ASIAN DEVELOPMENT BANK PPA: NEP 14004

PROJECT PERFORMANCE AUDIT REPORT

ON THE

MINI-HYDROPOWER PROJECT
(Loan No. 512-NEP[SF])

IN

NEPAL

January 1998

CURRENCY EQUIVALENTS

Currency Unit — Nepalese Rupee/s (NRe/NRs)

	At Appraisal	At Project Completion	At Postevaluation
NRe1.00 =	$0.083	$0.023	$0.0175
$1.00 =	NRs12.00	NRs42.70	NRs57.03

ABBREVIATIONS

EA	-	Executing Agency
EIRR	-	Economic Internal Rate of Return
FIRR	-	Financial Internal Rate of Return
GDP	-	Gross Domestic Product
MUV	-	Manufacturers' Unit Value
NEA	-	Nepal Electricity Authority
O&M	-	Operation and Maintenance
OPEC	-	Organization of Petroleum Exporting Countries
PCR	-	Project Completion Report
PEM	-	Postevaluation Mission
PPAR	-	Project Performance Audit Report
SHDB	-	Small Hydel Development Board
SHPD	-	Small Hydro Power Department
TA	-	Technical Assistance
UNDP	-	United Nations Development Programme

WEIGHTS AND MEASURES

GWh	-	gigawatt-hour
km	-	kilometer
kW	-	kilowatt
kWh	-	kilowatt-hour
kVa	-	kilovolt-ampere
MW	-	megawatt

NOTES

(i) The fiscal year of the Government ends on 15 July.
(ii) In this Report, "$" refers to US dollars.

PE - 503

CONTENTS

BASIC PROJECT DATA
Mini-Hydropower Project
Loan No. 512-NEP(SF)

PROJECT PREPARATION/INSTITUTION BUILDING

TA No.	TA Project Name	Type	Person-Months	Amount	Approval Date
399-NEP	Mini-Hydropower	AO	62	$750,000 (UNDP)	21 Apr 1981

KEY PROJECT DATA ($ million)	As per Bank Loan Documents	Actual
Total Project Cost	15.15	14.94
Foreign Currency Cost	9.80	11.66
Bank Loan Amount/Utilization	8.30	8.30
Amount Canceled		nil
Amount of Cofinancing	4.75	4.82

KEY DATES	Expected	Actual
Fact-finding Mission		26 Nov-18 Dec 1979
Preappraisal Mission		11-30 August 1980
Appraisal Mission		29 Oct-6 Nov 1980
Loan Negotiations		19-21 Mar 1981
Board Approval		21 Apr 1981
Loan Agreement		28 Apr 1981
Loan Effectiveness	27 Jul 1981	7 Apr 1982
First Disbursement		1 April 1985
Loan Closing	31 Dec 1986	31 Jul 1991
Project Completion	Dec 1984	Jun 1991
Months (Loan Effectiveness to Completion)	41	110

KEY PERFORMANCE INDICATORS (%)		Appraisal	PCR	PPAR
Economic Internal Rate of Return	Terhathum	17.8	7.8	-1.8
(For selected subprojects)	Tatopani	13.7	12.6	3.7
Financial Internal Rate of Return	Terhathum	5.9	1.4	-9.7
(For selected subprojects)	Tatopani	6.7	6.6	0.3

BORROWER Kingdom of Nepal
EXECUTING AGENCY Nepal Electricity Authority (NEA)[1]

MISSION DATA	No. of Missions	Person-days
Fact-finding	1	66
Preappraisal	1	24
Appraisal	1	48
Review	10	18
Project Completion	1	28
Postevaluation	1	42

[1] The original Executing Agency was the Small Hydel Development Board (SHDB), succeeded by the Small Hydro Power Department (SHPD) under NEA in 1985.

EXECUTIVE SUMMARY

The Mini-Hydropower Project was intended to provide hydropower generation to several district headquarters and major market and tourist centers in the hill areas of Nepal. The main components of the Project as appraised were (i) eight small hydropower generating plants and related transmission and distribution facilities, (ii) service connections and house wiring, (iii) canal and pipe irrigation, (iv) a central maintenance workshop, and (v) training for plant operators and linesmen. The Project also included a United Nations Development Programme (UNDP) technical assistance grant, administered by the Bank, to strengthen the institutional capabilities of the Small Hydel Development Board (SHDB), the Executing Agency (EA),[1] and to assist in Project implementation. The Bank's loan was $8.3 million to finance both the foreign exchange and local currency costs of the Project, which was cofinanced by the Organization of Petroleum Exporting Countries Fund in the amount of $4 million.

The Project was implemented with significant changes in scope and design, and was completed over six years behind schedule. It encountered numerous problems during construction related mainly to insufficient topographical, hydrological, and geological investigations during site selection and Project design. The performance of the UNDP-financed international consultant was not fully satisfactory, while the contractors providing civil works and equipment performed generally satisfactorily, given the numerous obstacles to completion. The actual Project cost was $14.94 million compared with $15.15 million estimated at appraisal, despite cancellation of several Project components, including two of the eight small hydro subprojects.

The Project did achieve its objective of providing electricity to six of the eight targeted hill areas and has improved the quality of life for some 4,800 households who use electricity primarily for lighting. The substantial load densities and electricity usage by industrial and commercial customers anticipated at appraisal, however, did not materialize; load factors for most subprojects are under 20 percent. Historically, the subprojects have not generated sufficient revenues to cover operation and maintenance costs, and are subsidized by the Nepal Electricity Authority (NEA).

The Project is rated unsuccessful based on its subprojects' marginal or negative economic internal rates of return and the fact that they are not operationally sustainable without continued subsidy from NEA. Lessons learned from this Project underscore (i) the importance of load promotion as a prerequisite for Project success, (ii) the need to address the underlying causes of Project weaknesses early in implementation, (iii) sound Project formulation and cost estimation, (iv) more realistic assessment of the EA's institutional capabilities, and (v) more rigorous supervision of consulting services used during Project appraisal.

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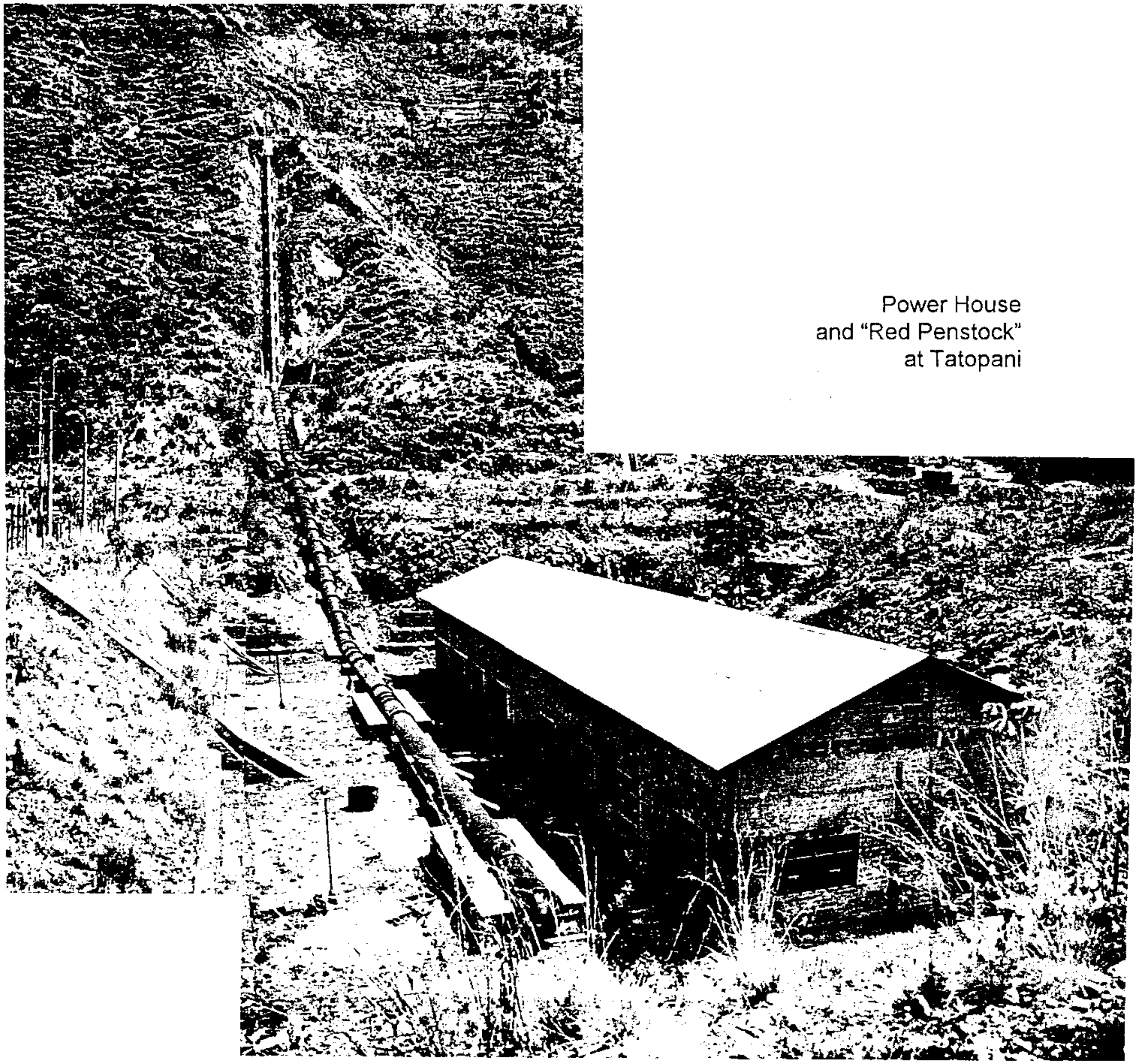
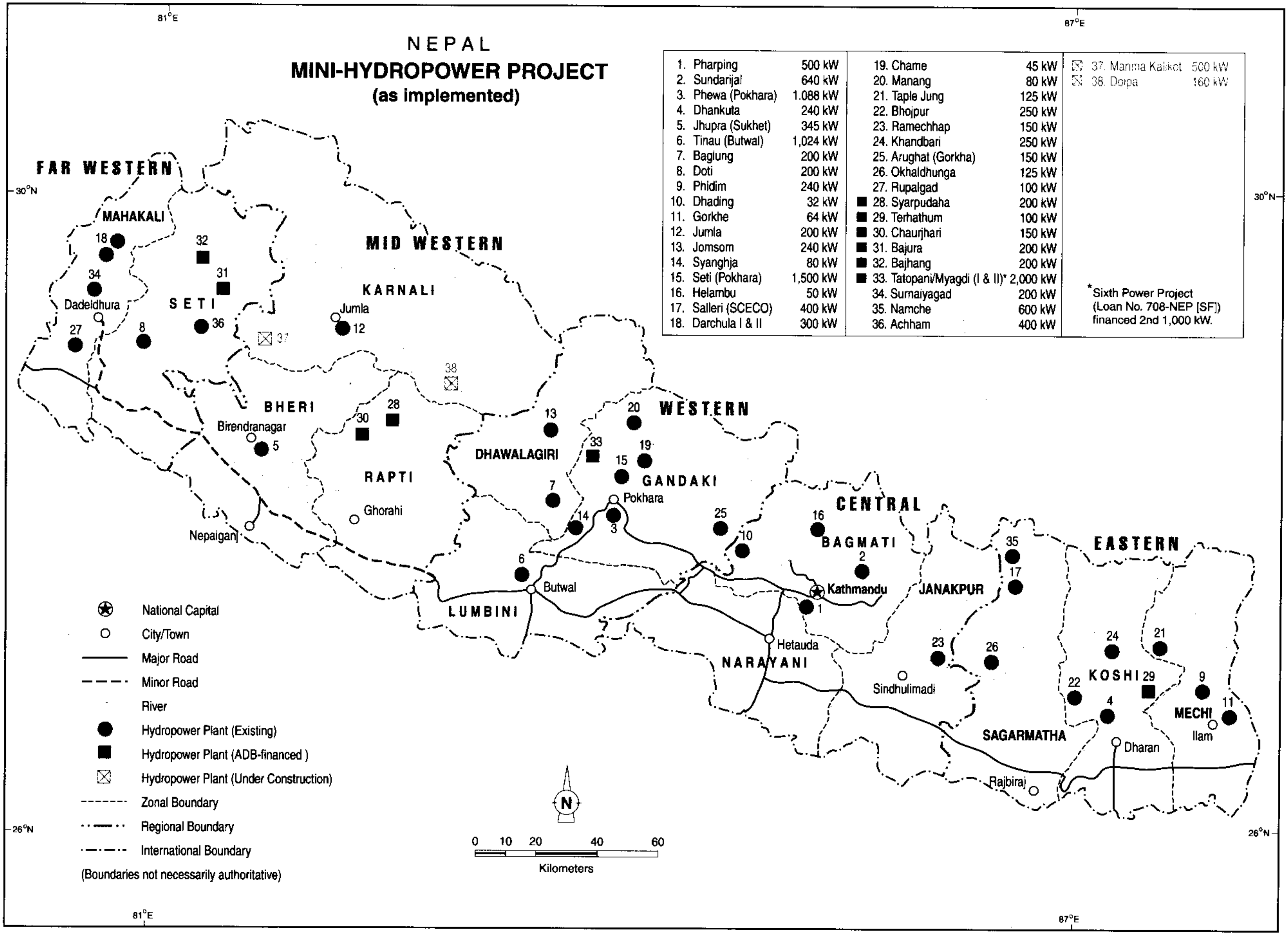
[1] The original EA was SHDB. When the Nepal Electricity Authority (NEA) was created in 1985, SHDB was dissolved and the Small Hydro Power Department under NEA assumed the role of EA.



