ECONOMIC ANALYSIS

A. Background

1. The economic evaluation of the proposed investments was carried out in accordance with Asian Development Bank's (ADB) guidelines on power sector projects appraisal.[1,2] The evaluation covers three investment components of the project loan: Component 1 for a new power plant of Ashuganj Power Station Company Limited (APSCL), Component 2 for strengthening the transmission system of Power Grid Company of Bangladesh (PGCB), and Component 3 for prepaid metering in Dhaka Division under the Bangladesh Rural Electrification Board (BREB).

2. **Output 1** comprises the installation of the 400 megawatt (MW) combined cycle power plant (CCPP) (East) in APSCL to replace the ageing 150 MW Unit #3 steam turbine power plant commissioned in 1986. The 400 MW CCPP (East) will use an average of 50 million standard cubic feet per day (mmscfd) gas, of which 35 mmscfd would be sourced by decommissioning the existing 150 MW Unit #3 steam turbine power plant. The remaining 15 million mmscfd would come through reduced dispatches of 150 MW Unit #4 steam turbine power plant, 150 MW Unit #5 steam turbine power plant, and 53 MW gas engine unit, by reducing their combined average output by an equivalent of 70MW. APSCL's overall gas allocation of 230 mmscfd from Petrobangla need not be increased. The proposed power plant will be installed in the existing site presently occupied by the 146 MW CCPP (GT-1, GT-2 and ST) and its fuel tank. The 146 MW CCPP has been decommissioned, and will be demolished to provide space for the proposed power plant. This investment will improve the overall operational efficiency of APSCL.

3. **Output 2** covers the following: (i) re-conductoring the 65 kilometer (km) 132 kilovolt (kV) double circuit Comilla (South)–Kachua–Chadpur line as the replacement for the existing 132 kV Comilla–Chadpur double circuit transmission line; (ii) the new 7 km 132 kV double circuit Madunaghat–Kalurghat underground transmission line; (iii) transformer capacity changes in Kalurghat substation in Chittagong (132/33 kV, 2 x 80/120 megavolt-ampere (MVA) gas-insulated substation (GIS), in Kachua substation in Chandpur [132/33 kV, 2 x 50/75 MVA air-insulated substation (AIS)], and in Madunaghat substation also in Chittagong (132/33 kV, 2 x 80/120 MVA GIS substation); and (iv) substation upgrading from AIS to GIS in Comilla (South). The investment will serve to remove network operation constraints, reduce transmission losses and improve transmission system reliability and availability.

4. **Output 3** includes the installation of 700,000 pre-payment meters in 10 (Palli Bidyut Samity) PBS[3] (Dhaka PBS-1, Dhaka PBS-2, Dhaka PBS-3, Gazipur PBS, Manikganj PBS, Munsiganj PBS, Mymensingh PBS-2, Narayanganj PBS, Narshingdi PBS-1 and Narshingdi PBS-2) replacing the old and less accurate electro-mechanical meters used in the existing post payment scheme. This investment will, among others, reduce the non-technical losses in the distribution network, improve the commercial and financial efficiency of distribution utilities, and contribute to the reduction of total demand through behavioral changes among customers.

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1 ADB.1997. *Guidelines for Economic Analysis of Projects*. Manila.
2 ADB. 2013. *Cost-Benefit Analysis for Development: A Practical Guide*. Manila.
3 Palli Bidyut Samity (PBS) is the Bengali name for a Rural Electric Society. It is a consumer owned entity organized on the basic principles of co-operative for distribution of electric power to its members and other consumers.

B. Economic Rationale

5. Bangladesh has been experiencing chronic power supply shortages over the past decades. In 2010, urban areas were reported to experience supply interruptions between 5–10 hours per day. Despite the power sector investments undertaken by both the public sector and the private sector in recent years, load shedding, though declining, remains an economic reality in the country. Power supply shortage registered in 2014 amounted to 932 MW.

6. In addition to deficiencies in generation capacity, load shedding in some areas of the country were also caused by constrained transmission and distribution capacities. Power generation of some plants could not be fully evacuated due to overloaded network as well as high transmission losses.

7. Significant improvements have been achieved in Bangladesh with respect to reducing distribution system losses. At the national level, the distribution loss had declined from the high of 25.34% in 2001 to 11.96% in 2014. Pilot demonstration projects on prepaid metering had however shown that system losses particularly those attributed to non-technical losses could be further reduced to around 6.5% while peak demand could also be reduced with the installation of more accurate and tamper sensitive prepayment meters.

