FINANCIAL ANALYSIS: PROJECT 1

A. Background and Rationale

1. Project 1 of the Green Power Development and Energy Efficiency Improvement Investment Program involves construction of the 30 megawatt (MW) Moragolla hydropower plant; transmission system strengthening; medium-voltage network efficiency improvement; energy-efficiency pilot subprojects, including smart grid, smart buildings, and cold thermal storage; and nonphysical components involving consultancy support for project supervision and capacity building for Ceylon Electricity Board (CEB). The second tranche for project 2, to be drawn in 2016, will focus on transmission system strengthening, medium-voltage network improvement, and energy-efficiency development. Project 1 will contribute to expanding Sri Lanka's transmission and distribution network by adding 10 kilometers (km) of 132 kilovolt (kV) and 220 kV transmission lines, 92.3 km of 33 kV distribution lines, 90 megavolt-amperes of 220/132/33 kV substation transformer capacity, and 320.5 megavolt-amperes to 132/33 kV substation transformer capacity. In addition, the project will contribute to around 100 gigawatt-hours of additional clean energy every year into the Sri Lankan system. The energy efficiency pilot subprojects will contribute to flattening the overall demand curve and reducing peak power demand. The main financial benefits from these subprojects will include (i) reduction of transmission and distribution losses by strengthening the network, (ii) reduction of coincident peak demand and energy consumption by undertaking energy-efficiency measures, and (iii) increased availability of power for additional customers to be served through the construction of new lines and by adding a generation facility.

B. Methodology and Assumptions

2. The financial analysis covers project 1 as the details of investments for project 2 will be finalized in the relevant periodic financing request. The financial analysis of the proposed subprojects is in accordance with the *Financial Management and Analysis of Projects* of the Asian Development Bank (ADB).[1] All costs and revenues to the subprojects are assumed at real terms. Cost streams used to estimate the financial internal rate of return (FIRR) reflect the incremental costs incurred in delivering the estimated incremental benefits. The financial benefits to CEB are derived by quantifying and valuing the additional retail sales arising from the new hydropower plant, increased transmission line and substation capacity, increased distribution substation capacity, improved network reliability, and new customer connections, and from the reduction in average cost of sales accruing through network loss reduction. Financial viability is examined by comparing the incremental costs and benefits on a with-investment and without-investment basis. A 25-year period was used for subproject evaluation assuming no terminal value. The weighted average cost of capital (WACC) to CEB is calculated as prescribed by ADB guidelines. Financial viability is assessed by comparing the WACC with the FIRR for the subprojects and for the aggregated project, and the sensitivity of the FIRR to adverse movements in the underlying assumptions is also assessed.

3. **Tariff policy.** Parliament approved the Sri Lanka Electricity Act in March 2009, empowering the Public Utilities Commission of Sri Lanka (PUCSL) to regulate the electricity subsector from April 2009. To ensure electricity prices reflect the cost of supply, PUCSL is empowered to rationalize the tariff structure so that the tariff is reflective of costs and allows CEB to recover all recurrent efficient costs. Any gap between cost-reflective tariffs and consumer tariffs will be met through a direct revenue subsidy from the government. The Regulation for Determination of Tariff provides for a return on invested capital at the weighted

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

average cost of capital of the utility. On this basis the tariff trajectory used for financial analysis is shown for financial years (FYs) 2013–2020 in Table 1.

Table 1: Projected Tariff Trajectory and Cost of Fuel adopted for Financial Analysis
(SLRs/unit)

Item	FY2013	FY2014	FY2015	FY2016	FY2017	FY2018	FY2019	FY2020
Tariff	18.63	20.87	21.81	22.79	21.95	20.46	19.48	19.04
Fuel charge	10.10	11.45	10.43	10.93	10.77	8.91	7.33	7.71

FY = financial year, SLRs = Sri Lanka rupees.
Source: Asian Development Bank estimates.

