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STAFF APPRAISAL REPORT

INDIA

PRIVATE POWER UTILITIES (TEC) PROJECT

FOR

THE TATA ELECTRIC COMPANIES

JUNE 6, 1990

The World Bank
Asia Country Department IV (India)
Transport and Energy Operations Division

International Finance Corporation
Department of Investments, Asia II
Division I

CURRENCY EQUIVALENTS

Currency Unit=Rupees (Rs)
Rs 1.00=Paise 100
US$1.00=Rs 17.0
Rs 1.00=US$0.0588
Rs 1,000,000=US$58,823
US$ 1.0=Yen 153

MEASURES AND EQUIVALENTS

1 Meter (m)	=	39.37 inches (in)
1 Kilometer (km)	=	1,000 meters (m) = 0.6214 miles (mi)
1 Cubic Meter (m^3)	=	1.31 cubic yard (cu yd) = 35.35 cubic feet (cu ft)
1 Thousand Cubic Meter (MCM)	=	1,000 cubic meters
1 Barrel (Bbl)	=	0.159 cubic meter
1 Normal Cubic Meter of Natural Gas (Nm^3)	=	37.32 Standard Cubic Feet (SCF)
1 Metric Ton of Oil (39 API)	=	7.60 barrels
1 Milligram	=	0.001 gram (g) = 0.035 ounce
1 Ton (t)	=	1,000 kilograms (kg) = 2,200 pounds (lbs)
1 Kilocalorie (kcal)	=	3.97 British Thermal Units (BTU)
1 Ton of Oil Equivalent (toe)	=	10 million kilocalories
1 Kilovolt (kV)	=	1,000 volts (V)
1 Kilovolt ampere (kVA)	=	1,000 volt-amperes (VA)
1 Megawatt (MW)	=	1,000 kilowatts (kW) = 1 million watts
1 Kilowatt-hour (kWh)	=	1,000 watt-hours
1 Megawatt-hour (MWh)	=	1,000 kilowatt-hours
1 Gigawatt-hour (GWh)	=	1,000,000 kilowatt-hours
1 Gigacalorie (Gcal)	=	1,000,000 calories

ABBREVIATIONS AND ACRONYMS

AAGR - Average Annual Growth Rate
ACSR - Aluminum Conductor Steel Reinforced
Act - The Electricity (Supply) Act, 1948 as amended
AEC - Ahmedabad Electricity Company
Andhra - The Andhra Valley Power Supply Company Ltd.
ASTM - American Society for Testing and Materials
BEST - Bombay Electric Supply and Transport Undertaking
BOOT - Build, Own, Operate and Transfer
BSES - Bombay Suburban Electric Supply Company
CC - Combined-Cycle
CCI - Controller of Capital Issues
CEA - Central Electricity Authority
CESC - The Calcutta Electric Supply Corporation
DOP - Department of Power
DSC - Debt Service Cover
ERR - Economic Rate of Return
FAC - Fuel Adjustment Charge
FGD - Flue Gas Desulphurization
GIS - Gas-Insulated Switchgear
GOI - Government of India
GOM - Government of Maharashtra
GOMID - Irrigation Department of the Government of Maharashtra
GSEB - Gujarat State Electricity Board
GT - Gas Turbine
HPP - Hydro Power Plant
HRSG - Heat Recovery Steam Generator
HV - High Voltage
Hydro Ltd. - The Tata Hydro-Electric Power Supply Company
IPR - Industrial Policy Resolution
IRR - Internal Rate of Return
KM - Kilometers
KV - Kilovolts
LF - Load Factor
LSHS - Low Sulphur Heavy Stock
MPCB - Maharashtra Polution Control Board
MPSEB - Madhya Pradesh State Electricity Board
MSEB - Maharashtra State Electricity Board
MW - Megawatt
NELCO - National Radio and Electronics Company
NHPC - National Hydroelectric Power Corporation
NO_x - Nitrogen Oxides
NPTC - National Power Transmission Corporation
NTPC - National Thermal Power Corporation
O & M - Operation and Maintenance
ONGC - Oil and Natural Gas Corporation
p.a. - per annum
PCD - Partly Convertible Debentures
PCR - Project Completion Report
PFC - Power Finance Corporation
Power - The Tata Power Company Ltd.
PS - Pumped Storage
SEB - State Electricity Board
SEC - Surat Electricity Company
SO_2 - Sulphur Dioxide
STG - Steam Turbine Generator
T&D - Transmission and Distribution
TEC - The Tata Electric Companies
TEDS - Tata Electronic Data Systems
TPP - Thermal Power Plant
WTI - Westinghouse-Tata-Indus Ltd.
WREB - Western Region Electricity Board
WRG - Western Regional Grid

Guarantor's and Borrower's Financial Year: April 1 - March 31

(In this report FY.. would mean the Guarantor's and the Borrower's fiscal year beginning April 1 of the previous year and ending March 31 of the indicated year; e.g. FY90 would mean the fiscal year from April 1, 1989 to March 31, 1990)

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Loan and Project Summary

Borrower	: Tata Electric Companies (The Tata Hydro-Electric Power Supply Company Limited, The Andhra Valley Power Supply Company Limited, and The Tata Power Company Limited, referred to collectively as the Tata Electric Companies -- TEC). The three companies have generated and supplied power in the Bombay area since the 1910s. They pool their resources, share their assets, costs and revenues in the same proportion 20:30:50, and are operated as one company under the same management. A majority of their shares (51.7%, 50.8% and 52.7%) is held by the public. The Tata interests hold only about 3% of the shares.
Guarantor	: IBRD Loan: India, acting by its President. The Government of India (GOI) would charge a guarantee fee of 2.75 % p.a. on the principal amount of the IBRD Loan withdrawn and outstanding.
IBRD Loan	: US$ 98 million equivalent.
Terms	: Repayment over 20 years, including 5 years grace, at the IBRD's standard variable interest rate.
IFC Investment	: First loan of US$ 30 million and second loan of Yen 4,600 million.
Terms	: Repayment on a 15-year balloon schedule, including 4 years grace. Interest rates fixed at 10 7/8 % p.a. for the first loan and 8 1/4 % p.a. for the second loan. Front-end fee 1%. Commitment fee 1% p.a. on the undisbursed balance.
Foreign Exchange and Interest Risks	: The interest rate risk on the IBRD loan, and the foreign exchange risk on IBRD and IFC loans will be borne by the Borrower.
Mortgage and Security	: IBRD and IFC loans will be secured against first charge on all of TEC's assets, subject to certain charges on current assets in favor of working capital lenders, pari passu with other senior lenders.

Project Objectives : The Project's objectives are to increase TEC's peak generating capacity, reduce their dependence on the Maharashtra State Electricity Board, reduce the average cost of generation and improve system reliability and quality of supply to consumers in the Bombay area.

Project Description : The Project comprises four components: a) a pumped storage unit at the existing Bhira hydroelectric station, to generate 150 MW of additional peak power by consuming off-peak thermal power; b) a 220 kV transmission line to carry this power to the license area; c) a gas based combined-cycle unit of 180 MW at the Trombay thermal power plant; d) a second flue gas desulphurization unit to control the sulphur dioxide emissions from the coal and oil burning Unit No. 5 at Trombay; and (e) review of design and technical specifications and supervision of construction of the Bhira pumped storage scheme and acquisition of know-how for the extension of the FGD facility at Trombay.

Estimated Cost:[1]

Project Components	Local	Foreign	Total
	--------US$ million--------		
I. 150 MW Pumped Storage Scheme at Bhira	30.8	22.2	53.0
II. Bhira-Dharavi 220 kV Transmission System	16.2	17.2	33.4
III. 180 MW Gas Based Combined Cycle Scheme at Trombay	43.9	47.1	91.0
IV. Flue Gas Desulphurization Stream at Trombay Unit 5	5.6	5.2	10.8
Total Base Costs	96.5	91.7	188.2
- Physical Contingencies	6.8	6.0	12.8
- Price Contingencies	16.7	13.0	29.7
Total Contingencies	23.5	19.0	42.5
Total Project Cost	120.0	110.7	230.7
Interest During Construction (IDC)			
- IBRD and IFC Loans	0.0	33.5	33.5
- Other	9.5	0.0	9.5
Total - IDC	9.5	33.5	43.0
Total Financing Required	129.5	144.2	273.7

1/ Including taxes and duties of about US$ 18.8 million.

Financing Plan:

	Local	Foreign	Total
	------US$ million------		
Internal Accruals	61.5	-	61.5
Debenture Issues			
- Convertible part	26.5	-	26.5
- Non-convertible part	15.9	-	15.9
Long Term Loans			
IFC a/	-	60.0	60.0
IBRD	-	98.0	98.0
Local Fin. Inst.	11.8	-	11.8
Total	115.7	158.0	273.7

Estimated Disbursements:

IBRD/IFC Fiscal Year	FY91	FY92	FY93	FY94	FY95
	(US$ million)				
IBRD Loan:					
Annual	1.0	18.6	37.9	32.9	7.6
Cumulative	1.0	19.6	57.5	90.4	98.0
IFC Loan:					
Annual	3.0	6.0	24.0	18.0	9.0
Cumulative	3.0	9.0	33.0	51.0	60.0

Rates of Return : Financial: 24%

Economic : 25% (1990-2000 time-slice of the Western Region Development Program).

Benefits :

(a) Technical: The project will increase TEC's peak generating capacity and capacity utilization of the existing thermal generating stations, and reduce the transmission losses and the average cost of generation and improve system reliability. It will also limit sulphur dioxide emissions from coal and oil burning at Trombay Unit 5.

(b) Institutional: Tariff adjustments and load management initiatives will bring the level and structure of TEC's tariffs more closely in line with supply costs. The support by the Bank Group for increased participation of the private sector in the development of the power sector in India, would free equivalent public resources which would be used for investments in other sectors that cannot attract private funds.

Risks :

(a) Technical: The physical project components, which are based on conventional technology, do not present unusual technical risks. The Mulshi Dam, upstream of the Bhira Hydro Power Project will continue to be monitored and inspected periodically by the Irrigation Department of the Government of Maharashtra (GOM).

(b) Financial: Under the Electricity (Supply) Act regulating power utilities in India, TEC set their tariffs to recover their full costs, including depreciation at 3.6% p.a., interest and a predetermined return on the capital base. Additional special reserves are allowed by the GOM to fully cover the debt service and raise internal funds for future investments. Continuation of these appropriations is essential for TEC to attain comfortable debt servicing.

(c) Relationship with Maharashtra State Electricity Board (MSEB): TEC's system and operations are closely interlinked with the State grid operated by the MSEB. TEC purchase power from MSEB during peak hours, and share the backdown during off peak hours. Maintaining the present working balance is critical for TEC's long-term viability.

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This report is based on the findings of a joint Bank and IFC appraisal mission to India in January 1990. Mission members from IFC were Messrs. D. Damianos (Sr. Investment Officer), O. Roche (Investment Officer), D. Fenton (Sr. Engineer) and M. Riddle (Sr. Environmental Adviser) and from the Bank, Messrs. A. Ceyhan (Sr. Power Engineer), M. Tomlinson (Energy Economist), R. Bentjerodt (Sr. Operations Officer), C.K. Teng (Financial Analyst), B. Baratz (Sr. Environmental Engineer), R. Lopez-Rivera (Power Engineer-Consultant), R.K. Malhotra (Irrigation Engineer) and Ms. N. Parshad (Operations Officer).

ANNEXES

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PRIVATE POWER UTILITIES (TEC) PROJECT

I. SECTORAL CONTEXT

Overview

1.01 The principal challenge facing the Government of India (GOI) as India's power sector enters the 1990s is to improve the balance in sector development between expansion and efficiency improvement. This will require GOI to ensure that the sector's institutional development keeps pace with the physical expansion of power supplies. Electricity demand is projected to grow at approximately 9% p. a. through 2000 and to continue to be supply constrained, though less so than at present. To meet a higher proportion of demand and improve supply quality, GOI plans to install an additional 80,000 MW of capacity by 2000. At a cost of about US$150 billion, (equivalent to between 25% and 30% of expected allocations under the Eighth and Ninth Plans) this would exert strong pressures on GOI's finances and pose considerable managerial and technical challenges for GOI and State utilities. To meet these enormous investment requirements, GOI recognizes that it must realize more of the private sector's potential to mobilize additional resources. Similarly, GOI is keen to exploit more of the private sector's ability to implement major projects efficiently.

1.02 At present, India's power systems have an installed capacity of over 59,000 MW, comparable to the power system of France or of the United Kingdom or to all the power systems in Sub-Saharan Africa combined[1/]. In FY89, India's systems generated 206,000 GWh - about 70% from coal stations, 25% from hydro stations and 5% from gas, oil and nuclear stations (Annex 1.0). Public supply has expanded quickly: since FY82, installed capacity has increased from 32,000 MW and generation from 114,000 GWh. Even so, India faces a shortage of generating capacity of 27% and approximately 10% of total demand is left unserved. The quality of electricity supplies also remains mostly unsatisfactory· interruptions to supply and voltage reductions are common, and technical and commercial losses have increased to 22% of net generation.

1.03 In parallel with expanding supply, the sector has made encouraging efficiency gains. Key amongst these is that plant load factor averaged 55% in FY90, compared with only 44% in FY81. Each 1 kW of capacity now provides 1,031 kWh (27%) more electricity annually than in FY81. In addition, the rate of coal consumption by power stations has been cut 10% since FY80. It now requires 720 tons of coal to generate 1 GWh, compared with 802 tons in FY80. This saves approximately 12 million tons of coal annually - about 8% of the sector's total consumption. These improvements reflect a strengthening of plant maintenance and operations and are commendable in view of the deteriorating quality of coal the sector is receiving. A significant institutional gain has been a 34% cut in staffing ratios: from 29 per thousand consumers in FY81 to 19 at present.

1/ Excluding the Republic of South Africa.

Efficiency has also improved, though more modestly, through increases in tariffs relative to supply costs. Between FY82 and FY89, the average tariff rate doubled to Rs. 0.67/kWh through real increases averaging 3.5% p.a.. Rates to industrial and commercial consumers (over 60% of total consumption) are now about 80% of marginal cost. The lowest rates are those to agriculture - on average Rs. 0.16/kWh - which are heavily subsidized. These low rates inflate demand and are a principal cause of the poor financial performance of the sector.

1.04 Notwithstanding the efficiency gains secured in recent years, considerable scope remains for further improvements. Key remaining constraints are weaknesses in the structure of the sector, inadequate financial autonomy of GOI and state-owned utilities and weak financial discipline. Physically, the impact of these constraints is that India's power systems provide less power and of a poorer quality than they should be able to, and at higher cost. Economic costs of shortages and poor quality supplies are exacerbated by inefficient end-use of power - the result mostly of a lack of commercial incentives in many markets and subsidized power prices.

1.05 Financially, the effects of remaining constraints are to undermine sector financial performance and hold down resource mobilization. Although GOI-owned and private utilities financially are much stronger than the State Electricity Boards (SEBs), it is the latter which dominate the finances of the sector. In FY89, SEBs incurred a combined loss after interest and depreciation of Rs. 17.7 billion (about US$ 1 billion). This corresponded to a return on net assets at historic cost of -9.8%. In FY90, SEBs' losses are expected to reach Rs. 21.6 billion (about US$ 1.28 billion) and the Boards' combined internal resource is expected to fall to Rs. -7.7 billion (about US$ -460 million). The Maharashtra State Electricity Board (MSEB) - TEC's licensor - is the most efficient and financially the strongest of the SEBs. Recently, MSEB increased its tariffs 20%. As a result, MSEB expects to be the first SEB able to meet GOI's minimum requirement for a 3% return on net assets at historic cost after depreciation and interest.

1.06 GOI is aware of these constraints and how they threaten future sector development. Under the Seventh Plan, GOI strengthened its resolve to address these constraints in a substantive way. Of particular note are GOI's initiatives to strengthen financial discipline in the sector and improve resource mobilization, both through direct negotiation with States and through creating the Power Finance Corporation (PFC). The latter will provide project financing to SEBs willing to make needed institutional reforms. GOI has also accelerated development of the efficient central utilities, (particularly the National Thermal Power Corporation -- NTPC) to improve cost recovery and ensure that priority projects are implemented on schedule. To tap private sector potential for additional resource mobilization, GOI also aims to ease financial and regulatory disincentives to private investment in the sector. To this end, GOI has under review a White Paper proposing, inter alia, to increase to 15% the return private utilities are permitted to earn on their capital base (para. 1.17). Finally, GOI is also reviewing its fuel use policy for the sector. As well as considering fuel imports, GOI has decided to sanction more domestic natural gas for power generation: 8,000 MW of gas-fired plant is to be added under the Eighth Plan.

Organization of the Power Sector

1.07 Responsibility for electricity supply is shared between GOI and the States. GOI controls the Central Electricity Authority (CEA), NTPC and its hydropower counterpart, the National Hydro Power Corporation (NHPC). All report to the Department of Power (DOP) within the Ministry of Energy. DOP also controls PFC and will take responsibility for the newly-created National Power Transmission Corporation (NPTC). CEA's task is to develop national power policy and coordinate sector development. Its effectiveness, however, is limited severely by shortages of skilled staff and resources. NTPC and NHPC are bulk supply utilities which sell power to the SEBs. NTPC provides about 13% of India's total power supplies, and has a track record of efficiency and financial strength. NHPC, on the other hand, has not yet enjoyed the same success and is developing relatively slowly. PFC will mobilize additional resources for the SEBs and pursue institutional strengthening of its borrowers through conditionality linked to its financing. NPTC will coordinate development and operation of transmission systems, initially systems associated with NTPC's and NHPC's power stations and later systems owned by the SEBs.

1.08 The States control the SEBs, which generate about 75% of total supplies and provide most distribution to final consumers. Although supposedly autonomous, SEBs in practice are under state control as regards their investments, tariffs, borrowings, and salary and personnel policies. SEBs are grouped into five regional systems. Activities coordinated regionally include generation schedules, overhaul and maintenance programs, power transfers and concomitant tariffs. SEBs also license India's private power utilities. Only five private utilities remain: TEC, Bombay Suburban Electric Supply (BSES), Ahmedabad Electricity Company (AEC), Surat Electric Company (SEC) and the Calcutta Electric Supply Corporation (CESC). The Bombay Electric Supply and Transport Ltd. (BEST) is a municipal corporation. All but BSES and BEST generate at least some of the power they distribute. However, BSES is embarking upon a 500 MW thermal power station, for which a second joint IBRD/IFC operation is being considered.

Private Utilities

1.09 At independence, private utilities and licensed local authorities together provided about 80% of public electricity supply. The Electricity (Supply) Act of 1948 created the SEBs and entrusted the Boards with primary responsibility for public power supply. The Act also made SEBs responsible for regulating private utilities. The Industrial Policy Resolution (IPR) of 1956 subsequently defined aspects of generation and distribution which were to be the exclusive responsibility of the State. All but the few remaining licensees consequently were taken over on the expiry of their licenses. No new licenses have been granted since 1956. However, the IPR did not rule out expansion of remaining licensees, or the possibility of joint ventures with the private sector when these could be shown to be in the national interest. Private utilities provide less than 5% of public supplies, though private captive generation in industry is extensive - equivalent to about 15% of public supplies. The latter has developed in response to poor quality and unreliability of public supplies.

Regulatory Framework

1.10 Private power utilities in India are regulated by the Electricity (Supply) Act of 1948 as amended (the Act). The Act allows them to charge through their tariffs to consumers their full cost, including depreciation (at 3.6% p.a.) and interest; plus special reserves as allowed by the State Government; plus profit equal to a 12% return on their remunerable capital base. The special reserves, like depreciation, are charged on the tariffs, thus increasing the revenues, but unlike cash costs, are not paid out. Hence they help increase the cashflow while the clear profit (after the special reserves) remains within the reasonable return limits. The capital base comprises share capital and free reserves, but excludes the special reserves. The rate of return is currently set at 12% p.a. (still the pre-1966 part of the capital base earns only 7% p.a.). If a utility makes higher profits, it can retain only 20% of the excess and roll-overs against future losses are not permitted. The private utilities are arguing that the 12% p.a. rate of return is inadequate. Their cost of borrowing is now 14% p.a. for long term loans and 17% p.a. for working capital.

1.11 In TEC's case, the special reserves allowed by the GOM include a Debt Redemption Reserve, to cover the difference between depreciation and principal repayments; a Foreign Exchange Liabilities Reserve, to cover exchange losses on the foreign currency loans; a Project Cost Reserve, to raise funds for future investments; and a Deferred Tax Liability Reserve, to cover an eventual tax liability of shareholders for unrealised capital gains (arising from different depreciation rates under the Income Tax Act and the Electricity Act) in the event a utility is taken over. These reserves were allowed by the state at a time that they did not result in an increase of the tariffs (other than the fuel adjustment charge, which is not subject to any restriction). When the fifth Trombay unit[2/] came into operation in 1984 and natural gas from the nearby Bombay High Oilfields was made available at a promotional price (for taking interruptible supplies), the average cost of generation declined. Rather than rebate the savings to consumers through tariff reductions, TEC were able to retain them through these reserves, to raise funds towards subsequent investments. This allows them to finance their future projects with more internal accruals and less debt, which in turn reduces the interest burden and therefore the future tariffs. Thus the savings come full circle back to the consumer.

1.12 GOI has been considering in the last 2-3 years a set of amendments in the Act, including increased depreciation allowance and return on capital, to improve the incentives for private sector investment in power generation (para. 1.17). While there is widespread recognition that present allowances are too low to attract new private investment, the proposed changes are unpopular with the States and the SEBs -- which face stiff opposition to higher rates for public electricity supplies. Because of the difficulty of building the necessary consensus with the States, progress on improving private sector incentives will probably materialize only at a comparatively modest pace, with the leadership

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2/ Financed under IBRD Loan 1549-IN -- The Third Trombay Project, which covered the construction of a 500 MW triple-fired (coal, low sulphur heavy stock fuel oil and gas) Trombay 5th unit.

continuing to be taken by States such as Maharashtra and Gujarat that already have a private sector presence.

Tariffs

1.13 Tariff adjustments by private utilities are permitted annually and do not require state approval, only 60 days notice by the licensee. The tariffs comprise a demand charge, a fixed component designed to recover the utility's fixed costs, and an energy charge for actual consumption, reflecting the utility's variable cost of generation. The latter comprises a basic energy charge and a fuel adjustment charge (FAC), reflecting the increases in the cost of fuel between two successive tariff revisions. In deciding the actual amount and especially the timing of their increases, the utilities also take into account economic and political factors, including the state of the economy in their area and the attitude of consumers and of the authorities. Petitions by consumers requesting stays of the increases are common as is their rejection by the courts. TEC normally follow the MSEB in raising tariffs. TEC's tariffs are lower than MSEB's for the same category of high voltage consumers and also are lower than the rate TEC pay for power purchased from MSEB, i.e. purchases raise TEC's average supply cost and hence its tariffs. TEC's cost of generation is lower because: (a) their newer thermal units are very efficient; (b) they use low-cost natural gas as fuel; (c) about a fifth of their generation is hydro; and (d) they do not have the costs associated with low voltage distribution. The evolution of TEC's and MSEB's tariffs since 1975 is shown in Annex 1.1. During project preparation, IBRD and IFC have reviewed with TEC the possibilities for improving the structure of TEC's retail tariffs to encourage further consumer load management. TEC confirmed that they will plan to restructure their tariffs to include, inter alia, options for time-of-day energy pricing and load management. TEC further agreed that, after consultation with the GOM, they will commence implementation of the restructured tariffs in their 1991 round of tariff adjustments.

GOI Strategy in the Power Sector

1.14 The Five-Year Plan constitutes the only formal statement of India's energy and power policies. While the Eighth Plan has yet to be finalized, preliminary indications suggest little change in objectives from those reflected in the Seventh Plan. Principal energy objectives are likely to remain to: (a) develop supplies at rates which will facilitate growth in other sectors and meet particular economic and social objectives assigned to the energy sector (e.g. extending irrigation pumping and meeting basic energy needs of the rural poor); (b) substitute indigenous energy for imported fuels wherever economically feasible; and (c) promote rational and more efficient energy use. Power sector objectives are broadly similar, though within GOI there is a growing recognition for the economic role of imported coal (and possibly imported gas) could play to fuel supply to the power sector. Over the short term, objectives are likely to focus on easing the persistent supply shortages and improving financial discipline in the sector.

1.15 Over the longer term, the organizational, institutional and financial objectives are less clearly defined. Although GOI is heavily constrained in its ability to act unilaterally, key initiatives it is likely to pursue will be to:

(a) accelerate development of the relatively efficient GOI-owned utilities; and (b) promote more extensive private sector participation in power supply.

1.16 GOI's recent initiative in forming PFC is expected to begin yielding results under the Eighth Plan. In addition, GOI's minimum 3% return requirement for SEBs, and its appropriations from States' budgets, provide strong incentives for States to work more concertedly to improve SEBs' resource mobilization.

Private Utilities: Prospective Policy Adjustments

1.17 As mentioned in paragraph 1.05, SEBs' combined losses in FY90 amounted to Rs. 17.7 billion, a return on net assets at historic cost of -9.8%. In FY90, their combined resource mobilization is expected to fall to Rs. -7.7 billion. These serious financial problems (para. 1.05) have left GOI deeply concerned about the difficulty it faces in financing sector investments through the Eighth Plan. It is primarily this concern that has prompted GOI to re-assess financial conditions under which the private sector can invest in public power supply. Key reforms included in the White Paper GOI is considering are:

(i) an increase in returns private utilities are permitted to earn --to five percentage points above the Reserve Bank of India (RBI) rate from two points at present (i.e. an increase to 15% from 12%);

(ii) an obligation for state governments to permit private utilities a special appropriation for repayment of loans;

(iii) a standard license period of 30 years with extensions, where granted, of 20 years -- currently, licenses may not exceed 20 years and extensions may not exceed 10 years;

(iv) release from the highly constraining Monopolies and Restrictive Trade Practices Act, under which private utilities presently are required to obtain clearances for new business ventures and major projects; and,

(v) streamlining of licensing procedures for new private utilities.

1.18 India's newly formed Cabinet is expected to discuss the proposals in the near future. However, the progress through the Government of these reforms has been interrupted -- in our assessment only temporarily -- by the change of administration and by the preoccupation of the concerned authorities with revision of the Eighth Plan. It is not yet clear whether the Cabinet will also propose increases in depreciation rates for private utilities. SEBs are keen to secure similar concessions. Without commensurate increases in tariffs, this would deepen SEBs' losses, possibly substantially. It is probable, however, that the Cabinet will require at least 60% of new investment by private utilities to come from sources other than the main financial institutions. This will help ensure that private investment resulting from the concessions does not draw heavily upon resources that otherwise would have been available to the SEBs.

