the interest rate for FX loans in the last few months remains in the same or even higher range.

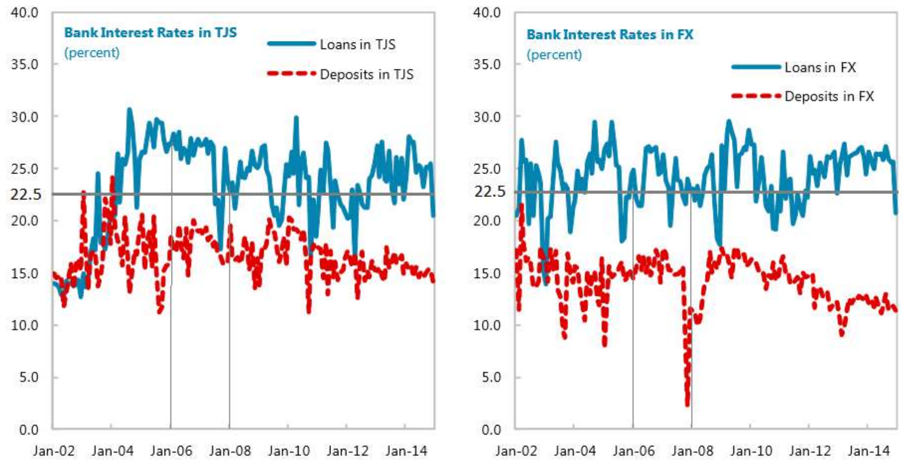

Figure 1. Tajikistan: Domestic Interest Rates and Spreads
Financial System Stability Assessment on Tajikistan, IMF, February 2016

69. Given these circumstances, the only solution considered by the Government is to use the incremental operating cash flows of BT to gradually repay the commercial loan to Orienbank, and this should be one of its priorities in order not to compound BT's bad debt.

70. **Payment to IPPs**. The situation with payables is also poor. In particular, payables for electricity purchases from IPPs – Sangtuda-1 and Sangtuda-2 – rose to TJS835 million (US$119 million). BT struggles to make payments to the IPPs in timely manner because the cost of electricity from them is higher than the end-user electricity tariff and the IPPs primarily supply electricity during the months of April-October (surplus energy season), when the other lower cost HPPs owned by BT, if functioning at optimal capacity, could generate at a significantly lower cost and spill water, given low summer demand and lack of export opportunities.

71. **Forecast of BT's financial performance.** The base-case forecast was done assuming that BT implements all the measures mentioned in the Action Plan for the Financial Recovery of BT, which was agreed with the Government. Those measures include average annual 15% increase of end-user tariffs to reach cost recovery by 2022; improvement of cash collections; improvement of inventory management and collection of receivables, which will increase cash revenues; and increase of exports starting from 2022 when the CASA-1000[5] project is commissioned (see Annex 6 for details).

72. Until 2020, BT will continue to experience deterioration in liquidity and financial leverage due to persisting net losses, slow reduction of accrued liabilities and expected disbursements under ongoing projects. The ratio of current assets to current liabilities will decrease to 0.08 from 0.20 in 2015, and debt-to-assets ratio will increase to 1.2.

73. By 2025, BT's net debt is forecast to decrease to 2 times its earnings before interest, tax, depreciation and amortization (EBITDA), and by 2023 the debt service coverage ratio will have reverted to a sustainable level of 1.11.

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[5] CASA-1000 is a new electricity transmission system currently under construction that will allow for the export of surplus hydroelectricity from Tajikistan and Kyrgyz Republic to Afghanistan and Pakistan.

74. Under a conservative scenario, assuming lower increase in average end-user tariffs, smaller improvements in collection rates and other financial efficiency indicators such as days of receivables outstanding and inventory turnover, BT's financial performance will remain distressed. The current assets will not be sufficient to cover the current liabilities even by the end of the forecast period. BT will not be able to repay the short-term commercial debt until 2024 and will only be able to repay a portion of the payables to the IPPs. The debt service coverage ratio will reach 1.1 by 2025.

Financial Recovery Plan of BT

75. On April 5, 2017, the Government of Tajikistan approved the Financial Recovery Plan of BT (see Annex 6). The approval of this plan was among the conditions for consideration of the Project by the Bank and the WB. With the approval of this document the Government, aware of the critical financial situation of BT, showed its commitment to the Project and the IFIs, and its willingness to improve the performance of BT. The approved plan consists of the Action Plan for Financial Recovery of BT and the Results Matrix of Potential Impact of the Implementation of the Action Plan.

76. The Action Plan is in line with the matrix of Key Short-term Measures to Improve Financial Standing of BT. It contains an exhaustive list of 17 critical measures for improvement of BT's financial standing, including a gradual increase of the tariff and the repayment of the outstanding principal amount of short-term commercial debt from additional funds generated as a result of implementation of the recovery measures.

77. The Results Matrix covers a six-year period from 2017 till 2022. It contains the computations of the potential financial impacts from the implementation of the most important measures included in the Action Plan. The implementation of these recovery measures will increase considerably the cash flow of the company, allowing BT to partially repay the debts to Sangtuda-1 and Santuda-2, long-term IFI loans (interest and principal) and the short-term loan from Orienbank (interest and principal). It was assumed that the loans will either be rolled over each year on the date of the repayment as was the practice before or will be restructured to long-term loans. As a result, by the end of 2022 the total deficit of BT would be reduced to TJS2,263 million (US$278 million). The MOF expects this deficit to be covered by additional financing, including soft loans and grants from IFIs, when the financial situation of BT is healthier due to the implementation of the recovery measures. Without the recovery measures, BT would not be able to repay its debts and its financial situation would be very critical.

Financial Management

78. The financial management arrangements of BT's PRG have been assessed as adequate for the Project's implementation. As capacity building actions, it was agreed that within 30 days after Project effectiveness, the PRG will: (i) hire additional financial management/accounting staff, acceptable to the Bank, to manage the increased workload, and (ii) finalize the upgrade of the accounting system. Additionally, by Project effectiveness, BT will develop the Financial Management Manual that is part of the Project Operational Manual (OM), acceptable to the Bank, to reflect the financial management arrangements and controls under the Project; and the PRG will prepare and submit to the

Bank Interim Un-audited Financial Reports in form and content satisfactory to the Bank. Such reports will be submitted within 45 days after the end of every quarter.

79. There are no pending audits for the projects implemented by the BT PRG. The audit of BT will be conducted: (i) on an annual basis; (ii) by independent auditors and on terms of reference acceptable to the Bank; and (iii) according to the International Standards on Auditing issued by the International Auditing and Assurance Standards Board of the International Federation of Accountants (IFAC). The terms of reference to be used for the Project audit would be prepared by BT and cleared by the Bank, before contracting the auditor. The annual audited Project and BT financial statements would be provided to the Bank and WB within six months of the end of each WB fiscal year and at the closing of the Project.

80. **Disbursement**: For the portion of credit funds allocated to the Project, BT will open a Designated Account in a commercial bank/ financial institution acceptable to the Bank and WB. The ceiling for the Designated Account and other disbursement details will be provided in the Disbursement Letter.

C. Fiduciary and Governance

81. The Borrower will be the MOF on behalf of the Republic of Tajikistan. The Project will be implemented by BT, a state-owned enterprise reporting to the MEWR of Tajikistan. The MOF will on-lend the IFI credits/loans to BT under Subsidiary Agreements with the same terms as received from the respective IFIs. The IDA Grant portion of the financing will be transferred to BT on grant terms.

82. Although the Project has political support and commitment at the highest level, the poor quality of data, accountability and transparency issues, and weak civil society oversight may affect the Project. Tajikistan's anti-corruption framework, which includes the Law of the Republic of Tajikistan on Combating Corruption (2008), Anti-Corruption Strategy in the Republic of Tajikistan 2013–2020 (2013), and the Code of Ethics for Civil Servants (2004), will help mitigate governance risks. The Project will provide further mitigation through due diligence on the cost estimates (review by PMC of the cost estimates from the feasibility study) and a robust procurement process.

Procurement

83. All procurement will be conducted through the procedures specified in the WB's Procurement Regulations for Investment Project Financing Borrowers (July 2016). These regulations are materially and substantially consistent with the Bank's Articles of Agreement and the Bank's Procurement Policy, and therefore are acceptable to the Bank.

84. **Power plant rehabilitation.** The rehabilitation will be carried out under the PDSI contract following International Request for Bids (without prequalification). The tendering documents will cover rehabilitation of all nine generating units, key auxiliary systems and associated BoP. The contract will be awarded only for the Phase I scope and will be extended for the Phase II scope as soon as the required additional financing is secured.

85. **Supply and installation of auto-transformers.** The procurement process will follow the International Request for Bids (single stage without prequalification) method and will be conducted following procurement regulations of the WB.

86. **Dam safety works and instrumentation.** A works contract will be used for the civil works and spillway gates rehabilitation included in the dam safety component. The upgrading of the dam instrumentation may be a separate contract following International Invitation for Bids (after prequalification).

87. **Market analysis**. The major contract will be a PDSI contract for the rehabilitation of the power plant equipment. Experience with the currently implemented Kairakum HPP Rehabilitation Project and 3600MW Rogun Hydropower Project demonstrates interest from potential bidders. Similarly, it is expected that most of the major manufacturers of large hydropower generating units (nine companies were identified) will be interested in bidding for the contract. The awareness of potential bidders about the Project was raised through the following two measures: (i) BT issued the General Procurement Notice for the Project in October 2016 and already received expressions of interest from several firms; (ii) BT held a conference for potential bidders in Istanbul on January 2017, to: (a) provide information on the proposed scope of the Project; and (b) seek comments and suggestions from the bidders on the planned procurement approach for the main package.

88. Market analysis for auto-transformers confirmed that this is a very competitive market with a large number of manufacturers and suppliers. BT has implemented a large number of power transmission and distribution network expansion/rehabilitation projects financed by various IFIs and bilaterals. Those procurements generated good competition with several bidders participating.

89. The package(s) for dam safety works are expected to be of relatively smaller values. Prequalification will be adopted for the package covering the civil works and the rehabilitation of the spillway gates. It is expected that a large number of internationally experienced companies specializing in such works would be interested.

90. The Project involves large procurement packages that require strong implementation capacity and BT does not have prior experience with procurement of packages of this size. Therefore, the PMC was hired to provide implementation support to BT for procurement and contract management. BT also lacks appropriate policies and procedures for recognition of revenues and receivables for electricity sales and some other issues identified by the auditor of the 2015 financial statements. An experienced consultant will be hired to support BT to address these shortcomings.

D. Environmental and Social

91. The Bank has decided to use the WB's Environmental and Social Safeguard Policies (Safeguard Policies) since (i) they are consistent with the Bank's Articles of Agreement and materially and substantially consistent with the provisions of the Bank's Environmental and Social Policy and relevant Environmental and Social Standards; and (ii) the monitoring procedures that the WB has in place to ascertain compliance with its

Safeguard Policies are appropriate for the Project. Under the WB's Safeguard Policies, the Project has been assigned Category B.

92. The WB carried out due diligence, including environmental and social impact studies of the Project. Overall the environmental and social impacts are expected to be positive as the works relate to physical rehabilitation of existing infrastructure with no new construction planned. Three of the WB's Operational Policies/Bank Procedures (OP/BP) on safeguards were applicable to the Project: OP/BP 4.01 Environmental Assessment, OP/BP 4.37 Safety of Dams and OP/BP 7.50 Projects on International Waterways.

93. The Environmental and Social Impact Assessment has been carried out by independent consultants and has been finalized.[6] In addition, a Stakeholders Engagement Plan and a Stakeholders Consultation Plan have also been prepared. Valuable community feedback was received from the public consultation workshops, which will be taken into account in the Environmental and Social Management Plan. BT has set up a grievance redress mechanism for its current operations and this will be used as the basis for the grievance redress mechanism of the Project.

94. The Bank's environmental and social mission was conducted in February 2017, and included discussions with WB staff members and a visit to the Nurek HPP. The Bank's observations confirmed the WB's due diligence; for example, the removal of asbestos from the plant area and the need for a comprehensive traffic plan were found to be key areas for urgent action. Also, the Bank observed that overall safety of workers in plant operations and maintenance requires improvements. The general housekeeping in the plant area, use of personal protective equipment and proper wiring and laying of cables inside the plant need to be ensured. Finally, there is a need to bolster safety measures through a safety audit to identify the scope of improvements and establish appropriate procedures.

95. The physical status of the Nurek dam (water availability, siltation, etc.) will be improved when Rogun dam begins operation. A Dam Safety Expert has already been engaged as part of the PoE and the Dam Safety and Geotechnical Expert initiated technical investigations in 2016. The Experts have also provided recommendations for dam safety measures.

96. The rehabilitation to be undertaken under the Project will not require much unskilled labour and therefore it is not anticipated that there will be a labor influx. Demand for employment in the neighboring jamoats (districts), as indicated in the WB's environmental and social documentation, was also not identified as of critical concern. Very well defined procedures for announcing job vacancies in the power plant existed and the labor department plays a lead role in ensuring that local people are employed as and when appropriate opportunities emerge.

97. During the public consultations, the community raised issues of water scarcity and flooding downstream, linked to the water releases from the Nurek dam. Water supplied for irrigation through pipelines linked to the dam is outside the jurisdiction of the Nurek HPP

[6] http://documents.worldbank.org/curated/en/270681485857484036/Environmental-and-social-impact-assessment

management and is managed by another government department. The WB's stakeholder and citizenship engagement strategies and actions will be vital to ensure that water management in the catchment area is appropriately addressed. Any other issues and concerns raised by the community will be resolved through periodic consultations planned during the life cycle of the Project.

E. Risks and Mitigation Measures

98. The Bank team classifies the risk rating of the Project as "High".

Financial management risks

99. The country's debt sustainability analysis by the IMF concluded that the risk of Tajikistan not being able to continue to service its sovereign debt obligations remains high and hinges very much on whether it can maintain the growth of the economy at the rate projected. The urgent need to address macroeconomic vulnerabilities may derail the Government's focus on a structural reform agenda. Active macroeconomic and structural policy dialogue is underway and development partners are providing technical assistance to strengthen institutions and capacity.

100. In general, the outlook is cautiously positive as the Government is making good efforts to improve the situation but there is still a long way to go. The approval of the Financial Recovery Plan of BT in April 2017 shows the commitment of the Government to improve the critical situation of BT. The Bank, WB and other development partners will be closely supervising implementation of the measures and providing the required advisory and analytical support to the Government.

101. The resolution of the short-term indebtedness issue is one of the key preconditions for BT's long-term financial sustainability. The Financial Recovery Plan of BT includes a number of measures to be implemented, as discussed in paragraph 77 above. BT will need more than six years to repay all its debts and reduce the deficit to zero. Nevertheless, the approval of this Financial Recovery Plan is a first step in the very much needed transformation of the utility into a viable business unit.

Stakeholder risk: riparian countries

102. The Project and its possible impacts were communicated in 2016 to the riparian countries (Afghanistan, Turkmenistan, Uzbekistan). At the request of the Government of Tajikistan, the WB notified these countries about the proposed Project, including a description of the components, and the planned activities and estimated impacts as required under OP 7.50. The WB sent its notification letters in mid-December 2016, and asked the riparian countries to provide replies and any concerns about the Project not later than January 12, 2017. As of early April 2017, no response has been received from the riparian countries, and therefore the WB considers that the riparian countries currently have no concerns, though the possibility of concerns/disagreements emerging in the future cannot be ruled out. The WB will communicate the matter to its Regional Vice President documenting the entire process, to close the process in its current form. Given that this is a rehabilitation, and not a new facility, the scope for disagreement should be reduced.

