**Republic of Tajikistan**

**Power Utility Financial Recovery Program-for-Results**

**(P168211)**

**Program Technical Assessment**

**Final Report**

**November 1, 2019**

1. **Technical Assessment of the Program Activities**
2. The Program supported under the proposed Program-for-Results (PforR) is technically sound and includes all of the key measures required for reverting BT to adequate financial condition and improving reliability of electricity supply. The Program is underpinned by solid analytical work and technical justifications. BT prepared a detailed financial model of the company, which identified key factors impacting profitability, liquidity, and solvency. Thereafter, the key priority measures to improve the financial performance of BT were identified and the financial impact from their implementation was estimated. The proposed priority measures to improve financial standing of BT were estimated to be robust and the impacts were estimated correctly.

***Results Area 1: Achievement of Financial Viability of BT***

1. **Implementation of the cost-recovery tariff methodology and further optimization of end-user tariff structure would increase BT’s operating cash flows**. The new cost recovery methodology allows for full recovery of cash costs at each segment of the power system value chain – generation, transmission, and distribution. It would also allow to cover the costs of dispatch services and the market operator. It should be noted that the Program aims to achieve only the Level 2 of the cost recovery, which is defined as the total revenue required to cover cost of energy from IPPs; O&M costs; debt service; and taxes, and does not include return on assets.[[1]](#footnote-1) The details on the cost-recovery ladder are presented in the Program Technical Assessment Report.
2. Moreover, currently, the end-user tariffs are differentiated by multiple groups of consumers, which is not supported by any clear allocation of costs, economic rationale or policy considerations. The end-user tariff structure would need to be revised and be based on certain technical and economic principles such as voltage level.
3. **Technical assessment**. Consistent implementation of the conceptually sound tariff methodology, coupled with clear trajectory for tariff increases to reach financial cost recovery and adequate institutional capacity to implement it, are essential for long-term financial viability of BT. The implementation of the tariff methodology should be based on the following key building blocks. The annual tariff adjustments can be continued even if all the key steps, summarized in the following table, are not completed. This would be possible given that BT already has an estimate of the total cost of electricity supply and can make annual adjustments accordingly until the more detailed cost allocation and end-user tariff structure adjustments are completed.

**Table 1: Key Steps in Implementation of Electricity Tariff Methodology.**

|  | **Key Steps** | **Activities** |
| --- | --- | --- |
| I | Approval of new electricity tariff methodology | The tariff methodology should be formally approved and become mandatory for computation of electricity tariffs by the regulated entity (BT) and the entity that would be reviewing and making recommendations to the Government regarding the tariffs (completed). |
| II | Establishment of institutional capacity for implementation of new tariff methodology | *Long-term:* Setting up an independent regulator with transparent processes that will be in charge of the tariff work is the long-term objective. However, this can require many years depending on different factors: availability of all required competences, political environment, required institutional processes, etc.  *Short to medium-term:* The most important first step is setting a technical tariff unit under the umbrella of whatever ministry or organization the decision makers see appropriate and easily executable. The objective is to develop the technical capability as soon as possible, without any institutional requirement.  The tariff unit needs to include operational (engineering) and finance competences. At minimum, it should be comprised of the following key staff:   * One senior engineer specialized in generation; * One senior engineer specialized in transmission and distribution; * One economist; * Two financial analysts (one senior and one junior); * One lawyer to supervise licensing. |
| III | Evaluation of electricity demand | Preparation of electricity demand forecasts for each tariff category based on the following key inputs:   * Historical demand data, including estimated un-served energy demand; * Billing database for the most recent year to determine consumption patterns; * Household expenditure surveys; * Projected growth rates of population and GDP; * Other key variables that may influence the domestic electricity demand. |
| IV | Least-cost generation plan (LCP) and transmission & distribution network development plans | LCP and related transmission and distribution investment plans should be prepared to be used as inputs to project tariffs and develop optimal tariff increase strategies:   * Identification of the list of potential technologies/projects to meet projected increase in electricity demand; * Projection of capital, fixed and non-fuel variable O&M costs, and fuel costs for various power generation technologies; * Identification and modelling of constraints inherent to the power system and/or specific technologies. * Use of system planning model to evaluate the LCP; * Optimal dispatch model to simulate the long-run generation from each power plant and estimate the long run marginal cost of generation; * Calculate long-run marginal cost (LRMC) of transmission and distribution. |
| V | Electricity supply cost allocation | * Allocate costs among voltage levels; * Collect or generate load profiling data for each customer/tariff category; * Allocate average costs and LRMC of transmission and distribution (using the load profiling data). |
| VI | Design of initial tariff structure | * Develop tariff structure to be based on the LRMC calculated above, with some adjustments considering affordability constraints for residential consumers. |
| VII | Preparation of tariff model and estimation of the level of tariffs | * Prepare detailed tariff model to project electricity tariffs; * Design optimal tariff increase trajectories based on estimated level of increase required to reach financial cost recovery. * Estimate mitigation potential of block tariff structure and/or TSA payments sufficient to ensure no net increase in the poverty rate. * Fix the end-user tariff levels considering the revenue requirements of BT to ensure full recovery of all cash costs. |
| VIII | Regular tariff and TSA adjustments based on indexation and cost adjustment mechanisms | * Adjust the generation, transmission, and distribution tariffs based on the change of electricity supply costs beyond BT’s control, such as fuel prices, inflation, energy costs of IPPs, and exchange rate fluctuations. * Annually adjust mitigation approaches to ensure no net increase in the poverty rate due to tariff increases. |

1. ***Step I: Approval of the new tariff methodology***. The Government of Tajikistan by its degree N331, dated June 22, 2019, approved the Tariff Methodology for the Electric Energy Sector. It is approved as a transitional methodology to support a smooth transition from the current vertically integrated market model to an unbundled. The methodology consists of three main components:

* Computation of the revenue requirement of the regulated power sector companies,
* End-user tariff calculation,
* Tariff-setting process and procedures.

1. The methodology allows to gradually reach full cost recovery. Tariffs are planned to be adjusted annually, which means regulatory period is one year. The methodology puts an obligation on the distribution company to provide annual demand forecast and the transmission company to prepare an electricity balance for the system for up to five-year period. This information will be used by the regulator while setting the tariffs.
2. Power sector entities will submit tariff applications to the regulatory agency three months before the anticipated tariff change date based on the detailed instructions on preparation and submission of the tariff application. There is a procedure on how regulatory agency and the power companies should interact during that process.
3. *Generation Tariffs:* The revenue requirement for the generation will include necessary fuel and operational costs of regulatory period less the projected export revenues with no depreciation allowance. Profit is set up as a percentage over those costs equal to the next year’s forecasted cash needs of the company to recover the expected debt service and finance some limited capital expenditures.
4. Generation tariff will be set up as a two-part tariff per month for total capacity and per kWh generated electricity. Before carrying out proper cost allocation to specify the capacity and electricity charges, the methodology proposes to allocate 10% of the total costs to the capacity charge.
5. *Transmission Tariff:* The revenue requirement for the transmission will include necessary operational costs of the regulatory period with no depreciation allowance. The allowed profit is computed like the generation. The tariffs will compensate technical losses of the electricity in the transmission grid. Transmission tariff will be set up as a one-part tariff per kWh of electricity transferred through the transmission grid.
6. *The Distribution Revenue Requirement:* The revenue requirement for the distribution will include necessary operational costs of the regulatory period and no depreciation allowance. The allowed profit is computed like the generation and transmission. Distribution service will have no separate tariff at this stage.
7. *End-user Tariffs:* End-user tariffs should be compensating all the generation, transmission and distribution related costs. End-user tariffs will compensate also technical losses of the electricity in the distribution grid. Therefore, the end-user tariffs will include some bad debt allowance at the level to be set up by the regulatory agency. The methodology is to set up weighted average end-user tariffs. Subsequently the allocation of costs among different customer groups will be carried out by the regulatory agency.
8. It should be noted that there is also a need to introduce an adjustment mechanism in the tariff methodology to compensate possible financial losses/gains from generation mix fluctuations, changes in fuel prices and exchange rate during the tariff year. Those are all costs that are not controlled by power sector companies. Therefore, if such mechanism is not introduced, then power sector will not be able to reach and maintain cost recovery.
9. ***Implementation Step II: Establishment of a regulator capable of reviewing and recommending approval of electricity tariffs as per new methodology***. This is an essential building block for long-term financial viability of the power sector. In the short to medium-term, the Government approved the creation of the Electricity Tariff Unit under AMC to be responsible for review of electricity tariffs for: (a) electricity generation, transmission, distribution, and other power system service providers; and (b) all approved categories/groups of end-users. Based on the review, AMC will be making recommendation to the Government regarding recommended level of tariffs. In the long-term, the Government is considering establishing an independent energy sector regulatory commission.
10. In order for the new Tariff Unit to effectively implement its functions, it will need to: (a) adopt the required technical, legal, reporting and other rules and regulations required for functioning of the tariff department; (b) carry out detailed cost-allocation study to improve the economic efficiency of end-user tariffs to ensure they reflect the cost of supply to each category of consumers; (c) have the required financing and competent staff; and (c) receive capacity-building support and training of the key staff. The Bank will be providing limited capacity-building support to BT and AMC on principles for cost allocation until detailed financial and operational data becomes available from unbundled companies; development of regulatory reporting forms; and training of key staff. The Government is in discussions with other development partners to secure financing for capacity-building of BT and AMC to operationalize the new electricity tariff methodology.
11. ***Implementation Steps III and IV: Preparation of electricity demand projection***. The demand projection is an input into the generation expansion plan (GEP), which would be prepared under the Program following the sound technical, economic, and financial principles.
12. ***Implementation Step V. Electricity supply cost allocation***. Power companies will need to evaluate the costs that should be the included into relevant tariffs. Similarly, the regulatory agency will need to be able to validate the revenue requirement for all the companies. Regulatory agency will also need support for allocating the cost of supply among different customer groups. In this context, it should be noted that new end-user tariff structure is still based on the approach of economic differentiation of consumer groups (residential, social, industrial, etc.) rather than economic costs associated with supplying each category of consumers. The Government is in discussions with various development partners to support with carrying out cost allocation to rebalance the end-user tariffs, so they reflect the cost incurred by BT for supplying each group. This is also essential in the context of the design of block/lifeline tariffs where the first step would be to determine whether the single category of residential tariff is currently reflective of the cost of supply to that category.
13. ***Implementation Step VI. Design of initial tariff structure***. The revision of end-user tariff structure will be conducted once the cost-allocation study is completed and BT has been able to clearly allocate the costs of supply to each group (by voltage level). As part of this step, BT and AMC may discuss whether they would want to specify the residential tariff at a level that is different from the cost recovery level given the affordability considerations.
14. ***Implementation Step VII. Preparation of the tariff model and estimation of the level of tariffs***. This step would include construction of detailed tariff model, which would allow to design optimal tariff increase trajectories based on the estimated level of increase required to reach financial cost recovery. Additionally, the tariff model would allow to estimate the mitigation potential of block tariff structure and/or TSA payments to ensure no net increase in the poverty rate.
15. ***Implementation Step VIII. Regular tariff and TSA program funding adjustments***. This entails regular adjustment of the generation, transmission, and distribution tariffs based on the change of electricity supply costs beyond BT’s control, such as fuel prices, inflation, energy costs of IPPs, and exchange rate fluctuations. As per new methodology, annual adjustment is allowed, and it should also take into account the change in the TJS-denominated costs due to depreciation of TJS against the main international currencies. Otherwise, BT’s financial standing would not improve materially considering that large amount of costs, such as payments to IPPs, and significant share of liabilities (short and long-term debts) are fixed in the US$. If the TSA program is used as the main mechanism to mitigate the impacts on the poor, then the fiscal allocation to the TSA should consider the planned revisions to the tariffs.
16. **Revision of subsidiary agreements between MOF and BT will materially reduce liabilities**. Currently, BT has several grants and loans with terms that do not match the original terms of such financing provided to the Republic of Tajikistan. Currently, BT has about US$450 million equivalent[[2]](#footnote-2) of liabilities to MOF, which were received as grants by the Republic of Tajikistan, and on-lent to BT as loans (Group 1 Subsidiary Agreements) at interest rates ranging from 3 to 8 percent. Moreover, BT has about US$960 million equivalent of loans that were received by the Republic of Tajikistan as loans and credits from various financiers and on-lent by MOF to BT under different terms (Group 2 Subsidiary Agreements). Specifically, the interest rates under these subsidiary agreements are between 1 and 5 percent higher than the interest rates under original financing agreements. This creates significant debt service costs for BT, which it is not able to service given below cost recovery tariffs and leads to rapid accumulation of fines and penalties to MOF on overdue debt service. It should be noted that there are some subsidiary agreements between MOF and BT (Group 3 Subsidiary Agreements) where the terms financing is fully aligned with those in the respective legal agreements between the Republic of Tajikistan and the financiers. Please see Table 2 for the list of all subsidiary agreements classified by groups.
17. ***Technical assessment***. The restructuring of BT’s subsidiary agreements with MOF would help to significantly improve the solvency of BT through reduction of the outstanding long- and short-term debt. In particular, subsidiary agreements would need to be revised to align the terms with those in the respective legal agreements between the Republic of Tajikistan and the financiers. This means that multiple loans would need to be converted to grants because the Republic of Tajikistan, through MOF, received the resources on grant basis. The subsidiary agreements would need to have the main terms (e.g. tenure, interest rates) revised to align them with the rates in the respective legal agreements between the Republic of Tajikistan and the financiers. This is estimated to reduce the outstanding principal amount of BT’s debt by TJS2 billion and significantly reduce the annual financing costs (interest payments) to MOF.