C. Computation of Weighted Average Cost of Capital

4. The WACC is calculated as the weighted average cost of debt and equity used to fund the project. The cost of debt is based on a mix of ADB loans from its ordinary capital resources and Special Funds resources accounting for 68.18% of base costs and a cofinancing loan from Agence Française de Développement (AFD) representing 13.64% of base costs. The government will contribute the remaining 18.18% in the form of counterpart financing for environmental and social mitigation, financing charges during implementation, taxes, and contingencies. The government is assumed to onlend the funds to CEB as a local currency loan with the same terms and conditions as agreed with ADB and AFD. The cost of debt for ADB is assumed at 2.13% by summing the 5-year LIBOR fixed rate swap[2] and a spread of 0.50%,[3] with a loan repayment term of 20 years including a 5-year grace period. The cost of equity for the government is assumed at 13.25% in accordance with the average weighted prime lending rate for all banks as published by the Central Bank of Sri Lanka. Domestic inflation and international inflation rates are considered as per ADB and International Monetary Fund estimates for years available and thereafter extrapolated for the remaining years of loan disbursement. The estimated costs of borrowing and equity capital are then adjusted for inflation to obtain the WACC in real terms. The WACC calculated by applying the weighting percentage to each source of financing is 1.06% (Table 2).

Table 2: Weighted Average Cost of Capital

Item	Unit	ADB OCR Loan	ADB ADF Loan	AFD Loan	Government	Total
Amount	$ million	121.00	29.00	30.00	40.00	220.00
Weighting	%	55.00	13.18	13.64	18.18	100.00
Nominal cost	%	3.27	2.00	3.00	13.25	
Tax rate	%	28.00	28.00	28.00	0.00	
Tax-adjusted nominal rate	%	2.35	1.44	2.16	13.25	
Inflation	%	2.30	2.30	2.30	7.20	
Real cost	%	0.05	(0.84)	(0.14)	5.64	
Weighted component of WACC	%	0.03	0	0	1.03	
Weighted average cost of capital						**1.06%**

( ) = negative value, ADB = Asian Development Bank, ADF = Asian Development Fund (Special Funds resources), AFD = Agence Française de Développement, OCR = ordinary capital resources, WACC = weighted average cost of capital.
Source: Asian Development Bank estimates.

[2] Published by ADB as of 17 March 2014.
[3] For any loan negotiated after 1 January 2014 as notified by ADB.

D. Calculation of Financial Internal Rate of Return

5. **Generation subproject.** The units generated from the Moragolla hydropower plant are expected to be sold at the prevailing tariff. The cost of generation is assumed to be the same as the power purchase cost, and incremental operation and maintenance (O&M) cost is assumed as 1.5% of the total subproject cost. On these premises, the incremental cash flows attributable to the proposed investment are estimated; the FIRR for the subproject is 2.24%.

6. **Transmission and distribution subprojects.** The proposed investments have two types of financial benefits: (i) increased electricity sales and (ii) reduced technical losses in the network. The increase in sales is primarily due to serving new consumers and issuance of new connections. About 10% of households affected by these projects will be new CEB consumers and will consume electricity at the minimum per capita rate, i.e., 490 kilowatt-hours. The other financial benefit is due to savings in O&M cost arising from reduced technical losses. For the distribution subprojects, using network load-flow studies CEB assessed that only 50% of benefits due to reduced losses could be retained by CEB, the remaining will be passed on to the consumer as a benefit by the regulator. The incremental O&M costs for the subprojects are assumed at 2% of the subproject cost. On the foregoing basis, the FIRR of the transmission subprojects is 9.27% and of the distribution subprojects 3.45%.

7. **Energy-efficiency subprojects.** By introducing energy conservation measures, the overall annual energy bill of consumers can be reduced. About 70% of total energy savings from these measures is assumed to be due to reduced coincident peak demand, while 30% is due to reduced electricity consumption. Based on the energy savings, the FIRR is 7.72%.

8. **Consolidated FIRR.** The consolidated FIRR for all the subprojects is 4.34%. The FIRRs for all the subprojects and on a consolidated basis are in Table 3.

Table 3: Financial Internal Rate of Return Results

Subproject	FIRR
Generation	2.24%
Transmission	9.27%
Distribution	3.45%
Energy efficiency	7.72%
Project supervision	
Consolidated	4.34%

FIRR = financial internal rate of return.
Source: Asian Development Bank estimates.