Power House
and "Red Penstock"
at Tatopani

Weir and Intake under repair at Tatopani

(Note:plunge pool downstream of weir and
narrow width of river upstream of weir)


NEPAL
MINI-HYDROPOWER PROJECT
(as implemented)
1. Pharping 500 kW
2. Sundarijal 640 kW
3. Phewa (Pokhara) 1.088 kW
4. Dhankuta 240 kW
5. Jhupra (Sukhet) 345 kW
6. Tinau (Butwal) 1,024 kW
7. Baglung 200 kW
8. Doti 200 kW
9. Phidim 240 kW
10. Dhading 32 kW
11. Gorkhe 64 kW
12. Jumla 200 kW
13. Jomsom 240 kW
14. Syanghja 80 kW
15. Seti (Pokhara) 1,500 kW
16. Helambu 50 kW
17. Salleri (SCECO) 400 kW
18. Darchula I & II 300 kW
19. Chame 45 kW
20. Manang 80 kW
21. Taple Jung 125 kW
22. Bhojpur 250 kW
23. Ramechhap 150 kW
24. Khandbari 250 kW
25. Arughat (Gorkha) 150 kW
26. Okhaldhunga 125 kW
27. Rupalgad 100 kW
28. Syarpudaha 200 kW
29. Terhathum 100 kW
30. Chaurjhari 150 kW
31. Bajura 200 kW
32. Bajhang 200 kW
33. Tatopani/Myagdi (I & II)* 2,000 kW
34. Surnaiyagad 200 kW
35. Namche 600 kW
36. Achham 400 kW
37. Manma Kalikot 500 kW
38. Dolpa 160 kW
*Sixth Power Project (Loan No. 708-NEP [SF]) financed 2nd 1,000 kW.
FAR WESTERN
MID WESTERN
WESTERN
CENTRAL
EASTERN
MAHAKALI
SETI
KARNALI
BHERI
RAPTI
DHAWALAGIRI
GANDAKI
LUMBINI
BAGMATI
NARAYANI
JANAKPUR
SAGARMATHA
KOSHI
MECHI
Dadeldhura
Jumla
Birendranagar
Nepalganj
Ghorahi
Pokhara
Butwal
Hetauda
Kathmandu
Sindhulimadi
Rajbiraj
Dharan
Ilam
81°E
87°E
30°N
26°N
National Capital
City/Town
Major Road
Minor Road
River
Hydropower Plant (Existing)
Hydropower Plant (ADB-financed)
Hydropower Plant (Under Construction)
Zonal Boundary
Regional Boundary
International Boundary
(Boundaries not necessarily authoritative)
0 10 20 40 60
Kilometers
N
97-1869 R

I. BACKGROUND

A. Rationale

1. The Mini-Hydropower Project was part of the Government's strategy to electrify all 75 district headquarters and promote balanced regional growth by providing electricity to inaccessible hill areas. The Government considered small hydropower projects[1] in the hill areas necessary social infrastructure to foster development, although such development might not be economically justified.[2]

B. Formulation

2. In July 1979, the Government approached the Bank to finance several isolated small hydropower plants. Fact-finding was conducted in December 1979, and the Mission reviewed proposals for some 25 small hydropower projects proposed by the Small Hydel Development Board (SHDB) based on prefeasibility or feasibility reports prepared by domestic consultants. A Preappraisal Mission was conducted in April-May 1980 with the participation of two international staff consultants. It was to have entailed detailed site inspections and a review of 18 project proposals by the Bank's staff consultants over two months. Owing to logistical problems, site inspections by the staff consultants were limited.[3] An Appraisal Mission in August 1980 engaged the same two consultants, narrowed the Project scope to eight subprojects, and produced a Memorandum of Understanding.[4] A Follow-up Mission in November 1980[5] entailed further revisions to Project scope and costs, and completed the Project appraisal. The loan was approved in April 1981.

C. Objectives and Scope at Appraisal

3. The main objective of the Project was to provide hydropower generation to several district headquarters and major market and tourist centers in the hill areas. Specific targets set at appraisal were to provide electricity for 250,000 people in 15 potential growth centers and 46 adjoining villages, and irrigation for 1,600 hectares in the Ilam District. The Project was intended to reduce consumption of imported fuel oil and increase the availability of power for irrigation, water supply pumping, agricultural product processing, and cottage industries.[6]

4. Project components originally included (i) eight small hydropower generating plants and related transmission and distribution facilities,[7] (ii) service connections and house wiring, (iii) canal and pipe irrigation at Ilam, (iv) a central maintenance workshop in Kathmandu,

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1 At appraisal, hydropower plants with capacities of 100 kilowatts (kW) to 1,000 kW were called "mini hydros." These plants are currently called "small hydros," while plants under 100 kW are termed "micro hydros."

2 Basic Principles of Sixth Plan 1980-85.

3 It is unclear whether the Bank's staff consultants inspected sites for any subprojects actually financed by the Bank other than Ilam, which was subsequently canceled when the design proved infeasible. Each site visit required at least one week. Helicopter transport was unavailable, and in the first four weeks of their seven-week Nepal mission, the staff consultants had visited only one of the 18 projects on their list.

4 The Mission was combined with Fact-finding for a new loan and entailed no subproject site inspections.

5 The Mission was combined with the Preappraisal and PCR missions for two other loans.

6 These Project objectives were not quantified at appraisal.

7 At Terhathum, Syarpudaha, Chaurjhari, Bajura, Bajhang, Tatopani, Dunche, and Ilam.

and (v) training for plant operators and linesmen. The Project also included a United Nations Development Programme (UNDP) technical assistance (TA) grant to strengthen the institutional capabilities of SHDB through Project implementation, development of selection criteria for small hydropower projects, preparation of additional small hydro projects for future development, and installation of an improved accounting system.

D. Financing Arrangements

5. The Project cost at appraisal was $15.15 million equivalent, including $9.8 million in foreign exchange. The Bank loan of $8.3 million equivalent from its Special Funds resources was to finance $5.16 million in foreign exchange costs and $3.14 million in local currency costs. The Organization of Petroleum Exporting Countries (OPEC) Fund for International Development provided $4 million to cover a portion of the $9.8 million foreign exchange component, and the Government financed the remaining $2.1 million equivalent in Project costs (Appendix 1). Consulting services of $750,000 included in the Project cost were funded by UNDP under a TA grant administered by the Bank. The Bank loan, representing 54.8 percent of the total Project cost, was primarily to finance civil works, while the OPEC Fund's 26.4 percent share financed generating equipment.

6. The Borrower was the Kingdom of Nepal, with SHDB acting as the Executing Agency (EA). SHDB was merged with the Electricity Department to form the Nepal Electricity Authority (NEA) in 1985 and was renamed the Small Hydro Power Department (SHPD). Subsequent to the Bank's loan, NEA has received seven Bank loans and 11 TAs totaling over $300 million. No further financing was extended for small hydropower development in Nepal, except for a $3.1 million loan to NEA under the Sixth Power Project to finance a second 1,000 kW of capacity and related facilities at Tatopani.

E. Completion

7. The Project was completed in June 1991, six and a half years later than the target date of December 1984 set at appraisal. The Project Completion Report (PCR), circulated in September 1991, concluded that the Project objective of electrifying isolated areas was achieved in six subprojects, but noted major difficulties with Project preparation. Overall, the PCR attributed project delays, cost overruns, and lower than projected economic internal rates of return (EIRRs) to the nature of small hydropower development, specifically a cost structure that cannot justify the detailed technical investigations needed to avoid subsequent design modifications and resulting delays and cost increases. The PCR, however, substantially understated the extent to which the Project was adversely affected by inadequate appraisal, insufficient counterpart staffing, and inadequate Bank monitoring in the early stages of implementation.

F. Postevaluation

8. This Project Performance Audit Report (PPAR) evaluates the Project's effectiveness in achieving its objectives and generating sustainable operations and benefits. Various aspects of the Project are assessed including formulation, design, efficiency of implementation, and sustainability. The PPAR's conclusions are based on the findings of the Postevaluation Mission (PEM) in May 1997, review of Bank documents and files, and discussions with Bank staff. During the PEM, discussions were held with representatives from SHPD, NEA, other development organizations active in small-scale hydropower and private

sector power companies. The Mission also obtained a historical perspective on the Project by meeting with three past Directors of the EA. The PEM visited two of six completed subproject sites. Copies of the draft PPAR were sent to the Government, the EA, and concerned Bank staff for review. All comments received were considered in finalizing the Report.

II. IMPLEMENTATION PERFORMANCE

A. Design

1. Technology and Site Selection

9. The existence of numerous difficulties encountered in designing, constructing, and operating the subprojects raises questions as to the appropriateness of the technology adopted at appraisal. The small hydropower systems proved disadvantageous because of overly sophisticated import-dependent technology, high capital and operating costs, and the requirement for highly skilled manpower. Experience indicates that far less costly micro-hydropower systems drawing upon local materials and labor would have been a more cost-effective means to provide electricity for domestic lighting to subproject areas.

10. The process of site selection was highly dependent on domestic consultants hired by SHDB to develop feasibility studies for some 25 sites, from which Bank staff consultants selected the eight subprojects. The appraisal drew upon limited socioeconomic data collected by these domestic consultants and SHDB.[1] The Bank's staff consultants charged with site selection at appraisal visited very few of the proposed sites and are only known to have inspected one of the eight subproject sites (para. 2).

11. At all six completed subprojects, civil works contractors found major differences between the design and the actual site conditions affecting weir locations, tunnel alignment, canal routes, and penstock alignments. The source of the problem appears to have been in Project formulation and appraisal, which assumed that three foreign engineers financed by the Swiss government primarily to support a Swiss-backed project would assist SHDB to conduct site surveys, as well as to prepare basic designs for the Project. Eight months after Loan Approval, the foreign-sponsored engineers unexpectedly left SHDB, leaving the responsibility for surveys and basic design to an EA with insufficient staffing and expertise.

2. Technical Aspects

12. A number of Project design problems stemmed from insufficient topographical, geological, and hydrological investigations and limited understanding of the construction and design requirements in remote, mountainous areas.[2] Four of the six project weirs were damaged during construction, and none survived the first two years of operation. Reconstructed weirs and intakes are damaged or destroyed each year, requiring extensive repair work. Very few gates are operating, and many intake screens are ineffective. Frequent

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1 Bank files contain little information produced by the Bank's staff consultants at appraisal. The formal report they were to have provided in May 1980 is not in the files.

2 Landslides, floods, and earthquakes that damaged weirs and intakes, and the discovery of topographical/ geographical conditions not previously recognized, required design changes, additional work, and added costs. For example, prefabricated penstock pipe based on inaccurate tender designs required time-consuming and costly modification on site; the discovery of hard rock required blasting to remove.

and long transmission outages, caused by falling trees, bamboo touching the lines, and lightning, could have been minimized by better design, specifically the installation of fault protection and isolation equipment on transmission lines and lightning arrestors at distribution transformers.[1]

3. Major Changes in Scope

13. There were numerous changes in Project scope and construction design well into the implementation phase. Changes in scope reduced the number of subprojects from eight to six; reduced installed capacity from 2,650 to 1,850 kW[2]; and cut supporting components including maintenance, training, and institutional strengthening for the EA. Topographical, geological, and hydrological constraints; competing water use requirements; and cost overruns were the main reasons for changes in Project scope.

14. The major changes in Project scope included

(i) cancellation of the Ilam subproject comprising a 450 kW hydro plant and related irrigation facilities owing to technical infeasibility;

(ii) cancellation of a 200 kW hydro plant at Dunche owing to discovery of a large lead deposit nearby, which made a connection to the national grid more cost effective;

(iii) capacity reductions at Terhathum (from 200 kW to 100 kW) and Chaurjhari (from 200 kW to 150 kW), both due to low water discharge;

(iv) redesign of the Tatopani hydropower plant to increase capacity from 1,000 kW to 2,000 kW;

(v) elimination of the central workshop component in Kathmandu, and related purchase of equipment and vehicles;

(vi) deletion of local training for operations and linesmen;

(vii) deletion of house wiring; and

(viii) elimination of TA's accounting component.

15. The cancellation of two hydropower plants at Ilam and Dunche and the 150 kW reduction in generating capacity at Terhathum and Chaurjhari were reasonable decisions based upon information developed subsequent to appraisal. The cancellation of Ilam and the changes in capacity at Terhathum and Chaurjhari could, however, have been foreseen at appraisal, as the difficulties cited subsequently by the UNDP-financed consultant, including insufficient water, unsuitable sites for intake, the need for costly additions of reservoir capacity, and technically infeasible terrain for canals linking streams to the penstock, could have been recognized during appraisal. Adequate hydrological and topographical surveys and an

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1 Outages can last several hours or days owing to the logistics of locating faults in remote areas.

2 Excluding the effects of the 1,000 kW increase at Tatopani, which was funded under Loan No. 708-NEP[SF]:*Sixth Power Project*.

understanding of the existing irrigation needs, which competed with power generation, were lacking. With respect to the change in civil works from 1,000 kW to 2,000 kW capacity at Tatopani, it is unclear why this change was not made at appraisal, as the Appraisal Report gave the potential for the site as 4,000 kW and estimated power demands that justified a design with more capacity.

16. The decision during construction to cancel the central maintenance workshop component, equipment purchases, local training for operators and linesmen, and the accounting system upgrade was influenced by the need to reduce total project costs owing to cost overruns.[1] While the decision to cancel the central maintenance workshop was justified based on the assumed availability of NEA maintenance resources after the merger of SHDB into NEA, the extent of maintenance resources envisaged at Project appraisal was not made available to the small hydro subprojects. The absence of a central maintenance facility, training, vehicles, and equipment adversely affected the overall operational performance of the subprojects.

