ASIAN DEVELOPMENT BANK PPA: IND 22344

PROJECT PERFORMANCE AUDIT REPORT

ON THE

RAYALASEEMA THERMAL POWER PROJECT
(Loan No. 988-IND)

IN

INDIA

May 1999

CURRENCY EQUIVALENTS
Currency Unit — Indian Rupee/s (Re/Rs)

		At Appraisal (June 1989)	**At Project Completion** (July 1997)	**At Postevaluation** (December 1998)
$1.00	=	Rs16.67	Rs36.65	Rs42.54
Rs100	=	$6.00	$2.73	$2.35

For the purpose of cost comparison in this report, local currency costs were converted into US dollars at the rate prevailing during each transaction.

ABBREVIATIONS

APSEB	-	Andhra Pradesh State Electricity Board
EIA	-	environmental impact assessment
EIRR	-	economic internal rate of return
FIRR	-	financial internal rate of return
MOEF	-	Ministry of Environment and Forest
MOP	-	Ministry of Power
O&M	-	operation and maintenance
PCR	-	project completion report
PPAR	-	project performance audit report
SEB	-	state electricity board
SERC	-	state level regulatory commission
TA	-	technical assistance

WEIGHTS AND MEASURES

kV	(kilovolt)	-	1,000 volts
MW	(megawatt)	-	1,000,000 watts
kWh	(kilowatt-hour)	-	1,000 Wh
GWh	(gigawatt-hour)	-	1,000,000 kWh

NOTES

(i) The fiscal year (FY) of the Government and Andhra Pradesh State Electricity Board ends on 31 March. FY before a calendar year denotes the year in which the fiscal year ends, e.g., FY1995 ends on 31 March 1995.

(ii) In this report, "$" refers to US dollars.

Operations Evaluation Office, PE-524

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BASIC DATA

PROJECT PREPARATION/INSTITUTION BUILDING

TA No.	TA Project Name	Type	Person-Months	Amount	Approval Date
1228	APSEB Operational Improvement Support	A&O	42	1,000,000	21 Nov 1989
1229	National Program for Environmental Management for Coal- Fired Power Generation	A&O	93	664,000	21 Nov 1989

KEY PROJECT DATA ($ million)	As Per Bank Loan Documents	Actual
Total Project Cost	610.3	452.3
Foreign Exchange Cost	260.6	178.2
Bank Loan Amount/Utilization	230.0	178.2
Bank Loan Amount/Cancellation		51.8

KEY DATES	Expected	Actual
Fact-Finding		2-18 Feb 1989
Appraisal		16 May-1 Jun 1989
Loan Negotiation		2-4 Oct 1989
Board Approval		21 Nov 1989
Loan Agreement		14 Mar 1990
Loan Effectiveness	15 Jun 1990	16 Jul 1990
First Disbursement		3 Aug 1990
Project Completion	31 Dec 1993	Feb 1995
Loan Closing	31 Dec 1994	7 Apr 1996
Months (Effectiveness to Completion)	54	77

KEY PERFORMANCE INDICATORS (%)	Appraisal	PCR	PPAR
Economic Internal Rate of Return	20.0	24.1	16.2
Financial Internal Rate of Return	3.0	7.2	Negative

BORROWER India

EXECUTING AGENCY Andhra Pradesh State Electricity Board

MISSION DATA

Type of Mission	No. of Missions	Person-Days
Appraisal	1	112
Project Administration		
- Inception	1	14
- Review	6	48
- Project Completion	1	22
- Operations Evaluation	1	36

EXECUTIVE SUMMARY

The Project was a component of the Government's long-term National Power Development Program, which aimed to meet the energy needs of the country. The Program emphasized improving the reliability of the electricity supply. The main objectives of the Project were to promote economic and industrial development in Andhra Pradesh, and enhance the power supply using indigenous coal.

The Rayalaseema Thermal Power station was planned for an electricity output of about 2,600 gigawatt-hours through the addition of 420 megawatts of generating capacity, comprising two 210 megawatts units.

The Bank loan for $230 million, approved on 21 November 1989, covered about 38 percent of the total project cost at appraisal. Concurrent with the Project, the Bank provided two advisory technical assistance (TA) grants, totaling $1,664,000, to support Operational Improvement of Andhra Pradesh State Electricity Board (APSEB) and to prepare the National Program for Environmental Management for Coal-Fired Power Generation.

The project design was sound and included improvements based on APSEB's experience in operating similar plants.

The performance of consultants, contractors, and suppliers was fully satisfactory. Except for delays due to slow progress in civil works and supply of boiler equipment, the implementation was generally on schedule. Organizational arrangements were efficient both at APSEB headquarters and at the project site.

The actual project cost was 26 percent lower than the appraisal estimate. Unforeseen low bid prices, coupled with the devaluation of the Indian rupee, resulted in significant loan savings. Finally, $178.2 million of the loan amount was utilized.

The first and second generating units became operational in March 1994 and February 1995. They were delayed by 9 and 15 months compared with the schedule at appraisal. However, the first unit suffered from a fire accident in December 1994, and was recommissioned in August 1995. While the accident happened due to the unfortunate failure of oil pipelines under testing, the Mission is concerned that the fire-fighting facilities have not yet been satisfactorily completed.

The TA for operational improvement was generally successful. APSEB successfully implemented the recommendations from the TA and improved data processing for the networks.

However, the TA, National Program for Environmental Management for Coal-Fired Power Generation, was ineffective. The Ministry of Environment and Forest, the Executing Agency for the TA, did not implement the recommendations. The TA should have involved the Ministry of Power as it has a direct role in overseeing the implementation of such environmental management practices by coal-fired generating facilities.

The Andhra Pradesh government and APSEB generally complied with the Bank's loan covenants. However, important financial covenants, linked with the operational efficiency of APSEB were not met. While the Bank's project completion report commended APSEB's achievement of covenanted targets for rationalizing tariffs, reducing system losses, and financial

indicators, the Mission's analysis established that the actual achievements were below the expectation at appraisal.

The Project has consistently achieved one of the highest plant load factors in APSEB and the country (APSEB has the best performing plants in the country). The power plant is being operated and maintained very well. The staff are highly skilled, knowledgeable, and devoted. The Project has delivered substantial benefits to the industrial and agricultural consumers.

The Mission conducted an elaborate economic and financial reevaluation and included sensitivity analysis to identify lessons for the sector in India and in other developing member countries. Under various scenarios, the economic internal rate of return was consistently above 16 percent. The Project satisfactorily achieved its main objective of improving the reliability of electricity supply and is rated as generally successful.

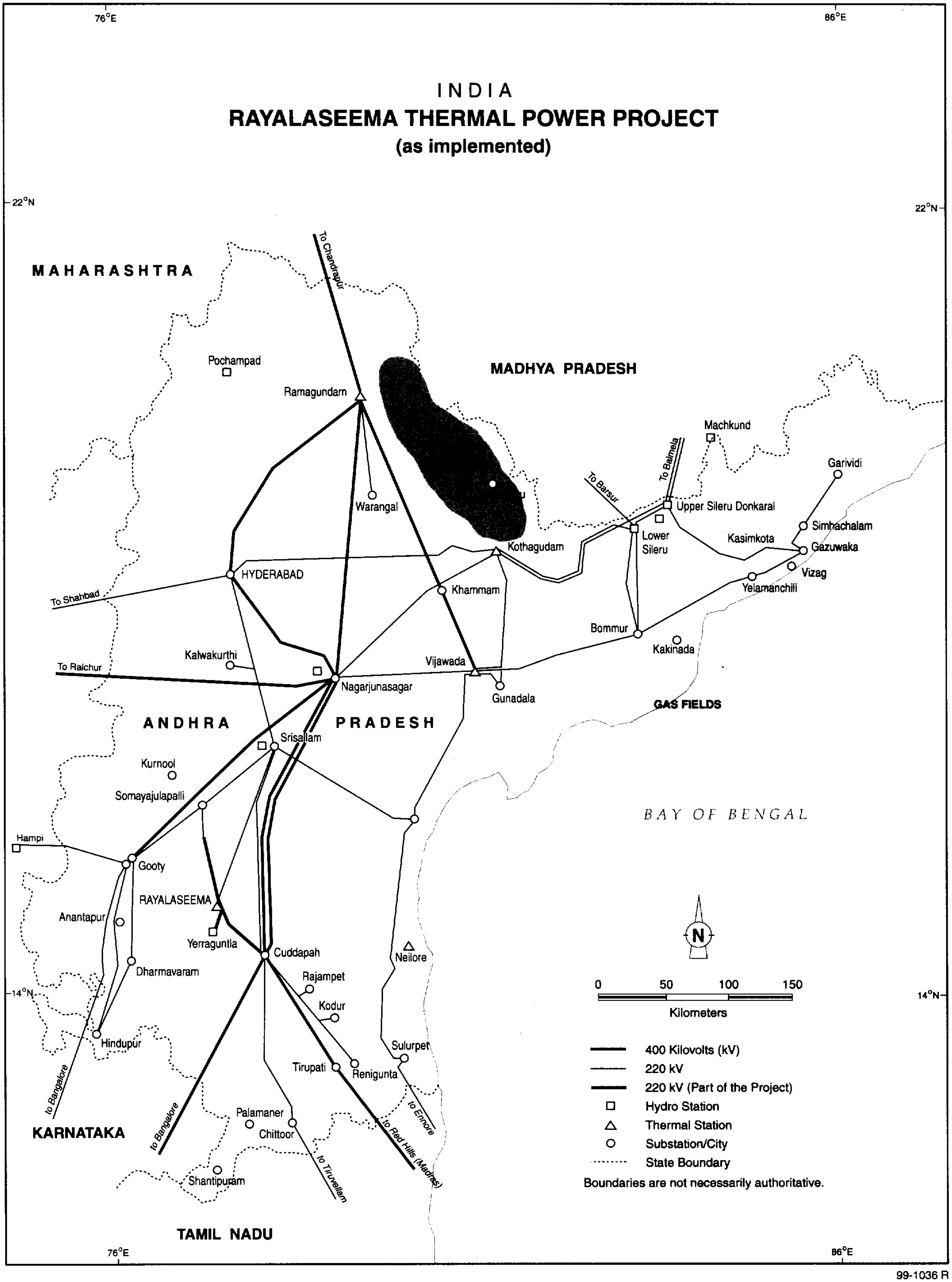
However, the Mission identified that the Project would face constraints to operate at and sustain this high level of performance if the plant is limited to using coal from Singareni collieries; the quality of the coal is below G grade, with an ash content as high as 60 percent, compared with the design level of 45-50 percent. The state government is advised to carefully reconsider the policy of using coal from Singareni collieries, keeping in view the high fuel cost, high operation and maintenance expenses, and the environmental impact of the disposed ash.

Until the onset of reforms (see below), the Mission was concerned about the Project's sustainability as the financial health of APSEB has been very poor. While the tariff was designed to subsidize lower income groups, the average tariff across all consumers had been inadequate to recover the cost of supply. APSEB barely recovers revenues on 60 percent of the power sold. This was exacerbated by a high level of system losses (both technical and nontechnical) at 33 percent.

The Mission observed, considering that the Project was intended to improve reliability of electricity supply, it was not appropriate for the Bank to look at APSEB in isolation of overall sector reforms, which was what was necessary. Instead, the Bank attempted to achieve financial sustainability for the entire APSEB by including covenants imposing ambitious targets for APSEB to rationalize tariffs and reduce system losses. However, prior to the reforms, APSEB did not have the institutional autonomy to raise tariff, to raise revenues in order to invest in loss reduction projects.

The Andhra Pradesh government is among the first states in India which is successfully pursuing the initiatives undertaken at the central level to reform the power sector. A state electricity regulatory commission has been set up in February 1999. This commission will be able to set tariffs that can recover costs, independent of political intervention. APSEB has been restructured into separate generation, transmission, and distribution entities that will be corporatized and eventually privatized.

However, the success of the reform process will be further strengthened by the sustainable operations of the distribution subsector, first as a government-owned corporate entity. It is also important to decrease the system losses to below 15 percent. Projects to improve efficiency in the transmission and distribution subsectors must be implemented. These cannot be achieved without direct external assistance. The Bank should also actively participate in the policy dialogue and coordinate with other funding agencies, especially the World Bank.


INDIA
RAYALASEEMA THERMAL POWER PROJECT
(as implemented)
76°E
86°E
22°N
14°N
MAHARASHTRA
MADHYA PRADESH
ANDHRA PRADESH
KARNATAKA
TAMIL NADU
BAY OF BENGAL
GAS FIELDS
To Chandrapur
Pochampad
Ramagundam
Warangal
Machkund
To Balmela
To Barsur
Upper Sileru Donkaral
Lower Sileru
Garividi
Simhachalam
Kasimkota
Gazuwaka
Vizag
Yelamanchili
Kothagudam
HYDERABAD
To Shahbad
Khammam
Bommur
Kakinada
Kalwakurthi
To Raichur
Vijawada
Nagarjunasagar
Gunadala
Srisailam
Kurnool
Somayajulapalli
Hampi
Gooty
RAYALASEEMA
Anantapur
Yerraguntla
Cuddapah
Nellore
Dharmavaram
Rajampet
Kodur
Hindupur
Sulurpet
Tirupati
Renigunta
to Bangalore
to Ennore
to Red Hills (Madras)
Palamaner
Chittoor
to Tiruvellam
Shantipuram
0 50 100 150
Kilometers
400 Kilovolts (kV)
220 kV
220 kV (Part of the Project)
Hydro Station
Thermal Station
Substation/City
State Boundary
Boundaries are not necessarily authoritative.
99-1036 R

I. BACKGROUND

A. Rationale

1. The Rayalaseema Thermal Power Project was developed as a component of the Indian Government's long-term National Power Development Program. The Program was formulated in response to the chronic power shortage experienced by the country. The gap between demand and supply was consistently increasing, particularly in southern India, where demand was rising at over 10 percent per annum. The emphasis of the Program was on improving electricity supply reliability.