E. Risk Assessment and Sensitivity Analyses

9. Project financial risks include (i) substantial increase in the prices of civil works and equipment, (ii) delays in project implementation, and (iii) failure to have access to necessary counterpart funds. These risks are considered to be moderate overall. Sudden increases in inflation and the exchange rate do pose a risk for the prices of equipment procured under the project, but advanced procurement will lessen this risk by reducing the time between loan effectiveness and disbursement. The cost risk is further minimized as a bottom-up approach was adopted for estimating the costs for different subprojects and was verified against CEB's most recent tender prices for reasonableness. CEB's implementation capacity is proven, and turnkey contracting will be used for the various subprojects. Counterpart funding is minimal and mostly takes the form of exemption of taxes and duties and contribution in-kind.

10. The sensitivity of the FIRR to adverse changes in key variables was examined considering a 10% change in cost and tariffs. Table 4 shows that the financial performance of the overall project is robust for the scenarios tested, with the FIRR exceeding the aggregate

WACC in all cases. On this basis, the investment is considered financially viable and offers acceptable returns under most likely scenarios.

Table 4: Sensitivity Analysis for Project

	Financial Internal Rate of Return					
Sensitivity Parameter	**Variation** (%)	**Generation** (%)	**Transmission** (%)	**Distribution** (%)	**Energy Efficiency** (%)	**Consolidated** (%)
Base case		2.24	9.27	3.45	7.72	4.34
Capital cost	+10	1.44	8.20	2.62	6.73	3.46
O&M cost	+10	2.01	9.06	3.15	7.55	4.12
Fuel cost	+10	1.61	10.17	3.22	7.46	4.38
Tariff	–10	0.43	9.01	2.19	7.72	3.31

O&M = operation and maintenance.
Source: Asian Development Bank estimates.

11. A business-as-usual scenario considers no change in tariff from the current year applicable tariff. In this case, the consolidated FIRR for the project would be 4.39%. However, given that an independent regulator finalizes tariff setting and the regulations provide for annual tariff review, this is not a likely scenario.

F. Summary of Historical Financial Performance and Financial Projections of CEB

12. CEB, a vertically integrated state-owned enterprise under the purview of the Ministry of Power and Energy, is responsible for about 60% of power generation, transmission of power for public supply throughout the country, and distribution to 90% of all electricity consumers. CEB's financial performance has come under increasing strain, as electricity tariffs have not kept pace with rising costs. In addition, being a public utility with an obligation to supply uninterrupted electricity, it has often had to rely on emergency power at exorbitant prices. CEB's current financial position is weak. Accumulated losses at the end of 2012 were SLRs199,817 million. The debt service coverage ratio has been negative for the past 5 years, indicating that the company is unable to service debt from its operating cash flows and relied on expensive short-term borrowing from external sources to meet its financial liabilities. CEB's capital structure has been deteriorating with the debt/(debt plus equity) ratio declining from 19.20% at the end of 2008 to 66.27% at the end of 2012. Government Treasury loans are the major source of long-term borrowing, increasing from SLRs64 billion at 31 December 2008 to SLRs305 billion by 31 December 2012. The government is currently considering converting its loans to CEB into equity. The deteriorating financial health of the company can be attributed to increased reliance on high-cost thermal electricity generation, substantial increases in the fuel oil cost, and consumer tariffs set below cost of supply.

13. Table 5 shows CEB financial results and financial indicators for 2008–2012. Accounting losses and negative cash flows are a persistent feature of its financial performance. Return on assets, debt coverage, and self-financing ratios indicate that CEB has been unable to operate as a going concern without government financial assistance.

14. CEB carries a substantial weight of fixed assets, as is expected of a vertically integrated electricity business. However, given the present tariff regime, with consumer tariffs set below cost of supply, much of this asset base could not generate a return. The implementation of cost reflective tariffs with a return on net assets would probably assist the situation in future.

15. In summary, CEB is financially stressed by its inability to generate sufficient cash flow to reinvest in its business, let alone to meet its present supplier obligations. Without government support in the form of subsidies and/or substantial increases in tariffs and commissioning of cheaper coal-based power plants, CEB's finances and network may deteriorate further.