However, it is possible that riparian governments may not have formed a position on the Project. While the notices described above were issued last year under the WB Policy on International Waterways (OP 7.50), their content and scope are similar to the requirements for adequate notice pursuant to AIIB's new Operational Policy on International Relations (March 2017).

Implementation and procurement risks

103. Institutional capacity for implementation risk is high given the lack of experience of BT with implementation of similar large-scale HPP rehabilitation projects. There is a clear institutional decision-making structure with respect to responsibilities of the PRG, the Working Group, Technical Council and the Supervisory Board of BT; however, BT will require significant technical support to successfully implement the Project. The PoE, which has already been selected, will provide the required advice on technical and dam safety aspects of the Project. PMC will conduct technical supervision of the Project and will help resolve technical issues. Considering the nature of the rehabilitation works, the main risks associated with procurement and implementation of the Project are as follows:

Risk Description	Risk Management Plan
Financing shortfalls	Partly mitigated by the decision to undertake the implementation in phases. The scope of the Phase I can be adjusted to match the available financing from donors.
Insufficient interest by bidders	Market analysis revealed the availability of a relatively large number of potential bidders.
Evaluated prices of bids exceeding the estimate	5% physical and 5% price contingencies (within power plant rehabilitation and dam safety measures). A further mitigation measure that can be considered for the key PDSI contract to create a separate lot for the rehabilitation activities that could be postponed. The bidders will submit bids for this lot but, if the lowest evaluated bid exceeds the available financing, this lot could be excluded from the Phase I contract award and be included in the Phase II award.
Cost overruns	5% physical and 5% price contingencies will be sufficient as this is a rehabilitation project and not a green-field investment.
Procurement & implementation delays	Procurement packaging is based on the feasibility study carried out by an internationally recognized consulting firm. Active and close supervision and involvement of the Recipient and the donors. Appointment of a competent PMC and PoE. Undertaking procurement activities in parallel with Project preparation activities.
Currency exchange fluctuations	Local currency expenditures are expected to be very low. If the currencies of major expenditures under the bid are significantly different from the currencies in which the financing is provided, the impact will need to be managed by the Government, as is the norm.
Payment delays resulting in implementation delays	LC with WB's Specialist Commitment mechanism will be used by the Recipient to pay for imported goods. This will allow paying the contractors for supplied goods through wire transfers from the WB's Treasury in HQ.
Disruption in upstream supply chain	Tajikistan is a land-locked country with limited regional connectivity and under-developed domestic transport network. BT will undertake market engagement with potential bidders/suppliers to understand how to mitigate this risk.
Non-compatible equipment	Bids will be invited for all nine generating units to avoid compatibility issues.

Annex 1: Results Framework and Monitoring

Project Objectives	
PO Statement The Project objectives are to rehabilitate and restore the generating capacity of three power generating units of the Nurek HPP, improve their efficiency, and strengthen the safety of the Nurek dam.	
These results are at	Project Level

Project Development Objective Indicators

Indicator Name	**Core**	**Unit of Measure**	**Baseline**[7]	**Cumulative Target Values** YR1	**YR2**	**YR3**	**YR4**	**YR5**	**YR6**	**Frequency**	**Data Source/ Methodology**	**Responsibility for Data Collection**
Indicator One: Generation capacity of energy constructed or rehabilitated under the Project	☒	MW	0	0	0	0	335	670	1,005	Annual	BT Project implementation progress reports based on inputs from PMC	BT
Indicator Two: Estimated annual electricity generation of three units included in the scope of the Project[8]	☐	GWh	At least 3,750	At least 3,750	At least 3,750	At least 2,500	At least 2,511	At least 2,522	At least 3,783	Annual	BT Project implementation progress reports based on inputs from PMC	BT
Indicator Three: Estimated increase of winter electricity generation of	☐	GWh	0	0	0	0	At least 11	At least 22	At least 33	Annual	BT Project implementation progress reports	BT

[7] All baseline values are as of 2015.
[8] The three units to be rehabilitated under Phase I. This indicator was computed based on the assumption that one unit will be taken out of service each year starting from YR3. It is assumed that rehabilitation of one unit will take up to 11 months. After rehabilitation, the annual electricity output from one unit will increase by at least 11 GWh.

rehabilitated units due to efficiency improvements[9]										based on inputs from PMC	
Indicator Four: Improved dam safety against hydrological and geological risks	☐	Text	No	No	No	No	No	Yes	Yes	Annual	BT Project implementation progress reports based on inputs from PMC	BT
Indicator Five: People provided with improved electricity service [10]	☒	Number	0	0	0	0	8,276,000 [11]	8,276,000	8,276,000	Annual	UN Population Reports / Data and National Statistical Service of Tajikistan	BT
Female beneficiaries	☒	% Sub-Type Supple-mental	0%	0%	0%	0%	49.3%[12]	49.3%	49.3%	Annual	UN Population Reports / Data and National Statistical Service of Tajikistan	BT

[9] This is based on the assumption that minimum 2 percent weighted average efficiency improvement will be obtained under water head varying from 75 to 100 percent of the maximum operating head.
[10] The total number of people connected to the central power system. This excludes the population (206,000 as of 2011) of the Gorno Badakhshan Autonomous Oblast, which has an autonomous power system. The population of the Oblast was assumed to remain unchanged during the Project implementation period. The baseline of the total population of Tajikistan is based on the UN forecast for 2014.
[11] The baseline is for 2015 and is the annual mid-year interpolated population. The population is conservatively assumed to remain unchanged during the implementation of the Project. The population number excludes population of Gorno-Badakhshan region because it is not connected to the central power system of Tajikistan. Source: UN Population Prospects Report, July 2015.
[12] UN World Population Prospects: The 2015 Revision. The share of females in the total population is assumed to remain unchanged.

Intermediate Results Indicators

Indicator Name	Core	Unit of Measure	Baseline	Cumulative Target Values						Frequency	Data Source/ Methodology	Responsibility for Data Collection
				YR1	YR2	YR3	YR4	YR5	YR6			
Intermediate Result Indicator One: Cumulative number of generating units rehabilitated	☐	Number	0	Contract for rehabilita-tion is signed and effective	Turbine hydraulic model test is completed	Design for generating units is completed and manufac-turing com-menced	1	2	3	Semi-annual	BT Project implementation progress reports based on inputs from PMC	BT
Intermediate Result Indicator Two: Cumulative number of auto-transformers replaced	☐	Number	0	Bidding document is issued and evaluation of bids is completed	Contract for replace-ment of auto-trans-formers is signed and effective	The supply of auto-trans-formers is underway	Installation of auto-trans-formers is underway	6	6	Semi-annual	BT Project implementation progress reports based on inputs from PMC	BT
Intermediate Result Indicator Three: Enhanced hydrological safety	☐	Text	Once in 10,000 years flood	Once in 10,000 years flood	Once in 10,000 years flood	Once in 10,000 years flood	Once in 10,000 years flood	Once in 10,000 years flood	Once in 100,000 years flood	Annual	BT Project implementation progress reports based on inputs from PMC	BT
Intermediate Result Indicator Four: Upgrade of the dam monitoring instrumentation completed	☐	Text	No	Bidding document is issued	Contract for upgrade of dam instrument ation is signed and effective	The supply and installation of the dam monitoring instrumenta tion commenced	The dam monitoring instrumenta tion is partly operational	The dam monitorin g instrumen tation is fully operation al	-	Semi-annual	BT Project implementation progress reports based on inputs from PMC	BT

Intermediate Result Indicator Five: Civil, electrical and mechanical works for improvement of the dam safety completed	☐	Text	No	Bidding document is issued	Contract for procure-ment of the dam safety improve-ment works is signed and effective	The dam safety improve-ment works are in progress	The dam safety improve-ment works are in progress	Rehabilit a-tion of the spillway tunnel, gates and hoisting system is complete d	-	Semi-annual	BT Project implementation progress reports based on inputs from PMC	BT
Intermediate Result Indicator Six: Update of Emergency Preparedness Plan (EPP) and preparation of O&M plans completed	☐	Text	No	Draft updated EPP and O&M plans are reviewed by BT and other relevant state agencies	Final updated EPP and O&M plans are approved by BT and other relevant state agencies	Final updated EPP and O&M plans are effective and imple-mented	Final updated EPP and O&M plans are effective and imple-mented	Final updated EPP and O&M plans are effective and imple-mented	Final updated EPP and O&M plans are effective and imple-mented	Semi-annual	BT Project implementation progress reports based on inputs from PMC	BT
Intermediate Result Indicator Seven: Percent of registered Project-related grievances (disaggregated by gender) responded to within stipulated service standards for response times[13]	☐	%	0	100	100	100	100	100	100	Semi-annual	Grievance redress reports of BT	BT

[13] Not more than 30 days.

Indicator Description

Program Development Objective Indicators

Indicator Name	Description (indicator definition etc.)
Generation capacity of energy constructed or rehabilitated under the Project.	This indicator measures the capacity of hydropower constructed or rehabilitated under the Project.
Estimated annual electricity generation of three units included in the scope of the Project.	This indicator measures the supply from rehabilitated units. This indicator will be estimated by dividing the total annual electricity generation by the total number of units and considering their efficiency compared to the base-line.
Estimated increase of winter electricity generation of rehabilitated units due to efficiency improvements.	This indicator measures additional winter generation of rehabilitated units during the time period of October-March due to minimum weighted average efficiency increase of 2 percent. The 2 percent increase was assumed under water head varying from 75 to 100 percent of the maximum operating head.
Improved dam safety against hydrological and geological risks.	This indicator measures the improvement of the dam safety from introduction of advanced flood forecasting system and reservoir management rules, rehabilitation of the spillway tunnels, gates and hoisting system, and works to make both sides of the concrete gallery of the dam impermeable.
People provided with improved electricity service.	The indicator measures the number of people that have received improved electricity service due to Phase I of the Project.

Intermediate Results Indicators

Indicator Name	Description (indicator definition etc.)
Cumulative number of generating units rehabilitated.	This indicator measures the progress with rehabilitation of generating units under the Project.
Cumulative number of auto-transformers replaced.	This indicator measures the progress with replacement of the six auto-transformers.
Enhanced hydrological safety.	This indicator measures ability of the dam to handle large floods.
Upgrade of the dam monitoring instrumentation completed.	The indicator measures the progress with procurement and installation of dam monitoring instrumentation.

Civil, electrical and mechanical works for improvement of the dam safety completed.	This indicator measures the progress with implementation of civil works aimed at improvement of dam safety.
Update of EPP and preparation of O&M plans completed.	This indicator measures the progress with preparation and introduction of updated EPP and O&M plans.
Percent of registered Project-related grievances (disaggregated by gender) responded to within stipulated service standards for response times.	This indicator measures the progress with responding to Project-related grievances related to environmental and social safeguard issues.

Annex 2: Detailed Project Description[14]

1. The Project aims to rehabilitate and restore the generating capacity of three power generating units of the Nurek HPP, improve their efficiency, and strengthen the safety of the Nurek dam. To that end, the Project will support rehabilitation of three generating units and key infrastructural components of the power plant, dam safety improvement measures, and technical assistance to help BT implement the Project. The detailed description of the Project components and the relevant technical justifications are presented below.

2. **Component 1: Rehabilitation of the three generating units, the key infrastructural components of the plant, and replacement of autotransformers (US$310 million to be financed by IDA and other financiers as described below).** This component will finance the replacement and refurbishment of mechanical, electrical, and electromechanical equipment and works required for rehabilitation of three generating units of the Nurek HPP and replacement of all six autotransformers. Specifically, this component will include the following sub-components.

3. **Sub-component 1.1**: **Replacement and refurbishment of mechanical, electrical, and electromechanical equipment required for the rehabilitation of three generating units of the Nurek HPP (US$270 million, including US$200.7 million from IDA, US$45 million from AIIB, and a financing gap of US$24.3 million).**

4. Assessment of the scope of the required rehabilitation works for the power plant equipment was based on detailed inspections carried out by the feasibility consultants, supplemented by information from recently performed rehabilitation works and a review of the Operation & Maintenance (O&M) history of the plant. The recently performed rehabilitation works included replacement of three runners and rehabilitation of two main inlet valves (MIVs).

5. For the turbines, the inspections carried out during the feasibility study included:

- Inspection of the spiral case and stay vanes, stay vanes inlet and outlet profile and visual examination in order to check the possible presence of cracks, corrosion or other defects; as well as inspection of guide vanes (while assembled in the distributor).
- Inspection of other turbine components such as operating ring, guide vane operating mechanism, turbine bearing and guide vane servomotor while assembled. For one unit, one upper stem bushing and lever were dismantled and examined. The turbine bearing cover on one unit was also dismantled.

6. Evaluation sheets for the inspected components were prepared providing an assessment of the condition of each piece of equipment, through a rating based on the assessment guidelines of the Hydropower Advancement Project.

7. The technical assessment of the Generator was performed following the Hydropower Advancement Project Condition Assessment Manual for Generators. The condition assessment

[14] Source: WB Project Appraisal Document (2017)

was carried out on four units and covered quantitative ratings of installed technology, O&M history and detailed inspections of the generator components.

8. A similar approach was adopted for the remaining equipment – transformers, auxiliary systems, the supervisory control and data acquisition system (SCADA), etc. – with detailed inspections being carried out in conjunction with a review of O&M history.

9. Following the technical assessment of the condition of the equipment, different rehabilitation options were considered, ranging from maximum reuse of existing equipment components after refurbishment to a complete rehabilitation of the plant so as to achieve near-new conditions. Based on a comparison of these options, the rehabilitation scope is defined as follows:

(a) <u>Replacement of three turbines</u>. This component will support design, supply and installation of new turbine runners and other turbine components, as well as the refurbishment of the existing embedded components. The technical specifications will require a new hydraulic design for the runner with the possibility of increasing the available generating capacity of each turbine by up to 12 percent over the current level. Replacement of the turbine runners and other turbine components, as well as the refurbishment of the existing embedded components will include:

(i) *Replacement of runners on three units*. The hydraulic design of the existing runners is obsolete and the runner blades show damages at the inlet and outlet. The cavitation damages on the suction side of the blades' inlet are characteristic of high head cavitation. The damages on the outlets of blades were most likely caused by cavitation. A new hydraulic design will be developed to eliminate cavitation and also allow increasing the available generation capacity. Another factor that will need to be taken into account in the design of the runners is the joint operating mode that is to be adopted for the Rogun and Nurek reservoirs after Rogun comes into operation.

(ii) *Refurbishment of spiral cases and stay vanes*. The spiral case and stay ring water passage surface will be sandblasted and the stay vane weld, radius transition zones and other sections of potential damage will undergo non-destructive examination. Refurbishment will include welding and grinding repair of stay vane surface defects, painting of the stay vanes and spiral casing, and correction of the upper faces of stay rings to ensure horizontality of head cover. Additionally, stay vane profile adjustments will be done if cracks or vibration issues are identified.

(iii) *Refurbishment of bottom and discharge rings*. Refurbishment of discharge and bottom rings will include sandblasting, repair of welds, repair of active surface of bolts and painting. The bottom ring will be refurbished and machined at site with a special machine to allow for installation of a new stainless steel wearing plate. Additionally, bottom ring guide vane bushings will be replaced by self-lubricating bushings.

(iv) *Refurbishment of draft tubes*. Refurbishment will include repair of the concrete lining in order to ensure smooth water passage.

