FINANCIAL ANALYSIS

A. Approach

1. Financial analysis of the project was carried out in accordance with the Financial Management and Analysis of Projects of the Asian Development Bank (ADB).[1] All financial costs and benefits are expressed in constant January 2014 prices. Cost streams used to determine the financial internal rate of return (FIRR) (i.e., capital investment, power purchases, and operation and maintenance) reflect the costs of delivering the estimated benefits.[2] Benefits flow to the Nepal Electricity Authority (NEA) through incremental electricity sales to end-use customers. To assess financial viability, the project's weighted average cost of capital (WACC) was calculated and compared with the project's FIRR. Capacity building (part of output 4) is excluded from the analysis as it does not directly generate revenue. However, project supervision (part of output 4) is included (the cost is included in transmission subproject costs). Output 3, mini-grid-based renewable energy systems in off-grid areas, is discussed in paragraph 8.

B. Key Assumptions

2. NEA's revenue per unit of electricity sales for fiscal year (FY) 2013 averaged NRs7.95/kilowatt-hour (kWh); this is used as the starting point for valuing incremental sales for on-grid components. For the Kali Gandaki corridor subproject, the combined Marsyangdi corridor and Marsyangdi–Kathmandu subprojects, and the Trishuli 3B subproject, electricity purchases are valued at the off-take quantities and prices agreed in signed power purchase agreements with independent power producers (IPPs) in each of the subproject areas. The analysis assumes that only 20% of the generating capacity for which survey licenses have been issued to IPPs in the subproject areas is commissioned within the 20-year evaluation period, and that average off-take prices would apply to those projects. The impact of the proposed Upper Marsyangdi 2 export-focused hydropower project is also excluded from the base-case analysis. The impact of these assumptions is discussed in the sensitivity analysis (para. 6). Transmission and distribution losses in the project areas are assumed to decrease from an aggregate of 25% to 20% over the evaluation period. The subprojects are assumed to have a 33-year economic life and residual value of 39% of the original investment at the end of the 20-year evaluation period.

C. Tariff Policy

3. Under existing arrangements, NEA submits proposals for tariff adjustments to the Electricity Tariff Fixation Commission (ETFC). As far as can be discerned, the commission has no prescribed format for these proposals or for tariff determination, nor is there a prescribed process for ETFC's review, public disclosure and consultation, and decisions around NEA's tariff proposals. Instead, NEA's proposals comprise ad hoc arguments for tariff adjustments to meet NEA's own view of desirable accounting and cash metrics, and ETFC's review process is nontransparent and conducted in private. NEA was granted a 20% average tariff increase for FY2013 after 10 years with no tariff increase; it filed for a further 20% average tariff increase at the start of FY2014, which is being reviewed by ETFC.

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

2 Costs in relation to general capacity development ($4.0 million or approximately 1% of total project cost) are excluded from this analysis because they do not directly contribute incremental revenue.

D. Weighted Average Cost of Capital

4. Subproject financing plans are used to estimate the WACC. Financing sources are assumed to comprise NEA and Government of Nepal equity contributions (for outputs 1–4) and foreign sources by way of the proposed Asian Development Fund (ADF) loan (outputs 1 and 2), a grant from Norway (outputs 1 and 4), and a loan from the European Investment Bank (EIB) (output 1). The government is assumed to onlend the ADF and EIB loans as local currency loans at an interest rate of 5% including margins for foreign exchange risk. The Norway grant is assumed to be passed through to NEA as Government of Nepal equity. NEA's equity is valued by adding issuing costs (1.50%) and a risk premium (2.50%) to the rate at which NEA issued its most recent domestic bond (7.75%),[3] giving an estimated cost of equity of 11.75%. Because NEA is not expected to earn an accounting profit or pay corporate tax in the near future, the WACC is calculated on a pre-tax basis. The domestic inflation rate is assumed as 7%. The aggregate WACC is calculated as 1.2% (Table 1).

Table 1: Weighted Average Cost of Capital

Item	Amount ($ million)	Weight (%)	Pre-Tax Nominal Cost (%)	Pre-Tax Real Cost (%)	Weighted Cost (%)
ADB ADF loan	175.0	42.5	5.0	0.0	0.0
European Investment Bank loan	120.0	29.1	5.0	0.0	0.0
Government of Nepal equity (including Norway grant)	117.1	28.4	11.8	4.4	1.2
Total	**412.1**	**100.0**			**1.2**

ADB = Asian Development Bank, ADF = Asia Development Fund.
Source: Asian Development Bank staff estimates.

E. Project Cash Flows, Rates of Return, and Sensitivity Analysis

5. Estimated incremental pre-tax cash flows attributable to the project are based on the methodology and assumptions. Under the conservative assumptions adopted, the project is not financially viable without significant increases of end-use electricity tariffs. This is because average IPP off-take rates are currently only slightly lower than average end-use tariffs (adjusted for transmission and distribution losses), and the former escalate (in nominal terms) by an average of 3% per annum. To ensure financial viability for the aggregate project, a minimum average tariff increase of approximately 38% is required. This increase could be achieved by, for example, a 20% real increase in 2015 and then annual real increases of 1.4% for the 20-year evaluation period. Subproject FIRRs range from –6.7% to 17.0% and the aggregate FIRR is 1.4% (Table 2) after this end-use tariff adjustment.