Table 5: Historical Financial Performance of Ceylon Electricity Board

Item	Unit	2008	2009	2010	2011	2012
Revenue	SLRs m	111,287	110,518	121,226	132,460	163,512
Cost of sales	SLRs m	(134,362)	(118,187)	(116,168)	(151,448)	(222,419)
Gross profit/(loss)	SLRs m	(23,075)	(7,668)	5,058	(18,989)	(58,906)
Profit/(loss) before tax	**SLRs m**	**(33,870)**	**(9,339)**	**4,832**	**(20,185)**	**(61,447)**
Profit/(loss) after tax	**SLRs m**	**(33,870)**	**(11,575)**	**332**	**(21,015)**	**(77,645)**
Electricity sales	GWh	8,418	8,441	9,268	10,023	10,474
Average revenue per unit sold	SLRs/kWh	13.2	13.1	13.1	13.22	15.61
Average cost per unit sold	SLRs/kWh	17.2	14.5	12.5	15.11	21.24
Return on average net fixed assets	%	(8.82)	(2.68)	0.07	(3.82)	(12.37)
Debt service coverage ratio		(21.03)	(1.17)	2.60	(0.11)	(3.68)
Debt (LT) / debt (LT)+equity	%	19.20	25.42	38.25	44.01	66.27

( ) = negative, GWh = gigawatt-hour, kWh = kilowatt-hour, LT = long term, m = million, SLRs = Sri Lanka rupees.
Source: Asian Development Bank estimates.

16. To assess CEB's suitability for the proposed ADB lending, a 10-year financial projection was prepared based on historical financial data and certain underlying assumptions on sales and electricity generation, tariff, capital expenditure, and operating expenses. These projections are based on a set of assumptions and adoption of certain policies by the government that represents a fundamental change in the operation of the power subsector and pricing regime, i.e., (i) increasing supply capacity and reducing cost of generation including from coal-fired power stations by achieving fuel cost reductions and reducing reliance on independent power producers (IPPs) with oil-fired generation, and (ii) establishing a cost reflective tariff by the independent regulator PUCSL to implement policies that rationalize tariff structures by allowing an adequate return on assets and/or equity.

17. Under this scenario CEB moves into a profitable position from FY2015 (Table 6). This is assisted by the significant increase in tariff by PUCSL to reflect cost of sales to consumers and commissioning of 600 MW coal-fired power stations that contribute to a decline in IPP power purchases in 2014, with most of the IPP's expensive power purchase agreements to expire by 2018. Fuel and power purchase cost is declining from SLRs14.83/kWh in FY2012 to SLRs11.37/kWh in FY2019. Balance between the revenue and cost per unit sold would be established from FY2017.

Table 6: Summary Financial Forecast of Ceylon Electricity Board to FY2022

Item	Unit	2014	2015	2016	2017	2018	2020	2022
Sale of electricity	SLRs m	256,480	311,458	363,736	406,290	409,310	451,767	519,097
Cost of sale	SLRs m	175,313	182,749	216,047	239,901	223,040	242,697	283,185
Gross profit	SLRs m	81,168	128,709	147,689	166,390	186,270	209,070	235,912
Depreciation	SLRs m	29,437	34,961	40,085	41,463	47,946	56,753	67,536
Interest on LT borrowing	SLRs m	46,102	50,741	56,625	54,387	61,938	65,060	69,465
Interest on ST borrowing	SLRs m	4,523	5,581	6,473	7,215	7,378	8,178	9,358
Profit before taxes	SLRs m	(29,105)	5,312	9,148	25,299	28,810	32,124	36,459
Tax	SLRs m	0	1,859	3,202	8,855	10,084	11,243	12,761
Profit/(loss) after tax	**SLRs m**	**(29,105)**	**3,453**	**5,946**	**16,444**	**18,727**	**20,880**	**23,698**
Units generated/purchased	GWh	13,508	14,513	15,380	16,275	17,178	19,034	21,023
Units sold	GWh	12,292	13,328	14,150	14,973	15,804	17,511	19,341
Average tariff	SLRs/kWh	20.87	23.37	25.71	27.13	25.90	25.80	26.84
Average fuel/PP cost	SLRs/kWh	12.98	12.59	14.05	14.74	12.98	12.75	11.37
Inflation	%	6.49	6.49	6.49	6.49	6.49	6.49	6.49

GWh = gigawatt-hour, kWh = kilowatt-hour, LT = long term, m = million, PP = power purchase, SLRs = Sri Lanka rupees, ST = short term.
Source: Asian Development Bank estimates.