FINANCIAL ANALYSIS

A. Introduction

1. This financial evaluation of the proposed investment was carried out in accordance with the Guidelines for Financial Management and Analysis of Projects of the Asian Development Bank (ADB).[1] The analysis examined the financial viability of the proposed reinforcement and expansion of the distribution network owned and operated by the Electricity Supply Enterprise (ESE), a department of the Ministry of Electricity and Energy (MOEE). The project's transmission component will be implemented by MOEE's Department of Power Transmission and System Control (DPTSC), a nonrevenue generating entity. As such, the transmission component was excluded from the financial analysis.

B. Methodology and Assumptions

2. **Project components**. The project will add about 400 megavolt ampere (MVA) of new 66 kilovolt (kV) and 33 kV substation capacity, plus about 600 km of new 66 kV and 220 km of new 33 kV overhead lines. The new distribution facilities are scheduled to be in operation by 2026. The project will implement a computerized billing system for ESE. The costs of this component have been included in this analysis, but no direct benefits have been ascribed. The benefits of this system will be more accurate and timely customer billing, leading to lower nontechnical losses and improved revenue collection performance (and thus higher revenues for ESE).

3. **Approach and methodology**. Project financial viability was assessed by comparing with-project and without-project scenarios. The without-project scenario assumed that ESE continues to rely on existing infrastructure, which causes lost revenue from capacity-related unscheduled outages and high network technical losses in project areas. The streams of costs and benefits were estimated as annual cash flows over 25 years after project commissioning. A 40-year average life was assumed for distribution system assets, and a residual value was ascribed based on straight-line depreciation. The base year for discounting was 2018, and costs and benefits were expressed in 2018 constant prices. Because the analysis was conducted in real, pre-financing terms, price contingencies and financing costs were excluded.

4. **Capital expenditures.** Capital expenditures include (i) replacement and/or addition of 66/33/11 kV substations to supply 33 kV and 11 kV networks, (ii) construction of 66 kV and 33 kV single and double circuit lines into and out of new and upgraded substations, (iii) implementation of a computerized billing system, (iv) consulting services for project implementation, and (v) physical contingencies.

5. **Incremental operation and maintenance costs.** Because the investment program focuses mainly on the expansion of facilities rather than the replacement of facilities, an increase in operation and maintenance costs is expected. Based on international benchmarks and experience, incremental operation and maintenance were assumed to be 2.5% of capital costs (applicable to in-service facilities, with operation and maintenance during construction assumed to be included in capital costs).

6. **Cost of supply.** ESE pays a flat wholesale energy rate for electricity purchases from Electricity Power Generating Enterprise (EPGE), the electricity supply entity under the MOEE. Periodic increases in this rate were assumed.

[1] ADB. 2005. *Financial Management and Analysis of Projects.* Manila.

7. **Revenue from incremental sale of electricity from increased distribution capacity.** The distribution investment will add about 400 MVA of substation capacity to ESE's network, which will allow ESE to increase its revenue. Without the investment, consumers would be forced to use less electricity or receive electricity from expensive off-grid sources (primarily small diesel generators). The new substation capacity is expected to initially increase incremental electricity sales only at times of peak demand (existing capacity would be sufficient to meet the demand during off-peak periods). However, the new substation capacity would eventually enable incremental electricity sales during off-peak periods. By 2034, the new substation capacity is expected to be fully utilized, providing 1,981 gigawatt-hours (GWh) of incremental sales.[2]

8. The project does not include reinforcement of the 11 kV and 0.4 kV networks. Based on the typical ratios of capital expenditure on high-, medium- and low-voltage distribution and in the context of the condition and capacity of the downstream networks in the project areas, an additional capital expenditure allowance of 40% of subproject capital costs has been assumed. The sensitivity to this assumption was tested because of its inherent uncertainty.