B. Contracting, Construction, and Commissioning

17. Detailed design and preparation of tender documents were carried out by the UNDP-financed international consultant with assistance from SHDB. Site surveys necessary to support detailed design work were to have been completed by SHDB by the spring of 1982. The surveys were delayed and inadequate owing to the remoteness of the subproject sites and the scarcity of staff at SHDB trained in survey techniques. Tender documents, in particular drawings and bills of quantities, were to a preliminary design standard and based on inadequate topographical surveys and geotechnical and hydrological investigations. Detailed designs, based on additional topographical surveys, were produced only after the civil works contracts were awarded.

18. The electro-mechanical equipment, penstocks, transmission and distribution equipment, meters, and communications equipment were procured under international competitive bidding, in accordance with the Bank's *Guidelines for Procurement*. Owing to the remoteness of the six sites, all equipment and substantial construction materials were either carried by porter or flown in by helicopter from the nearest cargo depot (Appendix 2). Six contracts were awarded on the basis of local competitive bidding for civil works. Civil works, tendering, and contract awards for all sites except Tatopani[2] were delayed nearly two years, first by delayed availability of basic designs, and second due to the decision by the consultant to limit tender qualification to Class B contractors or better, which resulted in no bids for civil works being received and necessitated retendering several months later. Overall, for the six subprojects, contractor performance was generally satisfactory, save for civil works contractors at Terhathum and Chaurjhari, and was not a major contributing factor to difficulties in Project implementation or subsequent operating performance.

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1 Because of cost overruns in the UNDP-financed consulting services, upgrading of the accounting system was transferred to Fifth Power Project (Loan No. 670-NEP[SF]).

2 The contract award for civil works at Tatopani was delayed nearly four years due primarily to a major design modification, which increased the capacity of civil works to accommodate 2,000 kW generation capacity.

C. Organization and Management

19. The capability of the EA to prepare and implement the Project was not realistically assessed at appraisal. SHDB had too few skilled engineers and too many other small hydropower projects under construction. During Project implementation, the EA's engineering staff comprised 18, including 12 engineers in training. An additional 33 site overseers brought the total number of staff to 51 to handle the implementation of all 20 small hydro projects then under construction, compared with the 55 staff expected at appraisal to implement only the Bank's eight subprojects.[1] Owing to this shortage of expertise, the EA relied upon inexperienced domestic consultants to perform initial site selection and feasibility studies.

20. There was no inception mission fielded, nor close monitoring for progress on site surveys/design and load promotion,[2] though it was known that the Project was SHDB's first Bank-financed one.[3] The first Bank review mission was fielded in March 1982, along with a review of five other ongoing projects and four TAs.

21. This Review Mission in March 1982 recognized several critical problems that were to adversely impact project performance, including the lack of basic site survey data, inaction on load promotion, the need for geological investigations at Tatopani, inappropriate site conditions at one of two subprojects subsequently canceled, conflicts with an existing irrigation regime at Chaurjhari, and the need for additional funding for consulting assistance to the EA. The significant problems recognized by the Mission during this review were attributed primarily to inadequate counterpart assistance, including the absence of a Project manager and competent engineering team, as envisaged by the Appraisal Mission. The Mission also discovered that the UNDP-financed consultant had not yet submitted the required monthly progress reports, and the Bank did not begin receiving these reports until March 1983, after a 14 month delay. Effective follow-up to this first Review Mission, however, was not carried out. Subsequent missions, typically once a year, for the next eight years, always dealt with several other projects, often larger loans. Bank staff made no site visits during nearly ten years of implementation.

D. Actual Costs and Financing

22. The final Project cost was $14.94 million, compared with $15.15 million estimated at appraisal (Appendix 1) despite significant reduction in project scope, including elimination of components appraised at nearly $4.8 million (Table 1).[4] The Bank's share of the cost was $8.3 million as approved, representing 55.6 percent. The $4 million loan from the OPEC Fund represented 26.8 percent of Project cost, and the Government financed $1.8 million equivalent or 12.1 percent. The consultancy funded by UNDP was $820,000 compared with $750,000 set at appraisal owing to an increase in funding for additional engineering services.

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1 Based on UNDP review in 1987. The organization chart of SHDB from July 1982 indicates a total engineering staff of 17 with 27 overseers.

2 These were critical activities in 1981 and early 1982.

3 File memoranda indicate such an inception mission was recommended by Central Projects Services Office, but not done.

4 Comprising $4.64 million for Ilam and Dunche subprojects, $0.115 million for the central maintenance component, and $0.04 million for house wiring.

Table 1: Analysis of Variance in Project Cost
($'000)

Component	Appraisal	Actual	Cost Variance	% Cost Variance
Six Subprojects Implemented	6,325	14,096	7,771	123%
Two Subprojects Canceled	4,640	—	(4,640)	(100%)
Central Workshop/Equipment/Training	135	20	(115)	(85%)
Consulting Services	750	820	70	9%
Subtotal	11,850	14,936	3,086	26%
Price Contingency	3,302	—	(3,302)	(100%)
Total	**15,152**	**14,936**	**(216)**	**(1%)**

— = magnitude zero.
Sources: Appraisal Report and ADB Controller's Department.

23. Actual costs for each subproject differed from cost estimates in the Appraisal Report due primarily to underestimates by the Bank's staff consultants and to the cost of additional work following various design modifications. The magnitude of this cost variance was known in July 1982 when the UNDP-financed consultant submitted revised cost estimates based on resurveys of some sites and on commencing detailed design. The consultant's revised base costs were more than twice those at appraisal owing primarily to a doubling of generation equipment cost and a significant increase in costs for transporting materials to subproject sites.[1] The Project as completed was 123 percent over the original appraisal costs, with six subproject costs ranging from 62 percent to 296 percent over budget (Table 2).[2] The impact of this cost variance on the Project was to (i) influence the decision to tender without detailed designs, as the Bank felt this was the only way to get a reliable cost measure; and (ii) influence the decision to cancel the central maintenance facility, equipment, vehicles, and operator training component.

Table 2: Project Cost Variances by Subproject
($'000)

Subproject	Appraisal Cost	Actual Cost	Cost Overrun	% Cost Overrun
Terhathum	509	1,131	622	122%
Syarpudaha	802	2,397	1,595	199%
Chaurjhari	763	1,782	1,019	134%
Bajura	531	2,103	1,572	296%
Bajhang	645	1,712	1,067	165%
Tatopani	3,075	4,971	1,896	62%
Total	**6,325**	**14,096**	**7,771**	**123%**

Sources: Appraisal Report, ADB Controller's Department, consultant's final report, and Postevaluation Mission estimate.

1 Appraisal prices were updated to 1982 in that analysis.
2 Actual cost per kW installed was $7,619 compared with $3,163 per kW at appraisal for the six subprojects completed.

E. Implementation Schedule

24. The Project was completed in June 1991 with the commissioning of Tatopani, compared with the May 1984 completion date set at appraisal (Appendix 3). The subprojects experienced implementation delays from 3.5 years for Terhathum to 6.5 years for Tatopani owing mainly to (i) delayed completion of site surveys and detailed designs; (ii) lengthy tender processes; (iii) inadequate technical investigations contributing to the need for substantial design modifications during construction[1]; and (iv) delays in transportation of materials to the sites, owing to remote locations and monsoons.[2]

25. The original implementation schedule at appraisal was overly optimistic. A review of other small hydropower projects then under way and the problems and delays they had encountered would have provided a more realistic basis for Project scheduling at appraisal.

F. Technical Assistance

26. Consulting services were provided under a UNDP TA grant for which the Bank was the executing agency. As envisaged at appraisal, the UNDP-financed consultant was to (i) assist SHDB in subproject implementation; (ii) assist SHDB in formulation of new projects for future implementation; (iii) improve staff skills in project selection, investigation, engineering, and implementation; and (iv) improve the accounting system.

27. From UNDP's perspective, the TA's focus was on institution building and strengthening the EA's technical capabilities, in particular strengthening the EA's skills in project selection. As administered, however, the TA focused largely on subproject implementation. The subcontractors' first phase performance did not meet the terms of reference, and their services were discontinued.[3] Consultancy resources were shifted to the implementation objective, as it became clear that the EA would need substantially more assistance in Project design, contract tendering, bid evaluation, and construction supervision then expected at appraisal.[4] The TA's focus on improving SHDB's capabilities to formulate small hydropower projects was undermined by the suspension of a subcontracted component to develop site selection criteria and to recommend a set of hydropower plants for future development.

28. Overall, the performance of the UNDP-financed consultant was impaired by inappropriate design input, decisions with respect to tendering that contributed to delays, and poor communication between the consultant and the EA and the Bank at the early stages of

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1 Soil instability discovered during excavation of the headrace tunnel at Tatopani necessitated a new and more costly tunnel alignment.

2 The nine-month delay in loan effectiveness does not appear to have been a significant cause for delay, as the Project depended initially on progress of the UNDP-financed consultants and SHDB site surveys, which were unaffected.

3 The subcontracted consultants under the UNDP-financed consultancy were to have evolved criteria for new project selection, whereas they focused on evaluating sites already proposed by SHDB.

4 The TA contract concluded in October 1981 for 59.5 person-months of service, which was increased by contract variation to 64.2 person-months in 1985 for additional engineering support for implementation.

Project implementation.[1] The consultant underestimated the extreme force of flash floods and the damage caused by landslides and huge boulders. The potential damage to weirs and intakes caused by floods was not fully appreciated. Many of the foundation and land stability problems would have been recognized and solutions engineered before construction, had a geologist and geotechnical engineer been included in the UNDP-financed consulting team.[2]

29. In retrospect, there seem to have been conflicting expectations on all parts, with the Bank assuming more staffing and survey/design capability at SHDB than there was, the UNDP-financed consultant assuming that SHDB would have completed accurate surveys and basic designs, and SHDB assuming greater assistance with engineering and construction supervision than envisaged at appraisal.

G. Compliance with Loan Covenants

30. Key areas of noncompliance with loan covenants that affected Project performance were tariff setting, Project staffing, and load promotion. The PCR was inaccurate in its assessment of compliance with covenants with respect to load promotion. Neither SHDB or its successor, SHPD, established a load promotion unit as required, and, while NEA may have established a Commercial Department to handle promotion of electricity use, its activities did not stretch to the isolated small hydro units. Similarly, there is no indication in Project files or from conversations with former SHDB/SHPD officials that a high level coordination committee was established to facilitate approval of productive schemes to use off-peak electricity from the subprojects. A full-time project manager was not appointed for this Project owing to staffing limitations at SHDB and the large number of other small hydro projects under way.[3] Tariffs follow those set by NEA and have not been adjusted to cover the operation, maintenance, and depreciation expenses of the EA's small hydropower systems.

III. PROJECT RESULTS

A. Operational Performance

1. Electricity Generation and Sales

31. Project operating performance is below that expected at appraisal. The Appraisal Report assumed substantially higher load densities and far greater use of electricity for commercial/industrial purposes than actual. Total electricity generated for the six subprojects in FY1995/96 was 3.2 million kWh compared with 12.7 million kWh projected at appraisal. Load factors for the six subprojects range from 8 percent to 31 percent, versus the 29-92 percent estimated at appraisal (Appendix 4). Electricity from the subprojects is used primarily for lighting. Domestic and Government/noncommercial use accounts on average for more than 90 percent of electricity sales, while industrial consumption is on average about 4 percent, compared with industrial consumption of 22 percent projected at appraisal.

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1 The UNDP-financed consultant had assumed that all necessary basic design drawing and surveys would have been completed by SHDB by the spring of 1982. Adequate surveys had not been done, and SHDB appeared not able to provide basic survey data requested by the Project consultant owing to lack of skilled staff and the remoteness of the subprojects.

2 Their omission may have been related to cost constraints, as midway through the Project, the UNDP consultant funding was stretched.

3 Reported by the Review Mission in March 1982.

32. The primary reasons for the sizable underperformance include unrealistic demand forecasts and the absence of load promotion efforts assumed at appraisal. The Appraisal Report overestimated the number of electricity connections, and in particular the number of higher use industrial and commercial consumers (Appendix 4). It assumed that economic activities such as irrigation pumping, agroprocessing, metal casting, handicraft making, and commercial ropeways would develop through the combined efforts of the EA's load promotion cell and a high-level coordinating committee. The Appraisal Report projected that these industrial customers would use 2,040,000 kWh in FY1995, compared with 161,000 kWh actually used. Some 1,200 commercial and Government connections were projected for the Project in 1985, while only 713 were connected as of 1995, with 600 of these being noncommercial/Government accounts (Appendix 5). The appraisal assumed per capita electricity use at 116 kWh per year, more than twice the actual average per capita electricity for the subprojects.[1] Inaccessibility to raw materials and to markets has discouraged the development envisaged at appraisal.

33. Production output is also affected by transmission faults; by frequent outages due to damage to transmission lines by bamboo touching lines and by falling trees; and by the cycle of postflood repairs to weirs and intakes, often requiring water diversions and curtailment of power supply. In the case of Chaurjhari, inadequate water flow, forcing operational shutdowns for more than two months each year and for large parts of each day, has reduced generation.

2. Operation and Maintenance

34. There has been no sustained effort to supply continuous electricity from the subprojects. Tatopani and Terhathum have the most continuous operating schedules but shut down daily for two hours around midday as a "maintenance break," though the break is taken irrespective of whether maintenance is required. Bajura and Syarpudaha shut down from 10 a.m. to 5 p.m. because of low demand for electricity. Bajhang also shuts down daily because of low demand, though its performance is improved since being leased to a private operator. At Chaurjhari, owing to the priority always given to irrigation, the plant operates only two hours each evening for half the year, and during canal clearing and repair in May and June, it shuts down completely. Partial operations have been the norm since Project inception, but were not anticipated at appraisal.