**Table 2: Subsidiary Agreements Between MOF and BT.**

|  |  |  |  |
| --- | --- | --- | --- |
|  | **Group 1 Subsidiary Loan Agreements** |  |  |
| 1 | Subsidiary Agreement No. TAJ-2014-006 (BT-026), dated 25.02.2014 | US$ | 136,000,000 |
| 2 | Subsidiary Agreement No. 0213-028 BT; dated 23.11.2010 | US$ | 112,500,000 |
| 3 | Subsidiary Agreement No.TAJ-020-BT, dated 23.01.2009 | US$ | 54,770,000 |
| 4 | Subsidiary Agreement No. TAJ-2015-009 (BT-033), dated 12.11.2015 | US$ | 54,000,000 |
| 5 | Subsidiary Agreement No. TAJ 2015-008 (BT-032), dated 01.10.2015 | US$ | 45,000,000 |
| 6 | Subsidiary Agreement No. TAJ 2010-027 BT, dated 16.07.2010 | US$ | 15,000,000 |
| 7 | Subsidiary Agreement, dated 29.06.2007, for SECO grant under Energy Loss Reduction Project | US$ | 6,600,000 |
| 8 | Subsidiary Agreement No. TAJ-015 BT, dated 30.10.2008, and Amendment to this Subsidiary Agreement, dated 24.11.2008 | US$ | 4,341,500 |
| 9 | Amendment, dated 21.12. 2011, to Subsidiary Agreement dated 29.06.2007 | US$ | 2,582,000 |
| 10 | Subsidiary Agreement No. TF096573-035 BT, 20.12.2011 | US$ | 3,150,000 |
| 11 | Subsidiary Agreement related to Grant Agreement H178 TJ, dated 07.12.2005 | SDR | 2,000,000 |
| 12 | Subsidiary Agreement, dated 07.12.2005, related to SDR5,500,000 IDA Credit No. 4093-TJ and SDR880,000 IDA Grant No. H178 | SDR | 880,000 |
| 13 | Subsidiary Agreement No. TAJ-021 (BT), dated 29.06.2007, and Subsidiary Agreement No. KFW-034 BT, dated 28.06.2011 | EUR | 7,000,000 |
|  | **Group 2 Subsidiary Loan Agreements** | **Currency** | **Amount** |
| 1 | Subsidiary Agreement No. BLA06015, dated 21.12.2006 | US$ | 267,219,451 |
| 2 | Subsidiary Agreement No. TAJ 2014-028-1, dated 18.12.2014 | US$ | 178,969,217 |
| 3 | Subsidiary Agreement No. TAJ 2014-028-2, dated 18.12.2014 | CNY | 929,977,078 |
| 4 | Subsidiary Agreement No. TAJ-2017-02 (BT-039), dated 29.12.2017 | CNY | 546,032,200 |
| 5 | Subsidiary Agreement No. BLA06016, dated 21.12.2006 | US$ | 55,227,590 |
| 6 | Subsidiary Agreement No. TAJ-2009-025 BT, dated 29.05.2009 | US$ | 51,000,000 |
| 7 | Subsidiary Agreement No. TAJ-2013(22) TOTAL No.(266) BT-025, dated 31.07.2011 | US$ | 35,043,319 |
| 8 | Subsidiary Agreement No. TAJ 2016-03 (BT-036), dated 19.08.2016 | EUR | 70,000,000 |
| 9 | Subsidiary Agreement, dated 07.12.2005, related to SDR5,500,000 IDA Credit No. 4093-TJ and SDR880,000 IDA Grant No. H178 | SDR | 5,500,000 |
| 10 | Subsidiary Agreement No. TAJ-021 (BT), dated 29.06.2007, and Subsidiary Agreement No. KFW-034 BT, dated 28.06.2011 | EUR | 18,000,000 |
| 11 | Subsidiary Agreement, dated 20.09.2003, and Amendment to Subsidiary Agreement, dated 15.02.2005, related to Financing Agreement No. 665 | KWD | 3,600,000 |
| 12 | Subsidiary Agreement No. 2009 0675-031 BT, dated 12.10.2011 | EUR | 7,000,000 |
| 13 | Subsidiary Agreement for ADB Loan No. 2303 - TAJ | SDR | 14,475,000 |
| 14 | Subsidiary Agreement No. TAJ 2015-010 (BT-034), dated 21.09.2015 | US$ | 5,000,000 |
|  | **Group 3 Subsidiary Agreements** | **Currency** | **Amount** |
| 1 | Subsidiary Agreement for ADB Loan No. 1912-TAJ, dated 20.10.2003 | SDR | 4,001,000 |
| 2 | Subsidiary Agreement, dated 18.03.2005, for Loan No. TAD-022 | Islamic Dinar | 6,623,000 |
| 3 | Subsidiary Agreement No. TAD-030-032-BT, dated 28.06.2011 | US$ | 14,067,000 |
| 4 | Subsidiary Agreement No. TAJ 2014-007 (BT-027) for IsDB Loan No. TAD-0054 | US$ | 13,070,000 |

1. **Introduction of AMI in the cities of Istaravshan, Isfara, and Konibodom**. In 2017, BT reported technical losses of 16.4 percent and commercial losses are estimated at around 8 percent. Relatively high level of technical losses is due to aged and in some cases overloaded networks. High level of commercial losses, together with current poor collection rates, is mostly due to inadequate execution of key processes of the revenue cycle (meter reading and transfer of data for billing are carried out manually), lack of a state-of-art billing system, and an unreliable/outdated customer database(unmetered customers and meters without contract).
2. The average collection rate increased during 2015-2017 due to increased collections from industrial (exclusive of TALCO) consumers, TALCO, and state budget financed organizations. The improvement in collections is partially due to improvement of metering in some parts of Dushanbe city and improvements in Sughd area due to implementation of EBRD/EIB financed metering and billing project. Nevertheless, despite some improvement, the collection rate for billed electricity at 84 percent (in 2018) remains below 95 percent, which the threshold level for well-functioning companies.
3. Therefore, the Government, drawing upon the successful experience of AMI in the city of Khujand (Sughd), decided to roll-out similar AMI in other major urban centers, including the cities of Istaravshan, Isfara, and Konibodom.
4. ***Technical assessment***. Those three cities account for 8 percent of total electricity consumption in BT service area. The inclusion of those three cities in the Program, to be supported by the Bank, is justified given that other large consumption centers – Dushanbe, Kulob, Bokhtar, and others accounting for about 34 percent of all consumption – would be covered under the planned projects by ADB and EBRD. Additionally, discussions are underway with other development partners to complete the roll-out of AMI to reach out to all remaining consumers (50 percent)[[3]](#footnote-3) in the service area of BT.
5. The improvement of metering and billing would improve the financial viability of BT. The implementation of AMI and grid enhancements in those three cities is expected to: (a) sustainably reduce commercial electricity losses from 8.5 percent to 2 percent; (b) contribute to permanent increase of collection rates to 95 percent; and (c) improvement of the quality of electricity service provided by BT to its 125,000 residential in those target cities.
6. The proposed technical solution is robust and consistent with accepted industry standards for metering and billing systems as reflected in the detailed feasibility studies. The design of the component also incorporates lessons learnt from the project in the Sughd region. The AMI will comprise:
7. Smart meters (with 2-way remote communication);
8. Meter data collection and management (with automated data collection);
9. Billing system (with structured customer accounts and billing procedure based on accurate measured data, including customer relationship management (CRM)).



1. The total financial cost is estimated at US$24 million (TJS226 million). This activity has high level of implementation readiness given that the bidding documents for supply and installation have already been finalized by BT based on acceptable standard procurement document templates. The procurement of the metering and billing system is expected to be launched by March 2020 and the system is expected to be commissioned by the end of 2022.
2. Introduction of AMI would help to reduce the commercial losses, but formal recognition of commercial energy losses of BT should be the first step in improving the trustworthiness of operational and financial reporting. Currently, there is no accounting for such commercial losses and those losses are included into sales. This leads to unrealistic sales volumes and impacts the accuracy of the receivables and provisioning for irrecoverable bad debts. Combined, all these factors have an impact on the reliability and accuracy of the operational and financial data of BT, and, in the long-term, would be impacting the creditworthiness of BT with lenders and impacting its ability to raise financing.
3. The details for distribution network overview and proposed AMI in each of the cities is presented below.

**Istaravshan**

1. ***Overview of the distribution network.*** The distribution grid in Istaravshan consists of 53.8 km of HV (110 kV), 28 km of MV(35 kV) and 1,096 km of LV overhead power lines.The statistics on substations is presented in the following table. There are 39,502 residential, 1,719 commercial and 76 industrialcustomers. About 90 percent of all meters are installed indoors. Total number of meters in Istarafshan is 45,176. The average age of meters is 10 years.

**Table 3: Distribution Grid of Istaravshan.**

|  |  |
| --- | --- |
| HV/MV substations 220 kV | - |
| MV/MV substations 110 Kv | 5 |
| MV/MV substations 35 kV | 1 |
| MV/LV (35 or 6 / 0.4 kV) substations | 327 |
| MV/LV (0.23 kV) substations (if any) |  |
| **Grid Line length** |  |
| 110k V Grid | 53.8 km |
| 35k V Gird | 28 km |
| 10k V Grid | 530.8 km |
| LV Grid | 566.8 km |
| Building supply cable (grid to building) | N/A |
| Customer supply cable (grid to meter) | N/A |

1. ***Communication***. This section discusses Meter-DC communication and DC-HEC communication of the proposed AMI.
2. Meter-DC Communication. Regarding the PLC vs. 2G/3G distribution of LV direct meters (1ph, 3ph), it was assumed that 80 percent of the metering points (in urban area) will be based on PLC communication, and the rest (in rural area) will be using 2G/3G communication. The PLC communication is expected to be managed by the Data Concentrators in all cases (No PLC Gateway is foreseen). All meter installations are expected to be inside meter boxes of 1, 2, 4 positions, and with higher number of meter numbers per building, a combination of more than one-meter box will be used. The substation and feeder totalizer meters at 1,562 distribution substations (X/0.4kV) will be equipped with meters that benefit direct RS/RJ communication to the DCs.
3. DC-HES Communication. The 2G/3G Communication accounts with full coverage of the DCs and Gateways in Dushanbe.
4. Backhaul Communication. The regional office in Istaravshan will be connected to the Main and Backup Control Centers using the 1Gbps FO upon availability, and 4G link as second priority. If FO is available, the 4G link can be used as redundant link, and no FO is available, 4G link as main and xDSL link as redundancy.