9. **Revenue from incremental sale of electricity from reduced technical losses.** Load flow analysis undertaken as part of project technical due diligence demonstrated the investment in distribution systems reduces technical losses significantly. In the sample analysis, reducing 33 kV and 11 kV line lengths through the addition of 66 kV and 33 kV points of supply reduced line losses from 26.9% of power input to 1.8% in one case and from 11.1% to 0.5% in another case. Overall, it is reasonable to consider that 66 kV, 33 kV, and 11 kV losses on the parts of ESE's network impacted by the project would be reduced from a reported 7% to about 2%. On a weighted average basis across all supply in the project areas, this conservatively represents a loss reduction of about 1.9 percentage points (69 GWh in 2026, increasing to 85 GWh by 2034). This was valued as a reduction in electricity purchases.

10. The government decides the timing and amount of electricity tariff adjustments. The last retail tariff increase was in 2015 (a weighted average increase of 40% over 2014 tariffs). Before that, a 30% increase was introduced in 2013. However, the rate at which ESE procures electricity was increased at the same time, resulting in a nominal increase in the retail margin but not a percentage increase. To reflect the government's willingness to implement a large increase and its stated intention to introduce cost-reflective end-use tariffs, the base case of this analysis assumed a one-off increase in the retail tariff of 25% in 2018–2019, a 25% increase in retail and wholesale rates in FY2022, and 15% increases every 5 years thereafter. These assumed trajectories result in nominal retail rate of MK211 per kilowatt-hour (kWh) and a wholesale rate MK131 per kWh at the end of the forecast period.

C. Weighted Average Cost of Capital

11. The weighted average cost of capital (WACC) was calculated in real terms. The government is expected to onlend the fund to ESE on equivalent terms and in foreign exchange. The corporate tax rate of 25% was adopted for the purposes of WACC estimation. Assessing the cost of equity is problematic because of the lack of depth and liquidity in the country's capital markets. The country risk premium for Myanmar is not widely reported, but the risk premiums for other developing economies is 6%–10%. Myanmar would be at the higher end of this range. In this context, a nominal risk-free cost of 9.0% was assumed plus a 10.0% premium to cover risks

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[2] 400 MVA of new substation capacity multiplied by power factor (0.92), load factor (0.7), and hours per year (8,760), giving 2,256 GWh per year before adjusting for 11 kV and 0.4 kV losses of about 13%.

and issuing costs, resulting in a nominal cost of equity of 19.0%. However, the low level of government contribution in the project's financing plan means that the analysis is not sensitive to the assumed cost of equity.

12. Table **1** shows the WACC calculation.

Table 1: Weighted Average Cost of Capital

Item[a]	**Amount** ($ million)	**Weight** (%)	**Pre-Tax Nominal Cost** (%)	**Tax Rate** (%)	**Post-Tax Real Cost** (%)	**Weighted Cost** (%)
ADB Concessional OCR loan	121.4	97.7	1.5	25.0	0.0	0.0
Equity	2.8	2.3	19.0	0.0	10.7	0.2
Total	**124.2**	100.0		**WACC (real, post-tax)**		**0.2**

ADB = Asian Development Bank; OCR = ordinary capital resources; WACC = weighted average cost of capital.
Source: ADB estimates.

D. Financial Internal Rate of Return

13. Incremental cash flows attributable to the investment were estimated based on the financial benefits that would accrue to ESE through incremental electricity sales (increasing to 1,981 GWh by 2034) and incremental electricity sales because of lower technical losses (85 GWh reduction in electricity purchases by 2034). Under these assumptions, the project is financially viable, with a financial internal rate of return (FIRR) of 2.8% compared with the WACC of 0.2%.