8. Despite the increasing role of the private sector in the power supply industry, the public sector will continue to play an important role in the medium– to long–term. This is because: (i) for generation and transmission sectors, long–term investment requirements under the current Power Sector Master Plan amount to $70 billion or a yearly equivalent investment of $3.5 billion. With the current global and domestic investment climate, such significant investments could not be raised by the private sector alone. As a strategy, the government should continue to invest in the sector and at the same time promote private power development; and (ii) power sector reform framework introduced by the government in the 1990s did not cover privatization of the transmission and distribution functions of the industry, and that such privatization will require a new legal framework which may take time to enact and implement. The government will remain to be the main driving force for the development of transmission and distribution infrastructure in the short and medium terms.

C. Demand Analysis

9. Access to on-grid electricity services (share of households connected to the grid) in Bangladesh has increased to 59.6% in 2013 from around 47% in 2010. Electricity consumption reached 36,233 gigawatt-hour (GWh) in 2014 which is almost three times the recorded electricity sales in 2000. Despite the increase of per capita power consumption by 5.7% per year between 2004 and 2014, Bangladesh remains to be one of the countries in the world with low per capita electricity consumption at 321 kWh in 2014. The Government of Bangladesh targets 100% grid access for all with average per capita electricity consumption of 600 kWh by 2021.

10. The residential sector accounted for around one-half of total electricity consumption in 2014, followed by the industrial sector which accounted for around one-third of the total consumption. The commercial sector registered around 10% share while the agriculture sector recorded almost 5%. The remaining share was accounted by other consumer groups.

11. In the past 10 years, electricity demand had risen annually by 8% while electricity generation had grown only by 7.4% per year. As a result, capacity shortage had been increasing by 3% yearly. Between 2010 and 2020, electricity demand is forecast in the power sector master plan (PSMP) 2010 to grow at around 10% per year. Total demand by 2020 would amount to almost 91,000 GWh. The key challenge for the government is to meet the projected demand at least-cost.

D. Least-Cost Analysis

12. With the availability of natural gas resource in the country, natural gas is the dominant fuel for power generation in Bangladesh representing 72.32% of total electrical energy served to the grid in 2014. Liquid fuels (diesel and heavy fuel oil) followed next with a share of 18.35% share while domestic coal and hydropower contributed 2.46% and 1.39% each, respectively. Electricity imports on the other hand accounted for 5.37%. The dominance of natural gas will continue while coal and liquid fuels will remain important in the next five years under the Medium Term Power Development Plan. The share of natural gas power generation will decline to around 40% of the total generation by 2020 under the PSMP 2010.

13. The average cost of generating power from these fuel sources in 2014 are the following: hydropower, Tk1.49/kWh (Karnafuli Hydropower Station); natural gas, Tk2.07/kWh (simple average of all gas-based power plants); coal, Tk6.30/kWh; heavy fuel oil, Tk17.86/kWh; and diesel oil, Tk37.35/kWh. Excluding hydropower due to its limited potential, domestic natural gas represents the least-cost supply option for Bangladesh. Among gas-based power plants, combined cycle power plants have the highest system efficiency ranging between 50%–60% compared with 35%–42% for steam turbines. CCPP are most suitable for base load and mid–load power generation, steam turbines and gas engines for mid–load while gas turbines for peaking. The CCPP project (Output 1) optimizes the use of domestic natural gas resource and is one of the least–cost options for base– and mid–load power generation in the country.

14. Spatial dimensions in least–cost planning were integrated in the preparation of long–term power development plans. Based on specified power generation locations and electricity demand centers, alternative alignments for high, medium and low voltage power transmission options were assessed and the least-cost alignment options were selected and recommended for development in transmission and distribution plans. The proposed transmission projects (Output 2) are those identified in the latest PSMP. Thus, these projects form part of the long–term least–cost solution in delivering electricity services in Bangladesh.

15. Target impacts of demand–side management (DSM) measures were considered in the long–term energy sales forecast in PSMP 2010. The demand forecast model used in least–cost planning takes into account the interaction between economic growth and energy intensity. Any measures, including the implementation of prepaid metering (Output 3), carried out by distribution utilities and other government agencies to manage demand, improve efficiency and promote conservation are integral parts of the overall intervention strategy envisaged to meet the long-term energy efficiency improvement targets.