(v) *Replacement of turbine head cover*. During the replacement of the runner for Unit 3, ultrasonic examination had revealed cracks in the head cover. There is a significant probability that all head covers (of identical design, manufactured with the same material and manufacturing processes, and subject to the same operating conditions) may suffer (already or in the near future) from similar cracks. Therefore, the head covers on all three turbines, as well as the operating rings, will be replaced. The turbine head cover drainage system will also be changed retaining the same principle of pump or hydro-ejector forced drainage plus gravity drainage.

(vi) *Refurbishment of guide vanes and their operating mechanism*. This will include:

- Replacement of wicket gates/guide vanes to allow for safe and reliable operation of the units for 30 years after completion of the Project.
- Replacement of regulating rings, levers and links.
- Use of self-lubricating material for all guide vane bushing, links and lever bearing as well as operating ring guides and supports.
- Supply of new servomotors as part of the new high-pressure governor oil system with the additional possibility of upgrading the rate pressure of the governing system.
- Replacement of turbine shaft and sealing.
- Installation of turbine discharge measurement system.

(vii) *Replacement of turbine governing system*. The electrohydraulic speed governor will be replaced by a modern microprocessor based speed governor. This will allow for safe and reliable operation of the units. Similarly, the instruments and auxiliary components such as electrohydraulic actuators, safety valves, motors and pumps, manual valves and other pieces of equipment will be replaced.

(viii) *Replacement of oil pressure system*, which includes air-oil pressure tanks, air pressure tanks, and oil sumps tanks; and replacement of pumps, safety valves, manual isolating valves, filters and electro-valves of the oil pressure system.

(ix) *Refurbishment of penstocks.* The penstocks will undergo non-destructive examination. Refurbishment will include welding and grinding repair of surface defects, and painting.

(x) *Refurbishment of MIV's.* The assessment of the structural and foundation conditions will be carried out, including possible pressure testing of the MIV. Refurbishment will include (as needed): provision of self-lubricated bearings, replacement of trunnion sleeve, replacement of the operation seal ring, replacement of by-pass valve, etc. In addition, the operating principle of the MIV will be modified to have closure by a counter weight, instead of the current closure by oil pressure.

(b) <u>Replacement of generators</u>. All the water-cooled generators will be replaced. The generators have not undergone any capital repair (installation of new winding or new stator cores). The operation of the generators is constrained by vibration of the shaft line and/or overheating. Thus, the Project will finance acquisition of new air-cooled generators for the three units being rehabilitated, which will allow avoiding operational capacity constraints currently experienced when distilled water system is out of order. Furthermore, the new air-cooled generators will allow increasing the rated capacity of the power plant. The option for generators with higher rated capacity will be specified in the bidding document. The insulated phase bus-bars and generator circuit breakers will also be replaced.

(c) Replacement of generator step-up transformers. The existing step-up transformers are old and have high electrical losses. The risk of sudden failure is high; one transformer suffered a major internal insulation failure in 2014 and could not be repaired, resulting in the generating unit being out of operation since then. The three transformers will be replaced, with the rated power defined in accordance with the new generator rated power and the operating power factor.

(d) Replacement of plant monitoring, control, automation and protection systems. The control, measurement, and monitoring equipment and the protection cubicles based on electro-magnetic relays will be replaced by modern equipment since those have not been changed since commissioning of the plant in 1972–1979. This equipment is obsolete and difficult to maintain given lack of spare parts. The new control system will allow automatic operation of the units.

(e) Replacement of auxiliary electrical systems. These systems will be replaced as they are obsolete and the non-availability of spare parts is a major constraint. This will include:

(i) *Replacement of Low Voltage and Medium Voltage switchboards at the powerhouse*, *the equipment of the dam and power rings of the underground complex*. This is needed to ensure reliability of the electricity distribution systems and to allow for integration with the new control and monitoring systems.

(ii) *Replacement of the stand-by diesel generator sets*. This will include replacement of the emergency diesel set of the water intake; installation of the new scheme for connection of the back-up generators to relevant switchboards and improvement of the emergency power scheme at the powerhouse through installation of an emergency medium-voltage diesel set.

(iii) *Replacement of cables and cable trays*. Most of the power and control cables are old and will be replaced.

(iv) *Improvement of the lighting system in the powerhouse and underground complex*. The indoor regular and emergency lighting systems will be replaced because they are in poor condition and show signs of excessive wear and tear.

(f) Replacement of auxiliary mechanical systems. This will include replacement or refurbishment of cooling water and technical water supply system of the units; cooling system of main power transformers; distilled water system to cool stator windings and rotor core; compressed air systems; drainage systems for the power house and the dam; dewatering system of the units; powerhouse heating, ventilation and air conditioning system; ventilation system of the underground complex; fire-fighting system; sewage system; hoisting equipment and elevators; and oil infrastructure system.

(g) Installation of new SCADA. This will include replacement of the existing electromagnetic relays-based control and monitoring system with a new modern SCADA system. The new system will be installed in the existing control room. The architecture based on the redundant real-time server will match the needs of the plant. The control room will be connected to different controllers installed in the power plant through an optical fiber network.

(h) Replacement and refurbishment of hydro-mechanical equipment at the power intake. This will include installation of a head loss measurement system; refurbishment of intake trash racks; replacement of seals on maintenance gates and other refurbishment works; replacement of electrical hoists, lifting cables on intake gates and other refurbishment work.

(i) Replacement of laboratory equipment and purchase of tools. This will include support to replace equipment and purchase tools required for the oil quality analysis laboratory, oil treatment plant, electrical and mechanical workshop, generator workshop, high voltage laboratory, and the instrumentation, control and protection laboratories.

10. **Sub-component 1.2: Replacement of six autotransformers (US$40 million, which will be 100 percent financed by EaDB)**. This sub-component will finance the supply and installation of six autotransformers. These 10.5/220/500kV single phase autotransformers are located in the 220kV switchyard. They interconnect the 220 and 500kV networks. These autotransformers are essential for reliable evacuation of electricity generated by the Nurek HPP and the auxiliary electricity supply. The age of the autotransformers is around 40 years and their condition creates a risk of malfunction or failure that could result in disconnection of the Nurek HPP from the electricity network.

11. **Component 2: Enhancement of dam safety (US$30 million, including US$15 million from IDA and US$15 million from AIIB)**. This component will finance activities designed to improve the safety of the operation of the Nurek HPP. The Feasibility Study for the Project assessed the existing condition of the Nurek dam and associated structures, including a Possible Failure Mode Analysis and made a number of recommendations to improve their safety. The following key safety-related elements are being addressed in the preparation of the Project and required measures are being included in the Project's design. The scope will be further refined based on the results of ongoing studies and would include the following activities:

(a) Rehabilitation of spillway tunnels, refurbishment of spillway gates/hoisting system, improvement of protection on permeable zone of the embankment dam above the core zone crest, etc.

(b) Implementation of measures to enhance safety against seismic hazards. The scope of those measures will be finalized after completion of the: (a) ongoing seismic hazard assessment and stability analyses of the Nurek dam; and (b) completion of the drilling of five boreholes on the downstream part of the left bank to check the slope stability.

The original design-stage seismic hazard assessment and stability analysis of the Nurek dam under seismic loading conditions are not available. In 2008, a pseudo static analysis with peak ground acceleration of 0.37 g was done but without indication of occurrence frequency. Given the 300-m height of the dam and potential hazard, a Probabilistic Seismic Hazard Assessment is being carried out to update the seismic design parameters, defining the Operating Basis Earthquake and the Safety Evaluation Earthquake. Using the updated seismic design parameters, a two-dimensional dynamic analysis of the main embankment dam will be carried out. This will include checking of the condition of the seismic belt, which has been affected by differential settlement over the years. The wedge stability in the left abutment under seismic loads will also be assessed. Based on the assessment results, appropriate measures (if required) to enhance safety will be designed and included in the Project.

The Feasibility Study identified a risk that movement of a 'triangular block' wedge in the downstream part of the left bank could cause shearing of the bottom spillway tunnel (2,020 m3/s), adversely impact the surface spillway tunnel (2,020 m3/s), and possibly even block the tailrace channel. Such an eventuality could render Nurek incapable of safely discharging floods. An independent expert geologist, who is familiar with the geological setting of this region, carried out an assessment of the risk of a significant movement of the triangular block wedge. The initial assessment is that a large-scale sliding movement is unlikely, although gradual minor movements along a fault are to be expected due to the oblique rise of a deep salt/gypsum layer. To confirm the findings, a number of boreholes are being drilled and the slope stability will be checked under various loading conditions to confirm these findings. Regular 3D geodetic monitoring will be undertaken by instruments. Appropriate remedial measures to allow the spillway tunnels to function adequately from a hydraulic and structural perspective will be implemented as part of the Project.

(c) <u>Update of Emergency Preparedness Plan (EPP)</u>. A full-fledged EPP will be prepared during Project implementation. The EPP will be based on a dam break analysis, including failure mechanism (breach geometry, duration, etc.), downstream topographic survey, and flooding simulation. It will cover risk categorization, roles/responsibilities of key entities, notification/ warning procedures, etc. including the downstream cascade HPPs.

(d) <u>Preparation of the O&M Plan</u>. The Plan will cover the reservoir operation procedure during floods including advanced flood forecasting and downstream warning systems, sedimentation monitoring/management plan, as well as regular surveillance, instrumentation data analysis/reporting, periodic inspection procedure, etc.

(e) <u>Refurbishment and upgrading of monitoring instruments and management system to improve the collection and analysis of the safety monitoring data</u>. The dam is equipped with about 2,800 monitoring instruments to measure seepage volume, piezometric pressure, soil pressure, settlement, displacement, joint opening, seismic acceleration, etc. of the main embankment dam and associated concrete structures. However, around 40 percent of monitoring sensors, cables, and multiplexor boxes have been damaged by aging, corrosion, etc. Some critical instruments need to be repaired or replaced for proper dam safety monitoring. Also, the software for managing measurement data requires updates as it does not allow for: (i) adding new instrument data, (ii) graphical data presentation, and (iii) automatic warning in the case of monitoring data exceeding thresholds. The Feasibility Study prepared an inventory of monitoring instruments and cost estimates for replacing/upgrading the monitoring system, including new sensors and data management system, which will be covered by the Project. An updated Instrumentation Plan including each instrument's reading frequency, warning thresholds, etc. as well as the analytical/reporting procedure using the updated management software will be prepared during Project implementation.

(f) Installation of an advanced flood forecasting/warning system. The Nurek dam was designed for a flood of 5,400 cubic meters/second, which was consistent with the design criteria used in the Soviet Union at the time of the construction. This corresponded to a 10,000-year return period flood, evaluated based on the hydrological records available up to that time. The other HPPs of the Vakhsh cascade, which are downstream of Nurek, were also designed for the 10,000-year return period flood. Recent hydrological studies, based on up-to-date hydrological data, have resulted in a 5 percent increase in the peak value of the 10,000-year flood. The under-construction Rogun dam upstream of Nurek will significantly reduce the flood risk because the Rogun dam is designed to attenuate extreme floods (up to the Probable Maximum Flood) so that the discharge downstream of Rogun is limited to the flood-handling capacity of Nurek (5,400 cubic meters/second).

To cover the eventuality that the construction of Rogun is delayed, a number of scenarios were analyzed under the technical studies to assess the safety of the Nurek dam against extreme floods, without taking into account any attenuation at Rogun. The analysis indicated that an improved flood forecasting system, combined with delayed reservoir filling for enhanced flood routing during years of expected high floods, can provide safety against a 100,000-year return period flood, significantly higher than the current flood-handling capacity. The possibility of utilizing a concrete gallery located near the top of the dam as an extension of the impervious core is being investigated as a further enhancement of the flood-handling capacity of the dam. Detailed design and execution of required measures, such as advanced flood forecasting system, modified reservoir operation procedure, and possibly some protective measures of the top pervious layer of the embankment body will be further studied to detailed design level and undertaken during Project implementation.

12. **Component 3: Technical assistance (US$10 million, which will be 100 percent financed by IDA).** This component will strengthen the Project's management and implementation arrangements as follows:

(a) PMC to assist with the design, bidding, quality control and construction supervision of the Project. BT has already signed US$5.2 million equivalent contract with PMC, which mobilized in January 2017.

(b) PoE on matters related to dam safety and other critical aspects of the Project, including matters relating to dam safety, its appurtenant structures, the catchment area, the area surrounding the reservoir and downstream areas, and other important matters.

(c) Additional technical and engineering studies, which may be required during Project implementation.

(d) Expert assistance for operations and maintenance, procurement and financial management, environmental and social risk management and monitoring.

(e) Capacity building for Nurek HPP and BT staff, including in project management, dam safety, O&M of hydro facilities, financial management and safeguards aspects of hydropower projects.

(f) Support to BT in implementation of key measures aimed at improvement of financial standing of the company.

(g) Implementation of the Stakeholder Engagement Plan.

(h) Project and entity audits.

(i) Incremental operating costs of the Project implementation entity.

Annex 3: Economic and Financial Analyses[15]

1. This Annex contains economic analysis of the entire Project (i.e., rehabilitation of all facets of the Project, including all nine generating units), economic analysis of the Phase I, financial analysis of the entire Project, financial analysis of the Phase I, and analyses and forecast of financial standing of BT.

Economic Analysis of the Entire Project

2. The economic analysis discusses the rationale for public financing of the Project and description of the analysis of the Project's development impact in terms of expected benefits and costs. The cost-benefit analyses were conducted for both Phase I of the Project and the entire Project.

3. Rationale for public sector provision/financing: The Project warrants public intervention given its economic viability and the fact that private sector financing and provision is not plausible due to:

(a) *Limited domestic capital markets:* Domestic private capital market in Tajikistan lacks the breadth and depth to mobilize the financing required for such a large infrastructure project.

(b) *Prohibitively high private capital cost due to scarce capital and risks:* Costs for private capital are significantly higher than for public debt given the macro and project-specific risks involved. Thus, in case of private financing, the end-users of electricity would benefit less.

(c) *Limited ability of BT to borrow on commercial terms*: BT would not be able to borrow on commercial terms even if sufficient financing was available from local capital markets. This is due to challenging financial condition of BT.

4. Thus, given the risks involved and significant social benefits of the Project, the public financing is justified.

5. The economic viability of the Project was assessed through cost-benefit analysis and was determined through assessment of the expected economic returns, which were evaluated in terms of the NPV and EIRR from total economic costs and benefits attributable to this component.

- The economic costs and benefits are expressed in US$2015 real price terms that are based on average exchange rates for 2015. The economic analysis is based on estimated real prices/costs and is exclusive of any taxes and duties that might be applicable to the Project inputs and outputs. The costs do not include Interest During Construction or any contingencies for expected price inflation. The evaluation does not incorporate any relative movements in exchange rates over the Project evaluation period. The other important inputs and assumptions are discussed below.

[15] Source: WB Project Appraisal Document (2017)

- *Under "without project" scenario the available capacity of the plant will reduce to 0MW by 2028*. Regular maintenance will help to continue running the plant for some time. However, given that useful economic life of electro-mechanical equipment is 30 to 35 years and most of the equipment at the Nurek HPP is beyond that age, the likelihood of major equipment failures that will result in loss of generating units is significant. Under the base-case, it was assumed that starting from 2019 the power plant will lose one generating unit per year. This assumption is based on the assessment of the technical condition of the generating units.