B. Formulation

2. The project feasibility study was conducted by experienced domestic consultants appointed by the Andhra Pradesh State Electricity Board (APSEB) and was acceptable to the Bank. The Project was appraised in May 1989.

C. Objectives and Scope at Appraisal

3. The main objectives of the Project were to promote economic and industrial development in Andhra Pradesh and enhance power supply using indigenous fuel. The power plant was planned for an electricity output of about 2,600 gigawatt-hours through the addition of 420 megawatts (MW) of generation capacity in the first stage (Appendix 1).

4. The Project was designed to utilize fuel from the state's Singareni collieries; it included two 690-ton coal-fired boilers, coal and ash handling systems, and other auxiliary support systems; and 255 circuit kilometers of 220 kilovolts transmission lines and a 220/33 kilovolts substation to interconnect with the existing grid. Concurrent with the Project, the Bank provided two technical assistance (TA) grants. The first was to support operational improvements of APSEB[1] and the second, to provide consulting services and related training programs for the National Program for Environment Management for Coal-Fired Power Generation.[2]

D. Financing Arrangements

5. The Bank approved a loan from its ordinary capital resources for $230 million on 21 November 1989 to finance about 88 percent of the foreign exchange cost. The Bank's financing was to cover about 38 percent of the total project cost ($610.3 million) as estimated at appraisal. In addition, the Bank extended $1,664,000 toward advisory TA, $1,000,000 of this assistance was allocated directly to APSEB, the Executing Agency. Additional financing became available on 19 November 1990, when the Bank entered into a complementary loan[3] agreement with the Power Finance Corporation Limited.

E. Completion

6. The Project was completed by February 1995 compared with the completion date of December 1993 envisaged at appraisal. The project completion report (PCR) prepared by the

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1 TA No. 1228-IND: *APSEB Operational Improvement Support*, for $1,000,000, approved on 21 November 1989.

2 TA No. 1229-IND: *National Program for Environmental Management for Coal-Fired Power Generation*, for $664,000, approved on 21 November 1989.

3 Loan No. 19-IND(C), complementary to Loan Nos. 798-IND: *North Madras Thermal Power Project* and 988-IND: *Rayalaseema Thermal Power Project*. The complementary loan consisted of a dollar tranche amounting to $60,000,000 and a yen tranche amounting to ¥7,500,000,000.

Bank discussed the design, scope, implementation, and operational aspects of the Project, and provided other detailed project information. The overall assessment in the PCR was that (i) the Project had been implemented successfully, although with a delay in physical implementation of 9 to 13 months, and (ii) there were appreciable cost savings resulting from highly competitive prices and the rupee devaluation. The PCR classified the Project as generally successful. However, the PCR also reported that (i) the poor financial performance of APSEB due to problems with tariff adjustment and system losses resulted in a substantial subsidy provided by the state government to compensate for the losses incurred, and (ii) APSEB could not achieve the targeted percentage of investment to transmission and distribution, self-financing, and debt service ratios, as covenanted under the Project Agreement.

F. Postevaluation

7. This project performance audit report (PPAR) presents the principal findings of an Operations Evaluation Mission in December 1998. It also presents an assessment of the Project's effectiveness in terms of objectives achieved, benefits generated, and the sustainability of the Project's operations. This PPAR involves an elaborate economic and financial reevaluation, including sensitivity analysis of various policy and operational variables, and identifies lessons for future operations in this sector in India, and other developing member countries.

8. The PPAR is based on a review of the PCR, appraisal report, and materials in Bank files; and discussions with staff members of the Bank, APSEB, the Borrower, other financing agencies, research institutes, representatives of local groups, and the domestic consultant. Copies of the draft PPAR were provided to the Borrower, APSEB, and Bank staff concerned for review and comments. Comments received were taken into consideration in finalizing the report.

II. IMPLEMENTATION PERFORMANCE

A. Design

9. The Project, consisting of two 210 MW units, formed the first development stage of the Rayalaseema Thermal Power Station of APSEB. The feasibility report for the Project was prepared by consulting engineers, appointed by APSEB, who had been successfully involved in a large number of similar projects. The development of the Project was based on tested conventional design with improvements incorporated based on experience gained by APSEB. The design paid due attention to the operating experience of the executing agency and was in line with tried-out technology at that time. The steam generators were designed to burn coal from the Singareni coalfields located in Andhra Pradesh, about 810 kilometers north of the power station. This coal was envisaged to have calorific value and ash content of 3,676 kilocalories/kilogram (kcal/kg) and 45 to 50 percent, respectively. This was the minimum quality of the coal needed to ensure that the least cost alternative (including coal from other sources in India and importation from outside India) will be met.

10. The Project was implemented without any major deviation from the design adopted at appraisal. The actual level of performance achieved by APSEB established appropriateness of the design rationale of these units.

B. Contracting, Construction, and Commissioning

11. APSEB assessed the performance of the consultants during project implementation to be fully satisfactory.

12. APSEB carried out procurement of Bank-financed equipment including main plant packages and other important auxiliary systems as per the Bank's *Guidelines for Procurement*. The main plant equipment and other auxiliary systems and support facilities were supplied, erected, and commissioned by a reputable state-owned supplier. Although the implementation arrangements were generally in place as programmed at appraisal, and the implementation progress was reviewed by regular Bank missions, slow progress in civil works for the foundation and supply of boiler equipment delayed commissioning of the units. APSEB, nonetheless, was of the view that the performance of contractors and suppliers was generally satisfactory. The equipment/facilities supplied were in compliance with specifications and no significant difficulties were experienced during project implementation. The Mission's field visits and inspection confirmed the satisfactory completion of works and installations.

C. Organization and Management

13. APSEB took advance action on project preparatory activities as envisaged at appraisal both at the APSEB headquarters in Hyderabad and at the power station site. Several staff members were assigned on a full-time basis to APSEB headquarters. They were supported by a specialist group at the station. An energy audit was conducted at substations using logging-type energy meters, and a separate computer training center was established.

D. Actual Cost and Financing

14. The total project cost at appraisal was estimated at $610.3 million equivalent. Unanticipated low bids for procurement from the domestic supplier coupled with a significant devaluation of the Indian rupee (from $1 = Rs16.67 in 1989 to $1 = Rs36.65 in 1997) resulted in substantial cost savings of $158 million, resulting in an actual cost of $452.34 million (26 percent lower than the appraisal estimate) (Appendix 2). This cost saving was achieved even though project implementation faced delays. Finally, $178.2 million of the loan amount was utilized, this was $51.8 million less than the approved loan amount of $230 million. At project completion, the Bank's loan represented approximately 39 percent of the total project cost; the Andhra Pradesh government's contribution of $136.8 million, 30 percent; and APSEB's contribution of $137.3 million,[4] 31 percent (Appendix 2). A part of the significant savings available under the Project was utilized to finance additional components not originally included for Bank financing.[5] The availability of local funds did not pose any constraint on implementation of the Project.

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4 Part of the proceeds of the complementary loan (Loan No. 19-IND[C]) was channeled to (i) APSEB to assist in financing the Rayalaseema Thermal Power Project, and (ii) Tamil Nadu Electricity Board for the North Madras Thermal Power Project. The dollar tranche of $60 million was fully disbursed, while $57,870,370.37 equivalent was actually disbursed from the yen tranche of Y7.5 billion. However, a breakdown of these disbursements by project was not available.

5 $17 million was used to procure additional equipment and essential spares required for optimal performance of units.

E. Implementation Schedule

15. Unit 1 became operational in March 1994 and Unit 2 in February 1995; they were originally scheduled for June and November 1993, a delay of about 9 and 15 months (Appendix 3). A fire accident, which occurred in Unit 1 in December 1994, was one of the primary reasons for delay in the otherwise achievable implementation schedule. Civil works and supply of boiler components were also delayed. APSEB's lack of familiarity with the Bank's practices in procurement was adequately addressed through the seminars arranged by the Bank in February 1992.

F. Technical Assistance

16. The Bank provided two advisory and operational TA grants with the loan. Both TAs were evaluated by the Bank in 1998.[6] The major objectives of the TA on APSEB Operational Improvement Support—to improve operational efficiency, electricity demand management, data processing, and staff skills—were relevant and consistent with the Project's overall objectives. The resources provided in terms of person-months, skills mix for consulting services, and counterpart facilities were adequate; and the study was completed generally as scheduled. However, the Bank and APSEB were not satisfied with the consultant's final report as it was poorly drafted. But the technical information and the recommendations were useful to APSEB. In addition to implementing the recommendations, APSEB formulated bankable projects on supervisory control and data acquisition in its distribution networks, installed meters for agricultural consumers, and improved the data processing systems. Overall, the impact was considered to be generally satisfactory.

17. The TA, on National Program for Environmental Management for Coal-Fired Power Generation, was intended to assist the Ministry of Power (MOP) and Ministry of Environment and Forest (MOEF) in formulating a national environmental management master plan, including a national level training program for the sector. The objective and scope of the TA were relevant to and consistent with the Bank's operational strategy in India. The resources provided under this TA were generally adequate, and a good inception report and well-structured final report were prepared by the consultants. While the recommendations of the consultant included specific proposals for coal processing and several measures for minimizing the environmental impact of a coal-fired power station, the TA performance audit report observed that MOEF, the Executing Agency, lacked technically qualified and experienced staff to independently implement the recommendations, and consequently, could not ascertain the exact status of implementation. MOEF advised the Mission that they did not incorporate the recommendations because they were not fully relevant. The valuable findings on coal processing based on management studies for Talcher and North Karanpura mines, which underscored the benefits of improved coal quality, reducing of transport costs, and increasing availability, in addition to major environmental benefits, have been ignored. The TA, therefore, failed to have a significant impact on best management practices within the coal-fired power generation sector. In hindsight, responsibility of implementation of the environmental management plan should have been vested with MOP possibly in collaboration with MOEF, as MOP has a direct role in overseeing the implementation of such environmental management practices within the country's coal-fired generating facilities under the policy framework and standards

6 TPA: IND 98008: *Technical Assistance Performance Audit Report on Advisory and Operational TAs in the Power Sector in India*, December 1998. The report includes a detailed assessment of the input, output, impact, and benefits of the TAs.

prescribed by MOEF. A closer linkage with these agencies would have helped to better internalize the TA recommendations.

18. It also emphasizes the need to improve coordination between the Bank and MOEF and for the Bank to conduct follow-up review to reasonably ensure effective implementation of the recommendations.

G. Compliance with Loan Covenants

19. The Andhra Pradesh government and APSEB generally complied with the Bank's loan covenants relating to the application of proceeds, engagement of consultants, and other reporting requirements. The status of compliance with the covenants under the loan is presented in Appendix 4. A covenant that was not complied with required the Borrower to ensure an adequate supply of required quality of coal. The PCR did not report the poor quality of Singareni coal and its adverse effects (para. 23). The financial covenants (Project Agreement, Schedule 3, paras. 6(a) and 7) requiring implementation of operational and financial action plans were not complied with. The PCR attested to APSEB's implementation of the agreed action plan thereby achieving targets for the rationalization of tariffs, reduction of system losses, etc. However, postevaluation analysis of financial performance of APSEB established that these financial covenants were not met. In the view of the Mission, considering that the Project's main objective was to improve reliability of electricity supply, imposing these covenants was not effective in addressing the larger problem of financial sustainability of APSEB (para. 30). Furthermore, as there were no parallel activities by other funding agencies aimed at improving transmission and distribution efficiencies, the covenant on reducing system losses to 14 percent was unrealistic.

III. PROJECT RESULTS

A. Operational Performance

20. The operational performance of the Project was assessed against the output projected at appraisal. In addition, the Mission reviewed system design, special features, operating practices, and maintenance scheduling, etc. of various equipment and supporting systems, and examined their appropriateness to attain and further sustain the desired level of operational performance. In addition, the Mission compiled details of various performance indicators, namely generation, plant load factors, auxiliary consumption, fuel consumption, etc. (Appendix 5, Table A5.4). An assessment of these indicators established a satisfactory level of performance of the various equipment/facilities and demonstrated a high level of operational performance of the station with a long period of uninterrupted generation.

21. During the stabilization period of Unit 1, there was a fire accident in December 1994 affecting parts of the powerhouse structure, and steam and oil pipe lines, including control and instrumentation cubicles. An analysis based on the information provided by APSEB and further discussions with them indicated that the accident happened due to the failure of oil pipelines under testing, which could occur during such testing and commissioning operations. The damage was attended to by the original supplier and the unit was recommissioned by the end of August 1995. However, the Mission is concerned that the fire-fighting facilities have not been

completed yet, making the station vulnerable to fire hazards. This is particularly important, in view of the existing similar state of affairs in other stations of APSEB.[7]

22. Site inspection of major operating areas including steam generators, turbine generator, and other auxiliary areas like coal handling, ash handling, ash disposal, etc., revealed healthy operation and maintenance (O&M) practices with strict adherence to the instructions prescribed by the manufacturers, including carrying out condition monitoring and regular checkup procedures. Regular soot-blowing operations, and maintenance of feed water quality and desired steam parameters have resulted in satisfactory performance of the steam generators which maintained loads close to the maximum rated capacity. O&M of turbine generator units was also quite satisfactory; all feed heaters were in service; and necessary tests/checks, regular overhauling, etc. were carried out regularly.

23. Under the conditions faced by APSEB, the performance was fully satisfactory. However, a higher level would have been achieved if it was not for the following impediments:

(i) **Coal Supply.** The power station is primarily linked with the state government's Singareni collieries for supply of coal. However, the quality of coal usually received is of substandard quality, below grade G, and with wide variation in calorific values and ash content,[8] which is well below the covenanted agreement between the Borrower and the Bank. Lately, the Project received a part linkage with Talcher coalfields supplying coal of better quality; operational improvements were noticed immediately.[9] While the project authorities would have been satisfied with at least a mix of Talcher coal, the government appears to be reluctant to reduce the coal supply from Singareni collieries, first because of the limited outlets using this coal, and second, in view of the inherent advantage of adjusting fuel costs against outstanding payables to APSEB for the purchase of power over a longer time frame. The Mission feels that the decision on the choice of coal should be delegated to APSEB, (and even the station) (para. 59).