**Table 4: Scope of Equipment required for AMI in Istaravshan.**

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  |  |  |  | **With growth and** |
| **#** | **Item** | **2018** |  | **Spare** |
|  |  |  |  |  |
| **1** | **1ph Direct Meters** | **27,718** |  | **29,425** |
| 1.1 | 1ph meter with PLC modem | 22,175 |  | 23,540 |
|  |  |  |  |  |
| 1.2 | 1ph meter with 2G/3G modem | 5,543 |  | 5,885 |
|  |  |  |  |  |
| **2** | **3ph Direct Meters** | **488** |  | **519** |
|  |  |  |  |  |
| 2.1 | 3ph meter with PLC modem | 391 |  | 416 |
|  |  |  |  |  |
| 2.2 | 3ph meter with 2G/3G modem | 97 |  | 103 |
|  |  |  |  |  |
| **3** | **3ph Indirect CT Operated Meters (In=5A, Un=0.4kV)** | **910** |  | **943** |
|  |  |  |  |  |
| 3.1 | 3ph Indirect (CT) Meters with PLC Modem | 264 |  | 274 |
|  |  |  |  |  |
| 3.2 | 3ph Indirect (CT) Meters with 2G/3G Modem | 65 |  | 68 |
|  |  |  |  |  |
| 3.3 | 3ph Indirect (CT) Meters with RS/RJ connection | 581 |  | 602 |
|  |  |  |  |  |
|  | **3ph Indirect CT+VT Operated Meters (I=5A, U=100V) with 2G/3G** |  |  |  |
| **4** | **modem** | **77** |  | **80** |
|  |  |  |  |  |
| **5** | **PLC Data Concentrator** with integrated 2G/3G Modem | **263** | | **280** |
|  |  |  | |  |
| **6** | **Current Transformers (In=5A, un=0.4%)** | **2,730** | | **2,832** |
|  |  |  | |  |
| 6.1 | 50/5A | 135 | | 140 |
|  |  |  | |  |
| 6.2 | 100/5A | 414 | | 429 |
|  |  |  | |  |
| 6.3 | 150/5A | 129 | | 134 |
|  |  |  | |  |
| 6.4 | 200/5A | 309 | | 320 |
|  |  |  | |  |
| 6.5 | 300/5A | 144 | | 150 |
|  |  |  | |  |
| 6.6 | 400/5A | 36 | | 38 |
|  |  |  | |  |
| 6.7 | 600/5A | 438 | | 454 |
|  |  |  | |  |
| 6.8 | 800/5A | 756 | | 783 |
|  |  |  | |  |
| 6.9 | 1000/5A | 237 | | 246 |
|  |  |  | |  |
| 6.10 | 1500/5A | 129 | | 134 |
|  |  |  | |  |
| 6.11 | 2000/5A | 3 | | 4 |
|  |  |  | |  |
| **7** | **VT+CT Set for MV clients** | **77** | | **80** |
|  |  |  | |  |
| 7.1 | CT+VT Set up to 10kV and 1000A (L1, L2, L3) | 77 | | 80 |
|  |  |  | |  |
| **8** | **Meter Boxes for Direct Meters** | **24,321** | | **25,819** |
|  |  |  | |  |
| 8.1 | Meter Box with 1 position for 1ph meter | 19,403 | | 20,597 |
|  |  |  | |  |
| 8.2 | Meter Box with 2 positions for 1ph meter | 3,150 | | 3,344 |
|  |  |  | |  |
| 8.3 | Meter Box with 4 positions for 1ph meter | 1,292 | | 1,372 |
|  |  |  | |  |
| 8.4 | Meter Box with 1 position for 3ph direct meter | 464 | | 493 |
|  |  |  | |  |
| 8.5 | Meter Box with 2 positions for 3ph direct meter | 12 | | 13 |
|  |  |  | |  |
| **9** | **Meter Boxes for Indirect Meters** | **987** | | **1,023** |
|  |  |  | |  |
| 9.1 | Meter Box with 1 position for 3ph meter + CT < 400A | 774 | | 802 |
|  |  |  | |  |
| 9.2 | Meter Box with 1 position for 3ph meter + CT >= 400A | 136 | | 141 |
|  |  |  | |  |
| 9.3 | Meter Box with 1 position for 3ph meter + CT + VT | 77 | | 80 |
|  |  |  | |  |

1. ***Distribution grid enhancement in Istaravshan*.** Based on the information provided by BT, there were 526 feeders with some information (of any type) available. In this first block, there were 37 feeders that contain at least some type of data (a value greater than zero) for measured current (A) on peak time or measured voltage (V) in end point. From this group, after elimination of the inconsistent data, only feeders that satisfied the necessary information for analysis were chosen. The following filter criteria was applied: a measured current (A) on peak time (greater than zero), information of cable section (in mm2), length of the feeder (less than 2 km) and if the feeder is underground or overhead. The result of this filtration resulted in selection of 30 feeders for the city of Istaravshan. This amount was assumed as representative of the entire city, representing over 81 percent of the total amount of feeders for which information was received.Thereafter extrapolation was done to estimate the scope of the grid enhancement.

**Table 5: Grid Enhancement Required for AMI in Istravshan.**

|  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | **Section (mm2)** |  |  | **Underground enhancement** |  |  | **Overhead enhancement** |  |  |
|  |  |  | **(km)** |  |  | **(km)** |  |  |
|  |  |  |  |  |  |  |  |
| 300 | |  | 0.00 | |  | 0.00 | |  |  |
| 240 | |  | 0.00 | |  | 0.00 | |  |  |
| 185 | |  | 0.00 | |  | 0.00 | |  |  |
| 150 | |  | 0.00 | |  | 0.00 | |  |  |
| 120 | |  | 0.00 | |  | 0.00 | |  |  |
| 95 | |  | 0.00 | |  | 3.37 | |  |  |
| 70 | |  | 0.00 | |  | 0.00 | |  |  |
| 50 | |  | 0.00 | |  | 1.69 | |  |  |
|  | |  |  | |  |  | |  |  |
| 35 | |  | 0.00 | |  | 0.00 | |  |  |
|  | |  |  | |  |  | |  |  |
| 16 | |  | 0.00 | |  | 0.00 | |  |  |
|  |  | |  | |  |  | |  |  |
|  | **Total (km)** |  |  | **0.00** |  |  | **5.07** |  |  |
|  | **Total extrapolated (km)** |  |  | **0.00** |  |  | **88.84** |  |  |

**Isfara**

1. ***Overview of the distribution network.*** The distribution grid in Isfara consists of 131.68 km of HV (110 kV), 101.73 km of MV(35 kV) and 1.170 km of LV overhead power lines. Isfara has 40,469 residential, 1,503 commercial and 35 industrial customers. 20 percent of all meters are installed indoors and the rest - outdoors. Total number of meters in Isfara is 43,035. The average age of the meter is around 10 years.

**Table 6: Distribution Grid of Isfara.**

|  |  |
| --- | --- |
| HV/MV substations 220 kV | - |
| MV/MV substations 110 Kv | 8 |
| MV/MV substations 35 kV | 12 |
| MV/LV (35 or 6 / 0.4 kV) substations | 774 |
| **Grid Line length** |  |
| 110k V Grid | 131.68 km |
| 35k V Gird | 101.73 km |
| 10k V Grid | 469.13 km |
| LV Grid | 700.88 km |
| Building supply cable (grid to building) | N/A |
| Customer supply cable (grid to meter) | N/A |

1. ***Communication***. This section discusses Meter-DC communication and DC-HEC communication of the proposed AMI.
2. Meter-DC Communication. Regarding the PLC vs. 2G/3G distribution of LV direct meters (1ph, 3ph), it is assumed that 80% of the metering points (in urban area) will be based on PLC communication, and the rest (in rural area) will be using 2G/3G communication. The PLC communication is expected to be managed by the Data Concentrators in all cases (No PLC Gateway is foreseen). All meter installations are expected to be inside meter boxes of 1, 2, 4 positions, and with higher number of meter numbers per building, a combination of more than one-meter box will be used. The substation and feeder totalizer meters at 1,562 distribution substations (X/0.4kV), will be equipped with meters that benefit direct RS/RJ communication to the DCs.
3. DC-HES Communication. The 2G/3G Communication accounts with full coverage of the DCs and Gateways in Dushanbe.
4. Backhaul Communication. The regional office in Isfara will be connected to the Main and Backup Control Centres using the 1Gbps FO upon availability, and 4G link as second priority. If FO is available, the 4G link can be used as redundant link, and no FO is available, 4G link as main and xDSL link as redundant.