B. Institutional Development

35. The structure of the small hydropower sector has evolved since appraisal, when the EA was SHDB, an autonomous body responsible for all functions related to small hydropower, including project planning, construction, and operation and maintenance (O&M). In August 1985, NEA was established through the merger of the Electricity Department and SHDB at the urging of various multilateral lenders. The organization of the newly created NEA along functional lines was intended to improve the coordination of power development, generation, and distribution. While the various review missions optimistically expected that this restructure would strengthen the small hydro sector, it may have actually weakened support for the sector. NEA is required to function on a commercial basis, and, due to the uneconomical nature of small hydro projects, SHPD appears to have become a burden, not a priority, for

[1] Based on results for FY1995/96 assuming six persons per connection.

NEA.[1] Small hydropower generation represents a mere 1.4 percent of NEA's installed capacity and less than 0.01 percent of Nepal's total energy supply, which still comes primarily from fuelwood.

36. Small hydropower project construction and operation are currently the responsibilities of the Small Hydro Power Department under the Rural Electrification and Small Hydro Electric Directorate of NEA (Appendix 6).[2] SHPD currently operates 20 hydropower plants, leases six others to private sector operators, and manages the construction of three new projects. Project planning and accounts administration are handled separately under the Directorate.

37. The institution building impacts of the Project were not as great as envisaged in the Appraisal Report owing largely to curtailment of project selection and design skills under the UNDP TA and the cancellation of the central maintenance workshop and training component of the loan. Overseas training sessions for three design engineers and four O&M staff provided under the TA, together with the Project implementation experience, have increased the skills base of SHPD and NEA. While the Project implementation experience and interaction with consultants certainly added to the skills and knowledge base of NEA as a whole, it is unclear the extent to which those benefits have been captured and further developed by SHPD because of high staff turnover and reduced resource allocation to the department.[3] The lack of training in electronic governor maintenance and repair, the shortage of spare parts and tools near subproject sites, the absence of O&M manuals on site, and the apparent shortage of skilled operators all demonstrate the Project's limited long-term impact on institution strengthening. Nonetheless, SHPD has demonstrated competency and resourcefulness in handling crises, having restored the Terhathum plant to operations within three months of the powerhouse being destroyed by flood in 1993.[4]

C. Financial Performance

1. NEA and SHPD Financial Results

38. Appendix 7 summarizes NEA's recent financial performance. Over the past six years it has shown steady improvements in energy sales, revenues, profitability, and return on assets owing largely to significant tariff increases since 1991 and improved staffing efficiencies. System losses, however, have shown no improvement and remain at around 26 percent. SHPD is dependent upon funding from NEA to cover its operating losses on its small hydropower plants, estimated at nearly $200,000 annually before adjustment for uncollected revenues.[5]

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1 With the merger of SHDB into NEA, some 26 trained engineers were transferred from SHDB to functional areas of NEA not particularly concerned with small hydro.

2 As originally set up in 1985, SHPD was responsible only for construction, but over time it has assumed broader responsibility for O&M.

3 Employee turnover tends to be high at SHPD owing to engineers' preference for working on larger projects/ operations and in less remote areas.

4 A landslide redirected waters toward the powerhouse, resulting in flood and the death of two employees. It is unclear the extent to which the subproject's design with respect to the powerhouse location may have contributed to the problem. The addition of flood protection works, however, had been one of the subproject's design changes.

5 Accounts receivable at Terhathum, for example, are currently running at 121 days, owing to large receivables due from public sector accounts.

2. Electricity Tariffs and Subproject Financial Performance

39. Tariffs for the subprojects are set in accordance with NEA's nationwide schedule, though at appraisal a separate tariff schedule was envisaged for the small hydro plants. NEA's average tariff was low prior to 1991, then was increased by 60, 25, 38, and 20 percent between 1991 and 1996 to restore its financial performance (Appendix 8). The current average tariff level, however, remains at less than 80 percent of the average long-run marginal cost of electricity in Nepal.[1]

40. Historically SHPD-managed plants have not generated sufficient revenues to cover operating costs (Appendix 9). Most run at significant deficits and are subsidized by NEA due to low load factors and tariff charges. Salaries are a major component of operating cost, aside from the sizable expenditures for repairing weirs, intakes, and channels each year. The problem should have been apparent at appraisal, as the two oldest projects, Dhankuta and Surkhet, commissioned in 1971 and 1977, respectively, were then recovering only 25 percent of their operating costs.[2] Similarly, a UNDP review of the Project in 1987 noted that, due to high operating costs, low tariffs, and low load factors, revenues from existing small hydropower plants covered only 8-30 percent of their operating costs.

3. Private Sector Lease Operations

41. NEA leases five small hydro plants to private sector operators, including the Bajhang subproject. There is an ongoing effort to lease most of SHPD's remaining small hydro plants to private operators, who are better positioned to reduce staffing levels and undertake load promotion activities.[3] Bajhang, the only leased subproject, produced its first profit on an increased revenue base in FY1995/96, the second year of its lease. NEA plans to put up three of the five remaining subprojects for private lease in an effort to reduce its operating subsidies to the small hydropower sector.[4] Indications are, however, that these subprojects may have limited interest for private operators given their remoteness, low load potential, and high maintenance and repair costs. Without significant increases in loads, it remains uncertain how privately operated facilities can cover the costs of facility repairs.[5]

D. Economic and Financial Reevaluation

42. The EIRRs in the Appraisal Report for the six subprojects ranged from 10.5 percent to 17.8 percent while the financial internal rates of return (FIRRs) ranged from 1.8 percent to 6.7 percent (Table 3). The reestimated EIRRs for Terhathum and Tatopani are -1.8 percent and 3.7 percent, and the reestimated FIRRs are -9.7 percent and 0.3 percent,

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1 Based on the Bank's appraisal of the Kali Gandaki "A" Hydro-Electric Project, June 1996.

2 The appraisal assumed O&M at 2 percent of Project capital costs, which reflected SHDB's previous experience with respect to capital costs, but bore no relation to revenue generation.

3 Greater potential for leasing exists where a private operator has commercial need for a captive source of electricity at the small hydro site.

4 Terhathum and Tatopani excluded. Under an NEA lease, tariffs cannot exceed NEA tariffs, so that the improved performance of privately operated plants appears driven by lower operating costs and increased electricity usage, particularly in off-peak hours.

5 Lease operations pay NEA a royalty based on profitability and contribute to a non-operating account for equipment replacement and repair. The contribution to the non-operating account, a modest flat fee and percentage of the profits, does not cover historic costs of repair and maintenance.

respectively. The EIRRs and FIRRs for the remaining subprojects would be negative because these subprojects have less revenue and lower load factors. The economic and financial evaluation at appraisal assumed significantly lower capital costs, greater electricity sales, and lower operating costs than actually occurred.[1] The PCR's recalculated EIRRs for the six subprojects, ranging from 2.1 percent to 12.6 percent, were overstated and based on inaccurate operating performance figures.[2] The negative and marginal EIRRs and FIRRs for Terhathum and Tatopani at reevaluation reflect significantly higher project costs and actual load factors and operating costs. Appendix 10 details the methodology at appraisal and for the PPAR reevaluation.

Table 3: Economic and Financial Reevaluation

	EIRR (%)			FIRR (%)		
Subproject	**Appraisal**	**PCR**	**PPAR**	**Appraisal**	**PCR**	**PPAR**
Terhathum	17.8	7.8	-1.8	5.9	1.4	-9.7
Syarpudaha	11.7	3.6	neg.	1.8	4.9	neg.
Chaurjhari	14.7	8.8	neg.	4.8	-3.0	neg.
Bajura	16.1	2.1	neg.	4.4	-8.3	neg.
Bajhang	10.5	4.8	neg.	5.2	-2.0	neg.
Tatopani	13.7	12.6	3.7	6.7	6.6	0.3

neg. = not reevaluated by the Postevaluation Mission, but are logically expected to be negative.

43. Sensitivity analysis applied at appraisal did not adequately evaluate the Project's main risk: failure of load promotion, specifically development of a sizable commercial/industrial consumer base. The risks associated with capital-intensive projects in such isolated rural areas warranted greater sensitivity testing than a 20 percent increase in capital costs (actual subproject cost overruns ranged from 62 percent to 296 percent), a 10 percent reduction in load growth (actual reduction from appraisal estimate was 74 percent), and a one year delay in commissioning (actual delays were from four to nearly seven years).

E. Socioeconomic and Sociocultural Results

44. The Project generated socioeconomic benefits in the form of improved lighting; extended hours for household chores and socializing; exposure to radio and television; and, to a lesser extent, electricity for milling, water supply pumping, and cottage industries.[3] Interviews with electricity consumers at Terhathum and Tatopani reflected a broad consensus that their quality of life has improved because of electricity, with many citing improvements in air quality in their homes with the reduction in smoke from kerosene-fueled lighting.[4] Lodge owners and

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1 Economic benefits at appraisal overestimated domestic kerosene use, assuming twice the consumption of kerosene per household on average than data supports. The Appraisal Report also overstated the percentage of commercial and industrial consumption.

2 The PCR's analysis was based on electricity sales and number of connections up to three times those figures collected by the Postevaluation Mission. The number of connections reported by the PCR for FY1991/92 even exceed those reported for FY1996/97 for three of the six subprojects.

3 The extent of industrial applications has been quite small, however. SHPD records indicate 5 industrial users out of about 600 current connections in Terhathum, including a weaving concern and two-person furniture-making operation.

4 Equally frequent, though, were complaints regarding electricity outages and the lack of a dependable source.

shopkeepers cited the benefits of refrigerators, radios, and television.[1] In most villages with electricity that were visited, the most affluent residents had a variety of electrical appliances including televisions, videotape recorders, compact disc players, cookers, blenders, and in one remote village, a microwave oven. Electric lighting, however, appears to be more broadly dispersed, with SHPD reporting more than 80 percent of houses connected in the villages of Terhathum and Tatopani.[2] Numerous Government offices and some institutions[3] have benefited from lighting and from heating in the winter, though use by schools appears limited owing to cost constraints and a perception that lights are unnecessary. Annual repairs on civil works provide some jobs for local villagers, who provide the labor for reconstruction of weirs and intakes.

45. The broad socioeconomic benefits to 250,000 people, including 100,000 direct beneficiaries in 15 growth centers expected at appraisal, did not materialize, however, owing primarily to the absence of a program to develop productive schemes requiring electricity in subproject areas (Appendix 5). While the appraisal recognized the importance of load promotion and support from related Government ministries for productive schemes, there appears to have been little follow-up in this critical area during implementation, and no discussion of funding sources for such development at appraisal. SHPD data indicate that socioeconomic benefits at the four sites not visited by the PEM are similar or less, given the load factors ranging from 8 percent to 17 percent and nearly 90 percent or more domestic/noncommercial consumption.

F. Women in Development

46. While Project objectives did not include any specific focus on women, electricity-powered mills have made rice, flour, and oilseed milling more efficient, which in turn has freed up time for women in the villages. In the absence of income-generating opportunities for women in these isolated villages, it is uncertain whether the increased free time and savings in physical energy, however, can be appropriately translated into economic benefits.[4]

G. Environmental Impacts and Control

47. The impact of the Project on the environment appears to have been minimal. The subprojects are very small, run-of-river systems that do not involve storage other than very small amounts required to meet variations in demand. River bank erosion at the sites is a natural feature of the river system. The stone masonry weirs at all sites are frequently washed away by floods and continually rebuilt in the dry season. There are no significant environmental effects downstream of the weirs, as not all of the stream flow is diverted because of the type of temporary gabion construction and the alluvium and boulder river beds. Streamflow is diverted only for a limited number of hours each day owing to noncontinuous operations of the small hydro plants. SHPD does not have a program of watershed management, as the subprojects are too small to warrant such investment. Significant forest

1 Wood remains the primary cooking fuel, though lodges in Tatopani indicated that electric rice cookers were useful during the peak tourist season.

2 Based upon 1991 census data, however, the actual coverage for electricity in the districts of Terhathum and Myagdi (Tatopani) was about 3 percent and 17 percent of households, respectively.

3 A large consumer in Terhathum is the district jail.

4 A weaving operation in Terhathum demonstrates the positive impact electricity can have when channeled into productive activity. The small operation pays by the piece, employs several village women, and operates with electric lights during evening hours when some women prefer to work.

clearing was not required for construction because of the small size of the developments, and there was no evidence of construction-related clearing at the two sites visited. The only significant visual impact observed was the red 210-meter long penstock pipe at Tatopani, which can be seen from a major tourist trekking route.

H. Sustainability

48. Four of the six subprojects are not sustainable in their current operating mode without continued subsidy from NEA, owing to low load densities, low tariffs, and high operating expenses, including annual reconstruction of civil works. All projects remain highly vulnerable to seasonal floods, landslides, and other natural occurrences owing in part to a lack of robustness in design. Tatopani appears operationally sustainable without subsidy since it is connected to the national grid. Similarly, Bajhang, under private operation, has demonstrated that a remote plant can increase its load factor and operate more profitably. While NEA's efforts to spin off a number of these small hydros to private sector operators promotes sustainability, a stronger commitment by NEA to a well-staffed, -trained, and -equipped SHPD is essential if the Project benefits achieved to date are to be sustained.