E. Project Costs

16. All project costs were expressed in terms of economic prices. Investment and operation and maintenance (O&M) costs in financial prices were adjusted to reflect the economic resource cost of project inputs in terms of domestic price numeraire. Costs were categorized into traded

goods, non-traded goods, foreign skilled labor, local unskilled labor, fuel and transfer payments, and were adjusted with appropriate conversion factors. The shadow rate exchange factor (SERF) was used to convert traded costs while the shadow wage rate factor was used for unskilled labor. Transfer payments and price contingencies were excluded from the analysis.

17. The SERF was calculated as the inverse of the standard conversion factor (SCF). SERF values for the last four years were estimated, and their 4–year average value of 1.03 was used in the analysis. Owing to high underemployment in Bangladesh, a shadow wage rate of 0.80 was used to estimate the economic value of unskilled labor.

18. The exchange rate in July 2015 of Tk77.8 = $1 and a discount rate of 12% were used in the calculations. A period of 25 years was used for economic assessment of the new power plant project, 35 years for transmission projects, and 30 years for the prepaid metering project.

19. For domestic natural gas, the price at the wellhead was calculated as the sum of the long-run marginal cost of gas extraction plus a depletion premium. The estimated life-cycle gas cost of $1.16 per thousand cubic feet[4] was used as a proxy for the long-run marginal cost. It was assumed that domestic gas supplies will be fully exhausted by 2025, and would be replaced by imported liquefied natural gas (LNG), the price of which was assumed to be equal to the price of imported LNG in Japan. The long-run marginal cost of gas transmission and losses in transmission and compression were included in the calculations. The LNG price was taken from the recent World Bank commodity price forecasts.[5] The depletion premium was calculated based on ADB's guidelines.[6]

F. Project Benefits

20. Project outputs were classified into incremental and non-incremental outputs. Incremental outputs refer to the additional output produced by the project over and above what would be available in the without–project situation. Non–incremental output is the output produced by the project that displaces high cost or unreliable supplies without the project. Incremental outputs were valued using the willingness–to–pay (WTP) methodology with adjustments made for transmission and distribution losses, while non-incremental outputs were valued at resource costs savings.

21. Bangladesh is a country with shortages in power supply. The framework for analyzing project benefits for power generation and supply expansion with power shortage was used in the analysis.[7] For existing residential consumers, the WTP consists of the incremental revenue and the consumer surplus. The consumer surplus was estimated using the Asian average for price elasticity of demand of –0.430 as the proxy value for Bangladesh. Electricity demand forecast used in the analysis was taken from PSMP 2010. For each project component, the consumer surplus was estimated. For non-residential consumers, project benefits were valued at the cost of unplanned outages[8] in industry and in terms of cost of diesel fuel substitute for commercial and agricultural consumers.

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[4] ADB. 2009. *Bangladesh: Preparing the Clean Fuel Sector Development Program*, TA 4952-BAN. Manila.
[5] World Bank (2015). *Commodity Markets Outlook*. April 2015 update.
[6] ADB.1997. Appendix 6: Depletion Premium, *Guidelines for Economic Analysis of Projects*. Manila.
[7] ADB. 2013. Chapter 8: Appraising Electricity Projects, *Cost-Benefit Analysis for Development: A Practical Guide*. Manila.
[8] USAID-SARI Energy Program. 2003. *Bangladesh: Economic Impact of Poor Power Quality on Industry*, Nexant.

22. In valuing non–incremental outputs, alternative sources of energy supply were considered. For Output 1 (400 MW Ashuganj CCPP, the non–incremental output due to improved efficiency was valued based on natural gas savings while the output due to increased capacity was valued based on the displaced diesel power generation. For Output 3 (prepaid metering investment), resource cost savings from main consumer categories were taken into consideration in determining the value of non–incremental output. Kerosene lamps for domestic lighting and diesel power generators at varying capacities were used for commercial, agricultural and industrial consumers. The aggregate project benefit was estimated as the weighted average benefit for all consumer categories using the shares from national sales data. The levelized costs were estimated using border prices and shadow priced using shadow exchange rate factor, taking into consideration the fuel, fixed and variable operating costs of electricity generation. Kerosene and diesel fuel prices were derived from global average spot market price of crude oil from the most recent World Bank commodity price forecasts.