**Table 7: Scope of Equipment required for AMI in Isfara.**

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|  |  | |  | | **With growth and** |
| **#** | **Item** | | **2018** | | **Spare** |
|  |  | |  | |  |
| **1** | **1ph Direct Meters** | | **42,198** | | **44,795** |
|  |  | |  | |  |
| 1.1 | 1ph meter with PLC modem | | 33,759 | | 35,836 |
|  |  | |  | |  |
| 1.2 | 1ph meter with 2G/3G modem | | 8,439 | | 8,959 |
|  |  | |  | |  |
| **2** | **3ph Direct Meters** | | **1,444** | | **1,534** |
|  |  | |  | |  |
| 2.1 | 3ph meter with PLC modem | | 1,156 | | 1,228 |
|  |  | |  | |  |
| 2.2 | 3ph meter with 2G/3G modem | | 288 | | 306 |
|  |  | |  | |  |
| **3** | **3ph Indirect CT Operated Meters (In=5A, Un=0.4kV)** | | **1,528** | | **1,584** |
|  |  | |  | |  |
| 3.1 | 3ph Indirect (CT) Meters with PLC Modem | | 536 | | 556 |
|  |  | |  | |  |
| 3.2 | 3ph Indirect (CT) Meters with 2G/3G Modem | | 134 | | 139 |
|  |  | |  | |  |
| 3.3 | 3ph Indirect (CT) Meters with RS/RJ connection | | 858 | | 889 |
|  |  | |  | |  |
|  | **3ph Indirect CT+VT Operated Meters (I=5A, U=100V) with 2G/3G** | |  |  |  |
| **4** | **modem** | | **136** |  | **141** |
|  |  | |  |  |  |
| **5** | **PLC Data Concentrator** with integrated 2G/3G Modem | | **622** |  | **661** |
|  |  | |  |  |  |
| **6** | **Current Transformers (In=5A, un=0.4%)** | | **4,611** |  | **4,780** |
|  |  | |  |  |  |
| 6.1 | 50/5A | | 276 |  | 286 |
|  |  | |  |  |  |
| 6.2 | 100/5A | | 843 |  | 873 |
|  |  | |  |  |  |
| 6.3 | 150/5A | | 261 |  | 271 |
|  |  | |  |  |  |
| 6.4 | 200/5A | | 567 |  | 588 |
|  |  | |  |  |  |
| 6.5 | 300/5A | | 249 |  | 258 |
|  |  | |  |  |  |
| 6.6 | 400/5A | | 75 |  | 78 |
|  |  | |  |  |  |
| 6.7 | 600/5A | | 663 |  | 687 |
|  |  | |  |  |  |
| 6.8 | 800/5A | | 1,128 |  | 1,169 |
|  |  | |  |  |  |
| 6.9 | 1000/5A | | 354 |  | 367 |
|  |  | |  |  |  |
| 6.10 | 1500/5A | | 192 |  | 199 |
|  |  | |  |  |  |
| 6.11 | 2000/5A | | 3 |  | 4 |
|  |  | |  |  |  |
| **7** | **VT+CT Set for MV clients** | | **136** |  | **141** |
|  |  | |  |  |  |
| 7.1 | CT+VT Set up to 10kV and 1000A (L1, L2, L3) | | 136 |  | 141 |
|  |  | |  |  |  |
| **8** | **Meter Boxes for Direct Meters** | | **39,549** |  | **41,984** |
|  |  | |  |  |  |
| 8.1 | Meter Box with 1 position for 1ph meter | | 33,759 |  | 35,836 |
|  |  | |  |  |  |
| 8.2 | Meter Box with 2 positions for 1ph meter | | 3,125 |  | 3,318 |
|  |  | |  |  |  |
| 8.3 | Meter Box with 4 positions for 1ph meter | | 1,329 |  | 1,411 |
|  |  | |  |  |  |
| 8.4 | Meter Box with 1 position for 3ph direct meter | | 1,228 |  | 1,304 |
|  |  | |  |  |  |
| 8.5 | Meter Box with 2 positions for 3ph direct meter | | 108 |  | 115 |
|  |  | |  |  |  |
| **9** | **Meter Boxes for Indirect Meters** | | **1,664** |  | **1,725** |
|  |  | |  |  |  |
| 9.1 | Meter Box with 1 position for 3ph meter + CT < 400A | | 1,299 |  | 1,346 |
|  |  | |  |  |  |
| 9.2 | Meter Box with 1 position for 3ph meter + CT >= 400A | | 229 |  | 238 |
|  |  | |  |  |  |
| 9.3 | Meter Box with 1 position for 3ph meter + CT + VT | | 136 |  | 141 |
|  |  | |  |  |  |
| **10** | **Test Equipment** |  | | | |
|  |  |  | | | |
| 10.1 | Test benches | 2 | | | |
|  |  |  | | | |
| 10.2 | Portable testers | 5 | | | |
|  |  |  | | | |
| 10.3 | Noise Measurement Devices | 10 | | | |

1. ***Distribution grid enhancement in Isfara.*** The following sections of the distribution grid of Isfara would require enhancement to accommodate proper functioning of AMI.

**Table 8: Grid Enhancement Required for AMI in Isfara.**

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **Section (mm2)** |  | |  | **Underground enhancement** |  |  | **Overhead enhancement** |
|  | |  | **(km)** |  |  | **(km)** |
|  |  | |  |  |  |
| 300 | |  | 0.00 | | |  | 0.00 |
| 240 | |  | 0.00 | | |  | 0.00 |
| 185 | |  | 0.00 | | |  | 0.00 |
| 150 | |  | 0.00 | | |  | 2.81 |
| 120 | |  | 0.00 | | |  | 0.00 |
| 95 | |  | 0.00 | | |  | 12.12 |
| 70 | |  | 0.53 | | |  | 0.00 |
| 50 | |  | 0.68 | | |  | 3.97 |
| 35 | |  | 0.00 | | |  | 0.00 |
| 16 | |  | 0.00 | | |  | 0.00 |
| **Total (km)** |  | |  | **1.21** |  |  | **18.90** |
| **Total extrapolated** |  | |  | **5.75** |  |  | **89.76** |

**Konibodom**

1. ***Overview of the distribution network***. The distribution grid in Konibodom consists of 71.6 km of HV (110 kV), 66.65 km of MV (35 kV) and 1,628 km of LV, all of them mostly mounted overhead. The total number of substations: for HV (220 kV) - 1, HV/MV - 2, for MV/MV – 12, and for MV/LV - 567. Konibodom has 45,301 residential, 1,512 commercial and 42 industrial customers. 20 percent of meters installed are installed indoors and 80 percent of meters of meters are installed outdoors. Total number of meters in Konibodom is 45,301. Almost all meters which installed in Konibodom’s are more than 15 years old.

**Table 9: Distribution Grid of Konibodom**.

|  |  |
| --- | --- |
| HV/MV substations 220 kV | 1 |
| MV/MV substations 110 Kv | 2 |
| MV/MV substations 35 kV | 12 |
| MV/LV (35 or 6 / 0.4 kV) substations | 567 |
| MV/LV (0.23 kV) substations (if any) |  |
| **Grid Line length** |  |
| 110k V Grid | 71.6 km |
| 35k V Gird | 66.65 km |
| 10k V Grid | 221.3 km |
| LV Grid | 1,406.81 km |
| Building supply cable (grid to building) | km |
| Customer supply cable (grid to meter) | km |

1. ***Communication***. This section discusses Meter-DC communication and DC-HEC communication of the proposed AMI.
2. Meter-DC Communication: Regarding the PLC vs. 2G/3G distribution of LV direct meters (1ph, 3ph), it is assumed that 80 percent of the metering points (in urban area) will be based on PLC communication, and the rest (in rural area) will be using 2G/3G communication. The PLC communication is expected to be managed by the Data Concentrators in all cases (No PLC Gateway is foreseen). All meter installations are expected to be inside meter boxes of 1, 2, 4 positions, and with higher number of meter numbers per building, a combination of more than one-meter box will be used. The substation and feeder totalizer meters at 1,562 distribution substations (X/0.4kV), will be equipped with meters that benefit direct RS/RJ communication to the DCs.
3. DC-HES Communication. The 2G/3G Communication accounts with full coverage of the DCs and Gateways in Dushanbe.
4. Backhaul Communication: The regional office in Konibodom will be connected to the Main and Backup Control Centres using the 1Gbps FO upon availability, and 4G link as second priority. If FO is available, the 4G link can be used as redundant link, and no FO is available, 4G link as main and xDSL link as redundant.
5. The following main infrastructure elements would need to be procured for the AMI for the city of Konibodom.

**Table 10: Scope of Equipment required for AMI in Konibodom.**

|  |  |  |  |
| --- | --- | --- | --- |
|  |  |  | **With growth and** |
| **#** | **Item** | **2018** | **Spare** |
|  |  |  |  |
| **1** | **1ph Direct Meters** | **16,476** | **17,490** |
|  |  |  |  |
| 1.1 | 1ph meter with PLC modem | 13,181 | 13,992 |
|  |  |  |  |
| 1.2 | 1ph meter with 2G/3G modem | 3,295 | 3,498 |
|  |  |  |  |
| **2** | **3ph Direct Meters** | **612** | **651** |
|  |  |  |  |
| 2.1 | 3ph meter with PLC modem | 490 | 521 |
|  |  |  |  |
| 2.2 | 3ph meter with 2G/3G modem | 122 | 130 |
|  |  |  |  |
| **3** | **3ph Indirect CT Operated Meters (In=5A, Un=0.4kV)** | **761** | **789** |
|  |  |  |  |
| 3.1 | 3ph Indirect (CT) Meters with PLC Modem | 131 | 136 |
|  |  |  |  |
| 3.2 | 3ph Indirect (CT) Meters with 2G/3G Modem | 32 | 34 |
|  |  |  |  |
| 3.3 | 3ph Indirect (CT) Meters with RS/RJ connection | 598 | 620 |
|  |  |  |  |
|  | **3ph Indirect CT+VT Operated Meters (I=5A, U=100V) with 2G/3G** |  |  |
| **4** | **modem** | **14** | **15** |
|  |  |  |  |
| 5 | PLC Data Concentrator with integrated 2G/3G Modem | 455 | 472 |
| 6 | Current Transformers (In=5A, un=0.4%) | 2,310 | 2,398 |
| 6.1 | 50/5A | 66 | 69 |
| 6.2 | 100/5A | 204 | 212 |
| 6.3 | 150/5A | 63 | 66 |
| 6.4 | 200/5A | 216 | 224 |
| 6.5 | 300/5A | 126 | 131 |
| 6.6 | 400/5A | 18 | 19 |
| 6.7 | 600/5A | 450 | 466 |
| 6.8 | 800/5A | 789 | 818 |
| 6.9 | 1000/5A | 240 | 249 |
| 6.10 | 1500/5A | 135 | 140 |
| 6.11 | 2000/5A | 3 | 4 |
| 7 | VT+CT Set for MV clients | 14 | 15 |
| 7.1 | CT+VT Set up to 10kV and 1000A (L1, L2, L3) | 14 | 15 |
| 8 | Meter Boxes for Direct Meters | 12,959 | 13,758 |
| 8.1 | Meter Box with 1 position for 1ph meter | 8,238 | 8,745 |
| 8.2 | Meter Box with 2 positions for 1ph meter | 2,752 | 2,922 |
| 8.3 | Meter Box with 4 positions for 1ph meter | 1,372 | 1,457 |
| 8.4 | Meter Box with 1 position for 3ph direct meter | 582 | 618 |
| 8.5 | Meter Box with 2 positions for 3ph direct meter | 15 | 16 |
| 9 | Meter Boxes for Indirect Meters | 775 | 804 |
| 9.1 | Meter Box with 1 position for 3ph meter + CT < 400A | 647 | 670 |
| 9.2 | Meter Box with 1 position for 3ph meter + CT >= 400A | 114 | 119 |
| 9.3 | Meter Box with 1 position for 3ph meter + CT + VT | 14 | 15 |

1. ***Grid strengthening in Konibodom***. There was a total of 247 feeders in Konibodom that contain at least some type of data (a value greater than zero) for measured current (A) on peak time or measured voltage (V) in end point. From this group, after retiring eliminating the inconsistent data, only feeders that satisfied the necessary information for analysis were chosen. The following filter criteria was applied: measured current (A) on peak time (greater than zero), information of cable section (in mm2), length of the feeder (less than 2 km) and if the feeder is underground or overhead. The filtering resulted in selection of the total of 52 feeders for the city of Konibodom. This amount was assumed to be representative of the whole situation in the city, representing over 21 percent of the total amount of feeders. Extrapolation was done to derive the total needs for grid strengthening in the city of Konibodom.
2. The following sections of the distribution grid of Konibodom would require enhancement to accommodate proper functioning of AMI.