Reduction of Available Capacity under "No Project" Scenario

Nurek Capacity Without Project	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Unit 2	270	270	270	-	-	-	-	-	-	-	-	-
Unit 5	280	280	280	280	-	-	-	-	-	-	-	-
Unit 7	300	300	300	300	300	-	-	-	-	-	-	-
Unit 1	270	270	270	270	270	270	-	-	-	-	-	-
Unit 3	300	300	300	300	300	300	300	-	-	-	-	-
Unit 4	300	300	300	300	300	300	300	300	-	-	-	-
Unit 6	300	300	300	300	300	300	300	300	300	-	-	-
Unit 8	0	0	340	340	340	340	340	340	340	340	340	-
Unit 9	300	300	300	300	300	300	300	300	300	300	-	-
Total	**2320**	**2320**	**2660**	**2390**	**2110**	**1810**	**1540**	**1240**	**940**	**640**	**340**	**-**

Source: WB team assumptions.

- *Replacement of one unit requires 11 months and only one unit is replaced at a time*. The generation of the plant during Project implementation was forecast taking this into account. This means that there are eight units generally available, except for routine maintenance and outages. This means that during erection works electricity generation from the plant will reduce only by the amount equivalent to the generation of one unit, which will be taken out of service for 11 months. No other impacts are anticipated on total energy generation of the plant during rehabilitation works.

- *The available generation capacity of the plant will increase from the current level of 2320MW to 3214MW*. This will be achieved due to the higher operating capacity of the new turbines and generators to be installed. For the base-case, an 8 percent capacity increase was assumed for the new units. The total available generating capacity for the plant under "with project" scenario was estimated assuming that after rehabilitation Units 3 and 8 would have a nominal capacity of 340MW each and the remaining units will have a capacity of 362MW each. Unit 8 is expected to be brought back into operation in 2019 under both "with" and "without project" scenarios because the major components have either already been rehabilitated or are being replaced with financing by BT.

- *400MW Dushanbe-2 CHP and 3600MW Rogun HPP were included in the estimate of winter electricity supply*. Dushanbe-2 CHP was commissioned in December 2016. It will be supplying 300MW of electricity and 167Gcal of heat. Dushanbe-2 CHP is assumed to operate primarily in October-March with total estimated average generation of 1,180 GWh. Construction of Rogun HPP is underway and the first two generating units are expected to come online by the end of 2019. Rogun HPP will start supplying electricity in winter and summer, however, the amount of supply will increase as construction of the dam progresses and the reservoir level increases. The winter and summer electricity supply estimates are based on the Techno-Economic Assessment Studies for Rogun HPP (August 2014). The electricity generation from Rogun HPP, which is used in this analysis, is based on the assumption of a dam 1,290 meters above sea level and 3600MW of installed capacity.

- *Average winter and summer generation levels were derived based on the simulation of the Nurek reservoir operation*. Based on the 2013 Nurek data, the following computation was carried out. The reservoir was emptied to the Minimum Operating Level in winter and filled up to the Fully Supply Level in summer. The simulation was carried out on the available historical daily inflows in Nurek over the period of 1972–2013. The powerhouse limitations in terms of head, turbine discharge, and generation capacity were taken into account. The simulated averages were very close to actual generation numbers for the period of 2007–2013 for which data is available. Specifically, there was 2.6 percent difference between historical and simulated long term average values, primarily due to the fact that actual generation figures are lower due to summer spillages caused by supply exceeding domestic demand.

- *The average winter and summer generation levels were estimated taking into account the current state of sedimentation and commissioning of Rogun HPP*. The base-case is based on the assumption that average winter generation during the time period of October-March will be 4,680 GWh and the average summer generation will reach 7,800 GWh. The current summer generation is on average 6,600 GWh and corresponds to summer electricity demand and the water is spilled. Those numbers will change after Rogun HPP starts generating at full estimated capacity because the current level of sedimentation of Nurek reservoir will be maintained for another 80 years (i.e., up to the end of the simulation period for the sedimentation studies).

- *Real PPA tariffs*. The weighted average PPA tariff was used to evaluate the economic benefits of the Project during summer months in form of avoided reduction in export revenues. The weighted average PPA tariff was estimated taking into account the current PPA tariff with Afghanistan using existing interconnections, agreed-upon PPA tariffs under CASA-1000 with Pakistan and Afghanistan, and the relevant shares of exports in the total exports. The escalation of PPA tariffs is not relevant for economic analysis of the Project.

- *Stochastic Dual Dynamic Programming tool was used to simulate the average maximum summer electricity supply capability of existing HPPs*. This assessment was needed to derive the surplus electricity supply capability in order to determine whether gradual reduction of supply from the Nurek HPP under "No Rogun" scenario can be replaced by surplus from other generating plants, including 600MW Baipasinskaya HPP, 670MW Sangtuda-1 HPP, 220MW Sangtuda-2 HPP, 240MW Golovnaya HPP, 30MW Perepadnaya HPP, and 15MW Centralnaya HPP. The simulations were done considering the historical sequence of inflows to Nurek (Tajikistan) reservoirs. The simulations were run for the period of 2016–2035. The surplus power for 2036–2071 was estimated by extrapolating the pattern of variation in hydro generation derived by SDDP simulations. The simulated supply under base-case does not assume construction of any other new power plants during the Project evaluation period.

6. The base-case for economic analysis is formed from expected values for the main evaluation variables, namely: (i) the base-case forecasts of winter and summer electricity demand and supply in Tajikistan; (ii) entire Project rehabilitation cost and in-service date; (iii) amount of electricity supplied under the Project based on simulated results of generation by the Nurek HPP during winter and summer seasons,[16] and (iv) the forecast costs of fuels under the Project counterfactual, i.e., construction of a gas-fired thermal power plant to replace generation from the Nurek HPP assuming it is not rehabilitated, which leads to reduction of supply.

7. Under the base-case, the stream of economic costs and benefits was discounted at the social opportunity cost of the capital, which was assumed to equal 10%. The choice of the discount rate is driven by the conservative assumption that the average real GDP will grow at an average annual rate of 5 percent during the useful economic life of the Project. The economic life of the replaced units is assumed to be 35 years from the date of commissioning of each of the refurbished units.

8. Economic costs of the Project: The economic costs include: (i) EPC costs for refurbishment of electrical, mechanical and electromechanical equipment and the works required for rehabilitation; (ii) the cost of six autotransformers; (iii) PMC, which will be acting as the owner's engineer; and (iv) the incremental O&M costs. The costs are projected according to the years in which they are expected to be incurred during the Project construction period.[17] The cost of the dam safety component is excluded from the economic analyses because those costs will need to be incurred irrespective of the power plant refurbishment (Component 1).

9. Economic benefits of the Project: The main economic benefit is the avoided increase of the cost of electricity supply to consumers due to replacement of the Nurek HPP with new supply sources. The evaluation of avoided increase in economic cost of supply was conducted taking into account the role of the Project in winter electricity supply, and the incremental supply costs associated with substituting the generation from the Nurek HPP. The plant accounts for a large share of total winter electricity supply. Specifically, the plant currently generates on average 4,700 GWh of electricity, which is 70 percent of the total winter generation during the time period of October-March and 47 percent of total unconstrained demand, inclusive of un-met demand. Therefore, under "no-project" scenario, gradual loss of electricity output from the Nurek HPP during economic evaluation time horizon will need to be filled by an alternative supply source. The Project will also generate global social benefits in form of avoided GHG emissions due to increased gas generation to replace Nurek under Project counterfactual. The benefits of avoided

[16] For the purposes of this analyses, winter includes generation during the months of October-March and summer includes generation during the months of April-September.
[17] Project construction costs are not levelized over the operating life of the Project.

GHG emissions were estimated based on the incremental gas-fired electricity supply to the grid and the forecast social cost of carbon (the World Bank Guidance on Social Value of Carbon in Project Appraisal, Sep. 2014).

10. Electricity from Dushanbe-2 CHP starting from December 2016 and from early generation at Rogun HPP starting from 2019 will not be sufficient to fully replace the loss of generation from the Nurek HPP given the estimated 2,700GWh of un-met winter electricity demand (2014) and the forecast increase of demand. Dushanbe-2 CHP is estimated to generate 1,180 GWh during winter and Rogun HPP at full capacity will be able to supply around 5,600 GWh of winter electricity, which will be sufficient to replace the Nurek HPP, but will not be sufficient to meet the forecast electricity demand, which also includes the un-met electricity demand of 2,700 GWh as of 2014.

11. **Winter supply and demand balance**: Assessment of the economic benefits from rehabilitation of the Project will require forecast of the winter electricity supply and demand balance during the time period of October-March. This is needed to determine whether the power system will experience electricity shortages in case the Nurek HPP is not rehabilitated.

Installed Capacities of Power Plants

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Available Installed Capacity "without project" in MW												
Rogun HPP	0	0	812	812	812	812	812	1200	3,600	3600	3600	3600
Nurek	2660	2660	2660	2390	2110	1810	1540	1240	940	640	340	340
Sangtuda-1	670	670	670	670	670	670	670	670	670	670	670	670
Baipasinskaya	600	600	600	600	600	600	600	600	600	600	600	600
Golovnaya	240	240	240	252	252	252	252	252	252	252	252	252
Sangtuda-2	220	220	220	220	220	220	220	220	220	220	220	220
Kairakum	126	126	174	174	174	174	174	174	174	174	174	174
Perepadnaya	30	30	30	30	30	30	30	30	30	30	30	30
Varzob cascade	25	25	25	25	25	25	25	25	25	25	25	25
Other SHPPs	15	15	15	15	15	15	15	15	15	15	15	15
Centralnaya	15	15	15	15	15	15	15	15	15	15	15	15
Pamir-1	14	14	14	14	14	14	14	14	14	14	14	14
Dushanbe-2 CHP[18]	300	300	300	300	300	300	300	300	300	300	300	300

12. Winter supply from existing and committed generation plants was estimated based on their average capacity factors (ACFs) during the winter time and their available installed capacities. For Rogun HPP, the numbers were taken from Techno-Economic Studies of Rogun HPP (August 2014).

[18] In both electricity and heat supply regime.

Winter ACFs of Main Power Plants

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Winter ACF "without project"												
Nurek	42.8%	42.8%	42.8%	47.2%	52.1%	58.8%	66.7%	80.2%	90.8%	94.8%	94.8%	94.8%
Sangtuda-1	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
Baipasinskaya	46.0%	46.0%	46.0%	46.0%	46.0%	46.0%	46.0%	46.0%	46.0%	46.0%	46.0%	46.0%
Golovnaya	68.0%	68.0%	68.0%	68.0%	68.0%	68.0%	68.0%	68.0%	68.0%	68.0%	68.0%	68.0%
Sangtuda-2	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%
Kairakum	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
Perepadnaya	58.0%	58.0%	58.0%	58.0%	58.0%	58.0%	58.0%	58.0%	58.0%	58.0%	58.0%	58.0%
Varzob cascade	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%
Other SHPPs	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%
Centralnaya	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
Pamir-1	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%
Dushanbe-2 CHP	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%

13. **Forecast of electricity demand**. The forecast winter and summer electricity demand was derived drawing upon the base-case total electricity demand forecast for Tajikistan. Demand projections are developed in two steps: unconstrained demand and economically efficient demand. The projections cover residential and non-residential demand, but exclude TALCO's demand, which is assumed to remain constant. The forecast of electricity demand used for this analysis reflects the demand for electricity that is consistent with economic efficiency principles. In principle, this demand is the estimated quantity of electricity that consumers would consume if they had to pay a price that fully covers the economic cost of supplying that amount of electricity. The forecast real GDP growth was used as the proxy of the growth in real income to derive the demand projection.

Key Assumptions of the Electricity Demand Forecast

	2017	2018	2019	2020	2025	2030	2035	2040	2045	2050
Change of real electricity price[19]	9.2%	13.1	13.1%	13.1%	2%[20]	2.0%	2.0%	2.0%	2.0%	2.0%
Real GDP growth rate[21]	6%	4.5%	4.5%	4.5%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%

14. The base-case forecast electricity demand assumed that the current average retail tariff will be increasing to the level of cost recovery by 2022 (US$0.04/kWh)[22] and then continue increasing at an annual rate of 2 percent.

[19] The nominal increase will be 17% per year in 2018–2021.
[20] 6% nominal increase was used in financial forecast.
[21] Real GDP forecast is based on IMF's forecasts from World Economic Outlook Report, Oct. 2016.
[22] WB team estimate.

15. To estimate economically efficient demand, the unconstrained demand projection was modified to incorporate the conserving effect of price, specifically, a price that reflects the economic cost of supplying power to meet the forecast consumers' demand for electricity. Conventionally in the derivation of electricity demand forecasts, this price signal assumes that the electricity price is increased incrementally to fully cover costs of supply. This approach broadly satisfies the requirement for economic efficiency, although in practice it recognizes that consumers need time to adjust their electricity usage to price increases without undue disruption.

Box 1. Electricity demand growth model

The methodology for deriving a forecast of the economically efficient level of demand for electricity over the long-term is based on the following relationship between electricity demand growth, and real income growth and real electricity price growth, assuming a constant elasticity power demand function: The rate of growth of demand is equal to the rate of growth of prices times the price elasticity plus the rate of growth of income times the income elasticity. This is expressed formally as:

$d = p*b + g*a$

where:

d = average rate of growth of demand between successive forecast periods

a = income elasticity (positive)

g = growth of real income between successive forecast periods

b = price elasticity of demand (negative)

p = change of real electricity prices between successive forecast periods.

The demand for electricity derived with this model is the forecast unconstrained end use consumption without reduction of losses from the present level. This forecast end use consumption is then transposed into the gross energy sent out to the power network from power generation plants needed to supply forecast unconstrained end use consumption.

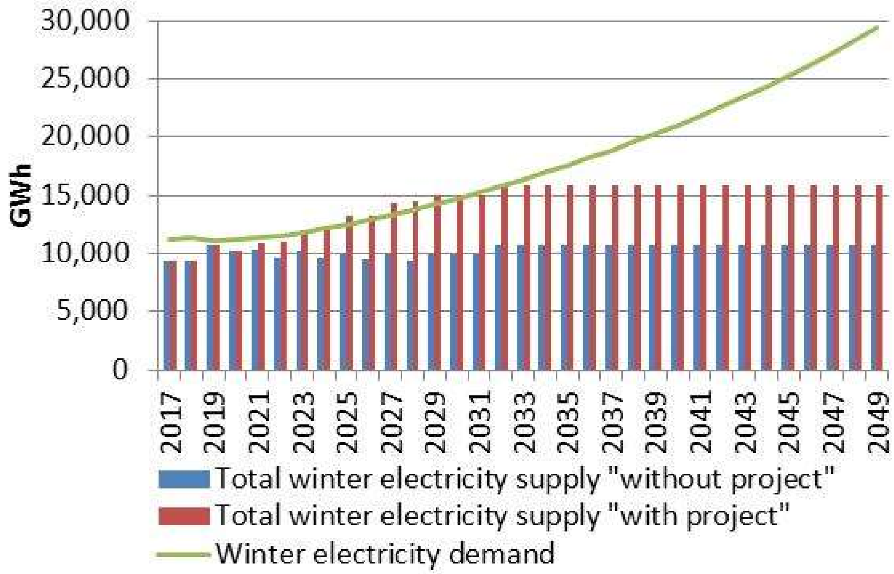
16. The sensitivity of demand to GDP growth and economic price of electricity was assumed for each main group of consumers. The assumptions for elasticity are based on observed elasticities derived from historical data.