1.19 In an interim initiative prior to policy changes being announced, GOI has approached selected private investment houses to present proposals for Build, Own, Operate and Transfer (BOOT) generation projects. Such projects fall within the provisions of the IPR (para. 1.09), under which SEBs may enter into joint ventures with the private sector for projects in the national interest. Results so far have been disappointing -- no new joint ventures have yet been launched - since the groups approached are wary of the same financial restrictions troubling existing private utilities.

1.20 While most in government recognize the need to extend private sector participation in power supply, some continue to view private utilities as profiteering at the expense of SEBs. These views are deeply held and will continue to slow the pace of reform. New incentives therefore are likely to be incremental in nature and are likely to be sponsored by states unevenly. The more progressive state governments, such as in Maharashtra, undoubtedly will take the lead. Overall, it is difficult to predict how quickly private participation could increase. If GOI decides to allocate additional natural gas to private sector combined-cycle projects, private participation could develop relatively quickly -- some projects could be completed within the Eighth Plan. However, at present, the outcome is uncertain.

<u>Bank Group Strategy in the Power Sector</u>

1.21 GOI's sector strategy is sound in its broad objectives and direction. As regards public utilities, however, additional efforts are needed in institutional development, planning, finance, pricing and load management. As regards the private sector, GOI's objectives need to be defined more clearly and its strategy needs expression through a first round of reforms. The nature of constraints afflicting public utilities recommends the IBRD adopt a sector-wide lending strategy. Consequently, the IBRD is extending its involvement with central entities and in parallel is pursuing direct involvement with selected SEBs which, together with their state government, are committed to reform. The IBRD and IFC strategy towards private utilities is to accelerate development of the existing suppliers and to advance thinking on lowering entry barriers for new investors. In dealing with public and private utilities alike, the IBRD and IFC are also promoting more comprehensive and vigorous analyses of environmental inputs in project design and improved implementation of environmental project components (para. 1.23).

1.22 The IBRD's support for central entities provides further institutional strengthening these entities require to manage their rapid development. It also helps promote efficiency in those SEBs with which the IBRD does not have a direct relationship. PFC's lending operations, for example, will be linked closely to institutional strengthening of its borrowers. The IBRD's support for particular SEBs aims to organize the Boards to operate more along commercial lines -- invariably a long process fraught with difficulty, but essential to improve overall sector efficiency. Recurring objectives in these operations are to: (a) tighten financial discipline and improve financial planning; (b) reorganize management to facilitate decision making; (c) improve the quality and timeliness of management information; and (d) strengthen technical abilities, particularly as regards project management. The IBRD's involvement throughout the sector also facilitates a dialogue with GOI on broader issues facing the sector - for example, on utilities' need for improved financial autonomy, ways to improve SEBs' financial performance and options to improve incentives for private investment in power supply. These and other issues are to be explored in detail in forthcoming IBRD economic sector work, which aims to identify and appraise feasible reform options[3/].

1.23 In addition to addressing areas where GOI's strategy requires support, the IBRD also attempts to catalyze progress in remaining areas. Key objectives the IBRD has adopted in this regard are to: (a) assist with development of a strategy to address in a uniform and co-ordinated way the environmental and sociological aspects of power development; and (b) support developments requiring coordinated actions within and outside the power sector -- improving coal quality and transport are priority areas.

1.24 Joint preparation of the proposed project by IBRD and IFC underscores the commitment of the World Bank Group to the development of private sector power supply in India. The association has proved key in advancing the Group's dialogue with GOI on the regulatory and other constraints presently deterring extended private sector participation in public power supply (para. 1.12). Under the forthcoming Private Power Utilities Project II, IBRD and IFC are seeking that GOI will take the first concrete steps to lowering the existing barriers to extended private participation in the sector.

Bank Group Participation

1.25 The Bank Group has made 29 IBRD loans (US$ 5,719 million) and 18 IDA credits (US$ 2,307 million) for power projects in India (Annex 1.2). In addition, a loan of US$ 485 equivalent for the Northern Region Transmission Project is being considered by the Executive Directors of IBRD. Twenty-seven projects have been completed: 20 generation; 4 transmission; and 3 rural electrification. Projects currently under implementation include 9 generation (3 of which are hydro); 2 transmission; and 6 which include a mix of generation, transmission and distribution. Four of the IBRD loans have been to TEC, in 1954, 1957, 1979 and 1984. With the exception of a few notable trouble spots, implementation of Bank power projects has proceeded broadly according to expectations. Loan and credit disbursements, however, continue to show large outstanding balances (US$ 3,753 million, as of March 31, 1990). These are due primarily to the very long construction periods of generation projects compounded by frequent delays in procurement and foreign exchange and import licence clearances by the various ministries and the rising number of projects under implementation. Balances have been increased further by frequent cost under-runs on major equipment contracts - the result of a recent softening of international markets and rapid real devaluation of the Rupee.

1.26 IFC has made 2 loans for power projects in India to AEC and TEC in FY89 and is considering a loan to CESC in FY90. Although disbursements from the FY89 loans have not yet commenced, both projects are progressing satisfactorily. Including this proposed project, IFC cumulative commitments in the Indian power sector would be about US$ 140 million equivalent; including about US$ 100 million to TEC.

3/ An economic sector work study entitled "Long Term Issues Facing The Power Sector" is expected to be completed by the end of 1990.

1.27 The Bank Group participation in these projects has strengthened the financial performance of these borrowers, not only by bringing in additional financing but more critically by encouraging regulatory improvements, e.g. the special reserves. Also, by protecting the borrowers from adverse state intervention it bolstered their private ownership as it enhanced their contribution to the public.

1.28 The Project Completion Report (PCR) for the Bank's Third Trombay Project (Loan 1549-IN; para. 1.11) notes that costs at project completion were 34% higher than at appraisal and completion was one year behind schedule. Despite this, the PCR rates the project a success: cost increases were largely beyond TEC's control and the replacement of an unsatisfactory contractor was handled expeditiously. TEC's financial performance throughout project implementation exceeded appraisal estimates and the PCR estimated the project rate of return to be 31%, compared with 14% estimated at appraisal. Implementation of the Fourth Trombay Project (Loan 2452-IN) which covers the construction of the 500 MW Trombay 6th unit, proceeded satisfactorily after a slow start due to GOI's delay in establishing a fund to secure the IBRD loan. The 500 MW unit was synchronized with the interconnected system on March 23, 1990. TEC's financial performance during project implementation again exceeded appraisal estimates.

II. THE BORROWER

Corporate Structure

2.01 TEC consist of three companies:

(a) The Tata Hydro-Electric Power Supply Company Limited (Hydro), formed in 1910;

(b) The Andhra Valley Power Supply Company Limited (Andhra), formed in 1916; and,

(c) The Tata Power Company Limited (Power), formed in 1919.

In the 1950s the three companies pooled their facilities and their staff to form a single integrated grid. Although they have not actually merged, they are operated as one company under the same management. They share their assets and liabilities, revenues and costs in the same proportion (20% Hydro; 30% Andhra; 50% Power) and are collectively referred to as the Tata Electric Companies.

Licenses

2.02 The three hydro-electric power stations at Khopoli, Bhivpuri and Bhira (para. 2.18) are still separately owned by the three companies under the original licenses issued in 1907, 1919 and 1921. The Trombay Thermal Power Station, the receiving stations and the transmission and subtransmission network are owned jointly in the ratio of 20:30:50 by Hydro, Andhra and Power respectively. The three companies operate Trombay under the jointly owned

Trombay Thermal Power Electric License issued in 1953 and amended in 1978, when the fifth Trombay unit was approved.

2.03 The MSEB has the option to acquire, with appropriate compensation, the assets of the undertakings covered by the licenses. This option is exercisable every 10 years, but not before August 15, 2004, the maturity date of TEC's last loan from the IBRD. GOI agreed to cause the State of Maharashtra to extend, not later than June 30, 1991, the validity of TEC's licenses at least up to September 15, 2010, the maturity date of the proposed IBRD loan (para. 6.01.b.i).

2.04 The licenses are not exclusive, i.e. other utilities may also be licensed to distribute power in the same area. There are two such distribution utilities in TEC's area (para. 2.20), who are supplied by TEC and retail power to 9 million consumers through their own distribution networks. In addition, TEC supply directly about 90 large industrial consumers. About 70 more of these direct consumers located in TEC's area were taken over by MSEB in 1980, because TEC did not have adequate capacity to supply them (para. 2.22). At that time TEC were importing about two thirds of their requirements from MSEB, an excessive dependence that has since decreased. TEC is still in a deficit position, but the probability that their distribution rights may be truncated again is considered very low. Under the terms of the License, TEC "will be allowed to retain such distribution rights and loads in the licensed area as may be warranted by their surplus generating capacity". MSEB has no financial incentive to take over more direct customers. GOI agreed to cause GOM not to take any actions, including delimiting TEC's area of supply, that would adversely affect TEC's operational performance and financial position (para. 6.01.b.ii).

<u>Shareholding</u>

2.05 TEC were founded by the two sons of Jamshetji Tata, who were granted the initial licenses. Today the Tata group's holding company "Tata Sons Inc." holds less than 2.5% of TEC's shares. The Tata family members own less than 10% of Tata Sons. More than 75% of Tata Sons' shares are held by Tata Trust, a charitable institution governed by a board of trustees independent from the Tata family. The essence of the "Tata Group" is effectively a network of professional managers, bred through a long tenure in the group companies.

2.06 The three companies are private sector entities, whose common shares are held as given in Table 2.1:

Table 2.1: Shareholders of the Tata Electric Companies
(As of March 31, 1989)

	Hydro	Andhra	Power
	-------- Percent (%)		---------
Individuals	51.7	50.8	52.7
Other Private	4.3	4.1	4.1
Life Insurance Corporation	9.6	9.2	7.4
Other Insurance Companies	12.9	17.7	10.2
Unit Trust of India	14.8	13.5	12.1
Financial Institutions	5.6	3.6	12.5
Nationalized Banks	1.1	1.0	1.1
	100.0	100.0	100.0
Number of Private Shareholders			
Individuals	30,568	27,713	55,302
Other Private	173	187	268

2.07 TEC's last share issue, by all three companies simultaneously, was in 1981 on a rights basis and was oversubscribed four times. Debentures are also issued individually but simultaneously. Each new loan agreement is signed by all three companies.

2.08 As part of the financing for this project TEC are planning a large issue of 5.3 million partly convertible debentures (PCD) in FY91 (para. 3.07). Subject to approval by the Controller of Capital Issues (CCI), TEC plan to distribute these as follows:

(a) 3.9 million (74.1% of the PCD issue) to existing shareholders on a 1:1 rights basis;

(b) 0.2 million (3.7%) to employees;

(c) 0.7 million (13.2%) to other Tata group companies; and,

(d) 0.5 million (9.4%) to a private financial institution.

After the compulsory conversion on the basis of one share per PCD, the number of shares outstanding will increase to 9.2 million, and the private sector shareholding of TEC will increase to over 60%.

Management, Organization and Training

2.09 The three companies are managed as one, sharing their assets and liabilities, revenues and costs in the proportions 20% Hydro; 30% Andhra; 50% Power. Each has a Board of ten directors of which four, i.e. the Chairman, Vice Chairman, Managing Director and Joint Managing Director, are on all three boards. Each board includes a representative of the Indian Financial Institutions. One GOI and one GOM representatives serve on the Board of Andhra. The other directors are representatives of leading industrial and banking institutions in

India. The three companies hold joint board meetings and share the same management and staff (Annex 2.0).

2.10 TEC are professionally managed and have an excellent record of efficient operation and technical innovation. They were the first to introduce in India 220 kV high voltage transmission lines, and in 1984 they successfully commissioned the first 500 MW generating unit. They have successfully implemented the Third and Fourth Trombay Power Projects (Loans 1549-IN and 2452-IN), partly financed by the Bank. As of January 1, 1990, TEC's human resources strength numbered about 3450, comprising about 122 senior managers, 953 engineers and technicians, 1987 skilled and semi-skilled workers, and the balance administrative personnel. The staffing is commensurate with the size and scope of activities of TEC and is adequate to carry out the proposed project.

2.11 TEC provide extensive in-house and external training, primarily for power plant operation personnel. Their training center at Vashi, about 10 km from Trombay provide specialized training on power system management. Their other key in-house training includes using computerized simulators to replicate the responses and operating sequences of the 500 MW Unit 5 at Trombay. TEC also offer training for SEBs' staff.

Maintenance

2.12 The maintenance of TEC's facilities is carried out by TEC's own staff. Well established preventive maintenance norms are applied for the electrical and mechanical equipment. Overhauling of units is planned in consultation with MSEB to minimize disruption to the system. Effective maintenance results in high availability: in FY89, the plant load factor for Trombay Thermal Power Plant was 67.5% overall, and in particular for the 500 MW 5th Unit 80%; in FY90, the plant load factor increased to 77.2% on average and about 94% for Unit 5 while the all-India average was about 60%.

Accounting and Audit

2.13 The accounting functions are well managed by a few competent and experienced officers, with a relatively sophisticated computerized system. While the financial accounting is centralized at the headquarters, TEC are implementing an on-line financial accounting system for the Trombay Thermal Power Station which will later be extended to other divisions. The management information system of TEC is one of the best in the electric utility sector in India. Financial planning and funding operations are still done by the Joint Managing Director in consultation with external advisers. As TEC's operations expand and diversify, top management plans to strengthen these functions by inducting a senior financial executive.

2.14 The internal audit division is appropriately staffed and reports are satisfactory. The external auditors' reports are unqualified and indicate compliance with the regulatory Acts. TEC agreed to furnish to IBRD and IFC, latest by July 31 of each year, their audited annual accounts including a copy of their combined accounts (para. 6.02.a).

Billing and Collections

2.15 TEC send out less than one hundred bills each month: one each to BSES, BEST, the Railways and the 90 direct industrial consumers. Industrial consumers and the railways get a 1% discount for prompt payment, or a 2% penalty beyond the payment date. Defaulting consumers face disconnection. In general, most of TEC's consumers pay within the ten-day discount period. TEC's billing and collection system is well established and efficient as evident by its low receivables of less than 40 days of sales in FY89. TEC also provide consultancy services on billing and collections to other electric utilities.

Insurance

2.16 TEC maintain fire and machinery breakdown insurance policy on their operating plant and machinery on replacement value basis while projects under construction are covered under a marine, storage and erection policy. TEC also ensure that turnkey contractors provide adequate insurance for the project.

Income Tax

2.17 TEC's profit from the electricity business is not subject to the minimum tax of 30% on book profits (before various deductions). Due to their substantial new investment program, TEC project that they will not be subject to income tax for most of this decade. The non-electricity businesses (para. 2.27) are still at an early stage, with expenses outstripping revenue, so that no tax is envisaged on them either.

Existing Operations and Facilities

2.18 The sixth unit at Trombay (500 MW) was completed ahead of schedule and came on stream, supplying power to the interconnected grid, on March 23, 1990. At present, TEC's own generating capacity is rated at 1,614 MW, comprising 276 MW from three hydro stations (Khopoli, Bhivpuri, Bhira[4/]) and 1,338 MW from one thermal station (Trombay[5/]) with 6 units. Net of internal plant usage and transmission losses, the units in operation in FY90, met about 900 MW of peak

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4/

Khopoli	:	72 MW
Bhira	:	132 MW
Bhivpuri	:	72 MW
Total	:	276 MW

5/

Units 1, 2 and 3	:	3 x 62.5 MW
Unit 4	:	150 MW
Unit 5	:	500 MW
Unit 6 (a)	:	500 MW
Total	:	1,337.5 MW

(a) Synchronized with the interconnected system in March 23, 1990.

load[6/]. The oldest three thermal units of 62.5 MW each were scheduled to be retired when unit 6 was commissioned, but in view of the peak power shortage, they are being extended until the combined-cycle unit of the proposed project comes on stream in FY94. The fourth unit (150 MW) will be relegated to a standby status from FY95.

2.19 TEC also own the transmission lines and switching substations, through which they deliver power to their clients at High (HV) and Medium (MV) Voltages. The transmission lines are at 6.6kV-220 kV and add up to a total length of 1,141 km overhead and 434 km underground.

Clients

2.20 TEC's clients are: (a) two distribution utilities (BSES and BEST; para. 1.08), who in turn through their own distribution network retail power to nine million consumers; and (b) about 90 large industrial consumers supplied directly by TEC. The license areas of TEC, BSES and BEST are shown in Map IBRD 22293.

2.21 The HV transmission and MV subtransmission is the primary responsibility of TEC. MSEB, BSES and BEST each have their own HV and MV lines interconnected with TEC's. In its license area which covers South Bombay, BEST is licenced to distribute power to consumers whose requirements do not exceed 250 KVA. For BSES, whose licence area covers north of the Bombay Metropolitan Area, this limit is 1,000 KVA. Larger consumers whose requirements exceed these limits may be supplied by either TEC or BEST/BSES and they choose the source that can supply them at the least cost. BEST and BSES purchase power in bulk delivered to them at TEC's receiving stations for onward distribution to their clients. Both BEST and BSES supply residential, commercial and industrial consumers. The peak load of TEC's clients was about 1,400 MW in FY90 and is growing at 8% p.a. TEC met around 900 MW from their own generation and imported the balance from MSEB. With the addition of Trombay Unit 6, TEC's own peak availability increased to about 1,300 MW. Thus, reliance on MSEB for peak power dropped to a very low level but will rise again as the peak load keeps growing at over 100 MW each year.

Wheeling

2.22 In addition, TEC "wheel" about 300 MW for MSEB, i.e. transmit it through their lines to MSEB's clients. In late 1970s TEC were importing over half of their requirements from MSEB, i.e. their direct customer base was too large for their own generating capacity. As one of its conditions for approving the Trombay fifth unit, MSEB took over about one third of TEC's direct industrial customers. The physical connections for supplying these customers did not change. Power coming from MSEB is brought to them through TEC's lines, but since 1980 they pay their bills to MSEB, which in turn pays TEC a tolling fee for the use of their lines.

6/ Peak availability is less than the rated capacity. During FY90, the annual peak occurred prior to the synchronization of Trombay Unit 6.

2.23 MSEB's reason for the takeover was that direct industrial consumers are highly desirable clients, because they pay higher tariffs and cost less to supply than residential consumers. Regarding those direct clients that have remained with TEC, MSEB has neither the grounds nor the motivation to take them over. First, TEC's dependence on MSEB has since been reduced to a reasonable level: imported energy was 25% of total energy sold in FY90, and is projected at 33% for FY2000. Second, MSEB is already charging the highest tariff in its book (Rs. 1.60/kWh after the May 1990 increase, i.e. about twice the MSEB average) for all the energy it sells to TEC, including that resold to the direct clients; hence MSEB would not enhance its income by taking them over, and it would increase its administrative costs.

Sales Growth

2.24 The recent evolution of TEC's sales by client category of client is shown in Table 2.2:

Table 2.2 : Sales by Client Category
(GWh)

	Licensees			Own Consumers				
Year	BEST	BSES	Total	Textile	Rail	Other	Total	Total
FY 82	1626	1688	3314	707	353	1116	2176	5490
FY 83	1766	2043	3595	322	349	1116	1787	5382
FY 84	1695	1899	3809	859	349	1240	2448	6257
FY 85	1876	2240	4116	935	355	1250	2542	6658
FY 86	1963	2428	4391	1013	354	1311	2678	7069
FY 87	2058	2627	4686	1025	359	1200	2584	7270
FY 88	2230	2948	5178	949	374	1227	2550	7728
FY 89	2325	3072	5397	910	370	1300	2580	7977
AAGR	5.2%	8.9%	7.2%	3.7%	0.7%	2.2%	2.5%	5.5%

(AAGR:Average Annual Growth Rate)

Currently, BSES and BEST account for about two thirds of TEC's sales and direct clients for one third. BEST, who supply the south of the city and BSES, who supply the north, have shown consistent growth over the decade; BEST at 5.2% and BSES at 8.9%. Both have a mixed consumer base of residential, commercial and industrial, which has to some extent been changing over this period. BSES's base remains largely static, whilst BEST's commercial consumption is steadily increasing with the development of office and hotel complexes. On the other hand, sales to TEC's direct clients, textiles, railways and other industries, have been largely static in the last 6 years. The average growth rate of energy sales, in kWh, is 5.5% p.a.

Dependence on MSEB

2.25 The average growth rate of the peak load, in kW, is much higher, about 8% p.a. Capacity additions are driven by the peak load growth, rather than by the energy requirement. In FY90 TEC's own generation covered two thirds of the peak load, but three quarters of the energy requirement in its system. By importing from the grid a larger portion of their peak load than of their energy requirement, TEC enjoyed a higher utilization of their own capacity. TEC's degree of dependence on MSEB for meeting their peak has varied between a high of one half in the early 1980s to a low one tenth since the addition of Trombay Unit 6 in March 1990. It will increase again as the system peak load grows at 8% each year, while the planned capacity additions are essentially to replace retiring units. Assuming no further additions beyond the components of the proposed project, TEC's dependence on MSEB would reach about one half of their peak load and one third of their energy requirement by FY2000.

2.26 TEC's preferred degree of dependence on MSEB would be for about a quarter of their peak load and about a tenth of their energy requirement. This profile would ensure a reasonable utilization of their own capacity, without exposing their franchise to the remote risk of erosion. To maintain this profile in the long-term, TEC would need to increase their generation capacity in line with the peak load growth. Assuming the required government approvals would be forthcoming as in the recent past, financial resources, both internal and external, would not be a constraint.

Diversification

2.27 TEC have also been exploring diversification avenues and have invested modest amounts to date both in other companies and through TEC divisions. Examples of the former are an investment of about Rs. 70 million in equity (listed shares) and loans to National Radio and Electronics Company (NELCO), a Tata group company manufacturing radios; and Rs. 2 million in WTI Advance Technologies Limited (Westinghouse-Tata-Indus), the computer services company with Westinghouse and IFC (IFC's $250,000 equity investment was approved in FY88). The Tata Electronic Data Systems Division (TEDS) is developing and marketing new products and services for plant operator training and defense applications; its revenues account about for 0.4% of TEC's total revenues in FY 89. The Contracts Division has been selected to participate in the construction of hotels by an Indian consortium in the Soviet Union.

2.28 These ventures are not substantial in cash flow terms and in any case their costs and revenues are accounted for separately from the electricity business and do not affect the tariffs. However, TEC regard them as an important insurance for the companies' long term survival. Consequently, they plan to gradually increase the level of investment and attention devoted to these activities. Of the Rs. 2,130 million to be raised from the new PCD issue (paras. 2.08 and 3.07), about Rs. 750 million is intended to be used for diversification.

III. THE PROJECT

Project Setting

3.01 The project will be located in the Western Region of the Indian interconnected power system, where the major supply utilities are the Gujarat State Electricity Board, the Madhya Pradesh State Electricity Board and the MSEB, all of which are state-owned. The Bhira hydro power plant is located about 100 km south-east of Bombay, while the Trombay thermal power plant is located in the metropolitan area. Bhira is at present connected to Bombay by 110 kV transmission lines and both plants supply TEC's license area in Bombay, which is the largest demand center in the region. Other suppliers in the Western Region are the TEC, AEC and SEC. A total of 17,669 MW was installed in the region as of March 31, 1989. Of this, private utilities owned 1,624 MW (AEC: 510 MW, TEC: 1,114 MW) i.e. 9%; the contribution of GOI-owned entities was 3,150 MW comprising 420 MW from Tarapore Nuclear Station, 2,100 MW from NTPC Korba and 630 MW from NTPC Vindhyachal coal-fired power plants. Thermal stations accounted for 85% of the capacity (78% in 1984), hydro about 13% (18% in 1984) and nuclear for the balance of about 2% (Annex 3.0).

3.02 The coincident maximum demand of the Region in FY89 was estimated to be 10,637 MW (Annex 5.0, Table 1), of which only 9,913 MW was able to be met because of a capacity shortage. Power systems operated with a frequency below 49.8 Hz for about 22.84% of the time in FY89. In Maharashtra, power cuts continue to be in force on certain categories of customers. In addition, due to forced outages of thermal plants, the Region periodically faces peaking shortages and load shedding, particularly in the evening peak hours. Moreover, the need for thermal plant to operate at partial load during off-peak hours is shortening equipment life considerably. To correct these imbalances, the long term expansion plan for the Region includes the installation of a number of peaking plants[7/] (para. 5.05).

Project Objectives

3.03 The physical objectives of the proposed project are to:

(a) provide additional peak generation capacity to meet more of the increasing demand in the Bombay area and reduce TEC's dependence on the state's grid;

(b) increase the capacity utilization of existing thermal generating units at Trombay[8/] and add a gas based combined cycle plant, all of which will reduce the average cost of generation;

7/ The existing 560 MW Koyna hydropower plant, owned and operated by MSEB is being expanded by an additional 1,000 MW capacity, within the Bank Maharashtra Power Project (Ln. 3096-IN), to allow the entire installation to operate in a more peaking mode than at present.

8/ By operating these units at a higher load factor during off-peak hours for pumping water at Bhira PS Scheme.

(c) mitigate the sulphur dioxide emissions from the coal and oil burning Trombay Unit No. 5; and,

(d) improve system reliability and quality of service to consumers.

The institutional and sectoral objectives are to:

(e) support increased private sector participation in the supply of power; and,

(f) encourage improved tariff structures and load management procedures for TEC's direct consumers.

Project Description

3.04 The proposed project is part of the least-cost development program for the Western Region Interconnected System. It consists of the following elements which are described in detail in Annex 3.1:

(i) Construction of a pumped storage (PS) scheme with one nominally rated 150 MW pump-turbine at the existing hydro-electric power plant at Bhira; the scheme will benefit from the existing Mulshi dam, tail pond and tunnel, so new civil works will be limited;

(ii) Expansion of the transmission link to evacuate the additional power from Bhira to TEC's licence area: upgrading of the transmission lines from Bhira to Dharavi in Bombay to 220 kV using the right-of-way of the existing 110 kV lines; installation of a 220 kV underground cable at the Dharavi end for environmental and resettlement reasons; and, extension of the Dharavi substation;

(iii) Construction of a 180 MW gas fired combined-cycle (CC) unit at the Trombay power station, with one 120 MW gas turbine-generator, a recovery boiler and one 60 MW steam turbine-generator and associated auxiliaries; and,

(iv) extension of the flue gas desulphurization (FGD) facility in Trombay Unit 5: installation of a second stream[9/] using the Flakt sea-water based technology, adopted successfully for the first stream and in operation since March 1988; this will scrub sulphur dioxide from the emissions of the Trombay Unit 5 to comply with the limits of the Maharashtra Pollution Control Board (MPCB); and

(v) review of design and technical specifications and supervision of construction of the Bhira pumped storage scheme and acquisition of know-how for the extension of the FGD facility at Trombay.