(ii) **Ash Disposal.** The system supplied by a reputable indigenous supplier, although based on an established design, showed deficiencies in proper ash handling. The level of vacuum created is generally not adequate to effectively drag ash from the hoppers. The wear and tear on the various equipment and the ash pipeline leakages cause additional difficulties with proper ash evacuation. The use of coal with a very high ash content is the main cause for this situation, resulting in high quantities of air/water pollutants in the stack emission, as well as plant effluents. The project authorities, however, are fully apprised of the situation and are incorporating modifications in the ash handling equipment. Further, they have programmed actions that will be completed within a year to achieve

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7 Incidentally, the same supplier has been selected to supply, erect, and commission these facilities in a number of projects under APSEB and almost all of them are suffering from implementation delays. A careful selection of potential suppliers after due scrutiny of their capabilities in both technical and financial areas to ensure availability of full-fledged, fire-fighting facilities during the implementation stage itself would facilitate addressing such a situation in the future.

8 The calorific value of the coal actually received was usually in the order of 3,000 ± 200 kcal/kg and with ash content of 50 to 60 percent against the designed calorific value of 3,676 kcal/kg and ash content of 45 to 50 percent. Large-size foreign materials supplied with the coal (boulders, iron rod, etc.) further affect operation of the plant, sometimes resulting in breakdowns.

9 The cost per ton (including transport) for Talcher coal is only marginally higher than for Singareni coal. Considering the lower ash content, the total fuel cost for a generator using Talcher coal would be considerably lower.

improvements in evacuation as well as to contain the level of pollutants below MOEF standards. They are also concerned about the long-term impact of using inferior quality coal on fuel cost, O&M expenses, longer overhaul period, and eventually the life of the equipment. A concerted effort on the part of APSEB and the Andhra Pradesh government will be required to minimize the adverse impacts, possibly by having a better mix of coal supply coupled with a time-bound improvement in the ash evacuation system.

(iii) **System Losses.** The system losses as declared by APSEB ranged between 32 and 33 percent, affecting energy available for sale. The covenanted level of ambitious reduction in system losses to 14 percent could not be achieved (para. 19).

B. Institutional Performance

24. The management and staff of APSEB demonstrated effective management and sound technical capabilities and environmental awareness in O&M of the station. Furthermore, they revised the organizational structure and strengthened interdepartmental functional linkages (Appendix 6). To further strengthen the autonomy and efficiency of generating plants, the management of finances for fuel input and routine O&M should be decentralized in the future.

25. The Government of India has undertaken a power sector reform program at the central and state levels to address the ever-widening gap between power demand and supply.[10] The program is aimed at establishing an independent regulatory mechanism at the central and state levels, restructuring of the state electricity boards (SEBs) and supplementing fund mobilization through private sector investment. The Bank's operational strategy for the Indian power sector now focuses on financial assistance to reform-oriented SEBs, such as APSEB.

26. The Central Electricity Regulatory Commission has already been set up and state-level regulatory commissions (SERCs) are targeted to be set up in a few months.[11] APSEB has been restructured, in a phased manner, into separate generation, transmission, and distribution companies followed by privatization of the government-owned distribution company.[12] These major achievements would substantially improve the operational and financial performance of APSEB.

27. The training provided through the TA for APSEB's Operational Improvement Support generated visible benefits (para.16).

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10 Generally, the energy sector in India has not undergone much change since project appraisal, in terms of its structure in relation to various government agencies at the central and state levels. The Planning Commission continues to be responsible for overall energy planning. The power sector policy development plan and its implementation is carried out by MOP. The states implement their own power development programs through their respective state electricity boards (SEBs). These programs are examined and approved by the Central Electricity Authority to ensure optimization at the national level. The Authority provides other technical support to MOP to consolidate the overall power development program at the national level.

11 The state of Andhra Pradesh (second state in India to pursue reform other than Orissa) recently passed the Andhra Pradesh Electricity Reform Bill, 1998. The Reform Act, 1998 came into effect on 1 February 1999.

12 The Project is now under Andhra Pradesh Power Generation Corporation.

C. Financial Performance

28. The financial projections of APSEB and their assumptions are given in Appendix 7. A summary of financial performance at appraisal and at postevaluation is shown in Table 1.

Table 1: Summary of Financial Performance of APSEB
(Rs10 million)

Item	1988 (Appraisal)	1998 (Operations Evaluation)
Total Sales and Other Receipts	736.9	4,363.4
Subsidies and Grants	—	1,255.9
Total Operating Revenue	736.9	5,619.3
Total Operating Surplus	124.0	875.1
Net Income	29.3	121.6
Net Fixed Assets	1,349.0	4,051.8
Current Assets	615.0	5,705.6
Total Assets	2,637.4	14,097.6
Total Equity	1,158.6	3,505.4
Long-Term Debt	655.0	3,796.2
Performance Indicators		
Rate of Return on Net Fixed Assets (%)	2.20	3.00
Operating Ratio	0.83	0.76
Rate of Return on Equity (%)	2.40	3.40
Current Ratio	0.80	0.90
Debt/Debt and Equity	0.36[a]	0.52
Debt Service Coverage Ratio	1.37[a]	0.80
Average Revenue Rate (Rs/Kwh)	0.82[a]	1.66
Self-Financing Ratio (3 year average)	31.66[a]	(250.90)

Note: Fiscal year ends March.
[a] Data for FY 1992.
— = no data available.

29. At appraisal, it was agreed by both APSEB and the Andhra Pradesh government (covenant in Project Agreement, Schedule 3, para. 7) that APSEB's tariff would be adjusted to ensure minimum financing of 20 percent of capital expenditure from their internal resources during the eighth plan. Thereafter, the self-financing ratio target would be increased to 25 percent without recourse to subvention from the state government. However, the tariff adjustments that were made were inadequate to meet these targets.[13] Therefore, the actual operating income generated was considerably lower than that envisaged at appraisal. This resulted in an inadequate generation of internal resources.[14]

[13] However, the tariff adjustment was far below the targeted level in the financial covenants. Huge cross subsidy to the agricultural consumers continued. The industrial tariff reached 381 p/unit while the agricultural consumers got unmetered power almost free of charge (average tariff which was 16 p/unit in 1975, was pegged at 18 p/unit until 1998). As a result, a sizeable amount of captive power generation (1,700 MW) is undertaken by the industrial consumers.

[14] In the last five years of operation, the self-financing ratios for three years were even negative. This required a large amount of government subsidy (a subsidy of Rs12.5 billion provided in FY1998) that could barely cover the operating expenses.

30. The unbundling of APSEB would finally provide the solution to the causes of the financial woes.[15] Unfortunately, earlier commercial practices did not allow APSEB the autonomy to set a tariff that is free from political intervention. As APSEB was dependent on government subsidy, it was not possible to invest in projects to improve system efficiencies. Therefore, it reveals the merits of adopting an effective strategy to reform the power sector in Andhra Pradesh and should be viewed not merely from the point of compliance with Bank specified project related covenants.[16] As this was only a load balancing project, expecting to reform the tariff structure for the entire SEB—by a covenant as part of this loan—was too ambitious.[17]

D. Economic and Financial Reevaluation

31. The Mission undertook a detailed assessment of the financial and economic viability of the Project, keeping in view the concerns raised at appraisal and in the PCR. The assumptions and methodology for the analysis were established following a comprehensive desk review and consultations with the operations departments, and considering the data constraints in the field.[18]

32. A comparison of the approaches at appraisal and in the PCR along with the assumptions and details of the estimates of cost and benefits in this evaluation are in Appendix 8. The economic analysis was performed in domestic currency (Indian rupees) at the domestic price numeraire. All benefits and costs were expressed in 1998 constant prices. The economic internal rate of return (EIRR) for the base case, where the technical losses were 23.87 percent, was 16.2 percent. As for the financial performance, the financial internal rate of return (FIRR) for the base case was negative.[19]

33. The sensitivity analysis includes three scenarios to assess the impact of coal, system losses, and agricultural tariff on the economic and financial performance.

34. The sensitivity analysis revealed that a higher EIRR can be achieved, by switching to Talcher coal, and reducing technical losses to 14 percent. Furthermore, the Talcher coal would provide reassurance that the economic least cost alternative is still maintained. In the wake of the successful power sector reforms, SERC will be allowed to set tariffs to enable APSEB to recover costs. Consequently, the Government is expected to provide direct compensation should it decide to subsidize agricultural consumers. The Government's subsidies could be

15 The Andhra Pradesh government informed APSEB that the reform bill permits SERC to set the tariff free from political intervention. Furthermore, the state government will have to compensate APSEB if it wishes to cross-subsidize the agriculture sector. The state government confirmed that specific provision has been kept under the Financial Restructuring Plan already approved by the Government. This restructuring plan includes revenue planned from revision of the tariffs to be prescribed by the SERC as well as provision of a subsidy for a period of 4 to 5 years. Proposed tariff revisions will be discussed in a public hearing before its finalization by the SERC.

16 The TA audit report analyzes the accomplishments under the power sector reform in each state in India. Andhra Pradesh is among the first states to implement reforms. Currently, the Bank is not actively involved in Andhra Pradesh. The Bank's intervention has accelerated the pace of reforms in other states.

17 As for this objective, a more realistic covenant would have been to require APSEB and the state government to reimburse the cost of supply to the power station to ensure efficient plant operation. In hindsight, the Appraisal Mission should have considered that the Project was embedded in a complex institutional environment and not attempted at tariff reforms through one relatively small project.

18 Recent project/program loan documents and PPARs for similar projects in the sector in India and Bangladesh were carefully reviewed.

19 The current level of tariff requires subsidies from the state government amounting to about Rs2,540 million annually to sustain APSEB operation (achieve at least an 8 percent FIRR).

quickly reduced by using Talcher coal, and substantially reduced further by improving system efficiency and increasing the agricultural tariff. Likewise, the shift to Talcher coal resulted in the highest net total benefits to the poor. Moreover, net benefits to poor agricultural users increase when losses are reduced. In fact, the poor can be asked to pay higher tariffs without losing much of the benefits. (The details are summarized in Appendix 8, Tables 1 and 2.)

35. Furthermore, these support the need to directly invest in the transmission and distribution subsectors and further improve the system efficiency.

E. Socioeconomic and Sociocultural Results

36. With the background of a prevailing high power deficit situation, implementation of the Project has definitely yielded positive impacts on the industry sector, especially the heavy industrial plants operating near the Project, which now have additional and a more reliable supply of power. The generation available from the station, located at the tail end of the regional grid has brought a noticeable improvement of the system parameters resulting in enhanced quality of the power supply to already connected consumers.

37. The specific degree and level of development impact on the agriculture sector, however, becomes difficult to assess on account of previous commercial arrangements that have tolerated unmetered power consumption by agricultural users. Measurement of the incremental impact brought about by the project facility is compromised under this existing reality.[20] While the rural electrification program has proceeded through new energization/regularization of existing pumpsets, despite the additional capacity available from the Project, the number of agricultural pumpset connections has only marginally increased from 1990/91 to 1997/98 as shown in Appendix 9.

38. The Project is located in a remote and uninhabited place. There was no resettlement as a result of the Project. The land was acquired after adequate compensation to the landowners as per the assessment made by the revenue authorities.

39. Project authorities undertook common rehabilitation measures oriented toward the neighboring communities. Individual landowners losing 0.405 hectare (ha) equivalent and more were provided employment; 18 were permanently absorbed into the Project. More than 100 persons from neighboring villages were absorbed as permanent O&M staff in the Project from December 1996 onward. In the construction and O&M areas, at least 100 local laborers regularly earn their livelihood from the power station.

40. The project authorities constructed a bridge across the Malyavaram south canal for conveyance to Kalamalla village roads connecting power stations to the nearby villages, drinking water supply arrangements to Kalamalla village, street lighting from power stations to these villages, etc. The roads connecting the Project with Potladurthi, Proddatur via Rameswaram, Chinnaddandluru, Chilamakur, and Muddanur via Kosinepalle are serving the

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[20] The primary reason for this could be attributed to the existing institutional mechanisms characterized by nonremunerative, heavily subsidized tariffs to agricultural consumers, and little incentive for new pumpset users to pay in the environment of inoperative cost recovery schedules prevalent within the agriculture sector as a whole. As a result, institutional efforts at extending rural electrification attempted by APSEB and the Rural Electrification Corporation appear to have been hampered by long-standing practices of avoidance of payment by agricultural users. A rational commercial arrangement through the independent regulatory mechanism, the SERC, would effectively address the situation. APSEB, with assistance from the World Bank, is currently implementing a program to install meters for agricultural users.

transport needs of these villages and connecting hamlets. Moreover, the hospital, school, post office, etc., put up in the project area, which are open to the people belonging to the neighboring villages, have also contributed significantly to improving the lifestyles in these remote as well as disturbed areas.

F. Environmental Impacts and Control

41. The Bank's Appraisal Mission conducted a detailed evaluation of the potential environmental effects of the Project on environmental resources/values. This resulted in identification of specific environmental protection and management requirements. APSEB satisfactorily undertook, as covenanted under the Project Agreement, a comprehensive environmental monitoring program and established an environmental monitoring cell.

42. The PCR reported that the environmental design criteria related to the Project were implemented, and the air and water pollutants are generally maintained within acceptable limits decided by MOEF. The Mission's discussions with Andhra Pradesh Pollution Control Board also confirmed general adherence to the standards.