Income and Price Elasticity Assumptions in Electricity Demand Forecast

	GDP growth elasticity	Price elasticity
Industry	0.9	0.0
Pumping irrigation	0.5	-0.15
Agriculture	0.5	-0.15
State-budget financed organizations	0.7	-0.30
Residential	0.9	-0.20
Other	0.8	-0.15

17. The forecast of winter electricity demand and demand at generation level suggests that Tajikistan will experience winter electricity deficit if the Nurek HPP is not rehabilitated. The existing and committed generation capacity (Rogun HPP) will not be able to substitute the loss of generation from the Nurek HPP. Therefore, the Government will need to identify new supply sources to substitute the loss of generation from the Nurek HPP.

Figure 1: **Forecast of Winter Electricity Supply and Demand Balance**



Source: Bank team estimates.

18. Determination of the alternative supply source or the Project counterfactual is needed to evaluate the economic benefit in the form of avoided increase in the cost of supply. The Project counterfactual ("no project" scenario) is the construction of Combined Cycle Gas Turbine (CCGT) power plants run on imported natural gas if the Nurek HPP is not rehabilitated and its generation starts decreasing. The gas-fired generation is assumed to be the Project counterfactual because: (i) there is no spare existing generation capacity during winter to replace the supply from the Nurek HPP; (ii) only CCGTs offer the operational flexibility offered by the Nurek HPP and supply the daily and seasonal load during winter period because the Nurek HPP is a load-following plant; and (iii) the updated results of the power supply options for Tajikistan suggest that it is the lowest-cost new supply option to replace the generation from the Nurek HPP. Thus, the economic benefit of avoided increase of power supply costs due to rehabilitation of the Nurek HPP was compared to the cost of constructing new CCGT units to replace the decreasing generation from Nurek if it is not rehabilitated.

19. The levelized energy cost of gas-fired generation is estimated at US$0.084/kWh taking into account the plant-gate costs for imported natural gas. The plant-gate cost of natural gas was computed as the sum of the:

(a) Estimated border price of imported natural gas, which was derived based on the average sales price of Turkmen gas to Russia and China under long-term contracts with long-term price forecast of US$6.4/MMBtu, including premium for winter supply only. The year-on-year changes of real border gas price were assumed to reflect the changes in the forecast European market prices as reflected in the WB's Commodity Price Forecast dated July 26, 2016.

(b) Levelized cost of a new 700km gas transmission pipeline from Turkmenistan. The pipeline cost was assumed to be US$1,300,000 per km and sufficient to supply the amount of gas required for 1200MW CCGT plant to replace the Nurek HPP. The cost of the pipeline was assumed to be amortized over 30 years. This adds additional US$2.6/MMBtu to the price of imported natural gas.

(c) Domestic transmission and distribution margin is estimated at US$1/MMBtu.

(d) The forecast of the plant-gate prices for imported natural gas is presented below.

Forecast of Plant-gate prices for Natural Gas in Tajikistan

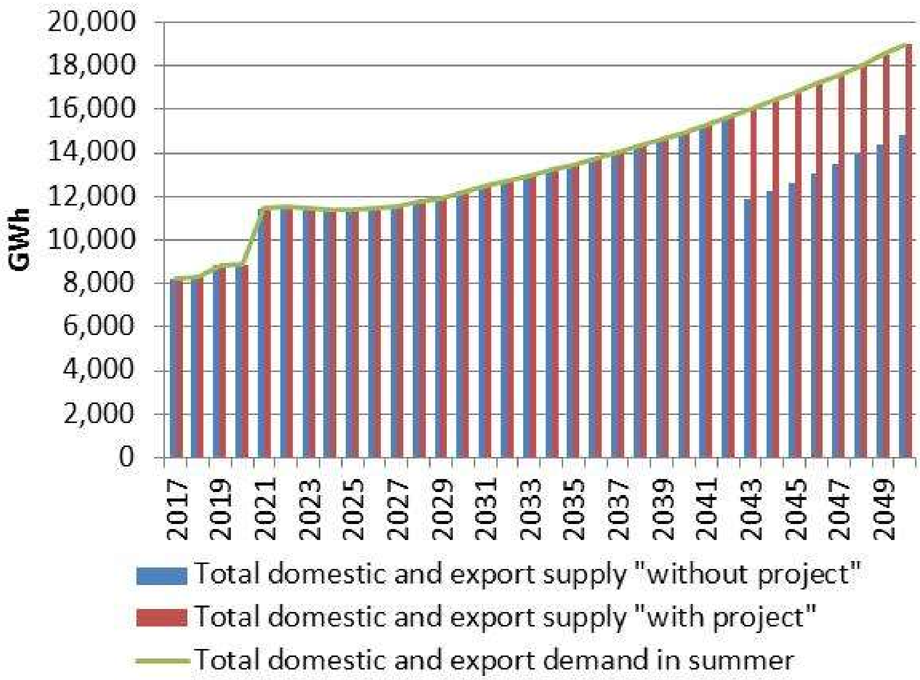
	2020f	20251f	2030f	2035f	2040f	2045f	2050f
Border price of imported natural gas	5.3	6.6	6.6	6.6	6.6	6.6	6.6
New transmission pipeline cost	2.6	2.6	2.6	2.6	2.6	2.6	2.6
T&D margin	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Plant-gate price of natural gas	8.9	10.2	10.2	10.2	10.2	10.2	10.2

20. Rehabilitation of the Nurek HPP will not generate any economic benefits for domestic supply during summer period. This is due to the large summer supply potential of Rogun HPP. Once this plant is commissioned, then economic cost of incremental electricity to replace the Nurek HPP will be close to zero. With the commissioning of the Rogun HPP, the power system will be able to fully meet the forecast demand in summer even in case of full loss of generation from the Nurek HPP. Therefore, electricity from the Nurek HPP for domestic market during the summer period has no economic value from the perspective of the Project.

21. Nevertheless, the Project will generate marginal summer benefits taking into account export demand, which consists of around 1,350 GWh of annual exports to Afghanistan as well as – 640 GWh to Afghanistan and around 2,140 GWh to Pakistan committed under CASA-1000 project. For the purposes of the economic and financial analyses of the Nurek rehabilitation project, we conservatively assumed that exports will remain at the above level during the entire period for economic evaluation of the Nurek rehabilitation project.

22. The power system will experience energy shortage for exports starting from 2046 given forecast increase of domestic demand in summer, which will eliminate the energy surplus on the system. Therefore, without the Nurek HPP, there will be no electricity available for exports starting from 2043, which will result in foregone economic revenues. Those revenues were computed at the average real PPA tariffs. Given that this will be almost 20 years from completion of the Project, the economic benefits discounted at social opportunity cost of capital are small.

Figure 2: Forecast of Summer Electricity Demand and Supply



Source: Bank team estimate.

23. **GHG reduction benefits for entire Project**: The Project will also generate global environmental benefits in form of net reduction of CO_2 emissions. The CO_2 emission reduction benefits from the Project were evaluated following the WB's Guidance Note on Greenhouse Gas Accounting for Energy Investment Operations (June 2013). Specifically, the net emissions were estimated using the following approach:

- Net emissions = Project emissions – (improved performance baseline emissions + life extension baseline emissions).
- Project emissions = annual electricity output x emissions factor for construction x economic life of the Project
- Improved performance baseline emissions = incremental generation capacity x emission factor for the country's grid x remaining life of the plant before rehabilitation
- Life extension baseline emissions included emissions from CCGT to supply electricity to make up for loss of generation from Nurek and construction emissions for CCGT plant.

Assumptions underlying GHG Accounting for the Entire Project

Items	Units
Emission factor for rehabilitation of Nurek	0.001kg/kWh
Emission factor for Tajik power grid	0.009kg/kWh
Emissions from CCGT	0.362kg/kWh
Emissions factor for construction of CCGT	0.503kg/kW of installed capacity

Source: WB team GHG Guidance Note and team assumptions.

24. The entire Project will lead to 68 million tCO_2e reduction in emissions vs. the baseline during economic life of the Project. Therefore, the Project will generate climate mitigation co-benefits.

25. Results: The economic analysis of the entire Project yielded an economic NPV of US$1,615 million and EIRR of 36 percent exclusive of the social cost of avoided CO_2 emission and an economic NPV of US$2,077 million and EIRR of 40 percent inclusive of the social cost of avoided CO_2 emissions.

26. Sensitivity analysis: Sensitivity analysis was conducted to assess the robustness of the estimated Project economic returns to changes in the main evaluation variables. Sensitivity analysis covers the following cases that in turn stress test the economic returns to the Project. The results of the sensitivity analyses are presented in the table below.

a. 20 percent lower forecast border price of imported natural gas with the expected base-case values for all other variables.
b. 20 percent higher investment cost with the expected base-case values for all other variables.
c. Loss of generating units at the rate of one unit in three years (instead of the base-case assumption of one unit each year) with expected base-case values for all other variables.
d. Combination of the above cases.

Sensitivity Analysis for Economic Evaluation of Entire Project

Exclusive of avoided CO_2 emissions	**NPV (million US$)**	**EIRR (%)**
Base-case	**1615**	**36**
a. 20 percent higher investment cost	1517	32
b. 20 percent lower-than-projected border price of imported gas	1384	30
c. Loss of generation capacity at a rate of one unit in three years[23]	272	12
d. Combination of a, b, and c	89	11

27. The results of the sensitivity analysis suggest that the Project is economically robust even in case of substantial variation of main variables that affect its viability.

28. It should be noted that delays with commissioning of Rogun HPP will increase the economic benefits for the Project because Rogun will not be able to substitute the loss of generation from Rogun HPP and the gap will have to be filled with expensive CCGT. With assumed delays in commissioning, all remaining major milestones (commissioning of remaining five units) are assumed to be delayed as well. The capital costs for Rogun HPP are sunk costs from perspective of economic evaluation of the Project and only variable costs matter, which are very small for hydropower plants. In case Rogun HPP is not constructed at all, then returns to the Project would be even bigger because all the generation loss from Nurek would have to be replaced by CCGT. If Rogun is not constructed, then generation from Nurek will also reduce, but that will have less impact on economic returns compared to the cost of energy from CCGT under the Project counterfactual.

[23] Total loss of generation by 2048 instead of 2028 under base-case.

Economic Analyses of Phase I of the Project

29. The economic analyses of the Phase I of the Project was conducted using the cost-benefit approach and using the same methodology. The base-case of the analyses for Phase I is similar to the base-case for analyses of the entire Project. The differences between the economic analyses of the Phase I and the entire Project are the following: (i) lower economic cost due to rehabilitation of only three generating units; and (ii) smaller avoided CCGT generation under "with project" scenario given that the remaining six units, which are not rehabilitated under Phase I, are assumed to completely lose generation by 2028.

30. **GHG reduction benefits for Phase I of the Project**. The Phase I will generate global environmental benefits in form of net reduction of CO_2 emissions. The assessment of net CO_2 emission reductions from Phase I of the Project was conducted using the same methodology as for the entire Project. The Phase I of the Project will lead to 29 million tCO_2e reduction in emissions vs. the baseline during economic life of the Project. Therefore, the Project will generate climate mitigation co-benefits.

31. Results: The economic analysis of the Phase I yielded an economic NPV of US$713 million and EIRR of 33 percent exclusive of the social cost of avoided GHG emissions and an economic NPV of US$905 million and EIRR of 37 percent inclusive of the social cost of avoided GHG emissions.

32. Sensitivity analysis: Sensitivity analysis was conducted to assess the robustness of the estimated Phase I economic returns to changes in the main evaluation variables. Sensitivity analysis covers the following cases that in turn stress test the economic returns to Phase I of the Project. The results of the sensitivity analyses are presented in the Table below. The results of the sensitivity analysis suggest that the Project becomes economically non-viable in cases: (i) when Nurek maintains generation capacity under "without project" scenario until 2048 instead of 2028 under base-case, and (ii) investment cost over-run and lower-than-forecast gas prices coupled with 20 years' slower loss of generation capacity.

Sensitivity Analysis for Economic Evaluation of the Phase I of the Project

Exclusive of avoided CO_2 emission costs	NPV (million US$)	EIRR (%)
Base-case	**713**	**33**
a. 20 percent higher investment cost	664	29
b. 20 percent lower-than-projected border price of imported gas	597	27
c. Loss of generation capacity at a rate of one unit in three years[24]	(479)	4
d. Combination of a, b, and c	(505)	3

Financial Analysis of Entire Project

33. Financial analyses of the entire Project and Phase I of the Project was conducted from the perspective of BT, which is the entity to incur the financial costs associated with the Projects and

[24] Total loss of generation by 2048 instead of 2028 under base-case.

to receive the financial benefits. Most of the key assumptions underlying the economic analyses are also applicable to the financial analyses. The following additional assumptions and inputs are worth highlighting for the financial analyses, which are different from the economic analysis.

- *Financial costs and prices*. Financial analysis was conducted inclusive of applicable taxes and duties on equipment, works and revenues. Given that projects financed through sovereign loans and approved by the Parliament are exempt from import duties and taxes, those will not have any implications on the cost estimates. Direct taxes such as profit and income taxes do not directly impact the costs of the inputs and works. The financial analysis was done based on nominal costs, prices and the discount rate.

- *Price and physical contingencies are included into the financial analysis*. The total economic cost of the Project was revised to include price contingency of 5 percent, which is computed on the estimated cost of power plant rehabilitation, replacement of autotransformers and PMC.

- *Exchange rate and inflation*. The average annual exchange rate was assumed to remain unchanged at TJS7.88 per US$1 during the entire evaluation period. The inflation, as measured by consumer price index (CPI) was assumed to equal 6.3 percent in 2016, 7.3 percent in 2017 and 6 percent for subsequent years drawing upon the forecast of the IMF World Economic Outlook (October 2016).

- *Average domestic tariff for electricity*. The average billed tariff is assumed to increase at an annual rate of 15 percent in 2017–2021. Starting from 2022, the nominal tariff increase is assumed at 6% per year to compensate for inflation of costs.

- *Collection rates*. The annual increases of electricity bill collection rates for 2016–2018 were assumed to equal the targets specified in the Action Plan as presented in Annex 6. Specifically, the collection rates were assumed to increase from 85 percent in 2015 to 90 percent in 2018, and then to 95 percent by 2022 and remain at that level afterwards.

Required Tariff Increase to Reach Cost Recovery by 2022

		2016	**2017**	**2018**	**2019**	**2020**	**2021**
Cost-recovery tariff with repayment of payables and the principals of expensive commercial loans over 5 years	Diram/ kWh	12.79	14.48	16.95	19.85	23.25	27.22
Average annual nominal increase[25]	%	2%[26]	13.2%	17.1%	17.1%	17.1%	17.1%

- *Electricity export tariffs*. Currently, Afghanistan accounts for the bulk of electricity exports. 1,350 GWh of annual exports to Afghanistan over existing 220kV interconnection were assumed to continue during the economic life of the Project. The 2016 export tariff

[25] Important note: The electricity demand forecast is based on real price increase, i.e., adjusted for forecast inflation.
[26] The 12 percent average tariff increase became effective on November 1, 2016. Thus, it translates only to 2 percent increase if spread over the entire year.

of US$0.037/kWh was assumed to escalate at annual rate of 2.5 percent. Electricity exports will increase starting from 2022 when CASA-1000 project is operational. The estimated additional exports to Afghanistan and Pakistan over CASA transmission facilities were reflected in the financial analyses of the Project based on the negotiated PPA quantities and tariffs. The duration of PPAs is 15 years. Therefore, for the purposes of the financial analyses, it was conservatively assumed that exports over CASA line will continue at the same quantity after expiration of PPAs under CASA.