IV. KEY ISSUES FOR THE FUTURE

49. **Privatization.** NEA and SHPD are working together with German-funded consultants to devise a plan for the leasing of a number of small hydropower plants to private operators. Preliminary indications from the consultants, however, suggest that privatization is not a practical option for many SHPD plants that are too isolated and where the technical and financial risks are too great to attract private operators. Accordingly, NEA and SHPD may need to consider other options to streamline small hydro operations and encourage off-peak consumption, including freeing the small hydro power systems from NEA's tariff schedule and working with various Government agencies and private sponsors to promote targeted development of off-peak use.[1]

50. **Increased Support for SHPD and Maintenance Program.** The urgent need for improvements in the ongoing operations of SHPD's small hydro plants should not be ignored in NEA's effort to either privatize or grid-connect the small hydros. Operational performance has been hampered by inadequate routine maintenance, which could be improved with the introduction of administrative procedures, clear instructions, and improved accountability. NEA should direct greater resources to the establishment of improved maintenance facilities and procedures for SHPD's small hydros, including the provision of tools, spare parts, and on-site staff skilled in basic generator repair.

51. **Future Role of NEA in the Small Hydropower Sector.** As previously noted, NEA's focus on larger-scale energy projects and its commercial mandate has rendered SHPD's small and financially weak operations more a burden than a priority for NEA. The Government, therefore, should consider whether NEA is the appropriate body to handle small hydropower or whether an independent body would be better positioned to address the unique needs of this sector.

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[1] Isolated load promotion efforts by NEA have limited potential as it is unclear how much industrial/ commercial activity can be promoted without easier access to raw materials and to markets.

V. CONCLUSIONS

A. Overall Assessment

52. The Project has achieved its main physical objective of electrifying several district headquarters, though the numbers of beneficiaries and the economic value of benefits are far lower than estimated at appraisal. The reevaluated EIRR for the two projects with the highest loads, Terhathum (8 percent of Project cost) and Tatopani (35 percent of Project cost) were -1.8 percent and 3.7 percent, respectively. The Project is considered unsuccessful based on the poor economic return together with serious issues with respect to the sustainability of future operations in the absence of improvements in load densities and operating efficiencies. While the communities have benefited from access to electricity, these positive impacts are not commensurate with Project costs.

B. Lessons Learned

53. The Project experience demonstrates the importance of identifying critical assumptions and conditions necessary for success, and monitoring closely the progress in those areas. Specifically, the Project's economic rationale was dependent upon load promotion and high level coordination with other Government ministries to channel productive investment to the subproject areas. This prerequisite for project success should have been more thoroughly assessed and the budgetary implications discussed at appraisal. Load promotion should have been included as an integral component of the Project, not simply as a loan covenant. While large-scale hydropower development remains key for Nepal's economic development, a broader lesson from this Project is that small hydropower plants may not be cost-effective, are not economically sustainable when constructed in isolation and should be considered only as a component of a larger plan for rural development.

54. The Project experience demonstrates the importance of addressing project weaknesses when found during implementation and addressing their underlying causes rather than simply reducing project scope to meet the budget set at appraisal. Early reports that Project costs were significantly underestimated and that one subproject was no longer feasible should have alerted the Bank to broader issues of appraisal quality and sound project design, and should have prompted reassessment of the entire Project given the substantially higher costs and greater uncertainties. The Project also highlights that when considering a project fraught with uncertainties owing to its remoteness and logistical issues, the cost of rectifying mistakes is great, and tendering should be based on detailed, not basic or preliminary investigations and designs.

55. Finally, the Project demonstrates the importance of (i) sound formulation independent of pressures from the borrower to satisfy policy goals (i.e., the electrification of all 75 district headquarters) when such goals may not be particularly in line with the Bank's economic development objectives, (ii) more realistic assessment of the EA's institutional capabilities, (iii) more rigorous supervision of consulting services used during appraisal, and (iv) thorough site inspections during project appraisal. With respect to Project design and implementation, the appraisal should not have relied upon the continued presence of Swiss-

sponsored engineers working with SHDB to provide support for site surveys and design of the Bank's Project.[1]

C. Follow-up Actions

1. For NEA and SHPD

56. To ensure technical sustainability of the Project, NEA/SHPD should implement training programs in the service and maintenance of electronic governors and should expand its training in rudimentary maintenance of the power plants and civil works, specifically for small hydro projects. SHPD should also consider how it might draw upon the local villages to provide casual labor for routine clearing of debris from Project facilities.[2] Operating practices should be improved by educating electricity customers to switch off lights when not in use to avoid the problem of putting stress on generation equipment during plant start-up. With respect to mitigating the environmental impact of the Tatopani subproject, SHPD should consider repainting the penstock pipe a color to match the hillside, as the bright red penstock detracts from the visual quality of one of Nepal's major trekking routes. At Terhathum, SHPD should repair the cracked masonry walls in the headrace canals and clear the channel and forebay of accumulated silt. Radio links should be established, as envisaged at appraisal, from powerhouses to the nearest NEA headquarters.[3] Fault protection and isolation equipment should be installed on transmission lines.

2. For the Bank

57. Any further assistance that the Bank provides for rural electrification in Nepal should recognize the availability of these six subprojects, which may be financially sustainable with proper attention to load promotion and efficient staffing, or where they are connected to the national grid. Insofar as electricity from small hydro plants has a direct and positive impact on the quality of life in low-income villages in remote areas of Nepal and the potential to fuel economic activity, the Bank should consider the subprojects, together with SHPD's other small hydro plants, as an available resource to support integrated development efforts in the hill areas.

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1 While supporting SHDB, these consultants were focused primarily on the implementation of the Swiss-financed Salleri Chialsa Project. They left the EA eight months after loan approval, and prior to the completion of basic designs for the subprojects.

2 An O&M manual in Nepali is required for such routine maintenance of civil works.

3 At Terhathum, for example, communication between the electricity district headquarters and the powerhouse is by four-hour walk.

APPENDIXES

PROJECT COSTS

Table 1: Financing Arrangements
($'000)

Source	At Appraisal			Actual		
	Foreign	Local	Total	Foreign	Local	Total
The Bank	5,160	3,140	8,300	6,840	1,460	8,300
Organization of Petroleum Exporting Countries Fund	4,000	—	4,000	4,000	—	4,000
United Nations Development Programme (UNDP) [a]	635	115	750	820	—	820
Government	—	2,102	2,102	—	1,816	1,816
Total	**9,795**	**5,357**	**15,152**	**11,660**	**3,276**	**14,936**

— = magnitude zero

[a] The Bank acted as the Executing Agency for the UNDP grant.

Sources: ADB Controller's Department, Small Hydro Power Department, and Postevaluation Mission estimate.

Table 2: Project Costs by Component
($'000)

Component	At Appraisal [a] Foreign	Local	Total	Actual Foreign	Local	Total	$ Overrun/ (Savings)	% Overrun/ (Savings)
Civil Works [b]	2,345	2,270	4,615	1,527	1,668	3,195	(1,420)	(31)
Generation [b]	1,788	187	1,975	5,506	81	5,587	3,612	183
Transmission/Distribution [b]	1,828	59	1,887	3,692	1,344	5,036	3,149	167
Central Maintenance Workshop/Vehicles/ Equipment/Wireless[c]	111	—	111	20	—	20	(91)	(82)
House Wiring/Service Connection	380	64	444	94	15	109	(335)	(75)
Training [d]	—	38	38	—	—	—	(38)	(100)
Irrigation[e]	558	195	753	—	—	—	(753)	(100)
Consulting Services	635	115	750	820	—	820	70	9
Overhead Costs	—	750	750	—	168	168	(582)	(78)
Total Base Cost	**7,645**	**3,678**	**11,323**	**11,660**	**3,276**	**14,936**	**3,613**	**32**
Physical Contingencies	2,150	1,679	3,829	—	—	—	(3,829)	(100)
Total Project Cost	**9,795**	**5,357**	**15,152**	**11,660**	**3,276**	**14,936**	**(216)**	**(1)**

— = magnitude zero

[a] No information regarding taxes and duties was provided in appraisal costs.

[b] Two subprojects at Ilam and Dunche were canceled.

[c] Workshop, equipment, and vehicles provided at appraisal were canceled.

[d] Training for operators and linesmen was canceled.

[e] For pipes and fittings only. Irrigation component at Ilam, appraised at $2.82 million in total, was canceled.

Sources: Appraisal Report, ADB Controller's Department, Small Hydro Power Department, and Postevaluation Mission estimate.

Table 3: Allocation and Utilization of Bank and OPEC Funds
($'000)

Description	Original Allocation		Last Revised Allocation [a]		Actual Disbursements		Overrun/ (Savings)	
	Bank	OPEC	Bank	OPEC	Bank	OPEC	Bank	OPEC
Civil Works [b]	5,447	0	2,920	0	2,987	0	(2,460)	0
Generation, Transmission, and Distribution	0	3,616	5,266	4,000	5,198	4,000	5,198	384
Service Connections and House Wiring	380	0	94	0	94	0	(286)	0
Irrigation	558	0	0	0	0	0	(558)	0
Equipment/Vehicles/Central Maintenance Workshop	111	0	20	0	20	0	(91)	0
Operator and Linesmen Training	38	0	0	0	0	0	(38)	0
Unallocated	1,766	384	0	0	0	0	(1,766)	(384)
Total	**8,300**	**4,000**	**8,300**	**4,000**	**8,300**	**4,000**	**0**	**0**

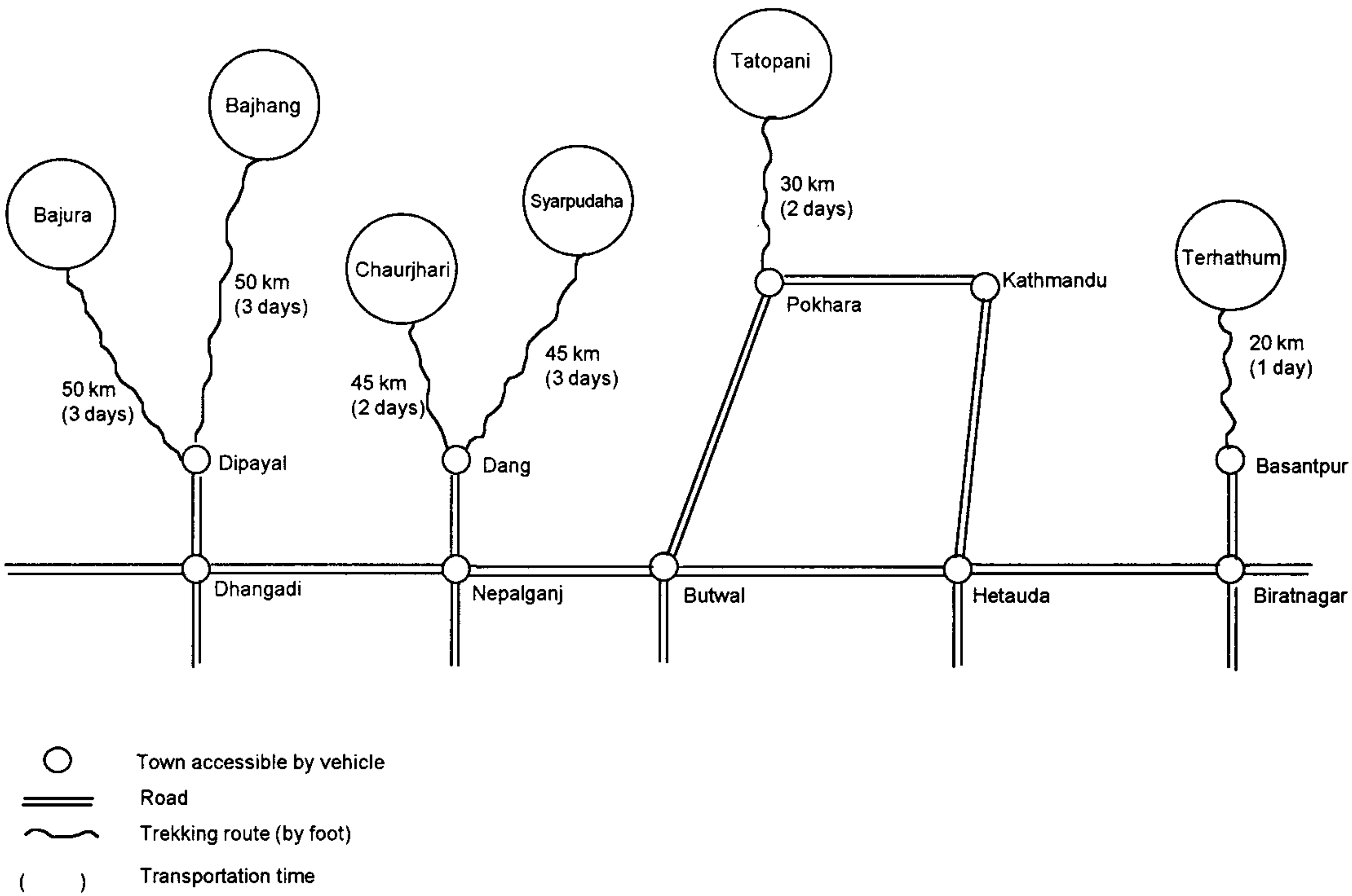
0 = magnitude zero.

[a] As of 13 October 1989.

[b] Includes contingencies of $832,000.

Sources: Appraisal Report and ADB Controller's Department.