**Table 11: Grid Enhancement Required for AMI in Konibodom.**

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **Section (mm2)** |  | |  | **Underground enhancement** |  |  | **Overhead enhancement** |
|  | |  | **(km)** |  |  | **(km)** |
|  |  | |  |  |  |
| 300 | |  | 0.00 | | |  | 0.00 |
| 240 | |  | 0.00 | | |  | 0.00 |
| 185 | |  | 0.00 | | |  | 0.00 |
| 150 | |  | 0.00 | | |  | 3.74 |
| 120 | |  | 0.00 | | |  | 0.00 |
| 95 | |  | 0.00 | | |  | 16.16 |
| 70 | |  | 0.71 | | |  | 0.00 |
| 50 | |  | 0.90 | | |  | 5.29 |
|  | |  |  | | |  |  |
| 35 | |  | 0.00 | | |  | 0.00 |
|  | |  |  | | |  |  |
| 16 | |  | 0.00 | | |  | 0.00 |
| **Total (km)** |  | |  | **1.61** |  |  | **25.20** |
| **Total extrapolated** |  | |  | **7.66** |  |  | **119.68** |

***Results Area 2: Ensuring Electricity Supply Reliability***

1. **Adequate electricity supply from Sangtuda-1 HPP.** Sangtuda-1 HPP accounts for about 10 percent of electricity generation, including in critical winter months, and therefore is critical for adequacy of electricity supply in the country. BT has historically been receiving an average of 1,800 GWh of electricity from Sangtuda-1 HPP and struggled to make timely payments as per terms of the 20-year PPA, which has some deviations from the traditional PPAs of similar nature. Nevertheless, it should be noted that the PPA does not create excessive risks for BT or the Government, which may lead to significant contingent liabilities or direct fiscal costs.
2. ***Technical assessment***. If Sangtuda-1 stops supplying electricity due to BT’s inability to make timely payments, then the gap can only be filled with then-commissioned units of Rogun HPP given that there is no other capacity to fill in this gap, which may create reliability issues given that Rogun HPP is not fully completed yet, including the work to be done to increase reliability of its interconnection to the electricity network. Additionally, use of electricity from Rogun would reduce electricity available for exports and, therefore, would result in foregone export revenues.
3. **Timely implementation of the rehabilitation and upgrade of electricity transmission and distribution assets is essential for reduction of frequency of equipment failures and resulting electricity supply interruptions**. BT has been under-spending on recurrent repair and maintenance works given the shortage of cash revenues. There are number of projects underway that are supporting rehabilitation and upgrade of key hydropower plants as well as some transmission substations and lines. Those projects are financed by various development partners. However, electricity distribution level infrastructure, which is essential for end-user supply reliability, became severely dilapidated throughout those years of under-spending on maintenance and rehabilitation. This has resulted in increased frequency of equipment failures and resulting outages for end-users.
4. ***Technical assessment***. Timely repairs and maintenance would help to reduce incidence of electricity supply outages that result in electricity supply outages for consumers. Those expenditures include rehabilitation, replacement, and upgrade of key electricity distribution assets in 17 regional distribution networks of BT and the transmission network, which cover the entire service territory of BT. The upgrade and rehabilitation would include: (a) replacement of old oil circuit breakers with vacuum circuit breakers at substations; (b) replacement of disconnectors at substations; (c) repair and replacement of power and voltage transformers at substations; (d) installation of new relay protection and automation cubicles at substations; (e) construction of new 0.4 kV and 10 kV power distribution lines; and (f) rehabilitation of existing power distribution lines.
5. BT prepared detailed cost estimates of priority rehabilitation and upgrade measures across for all regions serviced by BT. As per estimates, BT plans to invest US$65.4 million (TJS617 million) in rehabilitation and upgrade of key power distribution assets in 2019-2025. The bills of quantities and the unit prices are commensurate with the most recent prices observed in tenders conducted by BT and similar activities in neighboring countries (e.g. Kyrgyz Republic). The details regarding the types of works and goods to be replaced or rehabilitated are presented in the Annex 1.

***Results Area 3: Strengthening of BT’s Governance and Improvement of Transparency***

1. **Investment decision-making based on generation and T&D plans**. Investments into new generation need to be based on principles of technical feasibility, least economic cost, and financing constraints. It is important to regularly update the GEP and prepare the related T&D plans to ensure the planned power sector development investments are adequate to meet the projected electricity demand in the country at lowest possible economic cost and electricity export commitments of the country. The Program requires BT and/or the Government to follow those plans when deciding on the projects to be constructed to ensure adequate and reliable electricity supply in the country.
2. ***Technical assessment***. The sequencing of steps related to update of GEP, its adoption, preparation of the related T&D plans, and following those plans is technically sound and consistent with the good practices in identifying and sequencing the projects in power generation, transmission, and distribution to meet the projected long-term electricity demand, including export demand, considering a range of factors. GEPs are typically prepared for 10-25-year time periods.
3. Update of the GEP is the first step in power sector planning process. The Government has a Power Sector Development Master Plan (February 2017), however, it would require an update given significant developments in the sector in Tajikistan and material reduction in the cost of some non-hydro renewable energy technologies, such as wind and solar PV. The purpose of the GEP is to prepare a forecast of electricity demand in the country and identify the types of electricity generation projects by technology and location, their optimum size, and installed capacities to meet the projected electricity demand inclusive of export demand. The potential electricity generation projects should include all technologies that may be deemed technically viable and realistic from implementation perspective. The purpose of the GEP is to minimize the total capital, fuel, and non-fuel variable and fixed O&M costs of electricity generation considering other technical and non-technical objectives (e.g. value of lost load or unserved energy) and constraints (environmental impact from some of the site-specific potential projects, share of electricity imports in the total supply mix).
4. Once the update of GEP is completed, then power transmission plan needs to be prepared. The purpose of the transmission plan is to identify the areas of the current transmission network (110 kV and above) that are in need of expansion to cost-effectively maintain reliability and accommodate new generation and the growing load. The period to be covered by the transmission plan should be consistent with the period covered by GEP. The transmission plans also need to be regularly updated in synchronization with updates to the GEP. The transmission system is expected to maintain its integrity and continue to operate without a major disruption even when a component fails. The security of the transmission system is primarily achieved by ensuring that the outage of any single system component will not cause a cascading outage, i.e. an outage that cannot be restrained from spreading to other areas. A system that is resistant to the outage of any one component is said to be “N-1” secure. Additionally, the system should remain within the applicable emergency thermal ratings and voltage limits after an additional single contingency (N-1-1) condition. N-1 security is fundamental to system operation and achieving this level of security is generally accepted to be required, regardless of the cost.
5. Resource adequacy is defined as the ability of the electric system to supply the aggregate electric demand and energy requirements of end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages on the system – the Loss of Load Expectation (LOLE).The LOLE means the expected number of days in the year when the peak demand exceeds the available generating and demand-side resources. Fundamentally, a LOLE reliability standard involves evaluating the trade-off between the cost to customers of installing and maintaining additional back-up resources in comparison to the cost to customers of incurring additional electricity outages.
6. The next step in the power system planning is preparation of the electricity distribution network investment plan. The goal of the distribution system planning is to ensure that the projected electricity demand growth can be satisfied in an optimal way from the secondary feeders to the substations from where electricity must be delivered to the end-users at least economic cost while complying with several technical specifications. These considerations and several other factors, such as the difficulty of land acquisition, aesthetic and environmental considerations, can complicate the task. The design of electricity distribution systems is executed around the existing systems using a procedure containing the following steps: demand forecasting and assignment to existing or new areas, location and dimensioning of substations, and dimensioning and routing of feeders and distribution networks. The electricity distribution network investment plans should also be regularly updated (at least once in five years) considering the changes in the load growth conditions in various locations.
7. **Implementation of the principals of the good-practice corporate governance is important for long-term financial viability of BT**. On June 22, 2019, the Government the Government approved the new charters of the electricity transmission and distribution companies. Those were developed with the support of ADB, the BT, MEWR, and the State Investment Committee (SIC) developed and adopted the charters of new transmission and distribution companies. The new charters are a significant step forward and introduced elements of sound corporate governance. The existing charter of BT would also need to be modified to include the missing elements of good-practice corporate governance structure.
8. Additionally, the required documents are being finalized to initiate selection of Supervisory Boards and formation of the specialized committees (audit and compensation), for the new companies. The PforR would ensure that the newly-established elements of sound corporate governance are maintained throughout the implementation of the Program, including functional Supervisory Boards and specialized audit and compensation committees at BT generation, transmission, and distribution companies.
9. ***Technical assessment***. The following section contains the assessment whether good-practice corporate governance elements were included into the charters of the newly-established power transmission company (Shabakahoi Intiqoli Barq) and the power distribution company (Shabakahoi Taqsimoti Barq).
10. ***Board Composition and Committees.*** The new charters represent a significant improvement over the current charter of BT and has clearer set of requirements and functions with the Supervisory Boards and nomination process.

* The number of Supervisory Board members and the procedure for the appointment is to be determined by the Shareholders Meeting.
* The charters introduce a norm allowing the Board to invite international and local experts upon need.
* The charters allow establishment of specialized committees to provide guidance on particular issues.
* The article related to the Supervisory Boards states that the Board Members should adhere to the best interest of the Company.

1. ***General Director Appointment.*** The provisions have significantly improved and provide better checks and balances to oversee the General Director*.*The General Director appointment should be done by the Board. This is a direct line of accountability and the Board should be able to hold this person accountable. However, in current environment this may not be possible. Therefore, the charters contain a provision that the Board proposes candidates and also has the power to establish compensation and incentives for the General Director. Moreover, the Board now has a power to discipline the General. Therefore, these three powers in combination should provide proper checks and balances for the General Director in early stages.
2. ***Internal and External Audit.*** There has been significant progress with removing ambiguity related to internal and external audit requirements. The provisions in relevant sections of the charter now refer only to the external auditors. Although, there is no explicit reference to independent auditor, it states that the auditor should not have any material relations with the company. The external auditor appointment was left to the decision of the Board instead of allowing the Shareholders Assembly to approve their appointment. However, given that this is just one shareholder, this is considered adequate for the time being. Internal Audit was introduced to the charters (para 42, 6th bullet point) and its properly subordinated to the Board, which is very important.
3. **Charter Capital.** The revised provisions no longer allow increasing the charter capital to cover for losses or repay overdue loans. This is rather innovative that will push companies to work with profits and not rely on the budget to cover for their obligations. This is not a conventional requirement, but it may be helpful for introducing financial discipline and responsibility.
4. **Improvement of BT’s operational and financial transparency**. Currently, BT publishes very little information on its operational and financial indicators beyond the mandatory requirement to publish the audited financial statements of BT and specific projects consistent with the requirements of various international financial institutions. Moreover, the scarce information that is available to the general public is outdated.
5. ***Technical assessment***. Over time, strengthened governance and accountability should translate to increased operational efficiency, including the reduction of technical, commercial and collection losses. With an overarching objective of improving sector efficiency, the PforR supports improved transparency. Specifically, the Program requires BT generation, transmission, and distribution companies to publish on their website the key operational and financial data for the power sector on a quarterly basis, including data on service quality. These measures will improve the credibility of the sector and the investment environment.
6. **Economic Assessment of the Program Activities**
7. The economic analysis was conducted both for the Government program and the Program supported under the PforR. The analysis of the broader Government program is important to ensure that it is overall economically viable so that PAP measures could be recommended to modify it drawing upon the results of the assessment. The economic analysis is based on real economic prices and costs, and exclusive of taxes and tariffs. Net benefits and costs were estimated over the period 2019-2050 and discounted to the base year of 2019 using a social discount rate of 5.3 percent. Other key assumptions are listed in the Table below.