Electricity Export Tariffs

		2017	2020	2022	2025	2028	2031	2034	2036
Energy tariff for CASA exports to Afghanistan	US$/kWh	0	0	0.051	0.055	0.059	0.064	0.069	0.072
Energy tariff for CASA exports to Pakistan	US$/kWh	0	0	0.052	0.055	0.060	0.064	0.069	0.073
Energy tariff for exports to Afghanistan	US$/kWh	0.037	0.040	0.042	0.045	0.049	0.052	0.056	0.059
Annual escalation of export tariff to Afghanistan and CASA tariffs	%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Weighted average export tariff	US$/kWh	0.037	0.040	0.048	0.052	0.056	0.060	0.065	0.068

- *Transmission and distribution losses*: Transmission and distribution losses impact the amount of electricity sold to end-users. The transmission losses were assumed to remain at 3.7% of the energy input into transmission. The distribution losses were assumed to remain at 13.6% of input into distribution grid. BT was assumed to receive 12% loss allowance through the tariff.

34. The base-case for financial analysis is formed from expected values for the main evaluation variables, namely: (i) the base-case forecasts of winter and summer electricity demand and supply in Tajikistan; (ii) financial costs of the rehabilitation, including dam safety enhancement related costs, and in-service date; (iii) amount of electricity supplied under the Project based on simulated results of generation by the Nurek HPP during winter and summer seasons;[27] (iv) average domestic tariffs and export tariffs as presented above, (v) electricity bill collection rates as presented above and (vi) transmission and distribution losses as discussed above.

35. Under the base-case, the incremental cash inflows and outflows were discounted at the estimated cost of the debt to the Project, which was estimated 1.37%. The financial discount rate for the entire Project was assumed to be the same as for Phase I. At this stage, the cost of debt for the entire Project cannot be determined given the uncertainty with future financing envelope. Therefore, the average cost of debt for Phase I was assumed to apply both for the entire Project and the Phase I. There will be no equity financing for the Project and it was assumed that the MOF

[27] For the purposes of this analyses, winter includes generation during the months of October-March and summer includes generation during the months of April-September.

will on-lend the Project funds to BT at the same terms and conditions as stipulated in the legal agreements signed with financiers.

36. Financial costs of the Project. The financial costs include: (i) EPC costs for replacement of electrical, mechanical and electromechanical equipment and the works required for rehabilitation; (ii) supply and installation of six autotransformers; (iii) dam safety enhancement related measures; (iv) PMC, which will be acting as the owner's engineer; and (v) incremental O&M costs. The costs are projected according to the years in which they are expected to be incurred during the Project construction period.[28]

37. Financial benefits of the Project. The financial benefits of the Project were estimated as the avoided reduction in revenues from electricity sales when the Nurek HPP gradually loses generation capacity. The avoided reduction in revenues was estimated for winter domestic sales, and summer exports. The estimates of avoided revenue reduction take into account electricity losses in the power system and the estimated bill collection rates.

- Avoided reduction of revenues from domestic sales in winter was computed as the product of reduction in supply from Nurek and forecast average end-user electricity tariffs. The avoided reduction in revenues due to decline of electricity supply is largest during winter months when electricity demand is the highest and there is no spare capacity in the power system. In fact, there is winter energy deficit.
- Avoided reduction of revenues from summer exports was computed as the product of reduction in supply from Nurek and forecast PPA tariffs, including those signed under CASA. Avoided reduction from summer exports has small impact on financial viability of the Project given that the power system has significant surplus energy, which will increase further with commissioning of Dushanbe-2 CHP and Rogun HPP. Availability of surplus energy for exports due to loss of generation from Nurek will start reducing revenue from exports only starting from 2046. Taking into account that this will be 19 years from commissioning of the rehabilitated Nurek project, the present value of avoided reduction in export revenues is small.
- There is no financial cost to BT during summer months if the Nurek HPP starts losing generation. As explained above, this is due to significant energy surplus during summer months given hydrology and new generation projects. Specifically, Dushanbe-2 CHP and Rogun HPP will be capable of supplying around 10,000 GWh in summer, which exceeds the maximum average 7,700 GWh supply from Nurek.

38. Results: The financial analysis of the Project yielded a financial NPV of US$25,156 million and FIRR of 23 percent. This result suggests that the Project will have significant impact on precluding significant deterioration of financial viability of BT. Without the Project, BT's revenues will significantly reduce exacerbating the financial difficulties of the company.

39. Sensitivity analysis: Sensitivity analysis was conducted to assess the robustness of the estimated Project financial returns to changes in the main evaluation variables. Sensitivity analysis

[28] Project construction costs are not levelized over the operating life of the Project.

covers the following cases that in turn stress test the financial returns to the Project. The results of the sensitivity analyses are presented in the table below.

- 20 percent higher investment cost with the expected base-case values for all other variables.
- Loss of generation capacity at a rate of one unit in three years with the expected base-case values for all other variables. [29]
- Financial cost recovery tariff reached by 2029 instead of 2022 with the expected base-case values for all other variables.
- Combination of the above cases.

Sensitivity Analysis for Financial Evaluation of Entire Project

	NPV (million US$)	FIRR (%)
Base-case	**25,156**	**23**
a. 20 percent higher investment cost	24,940	21
b. Financial cost recovery tariff reached by 2029 instead of 2022	14,245	18
c. Loss of generation capacity at a rate of one unit in three years	21,491	14
d. Combination of a, b, and c	11,435	11

40. The results of the sensitivity analysis suggest that the Project is financially robust even in case of substantial variation of main variables that affect its viability.

Financial Analysis of Phase I of the Project

41. The financial analysis of the Phase I of the Project was conducted using the cost-benefit approach and using the same methodology. The base-case of the analysis for Phase I is similar to the base-case for analysis of the entire Project. The main difference between the financial analysis of the Phase I and the entire Project is the lower financial cost due to rehabilitation of only three generating units.

42. Results: The financial analysis of the Phase I yielded an economic NPV of US$25,979 million and FIRR of 23 percent.

43. Sensitivity analysis: Sensitivity analysis was conducted to assess the robustness of the estimated Phase I financial returns to changes in the main evaluation variables. Sensitivity analysis covers the following cases that in turn stress test the financial returns to Phase I of the Project. The results of the sensitivity analyses are presented in the table below.

[29] Total loss of generation by 2048 instead of 2028 under base-case.

Sensitivity Analysis for Financial Evaluation of the Phase I of the Project

	NPV (million US$)	FIRR (%)
Base-case	**25,979**	**23**
a. 20 percent higher investment cost	25,882	22
b. Financial cost recovery tariff reached by 2029 instead of 2022	21,818	21
c. Loss of generation capacity at a rate of one unit in three years	15,557	13
d. Combination of a, b, and c	12,068	11

Analysis of Financial Performance of BT

44. The assessment of the financial performance of BT is based on: (i) the audited financial statements for 2013–2015; (ii) information and data on tariffs, debts, and projected electricity generation and sales by BT; and (iii) the information obtained during the discussions with the management of BT and WB staff.

45. The financial condition of BT continued to deteriorate in the period from 2013 to 2015, due to (i) unsustainable and increasing debt levels, (ii) low cash collections, and (iii) below cost recovery end-user electricity tariffs.

46. As of the end-2015, BT's total liabilities exceeded its total assets. Operating losses persisted in the period of 2013–2015 leading to complete erosion of equity. Accumulated losses of the BT reached TJS5300 million (US$758 million). In 2015 alone, total liabilities of BT increased by 1.5 times, mainly due to more than 30 percent depreciation of the domestic currency.

47. As of the end-2015, total liabilities of BT stood at TJS11,617 million (US$1,662m), about 55% of which were borrowings from IFIs. The ability to sustain those loans was considerably impaired by absence of corresponding revenue allowance in the tariffs and under-collection of receivables. BT failed to make both principal and interest payments on them. By the end of 2015, it had already accrued TJS1156 million (US$165 million) of interest payable and incurred penalties for delinquency in total amount of TJS1133 million (US$162 million). In addition, BT has TJS1102 million (US$150 million) very expensive short-term dollar denominated commercial debt from a local bank, which costs the company about TJS253 million (US$36 million) per annum in interest expense.

48. The situation with payables deteriorated. In particular, payables for electricity purchases from IPPs - Sangtuda-1 and Sangtuda-2 HPPs (with 2016 tariffs of US$0.023 and US$0.032/kWh respectively) - rose to TJS835 million (US$119 million). BT struggles to make payments to those IPPs in timely manner because the cost of electricity from those IPPs is higher than the end-user electricity tariff and those IPPs primarily supply electricity during the months of April-October (surplus energy season) when the other lower cost HPPs, owned by BT, can generated at significantly lower cost and spill water given low summer demand and lack of export opportunities.

49. In 2015, total current liabilities of TJS5446 million (US$779 million) accounted for 47 percent of total liabilities. Current assets were only one fifth of that amount. This represented a

significant reduction in the liquidity, as measured by the ratio of current assets to current liabilities, which was at 0.39 in 2013.

50. Nonetheless, the relative stability of operating costs before depreciation and 11% average annual growth of sales revenue, driven by end-user tariff increases, lead to substantial improvement of EBITDA margin (25 percent in 2015 vs. 2 percent in 2013) and net debt[30]-to-EBITDA ratio of the company; albeit well above acceptable levels, net debt decreased from 222 times EBITDA in 2013 to 30 times EBITDA in 2015.

51. End-user electricity tariffs remain below the cost-recovery levels, which do not allow the company to finance even the required recurrent expenditures. The expected average end-user tariff for 2016 (12.89 diram/kWh) is estimated 55 percent below the cost-recovery level. The cost-recovery tariff was assessed following the cash needs approach. This was done through assessment of the amount of cash revenue that BT requires to fully finance the recognized recurrent expenses (accrual based items in the financial statements), which include the O&M costs, administrative costs, capital repairs from own funds, pension liabilities, debt service, and taxes. It also assumes gradual repayment of accrued liabilities (i.e., interest payables, overdue loans and payables to Sangtuda-1 and Sangtuda-2 HPPs for purchased electricity) over a five-year period starting 2017. It should be noted that the concept of cash-based cost of service is different from the concept of economically efficient cost of supply and does not take into account the return on invested capital and investments required to meet the long-run forecast electricity demand.

Cost-recovery Tariff Calculation

TJS million	2016F	2017F	2018F	2019F	2020F	2021F
[+] Cash cost of sales	**837**	**993**	**1,036**	**1,081**	**1,128**	**1,177**
Cost of purchased electricity	514	537	560	584	610	636
Cost of inventory used	160	184	195	206	219	232
Salary expenses	87	94	100	106	112	119
Taxes	34	34	34	34	34	34
Direct operating expense of Dushanbe-2 CHP	-	100	100	100	100	100
Other expenses	41	44	47	50	53	56
[+] Cash selling expenses	**320**	**353**	**374**	**397**	**420**	**446**
[+] Cash admin expenses	**79**	**83**	**86**	**89**	**92**	**95**
[+] Financing costs	**558**	**1,734**	**1,771**	**1,790**	**1,882**	**1,897**
Interest payments on IFI loans	242	275	288	299	309	302
Principal repayment on IFI loans	316	422	446	454	536	558
Payables for electricity purchase to Sangtuda-1	-	114	114	114	114	114
Payables for electricity purchase to Sangtuda-2	-	74	74	74	74	74
Interest payables on IFI loans	-	261	261	261	261	261
Overdues on IFI loans	-	340	340	340	340	340
Orienbank loans	-	248	248	248	248	248
[+] Profit	**-**	**-**	**-**	**-**	**-**	**-**
[=] Revenue requirement	**1,794**	**3,163**	**3,267**	**3,356**	**3,522**	**3,616**
Revenue from export	376	376	376	376	376	376
Revenue from domestic sales	1,419	2,787	2,891	2,980	3,146	3,240

[30] Net debt = total liabilities – cash and cash equivalents.

TJS million	2016F	2017F	2018F	2019F	2020F	2021F
Electricity dispatched to domestic consumers (million kWh)	**12,900**	**13,567**	**13,567**	**13,567**	**13,567**	**13,567**
Cost recovery tariff incl. VAT (Diram/kWh)	**12.98**	**24.24**	**25.15**	**25.92**	**27.36**	**28.18**
Proposed tariff increase schedule (Diram/kWh)	**12.79**	**14.48**	**16.95**	**19.85**	**23.25**	**27.22**

52. In 2015, BT earned TJS1548 million (US$252 million) from sales of electricity. The Company supplied 12,817 GWh of electricity to domestic consumers and exported 1,340 GWh to Afghanistan and the Kyrgyz Republic. The weighted average export price of electricity was US$0.035/kWh.

53. The collection rate for billed electricity was still below the industry average, at around 83 percent. As of the end of 2015, the Company had receivables outstanding for 97 days. The aluminum producer, TALCO, is the largest debtor to BT with its total debt of TJS412 million (US$59 million).

Bill Collection Rates by Customer Categories

Customer category	Bill collection rate (%)
Industry, excl. TALCO	96.0
TALCO	88.4
Utilities, state organizations, transport	76.2
Pumps and water pumping stations	27.6
Residential consumers	78.6
Average	**83.0**

54. **Forecast of Financial Performance of BT**. Financial performance of BT was forecast for two scenarios. The base-case scenario is based on the agreed-upon targets to be achieved by BT as reflected in the Action Plan for Financial Recovery of BT, including increase of end-user average tariff, improvements in collection rates, and other efficiency improvements. The conservative scenario assumes lower increase in average end-user tariffs, smaller improvements in collection rates and other financial efficiency indicators such as days of receivables outstanding and inventory turnover. The key assumptions for each of the forecast scenarios are presented below.

Key Assumptions underlying Forecast of Financial Performance

Base-Case Scenario	2017	2018	2019	2020	2021	2022	2023	2024	2025
Increase of average end-user tariff	13%	15%	15%	15%	15%	15%	6%	6%	6%
Electricity bill collection rates	88%	90%	93%	95%	95%	95%	95%	95%	95%
Days receivables outstanding	82	68	49	30	30	30	30	30	30
Inventory as days of sales	121	65	65	65	65	65	65	65	65
Conservative Scenario	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**

Base-Case Scenario	2017	2018	2019	2020	2021	2022	2023	2024	2025
Increase of average end-user tariff	12%	12%	12%	12%	12%	11%	4%	4%	4%
Electricity bill collection rates	87%	89%	90%	90%	90%	90%	90%	90%	90%
Days receivables outstanding	88	80	69	60	60	60	60	60	60
Inventory as days of sales	178	150	150	150	150	150	150	150	150

Base-Case Forecast of Financial Performance of BT

55. The projected financial performance of BT takes into account the targets specified in the Action Plan for Financial Recovery of BT and expected increase in export revenues starting from 2022 when CASA-1000 project is commissioned. In particular, projections of financial performance of BT were made on assumptions that:

(a) End-user electricity tariffs will converge to their cost-recovery levels by 2022, which implies an average annual tariff increase of 15 percent; from 2022 onward, end-user electricity tariff is assumed to increase at the nominal rate of 6 percent.

(b) Total power generation and domestic supply will increase by about 5 percent in 2017 upon completion of the Second Phase of construction of Dushanbe-2 CHP.

(c) Exports are forecast to increase by 2,800 GWh starting from 2022, when cross-border transmission facilities with Afghanistan and Pakistan under CASA-1000 project become operational.

