ECONOMIC ANALYSIS

1. The Power Transmission Improvement Project in Myanmar will support (i) the construction of an 8.2 kilometers (km) 230 kilovolt (kV) transmission line between Thida substation and Thaketa substation and an 8.6 km 230 kV transmission line between Thaketa substation and Kyaikasan substation, which includes the upgrading of the Kyaikasan substation; (ii) the construction of two 230 kV substations at South Okkalapa and West University; and (iii) the extension of the existing Thaketa substation. These substations are in the general area of the city of Yangon. The project will supply additional electric power to meet rapidly increasing demand for electricity. It will also substantially improve the reliability of the power system by completing the critically important 230 kV transmission ring line supplying electricity to the populous Yangon region. The analysis used a system approach to evaluate the economic returns of the project, since each component to be provided by the project will be interlinked with the network as a whole and will improve the system overall.

2. **Demand and supply analysis.** Electricity consumption in Myanmar grew at a compound annual growth rate (CAGR) of 9.8% during 2000–2012 but soared to a CAGR 20.0% during 2012–2015. About 50% of the consumption is concentrated in the Yangon region. The peak load reached 2,400 megawatts (MW) in 2014. The total installed generation capacity in 2014 was 4,366 MW, of which 3,005 MW (68.8%) was using hydropower, 1,236 MW (28.3%) gas, 120 MW (2.7%) coal, and 5 MW (or less than 1.1%) mini hydro and solar renewable energy sources. However, due to high reliance on hydropower, the poor efficiency of old thermal power plants, and lack of maintenance, the system's actual maximum power supply capacity was only half of the installed capacity.

3. The Asian Development Bank (ADB) forecasts annual average growth of 9.6% in electric demand during 2014–2030.[1] The peak load is expected to reach 3,800 MW by 2020 and 9,500 MW by 2030. To meet this demand, the country's aging power plants have been rehabilitated and new power plants are being constructed. The total capacity of the plants now planned or confirmed by the government for construction by 2020 will be about 2,000 MW. Capacity totaling another 7,000 MW is to be added by 2030. This expansion program will relieve the shortfall between generation capacity and demand but will also soon push the current transmission system to full capacity.

4. **Approach.** The project will help increase the electricity transmission network capacity in anticipation of the expanded power generation capacity and improve the reliability and quality of the power network and electricity supply. In line with ADB's Guidelines for the Economic Analysis of Projects, the analysis compared the economic costs and benefits expected to accrue from the project with a without-project scenario.[2] The analysis was based on a 20-year project lifetime, with operations starting in 2020 at completion of construction. It was also assumed that the increase in grid capacity the project will provide will be converted into additional supply of power from the grid.

5. Yangon faces power shortages and suffers from frequent load shedding and outages. Four gas-fired power plants have recently been rehabilitated and expanded in the Yangon region to address the problems in the short term. Peak demand in the region is projected to increase rapidly from 1,300 MW in 2014 to 1,900 MW by 2020 and 2,900 MW by 2025. Without the expanded and upgraded capacity to be provided by the project, this will make the

[1] ADB. Draft Energy Master Plan Study Report. Unpublished.
[2] ADB. 1997. *Guidelines for the Economic Analysis of Projects*. Manila.

transmission network a bottleneck. Load flow analysis has determined that electricity sales will increase by 1,000 GWh once the project becomes operational in 2020, and that incremental sales will grow to 3,300 GWh in 2025 in line with increasing demand.

6. **Economic cost.** The economic costs of the project comprise (i) all costs directly incurred during the implementation and subsequent operation of the project, i.e., investment costs and operation and maintenance (O&M) costs of transmission lines and substations; and (ii) generation and distribution costs. The O&M cost was assumed to be 3.5% of capital cost, since high-voltage substations require intensive O&M.

7. The total base capital cost of the project was converted into economic cost, with transfer payments (taxes and duties) and price contingencies excluded. The analysis used the domestic price numeraire. A shadow exchange rate factor of 1.1 was used to convert all traded goods and services to domestic prices.[3] Equipment and material procurement will be done through international competitive bidding and national competitive bidding. These costs were considered to represent traded goods and therefore multiplied by the shadow exchange rate factor. In calculating labor costs, a shadow wage rate factor of 0.75 was applied for unskilled labor because of supply surplus.

8. Resource costs were calculated as the sum of generation and distribution network costs. The generation cost was estimated at $0.0695 per kilowatt-hour (kWh), which was the weighted average cost of all generation facilities based on a power expansion plan prepared by the government's national electricity master plan, which was supported by the Japan International Cooperation Agency (JICA).[4] The distribution cost was estimated to be $0.0174 per kWh in the same report, using Yangon Electricity Supply Board expenses divided by the units sold.