LOCATION OF SUBPROJECT SITES AND TRANSPORTATION ROUTES DURING CONSTRUCTION



IMPLEMENTATION SCHEDULE

Figure 1: Terhathum, Syarpudaha, Chaurjhari, Bajura, and Bajhang Schedule
Appraisal Estimate versus Actual

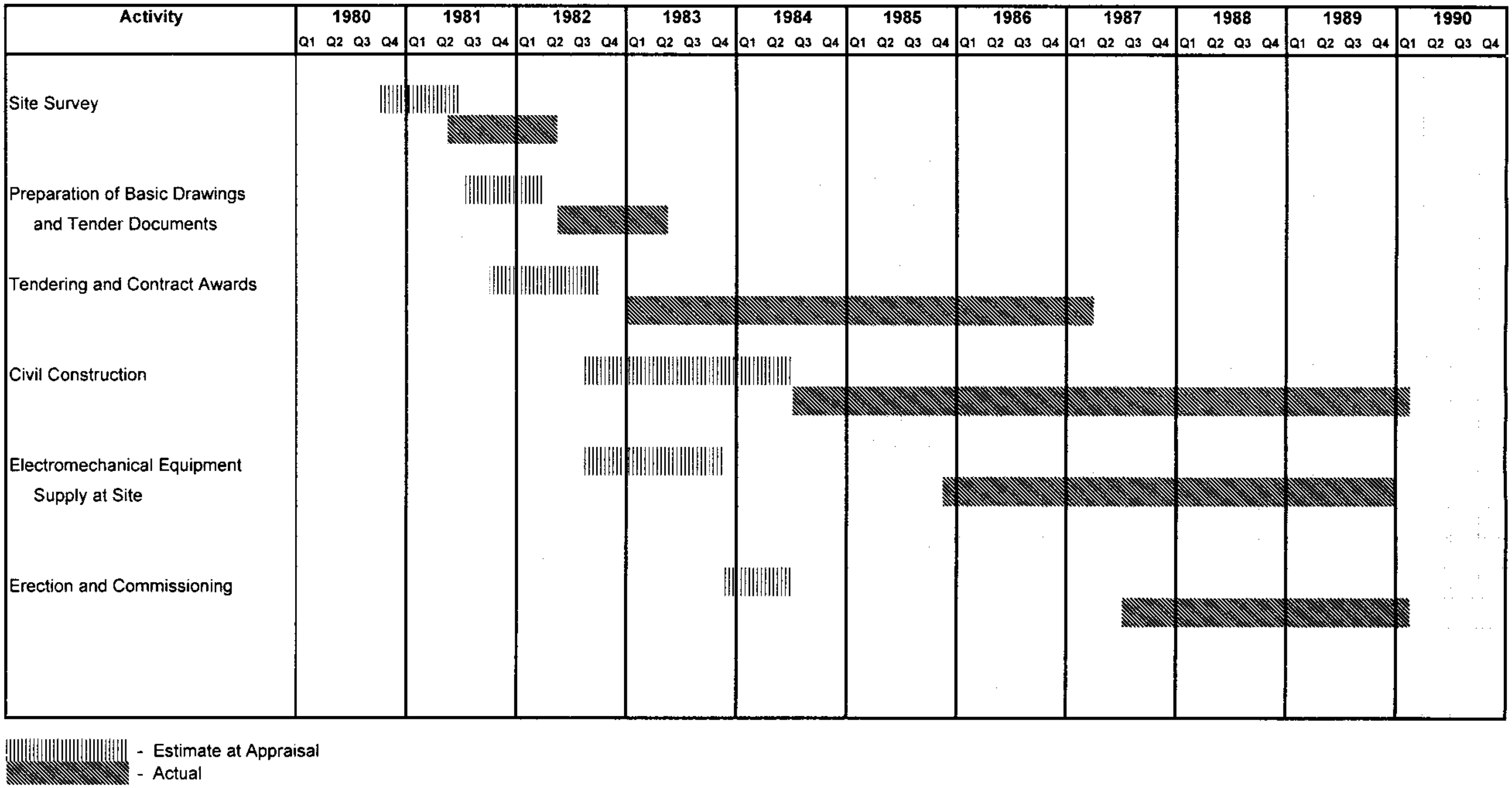
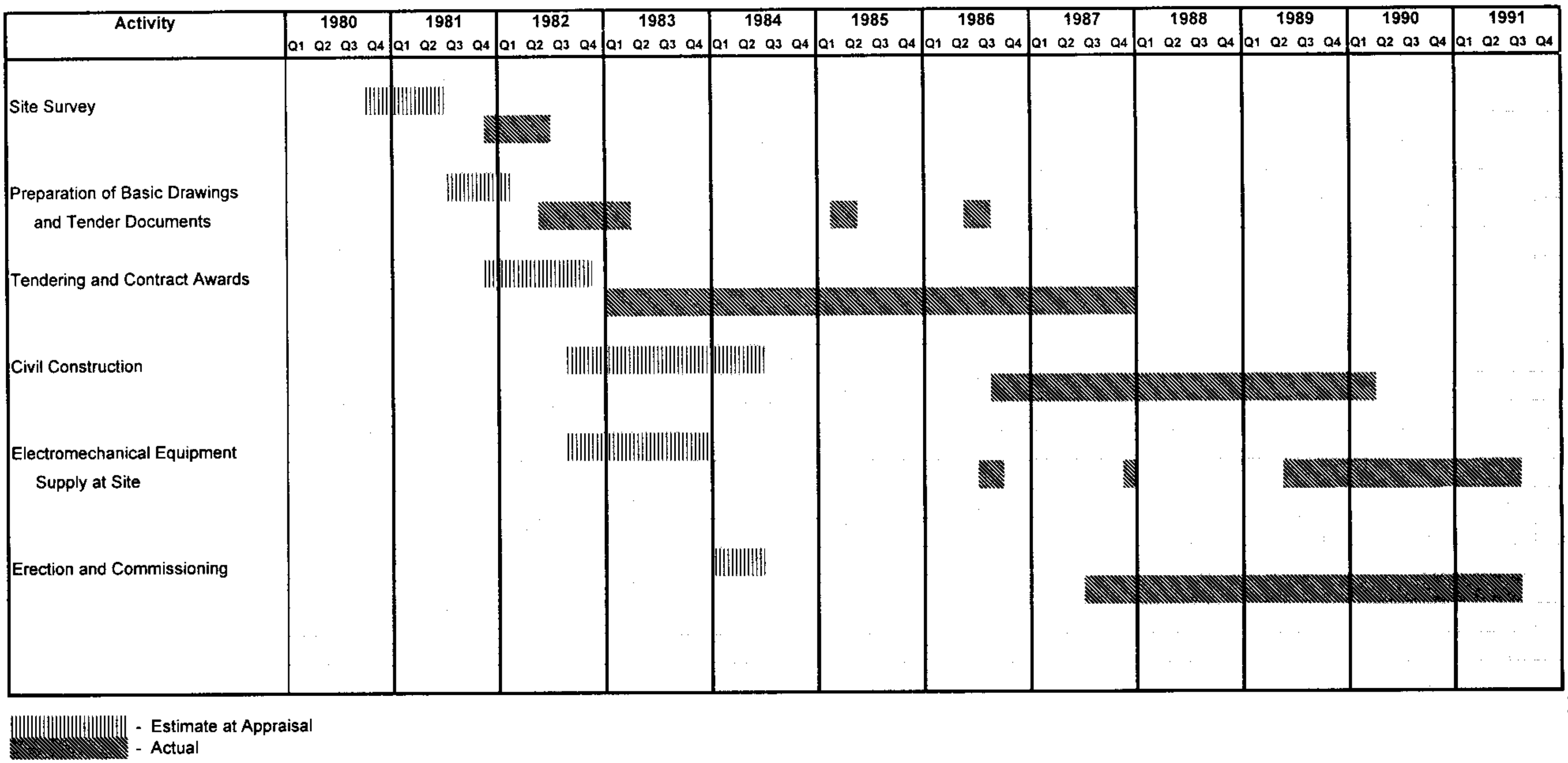


Figure 2: Tatopani Schedule
Appraisal Estimate versus Actual



SUBPROJECT OPERATING PERFORMANCE

Table 1: Performance Indicators by Subproject for FY1995/96 [a]

Subproject	Commissioning Date		Installed Capacity (kW)		Peak Demand (kW)		Energy Generated (kWh) [b]		Load Factor (%) [c]		Cost per kW Installed ($) [d]		System Loss (%)	
	Appraisal	Actual	Appraisal	Actual	Appraisal	Actual	Appraisal	Actual	Appraisal	Actual	Appraisal [e]	Actual	Appraisal	Actual
Terhathum	Dec-84	Jun-88	200	100	190	80	751,132	274,000	43	31	$2,547	$11,313	8.9	10.5
Syarpudaha	May-84	May-89	200	200	265	135	763,210	296,224	44	17	$4,008	$11,984	8.8	11.5
Chaurjhari	May-84	Jan-89	200	150	366	130	1,396,381	128,000	80	10	$3,814	$11,878	8.9	7.0
Bajura	May-84	Feb-90	200	200	124	68	500,546	131,647	29	8	$2,657	$10,516	8.9	14.7
Bajhang	May-84	Jul-89	200	200	232	100	1,172,962	242,870	67	14	$3,226	$8,558	8.8	26.7
Tatopani	May-84	Jun-91	1,000	2,000 [f]	1,564	1,740 [g]	8,083,443	2,227,107	92	13	$3,075	$4,970 [h]	8.9	12.0 [i]

kW = kilowatt, kWh = kilowatt-hour.

[a] Last full year for which actual data are available.

[b] Energy generation, including system losses.

[c] Load factors calculated on kWh generation.

[d] Civil works, generation, transmission, distribution, and service connection costs.

[e] Base cost in 1980 per appraisal.

[f] Increased to 2,000 kW from 1,000 kW under Loan No. 708-NEP(SF):Sixth Power Project. Funds from subject loan financed only 1,000 kW.

[g] Assumes connection with grid; without connection, peak demand falls to 850 kW.

[h] Excludes 1,000 kW capacity and related costs funded under the Bank's Sixth Power Project loan.

[i] For FY1994/95 before connection to grid.

Sources: Appraisal Report, ADB Controller's Department, Small Hydro Power Department, Consultant's Final Report (1991), and Postevaluation Mission estimates.

Table 2: Annual Energy Consumption and User Profile by Subproject [a]
FY1995/96

Subproject	'000 kWh		Overestimated	% Share	
	Appraisal	Actual	by	Appraisal	Actual
Terhathum					
Domestic	186	152		29%	62%
Noncommercial [b]	—	51		—	21%
Commercial [c]	240	10		37%	4%
Industrial	215	32		34%	13%
Subtotal	641	245	2.6 x		
Syarpudaha					
Domestic	297	185		46%	71%
Noncommercial	—	60		—	23%
Commercial	192	10		30%	4%
Industrial	156	5		24%	2%
Subtotal	645	261	2.5 x		
Chaurjhari [d]					
Domestic	455	51		38%	43%
Noncommercial	—	55		—	46%
Commercial	481	13		40%	11%
Industrial	269	0		22%	0%
Subtotal	1,205	119	10.1 x		
Bajura					
Domestic	159	54		38%	48%
Noncommercial	—	52		—	46%
Commercial	163	4		39%	4%
Industrial	97	2		23%	2%
Subtotal	419	112	3.7 x		
Bajhang					
Domestic	302	112		30%	63%
Noncommercial	—	57		—	32%
Commercial	571	5		56%	3%
Industrial	141	4		14%	2%
Subtotal	1,014	178	5.7 x		
Tatopani					
Domestic	4,191	1,458		58%	74%
Noncommercial	—	315		—	16%
Commercial	1,847	79		26%	4%
Industrial	1,162	118		16%	6%
Subtotal	7,200	1,970	3.7 x		
Total	11,124	2,885	3.9 x		

— = not estimated.
[a] Excludes system losses and internal consumption.
[b] Government offices and other public premises.
[c] Appraisal estimate for all subprojects combined commercial with government/public use.
[d] Actual figures are for FY1994/95.
Sources: Appraisal Report and Small Hydro Power Department.

Table 3: Subproject Operational Performance - Trend Analysis

Subproject	FY1991/92	1992/93	1993/94	1994/95	1995/96
Terhathum (100 kW)					
No. of Customers	403	403	421	428	593
Generation (kWh)	204,000	215,000	146,000	212,000	274,000
Peak Load (kW)	105	90	80	80	80
Load Factor	23%	25%	17%	24%	31%
System Loss	14.7%	14.0%	10.8%	13.2%	10.5%
Syarpudaha (200 kW)					
No. of Customers	525	600	650	628	675
Generation (kWh)	143,000	167,000	232,000	229,000	296,224
Peak Load (kW)	105	115	120	116	135
Load Factor	8%	10%	13%	13%	17%
System Loss	10.5%	12.4%	12.5%	10.5%	11.5%
Chaurjhari (150 kW)					
No. of Customers	340	400	450	425	504
Generation (kWh)	71,550	70,000	126,000	134,000	128,000
Peak Load (kW)	85	115	115	135	130
Load Factor	5%	5%	10%	10%	10%
System Loss	12.0%	10.3%	9.5%	6.7%	7.0%
Bajura (200 kW)					
No. of Customers	180	190	205	196	229
Generation (kWh)	130,000	141,000	178,000	147,000	131,647
Peak Load (kW)	50	55	60	48	68
Load Factor	7%	8%	10%	8%	8%
System Loss	10.8%	12.4%	11.5%	10.9%	14.7%
Bajhang (200 kW)					
No. of Customers	280	305	354	382	430
Generation (kWh)	95,000	123,000	161,417	187,766	242,870
Peak Load (kW)	60	70	75	88	100
Load Factor	5%	7%	9%	11%	14%
System Loss	13.7%	15.0%	21.8%	13.4%	26.7%
Tatopani (2,000 kW) [a]					
No. of Customers	1,700	1,900	2,200	2,665	3,200
Generation (kWh)	648,000	1,200,000	1,408,000	1,429,000	2,227,107 [b]
Peak Load (kW)	550	650	720	850	1,740
Load Factor	4%	7%	8%	8%	13%
System Loss	11.4%	12.0%	12.5%	11.4%	—

kW = kilowatt, kWh = kilowatt-hour.

— = not available as subproject is grid connected.

[a] Including 1,000 kW installed and connection to the national grid financed under Bank's Sixth Power Project.