6. The analysis examined the sensitivity of the FIRR to adverse changes in key variables: a 10% increase in capital costs, a 10% reduction in sales revenue, and a 10% increase in operation and maintenance; as well as a 1-year implementation delay and a combination of all downside scenarios. Additionally, the positive impact of a transmission use-of-system agreement to wheel electricity from the proposed Upper Marsyangdi 2 Hydropower Project to the Indian border was considered. Financial outcomes are sensitive to changes in these variables, as demonstrated by the adverse FIRRs and low switching values[4] evident in Table 3 (with the exception of the positive impact of inclusion of the proposed Upper Marsyangdi 2

[3] The NRs1.5 billion bond was repaid in FY2012.
[4] Switching value measures the percentage change in the variable required to reduce the FIRR to the project's WACC.

Hydropower Project, which demonstrates the financial value of third party use of NEA's transmission network). This reflects the minimal gross and net cash margins that NEA would achieve, even after the tariff increases assumed in this analysis. Relaxing the conservative base-case assumptions regarding the conversion rate of survey licenses to operating hydropower stations significantly reduces the tariff increases required for financial viability. Inclusion of the Upper Marsyangdi 2 (600 megawatt) Hydropower Project, from which all output is proposed to be sold to India, reduces the required real tariff increase to 30%.[5] In addition, assuming that 40% of the generating capacity for which survey licenses have been issued to IPPs is commissioned within the 20-year evaluation period (rather than 20% as per the base case) reduces the real tariff increase required to 25%.

Table 2: Calculation of Financial Internal Rate of Return[a, b]
(NRs million)

		Costs			
Year	**Revenue**	**Capital**	**Electricity Purchases**	**Operating**	**Net Cash Flow**
2014	0.0	29.8	0.0	0.0	(29.8)
2015	0.0	6,976.8	0.0	0.0	(6,976.8)
2016	0.0	16,550.4	0.0	0.0	(16,550.4)
2017	0.0	7,954.3	0.0	0.0	(7,954.3)
2018	4,138.7	4,653.3	2,931.5	267.0	(3,713.1)
2019	7,084.3	0.0	4,407.8	589.3	2,087.2
2020	7,568.8	0.0	4,935.5	589.3	2,044.0
2021	8,025.9	0.0	5,285.2	589.3	2,151.4
2022	8,499.6	0.0	5,619.0	589.3	2,291.3
2023	8,491.2	0.0	5,593.2	589.3	2,308.7
2028	8,233.9	0.0	4,936.3	589.3	2,708.3
2033	5,212.9	(4,935.0)	3,546.6	492.3	6,109.0
			Financial Internal Rate of Return = 1.4%		

[a] For brevity, only every 5th year is included in the table after 2023.
[b] Cash flow is calculated on a pre-tax basis for comparison with the pre-tax weighted average cost of capital.
Source: Asian Development Bank staff estimates.

Table 3: Sensitivity Analysis

Sensitivity Parameter	**Variation** (%)	**FIRR** (%)	**Switching Value** (%)
Base case		1.4	
1. Capital cost increase	+ 10.0	0.3	1.0
2. Revenue decrease	– 10.0	(1.3)	(0.7)
3. Operation and maintenance increase	+ 10.0	1.2	10.7
4. Delay[a]	– 3.4	0.7	
5. Combined 1–4		(2.7)	
6. Inclusion of Upper Marsyangdi 2[b]		(3.2)	

( ) = negative value, FIRR = financial internal rate of return.
[a] Excludes possible impact of liquidated damages and capacity charges payable to independent power producers.
[b] A transmission use of system agreement to wheel electricity from the Upper Marsyangdi 2 Hydropower Project would have an effect equivalent to a reduction in the subproject's capital cost.
Source: Asian Development Bank staff estimates.

7. The risk of an increase in capital costs is considered to be low: the cost estimates are based on recent tender prices but exclude tender prices deemed unrealistically low. Advance

[5] This does not take into account other benefits brought by the export-focused IPP projects, such as the 10%–20% free energy share allocated to the government. If this benefit is considered, the required real tariff increase will be further reduced, and NEA's financial sustainability will be enhanced.

procurement will lessen the time between loan effectiveness and disbursement. Further, NEA's implementation capacity is low but adequate, and consulting support will be provided for implementation. Regulatory or tariff revision risk is significant as the project is not financially viable without material increases of end-use tariffs. The process for tariff revision is opaque and ETFC is apparently not able to independently approve NEA's petitions for tariff increases. Delays in project execution in Nepal are common and NEA would potentially face claims for liquidated damages from IPPs unable to connect to the grid. NEA would also be adversely affected if project facilities are completed on time and commissioning of IPP plants in project areas is delayed.