9. **Economic benefit.** The project will produce incremental benefits through the additional power to be delivered by the expanded transmission capacity it will help deliver. It will also help reduce transmission losses[5] and outages.[6] The analysis estimated that the incremental electricity sales due to the project will total 1,000 gigawatt-hours in 2020 and climb to 3,300 gigawatt-hours in 2025 (para. 5) before remaining constant thereafter. These incremental sales have been valued at the economic value of electricity. This was estimated as the long-run marginal cost (LRMC) of electricity because current tariffs are heavily regulated and do not recover costs. Non-incremental benefits will result from resource cost savings from back-up diesel generation offset by increased grid power supply, but they are not quantified due to data limitations.

10. JICA has estimated the LRMC at $0.0932 per kWh (footnote 5). This is the sum of the LRMCs of generation, transmission, and distribution and calculated as a present value of the difference in investment cost between the base case and the case with marginal demand increase. The World Bank has estimated the per-kWh LRMC at $0.0733 for the existing network; $0.113 with additional generation; and $0.131 with additional generation, transmission, and distribution.[7] JICA's LRMC estimate is within a reasonable range of the World Bank estimate.

[3] This is calculated approximately, based on actual taxes and duties on imports in Myanmar, which is 6%.
[4] Japan International Cooperation Agency. Myanmar: Final Report on National Electricity Master Plan in Myanmar. Unpublished.
[5] A one percentage point decline in transmission losses was assumed, starting at project completion.
[6] The avoided outages in Yangon were estimated at 988 megawatt-hours per year, based on a survey to determine the duration of outages between the 66 kV Thaketa substation and Kyaikasan substation in 2013.
[7] World Bank. 2014. *Draft Final Roadmap and Investment Prospectus: Myanmar National Electrification Plan Roadmap and Investment Prospectus*. Washington, D.C.

11. **Economic internal rate of return.** The economic internal rate of return (EIRR) was calculated to be 14.4%. This EIRR confirms that the project is essential and exceeds the minimum rate of 12% deemed acceptable by ADB. The cost and benefit stream is presented in Table 1.

Table 1: Economic Cost and Benefit Stream

Year		Generation and Distribution costs	Incremental cost	Total Costs	Total benefits	Net benefits
(4)	2016	0.00	1.76	1.76	0.00	(1.76)
(3)	2017	0.00	15.57	15.57	0.00	(15.57)
(2)	2018	0.00	42.92	42.92	0.00	(42.92)
(1)	2019	0.00	14.79	14.79	0.00	(14.79)
1	2020	95.92	2.63	98.54	102.87	4.33
2	2021	134.28	2.63	136.91	144.02	7.11
3	2022	172.65	2.63	175.28	185.17	9.89
4	2023	211.02	2.63	213.64	226.31	12.67
5	2024	249.38	2.63	252.01	267.46	15.45
6	2025	287.75	2.63	290.38	308.61	18.23
7	2026	287.75	2.63	290.38	308.61	18.23
8	2027	287.75	2.63	290.38	308.61	18.23
9	2028	287.75	2.63	290.38	308.61	18.23
10	2029	287.75	3.13	290.88	308.61	17.73
11	2030	287.75	2.63	290.38	308.61	18.23
12	2031	287.75	2.63	290.38	308.61	18.23
13	2032	287.75	2.63	290.38	308.61	18.23
14	2033	287.75	2.63	290.38	308.61	18.23
15	2034	287.75	2.63	290.38	308.61	18.23
16	2035	287.75	2.63	290.38	308.61	18.23
17	2036	287.75	2.63	290.38	308.61	18.23
18	2037	287.75	2.63	290.38	308.61	18.23
19	2038	287.75	2.63	290.38	308.61	18.23
20	2039	287.75	3.13	290.88	308.61	17.73
	EIRR (%)					**14.4%**
	ENPV ($ million)					**11.9**
	Discount rate					**12%**

( ) = negative, EIRR = economic internal rate of return, ENPV = expected net present value.
Source: Asian Development Bank Estimates.

12. **Sensitivity analysis.** The sensitivity of the results of the economic analysis was tested by altering key assumptions to assess the impact of negative changes to base case parameters. This analysis examined the impact of (i) an increase in estimated direct project costs of 10% and (ii) a decline in project benefits of 10%. The sensitivity analysis shows that the project economic viability is robust against the usual variation of key parameters used in the economic analysis. The results are summarized in Table 2.

Table 2: Economic Sensitivity Analysis

Scenario	EIRR (%)	NPV ($ million)
Base case	14.4	11.9
Direct project costs increase by 10%	13.2	6.6
Project benefits decline by 10%	12.9	4.1

EIRR = economic internal rate of return, NPV = net present value.
Source: Asian Development Bank Estimates.