[b] Connected to grid beginning FY1995-96.

Source: Small Hydro Power Department.

SUMMARY OF PROJECT BENEFITS
Appraisal Target for 1985 versus Actual for FY1995/96

Item	Appraisal Target 1985	Actual FY1995/96
Subprojects	8	6
People Benefiting	250,000	90,000 [a]
Direct Beneficiaries	100,000	35,912 [b]
Growth Centers	15	6
Districts	11	6
Villages	46	38
Installed Capacity	2,650	1,850
GWh Generated	5.5	3.3
Households	7,000	4,797
Commercial and Public Premises	1,200	713 [c]
$ per kW [d]	$ 2,078 [e]	$ 7,619
$ per Capita of Direct Beneficiary [f]	$ 83	$ 231
Hectares Irrigated	1,600	— [g]

GWh = Gigawatt-hour, kW = kilowatt.

[a] Assumes the same proportion of total beneficiaries to direct beneficiaries as assumed at appraisal. Basis for appraisal assumption was not provided in Appraisal Report.

[b] Assumes six direct beneficiaries per household connection and 10 per nonhousehold connection, based on 1996 household data from the Central Bureau of Statistics, versus 15 direct beneficiaries per connection implied at appraisal.

[c] Of these, 600 are Government offices or public premises.

[d] Project costs for civil works, generation, transmission, distribution, and service connections.

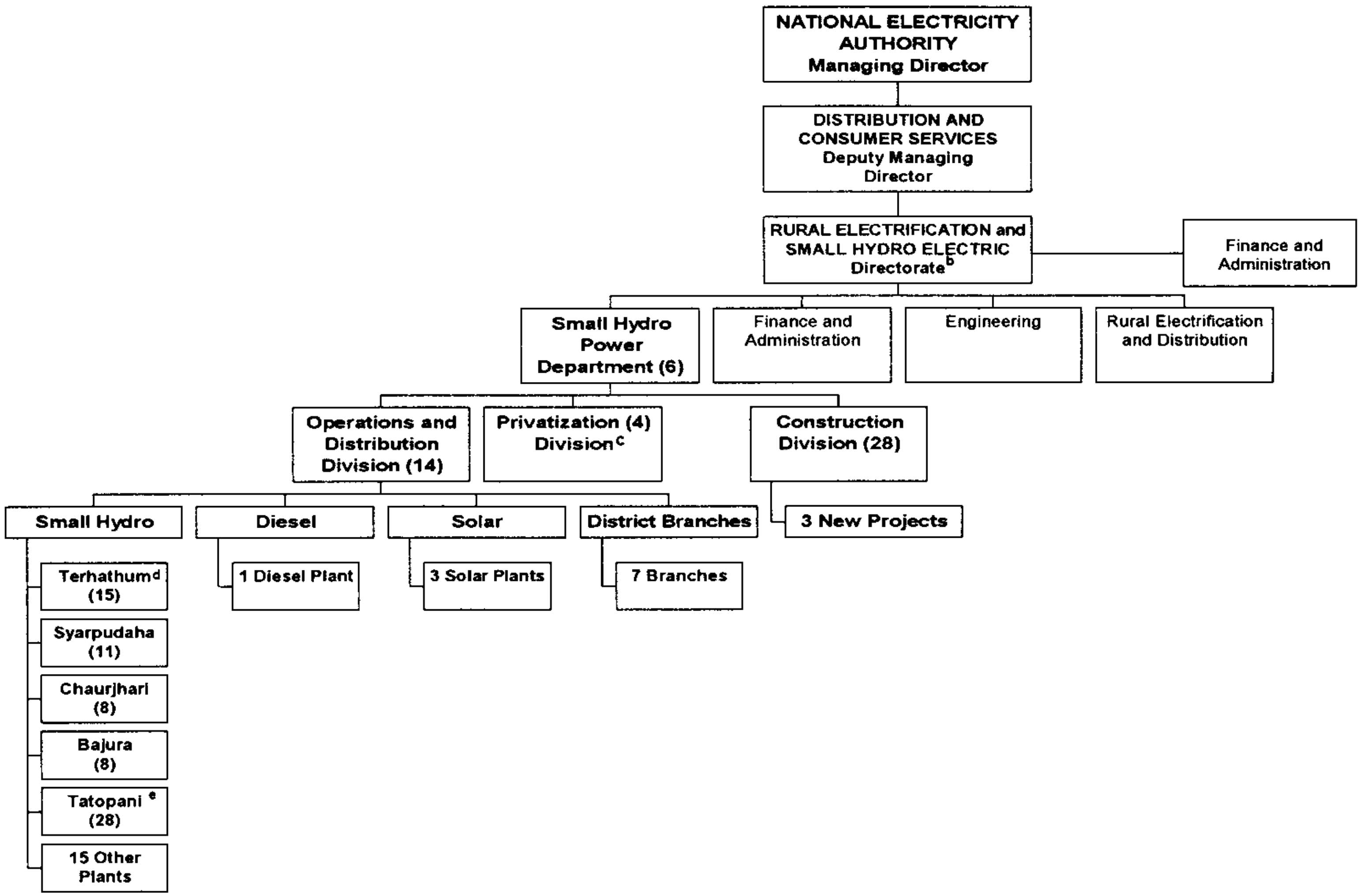
[e] Includes Ilam and Dunche subprojects.

[f] Bank's loan amount per capita.

[g] Irrigation component cancelled.

Sources: Appraisal Report, Small Hydro Power Department, and Postevaluation Mission estimate.

ORGANIZATION CHART FOR NEA AND SMALL HYDRO POWER DEPARTMENT [a]



( ) = Number of employees.
a As of Postevaluation Mission.
b Total staff of 609 comprises 69 officers/engineers/technicians and 540 assistants.
c Monitors lease contracts for Bajhang and other leased plants. Bajhang has five employees.
d Includes 7 persons at power station and 8 persons in Terhathum.
e Includes 20 persons at power station and 8 persons in Beni.

Appendix 7

SUMMARY OF NEPAL ELECTRICITY AUTHORITY'S FINANCIAL PERFORMANCE

Indicator	FY 1990/91	1991/92	1992/93	1993/94		1994/95	1995/96
Generation and Imports (GWh)	906	981	970	1,034		1,126	na
Energy Sales (GWh)	669	737	734	766		830	na
System Losses (%)	26.1	24.8	24.3	25.9		26.3	na
Total Revenues (NRs million)	993	1,514	1,905	2,612		3,465	4,012
Net Profit (NRs million)	(425)	(51)	106	101	a	223	679
Net Profit Margin (%)	(42.8)	(3.3)	5.6	3.9		6.4	16.9
Rate of Return on Revalued Assets	(1.9)	(0.5)	0.2	1.6		2.3	2.4

n.a. = not available, GWh = Gigawatt-hour.

[a] Decline caused by five-month closure of two plants with a generating capacity of 92MW due to floods.

Sources: Nepal Electricity Authority and the Bank.

SUMMARY OF SELECTED TARIFF RATES
(Effective 14 May 1996)

DOMESTIC	Minimum Charge (NRs)	Exempt (kWh)
MINIMUM MONTHLY CHARGES:		
Up to 5 amperes[a]	60.00	20
6-30 amperes	160.00	40
31-60 amperes	360.00	80
Three-phase supply	960.00	200
ENERGY CHARGE (NRs per kWh):		
0-20 units	3.00	
21-250 units	5.00	
Over 251 units	7.75	

INDUSTRIAL	Demand Fee (NRs/kVA)[b]	Energy Charge (NRs/kWh)
Low voltage (400/230 volts)		
Rural and cottage	20.00	4.00
Small industry	40.00	4.90
Medium voltage (11 and 33 kV)	84.00	4.40
COMMERCIAL		
Low voltage (400/230 volts)	100.00	5.80
Medium voltage (11 and 33 kV)	96.00	5.70
NONCOMMERCIAL		
Low voltage (400/230 volts)	68.00	5.80
Medium voltage (11 and 33 kV)	76.00	5.70

TREND ANALYSIS (NRs/kWh)[c]	1981	1985	1991	1993	1996
Domestic	1.00	1.10	2.45	3.00	5.00
Industrial - Rural/Cottage	0.30	0.90	1.85	2.25	4.00
Noncommercial - Low Voltage	n/s	1.50	3.37	4.07	5.80

AVERAGE NEA TARIFF LEVELS[d]	1984	1986	1988	1990	1991	1992	1993	1994	1995	1996
Current Prices (NRs/kWh)	0.80	1.16	1.20	1.38	1.40	1.99	2.54	3.38	3.99	4.75
Constant 1997 Prices (NRs/kWh)	3.08	3.63	2.93	2.76	2.55	3.02	3.48	4.28	4.64	5.11

n/s = not specified, kWh = kilowatt-hour, kV = kilovolt, kW = kilowatt.
[a] Meter capacity
[b] kVA = kW/0.8
[c] Assumes 50 units consumed.
[d] Excludes exports and is based on data in Report and Recommendation of the President on the Kali Gandaki "A" Hydroelectric Project (Loan No. 1452-NEP[SF]) for FY ending July.
Source: National Electricity Authority and the Bank.

Appendix 9

FINANCIAL PERFORMANCE OF SUBPROJECTS
Fiscal Years 1991-96
(NRs)

Subproject	FY 1991/92	1992/93	1993/94	1994/95	1995/96
Terhathum					
Revenue	356,000	408,000	438,000	770,800	1,140,000
O&M	709,000	657,000	2,160,000	1,478,557	1,236,317
Operating Income	(353,000)	(249,000)	(1,722,000)	(707,757)	(96,317)
Revenue as % O&M	50%	62%	20%	52%	92%
Syarpudaha					
Revenue	395,000	461,000	640,000	888,300	1,072,000
O&M	643,000	1,301,000	2,300,000	2,125,141	2,155,172
Operating Income	(248,000)	(840,000)	(1,660,000)	(1,236,841)	(1,083,172)
Revenue as % O&M	61%	35%	28%	42%	50%
Chaurjhari					
Revenue	189,000	241,000	446,000	572,700	501,000
O&M	430,000	631,000	1,090,000	1,044,226	824,475
Operating Income	(241,000)	(390,000)	(644,000)	(471,526)	(323,475)
Revenue as % O&M	44%	38%	41%	55%	61%
Bajura					
Revenue	345,000	374,000	472,000	784,500	681,000
O&M	603,000	769,000	2,186,000	1,905,758	3,831,787
Operating Income	(258,000)	(395,000)	(1,714,000)	(1,121,258)	(3,150,787)
Revenue as % O&M	57%	49%	22%	41%	18%
Bajhang					
Revenue	334,000	433,000	569,143 [a]	770000	857,000
O&M	705,000	906,000	989,000	782,000	785,000
Operating Income	(371,000)	(473,000)	(419,857)	(12,000)	72,000
Revenue as % O&M	47%	48%	58%	98%	109%
Tatopani					
Revenue	1,813,000	3,288,000	3,941,000	5,226,000	6,826,000 [b]
O&M	3,800,000	3,900,000	3,941,000	2,786,268	6,746,000
Operating Income	(1,987,000)	(612,000)	—	2,439,732	80,000
Revenue as % O&M	48%	84%	100%	188%	101%

— = magnitude zero, O&M = Operation and Maintenance.
[a] Leased to private sector operator in FY1993/94.
[b] Revenue increase due to grid connection.
Source: Small Hydro Power Department.

ECONOMIC AND FINANCIAL REEVALUATION

A. Methodology

1. The appraisal adopted a methodology of economic analysis that used only savings in kerosene lighting and diesel oil generation as a proxy for economic benefits, and did not differentiate between displaced and induced energy consumption.[1] The economic reevaluation follows the general approach of the appraisal, but measures the economic benefits of electricity consumption based on (i) the economic cost of kerosene that will be displaced by electricity use, and (ii) the amount of induced energy consumption valued at the willingness to pay for electricity (Tables 4 and 5).

B. Major Assumptions

1. General

2. The analysis assumes a 30-year economic life. All benefits and costs are adjusted to constant 1997 prices in NRs, adjusting foreign currency expenditures by the World Bank's manufacturers' unit value (MUV) index and local currency by Nepal's gross domestic product (GDP) deflator (Table 1). Nontradable local currency costs and benefits from induced energy consumption are converted to border parity prices using a 0.90 standard conversion factor. A conversion factor of 0.90 was also applied to unskilled labor costs. An average exchange rate of NRs57.03 to $1.00 for 1997 is used.[2]

Table 1: Applicators Used in Project Costs and Benefits

Year	MUV Index (1997=100)	GDP Deflator (1997=100)	Exchange Rate[a] (NRs/$1.00)
1985	0.63	0.28	18.25
1986	0.68	0.32	21.23
1987	0.74	0.37	21.82
1988	0.80	0.41	23.29
1989	0.85	0.46	27.19
1990	0.91	0.50	29.37
1991	0.93	0.55	37.26
1992	0.97	0.66	42.70
1993	0.97	0.73	48.61
1994	1.00	0.79	49.40
1995	1.09	0.86	51.89
1996	1.04	0.93	56.42
1997	1.00	1.00	57.03

MUV = manufacturers' unit value, GDP = gross domestic product.

[a] Average for period.

Sources: Small Hydro Power Department, ADB Controller's Department, ADB Key Indicators (1996), and International Bank for Rural Development Commodity Price Projections.

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[1] The Appraisal Report provided only estimates of EIRRs ands FIRRs for each subproject, and did not provide supporting details for the calculations (i.e., costs and benefits for the Project or individual subprojects by year).

[2] As of the Postevaluation Mission in May 1997.

2. Project Costs

3. Assumptions underlying Project costs include:

(i) Capital costs exclude financial charges, and interest during construction. The capital cost for the economic analysis further excludes taxes and duties.