43. Close scrutiny, however, identified deviations from the emission standards for some pollutants. The level of suspended particulate matter in the stack emission from Unit No. 2 remains beyond the limit due to certain design defects in electrostatic precipitators and improper ash evacuation from electrostatic precipitators hoppers as identified by an analysis of the performance of the ash handling system. Details of stack monitoring data are shown in Appendix 10. The power station has already programmed steps to address the situation, and modifications incorporated in the system have yielded some results. Difficulty in ash evacuation has also contributed to exceeding the maximum limit for the level of total suspended solids (TSS) in plant effluent (Appendix 10). Moreover, on account of seepage of effluent through a section of the ash pond, the TSS of ash pond effluent has exceeded the prescribed limits (Appendix 10). The ash bund surrounding the ash pond has not been constructed with the desired level of compactness resulting in such seepages. Project authorities have taken steps to relocate the ash disposal lines along the bund so that the delivered ash slurry would act as a filter to arrest effluent seepage. The Mission noticed improvements in TSS sampling and expects the modification works to be completed within a few months. Other mitigative measures, such as the dust suppression/extraction system in coal handling areas, dry ash collection, afforestation, etc., are being implemented.

44. It is imperative to continue taking effective and rigorous steps to control pollution especially considering the environmental challenges associated with high ash content domestic coal, the predominant fuel for thermal power generation. In this context, APSEB's present policy not to pursue new coal-fired stations in favor of gas projects as part of its capacity addition program is a welcome step.

G. Gestation and Sustainability

45. The power station began operating at high plant load factors within a few years of commissioning (Appendix 5, Table A5.4). With the successful unbundling of APSEB and achievement of reforms, APSEB can freely choose better quality coal without government intervention, which would contribute to sustaining the current level of operation of the power station. The tariff revisions by the newly created SERC would also solve the financial constraints faced by APSEB.

IV. KEY ISSUES

A. Coal Quality

46. The Bank's Appraisal Report[21] clearly identified that the quality of Singareni coal should be maintained at least at E grade to ensure that the delivered cost is lower than that of imported coal. Therefore, agreement on the required coal quality was incorporated in the Loan Agreement.[22] However, the quality of coal received from Singareni collieries is much inferior, with a higher ash content than envisaged at appraisal (para. 23). This has affected operational performance and posed problems in evacuating the larger quantity of ash. The levels of pollutants were beyond acceptable limits.

47. APSEB displayed strong technical and managerial capabilities along with sincere willingness to comply with environmental pollution control standards. Given the high level of plant load factor, using inferior input would possibly tell upon the equipment life, especially the coal and ash handling equipment, which would be stretched to their limit on a sustained basis. Over and above the higher fuel cost, the negative financial impact in terms of O&M cost, cost of environmental mitigative measures, etc., the choice of Singareni coal has serious implications for the techno-economic viability of the power station.

B. System Losses

48. During the last three years, APSEB could not invest more than an average of 24 percent of total investment to transmission and distribution (against an agreed target of 40 percent) allowing system losses to remain at a high level of 33 percent as claimed by APSEB. As the situation is commonly being evidenced with other SEBs in India, instead of selecting and fixing such target levels in covenants, the Bank should have first assessed the capability of the state government and an enabling environment to enforce policy reforms. An alternative could have been for the Bank to directly finance such projects.

V. CONCLUSIONS

A. Overall Assessment

49. Project formulation and design were consistent with the Bank's operational strategy in the power sector in India. The performance of consultants and contractors was generally satisfactory. Implementation was achieved generally as envisaged (except for delays that occurred due to a fire accident) and resulted in substantial cost savings. The Project achieved a high level of performance within a few months after commissioning. In addition, the Project successfully contributed to institutional development and capacity building in APSEB and the power station, both of which demonstrated strong technical and managerial capabilities along with awareness of environmental concerns. The Project's main objective of improving the reliability of electricity supply has been satisfactorily achieved. The benefits generated by the Project are visible. The EIRR of the Project at more than 16 percent for various scenarios confirms the findings. The Project also generated other unquantified, but substantial socioeconomic benefits. Overall, the Project is rated as generally successful. With the

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[21] R135-89-AR, IN147-97: Appendix 19, para. 17.

[22] Under the Loan Agreement, the Borrower is required to "ensure adequate supply of required quality of coal continuously..." The Borrower is also obliged to make alternative arrangements for better coal from other sources within India or imported from sources outside India.

successful achievement of the reforms—which would allow increasing the tariff without political interventions—APSEB could be expected to achieve a positive FIRR. Keeping in view the environmental concerns, the Andhra Pradesh government should review the policy on the use of poor quality domestic coal, such as Singareni coal. Using better quality coal, for example, Talcher coal, would further ensure the sustainability of the power station at the present level of performance and achieve a competitive cost for delivered power, which would be more crucial as private participants enter the generation subsector after the unbundling of APSEB.

B. Lessons Learned

50. The important lessons learned from the Project are applicable to other SEBs in India and other developing member countries.

51. The use of indigenous coal in power generation adds to the fuel cost and causes environmental degradation because it is transported over a long distance and has a high ash content; it also requires an appropriate ash handling system.

52. While there is a strong need to continue taking effective and consistent steps to control environmental pollution, the possible financial/economic cost implications and environmental impact as reflected in the project's operation reconfirm the Bank's policy of moving away from coal-fired power generation.

53. For advisory TAs with cross-cutting concerns (such as the environment), the Bank should improve coordination with the executing agency and relevant recipient agencies, and undertake follow-up review to ensure effective implementation of the recommendation.

54. The economic and financial reevaluation based on "resource cost savings" for nonincremental benefits demonstrated that poor consumers were actually paying more in the without project scenario than in the with project scenario (Appendix 8, page 3). Furthermore, the sensitivity analysis revealed that the net benefits to the poor can be increased by improving the quality of coal and reducing system losses. Consequently, the tariffs can be raised without reducing the net benefits to the poor. These can be useful in the policy dialogue in future projects.

55. With the power sector reform in India, the SEBs will be able to implement financial restructuring measures aimed at allowing them to perform more on a commercial basis and ensure viability of the project investments. However, this has to be a gradual process of restructuring and subsequent privatization rather than through an attempt of quick tariff reform through project covenants.

C. Recommendations for the Future

1. For the Bank

56. The Bank should support the power sector reform in India and participate in policy dialogue with other funding agencies and concerned government agencies to accelerate the pace of reforms, especially in the states selected for the Bank's assistance.

57. The high level of system losses prevailing in the transmission and distribution network of APSEB is a major concern. The Bank's funding strategy should focus on achieving actual reduction of losses effectively linked with project financing.

58. The Bank should undertake further reviews of compliance with unmet covenants and monitor environmental protection issues that may require follow-up actions by APSEB and MOEF.

2. For the Borrower

59. The Andhra Pradesh government is advised to seriously consider using better quality coal, such as the Talcher coal, to sustain the high level of performance of the power station, as well as reduce the environmental impact.

60. The Andhra Pradesh government should first ensure the financial sustainability of the distribution company of APSEB, before any attempts are made to privatize.

APPENDIXES

PROJECT FRAMEWORK ANALYSIS

Design/Summary	Targets	Monitoring Mechanism	Risks/Assumptions	Actual Outcomes
1. Sectoral Goals				
• Enhance power supply by substituting indigenous coal for petroleum commensurate with economic growth and social need.	• Accelerate generation capacity addition program to address power shortage.	• Benefit monitoring and evaluation (BME). • Review missions and project completion report.		• Generating capacity has increased from 53,000 megawatts (MW) in 1988 to 84,912 MW in 1997, by 60 percent in the last decade.
	• Improve power use efficiency and resource mobilization.			• Substantial investment of about Rs38,000 million or in 7th Plan to Rs79,000 million or in 8th Plan have been made. But potential demand continues to exceed supply by 10 percent annually.
	• Substitute indigenous energy resources for petroleum wherever economically feasible.		• Indigenous coal will continue to be a major energy source in India.	• Share of petroleum products in the imports decreased from 25.2 percent during 1985 to 24.6 percent in 1996.
2. Project Output				
• Improve power supply in southern region (component of least cost generation program for the region) to meet about 20 percent of supply requirement of the Andhra Pradesh State Electricity Board (APSEB).	• Average annual net electricity output at about 2,600 gigawatt-hours (GWh).	• BME • Project review missions	• The demand for electricity in southern region is projected to exceed supply by a wide margin.	• Generation of 2,436 GWh and 2,982 GWh was achieved during FY1997 and FY1998, respectively.
• Establish more balanced Andhra Pradesh Power System Configuration, reduce system losses, and increase supply reliability.	• From FY1991 until system losses are reduced to 14 percent, APSEB will allocate 40 percent of investment to transmission and distribution (T&D).	• BME • Project review missions • Project completion reports	• Andhra Pradesh government and APSEB's assurance	• Reduction of system losses and investment to T&D at target levels have not been achieved. System losses remain higher than 33 percent.

Design/Summary	Targets	Monitoring Mechanism	Risks/Assumptions	Actual Outcomes
• Utilize coal mined at the state-owned Singareni collieries, with calorific value around 3800 kilocalories/kilogram (kcal/kg) and ash content at 45-50 percent.	• Adequate and continuous coal supply of design quality will be ensured.	• BME • Project review missions • Project completion reports		Actual coal quality received from Singareni collieries has been much inferior than designed. The calorific value and ash content are 2,300 kcal/kg and 60 percent, respectively.
• Generate adequate internal resources to invest in operational efficiency improvement.	• State government/APSEB will implement operational and financial action plan.	• BME • Project review missions • Project completion reports		• Tariff adjustment has not been adequate to achieve targeted self-financing ratio.
	• Necessary tariff adjustment will generate at least a 20 percent self-financing ratio and debt service ratio of at least 1.2 times each year.			
• Ensure environmental acceptability through compliance with environmental protection and management requirements.	• Air and water pollutants will be contained within acceptable limits established by the Government of India.	• Environmental Monitoring Cell of APSEB • Review by Andhra Pradesh Pollution Control Board • Project review mission • Project completion report	• APSEB will implement, operate, and maintain project facilities in strict conformity with applicable local environmental standards.	• Actual usage of very high ash content coal (50 to 60 percent) has resulted in pollutant levels much beyond established limits.
3. Project Activities				
• Detailed engineering evaluation of bids and procurement, construction, and supervision, including technical assistance for operational improvement support and environment management for coal-fired generation.	• Project costs (civil works, plant and equipment, consulting services, etc.): $610.3 million	• Engagement of consultant/ contractor • Consultant supervision of contractors	• There are no significant risks for the Project.	• Actual project costs: $452.3 million (26 percent less than appraisal estimate).

Design/Summary	Targets	Monitoring Mechanism	Risks/Assumptions	Actual Outcomes
• Land purchase, equipment, civil works, erection, testing, and commissioning.	• Project implementation scheduled by December 1993. • Financing Plan Bank financing - $230 million Government of India - $258 million APSEB - $122.1 million	• Bank review missions • Bank project completion reports • Bank project performance audit reports Quarterly progress reports and audited accounting reports by the Executing Agency.	The government will ensure an adequate supply of required quality of coal on a continuous basis.	• Project delayed by 13 months due to fire accident. • Implemented without deviation from designed scope. • Able to achieve high level of performance. • Financing: Bank - $178.2 million Government financed - $136.8 million APSEB financed - $137.3 million
• Train for the Executing Agency personnel.	Train personnel in key areas under TA No. 1228.			• Training programs were effectively utilized by APSEB personnel.
• Formulate measures for effective demand management, optimize power system operation, and develop an integrated data processing system.	• Technical assistance on APSEB's Operational Improvement Support (TA No. 1228).	• Consultant's report • Technical assistance Performance audit report • Project completion report		• Recommendations were satisfactorily implemented.
• Prepare an environmental master plan, adoption of the Ministry of Environment and Forest (MOEF).	• Technical assistance on National Program for Environmental Master Plan (TA No. 1229).			• No ownership; recommendations were not incorporated by MOEF.

PROJECT COSTS

A. Cost Breakdown by Project Component (Rs million)

	Appraisal Estimate			Actual		
Component	Foreign Exchange	Local Currency	Total Cost	Foreign Exchange	Local Currency	Total Cost
1. Power Station						
a. Civil Works						
Preliminary works	0.00	1.79	1.79	0.00	0.32	0.32
Land and land development	0.00	3.18	3.18	0.00	75.86	75.86
Civil Works: Colony	0.00	104.35	104.35	0.00	372.02	372.02
Civil Works: Power station	0.00	752.49	752.49	0.00	1,581.80	1,581.80
Subtotal (a)	**0.00**	**861.81**	**861.81**	**0.00**	**2,030.00**	**2,030.00**
b. Mechanical Equipment						
Turbine generator	811.71	0.00	811.71	1,452.65	0.00	1,452.65
Steam generator	1,013.89	0.00	1,013.89	1,914.88	0.00	1,914.88
Instrument and controls	113.39	0.00	113.39	217.88	0.00	217.88
Coal and ash handling	286.41	0.00	286.41	364.84	268.20	633.04
Water treatment plant	0.00	148.65	148.65	0.00	71.80	71.80
Cooling water pumps	16.95	0.00	16.95	62.81	0.00	62.81
High and low pressure piping and valves	0.00	118.46	118.46	0.00	54.00	54.00
Other mechanical equipment	0.00	140.84	140.84	0.00	142.40	142.40
Subtotal (b)	**2,242.35**	**407.95**	**2,650.30**	**4,013.06**	**536.40**	**4,549.46**
c. Electrical Equipment						
Power transformers	47.38	0.00	47.38	173.65	108.00	281.65
Switchgear equipment	56.66	0.00	56.66	143.65	0.00	143.65
Control and relay panels	3.26	4.06	7.32	0.00	0.00	0.00
Other electrical equipment	0.00	288.06	288.06	0.00	236.80	236.80
Subtotal (c)	**107.30**	**292.12**	**399.42**	**317.30**	**344.80**	**662.10**
d. Miscellaneous						
Establishment	0.00	280.85	280.85	0.00	210.00	210.00
Training of O&M staff	0.00	2.17	2.17	0.00	2.00	2.00
Tools	0.00	79.78	79.78	0.00	7.00	7.00
Audit and account	0.00	56.17	56.17	0.00	20.00	20.00
Spares	75.03	21.01	96.04	0.00	0.00	0.00
Erection, testing and commissioning	250.44	69.70	320.14	0.00	451.30	451.30
Freight and insurance	257.39	98.93	356.32	0.00	133.50	133.50
Consultancy services	0.00	16.30	16.30	0.00	16.30	16.30
Taxes and duties	0.00	781.02	781.02	0.00	267.10	267.10
Subtotal (d)	**582.86**	**1,405.93**	**1,988.79**	**0.00**	**1,107.20**	**1,107.20**
Subtotal (1)	**2,932.51**	**2,967.81**	**5,900.32**	**4,330.36**	**4,018.40**	**8,348.76**

O&M = operation and maintenance.