(d) Power purchase prices under PPAs with Afghanistan and Pakistan are assumed to be US0.051/kWh and US$0.0515/kWh respectively.

(e) Prices of electricity purchased from Sangtuda-1 and Sangtuda-2 will growth at annual rate of 4 percent and 5 percent respectively.

(f) Bill collection rate will improve by 2 percent per year to reach 95 percent over a five-year period.

(g) Receivables will reduce from 85 to 45 days of sale by 2020.

(h) Inventory will reduce from 233 to 65 days of cost of sales by 2018; and

(i) From 2016 onward, the exchange rate of TJS against US dollar will be at TJS7.88 per US dollar.

56. Until 2020, BT will continue to experience deterioration in liquidity and financial leverage due to persisting net losses, slow reduction of accrued liabilities and expected disbursements under ongoing projects. The ratio of current assets to current liabilities will decrease to 0.08 from 0.20 in 2015, and debt-to-assets ratio will increase to 1.2.

57. At the end of 2016, BT will have accrued liabilities for a total TJS5131 million. Total debt service requirements for the forecast period of 2016–2025, including repayment of accruals, are estimated at TJS13,966 million, as shown on Figure 1 below. During the same period tariff

increases, improved collections and working capital management are expected generate an additional TJS15,805 million in cash. Once target collection rates and days receivables are reached in 2020, available operating cash flow of BT will allow to accelerate repayment of outstanding commercial debt, accrued payables for electricity and debts to IFIs. In that year, the EBITDA margin will increase to 54 percent, and operating cash flow per unit of sales is expected to increase fivefold to TJS0.50.

58. Commencement of electricity exports under the CASA-1000 project will also significantly contribute to improvement of financial standing of BT starting from 2022. The exports will increase from current level of 1,340 GWh to more than 4,100 GWh per year, including the existing exports to Afghanistan. Specifically, exports under the CASA-1000 project are expected to generate an additional US$150 million of income per year.

59. The Government is currently considering the following option for resolving the short-term indebtedness issue. BT will gradually repay the commercial loans to Orienbank in 2018–2021 using incremental operating cash flows from financial recovery measures. The increase of the incremental cash flows of BT was estimated assuming implementation of the Action Plan for Financial Recovery of BT. It was assumed that the loans will either be rolled over each year on the date of the repayment as was the practice before or will be restructured to long-term loans.

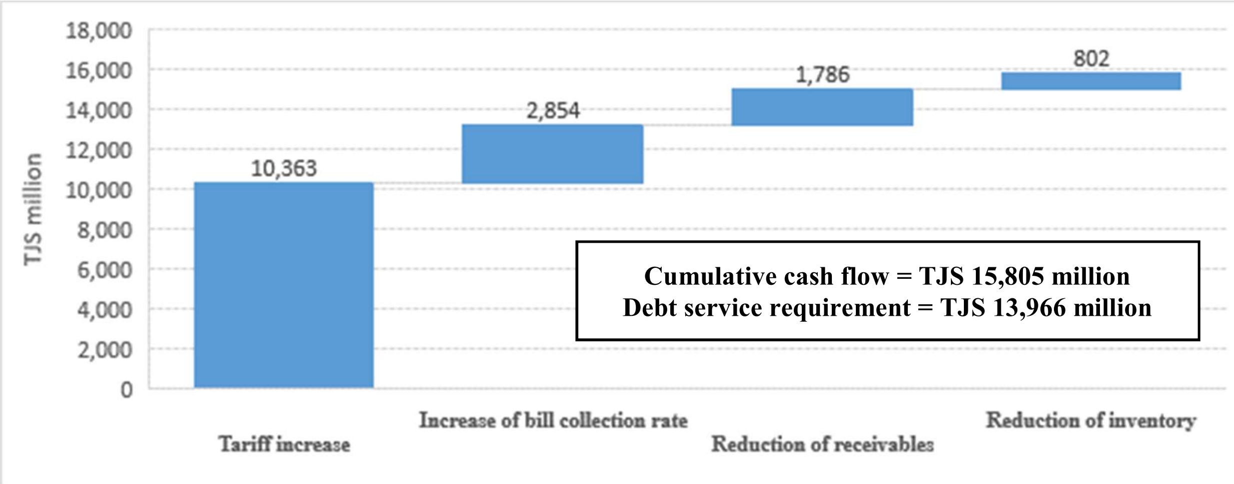
Impact of Financial Recovery Measures

	2016F	2017F	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F
Additional cash flow, million TJS	20.3	168.7	397.5	670.1	981.6	1,287.0	1,461.6	1,631.1	1,789.0	1,956.3
Additional cash flow, million TJS	33.6	79.9	140.3	219.1	295.2	345.7	397.7	421.6	446.9	473.7
Additional cash flow, million TJS	149.3	200.3	268.0	357.4	334.6	73.8	86.4	99.4	105.4	111.7
Additional cash flow, million TJS	164.4	219.1	214.6	22.5	25.1	23.2	52.3	26.5	26.2	28.0
Total cash flow	**367.6**	**667.9**	**1,020.4**	**1,269.0**	**1,636.5**	**1,729.7**	**1,998.1**	**2,178.7**	**2,367.5**	**2,569.7**
Cumulative cash flow	**367.6**	**1,035.5**	**2,055.9**	**3,325.0**	**4,961.4**	**6,691.1**	**8,689.2**	**10,867.9**	**13,235.4**	**15,805.1**

Debt Repayment Schedule under Base-Case Scenario

TSJ million	2016F	2017F	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F
Principal payment on IFI loans	217	252	446	454	536	558	613	605	605	605
Interest payment on IFI loans	242	268	277	285	289	277	260	236	212	189
Interest payment on Orienbank loan	253	286	286	268	211	106	-	-	-	-
Repayment of Orienbank loans	-	-	75	248	459	459	-	-	-	-
Repayment of payables to Sangtuda-1 & Sangtuda-2	-	-	-	-	44	62	160	177	222	222
Repayment of arrears on IFI loans	-	-	-	-	-	85	340	425	425	425
Repayment of interest payables	-	-	-	-	-	-	586	586	130	-
Total debt service requirement	**713**	**805**	**1,083**	**1,256**	**1,540**	**1,547**	**1,960**	**2,029**	**1,594**	**1,440**
Cash available for debt service	**729**	**827**	**1,111**	**1,293**	**1,596**	**1,629**	**2,862**	**3,978**	**5,070**	**6,708**

Cumulative Impact of Financial Recovery Measures vs. Debt Service Requirements



60. By 2025, net debt of BT is forecast to decrease to 2 times EBITDA, and by 2023 the debt service coverage ratio will have reverted to a sustainable level of 1.11, as shown in Table 13 below. Detailed debt repayment schedule is presented in table below.

Financial Ratios under Base-Case Scenario

	2013A	2014A	2015A	2016F	2017F	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F
Gross margin	52%	18%	41%	40%	39%	44%	49%	54%	59%	70%	70%	70%	71%
EBITDA margin	2%	12%	25%	28%	29%	37%	44%	50%	49%	62%	63%	63%	63%
OCF/Revenue	3%	16%	10%	38%	40%	47%	48%	50%	43%	51%	52%	51%	51%
Current ratio	0.39	0.29	0.20	0.16	0.14	0.10	0.09	0.08	0.09	0.27	0.56	1.08	1.86
Debt-to-assets	0.60	0.74	1.01	1.14	1.18	1.20	1.20	1.17	1.12	0.96	0.82	0.69	0.58
Operating cash flow / short-term debt service	0.05	0.10	0.06	0.11	0.08	0.15	0.20	0.25	0.31	0.52	0.95	1.48	1.95
DSCR	0.02	0.08	0.04	0.13	0.11	0.15	0.20	0.27	0.38	0.82	1.11	1.70	2.42

Conservative Forecast of BT Financial Performance

61. If BT does not fully achieve the targets specified in the Action Plan for Financial Recovery of BT, then the company's financial performance will remain distressed. Specifically, the current assets will not be sufficient to cover the current liabilities even by the end of the forecast period. BT will not be able to repay the short-term commercial debt until 2024 and will only be able to repay portion of the payables to IPPs. The debt service coverage ratio will reach 1.1 by 2025. The details are presented in the tables below.

Debt Repayment Schedule under Conservative Scenario

TSJ million	2016F	2017F	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F
Principal payment on IFI loans	121	82	246	360	499	521	613	605	605	605
Interest payment on IFI loans	242	268	277	285	289	277	260	236	212	189
Interest payment on Orienbank loan	253	286	286	286	286	286	286	-	-	-
Repayment of Orienbank loans	-	-	-	-	-	-	993	248	-	-
Repayment of payables to Sangtuda-1 & Sangtuda-2	-	-	-	-	-	-	-	44	177	666
Repayment of arrears on IFI loans	-	-	-	-	-	-	-	1,020	680	-
Repayment of interest payables	-	-	-	-	-	-	-	-	573	730
Total debt service requirement	**617**	**635**	**809**	**931**	**1,073**	**1,083**	**2,153**	**2,153**	**2,248**	**2,188**
Cash available for debt service	**620**	**646**	**836**	**969**	**1,129**	**1,163**	**2,282**	**2,410**	**2,542**	**2,594**

Financial Ratios under Conservative Scenario

	2013A	2014A	2015A	2016F	2017F	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F
Gross margin	52%	18%	41%	40%	38%	42%	45%	48%	51%	65%	65%	65%	64%
EBITDA margin	2%	12%	25%	27%	28%	33%	37%	40%	40%	55%	56%	55%	54%
OCF/Revenue	3%	16%	10%	32%	32%	37%	39%	40%	37%	49%	48%	44%	33%
Current ratio	0.39	0.29	0.20	0.17	0.16	0.15	0.14	0.14	0.15	0.17	0.21	0.29	0.43
Debt-to-assets	0.60	0.74	1.01	1.14	1.18	1.21	1.23	1.23	1.23	1.13	1.03	0.92	0.81
DSCR	0.02	0.08	0.04	0.13	0.11	0.13	0.15	0.17	0.20	0.42	0.52	0.72	1.09

Annex 4: Sovereign Credit Fact Sheet

A. Recent Economic Development

Tajikistan is a low-income country with rich water resources but scarce oil and gas resources. Despite suffering the negative effect of the 2008–2009 global crisis, Tajikistan's economy recovered quickly with average annual growth over 7 percent during 2010–2013, partly due to private consumption boom spurred by remittance inflows.

Growth softened and the external position weakened during 2014–2015, with a growth rate at 6.7 percent in 2014 and 4.2 percent in 2015. Remittances fell in line with the slowdown in Russia, and earnings from cotton and aluminum exports dropped due to global market developments. Despite regional headwinds, Tajikistan's economy grew by a robust 6.6 percent, during the first half of 2016, supported by a substantial increase in public investment. The GDP growth rate is projected to remain broadly stable at 6 percent in 2016, supported by the ongoing expansion of industry, construction, and agriculture.[31]

B. Economic Indicators

Selected Macroeconomic Economic indicators (2014–2018)

Economic Indicators	2014	2015*	2016*	2017*	2018*
National income and prices (change %)					
Real GDP	6.7**	4.2**	6.0**	6.0	6.2
CPI inflation (change %, end of year)	6.5	7.0	7.0	7.0	6.0
Central government operations (% of GDP)					
Overall Fiscal balance	-1.6	-1.7	-1.4	-1.2	-0.9
Total external debt (% of GDP)	45.9	44.0	42.1	40.3	41.5
Total public sector debt	31.7	31.0	30.4	30.1	29.5
Money and credit					
Broad money (M2, % end period) ***	3.5	12.2	--	--	--
Foreign direct investment (% of GDP)	1.6	1.8	2.0	2.2	2.5
Gross reserves (months imports)	1.5	1.7	1.9	2.2	2.5
Current account balance (% of GDP)	-2.5	-2.0	-2.0	-2.2	-2.3
Exchange rate (National currency/$, end period) ***	5.3	7.0	--	--	--

Note: * denotes projected figures. Source: World Bank Country Partnership Strategy 2014, ** Tajikistan economic update 2015 Fall,***CEIC

C. Economic Outlook and Risks

Looking ahead, an incipient recovery in Russia should support a moderate increase in remittances but domestic vulnerabilities increase and the ongoing fiscal adjustment may negatively impact on

[31] The WB in Tajikistan, Country Snapshot, October 2016.

growth. Downside risks include lower emerging market growth and instability in parts of the region.[32]

For debt outlook, the 2013 Debt Sustainability Assessment (DSA) for Tajikistan lowered the risk of debt distress from high to moderate, and further from moderate to low risk of debt distress in the 2015 DSA. However, since then a number of stress factors have come to the fore and create significant uncertainties and risks related to the macroeconomic framework, which may lead to a change in debt risk level.[33]

[32] IMF, 2016. Press Release No. 15/268– Press Release: IMF Executive Board Concludes 2015 Article IV Consultation with Tajikistan, June 9, 2015.
[33] WB, Tajikistan Economic Update No. 2 Fall 2015. 2016 DSA of Tajikistan has not been published by IMF.

Annex 5: Status of Achievement of Key Short-term Measures to Improve Financial Standing of BT, March 2017[34]

Measure		Current Issues	Outcomes and Targets	Status	Key Next Steps by the Government
1. Tariffs					
1.1	Adopt a cost-recovery electricity tariff methodology.	Existing tariff-setting methodology does not allow for recovery of the required costs of electricity service.	- A cost-recovery tariff methodology, eliminating cross-subsidies among consumer categories, is adopted by December 31, 2016, which will allow to include into the tariff: • cost of energy, • operating and maintenance costs, general and administrative expenses, capital repairs, • salaries, • debt service, and • taxes. - Regulatory reporting forms required for implementation of the new tariff-setting methodology are approved by December 31, 2016.	- BT submitted the new Concept of Electricity Tariff Policy for Government review and it is expected to be included in the Cabinet's upcoming session in the end of January 2017. - The Government Working Group will finalize the detailed methodology after the Government approval of the Concept of Electricity Tariff Policy.	- By February 28, 2017, the Government approves the new Concept of Electricity Tariff Policy, which is consistent with the principles of cost-recovery. - By February 28, 2017, the MEWR submits for review of the WB and other development partners the principles of new electricity tariff methodology. - By December 30, 2017, the Government approves the new electricity tariff methodology, which is consistent with the principles of cost-recovery.

[34] Source: WB Project Appraisal Document (2017)

	Measure	Current Issues	Outcomes and Targets	Status	Key Next Steps by the Government
1.2	Define institutional arrangements to implement the new electricity tariff methodology.	Currently, there are no clearly defined institutional arrangements in place to implement the new electricity tariff methodology.	- The Government designates by December 30, 2016 a specific unit/department to compute tariffs as per new methodology. - Phase II of EBRD's Regulatory Program TA would provide support to the Government with the establishment and operations of the new tariff setting unit. This support includes drafting changes to the existing legislation, providing training to staff on the new cost-recovery methodology as well as other tasks set out in the Terms of Reference for the above TA. - The relevant entity to be designated by the Government should be capable of reviewing and approving the tariff computations as per new tariff methodology.	- The Anti-Monopoly Commission will be responsible for review of tariffs computed as per new methodology and providing advice to the Cabinet of Ministers regarding approval. BT will compute the tariffs as per new methodology.	Implement the proposed institutional arrangement.