Table 2: Aggregate Financial Internal Rate of Return Calculation
(MK million)

Year[a]	**Benefits**	**Costs**					**Net Cash Flow**
	Electricity Sales	Project Capital	Other Capital	O&M	Electricity Purchases	Tax	
2018	0	0	0	0	0	0	0
2019	0	1,033	413	0	0	0	(1,446)
2020	0	4,841	1,936	0	0	0	(6,778)
2021	0	19,511	7,804	0	0	0	(27,315)
2022	0	45,050	18,020	0	0	0	(63,070)
2023	0	43,443	17,377	0	0	0	(60,821)
2024	0	35,407	14,163	0	0	0	(49,570)
2025	0	7,505	3,002	0	0	0	(10,506)
2026	34,099	0	0	3,920	22,160	547	7,473
2027	59,647	0	0	3,920	40,386	2,377	12,964
2028	77,208	0	0	3,920	53,291	3,541	16,456
2029	93,156	0	0	3,920	65,020	4,596	19,620
2030	88,264	0	0	3,920	61,605	4,226	18,512
2050	34,865	0	0	3,920	24,335	353	6,257
					Terminal value:		6,220
				FIRR (Post-tax real):			**2.8%**
					FNPV:		**85,362**

( ) = negative, FIRR = financial internal rate of return, FNPV = financial net present value, O&M = operation and maintenance.
[a] Selected years shown for brevity.
Source: Asian Development Bank estimates.

E. Sensitivity Analysis

14. The impact of the adopted assumption about the wholesale and retail tariff trajectories that the government sets was tested by modeling a scenario that assumes lower increases in retail or

wholesale tariffs. Downside scenarios were also tested in relation to capital cost, operation and maintenance costs, electricity purchase costs, demand growth, and commissioning delays. The results demonstrate that retail tariffs and wholesale purchase costs are the biggest risks to the project's financial performance (Table 3).

Table 3: Sensitivity Analysis

	Sensitivity Parameter	Variation	FIRR	FNPV (MK m)	SV (FIRR)
	Base case		2.8	85,362	0
1	Tariff increases lower than expected	(50%)	(1.7)	(51,853)	0
2	Project capital costs higher than expected	+ 10%	2.1	62,913	34.8
3	Related capital expenditure higher than expected	+ 50%	1.7	54,434	120.6
4	Increased electricity purchase costs	+ 10%	0.5	8,678	11.3
5	O&M costs higher than expected	+ 10%	2.6	78,378	139.7
6	Delay in commissioning	1 year	2.4	72,464	0
7	Lower-than-forecast demand growth[a]	(25%)	2.2	64,672	(100.8)

( ) = negative, FIRR = financial internal rate of return, FNPV = financial net present value, O&M = operation and maintenance, SV = switching value.
[a] The assumed rate of demand growth was reduced by 25% (about 2.5 percentage points) for this scenario.
Source: Asian Development Bank estimates.

F. Conclusions

15. Financial analysis demonstrates that the distribution component of the proposed investment is financially viable, assuming that the government continues a policy of periodic tariff increases. However, the base case assumption is that the average tariff will decline in real terms over the forecast period.

G. Electricity Supply Enterprise Financial Performance and Projections

16. The ESE's net profit before tax has declined from MK18.3 billion in FY2015 to a (provisional) net loss of MK1.3 billion in FY2017. This drop was caused by the growing inadequacy of the gross tariff margin set by the government and the carve-out of electricity distribution in the city of Mandalay with its high-value customer base in FY2016. As the ESE gears up its capital investment program, the government needs to set higher tariff margins to allow the ESE to generate sufficient cash to meet its expenditure and debt service obligations without government budgetary support. The modest tariff increases discussed in para. 10 would ensure that the ESE can generate sufficient cash to fund operations and some capital investment (Table 4).

H. Financial Performance of Department of Power Transmission and System[3]

17. Before the 2016 reorganization, Myanmar Electric Power Enterprise's (MEPE's) financial performance depended on its exposure to fuel price, the rate at which it sold electricity to Yangon Electric Supply Corporation (YESC) and ESE, and subsidies from the government. For example, MEPE posted an operating loss of MK480 billion in FY2016 because of soaring generation and fuel costs. On the other hand, increases in the rates at which MEPE sold electricity to ESE and YESC (and later to Mandalay Electricity Supply Corporation) allowed it to generate strong operating cash flows in FY2015. After the 2016 reorganization, all electricity generating assets now under the control of Electric Power Generating Enterprise, and MEPE became DPTSC, which is operating a transmission network for which annual costs of about MK70 billion (including a commercial return on the government's investment) are met by the government budget.