Component	Appraisal Estimate Foreign Exchange	Appraisal Estimate Local Currency	Appraisal Estimate Total Cost	Actual Foreign Exchange	Actual Local Currency	Actual Total Cost
2. Transmission Lines						
(220 kilovolts double circuit)						
Civil works	0.00	22.15	22.15	0.00	22.00	22.00
Line materials	151.63	0.00	151.63	177.63	0.00	177.63
Substation equipment	0.00	80.17	80.17	0.00	0.00	0.00
PLCC equipment	0.00	2.54	2.54	0.00	3.00	3.00
Erection	0.00	41.23	41.23	0.00	40.00	40.00
Spares	0.00	3.29	3.29	0.00	1.80	1.80
Miscellaneous	0.00	14.30	14.30	0.00	15.00	15.00
Freight & insurance	0.00	17.38	17.38	0.00	20.00	20.00
Establishment	0.00	41.65	41.65	0.00	40.00	40.00
Taxes and duties	0.00	51.39	51.39	0.00	10.00	10.00
Subtotal (2)	**151.63**	**274.10**	**425.73**	**177.63**	**151.80**	**329.43**
Subtotal (1 & 2)	**3,084.14**	**3,241.91**	**6,326.05**	**4,507.99**	**4,170.20**	**8,678.19**
3. Contingencies						
Physical contingencies	61.68	139.91	201.59	0.00	165.00	165.00
Price escalation	524.19	1,053.05	1,577.24	0.00	0.00	0.00
Subtotal (3)	**585.87**	**1,192.96**	**1,778.83**	**0.00**	**165.00**	**165.00**
	3,670.01	**4,434.87**	**8,104.88**	**4,507.99**	**4,335.20**	**8,843.19**
($ million equivalent)	260.55	349.68	610.23	178.20	274.14	452.34

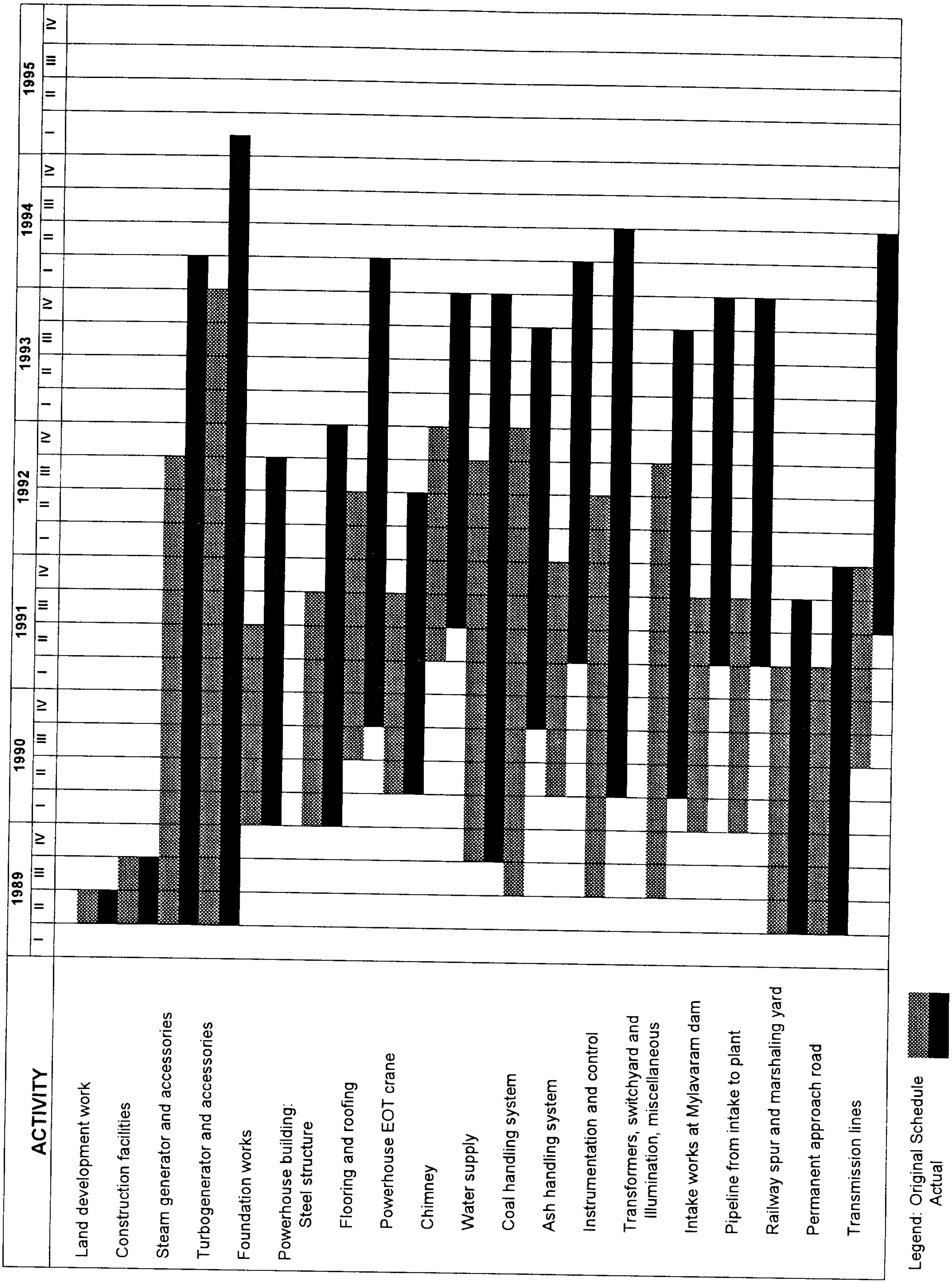
PLCC = Power Line Communication Carrier.

B. Financing Plan ($ million)

Item	Appraisal Estimate Foreign Exchange	Appraisal Estimate Local Currency	Appraisal Estimate Total Cost	Actual Foreign Exchange	Actual Local Currency	Actual Total Cost
a. Implementation Costs						
Borrower-financed	0.00	122.10	122.10	0.00	137.34	137.34
Bank-financed	225.00	0.00	225.00	173.20	0.00	173.20
Government-financed	0.20	150.00	150.20	0.00	50.00	50.00
Total	**225.20**	**272.10**	**497.30**	**173.20**	**187.34**	**360.54**
b. IDC Costs						
Borrower-financed	0.00	0.00	0.00	0.00	0.00	0.00
Bank-financed	5.00	0.00	5.00	5.00	0.00	5.00
Government-financed	30.40	77.60	108.00	0.00	86.80	86.80
Total	**35.40**	**77.60**	**113.00**	**5.00**	**86.80**	**91.80**

IDC = interest during construction.

IMPLEMENTATION SCHEDULE



STATUS OF COMPLIANCE WITH KEY CONDITIONS/COVENANTS

Covenant[a]	Reference to Loan Document[b]	Status at Project Completion as Reported in PCR	Status at Postevaluation
Coal Supplies			
1. The Borrower shall ensure that an adequate supply of required quality of coal is continuously made available. Alternative arrangements include coal from other sources within India or importation from outside India.	LA, Schedule 4	Not reported.	Not complied with. Coal provided from Singareni mines is below G grade instead of the E grade required according to design.
Project Implementation			
2. APSEB shall implement its "Operational and Financial Action Plan" and shall take all actions necessary to achieve its key objectives by the set target dates. The Action Plan will be reviewed annually and updated as necessary.	PA, Schedule 3, para. 4	Complied with. The Plan has been reviewed with the assistance of consultants under a Bank-financed technical assistance (TA).	Actions initiated in the areas of fund mobilization, demand-side management, reduction of system losses and rationalization of tariff areas, but specific targets have not been achieved.
Financial, Accounting and Related Matters			
3. APSEB shall allocate at least 40 percent of its annual capital expenditures to transmission and distribution facilities commencing FY1991 until line losses have been reduced to 14 percent of total net generation and purchases.	PA, Schedule 3, para. 5(a)	Being complied with. FY1996 system losses stood at 17.1 percent.	Percentage of annual investment to transmission and distribution during last 3 years covering FY1996 to FY1998 amounts to 27, 17, and 31 percent against covenanted investment of 40 percent every year. Reduction in system losses also has not been achieved. Until FY1996, it was suppressed and shown as 18.8 percent as against 17.1 percent noted in the project completion report. This was due to a large proportion of commercial loss, i.e., theft of energy was included as unmetered agricultural consumption. Based on energy audit conducted, APSEB admitted system losses to be in the range of about 33 percent since FY1997.
4. APSEB will take measures to become self-financing for future investment.	PA, Schedule 3, para. 5(b)	Not reported.	Not complied with. APSEB is solely dependent on subventions from Andhra Pradesh government.
5. Maintain net revenues for each fiscal year at least 1.2 times the debt service requirement.	PA, Schedule 3, para. 6(a).	Not complied with. 0.90 times in FY1996.	Not complied with. Audited financial performance shows since FY1995 the debt service ratio was always below 1.0.

Covenant[a]		Reference to Loan Document[b]	Status at Project Completion as Reported in PCR	Status at Postevaluation
6.	APSEB shall maintain tariffs at levels sufficient to achieve annually 20 percent self-financing in the period FY1991 to FY1995 and 25 percent in the period FY1996 to FY2000.	PA, Schedule 3, para. 7	Complied with. In FY1996 stood at 25.1 percent.	Not complied with. Until FY1998 self-financing ratios fluctuated erratically between –175.6 to 117.4.
7.	APSEB shall ensure that environmental standards are met by Project facilities.	PA, Schedule 3, para. 11(b)	Not reported.	Not complied with. Pollutant levels are much beyond acceptable limits (due to the use of inferior coal).
8.	APSEB shall meet local occupational safety standards.	PA, Schedule 3, para. 12	Not reported.	Not complied with. Despite the unfortunate fire incident, fire- fighting equipment is not yet fully installed.

a Covenants that were not satisfactorily met at operations evaluation.
b LA = Loan Agreement; PA = Project Agreement.

OPERATIONAL INFORMATION OF ANDHRA PRADESH STATE ELECTRICITY BOARD (APSEB)

Table A5.1: APSEB at a Glance As of March 1997

Item	APSEB	All India Average
1. Installed capacity (MW) (State + Private + Central)	6,764.00	84.91
2. Plant + Load factor (%)	78.10	64.10
3. Gross generation (GWh)	33,129	394,488
4. Auxiliary consumption (%)	6.33	6.94
5. System losses (%)	18.80[a]	20.60
6. Sale of power (GWh)	26,014.00	298,392.00
7. Share of agriculture in total sale (%)	48.40	32.80
8. Energization of pump sets (cumulative)	1,737,046	11,471,669
9. Per capita consumption (kWh) (Until March 1996)	369	335

GWh = gigawatt-hour, kWh = kilowatt-hour, MW = megawatt.

[a] Actual losses were at 33 percent in FY1998.

Table A5.2: APSEB's Financial Performance (Without Subsidies) (Rs million)

Item	FY1997	FY1998
Revenue from Sales	3,286	3,990
Cost of Sales	3,206	4,309
Net Income	**80.00**	**(319.00)**
Other Income	272.00	373.00
Depreciation	(419.00)	(434.00)
Finance Charges	(654.00)	(753.00)
Total Other Costs	**(801.00)**	**(814.00)**
Net Profit/(Loss)	**(721.00)**	**(1,133.00)**

Table A5.3: Unit Price Breakdown (Rs/kWh)

Item	FY1997	FY1998
Average Revenue Rate of Sales	1.560	1.666
Average Cost of Sales	1.521	1.800
Other Costs	0.380	0.340
Total (Breakeven Tariff)	1.901	2.140
Margin	(0.341)	(0.474)

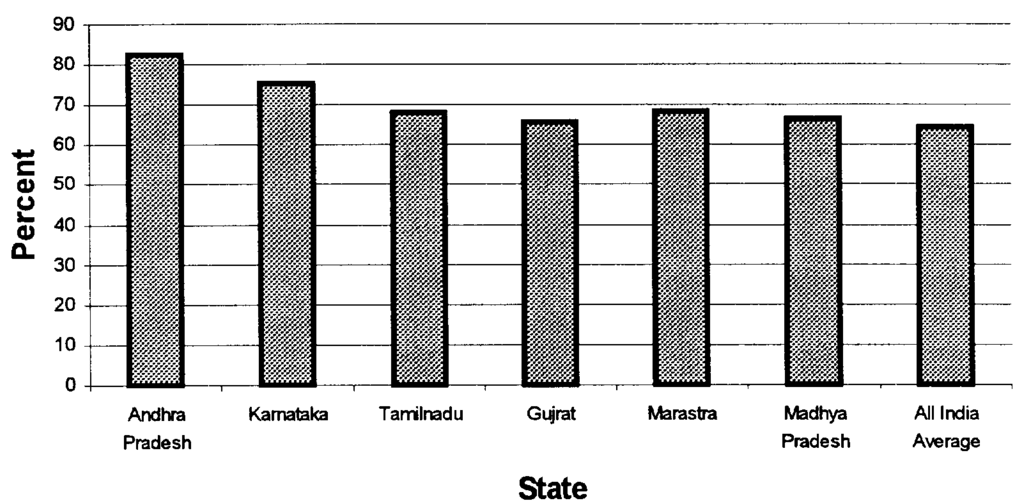
kWh = kilowatt-hour.