(ii) The capital cost for Tatopani includes the cost of the additional 1,000 kilowatts (kW) of generation and grid connection, funded under the Sixth Power Project, as Project benefits have been based on total generation from the 2,000 kW plant.

(iii) Operating and maintenance costs in real terms are based on actual costs for 1991-1996 for each subproject, and are projected thereafter at the average historic operating and maintenance cost for each subproject.

3. Project Benefits

4. Assumptions underlying Project benefits include:

(i) For the economic analysis, the benefits from displaced kerosene usage and induced electricity consumption are based on the assumptions in Table 2. The benefits from the induced electricity consumption are valued at the estimated willingness to pay. The lower bound of the consumers' willingness to pay is the tariff converted into economic terms through the application of a standard conversion factor. The upper bound is the financial price of kerosene. The consumer surplus is estimated as equivalent to 40 percent of the difference between the financial price of kerosene and the average tariff for electricity, times the amount of induced electricity consumption.

(ii) The cost of owning and maintaining kerosene lighting services is estimated to be approximately equivalent to the annual charges associated with the cost of light bulbs and house wiring, and therefore the cost has been excluded from the analysis. Since industrial users typically maintain backup generators because of the sporadic supply of electricity, the cost savings from reduced capital and maintenance charges related to kerosene generators are assumed equivalent to the cost of electric wiring and bulbs.

(iii) For the financial analysis, the benefits from incremental sales are valued at the average annual tariff, adjusted to constant 1997 prices for 1991-1996, and thereafter projected at the average annual tariff in 1997.

(iv) Load factors for Terhathum and Tatopani increase to nearly 50 percent reflecting gradual economic growth in the subproject areas.

(v) Electricity generation, sales and system loss data were obtained for 1991-1996 from SHPD.

Table 2: Selected Key Assumptions

Item	Percent of Total Connections: Terhathum	Percent of Total Connections: Tatopani	Kerosene Use per Consumer (Liters/month)	Fuel Conversion Factor[a]
User Category:				
Domestic	90%	91%	4.2	1.00 [b]
Industrial	1%	2%	18.0	0.50
Commercial	1%	1%	6.0	0.70 [c]
Noncommercial/Government	8%	6%	6.0	0.70 [c]
Current Prices:				
Kerosene (Economic price)NRs/liter	19.69	19.69		
Kerosene (Financial price) NRs/liter	18.00	18.00		
Tariff (Financial/Isolated) NRs/kWh	4.64	5.03		
Tariff (Financial/Grid) NRs/kWh	—	5.11		

— = not applicable.

[a] Number of kerosene liters to produce energy equivalent to 1 kilowatt-hour of electricity.

[b] Assumes a typical kerosene wick lamp is equivalent to a 25 watt bulb and consumes 0.025 liters per hour.

[c] Assumes use of more fuel efficient pressurized kerosene lanterns.

Sources: NEA *Ten Year Rural Electrification Study*, Small Hydro Power Department and Postevaluation Mission estimate.

Table 3: Summary Computation of Economic Benefits for FY1996/97[a]

	Terhathum	Tatopani
Total Number of Connections	600	3,500
Electricity Sold to Local Area (kWh)	282,857	1,963,312
Electricity Sold to NEA Grid (kWh)	—	1,808,357
Induced Use (kWh)	247,495	3,555,705
Displaced Use (kWh)	35,362	215,964
Induced Use	83%	89%
Displaced Use	13%	11%
Benefits from Induced Use (NRs/kWh)	1,032,729	7,910,244
Benefits from Energy Displaced (NRs/kWh)	674,012	4,120,141
Benefits from Consumer Surplus (NRs/kWh)	1,139,194	7,805,445
Benefits from Grid Connection (NRs/kWh)	—	8,312,608
Total Benefits (NRs/kWh)	2,845,935	28,148,439
Economic Benefits (NRs/kWh)	10.06	7.46
Economic Benefits ($/kWh)	$0.18[b]	$0.13[c]

kWh = kilowatt-hour.

— = not connected.

[a] Benefits in 1997 constant NRs.

[b] The resulting average value of electricity consumption of $0.18/kWh for the Terhathum subproject is reasonably consistent with estimated unit benefits for Bank-financed power projects in Nepal.

[c] The Tatopani subproject was commissioned in 1991 with 1,000 kW of capacity. The capacity was subsequently increased to 2,000 kW and the project was connected to the NEA grid in 1995. Economic benefits for electricity consumption in the local area for this subproject have an average unit value of about $0.19/kWh. After surplus generation is fed into the NEA grid, the resulting average economic benefit is about $0.13/kWh.

Sources: Small Hydro Power Department and Postevaluation Mission estimate.

Table 4: EIRR and FIRR Reevaluation for Terhathum
(NRs in constant 1997 prices)

		Economic				Financial			
Fiscal Year	Load Factor	Benefit	Project Capital Cost	Operating Cost	Net Benefits	Benefit	Project Capital Cost	Operating Cost	Net Benefits
1984/85			2,470,544		-2,470,544		2,552,891		-2,552,891
1985/86			12,204,277		-12,204,277		12,447,971		-12,447,971
1986/87			47,296,901		-47,296,901		46,956,633		-46,956,633
1987/88			11,779,029		-11,779,029		11,810,239		-11,810,239
1988/89	9%	1,143,950	8,789,886	1,047,144	-8,693,081	181,144	8,827,696	1,163,493	-9,810,045
1989/90	14%	1,798,659	1,016,190	1,040,305	-257,835	272,668	1,022,259	1,155,894	-1,905,485
1990/91	17%	1,949,853	2,391,569	1,045,980	-1,487,696	299,079	2,376,461	1,162,200	-3,239,583
1991/92	20%	1,992,551	116,748	969,504	906,299	540,892	116,514	1,077,227	-652,849
1992/93	21%	2,050,541		810,306	1,240,235	559,115	0	900,340	-341,225
1993/94	15%	1,640,735		2,453,075	-812,339	552,699	0	2,725,638	-2,172,940
1994/95	21%	2,049,685		1,553,902	495,783	899,153	0	1,726,558	-827,404
1995/96	28%	2,531,008		1,202,386	1,328,623	1,231,903	0	1,335,984	-104,081
1996/97	32%	2,845,935		1,203,939	1,641,995	1,311,429	0	1,337,710	-26,282
1997/98	36%	3,112,344		1,123,357	1,988,987	1,442,571	0	1,248,175	194,397
1998/99	37%	3,267,961		1,123,357	2,144,604	1,514,700	0	1,248,175	266,525
1999/00	38%	3,316,679		1,123,357	2,193,322	1,529,847	0	1,248,175	281,672
2000/01	38%	3,362,476		1,123,357	2,239,119	1,545,145	0	1,248,175	296,971
2001/02	38%	3,409,237		1,123,357	2,285,879	1,560,597	0	1,248,175	312,422
2002/03	39%	3,456,990		1,123,357	2,333,633	1,576,203	0	1,248,175	328,028
2003/04	39%	3,501,031		1,123,357	2,377,674	1,591,965	0	1,248,175	343,790
2004/05	40%	3,545,797		1,123,357	2,422,440	1,607,885	0	1,248,175	359,710
2005/06	40%	3,591,304		1,123,357	2,467,947	1,623,963	0	1,248,175	375,789
2006/07	40%	3,632,392		1,123,357	2,509,035	1,640,203	0	1,248,175	392,028
2007/08	41%	3,673,994		1,123,357	2,550,637	1,656,605	0	1,248,175	408,430
2008/09	41%	3,716,118		1,123,357	2,592,761	1,673,171	0	1,248,175	424,996
2009/10	42%	3,753,279		1,123,357	2,629,922	1,689,903	0	1,248,175	441,728
2010/11	42%	3,790,812		1,123,357	2,667,455	1,706,802	0	1,248,175	458,627
2011/12	42%	3,828,720		1,123,357	2,705,363	1,723,870	0	1,248,175	475,695
2012/13	43%	3,867,007		1,123,357	2,743,650	1,741,109	0	1,248,175	492,934
2013/14	43%	3,905,678		1,123,357	2,782,320	1,758,520	0	1,248,175	510,345
2014/15	44%	3,944,734		1,123,357	2,821,377	1,776,105	0	1,248,175	527,930
2015/16	44%	3,984,182		1,123,357	2,860,824	1,793,866	0	1,248,175	545,691
2016/17	45%	4,024,023		1,123,357	2,900,666	1,811,805	0	1,248,175	563,630
2017/18	45%	4,064,264		1,123,357	2,940,906	1,829,923	0	1,248,175	581,748
				EIRR	**-1.8%**			**FIRR**	**-9.7%**

Table 5: EIRR and FIRR Reevaluation for Tatopani
(NRs in constant 1997 prices)

Fiscal Year	Load Factor	Economic: Benefit (Isolated)	Benefit (Grid)	Project Capital Cost	Operating Cost	Net Benefits	Financial: Benefit (Isolated)	Benefit (Grid)	Project Capital Cost	Operating Cost	Net Benefits
1984/85				8,624,751		-8,624,751			9,174,004		-9,174,004
1985/86				14,339,614		-14,339,614			14,991,015		-14,991,015
1986/87				148,312,058		-148,312,058			155,536,257		-155,536,257
1987/88				52,548,904		-52,548,904			55,640,829		-55,640,829
1988/89				32,411,291		-32,411,291			34,189,602		-34,189,602
1989/90				35,472,663		-35,472,663			37,641,930		-37,641,930
1990/91				21,704,919		-21,704,919			23,085,547		-23,085,547
1991/92	7%	7,363,206		47,812,775	5,196,214	-45,645,783	2,754,601		49,401,038	5,773,571	-52,420,008
1992/93	14%	12,103,104		44,649,665	4,810,036	-37,356,597	4,505,812		46,004,035	5,344,485	-46,842,708
1993/94	16%	14,072,233		40,237,711	4,475,726	-30,641,203	4,973,028		40,569,226	4,973,028	-40,569,226
1994/95	16%	13,969,318		37,138,023	2,928,252	-26,096,957	6,102,565		37,859,087	3,253,613	-35,010,135
1995/96	25%	16,562,673	1,594,689		6,560,854	11,596,509	5,375,437	1,771,877		7,289,837	-142,523
1996/97	25%	19,835,831	8,312,608		4,842,450	23,305,989	1,304,759	9,236,231		5,380,500	5,160,490
1997/98	26%	20,827,623	8,728,239		5,456,925	24,098,936	10,389,847	9,698,043		6,063,250	14,024,640
1998/99	28%	21,869,004	9,164,651		5,456,925	25,576,729	10,909,339	10,182,945		6,063,250	15,029,034
1999/00	29%	22,962,454	9,622,883		5,456,925	27,128,412	11,454,806	10,692,092		6,063,250	16,083,649
2000/01	31%	24,110,577	10,104,027		5,456,925	28,757,679	12,027,547	11,226,697		6,063,250	17,190,994
2001/02	32%	25,316,106	10,609,229		5,456,925	30,468,409	12,628,924	11,788,032		6,063,250	18,353,706
2002/03	33%	25,905,811	10,821,413		5,456,925	31,270,299	12,881,503	12,023,792		6,063,250	18,842,045
2003/04	33%	26,511,479	11,037,841		5,456,925	32,092,395	13,139,133	12,264,268		6,063,250	19,340,151
2004/05	34%	27,133,638	11,258,598		5,456,925	32,935,311	13,401,915	12,509,554		6,063,250	19,848,219
2005/06	35%	27,772,837	11,483,770		5,456,925	33,799,682	13,669,954	12,759,745		6,063,250	20,366,448
2006/07	35%	28,429,646	11,713,446		5,456,925	34,686,167	13,943,353	13,014,940		6,063,250	20,895,042
2007/08	36%	29,104,659	11,947,715		5,456,925	35,595,448	14,222,220	13,275,238		6,063,250	21,434,208
2008/09	37%	29,798,493	12,186,669		5,456,925	36,528,237	14,506,664	13,540,743		6,063,250	21,984,157
2009/10	38%	30,511,791	12,430,402		5,456,925	37,485,268	14,796,797	13,811,558		6,063,250	22,545,105
2010/11	38%	31,245,221	12,679,010		5,456,925	38,467,307	15,092,733	14,087,789		6,063,250	23,117,272
2011/12	39%	31,999,480	12,932,590		5,456,925	39,475,146	15,394,588	14,369,545		6,063,250	23,700,883
2012/13	40%	32,775,292	13,191,242		5,456,925	40,509,609	15,702,480	14,656,936		6,063,250	24,296,166
2013/14	41%	33,573,411	13,455,067		5,456,925	41,571,553	16,016,529	14,950,075		6,063,250	24,903,354
2014/15	42%	34,394,622	13,724,168		5,456,925	42,661,866	16,336,860	15,249,076		6,063,250	25,522,686
2015/16	42%	35,239,746	13,998,652		5,456,925	43,781,473	16,663,597	15,554,058		6,063,250	26,154,405
2016/17	43%	36,109,633	14,278,625		5,456,925	44,931,333	16,996,869	15,865,139		6,063,250	26,798,758
2017/18	44%	37,005,173	14,564,197		5,456,925	46,112,445	17,336,806	16,182,441		6,063,250	27,455,998
2018/19	45%	37,927,291	14,855,481		5,456,925	47,325,847	17,683,543	16,506,090		6,063,250	28,126,383
2019/20	46%	38,876,952	15,152,591		5,456,925	48,572,617	18,037,213	16,836,212		6,063,250	28,810,176
2020/21	47%	39,855,161	15,455,643		5,456,925	49,853,879	18,397,958	17,172,936		6,063,250	29,507,644
					EIRR	3.7%				FIRR	0.3%