**Table 12: Assumptions of the Economic Analysis.**

| **Topic** | **Indicator** | **Unit** | **Source** | **Value (2019)** | **Change over time** |
| --- | --- | --- | --- | --- | --- |
| Social cost of carbon | Cost of carbon, low range | US$/ton | Guidance Note on Shadow Cost of Carbon in Economic Analyses (Nov. 12, 2017) | 41 | 2.25% per year |
|  | Cost of carbon, high range | US$/ton | Bank guidance | 82 | 2.25% per year |
|  | Carbon intensity, diesel backup generation | kg/kWh | Bank guidance | 0.65 | - |
|  | Carbon intensity, imported gas-fired generation | Kg/kWh | Bank guidance | 0.53 | - |
| Macro-economic | Exchange rates | TJS/US$ | Corporate financial model of BT | 9.42 | At relative rates of inflation for Tajikistan and the U.S. |
|  | Local inflation rate | % | IMF WEO, Oct. 2018 | 5.50% | 6.00% (After 2023) |
|  | USD inflation rate | % | IMF WEO, Oct. 2018 | 2.15% | 2.23% (After 2023) |
|  | TJK GDP, current prices | TJS billion | IMF WEO, Oct. 2018 | 74.97 | 10.2%/year (After 2023) |
|  | TJK population | Millions | IMF WEO, Oct. 2018 | 9.292 | 1.8%/year (After 2023) |
| Discounting | Social discount rate | % | Calculated consistent with World Bank Guidance Note on Discounting Costs and Benefits in Economic Analysis of World Bank Projects (May 9, 2016) | 5.3% | - |
| Demand growth | Electricity demand | GWh | BT | 13.750 | 1%/year |
| Value of electricity | Residential sector WTP | USc/kWh | Assumption | 4.00 | - |
|  | Cost of imports from Central Asia | USc/kWh | Assumption | 3.2 | - |
| Un-served energy | Share of equipment failures leading to outages | % | Team | 15% | - |
|  | T&D equipment failures – Base case | #/year | Team | 2,417 | 5.0%/year to 2030, then fixed |
|  | T&D equipment failures – Program | #/year | Team | 1,400 | -6.6%/year to 2025, then fixed |
|  | Duration of average outage | Hours | Team | 0.07 | - |
|  | Share of residential cons. with backup diesel | % | Team | 0% | - |
|  | Share of non-residential cons. with backup diesel | % | Team | 100% | - |
| Technical losses | Backup diesel generator efficiency | Litres /kWh | Assumption | 0.3 | - |
|  | Technical losses – Base case | % | BT | 15.8% | - |
|  | Technical losses, Program | % | Assumption | 15.8% | -0.5 p.p./year to 2025, then fixed |
|  | Share of transmission losses in total T&D losses | % | BT | 23% | - |
| Commercial losses | Commercial loss rate | % | BT | 8.0% | Govt. program: drops to 1.4%by 2025 for 28% of LV and MV customers. PfR Program: drops to 1.4% by 2025 for 9.3% of LV and MV customers. |
|  | Commercial loss demand response | % | Assumption | 50% | - |
| Generator costs | Variable O&M, hydro | USc/kWh | Least cost generation plan | 0.28 | - |
|  | Fixed O&M, hydro | US$/MW/year | Least cost generation plan | 12,870 | - |
| Economic costs | Metering and billing, Govt. program | US$ million | GoT | 55.0 |  |
|  | Metering and billing, PfR Program | US$ million | GoT | 18.295 |  |
|  | Rehabilitation and upgrade of T&D assets | US$ million | GoT | 57.0 | - |

Source: BT estimates.

1. Economic costs of the Government program. The main economic costs of the Government program include: (a) US$57 million for rehabilitation and upgrade of electricity transmission and distribution assets; (b) US$55 million for metering and billing investments in Dushanbe city; and (c) incremental variable O&M costs of electricity from Sangtuda-1 and Sangtuda-2 IPPs. The expenditures towards repayment of overdue payables to Sangtuda-1 and 2 as well as the repayment of commercial debt of BT are financial transactions and do not constitute an economic cost.
2. With the government program, Sangtuda-1 and 2 are assumed to continue supplying power with a variable O&M cost of US$0.28 c/kWh and fixed O&M of US$13,146 per MW per year. Given existing capacities of the plants this translates to an average marginal cost of generation of US$0.70 c/kWh and US$0.59 c/kWh for Sangtuda-1 and 2 respectively.
3. Economic benefits of the Government program. The main economic benefits of the Government program include: (a) avoided cost of electricity imports to make up for the discontinuation of supply from Sangtuda-1 and Sangtuda-2 IPPs; (b) avoided increase in un-served energy due to expected rise of transmission and distribution equipment failures; and (c) reduction of electricity supply cost due to reduction of technical and commercial energy losses.
4. Without the program, it is assumed that Sangtuda-1 and 2 will stop supplying electricity in 2023 due to continuous non-payments and the resulting inability to properly operate and maintain the plants. At that point. given the costs of backup diesel generation and domestic willingness to pay for power, it would be in the economic interest of the country to make-up for the shortfall of supply from the Sangtuda plants with power imported from its neighbors at an estimated average cost of US$0.032/kWh.
5. At BT, 15 percent of equipment failures are estimated to result in unplanned un-served energy for an average duration of 4 minutes. Without the program, it is estimated that equipment failures would increase by 5 percent per year to 4,558 incidents annually in 2030 and stay at that level, corresponding to an increase in un-served energy from 0.4 percent to 0.7 percent of demand. With program it is estimated that equipment failures would decrease by 6.6 percent per year to 1,400 incidents annually by 2025 and stay at that level, corresponding to a decrease in un-served energy from 0.4 percent to 0.2 percent of energy demand. The avoided unplanned un-served energy as a result of the program energy was valued at the WTP of residential consumers and copying costs of industrial consumers, which includes the levelized cost of back-up diesel generation. The WTP for residential consumers was conservatively estimated at US$0.04 c/kWh taking into account similar estimates in some other countries in ECA region and the differences in the disposable income levels.
6. Technical losses in 2019 were 15.8 percent of supplied power and are assumed to remain at that level without program. With program technical losses are assumed to decline by 0.5 percentage points per year, dropping to a new long-run level of 13.3 percent by 2025. The reduction in technical losses is expected due to improved reliability of transmission and distribution assets. The supply cost savings due to reduction in technical losses were estimated at the marginal economic cost of energy supply of 0.8 USc/kWh. Commercial losses amounted to 8 percent of supplied energy in 2019 and are expected to drop starting in 2022. The economic benefit of commercial loss reduction was estimated considering that the Government program would reduce commercial losses of 28% of low and medium voltage customers by 6.6 percent. It is assumed that for each percentage point reduction in commercial losses the targeted consumers would reduce electricity demand by half a percent.
7. Results: The economic analysis of the Government program yielded an economic Net Present Value (NPV) of US$776 million and Economic Internal Rate of Return (EIRR) of 58.8 percent exclusive of the social cost of avoided CO2 emissions. Under the low and high cost of CO2 emissions scenarios the program attains and NPV of US$1,717 and US$2,654 million with EIRR of 85.5 and 104.4 percent respectively. The avoided emissions benefits arise primarily because the program prevents substitution from domestic hydropower to imported gas-fired generation.
8. A reduction of un-served demand has the effect of increasing consumption and the supply to meet it. Lower technical losses reduce required supply to meet given demand while lower commercial losses reduce both demand and supply. The cumulative net effect of these forces relative to the without program scenario is illustrated by the chart on the right.

**Figure 1: Key Program Assumptions and Impact.**

Source: BT.

1. Sensitivity Analysis: Sensitivity analysis was conducted to assess the robustness of the estimated Project economic returns to changes in the main evaluation variables. The results of the sensitivity analyses suggest that the Project returns are robust even in case of significant variation of main evaluation variables.

**Table 13: Results of Sensitivity Analyses: Government Program.**

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Variable** | **Base case** | **Switching value**  **(NPV=0/EIRR=5.3%)** | **Scenario analysis** | | |
| **Scenario** | **NPV (US$m)** | **EIRR (%)** |
| - | - | - | Base case | 776 | 58.8 |
| Construction cost | 1. US$m | 1,044 US$m | 1. 30% higher | 761 | 50.4 |
| Electricity import price | 3.2 USc/kWh | 0.65 USc/kWh | 1. 30% lower | 484 | 44.4 |
| WTP for electricity | 4.0 USc/kWh | <0 USc/kWh | 1. 30% lower | 772 | 58.6 |
|  |  |  | Combination of a, b, c | 467 | 37.3 |

Source: BT.

1. Economic costs of the Program under PforR. The main economic costs of the Program include: (a) US$57 million for rehabilitation and upgrade of electricity transmission and distribution assets; (b) US$18.3 million for metering and billing investments in Dushanbe city; and (c) incremental variable O&M costs of electricity from Sangtuda-1 IPP.
2. Economic benefits of the Program under PforR. The main economic benefits of the Program include: (a) avoided costs of electricity imports to make up for the discontinuation of supply from Sangtuda-1 IPP; (b) avoided increase in un-served energy due to expected rise of transmission and distribution equipment failures; and (c) reduction of electricity supply cost due to reduction of technical and commercial energy losses. The economic benefit of commercial loss reduction was estimated considering that the Program would reduce commercial losses of 9.3% of low and medium voltage customers by 6.6% (reflecting the smaller scope of support for this component relative to the Government program).
3. Results: The economic analysis of the Program yielded an economic Net Present Value (NPV) of US$586 million and Economic Internal Rate of Return (EIRR) of 50.1 percent exclusive of the social cost of avoided CO2 emission. Under the low and high cost of CO2 emissions scenarios the program attains and NPV of US$1,278 and US$1,968 million with EIRR of 73.6 and 90.5 percent respectively.
4. Sensitivity Analysis: Sensitivity analysis was conducted to assess the robustness of the estimated Program economic returns to changes in the main evaluation variables. The results of the sensitivity analyses suggest that the Program returns are robust even in case of significant variation of main evaluation variables.

**Table 14: Results of Sensitivity Analyses: Program Supported under PforR.**

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Variable** | **Base case** | **Switching value**  **(NPV=0/EIRR=5.3%)** | **Scenario analysis** | | |
| **Scenario** | **NPV (US$m)** | **EIRR (%)** |
| - | - | - | Base case | 586 | 50.1 |
| Construction cost | 112 US$m | 816 US$m | 1. 30% higher | 572 | 42.5 |
| Electricity import price | 3.2 USc/kWh | 0.56 USc/kWh | 1. 30% lower | 373 | 37.9 |
| WTP | 4.0 USc/kWh | <0 USc/kWh | 1. 30% lower | 583 | 49.9 |
|  |  |  | Combination of a, b, c | 355 | 31.6 |

Source: BT.

1. The Government program differs from the Bank Program in that it includes non-supply form Sangtuda-2 in the counterfactual and covers more cities under its metering and billing program. As an extra robustness check, the EIRR was calculated for the situation in which Sangtuda power plants would have kept supplying irrespective of the program, thereby lowering the opportunity cost of the program. In this scenario the EIRR for the Government program is still 20.2 percent while that of the PfR Program is 19.4 percent.
2. **Financial Analysis of the Program and BT**

**Analysis of Financial Performance of BT**

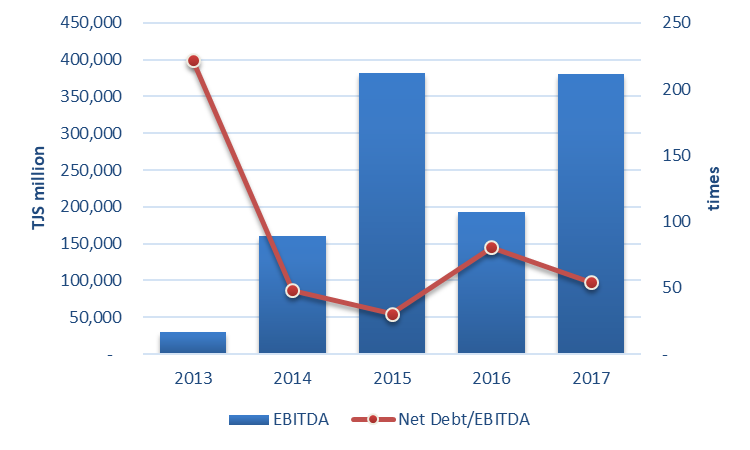
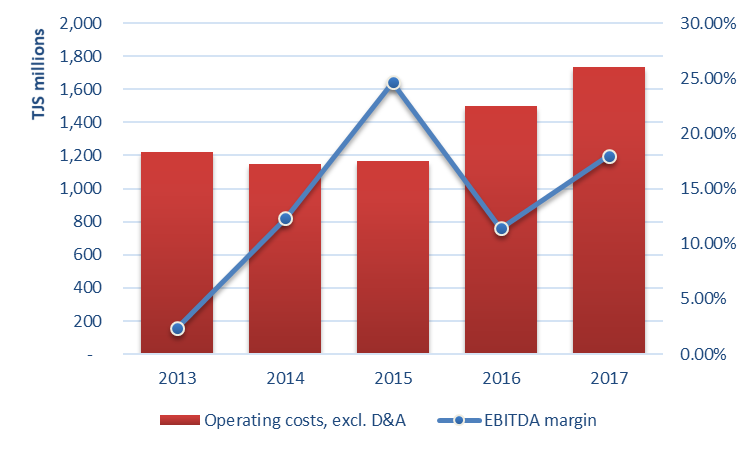
1. The financial condition of BT deteriorated in the period from 2013 to 2017 due to: (a) unsustainable and increasing debt levels and surging local currency denominated debt service costs driven by large depreciation of TJS; (b) low cash collections; and (c) below cost recovery end-user electricity tariffs.
2. As of the end-2017, BT’s total liabilities exceeded its total assets. Operating losses persisted in the period of 2013-2017 leading to complete erosion of equity in 2015. Accumulated losses of the BT reached TJS10,732 million (US$1,217 million), out of which TJS 5,437 million were losses from domestic currency depreciation. Over the observed period, Tajik somoni lost about half of its value against US$, which explained about 70 percent of the total increase of the Company’s financial debt to MOF and Orienbank.