9/ Each stream would process one quarter of the flue gases from the 500 MW unit.

Cost Estimates

3.05 The estimated cost of the proposed project is summarized in Table 3.1. Details are given in Annex 3.2.

Table 3.1: Estimated Project Costs /a

Project Components	Local	Foreign	Total	Local	Foreign	Total
	Rs. million			US$ million		
I. 100 MW Pumped Storage Scheme at Bhira	524	370	892	30.0	22.2	53.0
II. Bhira-Dharavi 220 kV Transmission System	276	293	569	16.2	17.2	33.4
III. 180 MW Gas Based Combined Cycle Scheme at Trombay	747	799	1546	43.9	47.1	91.0
IV. Flue Gas Desulphurization System at Trombay 5	94	99	193	5.6	5.2	10.8
Total Base Costs	1641	1559	3200	93.5	91.7	185.2
- Physical Contingencies	116	102	218	6.8	6.0	12.8
- Price Contingencies	283	640	923	16.7	13.0	29.7
Total Contingencies	399	742	1141	23.5	19.0	42.5
Total Project Cost	2040	2301	4341	120.0	110.7	230.7
Interest During Construction						
- IBRD and IFC Loans	0	742	742	0.0	33.5	33.5
- Other	159	0	159	9.5	0.0	9.5
Total - Interest During Construction	159	742	901	9.5	33.5	43.0
Total Financing Required	2199	3043	5242	129.5	144.2	273.7

/a Includes taxes and duties of about US$ 10.0 million.

Basis for the Estimates

3.06 Cost estimates for the civil works are based on available data from other projects engineered by TEC's consultants (para. 3.10). Cost estimates for equipment and materials are based on the budgetary offers received from a number of manufacturers and compared with the most recent quotations received for similar projects. The estimated cost for consulting services is based on the already received quotations. Base prices were updated to January 1990. Physical contingencies of 10% on civil works (20% for civil works at Bhira PS Scheme) and 5% on equipment were assumed on the basis of experience with similar projects and amount to about 7% of the base cost. Price contingencies, which amount to 16% of the base cost, are based on the expected annual domestic and international inflation rates. The domestic inflation rates used for cost estimates are as follows: 7.3% for FY91, 7.0% for FY92 and FY93, 6.6% for FY94 and 6.5% thereafter. The international inflation rates are assumed as follows: 4.9% for FY91 and thereafter.

Project Financing

3.07 The project is the largest component of TEC's investment program over the next few years. The overall program also includes routine capital expenditure, diversification investments and most notably an expansion of several lines and substations to augment TEC's transmission system. Half the cost of the latter is to be financed by a SF 60 million (US$ 40 million) IFC loan approved in FY89. The part of the overall financing notionally attributable to the proposed project, if segregated from the cumulative amounts, is shown in Table 3.2.

Table 3.2: Incremental Financing Plan for the Project

	Local	Foreign	Total	Local	Foreign	Total
	---------Rs Million--------			---------US$ million-------		
Internal Accruals	1,045	-	1,045	61.5	-	61.5
Debenture Issue						
- Convertible part	450	-	450	26.5	-	26.5
- Non-convertible part	270	-	270	15.9	-	15.9
Long Term Loans						
IFC	-	1,244	1,244	-	60.0	60.0
IBRD	-	2,033	2,033	-	98.0	98.0
Local Fin. Inst.	200	-	200	11.8	-	11.8
Total	1,965	3,277	5,242	115.7	158.0	273.7

3.08 The proposed IBRD and IFC loans of US$ 98 million and US$ 60 million equivalent, would cover about 38% and 24% respectively of the total project financing requirements, net of duties and taxes.

3.09 The IBRD loan would be lent directly to TEC and would be guaranteed by GOI, which would levy a guarantee fee of 2.75% p.a. The IFC loan would be made directly to TEC. The interest risk on the IBRD loan, and the foreign exchange risk on IBRD and IFC loans would be borne by TEC. The IBRD loan and the IFC loans would be cross effective with each other (para. 6.03.d).

Status of Engineering and Project Management

3.10 TEC would be responsible for implementing all the components of the proposed project, with the assistance of Tata Consulting Engineers (TCE) and an international consulting firm with specific experience on pump-turbine projects. TEC's proposed project management structure is shown in Annex 3.3. TEC will retain TCE as the lead consulting firm for all components of the project. TCE will assist in the engineering design, preparation of tender documents, specifications and drawings, assistance during bidding process, preparation of construction drawings, supervision during equipment manufacture, erection, and civil works construction. TCE engineered successfully all the projects realized by TEC, including Trombay Units 5 and 6, partly financed by IBRD and the transmission system development partly financed by IFC. TCE's experience is acceptable to the Bank for this project. For their part, TEC have demonstrated competence in project management during the construction of the above IBRD and IFC financed projects.

3.11 The type and size of the pump-turbine and generator-motor to be installed within the Bhira PS Scheme is relatively new in India and no substantial experience is available in the country with equipment of similar characteristics. Therefore, with IBRD financing under the Trombay IV Project (LN. 2452-IN) in mid-1989, TEC and TCE initiated the selection process for a qualified foreign consulting firm to assist in the review of design and technical specifications of these major mechanical and electrical equipment. TEC and TCE have received five offers and they have selected Electricite de France (EdF), who are satisfactory to IBRD and IFC. About 70 person-months would be required for these tasks. Consultants' supervision activities would be financed under the proposed project. The know-how for the expansion of the FGD scrubber stream at Trombay would be obtained from A/S Norsk Viftefabrikk (Flakt), Norway.

Project Schedule

3.12 The project would be implemented over a period of four years (Annex 3.4). The Bhira PS Scheme would be implemented in three years from the date of award of the contract for the main civil works, during the 1991-1994 period. Delivery of the main plant and equipment would be within 21 months and subsequent erection and commissioning is envisaged to be completed by September 1994. The transmission development associated with Bhira PS Scheme would also be implemented in the 1991-1994 period, to be ready when the pumped storage project is commissioned. The combustion turbine of the CC Scheme at Trombay would be manufactured and erected within 24 months of the award, i.e. during the 1991-1993 period, and will initially be operated in open cycle. The heat recovery boiler and steam turbine would be commissioned within 36 months of award, i.e. during the 1991-1994 period. Then the entire scheme will operate in combined cycle. The extension of the FGD Scrubber Stream at Trombay Unit 5 would be realized during 1991-1994 period, within 24-30 months of award. The proposed project would be completed by March 31, 1995.

Procurement

3.13 The procurement arrangements are summarized in Table 3.3 and details, as well as major milestones of the procurement process, are shown in Annexes 3.5 and 3.6. For performance guarantee reasons, the main package for the 180 MW Gas Based CC Scheme (120 MW gas turbine and its generator, 60 MW waste heat recovery boiler, steam turbine and generator and auxiliaries) would be procured as a single responsibility contract under international competitive bidding (ICB) and on a supply-and-erect basis. The turbine-generator / pump-motor for the Bhira PS Scheme would also be procured under ICB, also on a supply-and-erect basis. Among the remaining contracts, some would also include civil works (e.g. substation structure and transmission lines); this would ensure better coordination during implementation. Civil works packages would be procured under local competitive bidding (LCB), because the size of each package is too small (four contracts estimated to cost a total of about US$16.1 million; the largest being US$6.7 million for the Bhira PS Scheme) to attract interest from international contractors. In principle the IBRD funds would be used to finance the above mentioned main packages for the Trombay CC and Bhira PS Schemes, and the IFC funds would cover most of the remaining materials and equipment contracts. It is estimated that the majority of the latter will be imported directly by TEC, but a portion of the IFC funds may be used to pay for locally procured items. This allocation of the IBRD and IFC funds may be revised, in consultation with the Guarantor, during project implementation.

Table 3.3: Procurement Arrangements

(US$ millions) a/

Project Element		ICB	LCB	Other	N.A.	Total Cost
Preliminary Works		-	-	2.0	-	2.0
Civil Works		-	16.1	-	-	16.1
Material and Equipment		112.8	5.0	81.9	-	199.7
	IBRD:	(93.0)	(4.0)	(-)	(-)	(97.0)
	IFC :	(-)	(-)	(60.0)	(-)	(60.0)
Services		-	-	8.1	4.8	12.9
	IBRD:	(-)	(-)	(1.0)b/	(-)	(1.0)
Total		112.8	21.1	92.0	4.8	230.7
	IBRD:	(93.0)	(4.0)	(1.0)	(-)	(98.0)
	IFC :	(-)	(-)	(60.0)	(-)	(60.0)

a/ Contract values include contingencies and taxes and duties (US$ 18.8 million).
b/ Consultants' services to be procured under IBRD Guidelines for Consultants.
ICB: International Competitive Bidding.
LCB: Local Competitive Bidding.
Other: Direct imports and locally procured items.
N.A.: Not Applicable (Administrative Expenses)
Note: Figures in parenthesis are the respective amounts financed by the IBRD and IFC loans.

3.14 Contracts for materials, equipment and erection worth less than US$200,000 each and with an aggregate value of US$4 million may be procured on the basis of local competitive bidding in accordance with procedures satisfactory to IBRD. Bidding documents and recommendations for the award of contracts would be prepared by TEC with the assistance of TCE. Contracts financed under the IBRD Loan worth US$2 million or more would be subject to prior review by IBRD. This category is estimated to cover about 90% of the value of all ICB contracts. The smaller IBRD financed contracts under ICB would be subject to selective post award review. Local manufacturers would be expected to bid for most categories of equipment, and a domestic preference of 15% or the corresponding import duty, whichever is less, would be applied in the comparison of bids for equipment contracts. Foreign consultants to assist TEC and TCE in the design and implementation of the Bhira PS Scheme have been selected in accordance with Bank Guidelines on the selection of consultants (para. 3.11). The know-how supplied by A/S Norsk Viftefabrikk, Norway (Flakt) will be obtained through a negotiated contract, satisfactory to the IBRD and IFC; this contract would be financed under the IFC loan.

3.15 Procurement under ICB reduces the cost of inputs purchased from domestic suppliers, because of exemptions from customs and excise duties. Customs duties are not waived on imported packages. This treatment applies to loans from certain development lenders, including IBRD but not IFC. IFC loans do not qualify for the deemed export benefits, and do not entail the GOI guarantee fee.

Disbursements

3.16 Disbursements from the proposed IBRD loan would be made against: (a) 100% of the foreign currency expenditures and 100% of the local expenditures (ex-factory cost if manufactured in India) of equipment, and materials; (b) 100% of foreign expenditures and 70% of local expenditures for the erection of plants, transmission lines and substations; and (c) 100% of the foreign expenditures on consultants. Disbursements for equipment, materials, and erection under contracts valued less than US$200,000 equivalent would be made against statements of expenditures (SOE), the documentation of which would not be sent to the Bank but would be retained by TEC for inspection by supervision missions. All other disbursements would be fully documented. Retroactive financing, in an aggregate amount not exceeding US$2 million has been provided in the IBRD loan, for expenditures made after May 31, 1990.

3.17 To facilitate disbursements a special account would be established for the IBRD loan with an authorized allocation of US$7 million. Annex 3.7 shows the estimated disbursement schedule as derived from the construction programs of the project components (para. 3.12), assuming normal terms for commercial payments, including retention payments. The aggregated disbursement profile for the project is four years and does not fit IBRD's standard profiles because the components of the proposed project have particular characteristics. The Bhira PS Scheme does not involve the construction of any dam or tunnel, the upgrading of the transmission capacity from Bhira would not require any clearing and development of transmission line right-of-way, and in the Trombay CC Scheme the equipment which would require the longest manufacture and installation time is the waste heat recovery boiler which would be installed in about 36 months from the date of award of contract. The last payments are estimated to be made during the first half of 1995. Accordingly, the closing date for the loans would be June 30, 1995.

Security Arrangements

3.18 The proposed IBRD and IFC loans would be secured by first charge on all of TEC's assets, subject to certain prior charges on current assets in favor of working capital lenders, shared pari passu with other senior lenders. Annex 3.8 shows TEC's borrowing position and the priority of existing liens on its properties as of March 31, 1989. Partial disbursement of the IFC loan would be permitted against hypothecation on moveable assets.

3.19 The Bank loans (1549- IN and 2542-IN) for the Trombay fifth and sixth units (500 MW each) have been secured by mortgage, charge and floating charge on TEC's assets at the Trombay Thermal Power Station (including the 500 MW units), the Trombay Housing Colony and the Trombay License. TEC's other borrowings for these units are secured by mortgages, charges and floating charges on all their assets and all their joint and separate licenses. The other debentures of the three companies forming the TEC are secured by a mortgage, charge and floating charge on the respective assets and licenses of each, including their respective interests in the assets and licenses jointly owned by them.

3.20 TEC agreed to the following security arrangements for the proposed loans (para. 6.02.b):

(a) A mortgage over all the immoveable properties of TEC;

(b) A floating charge hypothecation on all moveable assets of TEC; and,

(c) Assignment by way of mortgage of TEC's Licenses, including extensions and renewals thereof.

3.21 The proposed security will be shared pari passu with TEC's existing senior lien holders and also with the Indian Financial Institutions and other senior lenders for the proposed project. The security will be obtained in the form of an equitable mortgage with an assurance from TEC that at the request of IBRD and/or IFC, TEC will convert such security to an English Mortgage and for this purpose will also execute a Power of Attorney to facilitate the conversion of the mortgage from an equitable one to the English form. The creation of an equitable mortgage and execution of a Power of Attorney are conditions of effectiveness of the proposed IBRD loan (para. 6.03.a and b).

Fuel Supply for the Trombay Thermal Power Plant

3.22 The actual amount of natural gas supplied to Trombay is currently about 2.5 million m3/day, equivalent to 748,000 tons/year. However, the "firm" gas supply committed by the Oil and Natural Gas Commission (ONGC) is 1.5 million m3/day. The 180 MW CC Scheme is estimated to operate at a load factor of 68% and generate 1,080 GWh p.a., consuming 630,000 m3/day of gas. This will be taken from the existing "firm" commitment; i.e. the project is not based on additional gas allocation. The balance of the gas will continue to be burned in the conventional thermal units 5 and 6. Unit 5 (500 MW) also burns coal and oil and Unit 6 is equipped to burn oil and gas only. ONGC has a gas pipeline to Trombay, and since 1978 has been supplying the existing units with associated gas from the Bombay High Oilfields, as and when it is available. TEC are so far the only user for much of this fuel, which would otherwise have to be flared. New consumers will be taking quantities of gas for the next few years, but new oil and gas finds are made regularly. Although ONGC can give no firm commitment today for supplies beyond 1.5 million m3/day, it seems that for some years there may be no market except TEC for a large part of the associated gas currently being flared offshore.

3.23 Gas now contributes the largest share of the calorific input at Trombay. The second is residual fuel oil, known as low sulphur heavy stock (LSHS), supplied by small dedicated pipelines from nearby refineries. This viscous liquid is extremely difficult to transport by heated trucks, hence TEC are a very convenient client for the refineries. Indian Oil Corporation has recently offered a further 240,000 tons/year of LSHS, which added to the already contracted 400,000 tons/year supplied by Bharat Petroleum Corporation and Hindustan Petroleum Corporation, would take care of the complete LSHS requirements. The actual quantities and unit costs of the fuels consumed in FY90, and their share in the total calorific input are given in Table 3.4:

Table 3.4: Quantities of Fuels Used at Trombay TPP and Unit Costs

FY90	Consumption ktoe	Unit Cost Rs/Gcal	Share of total calorific input	Share of total SO_2 emissions
Gas	829	200	59%	0%
Coal	122	200	3%	30%
Oil	510	277	38%	70%

3.24 Trombay TPP is equipped to receive coal by rail. Indian Railways now have facilities to deliver up to about 2.3 million tons of coal per year to Trombay. However, in order to remain within the SO_2 emissions limit stipulated by the MPCB, a much lower amount (about 1.3 million tons p.a.) is expected to be burned at Trombay.

3.25 Neither the limits to the supplies of these fuels, nor the extent of the demand for them which may develop from other users, is yet known, but it is likely that Trombay will burn gas, some LSHS and coal for a number of years to come. During negotiations of Loan 2452-IN (Trombay IVth Project), GOI undertook to ensure the availability of adequate supplies of suitable fuel for the optimum operation of the Trombay TPP. GOI reconfirmed this commitment (para. 6.01.a).

Water Rights for the Bhira Pumped Storage Scheme

3.26 There are no pending water rights issues that could affect the implementation and operation of the proposed Bhira PS Scheme, which will not require additional water and which will simply recycle some of the water now passing through the existing hydro electric power plant. Actual water usage in the three hydro stations of TEC is within the allocation sanctioned by the Krishna Water Tribunal. There is no dispute on the water rights of Bhira and the PS scheme has been cleared by the Maharashtra Water Authority.

Land Acquisition

3.27 At Bhira and Trombay, the proposed schemes would be located adjacent to the existing Bhira hydro and Trombay thermal power plants, respectively, and would be built completely within the limits of the lands already owned by TEC. No additional land therefore would be acquired; consequently no resettlement is involved. The double circuit 220 kV Bhira-Dharavi transmission line would use the right of way of the existing 110 kV lines; at Dharavi the lines would end through underground cables of about 5 km, which would be buried under the existing streets.

Environmental Aspects[10/]

3.28 All the components of the project will comply with GOI and GOM standards as well as with all applicable environmental policies and guidelines of the World Bank. The Bhira PS Scheme would result in expansion of the existing penstocks and power house. The operation of the scheme will have minimal effect on the environment and the water levels of the existing upstream (Mulshi Lake) and downstream reservoirs. One of the existing 110 kV single circuit transmission lines between Bhira and Dharavi will be dismantled and a new 220 kV double circuit line using the existing right-of-way will be built. At the Dharavi end, the line will be connected to the substation by an underground cable. The environmental impact of this component is also minimal. With the commissioning of the Trombay CC Scheme, Units 1, 2 and 3 (total capacity 187.5 MW) will be decommissioned. As a result, cooling water discharges from Trombay TPP will be reduced, even though existing cooling water discharges are within GOI and GOM standards and Bank guidelines. The major air emissions of concern from the proposed CC Scheme are nitrogen oxides (NOx), and the plant will be designed to meet GOI and GOM standards and Bank guidelines. The proposed FGD scrubber stream will be identical to the first FGD stream, which has been operating satisfactorily since March 1988. Air emissions and liquid effluents from this unit comply with GOI and GOM standards and Bank guidelines. Receipt by TEC of all necessary environmental clearances from the GOI and GOM authorities is a condition of effectiveness of the proposed IBRD loan (para. 6.03.c).

Benefits

3.29 The project will increase TEC's peak generating capacity, reduce their dependence on the supply from MSEB, reduce the transmission losses and the average cost of generation and improve system reliability. Tariff adjustments and load management initiatives will bring the level and structure of TEC's tariffs more closely in line with supply costs. The support by the IBRD and IFC would demonstrate the Bank Group's resolve in assisting the development of private sector participation in India's power sector.

Risks

3.30 The physical project components, which are based on conventional technology, do not present unusual technical risks, in particular when considering that, for the Bhira PS Scheme, water reservoirs and conduits already exist, and therefore civil works will be minimal. TCE and EdF (para. 3.10) have been appointed as engineering consultants; both are acceptable to the Bank for this project. The Mulshi Dam, upstream of the Bhira Hydro Power Project will be continued to be monitored and inspected periodically by the Irrigation Department of GOM in accordance with Indian regulations.

3.31 The future performance and viability of TEC depend on maintaining the present operational balance with MSEB. First, TEC rely on MSEB to make up its deficit in peak demand and energy requirements. Second, MSEB has a

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10/ Details are provided in Annex 3.9.

decisive input in the regulatory decisions that affect TEC, e.g. special reserves, tariffs, approvals for new projects. Third, TEC's physical assets are fully integrated with MSEB's in the Bombay area, as power generated in stations owned by TEC or MSEB travels alternately through lines and substations belonging to either, to reach the final consumer. This interdependence has helped TEC to maintain and develop their concession, while continuing to serve their consumers efficiently. Ensuring the supply of power to consumers "in the most efficient and economic manner" is MSEB's main mission under the Act, and it is fulfilled partly through TEC. In the political climate of the late 1970's there was a tendency for the state sector to take over all power generation and distribution, and the future of private utilities seemed bleak. Ten years later, as deficits persist, the role of the private sector in power is being encouraged, with additional incentives being considered. As long as TEC continue to be efficient and are able to control their costs and consequently the tariffs, there will be little incentive and much risk for MSEB to upset the present working balance. Consequently, the risk of an adverse change in MSEB's relationship with TEC that might seriously affect TEC's operations is considered remote (para. 2.04).

3.32 Increases in TEC's fuel costs or in MSEB's tariffs would increase TEC's tariffs, i.e. would be passed on to its consumers. The debt service coverage would not be affected, unless, in the event of sharp and sustained increases, consumers were able to stop TEC from raising its tariffs to the level allowed under the Act. As long as input costs and tariffs increases are not much steeper than general inflation and as long as power deficits persist, this risk is considered manageable.

Project Monitoring and Supervision

3.33 TEC will submit, starting with the quarter in which the loans are signed, quarterly reports covering the work of consultants, physical progress, costs, disbursements and administrative aspects of the proposed project. In addition annual financial and administrative reports will be submitted.

IV. FINANCIAL ANALYSIS

Past and Projected Financial Performance

4.01 TEC's recent and projected financial performance is detailed in Annex 4.0 and its FY85-FY2000 performance is summarized in Table 4.1.

Table 4.1: Financial Summary — Rs Million

FY End March 31	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
	Historical					Est.	Projected									
Revenues	4602	5242	6603	6882	7336	8269	9359	10956	12284	14754	16586	16405	15623	17158	20436	24677
Cost of Fuel	2611	2403	2794	2883	2884	3283	3914	4741	5023	5504	5770	6612	7141	7712	8499	9179
Other Operating Costs	570	526	611	708	909	1025	1101	1181	1288	1362	1464	1574	1692	1820	1958	2108
Power Purchases	716	1626	2036	2009	2736	2520	3360	3025	4104	5834	7281	6058	4836	5483	7825	11200
Depreciation	114	124	126	130	184	285	330	417	448	503	579	593	600	604	608	639
Interest	229	264	315	385	446	597	703	813	855	938	1020	975	943	918	877	790
Foreign Exchange Loss	7	7	35	65	87	107	147	182	229	267	303	332	362	392	421	444
Net Profit	382	322	593	312	451	475	422	713	395	331	321	422	401	421	443	516
Special Reserves	301	266	493	251	374	330	264	506	166	85	87	168	129	130	135	194
Distributable Profit	80	56	90	61	77	146	158	208	228	245	234	254	273	291	308	323
Dividends	52	52	56	72	71	72	108	144	144	144	144	144	142	142	142	142
Total Assets	4376	5253	7030	8455	9704	10931	12594	14444	15941	17033	17487	17116	16844	16940	16804	16585
Net Worth	1656	1929	2529	2796	3183	3587	4401	5471	5722	5909	6086	6353	6612	6891	7191	7585
Net Long Term Debt	2902	3315	3370	4227	4809	5414	6440	7203	8379	9019	8998	8489	8029	7769	7028	6993
Net LTDebt/Net Worth	1.75	1.72	1.33	1.51	1.51	1.51	1.46	1.32	1.46	1.53	1.48	1.34	1.21	1.13	0.98	0.92
Operating Cash Flow	734	719	1031	953	1120	1478	1619	2148	1941	2080	2284	2336	2317	2346	2360	2401
Debt Service	378	402	603	591	662	847	1295	1526	1551	1636	1793	1942	1881	1879	1870	1892
Debt Service Cover	1.94	1.79	1.74	1.61	1.69	1.74	1.25	1.41	1.25	1.27	1.24	1.20	1.23	1.25	1.26	1.27
Average Tariff, Rs/kWh	0.691	0.742	0.800	0.858	0.921	1.008	1.118	1.180	1.258	1.429	1.522	1.515	1.571	1.693	1.877	2.110

4.02 As a regulated utility under the Act (para. 1.10) TEC recover their full costs and earn a predetermined return on their capital base. They have always serviced their debt regularly and paid dividends at 16% and, in the last three years, at 18% of par. Despite the low depreciation rate allowed under the Act, TEC had a comfortable cash flow because of the special appropriations allowed by the State (para. 1.11). The cash flow raised through special appropriations, which are charged in the tariffs, was about 1.8 times the amount of depreciation during the FY85-FY89 period. The majority of TEC's debt (over 70% in FY89) is in foreign exchange, hence subject to revaluation in Rupee terms. This revaluation, charged through a special appropriation, has increased tariffs by less than 2% to date.

4.03 The cash costs of generation have been contained, mainly due to the use of competitively priced gas as the main fuel, as well as the high plant load factor and overall operating efficiency. The cost of purchased power increased sharply in the past 5 years, to currently about twice the full cost of TEC's own generation. MSEB's tariff to TEC is now significantly higher than TEC's average tariff: Rs. 1.60/kWh since May 1990 vs. TEC's 1.00.

4.04 TEC's financial condition is projected to remain solid, with a long term debt: net worth ratio of 1.5 maximum and a current ratio of 1.2 minimum. Cash flow will remain strong, with a debt service coverage (DSC) of 1.25 average through FY2000 and a minimum of 1.20 in FY96. About 20% of total new investment, including normal capital expenditures is expected to be covered by internal resources (self-financing). To yield the return allowed under the Act, after the various appropriations allowed today, tariffs will need to increase from Rs. 1.00/kWh average in FY90 to 2.11 in FY2000, i.e. at an average rate of 7.7% p.a..

4.05 These projections include the effect of fuel cost increases, assumed at 8% p.a., and imported power cost increases, assumed at 10% p.a., which are passed on to the consumers through automatic tariff rises. They also assume a 68.5% load factor of the newer thermal units, which is lower than the actual historic level, but much higher than the average in MSEB. The impact of adverse changes in these key assumptions on the tariffs and the DSC is quantified in the sensitivity analysis (para 4.08). The key assumptions for these projections are detailed in Annex 4.0, Table 5.