Measure		Current Issues	Outcomes and Targets	Status	Key Next Steps by the Government
1.3	Prepare a schedule and a path for electricity tariff increase to cost-recovery level.	- The Government increased the average electricity tariff by 25% in 2012 and 15% in 2014. - The average tariff for 2015 was TJS12.5/kWh, which is substantially below the estimated full cost-recovery level.	- Tariffs are increased by at least 15% by November 1, 2016. - Tariffs are increased annually and gradually to reach cost-recovery level, taking into account reduction of losses and improvement of electricity bill collection rates.	- The Government increased the average tariff by 12% from November 1, 2016. The tariffs for all categories of consumers were increase by 16.5%. However, the tariff for TALCO was not increased. Thus, the average was only 12%.	- By February 28, 2017, the Government approves the tariff increase for pumping irrigation, electric transport, and budget financed organizations. - By March 30, 2017, the MEWR submits to the WB the approved BT Financial Recovery Plan, which, inter alia, will contain the path for tariff increases required to reach cost-recovery.
1.4	Develop suitable mechanisms to mitigate social impacts of electricity tariff increases.	- The poverty in Tajikistan is estimated at over 32% (World Bank Development Indicators, 2014) and electricity tariff increase will make it more difficult for the poor to afford basic level of energy consumption. - Winter energy shortages coupled with electricity tariff increases will	By June 30, 2017, the Government submits a plan on mitigation of electricity tariff increases on the vulnerable consumers with a clear definition of what constitutes a vulnerable consumer. This should include description of the social policy measures and mechanisms the Government plans to use for protecting the vulnerable consumers.	The Government Working Group is finalizing the time-bound action plan for implementation of new tariff policy, including tasks to the relevant ministries for development of social mitigation measures.	By June 30, 2017, the MOF/Ministry of Health and Employment submits to the WB the description of the proposed mechanisms for mitigation of social impacts of tariff increases on the poor.

Measure		Current Issues	Outcomes and Targets	Status	Key Next Steps by the Government
		worsen the energy deprivation. - The WB has been providing technical assistance to reform/improve the existing social safety net of the country. Going forward, additional support will be provided by WB (under the subsidy window of the Energy Sector Management Assistance Program) and EBRD (Regulatory Reform TA) to help the Government put in place adequate safety net to protect the poor.			
2. BT Financial Improvement					
2.1	Improve the average collection rate for billed electricity.	Increased from 63% in 2013 to 83% in 2015, including collection from TALCO.	- Average for 2016, inclusive of TALCO, increases to 87%, which will generate additional	BT submitted to the WB a preliminary assessment of the collection rate for 2016.	By June 30, 2017, BT submits to the WB the audit report for BT 2016 annual financial statements. This will allow confirming the

Measure		Current Issues	Outcomes and Targets	Status	Key Next Steps by the Government
			TJS64 million (US$8 million)[35] **of cash.** - Average for 2017 increases to 88%. - Average for 2018 increases to 90%.		preliminary estimate for 2016 collections rate.
2.2	Reduce the time period between the sale of energy and collection of cash.	The number of days receivables are outstanding reduced from 104 days in 2013 to 91 days in 2015 as per financial statements compliant with International Financial Reporting Standards (IFRS).	- Reduction to 85 days by the end of 2016, which will generate additional **TJS25 million (US$3 million) of cash.** - Accounts receivable from TALCO reduce from TJS412 million (US$52 million) as of December 31, 2015 to TJS312 (US$39 million) as of December 31, 2016 (to be reflected in audit of BT's annual financial statements for 2016). - Accounts receivable from TALCO further reduce to TJS212 (US$39 million) as of December 31, 2017 (to be reflected in audit of BT's annual financial statements for 2017). - BT adopts a policy on allowance for doubtful	Will be estimated after BT submits to the WB the un-audited financial statements for 2016.	By February 22, 2017, BT submits to the WB the un-audited financial statements for 2016.

[35] All US$ equivalents are based on the average annual exchange rate for 2015.

Measure		Current Issues	Outcomes and Targets	Status	Key Next Steps by the Government
			receivables and write-offs, and the auditor of BT's financial statements for 2016 confirms its adoption.		
2.3	Increase efficiency of inventory management.	Average inventory reduces from 265 days in 2013 to 174 days in 2015 as per IFRS compliant financial statements.	Reduction to 130 days by the end of 2016, which will save **TJS120 million (US$15 million) in expenses.**	Will be estimated after BT submits to the WB the un-audited financial statements for 2016.	By February 22, 2017, BT submits to the WB the un-audited financial statements for 2016.
2.4	Develop a plan to repay the commercial debt and restructure liabilities in the form of fines and penalties on overdue debt service obligations.	As of the end-2015, the outstanding principal amount of short-term commercial debt was TJS1.2 billion or US$150 million (75% of annual revenue) at an effective annual rate of 22%. As of the end-2015, the accumulated fines and penalties for overdue debt service were TJS1.1 billion (US$137 million). As of the end-2015, the outstanding principal amount of loans from the MOF totaled TJS6.4billion or US$800 million (4.2 times annual revenue).	Prepare by December 15, 2016 a detailed plan for: (i) restructuring/repayment of the outstanding expensive commercial debt with specific time-lines and sources of funds/activities towards that effect; (ii) restructuring/write-off/conversion into equity of the portion of long-term loans from the MOF; and (iii) payment/restructuring/write-off/conversion into equity of accrued and unpaid interest and fines and penalties owed to MOF for overdue debt service payments on loans. The detailed plan together with the new tariff methodology shall allow the company to service its debt and maintain positive equity.	No debt restructuring plan was prepared and submitted to the WB yet.	By March 30, 2017, the MEWR submits to the WB the approved BT Financial Recovery Plan, which will include the proposed approach for resolution of the issue of BT's short-term debt to Orienbank.

Measure		Current Issues	Outcomes and Targets	Status	Key Next Steps by the Government
2.5	Unqualified audit opinion on BT's financial statement for fiscal year 2016.	- Until 2013, auditors of BT's annual financial statements issued disclaimer of opinion because the accounting for important items as receivables, payables and value of assets was not consistent with IAS and the reporting was not consistent with IFRS. - The auditors issued qualified opinion on 2014 and 2015 BT financial statements, which is a major progress. - The main reason for qualification was absence of the procedure for recognition of revenues and receivables.	Unqualified opinion on 2016 financial statements. Audit report will be published by June 30, 2017.	- BT signed the contract with the auditor and the auditor has already commenced the services.	- BT continues to implement the recommendations of the auditor related to issues identified during audit of 2015 financial statements in order to receive an unqualified audit opinion. - By June 30, 2017, BT submits to the WB the audit report for financial statements for 2016 and the Letter to the Management.
3. Functional Unbundling and Business Plan					

Measure		Current Issues	Outcomes and Targets	Status	Key Next Steps by the Government
3.1	Progress with unbundling of BT.	BT has already completed functional unbundling at one of the service zones - Central Electric Networks.	Functional unbundling of two or preferably three service zones of BT is completed by December 31, 2016.	Functional unbundling of BT completed.	No further actions required from the Government as part of this measure.
3.2	Adoption of a 5-year business and financial plan as well as a code of corporate governance.	- No business and financial plan. - No code of corporate governance.	BT adopts a 5-year business and financial plan as well as a code of corporate governance by June 30, 2017.	- No progress with preparation of business plan. - No progress with preparation of the code of corporate governance.	By March 30, 2017, BT prepares and submits for the WB review the draft of the 5-year business plan and the code of corporate governance.

Annex 6: Financial Recovery Plan of BT (approved by the Government of Tajikistan on April 5, 2017)[36]

Action Plan for Financial Recovery of OJSHC "Barki Tojik"

No	Activities	Responsible Agencies	Deadlines	Activity Results
1.	Adopt the Concept of New Tariff Policy and develop and approve a cost recovery tariff methodology by the end of 2017.	MEWR, MOF, Ministry of Justice (MOJ), Ministry of Economic Development and Trade (MOEDT), Antimonopoly Service, BT	2017–2018	The Concept of New Tariff Policy includes the foundations of norms for calculation of tariffs and provides the methodology for tariff calculation to cover all production costs, including generation, transmission, distribution of electricity, operational cost, repair and equipment maintenance cost, administrative costs, salaries, capital costs, debt service and tax liabilities.
2.	Gradual increase of electricity tariff by 2022 to a full cost recovery level.	MEWR, MOEDT, MOF, MOJ, Antimonopoly Service, BT	2018–2022	Increase of BT revenues from electricity sales to domestic consumers.
3.	Improve tariff collection rate for billed electricity and reach 95% collection rate by 2021	BT	On regular basis	Increase of BT revenues from electricity sales to domestic consumers.
4.	Ensure gradual collection of old receivables for billed electricity sales in the past and achieve a minimal level of receivables by 2022	BT	2018–2022	Increase of liquid assets, reduction of losses due to exchange rate differences and contribution to strengthened balance sheet of BT.
5.	Increase efficiency of inventory management at BT and purchase only necessary materials	BT	On regular basis	Improvement of cash conversion cycle, which will reduce the costs. Besides, it will have positive impact on the procurement discipline and policy of BT.

[36] Translated by the WB.

No	Activities	Responsible Agencies	Deadlines	Activity Results
6.	Reduce receivables from current sales of energy	BT	On regular basis	Reduction of time period between billing and collection of funds will have positive impact on the cash conversion cycle and ensure increase in operating cash. At present, the time period covers from 20 to 60 days.
7.	Determine actual level of electricity losses (commercial losses in particular) according to the requirements of IFIs.	MEWR, BT	On regular basis	Actual losses and key sources will be determined and accounting of actual balance will be ensured.
8.	Further reduction of technical losses.	BT	On a regular basis	Given winter energy deficit, reduction of technical losses will allow to increase supply of electricity during winter period.
9.	Fully abandon subsidization of separate groups of electricity consumers.	MOF, MOJ, MOEDT, MEWR, Antimonopoly service, BT	On a regular basis	Losses will be reduced and revenues of BT will increase.
10.	Ensure mandatory payments to IPPs and annual offset of BT liabilities to OJSC "Sangtuda-1" at the expense of tax liabilities of the latter.	MOF, MEWR, Antimonopoly service, BT	On a regular basis	Increased ability to meet obligations to OJSC "Sangtuda-1".
11.	Write-off of non-performing loans of the bankrupt companies and residents.	MEWR, BT	February, 2017	Improved accuracy of balance sheet, which will help to improve the financial situation of BT.
12.	Develop and submit recommendations on improving the debt situation of BT.	MOF, MOJ, MEWR, BT	On regular basis	Revisiting some of the financial obligations of BT to the MOF will allow to improve the financial situation of BT.
13.	Gradual repayment of the outstanding principal amount of short-term commercial debt of BT from additional funds generated as a result of implementation of above- mentioned measures.	BT	On a regular basis	Implementation of all measures specified in this Action Plan will increase cash revenues and improve the ability of BT to repay the principle amount of debt.

No	Activities	Responsible Agencies	Deadlines	Activity Results
14.	Taking urgent and efficient measures in installation of the energy billing system at all billing points.	MEWR, BT	2018–2020	Increase of electricity sales and reduction of losses; increase in cash collections.
15.	Increasing efficiency in collecting the debts from consumers by full execution of decisions taken by the economic court and formalized claims.	BT	On regular basis	BT will receive additional revenues.
16.	Ensure full and timely payment of bills for electricity used by TALCO.	Ministry of Industry and New Technologies, MEWR, TALCO, BT	On regular basis	BT will receive additional revenues.
17.	Payment of the bills by the state budget financed organizations based on the actual use of energy.	MOF, MOEDT, BT	On regular basis	The amount of BT's receivables will reduce and cash conversion cycle will improve.

Agreed with OJSHC "Barki Tojik" Supervisory Board members:

Minister of Energy and Water Resources	Usmonzoda Usmonali
Minister of Industry and New Technologies	Bobozoda Shavkat
Minister of Economic Development and Trade	Hikmatullozoda Nematullo
Minister of Justice	Shohmurod Rustam
Chairman of the State Committee on Investments and Management of State Property	Kahhorzoda Faiziddin
Chairman of OJSHC "Barki Tojik"	Ismoilzoda Mirzo
First Deputy Chairman of the Minister of Finance	Karimzoda Jamshed

I HEREBY APPROVE
Azim Ibrohim
Deputy Prime-Minister
of the Republic of Tajikistan

Results Matrix of Potential Impact of the Implementation of the Action Plan for Financial Recovery of OJSHC "Barki Tojik"[37]

	Financial Recovery Measures	**Target and Unit**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**TOTAL**
1	Increase the average tariff	Percent (%)	15	15	15	15	15	15	
		Additional revenue, million TJS	167	390	651	925	1225	1412	**4,771**
2	Increase the collection rate for billed electricity	Percent (%)	88	90	93	94	95	95	
		Additional revenue, million TJS	53	102	189	247	319	369	**1,279**
3	Gradual collection of old receivables for billed electricity	Additional revenue, million TJS	37	37	37	37	37	37	**222**
4	Reduce receivables due to current sale of energy	Additional revenue, million TJS	80	158	213	276	333	175	**1,235**
5	Increase efficiency of inventory management in OJSHC "Barki Tojik" and purchase only necessary materials	Additional revenue, million TJS	50	50	50	50	50	50	**300**
6	Reduce technical loss of energy for 0.5 percent per annum	Additional revenue, million TJS	4	11	21	28	42	59	**165**
RESULTS									
7	Forecast revenues without implementation of recovery measures	Million TJS	2162	2404	2670	2992	3348	4881	**18,457**
8	Forecast operating costs of OJSHC "Barki Tojik" taking into consideration fulfillment	Million TJS	2241	2338	2672	3112	3560	4390	**18,313**

[37] Translated by the WB.

	Financial Recovery Measures	Target and Unit	2017	2018	2019	2020	2021	2022	TOTAL
	of financial obligations (except for the credit agreements and full payment of interests to commercial banks)								
9	Free cash flow without implementation of recovery measures (difference between items 7 and 8)	Million TJS	-79	66	-2	120	-212	491	**144**
10	Free cash flow for fulfillment of financial obligations (total of items 1-6 and 9)	Million TJS	312	814	1159	1443	1794	2593	**8,115**
11	Ensure payment of long-term debts (interests + principal amount), including payment of interests to the local commercial banks (calculated based on the requirements of agreements)	Million TJS	756	784	876	935	929	975	**5,255**
12	Remaining funds for fulfillment of other financial obligations (difference between items 10 and 11)	Million TJS	-444	30	283	508	865	1618	**2,880**
13	Debt to Sangtuda-1	Million TJS							**654**
14	Debt to Sangtuda-2	Million TJS							**458**
15	Interest paid under long-term loans	Million TJS							**1,156**
16	Principal amount not paid under long-term loans	Million TJS							**1,508**
17	Debt to OJSC “Oriyonbank”	Million TJS							**1,347**
18	**Deficit**	**Million TJS**							**-2,263**
19	Additional liquidity injection into BT, including grants and concessional loans from IFIs	Million TJS							**2,263**
20	**Deficit**	**Million TJS**							**0**

Agreed with OJSHC “Barki Tojik” Supervisory Board members:

Minister of Energy and Water Resources	Usmonzoda Usmonali
Minister of Industry and New Technologies	Bobozoda Shavkat
Minister of Economic Development and Trade	Hikmatullozoda Nematullo
Minister of Justice	Shohmurod Rustam
Chairman of the State Committee on Investments and Management of State Property	Kahhorzoda Faiziddin
Chairman of OJSHC "Barki Tojik"	Ismoilzoda Mirzo
First Deputy Chairman of the Minister of Finance	Karimzoda Jamshed