23. The combined cycle power generation, transmission and prepaid metering projects considered under this multi-tranche loan facility are categorized as energy efficiency projects, because these improve the overall thermal efficiency of the existing gas-based plants or reduce overall transmission and distribution losses as well as reduce peak demand. Environmental benefits of these projects include reductions of local pollutant and greenhouse gas emissions. The reduction of 0.7 million tons carbon dioxide equivalent per year is expected to be achieved after the Output 1 is achieved.

G. Economic Feasibility of Tranche 3

24. **Output 1**. APSCL currently operates several gas-fired power plants with a total gas allocation of 230 mmscfd. The new 400 MW combined cycle power plant is aimed to replace a smaller and inefficient 150 MW Unit #3, which is a steam turbine power plant. Without the project, the total gas consumption of APSCL's power plants is estimated to be almost 200 mmscfd, while with the implementation of the project (commissioning of the 400 MW CCPP and decommissioning of 150 MW Unit #3), the total gas consumption of the company would increase to 217 mmscfd, but will remain below its gas allocation limit. Power generation without the project amounts to 9,661 GWh per year while with the project, case totals to 11,335 GWh/year. The first non–incremental benefit is attributed to improved efficiency of power plants, and estimated as the gas savings in producing the amount of electricity in without the project case and if generated by more efficient plants in with the project case. This results in gas savings of 14.84 mmscfd and valued at economic price of domestic natural gas. The second non–incremental benefit is due to the potential displacement of diesel power generation by the increased electricity production by the project. Based on the Bangladesh Power Development Board's (BPDB) current medium term investment plan and with declining power shortages, the new Ashuganj 400 MW CCPP would most likely be displacing more expensive power generation rather than supplying unmet demand. The study estimated that the 1,694 GWh per year additional electricity production would reduce generation from existing diesel power plants and was valued at short-run marginal production cost. With this, the project economic internal rate of return (EIRR) is 22.5%.

Table 1: EIRR Calculation for Output 1

	Costs			Benefits		
Year	Capital	Fuel	O&M	Incremental	Non-incremental	Net Benefits
2016	752	0	0		0	-752
2017	4,259	0	0		0	-4,259
2018	10,020	0	0		0	-10,020
2019	9,519	0	0		0	-9,519
2020	501	0	0		0	-501
2021	0	12,530	341		21,278	8,408
2022	0	13,749	341		22,546	8,456
2023	0	15,114	341		23,883	8,428
2024	0	16,643	341		25,346	8,363
2025	0	18,355	341		26,891	8,195
2026	0	18,355	341		26,891	8,195
2027	0	18,355	341		26,891	8,195
2028	0	18,355	341		26,891	8,195
2029	0	18,355	341		26,891	8,195
2030	0	18,355	341		26,891	8,195
2031	0	18,355	341		26,891	8,195
2032	0	18,355	341		26,891	8,195
2033	0	18,355	341		26,891	8,195
2034	0	18,355	341		26,891	8,195
2035	0	18,355	341		26,891	8,195
2036	0	18,355	341		26,891	8,195
2037	0	18,355	341		26,891	8,195
2038	0	18,355	341		26,891	8,195
2039	0	18,355	341		26,891	8,195
2040	0	18,355	341		26,891	8,195
2041	0	18,355	341		26,891	8,195
2042	0	18,355	341		26,891	8,195
2043	0	18,355	341		26,891	8,195
2044	0	18,355	341		26,891	8,195
2045	0	18,355	341		26,891	8,195
					EIRR	**22.5%**

EIRR = economic internal rate of return, O&M = operation and maintenance.

25. **Output 2**. Transmission projects contribute to (i) the improvement of system reliability, (ii) removal of network operation constraints (thus freeing up transmission-constrained generating capacity), and (iii) reduction of losses. The transmission project benefits were estimated by undertaking a transmission system load flow simulation analysis with and without the project. The load flow simulation takes into account power supply capacities, demand and technical constraints in power transmission. The aggregate impact of the implementation of the 65 km Comilla (South)–Chadpur transmission line replacement, the new 7 km Madunaghat–Kalurghat transmission line, transformer capacity improvements in Chadpur, Kalurghat and Madunaghat, and Comilla (South) substation upgrade to GIS, is to reduce the overall transmission losses by 1.1 MW in average, while power generation has also increased by 5.26 MW. The simulation shows that the increased generation would be coming from the existing power plants that were constrained to generate power due to grid technical limits. Both savings in losses and increased generation would meet the demand that otherwise be unserved and are valued as incremental benefit. The total incremental benefit amounts to 38.6 GWh per year. The cost of increased power generation was added to the project costs, which is benchmarked to

the levelized cost of the Ashuganj 400 MW combine cycle power plant under Component 1. The overall EIRR of this component was evaluated to be 16.2%.