4.06 TEC's ability to service their debt depends both on their maintaining an efficient operation and cost position relative to MSEB and also on their continuing to charge the special appropriations allowed by GOM. The financial projections assume that the special appropriations for project costs allowed by GOM would continue as per existing practice. To prevent adverse change in the existing practice, GOI agreed to cause GOM to continue to allow TEC the current practice of collecting certain special reserves as are permissible under the Electricity (Supply) Act (para. 6.01.b.iii). In addition, to ensure the continued financial strength of TEC, TEC agreed to limit their long-term borrowings such that their long-term debt to equity ratio will not exceed 2.0 at any given time (para. 6.02.c). To monitor TEC's financial position, TEC agreed to provide the Bank and IFC by December of each year, with their financial projections for the current and next four financial years (para. 6.02.d).

4.07 To compute the incremental project return, full financial projections were run for the case with and the case without the project, the latter excluding all the effects of the project on the generation, costs, revenues, investment and financing. The cash flows attributable to the project were calculated as the difference between the two cases. The project rate of return (ungeared, i.e. excluding the interest on the project loans only) is the IRR of the differential cash flow stream to TEC was computed at 23.8%. This does not include the savings accruing to consumers as a result of reduced tariffs in the case with the project, compared to what tariffs would be without it. The IRR of the Combined Cycle (with the FGD) project alone is 27.3% and that of the Bhira PS Scheme (with the transmission lines) is 17.8%.

Sensitivity Analysis

4.08 Increases in the fuel or purchased power costs are charged on to consumers in full, so TEC will raise the additional cash flow through increased tariffs and therefore the debt service cover (DSC) will not be affected. If both fuel costs and MSEB's tariffs increased by 13% p.a. (the other parameters remaining unchanged) TEC's tariffs would have to increase by an average of 10.9% p.a. (vs. 7.7% p.a. average in the base case) to maintain the same DSC. If fuel and imported power costs remained at today's levels the tariff increase would be only 1.2% p.a.. MSEB's ability to increase its current level of generation and provide surplus energy to TEC during off-peak hours is limited by constraints mainly on plant maintenance and coal supply. If TEC's average plant load factor decreased to 60% from 68.5% in the base case, the additional tariff increase necessary to maintain the same DSC would be small: 8.5% p.a. average vs. 7.7% in the base case. The impact of a 20% cost overrun or of a 1 year delay of the start up on tariffs, DSC or project IRR is insignificant. This is due primarily to the cost-plus nature of TEC's operation under the Act.

4.09 Most of TEC's debt (70% on 3/31/89) is in foreign currencies and a devaluation of the Rupee would increase interest and principal payments in Rs terms. The increase in interest costs would affect the tariffs, while inflated principal repayments, which are not charged through the tariffs, would depress the DSC somewhat. If the Rupee devalued vis a vis the US dollar more than in the base case (10% p.a.), tariffs would have to increase by 8.0% p.a. and the DSC would decrease to a minimum of 1.15 in FY96 vs. 1.20 in the base case. A summary table of the sensitivity analysis is shown in Annex 4.0. In summary, TEC's financial performance is projected to be quite robust, with the debt service cover remaining acceptable under a range of possible adverse changes.

V. ECONOMIC ANALYSIS

5.01 India's power systems are planned on a regional basis. Because of this, the economic analysis focuses primarily upon the Western Region power system, of which the components of the proposed project would be an integral part. However, when prices are low (as in India), demand and investment can be inflated above economic levels. Analysis of the Western Region power system therefore is complemented by analysis of the Bhira and Trombay projects separately to demonstrate that each is an economic component of the regional investment program.

Electricity Demand In The Western Region And Supply Capacity

5.02 Electricity consumption in the Western Region and projected demand through FY2000 are summarized in Annex 5.0, Tables 1 and 2. Between FY81 and FY88, generating capacity increased at 7.1% p.a., but demand was not able to be met in full: CEA estimates that in FY88, shortages were equivalent to about 9% of the maximum load met. Through FY2000, CEA expects maximum demand will increase on average at 8.8% p.a.. Capacity additions averaging 10.1% p.a. will meet this increase and fully cover the existing shortage. In addition to the present shortages at times of highest demand, scheduled maintenance and plant breakdowns also leave small shortages of supply during some off-peak periods. Through FY2000, CEA expects that total consumption in the Region will increase at 8.8% p.a.. Generation from new plant is expected to increase the supply in total by 8.9% p.a., and this would be sufficient to eliminate all off-peak deficits.

5.03 At present, the Region's elasticity of electricity consumption to economic growth is approximately 2.1. This can be expected to decline modestly with gradual improvement in industrial energy efficiencies. Even so, compared with projected economic growth of 6% p.a. under the Eighth Plan and 5% p.a. thereafter, generation expansions averaging 8.9% p.a. appear comparatively modest. Nevertheless, if economic growth fell to below 4.2% p.a., the Region could be left with an energy surplus. This is unlikely, but not inconceivable.

The effect of a surplus would be to reduce the utilization of base-load coal stations located near load centers (because of their high fuel costs). Stations generating only during peak periods (such as Bhira) would not be affected[11/]. Neither would combined-cycle stations (such as Trombay), whose fuel costs are lower than those of some existing load-center thermal stations[12/].

5.04 In practice, lower growth in total consumption is likely also to be associated with lower growth in maximum demand. If growth in maximum demand fell to below 7.8% p.a., the development program as presently planned would leave the Region with surplus generating capacity. While again unlikely, this also is not inconceivable. The prospect of a capacity surplus combined with a surplus of off-peak energy would reduce the desirable rate of adding new base-load capacity. Load-center coal stations would be the preferred candidates for deferral because of their relatively high costs (Annex 5.0, Table 5). It is most unlikely that deferral of combined-cycle stations would be economic.

Least-Cost Analysis

5.05 Bhira Pumped-Storage Project. CEA's least-cost generation planning for the Western Region through FY96 shows a requirement for additional capacity in excess of the 10,900 MW able to be installed during this period. Most of the requirement is for additional base load capacity, though to improve supply reliability during periods of highest demand, the Region also needs to install capacity that will generate only during peak periods. The Bhira pumped-storage project (which will concentrate generation by the existing station into 3 hours per day) is one project option meeting this requirement. Alternatives are a small coal-fired station or an open-cycle gas turbine. Simulations of the operations of the Western Region power system through FY2000 show that Bhira is the cheapest option (Annex 5.0, Table 3): present-valued to FY94 (when the station would be commissioned), Bhira offers a cumulative cost advantage over the coal alternative of Rs. 1452 million (US$ 85 million) and over the open-cycle gas turbine of Rs. 943 (US$ 55 million). Assessed over the whole of the station's 25-year operating lifetime, Bhira's cost advantages are respectively Rs. 5392 million (US$ 316 million) and Rs. 3779 million (US$ 222 million).

5.06 Trombay Combined-Cycle Project. The inclusion of the 180 MW combined cycle project in the least-cost program for the Western Region is justified by the cost advantage it offers compared with alternative options for additional base load generation. Although generation from Trombay delivered into the Bombay metropolitan area will cost slightly more than generation from a pithead coal-fired station (Rs 0.79/kWh versus Rs 0.76/kWh), Trombay is much cheaper than generation from a coal-fired station close to Bombay (Rs 0.91 kWh), (Annex 5.0, Table 4). Moreover, an important factor in Trombay's favor is that it can be commissioned 2 years earlier (during 1994) than could either of the coal-fired alternatives. Considered over the lifetime of the station, this gives Trombay a

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11/ In fact, a reduction in off-peak and load would improve the economics of Bhira by reducing the station's cost of pumping.

12/ The fuel costs of Trombay will be about 52 paise per kWh, whereas those of a load-center coal station are about 70 paise per kWh.

cost advantage over a pithead station, present-valued to FY93, of approximately Rs 1190 million (US$ 70 million) and over a load-center station of approximately Rs 2140 million (US$ 126 million).

5.07 TEC's "firm" supply of gas at Trombay is sufficient to fuel a 410 MW combined cycle project. This capacity could be reached with the addition of a subsequent combined-cycle project of 230 MW. In the meantime it is economic, and advantageous environmentally to proceed with the installation of the proposed 180 MW project. It is estimated that installing 410 MW in one phase would delay commencement of the project by at least two years. The phased approach thus enables 180 MW of combined cycle capacity to be commissioned sooner. The economies of scale of a single 410 MW project compared with two phases are small: about US$30 million (15% of the investment costs), and less than 1% of the operating costs. These economies are outweighed by the value of advancing incremental supply (approximately US$55 million each year [13/]). Hence the phased approach is economically preferable. Moreover, it is not clear that a 410 MW project, or a second phase 230 MW, would receive the necessary environmental clearances. Compared with the proposed 180 MW project, the 230 MW and 410 MW projects each entail diverting an additional 0.9 million m3/day of gas from the Trombay thermal units. This would increase coal burning in these units by 800,000 tons/year, and increase particulate emissions from the power station by a further 10 tons per day. Although the Trombay Units 5 and 6 were cleared (12 years ago) to burn coal, background pollution levels in Bombay were then much lower. It is now not clear that the MPCB would agree to either the 410 MW project, or a second phase of 230 MW. During negotiations, TEC confirmed that they will examine the technical and economic feasibility of installing an additional 230 MW combined cycle project when they next require to install additional base load generating capacity. In the event these feasibilities are established, TEC further confirmed that they would seek the necessary approvals and clearances from GOM, CEA and DOP.

Program Analysis

5.08 The program analysis considers the FY90-FY2000 time-slice of the Western Region development program. This period will include the construction and first few years operation of the Bhira pumped-storage and Trombay combined-cycle stations, their associated transmission and the additional flue gas desulphurization facilities on the existing Trombay station.

5.09 Program Costs. Capital and operating costs of the program time-slice are summarized in Annex 5.0, Tables 5 and 9. Financial costs have been converted to economic terms by excluding taxes and duties and by applying an SCF of 0.8 to residual local costs. Investments in generation cannot usually be related to particular investments in transmission and distribution. Because of this, these investments have been imputed at a rate of 60% of generation investments. New coal-fired stations are assumed to consume 0.61 kg/kWh of coal and 10 ml/kWh of oil. The economic costs of coal and oil are assumed to be Rs

13/ 180 MW net of losses of 15% for 6000 hours at Rs. 1.03/kWh - Rs. 1.58/kWh (para. 5.12) less fuel and O & M costs of Rs. 0.55/kWh (Annex 5.0, Table 4).

360/tonne and Rs 2.7/litre. New gas-fired stations are assumed to consume $0.23m^3$/kWh of gas and the economic cost of gas is estimated to be Rs 2,200 per thousand m^3. The cost of pumping in the Bhira pumped-storage station has been estimated as Rs 0.57/kWh. This is based on the fuel costs of a load-center coal station (which would be the cheapest source of additional off-peak energy) with allowances for 5% transmission losses and a 15% efficiency loss in pumping.

5.10 Program Benefits. Benefits that will be derived from the Western Region development program mostly will be in the form of additional electricity consumption. Additional benefits may be realized through reducing supply costs during off-peak periods and through improving supply quality. However, these additional benefits are likely to be comparatively small and so have not been included in the analysis. Incremental consumption has been valued assuming that by FY93 - the first year of benefits from the program time-slice - the average tariff level in the Western Region will reach Rs. 0.89/kWh (in FY90 prices) and that thereafter, the tariff will remain constant in real terms. The corresponding rate of economic benefit is assumed to be Rs. 0.71/kWh (Annex 5.0, Table 6).

5.11 Present excess demand (para. 5.02) indicates that consumers willingness-to-pay for public electricity exceeds existing tariff levels. Incremental revenues therefore reflect only a portion of consumers' benefits and only a small portion of benefits when tariffs are relatively low, as in India. Determining whether total benefits exceed marginal supply costs therefore requires examination of consumers' willingness-to-pay.

5.12 Consumers' willingness-to-pay is related to the costs of private supply, or to the costs of doing without electricity if private supply is either infeasible or financially unattractive. This analysis conservatively assumes that only half of consumers would be willing to pay the higher costs of private supply and that no one need go without electricity in the event public supply is unavailable. Rates at which consumer accrues have been estimated from the economic savings afforded by access to public electricity compared with the higher costs of private supply. The latter have been estimated from an updated review, conducted jointly with CEA, of the costs of private generation and irrigation using diesel pumps (Annex 5.0, Table 6). The average rate of economic benefit is estimated to be Rs. 0.87/kWh. Adding this to the economic benefit of incremental revenues gives a total economic benefit estimated to be Rs. 1.58/kWh (about US 9 cents/kWh).

Program Rates of Return

5.13 Estimated rates of return of the FY90 to FY2000 time-slice of the Western Region development program are:

(i) 7% counting as benefits only the economic value of incremental revenues; and

(ii) 25% when allowance is made for associated consumer surplus.

With a 12% discount factor, the Net Present Value (NPV) of the program time-slice (including the allowance for consumer surplus) is estimated to be Rs.

159,076 millions, equivalent to approximately US$ 9357 millions (Annex 5.0, Table 7).

5.14 Sensitivity analyses show the program time-slice could withstand cost increases of approximately 50% or reductions in benefits of about 35% before some reconfiguration of the program would be required for it to remain economic (Annex 5.0, Table 7). Similarly, the program time-slice could withstand an implementation delay of more than 4 years and remain economic; how long in practice would depend on the extent of associated cost increases. In the event some reconfiguration of the program became desirable, the demand and least-cost analyses (paras 5.05 - 5.07) provide assurance that the Bhira and Trombay power stations would not be preferred candidates for deferral.

Project Analyses

5.15 Bhira Hydro Station and Bhira-Dharavi Transmission. The estimated rate of return of these project components is 26% and their net present value (NPV -- with a 12% discount factor) is estimated to be Rs. 1,770 million (equivalent to US$107 million). Capital and operating costs of the project components, expressed in economic terms, are summarized in Annex 5.0, Table 8. Generation by Bhira will displace a portion of TEC's purchases from MSEB during peak periods. Supplies thereby released will be used by MSEB to meet additional peak demand in Maharashtra, but will require increases in MSEB's peak transmission and distribution capacity. These associated investments have been allowed for in the same way as in the program analysis (para 5.09). Pumping costs have been included at Rs. 0.57/kWh (para 5.09). As Bhira will only provide firm supply during peak periods, this generation (net, 203 GWh p.a.) has been valued at the full cost of alternative supply - Rs 2.45/kWh (Annex 5.0, Table 6). Additional seasonal energy that will be provided by the station (net, 23 GWh p.a.) and the savings in losses facilitated by the Bhira-Dharavi transmission line (89 GWh p.a.) have been valued at the average rate used in the program analysis - Rs 1.58/kWh (para 5.12).

5.16 Trombay Combined-Cycle and Flue Gas Desulphurization. The estimated rate of return of these project components is 27% and their NPV (with a 12% discount factor) is estimated to be Rs 2,792 million (equivalent to US$164 million). Capital and operating costs are again summarized in Annex 5.0, Table 8. The Trombay combined-cycle station is expected to operate on base load and to supply 1026 GWh p.a.. The flue gas desulphurization (FGD) equipment to be installed in the existing Trombay station will ensure that emissions from Trombay remain within permissible limits when coal is substituted for the gas diverted to the combined-cycle station. The FGD equipment will not significantly affect generation from the Trombay thermal units and neither will the increase in coal burning change the station's costs of generation. Energy provided by the combined-cycle station will be used to meet incremental demands from TEC's direct consumers and from the consumers of BSES and BEST, which TEC supply in bulk. The additional supplies will also reduce TEC's purchases of energy from MSEB, which will enable MSEB to increase supplies to its own consumers. Estimations have again made allowance for associated investments in transmission and distribution (para 5.09). Incremental supplies have been valued at the average rate used in the program analysis (para 5.12).

VI. AGREEMENTS AND RECOMMENDATION

Agreements Reached between IBRD and GOI and TEC

6.01 GOI has:

(a) Reaffirmed the availability of adequate supplies of fuel for TEC's Trombay Thermal Power Plant (para. 3.25); and,

(b) Agreed to cause GOM to:

(i) extend before June 30, 1991, TEC's license to at least up to September 15, 2010, the maturity date of the proposed IBRD loan (para. 2.03);

(ii) not to take any actions, including delimiting TEC's area of supply, that would adversely affect TEC's operational performance and financial position (para. 2.04); and,

(iii) continue to allow TEC the current practice of collecting certain special reserves as are permissible under the Electricity (Supply) Act (para. 4.06).

6.02 TEC agreed to:

(a) Furnish by July 31 of each year, its audited annual accounts including a copy of its combined accounts (para. 2.14);

(b) The security arrangements for the proposed loan (para. 3.20);

(c) Limit their long-term borrowings so that their long-term debt to equity ratio will not exceed 2.0 at any given time (para. 4.06); and,

(d) Provide their financial projections by December of each year covering their current and next four financial years projected performance (para. 4.06).

6.03 The following would be conditions of effectiveness of the proposed IBRD Loan:

(a) Creation of an equitable mortgage in a form satisfactory to IBRD (para. 3.21);

(b) Execution of a Power of Attorney in favor of IBRD to enable IBRD at its discretion to convert the mortgage to an English form (para. 3.21);

(c) Receipt by TEC of all environmental clearances from the GOI and GOM as shall be necessary for the construction of the Trombay CC Scheme (para. 3.28); and

(d) All conditions precedent to disbursement of the IFC Loan have been fulfilled (para. 3.09).

Agreements Reached between IFC and TEC

6.04 The terms and conditions of the Investment Agreement between IFC and TEC are consistent with the above.

Recommendation

6.05 On the basis of the project justification and the agreements reached, the proposed project is suitable for an IBRD loan of US$98 million and IFC loans of US$30 million and Yen 4,600 million to the Tata Electric Companies.

INDIA

PRIVATE POWER UTILITIES PROJECT I

ALL-INDIA: ELECTRICITY SUPPLY AND DEMAND

	Actual			Estimated			
	FY82	FY88	Annual Increase (%)	FY89 d/	FY95	FY2000	Annual Increase (%)
1. Power							
(a) Installed Capacity (MW)	32,347	54,247	9.0	59,040	103,916	165,481	9.8
(b) Generating Capability (MW)	20,121	28,242	5.8	31,713	61,418	99,365	10.9
(c) Peak Load (MW)	20,121 a/	39,660	12.0 b/	43,308	72,711	112,319	9.0
(d) Deficit (MW/% of Peak Load)	n.a.	11,418/ 28.8	-	11,595/ 26.8	11,293/ 15.5	12,954/ 11.5	-
2. Energy							
(a) Generating Capability (GWh)	113,827	187,976	8.7	205,909	381,866	629,037	10.7
(b) Energy Requirement (GWh) c/	113,827 a/	210,492	10.8 b/	229,662	384,764	598,773	9.0
(c) Deficit (GWh/% of Requirement)	n.a.	22,516/ 10.7	-	23,753/ 10.3	2,898/ 0.8	35,814/ 5.9	-

a/ Constrained by supply capacity. No estimates are available on the extent of suppressed demand in FY82.
b/ Growth rates are overstated as 1981/82 data reflect supply rather than demand.
c/ Total final demand for energy plus transmission and distribution losses.
d/ Estimated by CEA.

Source: Thirteenth Electric Power Survey of India, CEA, December 1987, plus Bank estimates.

INDIA

PRIVATE POWER UTILITIES PROJECT I

ELECTRICITY SUPPLY AND DEMAND

ALL-INDIA: ENERGY CONSUMPTION BY MAIN CONSUMER CATEGORY

	Actual (%)		Estimated (%)		
Consumer Category	FY82	FY88 a/	FY89 a/	FY95 b/	FY2000 b/
1. Domestic	11.6	14.7	15.3	19.4	23.6
2. Public Lighting	0.9	0.9	1.1	1.3	1.5
3. Public Water	2.3	1.8	1.9	2.2	2.5
4. Agriculture	16.9	23.8	24.1	28.1	32.0
5. Industry	57.7	48.8	47.5	39.1	30.6
6. Traction	2.8	2.5	2.5	2.4	2.4
7. Commercial c/	7.8	7.5	7.6	7.5	7.4
Total	100.0	100.0	100.0	100.0	100.0

a/ Estimated by CEA.
b/ Estimated by Bank.
c/ Includes consumption by other miscellaneous categories of consumers.

Source: Thirteenth Electric Power Survey of India, CEA, December 1987.

INDIA

PRIVATE POWER UTILITIES PROJECT I

Comparison of MSEB's and TEC's Tarrifs

Revision Date (Av. Rate of business)	MSEB Demand (Rs/KVA/ Month	MSEB Energy (P/Kwh	MSEB FAC[a] (P/Kwh)	TEC Demand (Rs/KVA/ Month)	TEC Energy (P/Kwh)	TEC FAC[a] (P/Kwh)
10.16.75	15	9.5	5.0/5.1	16.5-20.3	9 -10.6	5.7/ 7
01.28.77	16	11	5.3/5.3			
03.16.79				18.4-22.6	10.1-11.8	9 / 9
03.17.81				21.4-26.4	11.7-13.7	14 / 17
09.16.81	22	20	10 /10	26 -27	20 -20.8	23.5/23.5
02.01.86	35	85	44 / 2	28 -34	68 -83	50 / 0
06.01.87	35	88	6 / 6			
12.01.87				28 -34	68 -85.5	3 /0.5
05.01.89[b]	35	108	15 / 0			

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[a] Fuel Adjustment Charge before/after the revision (the difference was merged in the Basic Energy Charge).

[b] Anticipated.

Source: MSEB and TEC

Annex 1.2

INDIA

PRIVATE POWER UTILITIES PROJECT I

Previous Loans and Credits to Indian Power Sector (as of March 31, 1990)
(Amount in US$ Million)

	Borrower	IBRD Loans	Number	Approval Date	Closing Date	Loan Amount	Amount Disbursed	Status
1.	India	First DVC - Bokaro - Konar	23	4/50	2/56	18.5	16.7	Complete
2.	India	Second DVC - Maithon - Panchot	72	1/53	6/58	19.5	10.5	Complete
3.	Tata	Trombay Power	106	11/54	9/66	16.2	13.9	Complete
4.	Tata	Second Trombay	164	5/57	9/66	9.8	9.7	Complete
5.	India	Third DVC - Durgapur	203	7/58	6/65	25.0	22.0	Complete
6.	India	Koyna Power	223	4/59	4/65	25.0	18.7	Complete
7.	India	Power Transmission	416	6/65	12/70	70.0	50.0	Complete
8.	India	Second Kothagudem Power	417	6/65	12/70	14.0	13.8	Complete
9.	Tata	Third Trombay Thermal Power	1549	4/78	12/84	105.0	105.0	Complete
10.	India	Ramagundam Thermal Power (*)	1648	1/79	6/87	50.0	45.6	Complete
11.	India	Farakka Thermal Power (*)	1887	6/80	6/89	25.0	2.5	Complete
12.	India	Second Ramagundam Thermal Power (*)	2076	12/81	6/90	280.0 a/	256.4	
13.	India	Third Rural Electrification	2165	6/82	6/88	304.5	295.5	Complete
14.	India	Upper Indravati Hydro	2278	5/83	6/94	156.4	0.3	
15.	India	Central Power Transmission (*)	2283	5/83	3/90	250.7	77.6	
16.	India	Indira Sarovar	2416	5/84	6/92	17.4	4.9	
17.	India	Second Farakka Thermal Power (*)	2442	6/84	12/91	300.8	97.3	
18.	Tata	Fourth Trombay Thermal	2452	6/84	6/90	135.4	118.9	
19.	India	Chandrapur Thermal Power	2544	5/85	12/92	300.0	126.0	
20.	India	Rihand Power Transmission (*)	2555	5/85	12/89	250.0	165.1	
21.	India	Kerala State Power	2582	6/85	9/91	176.0	23.2	
22.	India	Combined Cycle (*)	2674	4/86	12/91	485.0	343.9	
23.	India	Karnataka Power	2827	6/87	12/95	330.0	21.7	
24.	India	National Capital Power Supply (*)	2844	6/87	6/95	485.0	120.9	
25.	India	Talcher Thermal Power (*)	2845	6/87	3/96	375.0	30.2	
26.	India	Second Karnataka Power	2938	5/88	12/96	260.0	20.9	
27.	India	Uttar Pradesh Power	2957	6/88	12/96	350.0	26.6	
28.	India	Nathpa Jhakri Power	3024	3/89	12/97	485.0	35.0	
29.	India	Maharashtra Power	3096	6/89	12/96	400.0	20.0	
	Total					5,719.2	2,092.8	
	(Total Loans for NTPC Projects)					(2,501.5)		

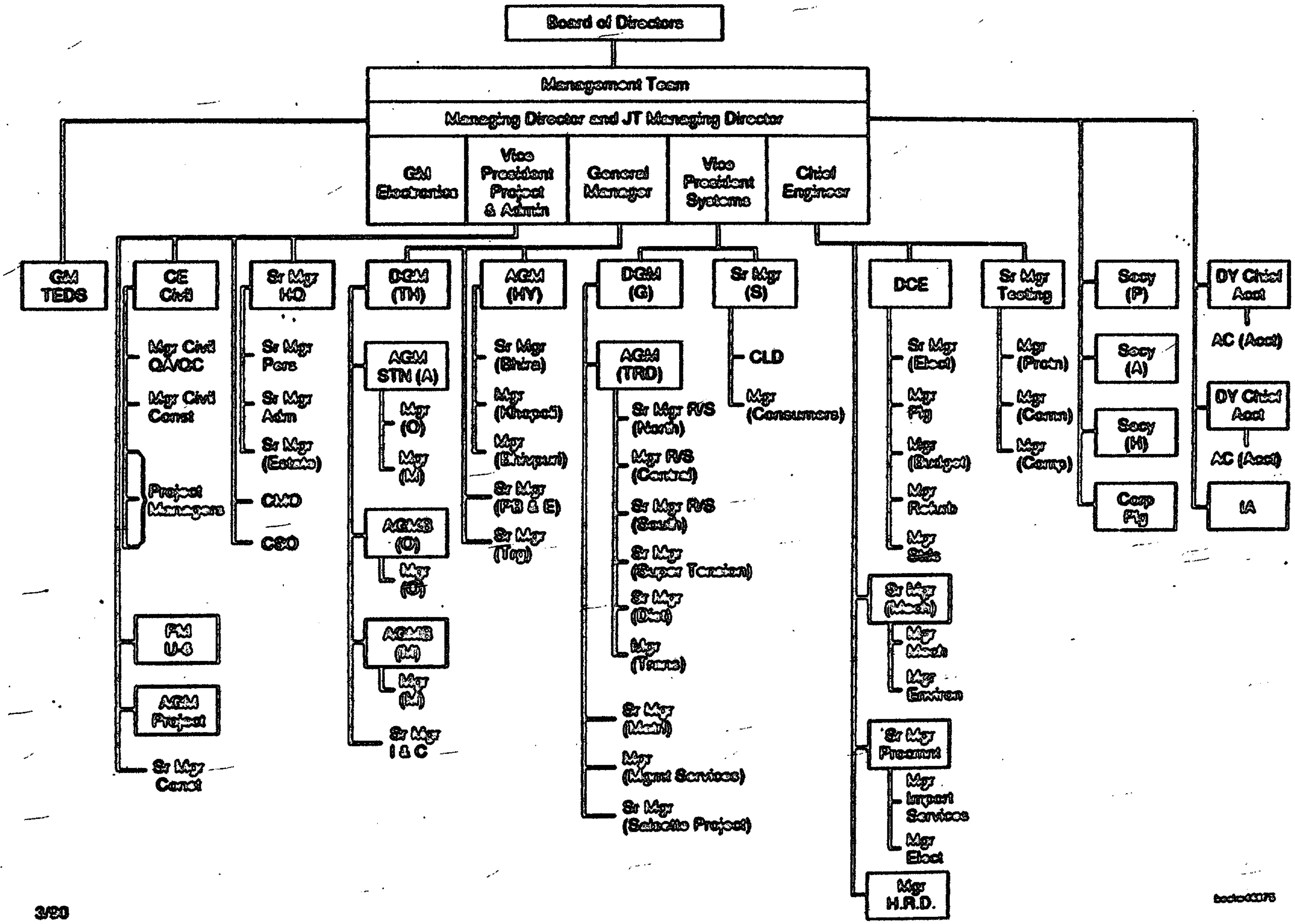
a/ Out of original loan amount of US$300 million, US$20 million was cancelled.