Table A5.4: Project Operational Performance

	FY1995	FY1996	FY1997	Nov 1998
A. Generation Target (GWh)	—	3,125	3,020	230
B. Generation Achieved (GWh)	1,327.46	2,436.54	2,982.57	289.83
Availability Factor (%)	88.31	80.87	91.1	97.07
Load Factor (%)	80.23	81.93	88.99	98.74
Plant Load Factor (%)	70.85	66.22	81.07	95.84
Special Coal Consumption (Ml/kWh)	0.84	0.79	0.744	0.77
Special Oil Consumption (kg/kWh)	7.27	5.13	1.389	0.983
Auxiliary Power Consumption (%)	12.12	10.70	10.48	9.99
Water Consumption (MT)	45,690	474,246	431,491	27,269
Water Consumption (%)	3.77	4.92	3.918	2.83
Heat Rate (kcal/kWh)	3,365	2,733	2,506	2,473
Design – Heat Rate 2251 kcal/kWh				
Calorific Value 3686 kcal/kg				

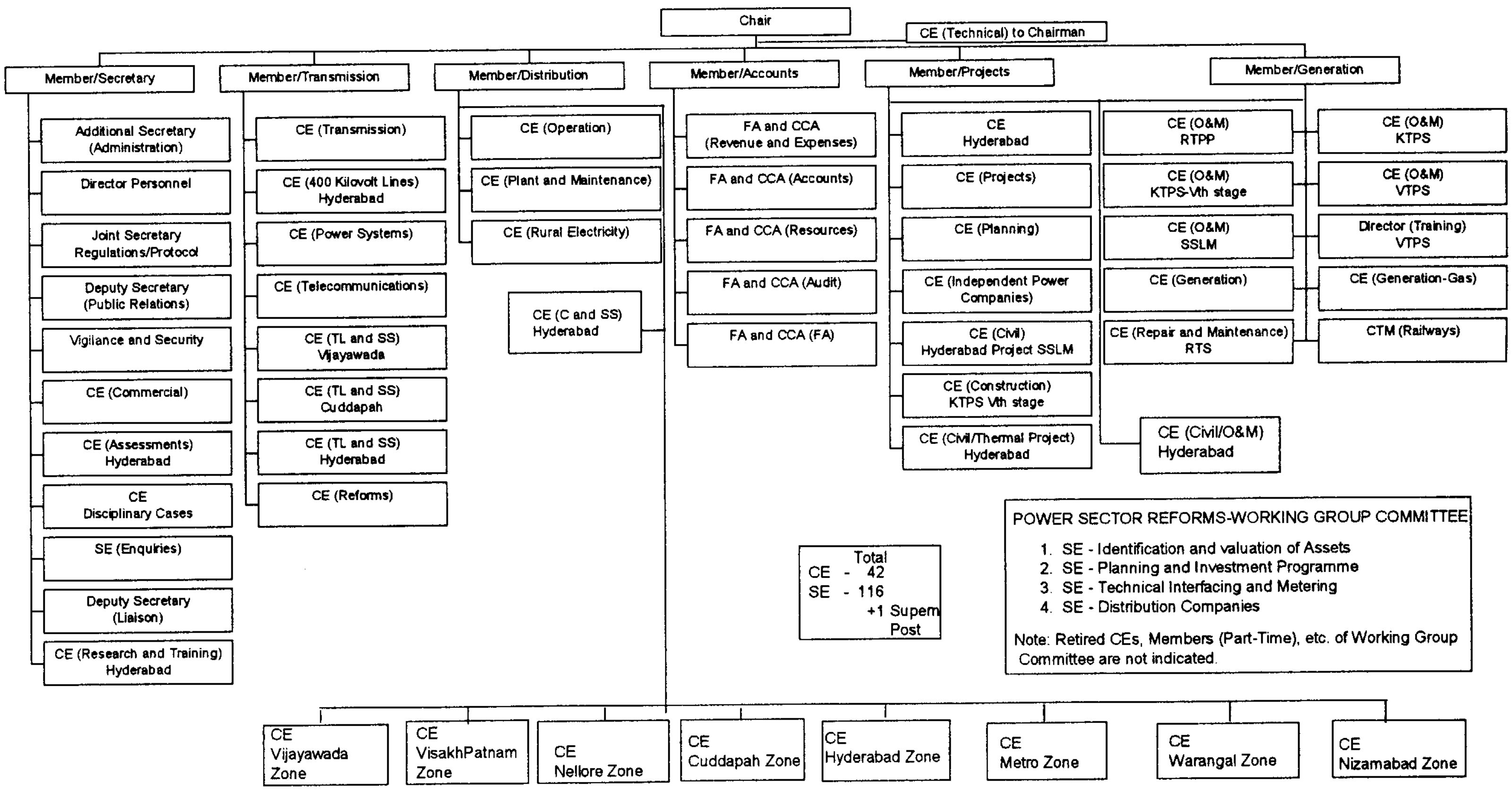
GWh = gigawatt-hour, kcal = kilocalorie, kg = kilogram, kWh = kilowatt-hour, Ml = milliliter, MT = metric ton.

Figure A5.1: Comparison of Performance of APSEB with Other Major State Electricity Boards and Against All India Average



Plant Load Factor (Percent) FY1997

ORGANIZATION CHART OF ANDHRA PRADESH STATE ELECTRICITY BOARD



CE = Chief Engineer, C and SS = Consumers and Sales, FA = Finance Accountant, FA and CCA = Finance Accountant and Chief Controller of Accounts, O&M = operation and maintenance, RTPP = Rayalaseema Thermal Power Project, SE = Superintendent Engineer, SS = substations, TL = transmission lines.
CTM, KTPS, RTS, SSLM, VTPS = acronyms of other power stations in APSEB.

FINANCIAL STATEMENT AND PERFORMANCE INDICATORS (FY1992-FY1998)

Table A7.1: Income Statement

Particulars	Actuals FY1992	FY1993	FY1994	FY1995	FY1996	FY1997	FY1998
Net generation (GWh)	17,284.00	16,914.00	18,242.00	19,500.00	20,417.00	23,099.00	24,476.00
Imports	5,010.00	7,194.00	8,249.00	9,129.00	8,732.00	8,501.00	11,187.00
APCPCL power wheeled thro APSYS	256.00	306.00	372.00	338.00	427.00	492.00	694.00
Total available energy	22,550.00	24,414.00	26,863.00	28,967.00	29,576.00	32,092.00	36,357.00
Losses (%)	19.30	19.20	19.00	18.94	18.80	32.80	32.20
Sale of electricity (GWh)	18,188.00	19,386.00	21,346.00	23,095.00	23,562.00	21,068.00	23,944.00
Average rate (Paise/kWh)							
Increase in average rate (%)	82.11	94.28	98.62	92.89	97.12	155.99	166.65
Revenue (Rs10 million):							
Sale of power	1,493.50	1,827.80	2,105.20	2,145.30	2,288.30	3,286.40	3,990.20
Other receipts	70.30	107.60	197.90	130.83	154.90	272.20	373.20
Total revenue	1,563.80	1,935.40	2,303.10	2,276.13	2,443.20	3,558.60	4,363.40
Electricity duty							
Revenue subsidies and grants	69.56	0.10	0.10	944.30	1,259.20	850.40	1,255.90
Additional revenue to achieve 3% ROR							
Total operating revenue	**1,633.36**	**1,935.50**	**2,303.20**	**3,220.43**	**3,702.40**	**4,409.00**	**5,619.30**
Expenses:							
Generation of power (fuel)	375.30	483.90	608.80	940.29	1,071.30	1,319.70	1,627.40
Purchase of power	413.60	591.40	742.70	719.09	982.70	1,049.40	1,767.50
Repairs and maintenance (O&M)	78.50	103.00	122.30	132.28	136.80	187.40	204.20
Employees costs	200.70	222.60	246.60	298.73	342.90	395.10	461.40
Administrative and general charges	47.90	58.50	67.70	114.40	72.60	151.30	177.60
Other expenses	21.00	1.00	2.20	21.60	1.80	20.20	2.72
Electricity duty	40.00	42.10	51.50	65.23	59.70	68.14	73.70
Prior period expenses (net)	5.20	(106.70)	(99.90)	18.95	(138.80)	14.75	(5.00)
Total operating expenses	**1,182.20**	**1,395.80**	**1,741.90**	**2,310.57**	**2,529.00**	**3,205.99**	**4,309.52**
Net income before interest and depreciation	451.16	539.70	561.30	909.86	1,173.40	1,203.01	1,309.78
Depreciation	115.30	146.80	172.30	286.82	348.20	419.00	434.70
Net income before interest and after depreciation	335.86	392.90	389.00	623.04	825.20	784.01	875.08
Interest Expenses:							
Total interest	302.60	397.10	411.70	660.31	821.30	872.50	994.80
Less: interest capitalized	51.10	83.70	109.70	124.51	126.70	217.70	241.30
Interest charged to operation	251.50	313.40	302.00	535.80	694.60	654.80	753.50
Net income	**84.36**	**79.50**	**87.00**	**87.24**	**130.60**	**129.21**	**121.58**
Net fixed assets at the beginning of the year	2,260.57	2,436.90	2,725.70	2,908.20	4,353.03	4,306.49	4,051.80
ROR as per GOI Act	3.73	3.26	3.19	3.00	3.00	3.00	3.00
ROR without subsidy = (Net income - subsidies)/Net fixed asset	0.01	0.03	0.03	(0.29)	(0.26)	(0.17)	(0.28)

Table A7.2: Balance Sheet

Particulars	Actuals						
	FY1992	FY1993	FY1994	FY1995	FY1996	FY1997	FY1998
Current Assets:							
Cash and bank balance	(6.80)	(93.00)	42.60	25.80	(1.30)	52.10	67.90
Accounts receivable (electricity dues)	265.10	345.80	436.70	456.90	456.80	566.70	732.00
Accrued revenue	163.20	242.20	361.30	357.20	320.60	433.20	491.20
Inventories	231.70	317.00	302.10	338.60	388.60	464.40	601.00
Capital stores	100.26	112.50	105.00	132.70	135.90	119.20	95.40
Government subsidy (net)				944.20	1,259.20	850.50	1,256.10
Others	317.80	425.70	501.70	652.60	895.00	1,130.10	2,462.00
Total current assets	**1,071.26**	**1,350.20**	**1,749.40**	**2,908.00**	**3,454.80**	**3,616.20**	**5,705.60**
Fixed Assets:							
Gross fixed assets	3,500.50	3,998.30	4,402.70	6,190.60	6,524.10	6,847.90	7,884.70
Less: Accumulated depreciation	846.10	993.60	1,159.60	1,425.80	1,729.70	2,143.50	2,578.80
Net fixed assets	2,654.40	3,004.70	3,243.10	4,764.80	4,794.40	4,704.40	5,305.90
Works-in-progress	1,229.30	1,696.90	2,304.90	1,683.60	2,795.10	3,513.50	3,086.10
Total fixed assets	**3,883.70**	**4,701.60**	**5,548.00**	**6,448.40**	**7,589.50**	**8,217.90**	**8,392.00**
Total assets	**4,954.96**	**6,051.80**	**7,297.40**	**9,356.40**	**11,044.30**	**11,834.10**	**14,097.60**
Current Liabilities:							
Accounts payable	578.30	728.60	723.50	921.40	1,817.90	2,507.60	3,620.60
Accrued interest	12.20	15.10	(156.60)	(87.90)	(0.50)	195.70	328.80
Bank overdraft	23.30	0.60		93.40	197.40	212.10	206.80
Current portion of term debt	168.00	236.90	414.90	685.50	768.60	1,121.30	572.60
Deposits and retentions	95.30	111.60	148.50	179.10	322.70	428.70	467.00
Security deposits (from consumers)	282.10	342.40	429.40	490.90	547.20	668.40	747.80
Others	124.00	160.30	170.70	252.90	265.90	537.40	595.00
Total current liabilities	**1,283.20**	**1,595.50**	**1,730.40**	**2,535.30**	**3,919.20**	**5,671.20**	**6,538.60**
Long-term debt	1,319.90	1,711.54	2,381.14	3,293.40	4,036.60	2,964.79	3,796.16
Provident and pension funds	159.80	178.20	193.70	213.40	243.70	244.60	257.40
Equity and gap advances							
State government equity			908.10	908.10	1,321.10	1,321.10	1,321.14
Perpetual loan	1,598.70	1,830.30	1,201.80	1,357.10	251.00	58.40	342.40
Grants (capital)	30.20	32.10	35.20	37.90	54.80	62.20	68.40
Consumers contribution	217.50	279.00	334.90	411.80	487.90	652.60	792.80
Reserves and surplus	345.66	425.16	512.16	599.40	730.00	859.21	980.70
Total equity	**2,192.06**	**2,566.56**	**2,992.16**	**3,314.30**	**2,844.80**	**2,953.51**	**3,505.44**
Total equity and liabilities	**4,954.96**	**6,051.80**	**7,297.40**	**9,356.40**	**11,044.30**	**11,834.10**	**14,097.60**