Table 2: EIRR Calculation for Output 2

	Costs			Benefits		
Year	Capital	Cost of Supply	O&M	Incremental	Non-incremental	Net Benefits
2016	359	0	0	0		-359
2017	2,317	0	0	0		-2,317
2018	1,318	0	0	0		-1,318
2019	0	293	100	962		570
2020	0	293	100	1,004		611
2021	0	293	100	1,046		653
2022	0	293	100	1,092		699
2023	0	293	100	1,139		746
2024	0	293	100	1,189		797
2025	0	293	100	1,242		849
2026	0	293	100	1,242		849
2027	0	293	100	1,242		849
2028	0	293	100	1,242		849
2029	0	293	100	1,242		849
2030	0	293	100	1,242		849
2031	0	293	100	1,242		849
2032	0	293	100	1,242		849
2033	0	293	100	1,242		849
2034	0	293	100	1,242		849
2035	0	293	100	1,242		849
2036	0	293	100	1,242		849
2037	0	293	100	1,242		849
2038	0	293	100	1,242		849
2039	0	293	100	1,242		849
2040	0	293	100	1,242		849
2041	0	293	100	1,242		849
2042	0	293	100	1,242		849
2043	0	293	100	1,242		849
2044	0	293	100	1,242		849
2045	0	293	100	1,242		849
2046	0	293	100	1,242		849
2047	0	293	100	1,242		849
2048	0	293	100	1,242		849
					EIRR	**16.2%**

EIRR = economic internal rate of return, O&M = operation and maintenance.

26. **Output 3**. Prepaid metering is not new in Bangladesh. BPDB and Dhaka Electricity Supply Company (DESCO) have implemented pilot projects to evaluate the technical, financial and economic viability as well as social acceptability of the prepaid metering system. BREB's current project of installing 700,000 prepaid meters in 10 PBSs is part of the overall thrust of the government to scale-up deployment of prepayment schemes. The main financial benefits highlighted in both BPDB and DESCO's pilot projects are the significant reduction in non-technical system losses as well as in the reduction of energy demand. The key non-incremental economic benefit considered in this study is on the other hand the reduction in demand due to behavioral changes associated with real-time feedback on customer's energy usage. In the DESCO pilot project, average demand declined by 1.7 MW after installing prepaid meters in

19,000 households that are connected to a single feeder line. On average, this translates to a demand reduction of 0.09 kW per household. The study considered that only 10% of the conservation effect observed in the DESCO project could be attributed to behavioral changes.[9] The savings impact of the 700,000 prepaid meters was estimated to be 48.7 GWh. These savings would otherwise be dissipated as heat, as standby losses of household electrical appliances or used for unproductive services with no economic value. This yields a project EIRR of 26.6%.

Table 3: EIRR Calculation for Output 3

	Costs			Benefits		
Year	Capital	Fuel	O&M	Incremental	Non-incremental	Net Benefits
2016	1,402		0		0	-1,402
2017	1,438		0		0	-1,438
2018	755		0		0	-755
2019	0		90		1,214	1,124
2020	0		90		1,267	1,177
2021	0		90		1,319	1,230
2022	0		90		1,377	1,287
2023	0		90		1,436	1,346
2024	0		90		1,501	1,411
2025	0		90		1,566	1,476
2026	0		90		1,566	1,476
2027	0		90		1,566	1,476
2028	0		90		1,566	1,476
2029	0		90		1,566	1,476
2030	0		90		1,566	1,476
2031	0		90		1,566	1,476
2032	0		90		1,566	1,476
2033	0		90		1,566	1,476
2034	0		90		1,566	1,476
2035	0		90		1,566	1,476
2036	0		90		1,566	1,476
2037	0		90		1,566	1,476
2038	0		90		1,566	1,476
2039	0		90		1,566	1,476
2040	0		90		1,566	1,476
2041	0		90		1,566	1,476
2042	0		90		1,566	1,476
2043	0		90		1,566	1,476
2044	0		90		1,566	1,476
2045	0		90		1,566	1,476
					EIRR	**26.6%**

EIRR = economic internal rate of return, O&M = operation and maintenance.