	Borrower	IDA Credits	Number	Approval Date	Closing Date	Loan Amount	Amount Disbursed	Status
1.	India	Fourth DVC - Durgapur	19	2/62	12/69	21.9	19.9	Complete
2.	India	Second Koyna Power	24	8/62	9/70	21.1	21.1	Complete
3.	India	Kothagudem Power	37	5/63	12/68	24.1	24.1	Complete
4.	India	Beas Equipment	89	6/66	6/74	26.6	26.3	Complete
5.	India	Second Power Transmission	242	4/71	3/77	75.0	72.9	Complete
6.	India	Third Power Transmission	377	3/73	9/78	85.0	85.0	Complete
7.	India	Rural Electrification	572	7/75	12/80	57.0	57.0	Complete
8.	India	Fourth Power Transmission	604	1/76	6/83	150.0	149.9	Complete
9.	India	Singrauli Thermal Power (*)	685	3/77	6/84	150.0	150.0	Complete
10.	India	Korba Thermal Power (*)	793	4/78	3/86	200.0	199.9	Complete
11.	India	Ramagundam Thermal Power (*)	874	1/79	6/87	200.0	200.0	Complete
12.	India	Second Rural Electrification	911	5/79	3/84	175.0	171.7	Complete
13.	India	Second Singrauli Thermal Power (*)	1027	5/80	3/89	300.0	292.8	Complete
14.	India	Farakka Thermal Power (*)	1053	6/80	12/88	225.0	225.0	Complete
15.	India	Second Korba Thermal Power (*)	1172	7/81	12/89	400.0	370.3	Complete
16.	India	Upper Indravati Hydro	1356	5/83	6/91	170.0	114.0	
17.	India	Indira Sarovar	SF020	5/84	6/92	13.0	0.7	
18.	India	Indira Sarovar	1613	5/86	6/92	13.2	0.0	
	Total					2,306.9	2,180.6	
	(Total Credits for NTPC Projects)					(1,475.0)		

(*) NTPC Projects

Annex 2.0

INDIA
PRIVATE POWER UTILITIES PROJECT I
Tata Electric Companies' Organization Structure



3/90

INDIA

PRIVATE POWER UTILITIES PROJECT I

Western Region Interconnected Power System

A. Details of Power Cuts and Regulatory Measures*

Maharashtra

1.	Essential and Service Industries	:	Nil
2.	Continuous Process Industries and Textile Industries	:	10%
3.	Other Industries	:	15%

Gujarat

After May 1988 power supply to rural loads is available only from 12-24 hours generally.

Madhya Pradesh

1. Single and 2 shift industries not to work between 1400-2200 hours.
2. Staggering of weekly offs for HT consumers.
3. Mini Steel Plants to draw power from 2200 hours to 1400 hours.

* Source: WREB Annual Report 1988-89.

C. Existing and Planned Capacities in the Western Region

1. Existing Capacity as of March 31, 1989

Sr. No.	Particulars Number of Units x MW	Capacity MW
Hydro		
1. Koyna	4 x 65; 4 x 75; 4 x 80	880
2. Tillari		60
3. Koyna DPH	2 x 20	40
4. Eldari	3 x 7.5	22.5
5. Vir	2 x 4.5	9
6. Bhatgar		16
7. Radhanagari	4 x 1.2	4.8
8. Vaitarna		60
9. Vaitarna-Dam toe	1 x 1.5	1.5
10. Tata Electric Cos.	Bhira - 6 x 22) Bhivpuri - 6 x 12) Khopoli - 6 x 12)	276
11. Bhira Tailrace	2 x 40	80
12. Paithan		12
13. Pench 1/3 Share		53
14. Bhandardara		10
15. Pawna		10

		1534.8
Thermal		
1. Nasik	2 x 140; 3 x 210	910
2. Trombay 1,2 and 3	3 x 62.5	187.5
3. Trombay 4 and 5	1 x 150) 1 x 500)	650
4. Koradi		1100
5. Bhusaval		482.5
6. Paras		92.5
7. Parli	2 x 30) 3 x 210)	690
8. Khaperkheda	3 x 30) 1 x 210)	300
9. Uran (gas)		672
10. Chandrapur		840

		5924.5

2. Planned additions by 1994-95, in accordance with the survey:

Hydro	MW	Thermal	MW
1. Bhatsa	15	1. Chandrapur	1000
2. Khadakwasla	16	2. Khaper Kheda Extn II-IV	630
3. Ujjani	12	3. Trombay 6	500
4. Kanher	4	4. Uran Waste Heat	240
5. Dhom	2	5. Dahanu	500
6. Terwanmedh	0.2		
7. Warna	16		
8. Manikodh	6		
9. Surya	6		
10. Dimbhe	5		
11. Duganga	24		
12. Bhandara Ph2	34		
13. Koyna IV	1000*		
	-----		-----
	1140.2		2570

* Unlikely to be commissioned fully by 1994-95 and thus peaking deficits will further increase.

INDIA

PRIVATE POWER UTILITIES PROJECT I

TATA ELECTRIC COMPANIES

Project Description

A. Bhira Pumped Storage Scheme

1. The Bhira Pumped Storage Scheme[1] would form the extension to the existing six-unit 132 MW conventional hydro power plant (HPP) which draws water from the Mulshi reservoir lake across the Mula River. Mula River joins the Bhima River which in turn meets the Krishna River and flows eastward, through the States of Karnataka and Andra Pradesh, to the Bay of Bengal. Through intakes on the Mulshi Lake the water flow is diverted westward to Bhira hydro power scheme located at the western foot of the Western Ghats, to take advantage of the steep terrain drop. The Bhira Hydro Power Scheme consists of the Mulshi dam, two approach channels, two tunnels, Bhira power house, downstream pond and Bhira Tailrace Hydro Power Project. Except for the latter which is owned and operated by the MSEB, the other structures are owned and operated by TEC. The Mulshi dam is situated about 95 km southeast of Bombay and about 40 km east of Pune. The Bhira power station is situated 22 km west of Kolad which is on the National Highway No. 17, from Bombay to Goa.

2. The original Bhira hydro power project, built from 1921 to 1927 when it was commissioned by TEC, consists of a masonry gravity dam 50.6 m high and an ungated spillway. The dam is horizontally arched and the combined length at the crest is 1,555 m. Approach channels and the intake works are followed by the headrace tunnel 4,335 m long with a cross sectional area of 13 m2 and rated capacity of 34 m3/s. The tunnel terminates at the surge shaft from which three galleries take off, feeding the six penstocks located along the slopes of the Western Ghats. Each penstock is 1.5 m in diameter for 1,144 m after which bifurcates into penstocks 0.9 m in diameter for the last 620 m. Thus a total of twelve penstocks enter the Bhira power house. There are two pelton turbines of about 11 MW each driving a generator. The power house had initially five units of 17.5 MW each (total capacity: 87.5 MW) with provision for a sixth unit. Later the generators were upgraded and the sixth unit was added.

3. The Mulshi dam is thus 63 years old. After experiencing the seismic shock of December 11, 1967 (known as the Koyna earthquake), it has not shown

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[1] Pumped storage is a method of energy storage in which electrical energy produced during low-demand periods is used to pump water into an elevation from which water is released during high-demand periods to supply high-value energy. A pumped storage HPP produces power during peak-load periods by using water previously pumped from a lower reservoir to an upper reservoir during off-peak periods.

any problems. As advised by GOM, and as a matter of routine the stability of the dam is being surveilled in the context of the latest Indian Standards. Large diameter core samples of dam masonry have been recently tested at the Maharashtra Engineering Research Institute in Nasik. The average tensile and comprehensive strength values measured are considered suitable. Stability analysis of the dam, carried out by TCE, concluded that the dam is safe under all loading conditions and that the maximum tensile and comprehensive stresses are well within the actual strength of the masonry. The final results of the analysis will be sent to the Irrigation Department of GOM for their review and opinion. The dam was inspected in 1989 and the inspection form issued by GOM Irrigation Department concluded that the dam is in good condition and it is well maintained by TEC. A copy of the Certificate of Inspection is included in the Project File (Annex 6.0).

4. Mulshi Lake live storage is estimated at 523 million m3, with a reservoir surface area of about 41.5 km2. The discharging capacity of the spillway is 1,926 m3/s at maximum water level of 606.1 m.

5. An approach channel has been cut in the lake bed for conveying water at low lake levels to the tunnel intakes. An auxiliary approach channel exists for utilizing part of the storage in the event of emergencies such as a delayed monsoon season. Both channels have stop log gates and can convey 148.5 m3/s at minimum reservoir level of 590.1 m; both are unlined at present.

6. The original tunnel, 4,335 m long with a cross sectional area of 13.0 m2 and rated capacity of 34 m3/s (equivalent to about 120 MW generation capacity), was lined in about 9% of its length. Lining and rock falls obstructed it gradually, forcing TEC to construct first an auxiliary reservoir at a location called Dongerwadi and later a new headrace tunnel, including a new approach channel, intake works, surge shaft, valve house and connections to the penstocks, because the critical power supply situation of the TEC system made it impossible to stop the plant for the period required to carry the repair works. The new tunnel was completed in 1965 and the original tunnel has been in disuse since then and is not in good condition. Its rehabilitation is part of the proposed project.

7. The new tunnel is 4,530 m long, including 405.9 m in surface steel conduit. It is 4.25 m in diameter with 1.52 m level bottom and a cross sectional area of about 14.2 m2. It is concrete-lined throughout its length and is connected to the original twelve penstocks. Its rated capacity is 54.4 m3/s which would cater to a station capacity of 192 MW. An additional stop log gate is located downstream of the off-take channel feeding the new tunnel.

8. Presently the total nominal installed capacity is 132 MW formed by six units of 22 MW each. The maximum output capacity of the plant is 148 MW. Its average annual generation capability is about 850 GWh. Water from Bhira is evacuated to Kundalika River. The plant production is evacuated from the switchyard to the Khopoli HPP and to a substation in Panvel through a 110 kV system about 55 km long. The Bhira hydropower scheme is in good condition and is well operated and maintained.

9. The capacity of the Bhira Tailrace Hydro Power Project is 80 MW (2 x 40 MW). The discharges from Bhira are diverted by a masonry weir into a lined diversion channel with a capacity of 90 m3/s down to a pickup pond impounded by an earth dam across the Kundalika River. The live storage capacity of this pond is 1.54 million m3. Through a tunnel, water from this pond is conducted to a forebay with a live storage capacity of 1.76 milliom m3, just upstream of the tail race power house.

10. The proposed Bhira PS Scheme would utilize the hydraulic structures of the existing Bhira HPP, some of which would be modified, improved or rehabilitated to better its hydraulic and structural characteristics required for the existing and proposed pumped storage projects. The pumped storage scheme would utilize the Mulshi Lake as upper reservoir and the pickup pond of the tail race project as the lower pond.

11. The major works to be carried out are summarized in the following paragraphs.

a. Power Plant Civil Works. Rehabilitation of the main and auxiliary approach channels including removal of silt, rehabilitation of channel slopes, repairs to the concrete linings. These works would more than double the carrying capacity of the channels at minimum drawdown level. Rehabilitation of intake works in the original and new tunnels would include repairs and alterations as necessary to trash screens, gates, gate guides, sill, stoplogs and other items. Hydraulic model studies are being carried out to identify the scope of the modifications.

b. Head Race Hydro System. (i) Original Tunnel. Work would consist of cleaning, trimming of existing rock surface, concrete lining for its entire length. Carrying capacity of the tunnel would be increased to enable generation of 150 MW for exclusive operation of the existing Bhira HPP. (ii) New Tunnel. The existing simple surge shaft would be modified to contain the up and down surges within limits of the turbine operation. A concrete slab would be built at the bottom of the shaft which would convert single surge shaft into an orifice surge shaft. (iii) Galleries. A new valve house would be constructed at the gallery No. 4 of the new tunnel at Dongerwadi to accommodate 3.7 m diameter butterfly valve and accessories on the new penstock to suit the operating conditions of the pump-turbine. (iv) Penstock. A new surface penstock of high tensile steel (ASTM 517, Grade F) between the new valve house at Dongerwadi and the beginning of the pressure shaft on the upstream side of the proposed power house would be built. This penstock would be approximately 1,480 m long with varying diameters of 3,7 m, 3.5 m and 3.3 m. (v) Pressure Shaft. An inclined pressure shaft 180 m long, 3.3 m in diameter and lined with high tensile strength steel (ASTM 517, Grade F) would be built between the end of the penstock and power house.

c. Power House. A 20 m x 20 m shaft power house oval in shape, to accommodate the 150 MW pump-turbine and generator-motor and other equipment would be built to the east of the existing power house.

d. Tail Race Structures. (i) Tail Race Tunnel. A concrete lined tunnel of 3.9 m diameter, 70 m long would be built at the exit of the new power house. The tunnel would be followed by a tail race channel. Trash screens, gates, stoplogs, hydraulic hoist, gate house and auxiliary equipment would also be procured and installed at the end section of the tunnel. (ii) Forebay. A forebay, leading to the existing pond of the tail race project, would be constructed immediately downstream of the new tail race channel.

e. Mechanical and Electrical Equipment. One 150 MW reversible Francis pump turbine and one 180 MVA generator-motor, both at nominal ratings, with associated mechanical and electrical systems and auxiliaries would be procured and installed at the new power house. One 13.8/220 kV, 180 MVA step-up transformer would also be procured and installed at the new switchyard which would be constructed on the west side of the new power house.

12. Geology and Topography. Extensive geological and topographical surveys and drill holes (20 diamond drill holes with an approximate total depth of 2,800 m) have shown that the geology of the area and the topographic features are favorable for constructing the proposed Bhira PS Scheme. Adequate measures will be taken to determine safe charges for blasting and blasting pattern to protect existing structures.

B. Expansion of the Bhira-Dharavi Transmission System

13. With the installation of the 150 MW Bhira PS Scheme, the existing four 110 kV transmission lines would not be sufficient to evacuate the total generated power. Furthermore, it is computed that by uprating the transmission system to 220 kV, the losses in the TEC transmission system would be reduced by about 32 MW at the generation mode (during the peak hours) and 16 MW at the pumping mode; total annual energy savings are computed to be about 89 GWh. It is therefore proposed to built a 220 kV, double circuit transmission line with twin 0.2 sq.in copper equivalent ACSR conductors per phase. A 220 kV switchyard would be erected at Bhira, with the provision for two 220 kV feeders to which the new double circuit line would be connected. At the Dharavi end of the system, an underground cable would be buried under the existing streets to avoid resettlement problems because of the concentrated habitations around the substation, and two 220 kV feeders would be built for the connection of the double circuit line.

14. The line would be erected along the right of way of the existing single circuit 110 kV lines. The route length of the new transmission line is 110 km. The other technical parameters are summarized as follows:

- Conductor : Twin Panther (2x0.2 sq.in copper equivalent); ACSR
- Ruling span : 300 m
- Number of insulators per string: 14

15. Two 220 kV feeder bays consisting of circuit breakers, isolating switches, grounding switches, current transformers, potential transformers,

associated protection systems, etc. would be added to Bhira and Dharavi switchyards, respectively. The recommended scheme for the 220 kV switchyard at Bhira is breaker and half scheme. This scheme would provide high reliability and adequate flexibily for future expansion. The other technical parameters are summarized as follows:

- Highest system voltage	: 245 kV
- Short circuit rating	: 40 kA for 3 sec.
- Power frequency withstand voltage	: 460 kV
- Rating of bus breakers:	
- Dharavi	: 2000 A
- Bhira	: 2500 A
- Insulation Level	
- for 220 kV	: 1050 kV
- for 110 kV	: 550 kV

16. A three-winding autotransformer with delta connected tertiary would be installed at Bhira to interconnect the 220, 110 and 22 kV networks. Its other technical parameters are summarized as follows:

- Rating	: 220/110/22 kV; 125/125/35 MVA
- Tap changing	: Off circuit taps with ±10% range in steps of 2.5% on 220 kV winding
- Insulation Level	
- 220 kV	: 1050 kV
- 110 kV	: 550 kV
- Type of earthing	: Star winding grounded through resistance

17. To ensure reliable communication, system operation, protection and data transmission from Bhira, a fibre optic communication system (composite fibre optic groundwire system) would be installed between Bhira and Dharavi and interconnected with the already planned fibre optic system of the TEC grid.

C. Gas Based Combined Cycle Scheme at Trombay TPP (Trombay 7)

18. The proposed Gas Based CC Scheme (Trombay 7th Unit) would comprise a gas turbine generator (GT) of 120 MW, and a heat recovery steam generator (HRSG), a steam turbine and a generator (STG) of 60 MW. Thus the total installed capacity of the scheme would be 180 MW. The 120 MW GT would use natural gas as the main fuel. A diesel generator of 3 MW capacity, burning diesel oil, would also be provided to supply power for start-up purpose under black-out conditions. When the CC Scheme would be commissioned, the oldest three units of Trombay (3x62.5 MW = 187.5 MW) would be shut down; the existing three generators which were repaired/rehabilitated during the late 1970s would be operated as synchronous condensers, to alleviate the voltage drops in the Bombay area.

19. Installed Capacity. The Committee of Experts, set up by the Government of Maharashtra and including representatives from the Central Electricity Authority, following frequent system shutdowns (the most recent being in

August 1989), recommended the installation of a gas turbine generator, with facility for quick starting as being essential for the metropolitan Bombay. The GT part of the proposed CC Scheme would serve as an emergency source of power supply for the essential load of Bombay city, which has been estimated at 120 MW. An unfired HRSG, using the exhaust gases of the GT unit, would produce enough steam to operate a steam turbine generator of about 60 MW capacity. Hence the capacity of the CC Scheme would be 180 MW. GT units up to ratings of about 150 MW have been commercially proven. These units can achieve a thermal efficiency of about 30-32 percent on the simple cycle mode. Combined with a waste heat recovery steam generator unit, an overall efficiency of about 45-50 percent can be obtained. Although the proposed CC Scheme would be operated as a base load station, the daily load pattern of the power grid would determine the actual generation from the scheme. The plant capacity utilization has been considered as 6,000 kWh/kW and the availability of the plant is estimated at about 90 percent.

20. Configuration. Taking into account the performance of gas turbine units of 130-150 MW and of the steam cycle equipment and investment and O & M costs, a configuration of 1 GT + 1 HRSG + 1 STG has been adopted.

21. Location and Land. Trombay TPP is situated on the north-eastern part of Bombay city near the Kurla railway station of Central Railway, at a sea coast site. Trombay is also well linked by road. Heavy equipment would be transported by barges, which would be beached at the power plant site during high tide conditions, when draft of over one meter would be available. The CC Scheme would be installed adjacent to Unit 6 (500 MW) on the western side of the steam turbine-generator building. An area totalling 22,800 m2 (80m x 285m) would be required for the GT unit, HRSG and turbo-generator unit, generator transformer yard and switchyard. The area available west of Unit 6, which measures 48,000 (150m x 320m) is adequate. The proposed site is generally level, requiring only limited amount of land development which would include a certain amount of filling in low laying parts. From geo-technical investigations carried out for Unit 6, weathered basalt rock of about 2 meters thickness, was encountered from depths between 10 to 12 meters. Below this sound rock was encountered. Piling is envisaged for all buildings and major equipment foundations.

22. Cooling Water Supply and Discharge. Trombay, being a sea coast site, sea water is used for cooling the steam turbine condensers of Units 1-6. Units 1, 2 and 3 presently draw sea water each using two pumps located at the jetty. Units 1 and 2 are connected by a 1,800 mm diameter cement lined pipe, fed by four pumps each with a flow rate of 4,860 cubic metrs per hour. The cooling water requirements of the CC Scheme is estimated at 14,500 cubic meters per hour including auxiliary requirements and would be supplied from the existing three pumps of Units 1 and 2; the remaining pump would be for standby service. These pumps are in good working condition. Studies made by the Central Water and Power Research Station at the time of engineering of Unit 6, confirmed that recirculation would not take place under all conditions of tide. Presently, Units 1, 2 and 3 discharge the used condenser water through the discharge channel located near the intake structure, compared to the discharge points of Units 5 and 6 and the proposed CC Scheme. Discharge

from the latter would be substantially less compared to that of Units 1, 2 and 3, on account of lesser steam turbine capacity and higher overall efficiency. Hence no recirculation effect is anticipated. The existing units are operating without any adverse effect on marine life.

23. Make Up Water Supply. Raw water for the make-up of the steam generator would be supplied by Municipal Corporation of Greater Bombay. Presently 9,700 cubic meters per day are sanctioned by the corporation and drawn by TEC. The requirement of the CC Scheme is estimated at about 400 cubic meters per day; while Units 1, 2 and 3 presently consume 2,000 cubic meter per day. Therefore the requirements of the CC Scheme would be supplied from the existing raw water allocation for the Trombay TPP.

24. Demineralised Water. The total capacity of the demineralised water plants of Units 5 and 6 is 3,240 m3/d at 45 m3/h rate, with one standby stream, while the combined requirements of these units is 2,400 m3/d. The demineralised water requirement of the CC Scheme, which is estimated at 336 m3/d at 14 m3/h rate would thus be provided by the existing plants.

25. Aviation Clearance. The 275 m tall chimney of Unit 6 was cleared by the Aviation Authorities. The CC Scheme would have a bypass stack/HRSG stack of about 45 meters, which is well within the above limit.

26. Fuel Gas Supply. The requirement of gas for the 180 MW CC Scheme for an average daily generation of 3 GWh (1,080 GWh per annum) is 0.53 m3/d (average) based on a heat rate of 1,748 kcal/kWh, density 0.82 kg/Nm3 and calorific value 12,300 kcal/kg[2].

27. Evacuation of Power. There are four 110 kV and three 200 kV transmission lines from Trombay to Chembur, Parel, BARC, Carnac, Dharavi and Kalwa substations. Local distribution to industries located nearby Trombay is made with 22 kV lines. The total firm transmission/distribution capacity of all these lines is about 2,300 MVA and is thus adequate for evacuating generation of 1,330 MW Trombay Units 4, 5 and 6 and the proposed CC Scheme[3].

28. Staff and Staff Colony. A nearby housing colony has been constructed by TEC for the operation and maintenance staff of Trombay TPP. This is being continuously developed by TEC depending on requirements. After decommissioning of Units 1, 2 and 3, adequate staff would be available for the O & M of the CC Scheme.

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[2] Gas supply for the Trombay TPP is reviewed in para. 3.22.

[3]

Trombay Unit 4:	150 MW
Trombay Unit 5:	500 MW
Trombay Unit 6:	500 MW
Proposed CC Scheme:	180 MW
Total:	1330 MW

29. Technical Features. (a) The GT would essentially comprise: - a gas turbine with a multistage axial compressor and a turbine; combustors would be mounted on the compressor discharge casing; - an accessory module in which lubricating oil system, starting motor, hydraulic system, etc. would be mounted; - an inlet system, with a high efficiency filter to remove salt crystals in the inlet air and an air intake silencer to supress the noise in the intake air system; - an exhaust system which would allow the exhaust gases escape into the atmosphere either through a bypass stack or through HRSG, with exhaust silencers, ducts, and dampers; and, - a generator which would be driven by the GT directly at 3,000 rpm. The generator would be enclosed to reduce the noise levels to acceptable levels. The GT and auxiliaries would be protected with Halon 1301 fire protection systems. The GT would be started either by a starting motor or by operating the generator as a converter fed synchronous motor in conjunction with a static frequency control system. A diesel generating set of 3 MW capacity would also be provided to supply the gas turbine start-up and auxiliary power requirement during complete black-outs. (b) The HRSG would be double pressure (high and low pressure levels), unfired, horizontal/vertical (to be optimized during the engineering) gas flow type with self supporting stack. A condensate pre-heater would be provided to absorb the available heat energy of the exhaust gases from the GT to the maximum extent. A constant pressure deaerator would be installed for feed water heating and deaeration of HRSG feed water. (c) Steam from HRSG would be supplied to a condensing type steam turbine through main steam piping. The turbine control system would be of electro-hydraulic type with a hydro-mechanical system as a backup. The steam turbine would be complete with lube oil system, hydraulic control system, safety and protections, gland sealing steam system and jacking oil system. The turbine would also be provided with a surface type condenser fixed below the turbine exhaust. Two 100% mechanical vacuum pumps would be provided for the evacuation of the air from the condenser. (d) The generator would have a nominal 70.5 MVA rating at 0.85 lagging power factor (60 MW). It would deliver power at 11 or 13.8 kV, 3-phase, 50 Hz. The star point of the generator winding would be connected to earth through a transformer having the secondary shunted by a resistance. The generator would be air or hydrogen cooled; the coolers would be adequately sized so that with one cooler section out of circuit for maintenance, the generator can carry two-third of the rated load continuously without exceeding the premissible temperature rise. Air or hydrogen would be cooled in water cooled heat exchangers with cooling water which in turn will be cooled in air. The excitation system would be either brushless or static type and would have automatic voltage regulator capable of maintaining stability under transient conditions. (e) The power from the scheme would be evacuated through a 11 or 13.8/230 kV step-up transformer which would be connected to the existing 220 kV outdoor switchyard of Units 5 and 6 (the switchyard would need to be extended). The windings of the transformer would be connected in delta on low voltage and star on high voltage side, suitable for solid grounding. The transformer would have ONAN/ONAF/OFAF type of cooling and would be provided with $\pm$5% off-circuit taps in equal steps of 2.5%. The high voltage terminals would be connected to the 220 kV switchyard by overhead lines and the low voltage terminals would be connected to the generator terminals through isolated phase bus-ducts. Lightning arrestors would be provided at 220 kV

terminals of the transformer. (f) Auxiliary systems would comprise the fuel (gas and diesel oil) supply, auxiliary cooling water, condensed cooling water, demineralised water, service water, potable water, fire alarm and protection, air conditioning and ventilation, control and monitoring, compressed air, power station electrical supply, plant direct current, illumination, communication, safety earthing and lightning protection, emergency power supply and black start, etc. systems.