F. Financial Analysis of Off-Grid Components

8. For the off-grid component, only mini-hydro projects are revenue earning in the sense that their tariffs need to be set to repay loans from commercial banks (for which ADF loan funds will be provided, channeled to commercial banks through the Alternative Energy Promotion Centre [AEPC]). For wind and solar projects, users will only be required to contribute to plant operation and maintenance. Levelized tariffs to recover debt service and operating costs are calculated for five sample projects, and range from $0.07/kWh for a mini-hydro, mini-grid project to $0.15/kWh for a solar mini-grid project. These tariffs compare favorably with diesel and kerosene alternatives, and would be adequate to ensure the project FIRR is equal to the cost of borrowed funds (for mini-hydro projects). Under the assumption that only productive-use consumers would contribute to debt-service costs and all other consumers would only contribute to operation and maintenance costs, cost-recovery tariffs are estimated for the two sample mini-hydro projects at $0.15/kWh for productive-use consumers and $0.02/kWh for other consumers. User communities are expected to consider project-by-project willingness and ability to pay. Tariffs are expected to be rebalanced between productive-use consumers and domestic consumers accordingly.

G. Historical Financial Performance of NEA and AEPC

9. Highlights of NEA's historical financial performance during FY2008–FY2013 are provided in the Financial Management Assessment of NEA.[6] NEA's financial performance is characterized by an average cost per unit of electricity sold that has been significantly greater than the average revenue per unit sold. For FY2013, the revenue gap was NRs1.8/kWh; this is despite a 20% average tariff increase that was finally granted to NEA for FY2013 after 10 years with no tariff increase. NEA is insolvent, and has insufficient cash to meet interest and principal payment obligations on borrowings from the government; to maintain its assets in good condition; and to invest in urgently needed generation, transmission, and distribution capacity. By the end of FY2013, interest and royalty arrears had increased to NRs23.4 billion, representing approximately 1 year of electricity sales. Accumulated losses of NRs27.2 billion were converted to equity in FY2011, but by the end of FY2013 losses had increased to NRs14.4 billion. NEA's liquidity position has been deteriorating rapidly, and current liabilities are now more than twice current assets. The situation is untenable and critical, as NEA is unable to pay its debts, has no remaining sources of cash available on which to draw, has no prospect of being able to discharge its accumulated arrears of interest and royalties at present tariffs and has run down the condition of its plant (including its hydroelectric plant) beyond a prudent level.

10. AEPC receives an annual budgetary allocation from the Ministry of Environment, Science and Technology, supplemented by income from interest margins charged to

[6] Financial Management Assessment of the NEA and AEPC, the supplementary linked document 27 of the RRP.

commercial banks that are onlending funds on behalf of AEPC and from income generated by the sale of carbon credits. AEPC prepares an annual budget based on the ceiling fixed by the government. The budget will be endorsed by the Ministry of Finance and eventually approved by Parliament. The approved budget along with its expense line items will be reflected in the government's Red Book. Since 2011, AEPC has managed annual budgets averaging NRs2.5 billion and disbursed an average of NRs2.2 billion per annum. AEPC's annual operating costs are a small component of this expenditure. None of this funding (nor assets financed through this funding) is retained on AEPC's balance sheet.

H. NEA Financial Projections

11. NEA has developed indicative 10-year financial projections (footnote 6). The projections incorporate elements of the Financial Restructuring Plan for NEA to the extent that they have been approved by the government and materially impact NEA's financial performance.[7] A core assumption is an annual nominal tariff increase of 7% per annum, in line with domestic inflation. In the absence of tariff increases, government equity in NEA would be negative by FY2017 (that is, all shareholder value in NEA would be destroyed). NEA's official electricity sales forecast up to FY2020 was adopted for the purposes of projections. Beyond FY2020 and in the absence of a long-term capital investment program and committed funding sources, no increase in electricity sales was modeled. An assessment was made of the capital investment in transmission and distribution that NEA would need to make to meet forecast electricity demand growth over the period. This required expenditure was then compared with committed expenditure, and the difference was scaled to a level considered to be ambitious but achievable (approximately $150 million per annum from FY2018 to FY2020). The modeled 7% annual tariff escalation would see accounting losses stabilized at around NRs25 billion and net cash loss would be stable by the end of the forecast period at around NRs6 billion per annum (assuming no payment of interest and principal to the government). However, this is still well short of desirable financial performance for NEA, and NEA would still be insolvent, have negative equity, be unable to generate internal funds for capital investment, and be completely dependent on the government for its ongoing survival. Clearly the Financial Restructuring Plan and modest tariff increases alone will not be sufficient to turn NEA's poor financial performance around. Measures will also need to include recognition of the impaired value of NEA's net assets; reduction of debt to a manageable level; restructuring of NEA's balance sheet to the extent needed to produce satisfactory financial ratios; and, most importantly, the injection of cash equity into the business. Government commitment has been sought in this context.

I. AEPC Financial Projections

12. AEPC and the government expect AEPC's total annual budget to increase to around NRs5 billion over the next 2–3 years, about 60% comprises funds received from development partners and the balance is government budgetary allocation. The AEPC component of the project will represent around 10% of annual funds flowing through AEPC. AEPC's operating expenditure is expected to continue to represent a very small component of funds managed.

[7] In January 2012, the government approved parts of the Financial Restructuring Plan prepared by NEA and a government-appointed task force.