**Figure 2: Dynamics of BT’s Financial Liabilities vs. USD/TJS exchange rate.**

Source: Corporate Financial Model of BT.

1. As of the end-2017, total liabilities of BT stood at TJS20,663 million (US$2,343 million), about 61 percent 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 2017, it had already accrued TJS2,197 million (US$250 million) of interest payable and incurred penalties on overdue loans in total amount of TJS2,657 million (US$301 million). In addition, BT has TJS1,618 million (US$183 million) very expensive dollar denominated commercial debt from a local bank, which costs the company about TJS372 million (US$42 million) per annum in interest expense.
2. The situation with payables, which account for about 10 percent of its total liabilities, also deteriorated. In particular, payables for electricity purchases from IPPs, Sangtuda-1 and Sangtuda-2 HPPs, rose to TJS1,855 million (US$201 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.
3. In 2017 total current liabilities of TJS9,869 million (US$1,119 million) accounted for 48 percent of total liabilities. Current assets were only 15% 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.
4. Nonetheless, the relatively stable operating costs before depreciation during the period of 2013-2015 and 14 percent average annual growth of sales revenue, driven by end-user tariff increases, lead to substantial improvement of EBITDA margin (18 percent in 2017 vs. 2 percent in 2013) and net debt[[4]](#footnote-4)-to-EBITDA ratio of the company (222 times EBITDA in 2013 vs. 50 times EBITDA in 2017).

Figure 3: EBITDA Margin and Net Debt/EBITDA Margin.



Source: Corporate Financial Model of BT.

1. The steady increase in the operating profit of BT was interrupted by about 60% increase in cost of electricity purchase in 2016. This was caused by 26 percent increase in the real cost of purchase of electricity, though the impact of somoni depreciation accounted for 73 percent of total change in electricity purchase cost between 2013 and 2017.

Figure 4: EBITDA Margin and Net Debt/EBITDA Margin.

Source: Corporate Financial Model of BT.

1. In 2017, BT earned TJS2,113 million (US$239 million) from sales of electricity. The Company supplied 13,549 GWh of electricity to domestic consumers and exported 1,410 GWh to Afghanistan and Kyrgyz Republic.
2. As of the end-2017, the collection rate for billed electricity was still below the industry average, at around 84.1 percent. The Company had 94 days receivables outstanding. The aluminum producer, TALCO, is the largest debtor to BT with its total debt of TJS399 million (US$45 million).

Table 15: Bill Collection Rates by Customer Categories in 2017.

| **Customer category** | **Bill collection rate** |
| --- | --- |
| Industry, excl. TALCO | 94.9 |
| TALCO | 96.8 |
| Budgetary organizations, housing and communal enterprises and electric transport | 83.7% |
| Pumps and pumping stations | 61.4% |
| Residential consumers | 76.9% |
| **Average** | **84.1%** |

Source: Corporate Financial Model of BT.

1. 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 2017 is estimated at 20 percent of 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 an eight-year period starting 2018. It should be noted that 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.

Table 16: Cost-recovery Tariff Projections.

| *In TJS million* | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Cash cost of sales** | **1,474** | **1,617** | **1,738** | **1,869** | **2,079** | **2,236** | **2,405** | **2,587** |
| Cost of purchased electricity | 922 | 997 | 1,082 | 1,175 | 1,275 | 1,385 | 1,503 | 1,632 |
| Materials | 293 | 348 | 370 | 394 | 489 | 520 | 553 | 588 |
| Salary and related expenses | 108 | 115 | 122 | 129 | 137 | 145 | 153 | 163 |
| Taxes | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 |
| Other | 106 | 113 | 120 | 127 | 134 | 142 | 151 | 160 |
| **Cash selling expenses** | **358** | **376** | **395** | **415** | **437** | **460** | **484** | **510** |
| **Cash admin expenses** | **94** | **99** | **104** | **109** | **114** | **120** | **126** | **133** |
| **Finance costs** | **2,598** | **2,425** | **2,359** | **2,270** | **2,266** | **1,853** | **1,874** | **1,898** |
| Current interest on MOF loans | 440 | 398 | 278 | 226 | 244 | 231 | 200 | 170 |
| Current interest on Orienbank loans | 398 | 329 | 256 | 177 | 92 | - | - | - |
| Current period principal repayment on MOF loans | 584 | 488 | 578 | 581 | 603 | 669 | 695 | 721 |
| Current period principal repayment on Orienbank loans | 346 | 358 | 371 | 386 | 401 | - | - | - |
| Repayment of overdue interest on MOF loans | 293 | 304 | 315 | 327 | 340 | 353 | 366 | 380 |
| Retirement of delinquent MOF loan principal | 301 | 312 | 324 | 336 | 349 | 363 | 376 | 391 |
| Retirement of overdue payables to Sangtuda-1,2 | 236 | 236 | 236 | 236 | 236 | 236 | 236 | 236 |
| **Profit** | - | - | - | - | - | - | - | - |
| **Required revenue** | **4,524** | **4,517** | **4,595** | **4,663** | **4,900** | **4,678** | **4,901** | **5,146** |
| *Cost recovery end-user tariff (diram/kWh)* | *38.97* | *38.53* | *38.81* | *39.09* | *40.53* | *38.31* | *39.72* | *41.25* |

Source: Corporate Financial Model of BT.

1. Forecast of Financial Performance of BT. Financial performance of BT was forecast for two scenarios. The BAU Scenario is the scenario without implementation of the Government program for Financial Recovery of BT. The Financial Recovery Scenario is based on the agreed-upon targets to be achieved by BT as reflected in the Action Plan for Financial Recovery, including increase of end-user average tariff, improvements in collection rates, and other efficiency improvements. The key assumptions for each of the forecast scenarios are presented below.

Projected Financial Performance of BT: BAU Scenario

1. The projections of financial performance of BT were made on assumptions that:
2. End-user electricity tariffs will remain flat starting from 2019 onward; the actual tariff increase of about 15 percent in 2018 has already been factored into the model.
3. Bill collection rate will remain at 85 percent over an eight-year period.
4. Technical losses will stay at their current level.
5. Domestic supply of electricity will increase by 1 percent during the projection period.
6. Exports to Afghanistan and Pakistan 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.
7. Electricity will be sold to Afghanistan and Pakistan at marginal prices of USc5.11/kWh and USc5.16/kWh respectively
8. The following volumes and tariffs for exports to Uzbekistan:

Table 17: Cost-recovery Tariff Projections.

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
|  | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** |
| Volume (GWh) | 2,000 | 2,000 | 2,500 | 3,000 | 3,200 | 3,200 | 3,200 |
| Tariff (USc/kWh) | 0.020 | 0.025 | 0.026 | 0.027 | 0.028 | 0.028 | 0.028 |

Source: BT.

1. BT will purchase 2,600 GWh of electricity from Sangtuda-1 and Sangtuda-2.
2. Prices of electricity purchased from Sangtuda-1 and Sangtuda-2 will growth at annual rate of 4 percent and 5 percent respectively.
3. The exchange rate of Tajik somoni against US dollar will change by the differential between Tajik and US inflation rate in accordance with PPP approach.
4. The BT will not accumulate new penalties on overdue loans.
5. In BAU Scenario, BT will continue to struggle with insufficient liquid assets to meet its current liabilities. In 2025 the ratio of current assets to current liabilities is estimated to be 0.26. Low collection ratio will lead to further build-up of overdue receivables, which may exceed 300 days of sales by 2025. This will result in continued non-payment to electricity suppliers and to the Ministry of Finance on its long-term liabilities at least till the start of exports to Afghanistan and Pakistan under CASA-1000. Total debt of BT, including payables to Sangtuda-1 and Sangtuda-2 as well, will reach TJS29,104 million (US$2,383 million) or 140 percent of its assets. Losses from the foreign exchange rate changes will eat up any operating profit; total cumulative loss over the eight-year forecast period is estimated to be TJS8,539 million (US$835 million), and the cash deficit will widen to TJS16,393 million by 2025 from TJS10,433 million in 2017.

**Projected Financial Performance of BT: Financial Recovery Scenario**

1. Under this scenario, the projections of financial performance of BT were made on assumptions that:
2. End-user electricity tariffs will increase by 15 percent annually during 2019-2021 and 8% thereafter.
3. Bill collection rate will remain at 85 percent over the period 2018-2020 and start increasing to reach 95 percent by 2025.
4. Technical losses will reduce by 0.50 percentage point annually.
5. Overdue receivables will be recovered.
6. All grants on-lent by the Ministry of Finance to BT on credit terms will be converted to grants in 2019.
7. In 2020, half of subsidiary agreements of BT with MOF will be revised to mirror the terms of borrowing by MOF from IFI, and the other half will be revised in 2021.
8. Domestic supply of electricity will increase by 1 percent during the projection period
9. Exports to Afghanistan and Pakistan 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.
10. Electricity will be sold to Afghanistan and Pakistan at marginal prices of USc5.11/kWh and USc5.16/kWh respectively.
11. The following volumes and tariffs for exports to Uzbekistan:

Table 18: Cost-recovery Tariff Projections.

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
|  | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** |
| Volume (GWh) | 2,000 | 2,000 | 2,500 | 3,000 | 3,200 | 3,200 | 3,200 |
| Tariff (USc/kWh) | 0.020 | 0.025 | 0.026 | 0.027 | 0.028 | 0.028 | 0.028 |

Source: BT.