D. Expansion of the Flue Gas Desulphurization (FGD) Unit at Trombay Unit 5

30. Maharashtra Pollution Control Board (MPCB) has stipulated the following requirements, while giving its clearance for the installation of Unit 6: (i) Unit 5 shall be provided with an FGD plant with a minimum removal efficiency of 90% for sulphur dioxide; and, (ii) the total sulphur dioxide emission from Trombay TPP shall not exceed 15 tons per day after the installation of Unit 6. Keeping in view MPCB's stipulations, TEC installed a pilot FGD plant to treat 25% of flue gases (equivalent to 125 MW) from Unit 5; this plant has been operating successfully since its commissioning in March 1988. Taking into account, the limited amount of gas allocated for Trombay and the savings in fuel cost following a change over to coal from LSHS and/or gas, the FGD unit would be expanded up to 50%[4].

31. The existing FGD unit uses the Seawater Process developed by Flakt, Norway, and was built by TEC based on the know-how obtained from Flakt. Flue gases from the existing ID fan discharge plant are conveyed to a concrete scrubber using a booster fan. Inside the scrubber the gases flow counter current to seawater. Sulphur dioxide is absorbed due to the natural alkanility of the sea water and clean flue gases leave the top of the scrubber at appropximately 4°C. They are then mixed with part of the raw gases in a reheat mixer. The reheated gases at 57°C exit through the existing 152 m tall stack of Unit 5. Seawater required for absorbtion is provided from Unit 5 condenser cooling water system seal well, by a siphon system to a distribution chamber. It is then pumped to the top of the scrubber. Acidic liquor from the scrubber flows by gravity into a mixing chamber located near the seal well, where it mixes with excess seawater again drawn from the seal well and then overflows into the aeration basin. In order to bring the quality of this effluent

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[4] In May 1988, prior to obtaining satisfactory operational results of the Flakt Seawater FGD technology, TEC had TCE carry an economic comparison between Flakt Seawater System and the ammonia process (the latter process uses ammonia liquor for scrubbing of flue gas and the know-how is provided by Krupp-Koppers, Federal Republic of Germany; ammonia sulphate is a byproduct produced as a saleable fertilizer). TCE's conclusion was that the seawater and ammonia systems would be comparable in net annual operating ~~costs,~~ if ammonia was made available to TEC with a subsidized price as applicable to fertilizer units. Following the satisfactory operating performance of the initial seawater based stream, TEC opted for its expansion. The Bank agrees with this decision.

within the permissible limits, the effluent is aerated by supplying air with the help of aeration fans and aeration grid. The treated effluent is then discharged to the sea. The design basis for the installation of the proposed FGD stream is:

- Flue gas quantity	: 44,420 Nm3/h
- Maximum flue gas temperature	: 153°C
- Sulphur content in coal	: 0.35%
- Coal firing rate	: 200 t/h
- Suphur dioxide removal efficiency	: 85% minimum
- Particulate content of raw flue gas	: 157 mg/Nm3

32. However, in order to have gases leaving the stack at higher temperatures, resulting in higher plume rise and less condensation of acidic water in ducts and stack, the clean gases exiting the scrubber would be heated to 45°C by using the heat content of the raw flue gas to reheat the clean gases from the scrubber by installing a regenerative heat exchanger. The raw gas, after being cooled in the regenerative heat exchanger, would be conveyed to the scrubber by using a booster fan. The existing pipeline to transfer scrubber liquor from the scrubber to the mixing chamber of the aeration basin would be adequate for the increased flow rate. The major process and operating parameters for the proposed FGD stream are:

- Seawater flow to scrubber	: 2,100 m3/h
- Seawater flow into aeration basin	: 8,500 m3/h
- Quality of treated effluents	: To meet the requirements of Indian Standard 2490
- Seawater temperature at inlet of scrubber	: 43°C
- Clean gas temperature at scrubber outlet	: 45°C
- Electric power of the streams (installed)	: 3,000 kW

INDIA

PRIVATE POWER UTILITIES PROJECT I (TATA ELECTRIC COMPANIES -- TEC)

Project Cost Summary

Project Components	Local	Foreign	Total	Local	Foreign	Total
	Rs. million			US$ million		
I. 150 MW Pumped Storage Scheme at Bhira						
- Preliminary Works	32	0	32	1.9	0.0	1.9
- Civil Works	142	28	170	8.3	1.6	10.0
- Equipment	269	345	614	15.8	20.3	36.1
- Engineering and Supervision	17	5	22	1.0	0.3	1.3
- Administrative Expenses (1)	65	0	65	3.8	0.0	3.8
Total Base Costs (2)	524	378	902	30.8	22.2	53.1
- Physical Contingencies	44	24	68	2.6	1.4	4.0
- Price Contingencies	80	116	196	4.7	4.0	8.7
Total Contingencies	124	140	264	7.3	5.4	12.7
Total Project Cost (2)	648	518	1166	38.1	27.6	65.8
- Taxes and Duties (3)	71	0	71	4.1	0.0	4.1
- Transport and Erection (3)	48	0	48	2.8	0.0	2.8
II. Bhira-Dharavi 220 kV Transmission Ssytem						
- Preliminary Works	1	0	1	0.0	0.0	0.0
- Civil Works	26	0	26	1.5	0.0	1.5
- Electrical and Mechanical Equipment	223	293	516	13.1	17.2	30.4
- Engineering and Supervision	21	0	21	1.2	0.0	1.2
- Administrative Expenses	6	0	6	0.4	0.0	0.4
Total Base Costs (2)	276	293	569	16.2	17.2	33.5
- Physical Contingencies	15	15	30	0.9	0.9	1.7
- Price Contingencies	52	111	162	3.0	2.1	5.1
Total Contingencies	67	125	192	3.9	3.0	6.9
Total Project Cost (2)	343	419	761	20.2	20.2	40.4
- Taxes and Duties (3)	106	0	106	6.2	0.0	6.2
- Transport and Erection (3)	49	0	49	2.9	0.0	2.9

Project Components	Local	Foreign	Total	Local	Foreign	Total
	------Rs. million------			------US$ million------		
III. 180 MW Gas Based Combined Cycle Scheme at Trombay (Trombay 7)						
- Preliminary Works	1	0	1	0.0	0.0	0.0
- Civil Works	79	0	79	4.6	0.0	4.6
- Electrical and Mechanical Equipment						
- Gas Turbine	42	599	641	2.5	35.2	37.7
- Heat Recovery Boiler	199	42	241	11.7	2.5	14.2
- Steam Turbine and Generator	214	74	288	12.6	4.4	16.9
- Other Mechanical Equipment	72	33	105	4.3	1.9	6.2
- Other Electrical Equipment	69	42	111	4.1	2.5	6.5
- Tools, Miscellanous Works	22	0	22	1.3	0.0	1.3
Total Elec. & Mech. Equipment	618	790	1407	36.3	46.4	82.8
- Services						
- Engineering and Supervision	3	10	13	0.2	0.6	0.8
- Administrative Expenses	47	0	47	2.8	0.0	2.8
Total Base Costs (2)	747	800	1546	43.9	47.0	91.0
- Physical Contingencies	49	60	109	2.9	3.5	6.4
- Price Contingencies	135	329	465	8.0	6.3	14.3
Total Contingencies	184	390	574	10.8	9.8	20.7
Total Project Cost (2)	931	1189	2120	54.8	56.9	111.6
- Taxes and Duties (3)	109	0	109	6.4	0.0	6.4
- Transport and Erection (3)	94	0	94	5.5	0.0	5.5
IV. Flue Gas Desulphurization Stream at Trombay Unit 5						
- Civil Works	23	0	23	1.3	0.0	1.3
- Electrical and Mechanical Equipment	66	65	131	3.9	3.8	7.7
- Engineering and Supervision	0	23	23	0.0	1.4	1.4
- Administrative Expenses	5	0	5	0.3	0.0	0.3
Total Base Costs (2)	94	88	182	5.6	5.2	10.7
- Physical Contingencies	8	3	11	0.5	0.2	0.7
- Price Contingencies	16	33	50	1.0	0.6	1.6
Total Contingencies	25	37	61	1.4	0.8	2.2
Total Project Cost (2)	119	125	243	7.0	6.0	13.0
- Taxes and Duties (3)	34	0	34	2.0	0.0	2.0
- Transport and Erection (3)	12	0	12	0.7	0.0	0.7

Project Components	Local	Foreign	Total	Local	Foreign	Total
	-------Rs. million---------			-------US$ million---------		
TOTAL PROJECT COST						
- Preliminary Works	33	0	33	1.9	0.0	1.9
- Civil Works	269	28	297	15.8	1.6	17.4
- Equipment	1176	1493	2669	69.2	87.8	157.0
- Engineering and Supervision	41	38	79	2.4	2.2	4.6
- Administrative Expenses	124	0	124	7.3	0.0	7.3
Total Base Costs (2)	1641	1559	3200	96.6	91.7	188.2
- Physical Contingencies	116	102	218	6.8	6.0	12.8
- Price Contingencies	283	589	873	16.7	13.0	29.7
Total Contingencies	399	691	1091	23.5	19.0	42.5
Total Project Cost (2)	2041	2250	4291	120.0	110.7	230.7
- Taxes and Duties (3)	320	0	320	18.8	0.0	18.8
- Transport and Erection (3)	203	0	203	12.0	0.0	12.0
Total Base Costs excl. Taxes & Duties	1322	1559	2881	77.8	91.7	169.4
Total Contingencies	399	691	1091	23.5	19.0	42.5
Total Project Cost,excl. Taxes & Dut.	1721	2250	3971	101.2	110.7	211.9

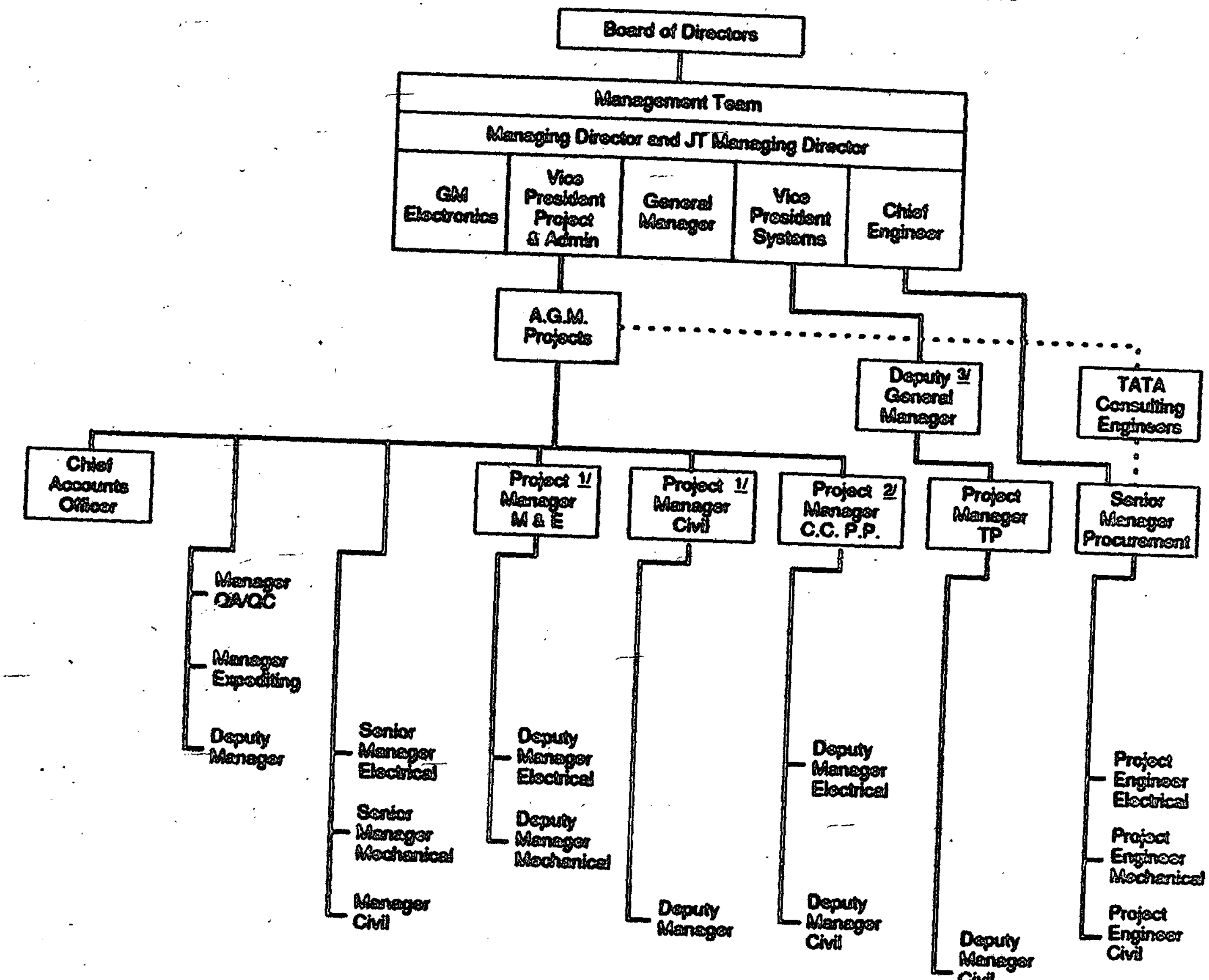
(1) Including expenses for the common facilities with the Bhira Tailrace Project.

(2) Including Taxes and Duties and Transport and Erection expenses as given below.

(3) Included in the Base Costs.

Annex 3.3

INDIA
PRIVATE POWER UTILITIES PROJECT I
Tata Electric Companies' Project Management Structure



1/ Bhira pumped storage project

2/ Trombay CC PP & FGD project

3/ 220KV transmission project

3/90

bcdwx6375a

INDIA

PRIVATE POWER UTILITIES PROJECT I

PROJECT IMPLEMENTATION SCHEDULE

	1990				1991				1992				1993				1994				1995			
Project Component and Activity	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4
a. Bhira Pumped Storage Scheme																								
Powerhouse Excavation and Lining of the Old Tunnel			S	I	O E	A			|															
Concreting Works					S	I	O E	A						|									
Penstock (Steel+ Man. & Erection)			S	I	O E	A			a			b				|							
Main Plant and Equipment				S I	O	E A							c						d					
B. Bhira-Dharavi 220 kV Trans. System																								
High Tensile Steel Tower Material, Insulators, Hardware and Conductors				S I	O	E A				e									f					
C. Combined Cycle Scheme at Trombay																								
Civil Works					S	I	O E	A					|											
Main Plant and Equipment				S	I O	E A					g				h i				j		k			
Control and Instrumentation						S I	O	E A						|									
Diesel Generator Set				S	I O	E	A					|											
Transformers and Other Equipment						S I	O	E A					|											
D. Expansion of FGD Scrubber Unit at Trombay Unit 5																								
Civil Works				S	I O	E A						|											
Main Plant and Equipment					S I	O E	A					l					m							

S: Specifications Ready
I: Invitation to Bid
O: Opening of Bids
E: Evaluation Completed
A: Award of Contract

a/ Delivery of steel for penstock; manufacture begins
b/ Erection of penstock begins
c/ Erection of main plant begins
d/ Bhira Pumped Storage Scheme commissioned

e/ Delivery of materials and erection of towers and switchgear begins
f/ Bhira-Dharavi Transmission System commissioned

g/ Gas Turbine delivered; its erection begins
h/ Gas Turbine commissioned
i/ Erection of boiler and steam turbo-generator begins
j/ Combined Cycle Scheme commissioned
k/ Commercial operation of the Combined Cycle Scheme

l/ Erection of the plant begins
m/ FGD Scrubber Unit commissioned

Annex 3.4

INDIA

PRIVATE POWER UTILITIES PROJECT I

PROCUREMENT ARRANGEMENTS

(US$ millions) a/

Project Element	ICB Contract Value	ICB IBRD Finance	LCB Contract Value	LCB IBRD Finance	Other Contract Value	Other IBRD Finance	N.A. Contract Value	Total Cost Contract Value	Total Cost IBRD Finance
A. Bhira Pumped Storage Scheme									
- Preliminary Works	-	-	-	-	2.0	-	-	2.0	0.0
- Civil Works	-	-	6.7	-	-	-	-	6.7	0.0
- Equipment									
- Power House Construction Equipm.	-	-	-	-	8.0	-	-	8.0	0.0
- Penstock and Pressure Shaft	-	-	0.0	-	7.1	-	-	7.1	0.0
- Pump Turbine and Generator-Motor, including control equipment	28.4	25.2	-	-	-	-	-	28.4	25.2
- Generator transformer	-	-	-	-	2.2	-	-	2.2	0.0
- Bus Duct	-	-	-	-	0.7	-	-	0.7	0.0
- Other Equipment	-	-	2.0	1.7	3.5	-	-	5.5	1.7
- Services									
- Engineering and Supervision	-	-	-	-	1.3	-	-	1.3	0.0
- Other Services	-	-	-	-	-	-	3.8	3.8	0.0
Project Total Cost b/	28.4	25.2	8.7	1.7	24.8	0.0	3.8	65.7	26.9
B. Bhira-Dharavi 220 kV Transmission System									
- Civil Works	-	-	1.9	-	-	-	-	1.9	0.0
- Equipment									
- Towers and Accessories	-	-	-	-	5.9	-	-	5.9	0.0
- Conductors	-	-	-	-	3.4	-	-	3.4	0.0
- Bus Bars; Insulators; ICTs	-	-	-	-	3.8	-	-	3.8	0.0
- Feeder Bays at Dharavi	-	-	-	-	2.0	-	-	2.0	0.0
- Fibre Optic Communications	-	-	-	-	3.8	-	-	3.8	0.0
- 220 kV Cable	-	-	-	-	14.2	-	-	14.2	0.0
- Other Equipment	-	-	1.0	0.7	2.8	-	-	3.8	0.7
- Services									
- Engineering and Supervision	-	-	-	-	1.2	0.5	-	1.2	0.5
- Other Services	-	-	-	-	-	-	0.4	0.4	0.0
Project Total Cost	0.0	0.0	2.9	0.7	37.1	0.5	0.4	40.4	1.2

Project Element	ICB Contract Value	ICB IBRD Finance	LCB Contract Value	LCB IBRD Finance	Other Contract Value	Other IBRD Finance	N.A. Contract Value	Total Cost Contract Value	Total Cost IBRD Finance
C. 180-MW Combined Cycle Scheme at Trombay									
- Civil Works	-	-	5.7	-	-	-	-	5.7	0.0
- Equipment									
- Gas Turb.+Heat Recov. Steam Gen.+ Steam Turbine-Generator	84.4	67.8	-	-	-	-	-	84.4	67.8
- Control and Instrumentation	-	-	-	-	2.2	-	-	2.2	0.0
- Diesel Generator Set	-	-	-	-	2.2	-	-	2.2	0.0
- Other Mechanical Equipment	-	-	-	-	3.2	-	-	3.2	0.0
- Transformers	-	-	-	-	2.0	-	-	2.0	0.0
- Bus Ducts	-	-	-	-	0.5	-	-	0.5	0.0
- Other Electrical Equipment	-	-	2.0	1.6	3.5	-	-	5.5	1.6
- Tools, Miscellaneous	-	-	-	-	1.6	-	-	1.6	0.0
- Services									
- Engineering and Supervision	-	-	-	-	0.8	0.5	-	0.8	0.5
- Other Services	-	-	-	-	3.3	-	0.2	3.5	0.0
Project Total Cost	84.4	67.8	7.7	1.6	19.3	0.5	0.2	111.6	69.9
D. Expansion of FGD Scrubber Unit at Trombay Unit 5									
- Civil Works	-	-	1.8	-	-	-	-	1.8	0.0
- Equipment									
- Regenerative Heat Exchanger	-	-	-	-	4.2	-	-	4.2	0.0
- Booster Fan	-	-	-	-	1.3	-	-	1.3	0.0
- Other Equipment	-	-	0.0	-	3.8	-	-	3.8	0.0
- Services									
- Engineering and Supervision	-	-	-	-	1.5	-	-	1.5	0.0
- Other Services	-	-	-	-	-	-	0.4	0.4	0.0
Project Total Cost	0.0	0.0	1.8	0.0	10.8	0.0	0.4	13.0	0.0

	ICB		LCB		Other		N.A.	Total Cost	
Project Element	Contract Value	IBRD Finance	Contract Value	IBRD Finance	Contract Value	IBRD Finance	Contract Value	Contract Value	IBRD Finance
PROJECT TOTAL									
- Preliminary Works	0.0	-	0.0	-	2.0	-	0.0	2.0	0.0
- Civil Works	0.0	0.0	16.1	0.0	0.0	0.0	0.0	16.1	0.0
- Equipment	112.8	93.0	5.0	4.0	81.9	0.0	0.0	199.7	97.0
- Services	0.0	0.0	0.0	0.0	8.1	1.0	4.8	12.9	1.0
Project Total Cost	112.8	93.0	21.1	4.0	92.0	1.0	4.8	230.7	98.0
IFC Finance					60.0			IFC:	60.0

a/ Contract values include contingencies and taxes and duties (US$ 18.8 million)

ICB: International Competitive Bidding.
LCB: Local Competitive Bidding.
Other: Direct imports and locally procured items.
N.A.: Not Applicable (Administrative Expenses)

INDIA

PRIVATE POWER UTILITIES PROJECT I

(TATA ELECTRIC COMPANIES -- TEC)

PROCUREMENT SCHEDULE

Project Element	BIDDING				CONTRACT AWARD
	Specifications Ready	Invitation	Opening	Evaluation	
A. Bhira Pumped Storage Scheme					
- Civil Works					
- Penstock and Pressure Shaft	September 90	October 90	January 91	March 91	May 91
- Other Civil Works	September 90	October 90	January 91	March 91	May 91
- Equipment					
- Pump Turbine and Generator-Motor, including control equipment	October 90	January 91	March 91	May 91	June 91
- Generator transformer	October 90	January 91	March 91	May 91	June 91
- Bus Duct	December 90	February 91	April 91	June 91	August 91
- Other Equipment	December 90	February 91	April 91	June 91	August 91
- Services					
- Engineering and Supervision		October 89 (A)	December 89 (A)	April 90 (A)	May 90
B. Bhira-Dharavi 220 kV Transmission System					
- Civil Works					
- Equipment					
- Towers and Accessories	November 90	December 90	February 91	April 91	June 91
- Conductors	November 90	December 90	February 91	April 91	June 91
- Busbars; Insulators; ICTs	November 90	December 90	February 91	April 91	June 91
- Feeder Bays at Dharavi	November 90	December 90	February 91	April 91	June 91
- Fibre Optic Communications	December 90	January 91	March 91	May 91	July 91
- 220 kV Cable	December 90	January 91	March 91	May 91	July 91
- Other Equipment					
- Services					
- Engineering and Supervision					(B)

Project Element	BIDDING: Specifications Ready	Invitation	Opening	Evaluation	CONTRACT AWARD
C. 180 MW Combined Cycle Scheme at Trombay					
- Civil Works					
- Equipment					
- Gas Turbine+Heat Recovery Steam Gen.+ Steam Turbine+Generator+Auxiliaries	September 90	December 90	March 91	May 91	July 91
- Control and Instrumentation	April 91	June 91	August 91	October 91	December 91
- Diesel Generator Set	December 90	January 91	March 91	May 91	July 91
- Other Mechanical Equipment	April 91	June 91	August 91	October 91	December 91
- Transformers	April 91	June 91	August 91	October 91	December 91
- Bus Ducts	April 91	June 91	August 91	October 91	December 91
- Other Electrical Equipment	April 91	June 91	August 91	October 91	December 91
- Services					
- Engineering and Supervision					(B)
D. Expansion of FGD Scrubber Unit at Trombay Unit 5					
- Civil Works					
- Equipment					
- Regenerative Heat Exchanger	November 90	February 91	April 91	June 91	July 91
- Booster Fan	November 90	February 91	April 91	June 91	July 91
- Other Equipment	December 90	January 91	March 91	May 91	July 91
- Services					
- Basic Engineering (Know-How) and Supervision					September 90

(A) Implemented.
(B) Consultants selected.