Table A7.3: Sources and Applications

Particulars	FY1992	FY1993	FY1994	FY1995	FY1996	FY1997	FY1998
	Actuals						
SOURCES							
Internal resources:							
Operating income	335.86	392.90	389.00	623.04	825.20	784.01	875.08
Depreciation	121.77	147.50	166.00	266.20	303.90	413.80	435.30
Grants	2.40	1.90	3.10	2.70	16.90	7.40	6.20
Consumers contributions	60.20	61.50	55.90	76.90	76.10	164.70	140.20
Total internal resource	**520.23**	**603.80**	**614.00**	**968.84**	**1,222.10**	**1,369.91**	**1,456.78**
External sources:							
Equity from state government			908.10	-	413.00	-	0.04
Perpetual loans from state government	208.42	231.60	(628.50)	155.30	(1,106.10)	(192.60)	284.00
Long-term loans	376.59	628.54	1,084.50	1,597.76	1,511.80	49.49	1,403.97
Provident and pension fund	18.20	18.40	15.50	19.70	30.30	0.90	12.80
Total external resource	**603.21**	**878.54**	**1,379.60**	**1,772.76**	**849.00**	**(142.21)**	**1,700.81**
Total sources	**1,123.44**	**1,482.34**	**1,993.60**	**2,741.60**	**2,071.10**	**1,227.70**	**3,157.59**
APPLICATIONS							
Investments:							
Capital investment							
Capital expenditure	730.80	881.70	902.70	1,042.09	1,318.30	824.50	368.10
Interest during construction	51.10	83.70	109.70	124.51	126.70	217.70	241.30
Total investment	**781.90**	**965.40**	**1,012.40**	**1,166.60**	**1,445.00**	**1,042.20**	**609.40**
Debt Services:							
Interest charged to operation	251.50	313.40	302.00	535.80	694.60	654.80	753.50
Long-term debt (repayment)	128.70	168.00	236.90	414.90	685.50	768.60	1,121.30
Total debt service	**380.20**	**481.40**	**538.90**	**950.70**	**1,380.10**	**1,423.40**	**1,874.80**
Noncash working capital	(44.34)	99.04	306.10	734.50	(622.90)	(1,276.60)	652.20
Cash balances	5.68	(63.50)	136.20	(110.20)	(131.10)	38.70	21.10
Working capital total	**(38.66)**	**35.54**	**442.30**	**624.30**	**(754.00)**	**(1,237.90)**	**673.30**
Total applications	**1,123.44**	**1,482.34**	**1,993.60**	**2,741.60**	**2,071.10**	**1,227.70**	**3,157.50**

Table A7.4: Ratios

Particulars		Actuals FY1992	FY1993	FY1994	FY1995	FY1996	FY1997	FY1998
Self-financing ratio								
Annual (1)	percent	23.58	2.42	(22.82)	(61.41)	32.17	117.36	(175.62)
3-year average (2)	percent	31.66	3.54	(31.80)	(82.29)	56.08	167.65	(250.88)
Debt service coverage (3)	-	1.37	1.25	1.14	1.02	0.89	0.96	0.78
Debt-Equity (4)	-	0.60	0.67	0.80	0.99	1.42	1.00	1.08
Operating ratio (5)	-	0.72	0.72	0.76	0.72	0.68	0.73	0.77
Debt % of Debt + Equity (6)	percent	40.30	42.41	46.25	51.41	60.07	52.08	53.63
Current ratio (7)		0.83	0.85	1.01	1.15	0.88	0.64	0.87

(1) Internal sources less Total debt service and Noncash working capital divided by Total investment.

(2) Average ratio calculated using current years total Internal sources and average of the previous, current, and the succeeding years Total investment.

(3) Total internal sources divided by Total debt service.

(4) Long-term debt divided by Total equity.

(5) Operating expenses divided by Operating revenue.

(6) Long-term debt x 100 divided by Long-term debt plus Total equity.

(7) Current assets divided by Current liabilities.

Table A7.5: Performance Indicators

Particulars	1992	1993	1994	1995	1996	1997	1998
ROR on Net fixed assets (%)	3.7	3.3	3.2	3	3	3	3
ROR on Equity (%)	3.8	3.1	2.9	2.6	4.6	4.3	3.4
Debt service coverage ratio	1.4	1.3	1.1	1	0.9	1	0.8
Average revenue rate (Rs/kWh)	0.821	0.043	0.986	0.929	0.971	1.56	1.666

GWh = gigawatt-hour, kWh = kilowatt-hour.

APCPCL, APSYS = full expansion not available, GOI = Government of India, O&M = operation and maintenance, ROR = Rate of return.

ECONOMIC AND FINANCIAL REEVALUATION

A. General Methodology

1. The assessment of the financial and economic viability of the Project was performed by comparing the without project and with project situations. All the costs and revenues/benefits were expressed in constant 1998 prices using the World Bank's manufacturers' unit value index for traded items and the gross domestic product deflator for the nontraded items. The economic analysis was undertaken using a common basis of measuring project costs and benefits at the domestic price level expressed in rupees. The shadow exchange rate factor of 1.11 was therefore applied to all the tradable project outputs and inputs that were valued at the border price equivalent. Other nontradable outputs and inputs that were measured at domestic market price values were left unadjusted. Domestic labor was not shadow priced.

B. Economic and Financial Costs

2. Price contingencies and interest during construction were excluded from the total project cost for purposes of the financial analysis. The economic capital cost, on the other hand, was estimated based on the plant's actual financial costs (excluding taxes, duties, and general price contingencies) broken down into tradable and nontradable, for both foreign exchange items as well as local goods and services. The World Bank's Commodity Price Forecasts were used as the bench mark world price for coal, and then adjusted on the basis of quality. The economic fuel cost was based on the free-on-board price of coal, converted into domestic currency using the prevailing exchange rate plus internal transport cost. The operation and maintenance cost, estimated at 27 paisa per kilowatt-hour (kWh) of sales, included the cost of water, repairs, salaries/wages, and other administrative charges. These costs were measured in domestic market price values and were left unadjusted for the economic analysis.

C. Valuation of Project Output

3. For the financial analysis, sales output was estimated using the actual generation of the plant, adjusted for auxiliary consumption and total systems losses. The revenues from incremental sales were valued in terms of the actual average tariff (rupees/kWh) for each of the four major categories of consumers (agriculture, domestic, commercial, and industry), expressed in constant 1998 prices.

4. Given the huge existing demand and supply gap in the Andrah Pradesh State Electricity Board's (APSEB) area of influence, the quantification of benefits for the economic analysis was based on the assumption that the project output fully displaced nonincremental demand and the benefits were valued in terms of resource cost savings. The valuation of benefits was undertaken in two parts. First, for each of the major consumer categories, the fuel substitution shares of the incremental electricity were estimated. Second, electricity consumption that is replacing the use of alternative energy was valued in terms of the cost saved by using electricity instead of the alternative energy sources. The alternative sources of energy used in the analysis included (i) inverters, kerosene lamps, and kerosene sets for domestic users, (ii) small diesel set for commercial users, (iii) diesel irrigation pumps for the agriculture sector, and (iv) captive power plants for the industry sector. The economic benefits for industrial consumers were valued at the economic price of electricity produced by captive power plants less the tariff

charged for the sector.[1] The economic price of the captive power was estimated based on actual data received from the state electricity board and captive power users as well as other published data/studies. For the agriculture sector, a comparison of the economic cost of electricity versus diesel irrigation was undertaken. For the commercial users, the difference between the economic cost of electricity using small diesel sets and the prevailing tariff charged for the sector was used.

D. Results of the Financial and Economic Reevaluation

5. The financial internal rate of return (FIRR) was not estimated as the base case net present value (assuming an 8 percent weighted cost of capital) was negative. While the state electricity board admitted to not being able to collect payments from the farmers, the present estimate included revenues from the agriculture sector. Otherwise, the base case FIRR would have been much lower. In contrast, both the appraisal and project completion reports presented positive results. Following the same methodology applied at postevaluation, the estimated FIRRs at appraisal and completion were 3 and 7.2 percent, respectively. The projected average tariff revenue of Rs0.86/kWh was used at the time of appraisal, and the prevailing average tariff revenue of Rs1.03/kWh at the time of project completion was used in the project completion report. The major factors responsible for the higher estimates at project appraisal and completion were the overoptimistic estimates for systems losses (resulting in higher sales volume), and the very low fuel cost estimates arising from expected higher quality coal combined with lower coal prices and transport charges. Similarly, the estimated base case economic internal rate of return (EIRR) of 16.2 percent, was lower when compared with the estimates at project appraisal and completion of 20 and 24.1 percent, respectively.

E. Sensitivity Analyses

6. The calculation of the base case FIRR and EIRR used the most likely values of the parameters incorporated in the cost and benefit streams. Considering the difficulties in predicting future values and uncertainty about project results given different values of such parameters, an assessment of the effects of changing the value of one or more selected variables and the resulting change in the net present value (NPV), FIRR, and EIRR calculations was undertaken. For both the FIRR and EIRR, two major scenarios were tested: (i) the use of a better grade of coal, i.e., the Talcher coal; and (ii) a reduction in system losses; while a third case testing the impact of an increase in agriculture tariff by Re1/kWh was done for the FIRR. Although all three cases yielded negative FIRRs, a further analysis showed that a shift to Talcher coal will be most financially beneficial as this means the largest reduction in annual government subsidy needed for net benefits to approximate the cost of capital. In addition, the use of Talcher coal, although more expensive, translates into less demand for coal due to its higher coal heat value. Moreover, the use of a better grade coal would be beneficial to the environment due to its lower ash content not to mention the benefits it would extend to the poor (para. 7). As a result, the EIRR was reestimated at a high of 26.5 percent. A reduction in the system losses to 14 percent (which is embodied in the loan covenants) brings the second best results from the financial and economic points of view. The analysis also supports the need for direct investment to reduce system losses (as the government's subsidy will be reduced). Also, the Re1/kWh increase in agricultural tariff will contribute to the savings of the government, as the subsidy required will be lower. Such an increase in tariff is probable as evidenced by the

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[1] In the presence of incremental benefits, this could result in a decrease in benefits and economic internal rate of return (EIRR), as the average tariff (which is below the cost of supply) will be used in calculating the weighted average demand price.

consumers' willingness to pay. This is a very important finding, as under the new reform initiatives, the Andhra Pradesh government is mandated to directly compensate APSEB for subsidizing agricultural consumers. With the use of Talcher coal and a reduction in system losses to 14 percent combined, the Project would yield a positive FIRR of 10.5 percent.

Table A8.1: Sensitivity Analysis

Scenario	Percent			Annual Government Subsidy (Rs million)
	Losses	EIRR	FIRR	
Appraisal	21.75[a]	20.0	3.0	
Project Completion	—	24.1	7.2	
Base Case	33.16	16.2	Negative	2,540
Shift to Talcher Coal	33.16	26.5	Negative	670
Reduction in System Losses	14.00	21.0	Negative	1,515
Talcher Coal + Loss Reduction	14.00	30.0	10.5	0

— not explicitly stated in the project completion report.
EIRR = economic internal rate of return, FIRR = financial economic rate of return.
[a] Includes auxiliary consumption of 9 percent.

B. Distribution Analysis

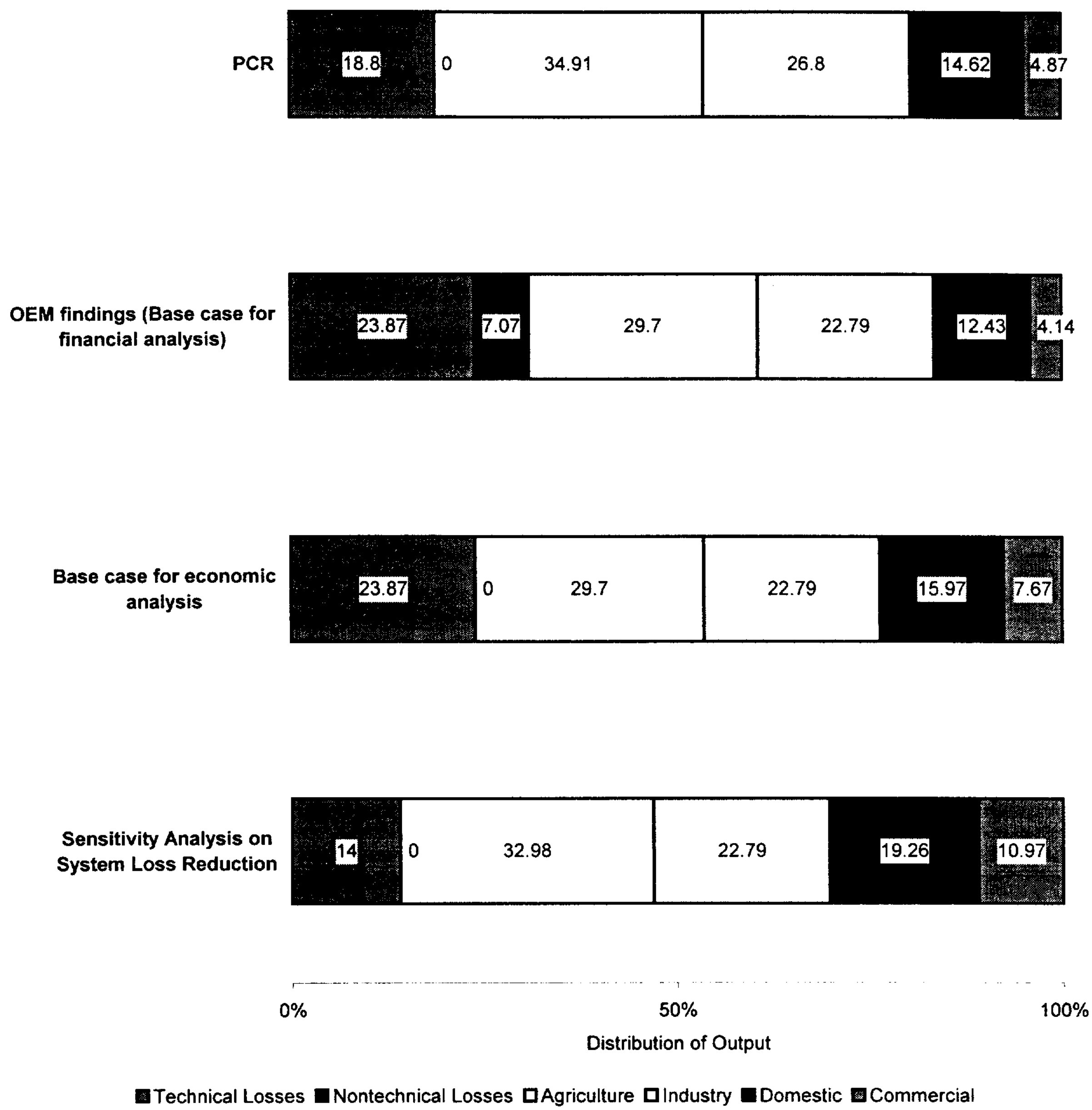
7. The distribution of benefits and subsidies are presented in Table A8.2. The distribution of benefits to the poor has been estimated assuming that 50 percent of government, 80 percent of agricultural consumers, and 30 percent of domestic consumers comprise poor people. The results indicate that a shift to Talcher coal will yield the highest net total benefits to the poor, followed by a reduction in system losses. Indeed, a tariff increase, if introduced after loss reduction, will not affect the poor.