[3] Because DPTSC is not revenue generating, no financial projections were prepared.

Table 4: Electricity Supply Enterprise Summarized Financial Projections, 2018–2027

Item		2018	2019	2020	2021	2027
				Forecast		
Average revenue per unit sold	(MK/kWh)	67	84	84	84	123
Average cost per unit sold	(MK/kWh)	68	68	70	71	101
Electricity purchases and generation	(MK/kWh)	61	61	61	60	80
Network	(MK/kWh)	4	5	6	7	13
Depreciation	(MK/kWh)	3	3	4	5	8
Operating revenue	(MK m)	418,124	583,389	639,150	697,467	1,695,917
Depreciation and amortization	(MK m)	16,282	19,741	27,017	37,492	114,340
Other operating expenses	(MK m)	400,994	450,598	498,255	547,620	1,261,314
Operating income (EBIT)	(MK m)	848	113,049	113,877	112,354	320,263
Interest expenses (gross)	(MK m)	(7,222)	(6,750)	(10,028)	(14,229)	(10,133)
Interest expenses (net of capitalized interest)	(MK m)	(7,470)	(7,405)	(10,948)	(15,357)	(16,626)
Forex currency gains/(losses)		(11,677)	(8,740)	(18,552)	(36,859)	(139,570)
Profit before tax (PBT)	(MK m)	(3,359)	111,714	106,273	90,853	197,320
Net income	(MK m)	(3,359)	83,786	79,705	68,139	147,990
State contribution	(MK m)	n.a	22,343	21,255	18,171	39,465
Capital expenditure	(MK m)	(74,448)	(157,251)	(255,535)	(260,021)	(301,405)
Current assets	(MK m)	468,312	575,486	685,293	815,398	1,846,623
Non-current assets	(MK m)	330,610	468,775	698,213	921,870	2,194,751
Fixed assets (net)	(MK m)	293,386	390,149	570,445	791,859	2,044,048
Short-term borrowings	(MK m)					
Current liabilities (other than short-term borrowings)	(MK m)	76,146	96,846	106,526	129,937	322,585
Long-term borrowings (current and non-current)	(MK m)	147,847	313,838	585,130	879,038	2,511,605
Non-current liabilities (other than long-term borrowings)	(MK m)	569,677	566,882	566,706	553,180	515,060
Equity	(MK m)	5,252	66,694	125,144	175,112	692,124
Operating ratio		100%	85%	86%	87%	84%
Accounts receivable		30	30	30	30	30
Return on average net fixed assets		0%	33%	24%	16%	16%
Interest coverage ratio		1.7	95.6	52.0	32.3	8.4
Debt (LT) / Debt (LT)+Equity		13%	20%	31%	38%	38%
Current ratio		6.2	5.9	6.4	6.3	5.7

( ) = negative, EBIT = earnings before interest and taxes, LT = long term, MK/kWh = Myanmar kyat per kilowatt hour, MK m = Myanmar kyat million, n.a = not applicable, PBT = profit before tax.
Source: Asian Development Bank staff estimates.

18. The financial risk is rated *substantial* because of the following: (i) the dependence of DPTSC on the MOEE budget for it operation and investment; (ii) the dependence of the ESE on the revenue margin, currently set by the government; and (iii) the current internal financial management and reporting are not up to international standards. To mitigate these substantial risks, the loan agreement will require regular review and adjustment of electricity tariff, as well as strengthening of the technical and financial performance of the ESE and DPTSC. In the long run, ADB together with other development partners aims to support the sector reform, that leads to the establishment of independent transmission and distribution companies with financial management and accounting according to international standards.