INDIA

PRIVATE POWER UTILITIES PROJECT I

SCHEDULE OF DISBURSEMENTS FOR IBRD AND IFC LOANS

(US$ million)

IBRD and IFC Fiscal Years Quarters Ending	IBRD Loan		IFC Loan	
	Total Quarterly Disbursements	Cumulative	Total Quarterly Disbursements	Cumulative
FY91				
September 30, 1990	-	-	-	-
December 31, 1990	-	-	-	-
March 31, 1991	-	-	1.500	1.500
June 30, 1991	1.000	1.000	1.500	3.000
FY92				
September 30, 1991	5.720	6.720	1.000	4.000
December 31, 1991	3.780	10.500	1.200	5.200
March 31, 1992	5.530	16.030	1.900	7.100
June 30, 1992	3.580	19.610	1.900	9.000
FY93				
September 30, 1992	4.310	23.920	4.000	13.000
December 31, 1992	7.100	31.020	7.000	20.000
March 31, 1993	15.420	46.440	7.000	27.000
June 30, 1993	11.100	57.540	6.000	33.000
FY94				
September 30, 1993	10.250	67.790	4.000	37.000
December 31, 1993	9.490	77.280	5.000	42.000
March 31, 1994	7.630	84.910	5.000	47.000
June 30, 1994	5.560	90.470	4.000	51.000
FY95				
September 30, 1994	2.630	93.100	3.000	54.000
December 31, 1994	1.800	94.900	4.000	58.000
March 31, 1995	2.300	97.200	1.500	59.500
June 30, 1995	0.800	98.000	0.500	60.000

Closing Date of the IBRD and IFC Loans: June 30, 1990

TATA ELECTRIC COMPANIES

STATEMENT OF SEPARATE & JOINT SECURED BORROWINGS

ANNEXURE 3 PART I

Rs. Million

Sl. No	Borrowings	TATA HYDRO Principal amount o/s as at 31-3-1989	TATA HYDRO Amounts committed for subsequent borrowings	ANDHRA VALLEY Principal amount o/s as at 31-3-1989	ANDHRA VALLEY Amounts committed for subsequent borrowings	TATA POWER Principal amount o/s as at 31-3-1989	TATA POWER Amounts committed for subsequent borrowings	TOTAL Principal amount o/s as at 31-3-1989	TOTAL Amounts committed for subsequent borrowings
	I. DEBENTURES								
(a)	11 % Debentures (1991-93)	22.2		23.0		47.2		93.2	0.0
(b)	11 % Debentures (1989-93) issued to UTI	9.1		13.1		21.0		43.2	0.0
(c)	13 % Debentures (1991-93) issued to UTI	17.0		13.0		23.1		53.1	0.0
(d)	14 % Debentures (1989-93) issued to UTI	3.3		4.9		8.2		16.4	0.0
(e)	15 % Debentures (1994-96) issued in lieu of Pref. Shares	8.9		4.9		8.7		22.5	0.0
(f)	14 % Debentures (proposed for Working Capital)		30.0		45.0		75.0		150.0
		60.5	30.0	66.5	45.0	111.4	75.0	238.4	150.0
	II. LOANS								
(g)	IBRD Loan 1549 - IN	264.2		576.2		449.4		1290.0	
(h)	IBRD Loan 2452 - IN	303.9	124.6	653.9	103.9	764.7	311.5	1539.5	620.0 (@ 22.90)
(i)	Loan from IFC/W (Swiss Francs 60 Million)		132.0		198.0		330.0		660.0
(j)	Rupee Term Loans	105.4	150.0	153.1	225.0	263.5	375.0	527.0	750.0
(k)	Cash Credit : State Bank of India	12.3	24.7	10.6	23.9	33.7	57.0	68.6	119.4
		687.8	431.3	1681.0	665.0	1723.2	1074.3	4092.9	2152.4
	TOTAL SECURED BORROWINGS	748.3	461.3	1678.3	691.0	1834.7	1149.3	4331.3	2302.4

TATA ELECTRIC COMPANIES

PRIORITY OF LIENS ON EXISTING FIXED ASSETS

Sl. No	Borrowings	Trombay Units 5 & 6 (500 MW) Plants	Other Trombay Fixed Assets	Trombay License	Other Jointly owned Assets	Corporate Assets	Corporate Hydro Licenses
	I. DEBENTURES						
(a)	11 % Debentures (1991-93)	Subordinate (2)	First (1)	Subordinate	First	First	First
(b)	11 % Debentures (1983-93) issued to UTI	First	First	First	First	First	First
(c)	15 % Debentures (1991-93) issued to UTI	Subordinate	First	Subordinate	First	First	First
(d)	14 % Debentures (1983-93) issued to UTI	First	First	First	First	First	First
(e)	15 % Debentures (1994-96) issued in lieu of Pref. Shares	Third (3)	Subordinate	Nil	Subordinate	Subordinate	Nil
(f)	14 % Debentures (proposed for Working Capital)	First	First	First	First	First	First
	II. LOANS						
(g)	IBRD Loan 1549 - IN	First	First	First	Nil	Nil	Nil
(h)	IBRD Loan 2022 - IN	First	First	First	Nil	Nil	Nil
(i)	Loan from IFC/W (Swiss Francs 60 Million)	First	First	First	First	First	First
(j)	Rupee Term Loans	First	First	First	First	First	First

(1) All holders of first mortgage on specific assets share in the proceeds from the disposition of those assets on a pari passu basis.

(2) All holders of subordinate or second mortgage on specific assets share in the proceeds from the disposition of those assets on a pari passu basis only after the claims of the first mortgage holders have been fully satisfied.

(3) Ranking after the claims of the first and subordinate or second mortgage holders have been fully satisfied.

INDIA

PRIVATE POWER UTILITIES PROJECT X

ENVIRONMENTAL ISSUES

Bhira Pumped Storage Scheme

1. The Bhira PS Scheme involves upgrading and expansion of existing facilities. The Mulshi Lake reservoir (40 km^2) will serve as a head pond for the project, while the pickup pond can be conveniently used to store water for the pump storage unit (as the tail pond). There will be no increased overflow (water loss downstream) at either the Bhira Dam or from the pickup pond as a result of this project, thus this project will not adversely effect downstream water users. The existing units at Bhira (6 x 25 MW and 1 x 23 MW = 173 MW) use 40.5 m3/sec of water for full load operations, while the proposed project will use 40 m^3/sec for generation (150 MW) and 30 m^3\sec during pumping. During the generation cycle, the maximum drawdown of the reservoir as a result of this project will not exceed approximately 10 cms (assuming 5 hours of generation). However, over the 24 hour generation/pump cycle there will be no change in the water level of the reservoir (or the pickup pond) as a result of this project.

2. Given the projects planned use of existing facilities, the construction on existing rights-of-way, and the marginal change in water level of the reservoir and pickup pond during the 24 hour generation/pump cycle, the environmental impacts associated with this project are minimal. As required by the GOI, TEC has prepared a proforma environmental assessment for this project, which has already received necessary GOI and GOM environmental approvals.

Bhira-Dharavi Transmission System

3. In order to bring the additional power from Bhira to Dharavi (Bombay), a distance of about 100 km, the existing 110 kV transmission lines will be upgraded to a double circuit 220 kV line using the existing right-of-way. A number of visual inspections were made of the existing right-of-way at locations deemed to be potentially sensitive from an environmental standpoint (e.g. at the western ghats, near areas of forestry reserve, in the suburbs of Bombay, etc.). In all cases, any environmental impacts associated with the transmission line will be minimal. GOI and GOM environmental approvals are not required for this project given the use of the existing right-of-way. At the Dharain end, the line will be connected to the substation by an underground cable, which would be buried under the existing streets.

Combined Cycle Plant

4. The proposed combined cycle plant will be located at TEC's Trombay TPP which currently has 3 units of 62.5 MW (Units 1, 2 and 3), 1 unit of 150 MW (Unit 4) and 2 units of 500 MW (Units 5 and 6). Total capacity at Trombay is currently 1337.5 MW, but this would be reduced to 1330 MW following the start-up of the proposed combined cycle scheme (180 MW) with the simultaneous shutdown and decommissioning of Units 1, 2 and 3 (187.5 MW).

5. TEC has completed a proforma environmental overview for this project which has recently been forwarded to the Environment Department, Government of India (GOI) for review and approval. The major air emissions of concern from the combined cycle plant are NOx. TEC proposes to design the plant such that the NOx concentration in the stack emissions will not exceed 50 ppm, well within the GOI and GOM NOx standards. The 50 ppm concentration figures is also within the Bank stack emissions limit of 86 nanograms of NOx per joule of heat input. TEC is in the process of completing plume dispersion modelling to determine the optimum stack height for achieving necessary plume mixing to comply with ambient NOx air quality requirements of the MSPCB and the Bank guidelines for 100 micrograms/m^3. The option of using a single stack as opposed to the 2 stacks initially proposed, is under finalization. The single stack layout would improve energy efficiency by about 3%.

6. With regard to water pollution concerns, the demineralized water requirements will be provided by Trombay's existing water treatment plant and any effluents from this plant are treated to acceptable levels prior to discharge. Cooling water will be taken from Trombay's existing cooling water pump house and, after use, discharged into the cooling water discharge channel currently used by Trombay's existing units (Units 1-6). Modelling studies by the Central Water and Power Research Station (CWPRS) in Pune, as well as data from water quality monitoring programs, indicate that the existing cooling water discharge is about 5°C above ambient water temperature at the discharge point (a GOI, and GOM and Bank requirement). For the proposed 180 MW combined cycle plant, the steam turbine will be rated at 60 MW. Since 187.5 MW (3 x 62.5 MW) will be decommissioned on start-up of the combined cycle plant, there will in fact be a reduction in cooling water requirements and hence in cooling water discharges to the marine environment.

Flue Gas Desulphurization

7. Currently Trombay's Unit 5 (500 MW) has a flue gas desulphurization (FGD) system on one of the four flue gas streams from the boiler. This system, which has been operating successfully for almost 2 years, is based on the Seawater Process developed by A/S Norsk Viftefabrikk. The system consistently removed in excess of 85% of the SOx (approximately 6 TPD) from the flue gas stream.

8. In order to increase the use of coal as a primary fuel in Unit 5 and remain within the MSPCB daily SOx limit for the entire Trombay operation of 15 TPD, an additional FGD module on the second flue gas stream from Unit 5's boiler will be installed. The proposed FGD module will be identical to the existing seawater based system, with an SOx removal efficiency of 85%. Total SOx removal when the two FGD modules are in operation will be approximately 12 TPD. This will allow TEC increased flexibility regarding the use of coal, the cheapest fuel, while ensuring Trombay's operation remain within MSPCB's SOx limits.

9. The seawater effluent from the existing FGD system is treated to ensure that the pH on discharge to the ocean is between 6 and 9 (a GOI, GOM and Bank requirement). With installation of the new FGD module, additional seawater treatment capacity will be constructed, again to ensure that the pH of the discharge is between 6 and 9.

INDIA

PRIVATE POWER UTILITIES PROJECT I
TATA ELECTRIC COMPANIES
Financial Analysis

Table 1: Income Statement

Rs Million

FY Ending March 31	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Revenues from Power Sales	4602	5242	6603	6632	7896	8209	9859	10856	12264	14754	16586	16405	15896	17158	20486	24677
Cost of Fuel	2611	2403	2794	2938	2894	3293	3914	4741	5063	5504	5770	6612	7141	7712	8499	9179
Other Operating Expenses	570	526	611	708	809	1025	1101	1181	1269	1362	1464	1574	1692	1820	1958	2103
Power Purchases	716	1629	2088	2009	2786	2580	3390	3026	4104	5834	7281	6058	4938	5488	7825	11200
Depreciation	114	124	128	130	184	288	330	417	448	503	579	596	600	604	609	639
Tax on Sales	31	33	34	37	73	75	90	85	89	94	99	99	92	92	99	103
Wheeling Charges Payable	51	55	60	76	70	77	77	83	83	77	77	77	77	77	78	78
Miscellaneous Write Offs	2	2	2	2	2	2	13	13	13	12	11	11	11	11	11	11
Operating Margin	507	467	893	692	729	909	983	1411	1162	1288	1305	1379	1345	1350	1357	1365
Wheeling Charges Receivable	90	100	110	111	133	133	142	142	142	142	142	142	142	142	142	142
Other Revenues	20	43	49	54	118	139	150	165	175	186	197	209	220	231	242	254
Income Before Interest	669	633	1033	857	980	1180	1275	1718	1479	1566	1643	1729	1708	1731	1741	1761
Interest	229	264	315	385	446	597	703	813	855	939	1020	975	943	918	877	790
Foreign Exchange Losses	7	7	35	65	67	107	147	192	229	267	303	332	362	392	421	444
Income Tax	21	39	156	95	-4	0	0	0	0	0	0	0	0	0	0	0
Net Profit	392	322	538	312	461	475	422	718	395	331	321	422	401	421	448	518
	1.0	2.6	1107	1650	627											
Contingency Reserve	18	18	19	10	12	15	22	26	29	35	37	37	37	38	40	41
Investment Allowance Reserve	63	8	228	0	144	105	20	250	70	6	0	0	0	0	0	0
Deferred Tax Liability Fund			0	25	43	50	50	50	50	50	50	50	50	50	50	50
Debt Redemption Reserve		29	23	32	32	0	0	0	0	0	0	81	41	42	45	108
Project Cost Reserve	194	212	218	151	144	160	172	181	17	0	0	0	0	0	0	0
Adjustments	3		0	34	-1											
Distributable Profit	80	56	90	61	77	146	159	208	228	246	234	254	273	291	308	323
Dividends	52	52	58	72	71	72	108	144	144	144	144	144	142	142	142	142
Retained Earnings	28	4	32	-11	6	74	51	64	85	102	90	111	131	149	166	181
Net Profit/Revenues	8%	6%	9%	5%	6%	6%	4%	6%	3%	2%	2%	3%	2%	2%	2%	2%
Net Profit/Net Worth	28%	17%	28%	11%	14%	18%	10%	18%	7%	6%	5%	7%	6%	6%	6%	7%
Operating Income/Revenues	11%	9%	14%	10%	10%	11%	10%	13%	9%	8%	8%	8%	8%	8%	7%	5%
Operating Income/LT Capital	21%	17%	29%	16%	16%	20%	16%	22%	16%	16%	16%	16%	19%	20%	21%	24%
Interest Cover, times	2.9	2.4	3.5	2.2	2.2	2.0	1.8	2.1	1.7	1.6	1.6	1.8	1.8	1.9	2.0	2.2

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Table 2: Balance Sheet

Rs Million

On March 31	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
ASSETS																
Gross Fixed Assets	3814	3893	3807	3908	4207	6031	8045	9994	11760	14885	14802	16017	15152	16207	16022	16407
Accumulated Depreciation	-687	-760	-914	-1041	-1173	-1463	-1793	-2216	-2634	-3166	-3745	-4341	-4940	-5544	-6130	-6722
Work in Progress	103	438	1548	2876	2842	2749	1025	1441	1423	99	99	221	429	320	60	60
Revaluation FX Cost	94	303	712	1000	1119	1220	1407	1789	1776	1720	1779	1756	1603	1567	1597	1601
Net Fixed Assets	3140	3720	5170	6621	7886	8531	8380	11003	12326	13047	12918	12652	12326	12199	11666	10946
Cash	120	71	20	140	83	268	282	534	120	88	365	279	202	328	400	618
Inventories	381	401	612	509	719	794	1034	1074	1084	1094	1104	1114	1124	1134	1144	1154
Receivables	459	620	753	689	756	808	965	930	1046	1228	1358	1340	1304	1394	1628	1628
Other Current Assets	144	280	427	407	244	234	163	158	158	158	158	158	153	158	153	163
Total Current Assets	1112	1410	1714	1744	1762	2037	2357	2547	2414	2568	2978	2900	2033	3011	3020	3750
Contingency Reserve	50	63	104	120	138	145	160	101	203	205	271	307	345	392	420	460
Other Investments	83	22	20	64	116	160	312	614	916	1110	1170	1222	1274	1326	1378	1430
Unamortized Expenses	10	16	14	12	10	6	103	90	79	67	56	45	34	22	11	0
Total Assets	4376	5258	7030	8453	9704	10881	12594	14444	15941	17033	17407	17118	16044	16940	16804	16535
LIABILITIES																
Common Shares	318	310	380	380	380	380	680	760	760	760	760	760	760	760	760	760
Preference Shares	12	12	12	12	12	12	12	12	12	12	12	0	0	0	0	0
General Reserve	389	392	424	473	476	551	801	1265	1350	1452	1542	1653	1784	1883	2093	2279
Consumers' Contributions	21	25	27	29	34	34	34	34	34	34	34	34	34	34	34	34
Contingency Reserve	68	104	120	133	140	162	184	209	203	274	310	348	385	428	468	504
Investment Allowance Reserve	305	318	541	541	605	720	810	1030	1130	1130	1130	1130	1130	1130	1130	1130
Deferred Tax Reserve	75	75	75	100	148	198	248	298	348	398	448	498	548	598	648	698
Debt Redemption Reserve		23	56	83	120	120	120	120	120	120	120	201	242	284	320	481
Project Cost Reserve	451	663	881	1032	1176	1386	1503	1609	1703	1703	1703	1703	1703	1706	1703	1703
Share Capital & Reserves	1656	1929	2520	2793	3168	3507	4401	5471	5722	5899	6063	6353	6612	6891	7191	7535
Foreign Exchange Loans	1547	1749	2045	3128	3788	4142	4901	5680	7109	7523	8160	7699	7102	6615	5985	5310
Rupee Loans	752	750	668	579	527	911	1144	1017	990	930	935	812	699	1280	1226	1000
Debentures	426	612	456	280	280	841	699	770	789	693	651	603	600	600	600	600
Fixed Deposits	217	349	391	480	401	591	391	381	261	261	261	261	261	261	261	261
Consumer Security Deposits	48	48	48	48	47	47	47	47	47	47	47	47	47	47	47	47
Less Current Maturities	88	180	203	216	260	509	714	685	687	776	887	938	932	994	1102	263
Net Long Term Debt	2902	3315	3370	4227	4803	6414	6440	7208	8370	8019	8093	8489	8029	7769	7026	6998
Short Term Bank Credit		51	0	41	86	0	0	0	0	0	0	0	0	0	0	0
Sundry Creditors				622	691	659	627	500	589	744	854	752	659	704	900	1161
Other Current Liabilities				584	703	683	618	576	565	585	685	584	584	584	604	604
Current Maturities of LT Debt	138	293	203	216	260	509	714	685	687	776	887	938	932	994	1102	263
Total Current Liabilities	138	344	203	1482	1718	1851	1764	1771	1841	2105	2406	2274	2204	2281	2606	2027
Total Liabilities	4376	5258	7030	8453	9705	10881	12605	14444	15942	17084	17408	17116	16845	16941	16804	16563
Net Long Term Debt/Equity	1.75	1.72	1.30	1.51	1.51	1.51	1.46	1.32	1.46	1.53	1.40	1.34	1.21	1.13	0.98	0.92
Current Ratio	8.06	4.10	8.08	1.22	1.02	1.07	1.34	1.44	1.31	1.22	1.24	1.27	1.30	1.32	1.29	1.35
Balance Test	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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Table 8: Cash Flow Statement

Rs Million

FY Ending March 31	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Income before Interest & Tax	639	683	1030	916	930	1180	1276	1718	1479	1566	1643	1729	1708	1781	1741	1751
Income Tax	-21	-89	-156	-63	4	0	0	0	0	0	0	0	0	0	0	0
Depreciation	114	124	128	130	184	295	330	417	448	503	579	593	600	604	608	639
Miscellaneous Write Offs	2	2	2	2	2	2	13	13	13	12	11	11	11	11	11	11
Operating Cash Flow	734	719	1031	953	1120	1478	1619	2148	1941	2080	2234	2336	2317	2346	2360	2401
Net Working Capital Incr/(Decr)	163	212	-159	-48	-99	137	628	23	4	32	30	100	67	54	48	30
Cash Available to Service Debt	570	507	1218	1001	1220	1341	992	2125	1937	2049	2203	2236	2250	2292	2312	2371
Interest Foreign Exchange Loans	100	117	130	243	281	337	450	541	621	726	782	776	727	675	617	555
Interest on Rupee Loans	128	147	127	142	165	210	240	272	295	242	237	200	216	248	230	203
Principal Repayments FX Loans		50	100	140	152	165	298	383	428	499	601	780	809	840	872	935
Principal Repayments Rs Loans	149	88	130	60	64	65	263	310	290	160	175	188	129	122	122	107
Total Debt Service	379	403	603	591	662	847	1253	1526	1651	1635	1793	1942	1881	1879	1870	1892
Cash After Debt Service	193	105	608	410	558	493	-263	599	286	414	407	294	369	412	442	479
Investments	27	6	16	54	71	57	167	324	227	231	87	89	89	89	89	92
Dividend	52	52	60	72	71	72	103	144	144	144	144	144	142	142	142	142
Repayments & Adjustments	23	0	0	34	0	0	112	0	0	0	0	0	0	0	0	0
Cash Surplus/(Deficit)	91	47	534	251	416	365	-659	132	-84	39	176	61	138	181	210	245
Additions to Fixed Assets	124	403	1294	1210	1194	1056	1176	1469	1784	1225	552	262	349	601	250	140
Financing Requirements/(Surplus)	34	357	760	959	778	691	1835	1337	1868	1186	376	200	211	420	40	-105
Equity Subscriptions	1	0	72				200	200				-12				
Conversion Premium							300	300								
Drawals FX Loans	50	45	528	884	608	342	688	665	1627	1046	543	0	0	0	0	0
Drawals Rs Loans	16	0	0	100	0	548	657	300	0	100	100	122	208	461	110	0
Fixed Deposits from Public	-26	182	11	76	23	100	0	0	0	0	0	0	0	0	0	0
Consumer Security Deposits	-4	0	-3	1	-1	0	0	0	0	0	0	0	0	0	0	0
Bank Credit	0	51	0	41	25	-66	0	0	0	0	0	0	0	0	0	0
Other Items	4	2	5	31	3	5	5	5	5	5	5	5	5	5	5	5
Total Financing	42	230	621	1085	663	925	1800	1470	1632	1151	648	115	213	466	115	5
Cash Incr/(Decr) for the Year	8	-127	-108	126	-115	234	-35	133	-236	-35	272	-86	3	46	75	110
Debt Service Cover	1.84	1.79	1.74	1.61	1.69	1.74	1.26	1.41	1.25	1.27	1.24	1.20	1.23	1.25	1.26	1.27

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Table 4: Sensitivity Tests

Rs Million

SENSITIVITY TESTS	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	AAGR 1990-2000
Base Case												
Average Tariff, Rs/kWh	1.008	1.118	1.180	1.258	1.429	1.522	1.515	1.571	1.693	1.877	2.110	7.7%
Debt Service Cover	1.74	1.26	1.41	1.26	1.27	1.24	1.20	1.23	1.26	1.26	1.27	
Project IRR	23.8%											
Bhira PS & TL alone												
Average Tariff, Rs/kWh	1.000	1.114	1.178	1.286	1.404	1.560	1.641	1.725	1.866	2.059	2.301	8.7%
Debt Service Cover	1.67	1.28	1.40	1.28	1.26	1.25	1.26	1.30	1.32	1.34	1.34	
Project IRR	17.8%											
Combined Cycle & FGD alone												
Average Tariff, Rs/kWh	1.002	1.118	1.176	1.241	1.410	1.501	1.578	1.647	1.776	1.984	2.200	8.2%
Debt Service Cover	1.68	1.22	1.38	1.19	1.21	1.19	1.19	1.22	1.24	1.26	1.27	
Project IRR	27.3%											
Fuel & Imported Energy Cost Remaining at FY90-91 Level												
Average Tariff, Rs/kWh	1.003	1.065	1.077	1.072	1.148	1.140	1.076	1.088	1.077	1.101	1.135	1.2%
Debt Service Cover	1.74	1.26	1.41	1.25	1.27	1.25	1.20	1.23	1.25	1.27	1.27	
Project IRR	22.6%											
Fuel & Imported Energy Cost Rising 12% pa (BC 8-10%)												
Average Tariff, Rs/kWh	1.008	1.189	1.287	1.352	1.588	1.738	1.787	1.921	2.189	2.445	2.825	10.9%
Debt Service Cover	1.74	1.25	1.41	1.25	1.27	1.24	1.20	1.23	1.25	1.26	1.26	
Project IRR	25.3%											
Load Factor 60% (BC 68%)												
Average Tariff, Rs/kWh	1.008	1.158	1.254	1.331	1.511	1.608	1.631	1.710	1.846	2.036	2.274	8.5%
Debt Service Cover	1.74	1.25	1.41	1.25	1.27	1.24	1.20	1.23	1.25	1.26	1.27	
Project IRR	23.2%											
Project Cost Overrun 20%												
Average Tariff, Rs/kWh	1.011	1.121	1.188	1.268	1.441	1.535	1.533	1.589	1.709	1.890	2.121	7.7%
Debt Service Cover	1.77	1.27	1.44	1.28	1.30	1.27	1.20	1.23	1.24	1.26	1.27	
Project IRR	24.7%											
Startup Delayed 1 year												
Average Tariff, Rs/kWh	1.008	1.118	1.180	1.258	1.429	1.616	1.645	1.571	1.693	1.877	2.110	7.7%
Debt Service Cover	1.74	1.26	1.41	1.26	1.27	1.24	1.20	1.23	1.25	1.26	1.27	
Project IRR	23.8%											
Rs/$ Devaluation 10% pa												
Average Tariff, Rs/kWh	1.008	1.118	1.190	1.259	1.442	1.542	1.546	1.616	1.748	1.940	2.179	8.0%
Debt Service Cover	1.74	1.26	1.41	1.24	1.26	1.21	1.15	1.16	1.17	1.17	1.17	
Project IRR	40.3%											

ENERGY GENERATION & SALES, GWh	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Generation Units 1-2-3	590	500	500	500	500						
Generation Unit 4	920	700	700	700	700	700	700	700	700	700	700
Generation Unit 5	4100	3000	3000	3000	3000	3000	3263	3263	3263	3263	3263
Generation Unit 6		2000	3000	3000	3000	3000	3000	3000	3000	3193	3193
Generation Combined Cycle						720	1080	1080	1080	1080	1080
Total Thermal Generation	5610	6200	7200	7200	7200	7420	8043	8043	8043	8236	8236
Hydro Generation	1156	1300	1300	1300	1300	1300	1521	1521	1521	1665	1665
Station Use and Losses	-622	-773	-840	-824	-1112	-1132	-1129	-1104	-1105	-1324	-1352
Purchases from MSEB	2056	2091	1629	2115	2940	3313	2395	1657	1677	2311	3144
Energy Sales, in GWh	8200	8818	9289	9791	10328	10901	10830	10117	10136	10888	11693
BSES Requirements, GWh	3293	3573	3877	4208	4564	4952	5372	5829	6325	6862	7445
BSES Net Generation							684	2052	2735	2735	2735
BSES Purchases from TEC	3293	3573	3877	4208	4564	4952	4688	3777	3590	4127	4710
BEST	2317	2417	2521	2629	2742	2860	2983	3111	3245	3384	3530
Direct Industrial Clients	2040	2272	2329	2387	2447	2508	2571	2635	2701	2768	2837
Railways	550	556	561	567	572	578	584	590	596	602	608

CASH OPERATING COSTS	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Total Calorific Input, Tcal	14482	15580	17930	17930	17930	17401	18680	18680	18680	19184	19184
LSHS Consumption, kt	510	640	640	640	640	640	640	640	640	640	640
Gas Consumption, kt	829	748	748	599	599	449	449	449	449	449	449
Coal Consumption, kt	122	272	860	1245	1245	1498	1818	1818	1818	1931	1931
LSHS Price, Rs/t	2935	3170	3423	3697	3993	4312	4657	5030	5432	5867	6336
Gas Price, Rs/t	2060	2225	2403	2595	2803	3027	3269	3530	3813	4118	4447
Coal Price, Rs/t	750	810	875	945	1020	1102	1190	1285	1388	1499	1619
Total Fuel Cost, Rs M	3296	3914	4741	5093	5504	5770	6612	7141	7712	8499	9179
Salaries & Staff Expenses	343	370	400	432	467	504	544	588	635	686	741
Repairs & Maintenance	241	260	281	304	328	354	382	413	446	482	520
Insurance	37	40	43	47	50	54	59	63	68	74	80
Other Operational Expenses	99	107	115	124	134	145	157	169	183	198	213
Other Administrative Expenses	213	231	249	269	290	314	339	366	395	427	461
Inadmissible Expenses	92	93	93	93	93	93	93	93	93	93	93
Total Other Operating Expenses	1025	1101	1181	1268	1362	1464	1574	1692	1820	1958	2108
Maximum Demand Purchased, MVA	500	500	500	500	500	500	500	500	500	500	500
Demand Charge, Rs/kVA/month	85	100	110	121	133	146	161	177	195	214	236
Basic Energy Charge, Rs/kWh	1.08	1.20	1.32	1.45	1.60	1.76	1.93	2.13	2.34	2.57	2.83
Fuel Adjustment Charge, Rs/kWh	0.08	0.12	0.13	0.15	0.16	0.18	0.19	0.21	0.23	0.26	0.28

PROJECT RETURNS	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Case Without the Project											
Operating Cash Flow, Rs M	1378	1565	2042	1669	1659	1755	1647	1630	1669	1694	1747
Interest, Rs M	597	700	778	714	688	659	617	597	591	571	508
Average Tariff, Rs/kWh	0.988	1.112	1.168	1.225	1.388	1.573	1.688	1.784	1.935	2.134	2.382
Additions to Fixed Assets	1034	742	601	265	140	140	262	348	601	250	140
Case With the Project (all 4)											
Operating Cash Flow, Rs M	1478	1619	2146	1941	2080	2234	2336	2317	2346	2360	2401
Interest, Rs M	597	706	813	855	968	1020	975	943	918	877	790
Average Tariff, Rs/kWh	1.000	1.118	1.180	1.253	1.429	1.522	1.515	1.571	1.693	1.877	2.110
Additions to Fixed Assets	1056	1176	1469	1784	1225	552	262	348	601	250	140
Capex CC & Bh+TL+FGD	-22	-434	-868	-1519	-1085	-412	0	0	0	0	0
Increm.Oper.Cash Flow	99	53	103	272	422	478	689	687	677	666	654
Incremental Interest	0	7	35	141	280	360	357	346	326	306	283
Cash Flow to TEC, Rs M	77	-374	-727	-1106	-384	426	1046	1033	1004	972	937
Project IRR (net)	23.8%										
Energy Sales, in GWh	6658	7036	7336	7728	7937	8200	8818	9289	9781	10328	10801
Tariff Difference, Rs/kWh	0.012	0.006	0.011	0.028	0.041	-0.051	-0.173	-0.212	-0.243	-0.257	-0.272
Benefit to Consumers, Rs M	-80	-43	-84	-214	-324	420	1526	1972	2374	2657	2934
Cash Flow to TEC+Consumers	-3	-423	-845	-1461	-987	483	2214	2659	3052	3323	3818
Project IRR (gross)	39.4%										

MAIN ASSUMPTIONS FOR THE FINANCIAL PROJECTIONS

Project Completion by 3/31/95. Startup from FY96, except for some generation from the CC unit on open cycle from FY95.