Table A8.2: Poverty Impact

Scenario	Net Benefits to Poor (Rs million)				Poverty Impact Ratio
	Government + APSEB	Agriculture	Domestic	Total	
Base Case	-7,467	7,615	1,839	1,988	0.73
Coal Change	-2,960[a]	7,615	1,839	6,495	0.55
System Loss Reduction	-5,772	8,382[b]	1,979	4,589	0.70
Tariff Increase + Loss Reduction	-3,989	5,530[b]	1,979	3,519	0.54

APSEB = Andhra Pradesh State Electricity Board.
[a] Coal change offers the best results in reducing the Government subsidy and yields highest net total benefit to the poor.
[b] Net benefits to poor agricultural users increase when losses are reduced. In fact, the poor can afford to pay higher tariffs without losing much of the benefits.

Figure A8.1: Consumption and Losses of Rayalaseema Thermal Power Project's Power Output



PCR = project completion report, OEM = Operations Evaluation Mission.

Notes:

(i) The output is electricity generated net of auxilliary consumption at about 10 percent.

(ii) Energy Audit by Andhra Pradesh State Electricity Board revealed that the losses were at a high of 33 percent, including nontechnical losses at 7 percent of output. In the economic analysis the benefits are calculated for the nontechnical losses.

(iii) The loss reduction program aims to achieve the coventanted 14 percent technical losses, and zero nontechnical losses.

Table A8.3: Economic Internal Rate of Return
(Rs million, 1998=100)

	Costs					Benefits					
	Capital Cost		Fuel	O&M	Total	Consumers				Total	Net
Year	Foreign	Local	Cost	Cost	Cost	Agriculture	Domestic	Commercial	Industry	Benefits	Benefits
1991	394	850			1,243						(1,243)
1992	746	790			1,537						(1,537)
1993	1,240	956			2,196						(2,196)
1994	1,144	920			2,064						(2,064)
1995	443	607	39	5	1,094	22	18	8	17	64	(1,030)
1996	178	239	2,206	274	2,896	1,253	987	449	935	3,624	727
1997	1,071	36	3,822	474	5,402	2,171	1,710	777	1,619	6,277	875
1998		73	4,353	540	4,966	2,473	1,948	885	1,844	7,150	2,184
1999		254	4,353	540	5,148	2,473	1,948	885	1,844	7,150	2,003
2000			4,353	540	4,894	2,473	1,948	885	1,844	7,150	2,257
2001			4,353	540	4,894	2,473	1,948	885	1,844	7,150	2,257
2002			4,353	540	4,894	2,473	1,948	885	1,844	7,150	2,257
2003			4,353	540	4,894	2,473	1,948	885	1,844	7,150	2,257
2004			4,353	540	4,894	2,473	1,948	885	1,844	7,150	2,257
2005			4,353	540	4,894	2,473	1,948	885	1,844	7,150	2,257
2006			4,353	540	4,894	2,473	1,948	885	1,844	7,150	2,257
2007			4,353	540	4,894	2,473	1,948	885	1,844	7,150	2,257
2008			4,353	540	4,894	2,473	1,948	885	1,844	7,150	2,257
2009			4,353	540	4,894	2,473	1,948	885	1,844	7,150	2,257
2010			4,353	540	4,894	2,473	1,948	885	1,844	7,150	2,257
2011			4,353	540	4,894	2,473	1,948	885	1,844	7,150	2,257
2012			4,353	540	4,894	2,473	1,948	885	1,844	7,150	2,257
2013			4,353	540	4,894	2,473	1,948	885	1,844	7,150	2,257
2014			4,353	540	4,894	2,473	1,948	885	1,844	7,150	2,257
2015			4,353	540	4,894	2,473	1,948	885	1,844	7,150	2,257
2016			4,353	540	4,894	2,473	1,948	885	1,844	7,150	2,257
2017			4,353	540	4,894	2,473	1,948	885	1,844	7,150	2,257
2018			4,353	540	4,894	2,473	1,948	885	1,844	7,150	2,257
2019			4,353	540	4,894	2,473	1,948	885	1,844	7,150	2,257
2020			4,353	540	4,894	2,473	1,948	885	1,844	7,150	2,257
										NPV	**4,906**
										EIRR	**16.2%**

EIRR = economic internal rate of return, NPV = net present value, O&M = operation and maintenance.

Assumptions:

1. Plant load factor = 80%.
2. Border price for coal cost, insurance, and freight including freigft charges = Rs1770 per metric ton.
3. Station heat rate = 2876 kcal/kWh; coal heat value = 3441.8 kcal/kg.
4. Auxiliary consumption = 10.7%; technical losses = 23.87%; nontechnical losses = 9.29%.
5. Resource cost savings (Rs/kWh): agriculture = 3.1689; domestic = 4.6354; commercial = 4.4250; industry = 3.0720.
6. Electricity sales (net of technical losses) to agriculture, domestic, commercial, and industry were estimated at about 39%, 21%, 10%, and 30%, respectively.
7. Shadow exchange rate factor of 1.11 applied to all inputs at border price equivalent.
8. O&M includes administrative and other costs. It is estimated at paisa 27/kWh of energy sales including nontechnical losses.

Table A8.4: Financial Internal Rate of Return
(Rs million, 1998=100)

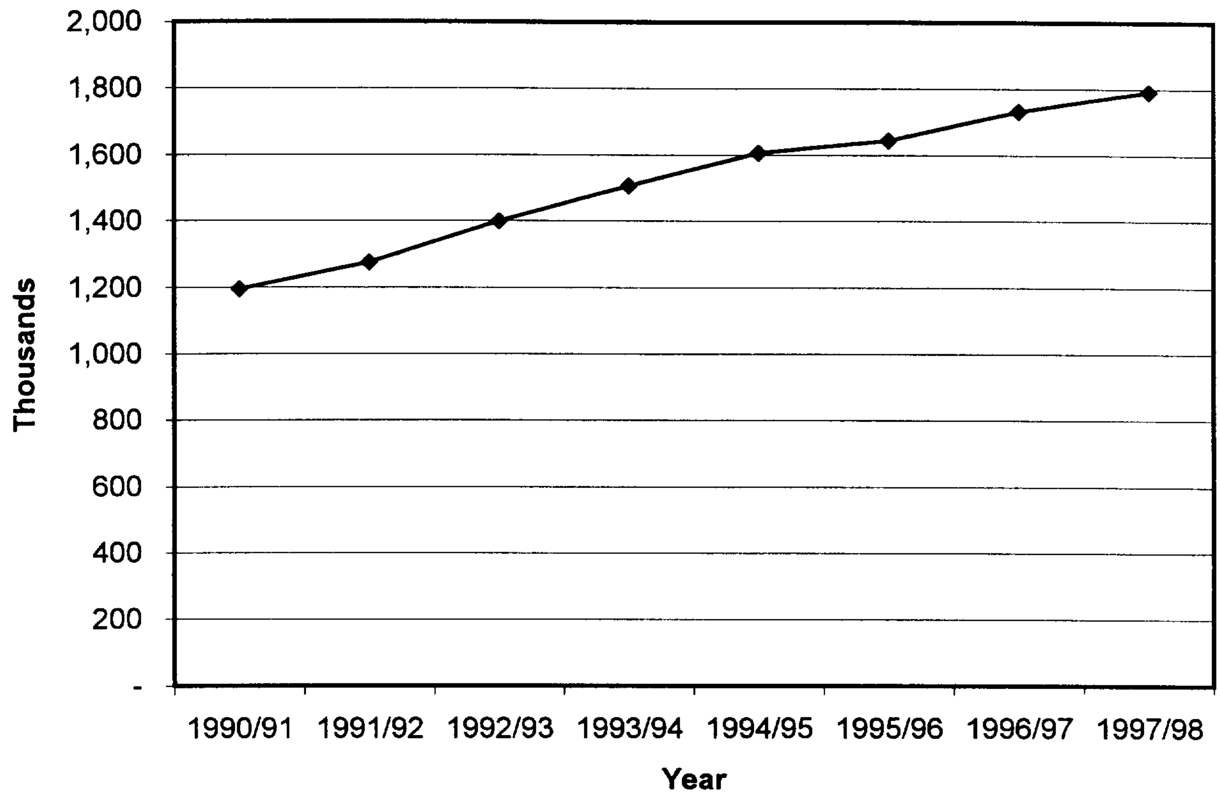
	Costs						Revenues					
	Capital Cost		Taxes/	Fuel	O&M	Total	Consumers				Total	Net
Year	Foreign	Local	Duties	Cost	Cost	Cost	Agriculture	Domestic	Commercial	Industry	Revenue	Revenues
1991	355	781				1,136						(1,136)
1992	672	726	223			1,621						(1,621)
1993	1,117	879	298			2,294						(2,294)
1994	1,031	845	291			2,167						(2,167)
1995	399	558	189	29	5	1,180	2	4	3	17	26	(1,154)
1996	160	220	0	1,659	274	2,312	91	238	196	941	1,467	(845)
1997	964	33	59	2,873	474	4,404	158	413	340	1,630	2,541	(1,863)
1998		67		3,273	540	3,880	180	470	388	1,857	2,895	(985)
1999		234		3,273	540	4,047	180	470	388	1,857	2,895	(1,152)
2000				3,273	540	3,813	180	470	388	1,857	2,895	(919)
2001				3,273	540	3,813	180	470	388	1,857	2,895	(919)
2002				3,273	540	3,813	180	470	388	1,857	2,895	(919)
2003				3,273	540	3,813	180	470	388	1,857	2,895	(919)
2004				3,273	540	3,813	180	470	388	1,857	2,895	(919)
2005				3,273	540	3,813	180	470	388	1,857	2,895	(919)
2006				3,273	540	3,813	180	470	388	1,857	2,895	(919)
2007				3,273	540	3,813	180	470	388	1,857	2,895	(919)
2008				3,273	540	3,813	180	470	388	1,857	2,895	(919)
2009				3,273	540	3,813	180	470	388	1,857	2,895	(919)
2010				3,273	540	3,813	180	470	388	1,857	2,895	(919)
2011				3,273	540	3,813	180	470	388	1,857	2,895	(919)
2012				3,273	540	3,813	180	470	388	1,857	2,895	(919)
2013				3,273	540	3,813	180	470	388	1,857	2,895	(919)
2014				3,273	540	3,813	180	470	388	1,857	2,895	(919)
2015				3,273	540	3,813	180	470	388	1,857	2,895	(919)
2016				3,273	540	3,813	180	470	388	1,857	2,895	(919)
2017				3,273	540	3,813	180	470	388	1,857	2,895	(919)
2018				3,273	540	3,813	180	470	388	1,857	2,895	(919)
2019				3,273	540	3,813	180	470	388	1,857	2,895	(919)
2020				3,273	540	3,813	180	470	388	1,857	2,895	(919)
											NPV	**(13,972)**
											FIRR	**negative**

FIRR = financial internal rate of return, NPV = net present value, O&M = operation and maintenance.

Assumptions:

1. Plant load factor = 80%.
2. Cost of coal including freight charges = Rs1330.70 per metric ton.
3. Station heat rate = 2876 kcal/kWh; coal heat value = 3441.8 kcal/kg.
4. Auxiliary consumption = 10.7%; technical losses = 23.87%; nontechnical losses = 9.29%.
5. Revenues were estimated using the average tariff (Rs/kWh): domestic = 1.44; agriculture = 0.23; industry = 3.10; and commercial = 3.56).
6. Electricity sales to agriculture, domestic, commercial, and industry were estimated at about 43%, 18%, 6%, and 33%.
7. Weighted cost of capital of 8%.
8. O&M includes administrative and other costs. It is estimated at paisa 27/kWh of sales including nontechnical losses.

Agriculture Pumpsets Energized from FY1990/91 to FY1997/98
(cumulative number for Andhra Pradesh State Electricity Board)



Source: Andhra Pradesh State Electricity Board (APSEB).

PLANT EMISSION AND ENVIRONMENTAL POLLUTION BY THE PROJECT

Table A10.1: Stack Monitoring Data
Suspended Particulate Matter (Mg/.m3)

Unit	1998 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
1	—	153	296	106	113	310	110	116	248	120
2	160	196	210	216	210	245	410	221	—	206

— = not available.
Limit: 115 Mg/m^3 (Andhra Pradesh Pollution Control Board).
150 Mg/m^3 (Ministry of Environment and Forest).

Table A10.2: Ash Pond Effluent

Effluent	1998 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
pH	8.70	8.70	8.60	8.67	8.54	8.40	8.58	8.60	8.40	8.30
TDS	470	556	451	501	543	611	566	479	444	420
TSS	1,415	899	448	264	708	961	655	458	380	411

pH = a measure of acidity/alkalinity of water, TDS = total dissolved solids, TSS = total suspended solids.
Limits: pH = 5.5 to 9.0
TDS = 2,100 parts per million (ppm), TSS = 100 ppm

Table A10.3: Plant Effluent

Effluent	1998 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
pH	8.40	8.50	8.40	8.55	8.45	8.30	8.60	8.50	8.50	8.45
TDS	506	520	484	557	513	580	591	455	435	445
TSS	718	743	1,101	1,111	1,300	1,057	1,084	1,101	1,190	1,078

pH = a measure of acidity/alkalinity of water, TDS = total dissolved solids, TSS = total suspended solids.