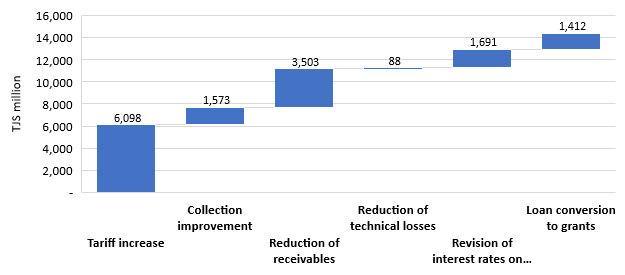
1. BT will purchase 2,600 GWh of electricity from Sangtuda-1 and Sangtuda-2.
2. Prices of electricity purchased from Sangtuda-1 and Sangtuda-2 will growth at annual rate of 4 percent and 5 percent respectively.
3. The exchange rate of Tajik somoni against US dollar will change by the differential between Tajik and US inflation rate in accordance with PPP approach.
4. The BT will not accumulate new penalties on overdue loans.
5. Increase of end-user tariffs, gradual improvement of collection rates, more efficient working capital management and reduction of technical losses will help BT generate more cash from operations. EBITDA margin will increase to 55 percent by 2025, and the liquidity will improve[[5]](#footnote-5). Revision of on-lending term of the Ministry of Finance will reduce the debt service costs of the BT and free up additional cash for repayment of its overdue liabilities. Commencement of electricity exports under 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 1,421 GWh to more than 5,900 GWh per year, including the existing exports to Afghanistan. Specifically, exports under CASA-1000 project are expected to generate additional US$145 million of income per year. BT will gradually repay its current and overdue financial liabilities using incremental operating cash flows from financial recovery measures. It is estimated that by 2024 BT will have fully repaid its overdue debt (principal plus interest) to Ministry of Finance, overdue payables to Sangtuda-1 and Sangtuda-2 and debt to Orienbank. As a result, by the end of 2025 the debt-to-assets ratio will have come down to 0.95, net debt (i.e. total financial debt net of cash balance) will stand at 4 time of earnings before interest, tax and depreciation (EBITDA)[[6]](#footnote-6), and operating cash flow will be more than 2 times its debt service requirements (DSCR). The detailed projection of balance sheet, income statement, and cash flow statement of BT are contained in the Technical Assessment Report of the Program.

Table 19: Projected Impact of Financial Recovery Measures.

|  | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** |
| --- | --- | --- | --- | --- | --- | --- | --- |
| 1. Tariff increase | 15% | 15% | 15% | 8% | 8% | 8% | 8% |
| **Additional cash flow, TJS million** | **166.2** | **406.0** | **686.6** | **893.2** | **1,091.3** | **1,308.5** | **1,546.7** |
| 2. Collection improvement | 85% | 85% | 86% | 88% | 91% | 93% | 95% |
| **Additional cash flow, TJS million** | **-** | **-** | **82.7** | **180.4** | **295.2** | **429.4** | **585.5** |
| 3. Reduction of receivables for supplied electricity | 123 | 105 | 68 | 60 | 58 | 58 | 59 |
| **Additional cash flow, TJS million** | **350.7** | **614.3** | **861.8** | **500.3** | **447.9** | **335.1** | **254.3** |
| 4. Reduction of technical losses by 0.5p.p. per annum | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% |
| **Additional cash flow, TJS million** | **4.3** | **6.4** | **8.9** | **11.6** | **14.6** | **18.0** | **21.8** |
| **5. Additional cash flow from revision of interest rates on subloans from MoF, TJS million** | **-** | **93.4** | **319.4** | **343.0** | **348.1** | **313.3** | **274.1** |
| **6. Additional cash flow from conversion of MoF loans to grants, TJS million** | **187.7** | **281.9** | **153.7** | **175.9** | **186.8** | **204.3** | **221.6** |
| **Total cash flow, TJS million** | **708.9** | **1,402.1** | **2,113.1** | **2,104.4** | **2,383.9** | **2,608.6** | **2,904.0** |
| **Cumulative cash flow, TJS million** | **708.9** | **2,111.0** | **4,224.0** | **6,328.4** | **8,712.3** | **11,320.9** | **14,224.9** |

Source: Corporate Financial Model of BT.

Figure 5: Cumulative Impact of Financial Recovery Measures

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Source: Corporate Financial Model of BT.

Table 20: Project Repayment Schedule for Payables and Debts under Financial Recovery Scenario.

|  | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Current payables to Sangtudas-1 and 2 | 455 | 806 | 1,175 | 1,275 | 1,385 | 1,503 | 1,632 |
| Overdue payables to Sangtudas-1 and 2 | - | 21 | 223 | 793 | 835 | 1,198 | 1,528 |
| Interest on Orienbank loans | 412 | 427 | 355 | 207 | - | - | - |
| Retirement of Orienbank loans | - | 372 | 675 | 902 | - | - | - |
| Current interest on MOF debt | 641 | 278 | 226 | 244 | 232 | 200 | 170 |
| Repayment of overdue interest on MOF debt | 420 | 931 | 952 | 256 | - | - | - |
| Repayment of MOF debt principal due | - | - | - | 641 | 2,461 | 1,470 | 721 |
| Retirement of overdue MOF debt | - | - | - | - | - | 790 | 1,437 |
| **Total payments, TJS million** | **1,928** | **2,836** | **3,607** | **4,319** | **4,879** | **5,161** | **5,488** |

Source: Corporate Financial Model of BT.

Table 21: Projected Financial Ratios under Financial Recovery Scenario.

|  | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **Gross margin** | 40% | 45% | 49% | 60% | 60% | 60% | 61% |
| **EBITDA margin** | 34% | 40% | 45% | 56% | 57% | 57% | 56% |
| **Current ratio** | 0.15 | 0.19 | 0.18 | 0.22 | 0.30 | 0.49 | 1.21 |
| **Debt-to-assets** | 1.43 | 1.30 | 1.28 | 1.19 | 1.08 | 0.95 | 0.81 |
| **DSCR** | 0.10 | 0.14 | 0.24 | 0.44 | 0.57 | 0.83 | 1.34 |

Source: Corporate Financial Model of BT.

**Annex 1: Summary of BT Recurrent Repair and Maintenance Program for T&D Network**

**Table 1: Summary of BT Recurrent Repair and Maintenance Program for 2020-2025.**

| **№** | **Name of the Unit** | **2020** | | **2021** | | **2022** | | **2023** | | **2024** | | **2025** | | **Total for 2020-2025** | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **US$** | **TJS** | **US$** | **TJS** | **US$** | **TJS** | **US$** | **TJS** | **US$** | **TJS** | **US$** | **TJS** | **US$** | **TJS** |
| **1** | **Southern electric networks** | 591,863 | 5,580,081 | 450,226 | 4,244,728 | 490,494 | 4,624,381 | 601,785 | 5,673,627 | 637,462 | 6,009,992 | 3,098,736 | 29,214,883 | **5,870,566** | **55,347,692** |
| **2** | **Kurgan-Tyube electric networks** | 141,786 | 1,336,757 | 19,097 | 180,044 | 28,645 | 270,066 | 106,691 | 1,005,883 | 12,867 | 121,306 | 68,914 | 649,720 | **377,999** | **3,563,776** |
| **3** | **Kulyob electric networks** | 856,653 | 8,076,525 | 250,557 | 2,362,250 | 629,534 | 5,935,244 | 498,818 | 4,702,854 | 448,029 | 4,224,015 | 448,029 | 4,224,015 | **3,131,619** | **29,524,902** |
| **4** | **Kulyob city electric networks** | 786,984 | 7,419,686 | 446,823 | 4,212,643 | 394,631 | 3,720,578 | 763,654 | 7,199,729 | 1,334,461 | 12,581,294 | 1,334,461 | 12,581,294 | **5,061,012** | **47,715,224** |
| **5** | **Dangara electric networks** | 446,400 | 4,208,658 | 643,736 | 6,069,140 | 162,792 | 1,534,803 | 123,927 | 1,168,384 | 186,408 | 1,757,450 | 1,254,792 | 11,830,179 | **2,818,054** | **26,568,614** |
| **6** | **Nurek electric networks** | 92,550 | 872,564 | 69,724 | 657,357 | 105,745 | 996,960 | 105,745 | 996,960 | 70,301 | 662,801 | 70,301 | 662,801 | **514,366** | **4,849,443** |
| **7** | **Yavan electric networks** | 419,105 | 3,951,320 | 838,877 | 7,908,933 | 896,911 | 8,456,080 | 323,772 | 3,052,521 | 421,311 | 3,972,119 | 109,014 | 1,027,780 | **3,008,990** | **28,368,754** |
| **8** | **Dushanbe electric networks** | 1,458,153 | 13,747,462 | 1,350,608 | 12,733,528 | 2,043,061 | 19,261,979 | 1,223,280 | 11,533,082 | 875,306 | 8,252,387 | 1,933,618 | 18,230,154 | **8,884,025** | **83,758,591** |
| **9** | **Central electric networks** | 1,731,335 | 16,323,022 | 1,359,526 | 12,817,609 | 1,322,575 | 12,469,239 | 1,890,743 | 17,825,920 | 1,918,139 | 18,084,210 | 1,893,616 | 17,853,007 | **10,115,932** | **95,373,007** |
| **10** | **Tursunzade electric networks** | 532,365 | 5,019,139 | 630,553 | 5,944,853 | 837,760 | 7,898,400 | 458,495 | 4,322,687 | 387,834 | 3,656,498 | 331,996 | 3,130,059 | **3,179,003** | **29,971,637** |
| **11** | **Rasht electric networks** | 254,943 | 2,403,599 | 299,909 | 2,827,539 | 169,131 | 1,594,563 | 117,647 | 1,109,177 | 199,939 | 1,885,026 | 118,152 | 1,113,937 | **1,159,720** | **10,933,841** |
| **12** | **Sughd electric networks** | 717,432 | 6,763,944 | 1,109,902 | 10,464,160 | 488,333 | 4,603,999 | 769,468 | 7,254,542 | 657,609 | 6,199,935 | 813,049 | 7,665,424 | **4,555,792** | **42,952,004** |
| **13** | **Khujand electric networks** | 419,250 | 3,952,689 | 192,319 | 1,813,179 | 192,319 | 1,813,179 | 194,324 | 1,832,089 | 444,887 | 4,194,392 | 3,204,480 | 30,211,841 | **4,647,578** | **43,817,368** |
| **14** | **Istaravshan electric networks** | 647,095 | 6,100,808 | 1,180,237 | 11,127,276 | 697,046 | 6,571,753 | 878,703 | 8,284,413 | 1,290,662 | 12,168,357 | 1,320,070 | 12,445,623 | **6,013,813** | **56,698,229** |
| **15** | **Isfara electric networks** | 358,352 | 3,378,542 | 180,299 | 1,699,855 | 403,089 | 3,800,318 | 1,320,070 | 12,445,623 | 861,381 | 8,121,097 | 743,646 | 7,011,094 | **3,866,836** | **36,456,530** |
| **16** | **Penjikent electric networks** | 83,472 | 786,970 | 139,168 | 1,312,075 | 69,584 | 656,037 | 188,146 | 1,773,843 | 188,146 | 1,773,843 | 8,944 | 84,324 | **677,460** | **6,387,093** |
| **17** | **Buston city electric networks** | 338,344 | 3,189,903 | 448,029 | 4,224,015 | 448,029 | 4,224,015 | 162,792 | 1,534,803 | 162,792 | 1,534,803 | 0 | 0 | **1,559,985** | **14,707,538** |
| **Total** | | **9,876,079** | **93,111,668** | **9,609,587** | **90,599,183** | **9,379,677** | **88,431,594** | **9,728,059** | **91,716,137** | **10,097,531** | **95,199,523** | **16,751,818** | **157,936,135** | **65,442,749** | **616,994,241** |

1. The Government, as the owner of BT, in the medium term can forego return on assets from public policy perspective as long as it does not impact the ability of BT to finance the new capital investments. Without return on assets, BT will be able to borrow (public and commercially) given that it is expected to receive enough revenue through tariff to cover debt service. [↑](#footnote-ref-1)
2. US$ equivalents were converted at the exchange rates as of the date of respective subsidiary agreements. [↑](#footnote-ref-2)
3. About 8 percent already have an AMI. [↑](#footnote-ref-3)
4. Net debt = total liabilities – cash and cash equivalents. [↑](#footnote-ref-4)
5. The ratio of current assets to current liabilities, inclusive and exclusive of penalties on overdue loans will be 0.63 and 1.19 respectively. [↑](#footnote-ref-5)
6. A proxy for operating cash flow. [↑](#footnote-ref-6)