27. **Combined Project**. The EIRR of the combined project is estimated at 22.3% which is close to that of Output 1. This is explained due to the fact that Output 1 represents 76% of the total project economic cost.

[9] The European Environment Agency (EEA) has reported that direct feedback measures such as prepaid meters could achieve energy savings between 5-15%, and that higher savings had been observed in low income households. EEA (2013), *Achieving Energy Efficiency Through Behaviour Change: What Does It Take?* Copenhagen.

Table 4: EIRR Calculation for Combined Project

		Costs		Benefits		
Year	Capital	Fuel + Cost of Supply	O&M	Incremental	Non-incremental	Net Benefits
2016	2,513	0	0	0	0	-2,513
2017	8,014	0	0	0	0	-8,014
2018	12,094	0	0	0	0	-12,094
2019	9,519	293	190	962	1,214	-7,825
2020	501	293	190	1,004	1,267	1,287
2021	0	12,823	531	1,046	22,598	10,291
2022	0	14,042	531	1,092	23,923	10,443
2023	0	15,407	531	1,139	25,319	10,521
2024	0	16,936	531	1,189	26,847	10,570
2025	0	18,648	531	1,242	28,457	10,520
2026	0	18,648	531	1,242	28,457	10,520
2027	0	18,648	531	1,242	28,457	10,520
2028	0	18,648	531	1,242	28,457	10,520
2029	0	18,648	531	1,242	28,457	10,520
2030	0	18,648	531	1,242	28,457	10,520
2031	0	18,648	531	1,242	28,457	10,520
2032	0	18,648	531	1,242	28,457	10,520
2033	0	18,648	531	1,242	28,457	10,520
2034	0	18,648	531	1,242	28,457	10,520
2035	0	18,648	531	1,242	28,457	10,520
2036	0	18,648	531	1,242	28,457	10,520
2037	0	18,648	531	1,242	28,457	10,520
2038	0	18,648	531	1,242	28,457	10,520
2039	0	18,648	531	1,242	28,457	10,520
2040	0	18,648	531	1,242	28,457	10,520
2041	0	18,648	531	1,242	28,457	10,520
2042	0	18,648	531	1,242	28,457	10,520
2043	0	18,648	531	1,242	28,457	10,520
2044	0	18,648	531	1,242	28,457	10,520
2045	0	18,648	531	1,242	28,457	10,520
2046	0	293	100	1,242	0	849
2047	0	293	100	1,242	0	849
2048	0	293	100	1,242	0	849
					EIRR	**22.3%**

EIRR = economic internal rate of return, O&M = operation and maintenance.

H. Sensitivity and Risk Analysis

28. Risks exist that these projects would not achieve the hurdle economic returns due to uncertainties in the values of key parameters used in the analysis. These parameters include capital costs, O&M costs and fuel costs. To investigate the impact of the uncertainties on project viability, the sensitivity of EIRR to the variation of these parameters were analyzed. The sensitivity analysis show that the potential variation in key project parameters such as increase in capital, O&M and fuel costs would still render the overall project economically viable.

Table 5: Sensitivity Analysis

	Output 1		Output 2		Output 3	
	EIRR (%)	Switching Value (%)	EIRR (%)	Switching Value (%)	EIRR (%)	Switching Value (%)
Base	22.5		16.2		26.6	
Capital costs (10% increase)	20.9	110	14.9	39	24.8	165
O&M costs (20% increase)	22.4		15.8		26.3	
Fuel cost (10% increase)	20.1	37				
Supply cost (10% increase)			15.6	73		
Combined	18.5		14.0		24.5	

EIRR = economic internal rate of return, O&M = operation and maintenance.
Source: Asian Development Bank estimates.

I. Conclusion

29. The economic assessment indicates that Tranche 3 project components are part of the aggregate least-cost solution to address chronic power shortage as well as in meeting incremental demand in Bangladesh.

30. The economic performance of each output is found to be robust. The sensitivity analyses show that the potential variation of key project parameters such as increase in capital, O&M and fuel costs would not decrease the overall project viability.

31. From economic standpoint, these projects are beneficial to the economy and should be financially supported.