Sales Volume: Energy sold to BEST increasing at 4.3% pa; direct industrial customers at 2.5% pa; railways at 1.0% pa. Energy sold to BSES calculated as the difference between its requirements, increasing at 8.5% pa, and its own net generation from the planned 500 MW station at Dahanu, starting in FY96.

TEC's Own Generation: Units 1-2-3, rated capacity 180 MW, to be relegated to standby status only, with zero generation, from FY95 as the new CC unit comes in. Units 5 and 6 generating 3,000 GWh p.a. (68.5% load factor) plus the off-peak energy consumed by the planned pumped storage units at Bhira from FY96 and Bhivpuri from FY99. The Combined Cycle also operating at 68.5% LF. Sensitivity test done for 60% LF.

Purchased Power: The difference between sales and own generation is purchased from MSEB.

Fuel Mix: Oil at 640,000 t pa; gas at 2.5 million m3/day in FY91 and FY92, declining to 2.0 in FY93 and FY94 and to 1.5 Mm3/d thereafter; the balance of the calorific requirement for the total generation provided by coal.

Fuel Prices increasing at 8% pa from the actual current level in the base case. Sensitivity tests done for 0 % and 13% pa increases.

MSEB's tariffs paid by TEC increasing at 10% pa from the level to which they were just raised in May 1990 (the demand charge increased from 35 to 100 Rs/kVA per month and the energy charge from 1.16 to 1.32 Rs/kWh). Sensitivity tests done for 0% and 13% pa increases together with fuel prices (if fuel costs increase, tariffs will have to follow).

Other Operating Costs, i.e. wages, maintenance etc., escalated at 8% p.a. in the base case.

TEC's tariffs are calculated in accordance with the provisions of the Act.

Depreciation is taken at 3.6% p.a.

Interest at the actual rates per the respective loan agreements.

Exchange rate Rs/$: Consistent with the IBRD projections, the Rs is assumed to devalue vs. the $, 10% in each of FY91 and FY92 and 3.8% p.a. thereafter. Sensitivity test is done for devaluation remaining at 10% p.a. after FY92.

Reserves:

Contingency Reserve and Investment Allowance Reserve as provided by the Act. The other special appropriations were allowed by the state of Maharashtra ad hoc. The application of these reserves by TEC has not been audited by the State since 1984.

Debt Redemption Reserve is taken at the difference between depreciation and principal repayments due each year.

Project Cost Reserve charged when it does not result in a tariff increase in the year charged, up to a cumulative amount of Rs 580 million sanctioned by the State.

Deferred Tax Reserve charged similarly at Rs 50 M each year. This is to cover the capital gains (arising from the different depreciation rates under the Act and for income tax) that shareholders would have to pay in the event the State bought out TEC. The funds raised through this reserve must be invested in specified Government securities.

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PRIVATE POWER UTILITIES PROJECT I

Economic Analysis

Western Region: Actual and Projected Power and Energy Demands

	Actual		Average Growth	Projected		Average Growth
	FY82 a/	FY 88 (Provisional)	FY82/FY88 (% p.a.)	FY89 b/	FY2000	FY89/FY2000 (% p.a.)
1. PEAK LOAD (MW)						
Gujarat c/	1,824	2,661	8.6	2,978	6,656	7.8
Madhya Pradesh	1,107	2,178	11.9	2,458	7,308	10.4
Maharashtra d/	2,993	4,690	7.8	5,208	13,006	8.7
Total	5,811	9,529	8.6	10,637	26,970	8.8
Maximum Load Able To Be Met	5,811	8,765	7.1	9,913	28,616	10.1
Deficit	- a/	764		724	0	
2. ENERGY REQUIREMENT (GWh)						
Gujarat c/	9,450	17,419	10.7	18,578	38,449	6.8
Madhya Pradesh	5,892	13,494	14.8	14,394	42,721	10.4
Maharashtra d/	17,185	29,111	9.2	31,899	80,285	8.8
Total	30,378	60,024	12.0	64,872	163,328	8.8
Total Supply	30,378	59,537	11.9	63,407	163,328	8.9
Deficit	- a/	487		1,465	0	

a/ Data for FY82 reflect consumption rather than power and energy demands. No data are available on the extent of unmet load or the amount of unserved energy.
b/ Actual data for FY89 are not yet available from CEA.
c/ Including Dadra and Nagar Haveli.
d/ Including Goa, Daman and Diu

Source: Thirteenth Electric Power Survey of India, CEA, December 1987, updated by CEA, April 1990, plus Bank estimates.

Annex 5.0, Table 1

INDIA

PRIVATE POWER UTILITIES PROJECT I

Economic Analysis

Western Region: Electricity Consumption By Consumer Category

	Actual				Average Growth	Projections				Average Growth
	FY82		FY88		FY82/FY88	FY89 b/		FY2000		FY89/FY2000
	(GWh)	(%)	(GWh)	(%)	(% p.a.)	(GWh)	(%)	(GWh)	(%)	(% p.a.)
CONSUMER CATEGORY										
1. Domestic	3,257	11.2	6,912	14.3	13.4	7,678	14.7	28,294	21.8	12.6
2. Commercial	1,639	5.6	2,701	5.6	8.7	2,916	5.6	6,390	4.9	7.4
3. Industrial:										
LV and MV	2,606	8.9	3,739	7.7	6.2	4,193	8.1	10,383	8.0	8.6
HV	15,489	53.1	22,307	46.1	6.3	22,700	43.6	54,320	41.8	8.3
Total Industrial	18,093	62.1	26,047	53.9	6.3	26,893	51.7	64,703	49.8	8.3
4. Public Lighting	303	1.0	452	0.9	6.9	457	0.9	1,220	0.9	9.3
5. Traction	1,088	3.7	1,272	2.6	3.0	1,378	2.6	4,218	3.2	10.7
6. Agriculture	3,787	13.0	9,448	19.5	16.5	11,020	21.1	20,900	16.1	6.0
7. Public Water	738	2.5	1,229	2.5	8.9	1,278	2.5	3,677	2.8	10.1
8. Bulk Supplies	259	0.9	310	0.7	3.0	482	0.9	463	0.4	-0.4
Total a/	29,146	100.0	48,371	100.0		52,105	100.0	129,865	100.0	
					Average: 8.8					Average: 8.7

a/ Differences with figures for energy availability in Table 1 reflect technical and non-technical losses.
b/ Actual data for FY89 are not yet available from CEA.

Source: Thirteenth Electric Power Survey of India, CEA, December 1987, updated by CEA, April 1990.

Annex 5.0, Table 2

INDIA

PRIVATE POWER UTILITIES PROJECT I

Least-Cost Analysis

I. Comparative Analysis Of System Cost With Bhira And Alternatives

	Billions of Rupees		
Year	Bhira 150 MW	Coal 150 MW	Gas 150 MW
FY94	10.237	10.355	10.301
FY95	19.784	19.983	19.900
FY96	29.071	29.343	29.236
FY97	38.263	38.597	38.472
FY98	47.432	47.804	47.683
FY99	56.767	57.169	57.056
FY2000	66.417	66.888	66.756
PV at 12%	174.278	175.730	175.221
FY2000/FY2019	1195.506	1203.984	1201.608
PV at 12%	729.908	735.300	733.687

INDIA

PRIVATE POWER UTILITIES PROJECT I

Least Cost Analysis

II. Comparison Of Generation Cost From Trombay With Alternative Base Load Options

1. **Trombay** - Net Generation 1080 GWh per annum

	Rs per kWh	Notes
a. Capacity Charge	0.23	Rs 10,590/kW, 25-year lifetime
b. Fuel	0.52	$0.207m^3$/kW, Rs $2.512/m^3$
c. O&M	0.03	2.5% total capital cost
d. Transmission	-	None required
e. T&D Losses	0.01	1%
Total	0.79	

2. **Load-Center Coal Station** - Net Generation 1080 GWh per annum

	Rs per kWh	Notes
a. Capital Charge	0.41	Rs 19,460/kW, 25-year lifetime
b. Fuel	0.37	0.59 kg/kWh, Rs 630 per tonne
c. Oil Support	0.03	10 ml/kWh, Rs 2.7 per litre
d. O&M	0.07	As 1(c)
e. Transmission	0.02	5% station cost
f. T&D Losses	0.01	1%
Total	0.91	

3. **Pit-Head Coal Station** - Net Generation 1080 GWH per annum

	Rs per kWh	Notes
a. Capital Charge	0.41	AS 2(a)
b. Fuel	0.11	0.59 kg/kWh, Rs 190 per tonne
c. Oil Support	0.03	As 2(c)
d. O&M	0.07	As 1(c)
e. Transmission	0.12	30% station cost
f. T&D Losses	0.02	3%
Total	0.76	

INDIA

PRIVATE POWER UTILITIES PROJECT I

Program Analysis: Program Costs and Benefits

	(Rupees Million)								(GWh)	(Rupees Million)	
	GENERATION					TRANSMISSION AND DISTRIBUTION					
	Capital Costs										
Year	Coal	Gas	Hydro	O&M	Fuel	Capital Costs	O&M	Total Costs	Incremental Supply	Incremental Revenues	Incremental Revenue and Consumer Surplus
FY91	2248	2832	701					5781			
FY92	5968	4344	922	60	1217			12511	1999	1419	3159
FY93	13803	5124	2393	264	5356			26940	8793	6246	13898
FY94	16919	1740	3761	358	7259			30037	11972	8500	18915
FY95	21165		4782	920	7681	10466		45014	13280	9429	20982
FY96	23531		6270	1833	9013	15699		53846	19819	13929	30997
FY97	21717		6552	1800	11172	15699	419	57359	26313	18683	41575
FY98	13869		5128	2558	13306	20932	628	56421	34035	24165	53775
FY99	5534		2744	3402	16372	20932	837	49822	44790	31801	70768
FY2000	1315		1075	3891	19746	10466	942	37434	56971	40449	90014
FY2001				3891	21808	10466	1047	37211	63363	44988	100114
FY2002				3891	22461		1117	27469	65391	46427	103317

Annex 5.0, Table 5

INDIA

PRIVATE POWER UTILITIES PROJECT I

Estimation of Consumer Surplus

I. AGRICULTURAL CONSUMERS

The economic value of consumers' willingness-to-pay for public electricity for irrigation is estimated as the electricity rate which equates the economic costs of diesel and electric irrigation pumping.

Estimated Costs of Diesel and Electric Pumping

	Electric	Diesel
Motor/Engine Size (H.P.)	5.0 a/	7.0
Pump Lifetime (years)	15.0	10.0
Pump Capital Cost (Rs)	4,440	11,365
Annual Charge (Rs)	652	2,011
O&M Costs (Rs)	1,017	2,857
Costs of Diesel Fuel (Rs/hr) b/	-	8.8
Annual Diesel Costs (Rs)	-	7,000
Cost of Electricity (paise/kWh)	XXX	-
Annual Electricity Cost (Rs)	2,984(XXX) c/	-
Total Annual Cost	1,699 + 2,984(XXX)	11,868

Electricity rate at which electric and diesel pumping costs the same:

Paise XXX/kWh = (11,868 - 1699)/2,984
= Paise 341/kWh

---

a/ 1 H.P. = 0.746 kW.
b/ Assuming an economic price of high speed diesel of Rs 3.5 per litre, consumption of 2.5 litres per hour and operation for 800 hours per year.
c/ 2,984 = 5 x 0.746 x 800.

INDIA

PRIVATE POWER UTILITIES PROJECT I

Estimation of Consumer Surplus

II. OTHER CONSUMERS

Consumers' willingness-to-pay for public electricity is related to the additional financial costs that would be incurred through private supply. Correspondingly, the economic value of this willingness-to-pay is related to the economic costs of private supply, which are estimated below.

Estimated Costs of Autogeneration

	Cost per kW of Capacity (Rs)	
	50 kW Machine	200-400 kW Machine
1. Fixed Costs		
Capital Cost a/	6,300	4,420
Annual Charge b/	925	649
Salaries	668	449
Maintenance	134	92
Total Annual Fixed Costs	1,727	1,190
	Cost per kWh Generated (Paise)	
2. Variable Costs		
Diesel Fuel c/	140	112
Lubricant	4	4
Total Variable Costs	144	116
3. Fixed Costs at 15% Load Factor d/	131	91
4. Average Cost of Generation	275	207

a/ C.I.F. price, plus handling and installation.
b/ Assuming a 15-year life and 12% discount rate.
c/ Assuming an economic cost of high speed diesel of Rs 3.5 per litre and specific consumptions of 0.4 litre per kWh and 0.32 litre per kWh respectively in the 50 kW and 200-400 kW machines.
d/ CEA's estimate of the average load factor of private generators.

INDIA

PRIVATE POWER UTILITIES PROJECT I

Estimation of Consumer Surplus

III. AVERAGE RATE OF CONSUMER SURPLUS

To the economic value of the average tariff rates for each consumer category has been added half the additional economic costs of private supply. This conservatively assumes that the price elasticity of demand is unity, i.e. that demand would contract in proportion to the additional cost of private supply. In practice, price elasticities at low levels of electricity consumption usually are well below unity, implying that more than half of consumers would pay the additional costs of private supply. Rates of surplus for each consumer category have been weighted into an overall average using expected consumption shares.

Estimated Rates of Consumer Surplus (For FY93) a/

Consumer Category	Consumption Share (%)	Autogeneration Cost (paise/kWh)	Estimated Average Tariff (paise/kWh) Financial b/	Estimated Average Tariff (paise/kWh) Economic c/	Surplus Imputed (paise/kWh) d/
Domestic	17.1	275	52	42	117
Commercial	5.3	275	87	70	103
Industry (LV+MV)	8.3	207	99	79	64
Industry (HV)	46.3	207	121	97	55
Agriculture	16.4	341 e/	19	15	163
Other f/	6.6	207	122	98	55
	100.0				
		Average	89	71	87

a/ The first year of incremental supplies from projects included in the program time-slice.
b/ Estimated on the basis of FY88 actuals increased by 4.7% per annum - the average annual real increase in tariffs in the Western Region between FY85 and FY88.
c/ Financial rates multiplied by SCF of 0.8.
d/ Surplus imputed at half the difference between the economic value of the average tariff level and the estimated cost of autogeneration.
e/ The electricity rate equating the economic costs of diesel and electric pumping.
f/ Comprises: public lighting, public water pumping and bulk sales.

INDIA

PRIVATE POWER UTILITIES PROJECT I

Program Returns

		IRR (%)	NPV at 12% Rs. Million	NPV at 12% US$ Million (Rs 17/US$)
i)	Base Case	24.88	159,075.67	9,357.39
ii)	Costs +5%	23.18	144,758.19	8,515.19
iii)	Costs +10%	21.83	130,440.72	7,672.98
iv)	Costs +20%	18.94	101,805.76	5,988.51
v)	Costs +30%	16.65	73,170.81	4,304.17
vi)	Costs +40%	14.66	44,535.86	2,619.76
vii)	Costs +50%	12.90	15,900.91	935.35
viii)	Benefits -5%	23.09	136,804.41	8,047.32
ix)	Benefits -10%	21.31	114,533.15	6,737.24
x)	Benefits -20%	17.75	69,990.63	4,117.10
xi)	Benefits -30%	14.13	25,448.11	1,496.95
xii)	Benefits -35%	12.27	3,176.85	186.87
xiii)	2-Year Delay	18.34	94,529.10	5,560.54
xiv)	3-Year Delay	16.68	70,613.08	4,153.71
xv)	4-Year Delay	15.12	47,939.40	2,819.96

INDIA

PRIVATE POWER UTILITIES PROJECT I

Project Analyses

I. BHIRA HYDRO STATION AND BHIRA-DHARAVI TRANSMISSION

Rs Millions

Year	Bhira	Assoc. T & D	Bhira-Dharavi	Capex. Total	Oper. & Maint.	Pumping	Benefits a/	Net Benefits
FY91	102.5	61.5	68.3	232.3				-232.3
FY92	170.9	102.5	113.9	387.3				-387.3
FY93	273.3	164.0	182.3	619.6				-619.6
FY94	136.7	82.0	91.1	309.8	15.5	69.3	337.2	-57.4
FY95/FY2019					15.5	138.5	674.4	520.4

IRR = 26%   NPV at 12% = Rs 1,770 Millions

II. TROMBAY COMBINED-CYCLE AND FLUE GAS DESULPHURIZATION

Rs Millions

Year	Trombay	Assoc. T & D	FGD	Capex. Total	Oper. & Maint.	Fuel	Benefits a/	Net Benefits
FY91	211.3	126.8	21.9	360.0				-360.0
FY92	422.6	253.6	43.8	720.0				-720.0
FY93	493.1	295.9	51.0	840.0				-840.0
FY94	287.8	169.1	23.2	480.1	47.4	280.8	713.5	-808.2
FY95/FY2019					47.4	561.6	1427.0	-609.0

IRR = 27%   NPV at 12% = Rs 2,792 Millions

a/ Net of transmission and distribution losses of 12%.

Annex 5.0, Table 9

INDIA

PRIVATE POWER UTILITIES PROJECT I

Summary of Analysis Assumptions

- Analysis has focussed on the FY91 to FY2000 time-slice of investments, including only those projects that would be implemented fully during the period. Construction periods assumed are: coal-fired stations - 5 years; hydro stations - 8 years; and gas-fired stations - 3 years.

- Station capital costs (in economic terms and January 1990 prices) are estimated to be: coal stations - Rs 13.146 million/MW (based on Talcher); hydro stations - Rs 10.365 million/MW (based on Nathpa Jhakri); and gas stations - Rs 6.0 million/MW (based on Trombay).

- Associated transmission and distribution investments assumed to be equivalent to 60% investments in generation.

- Annual operating and maintenance costs are assumed as: coal-fired and gas-fired stations - 2.5% of station capital costs; hydro stations - 1.1% of station capital costs; and transmission and distribution - 1% of capital costs.

- Average fuel consumptions of new stations are assumed as: coal stations - 0.61 kg/kWh of coal and 10 ml/kWh of oil; and gas stations - 0.23 m^3/kWh (an average of open-cycle and combined-cycle consumption rates).

- Economic fuel costs are assumed as: coal - Rs 360 per tonne (an average of costs at pithead and load center stations); oil - Rs 2.7 per litre; and gas - Rs 2,200 per thousand m^3. For pumped-storage projects, fuel costs are based on coal at Rs 520 per tonne (the cost at a load center station).

- Annual generation by new stations is assumed as: coal - 1,000 hrs in first year, 3,500 hrs in second year, and 6,150 hrs per year thereafter; gas - 6,000 hrs per year; hydro - 2,600 hrs per year, and pumped-storage (excluding Bhira) - 2,200 hrs per year.

- Consumption by station auxiliary equipment is assumed as: coal - 10% of gross generation; gas - 2% of gross generation; and hydro - 1%.

- Transmission and distribution losses are assumed as 20% in FY90 declining to 15% by FY2000.

ANNEX 6.0

INDIA

PRIVATE POWER UTILITIES PROJECT I

Documents in Project File

1. Feasibility Report for Gas Turbine Combined Cycle Power Plant, Tata Consulting Engineers, Bangalore, November 1988.

2. Feasibility Report - 180 MW Combined Cycle Power Plant at Trombay Thermal Generating Station, Tata Consulting Engineers, Bangalore, December 1989.

3. Project Report - Dharavi Switching Station Extension, Tata Consulting Engineers, Bombay, November 1989.

4. Supplement to Detailed Project Report - Bhira Generating Station Extension, 150 MW 7th Unit (Pumped Storage), Tata Consulting Engineers, Bombay, September 1988.

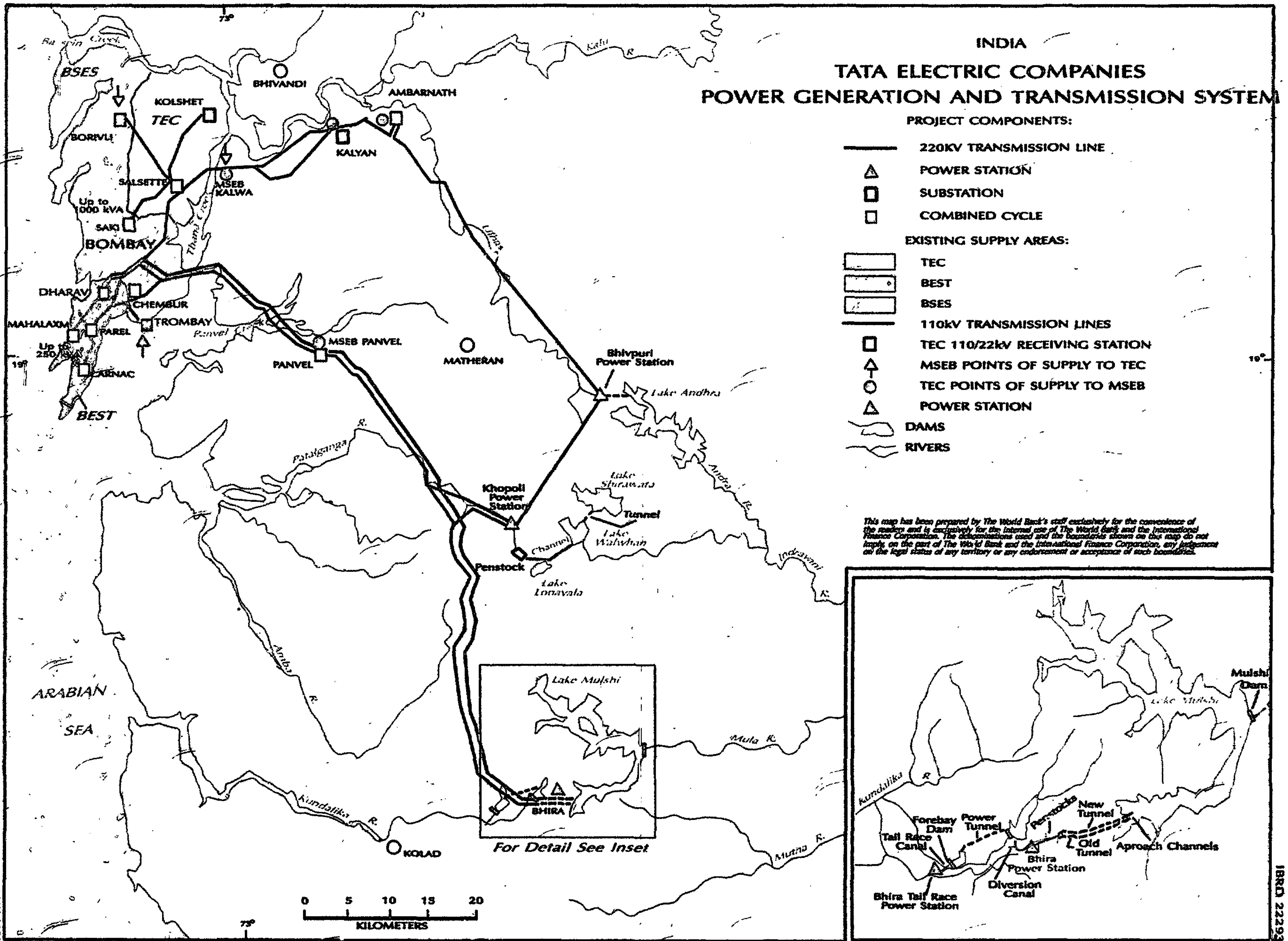
5. Summary Information on Combined Cycle Schemes, Tata Consulting Engineers, January 1990.

6. Flue Gas Desulphurisation, Relevance in Indian Context, Bombay Suburban Electric Supply Ltd., 1989.

7. Project Report - Flue Gas Desulphurisation Plant for Trombay 500 MW Unit 5, Tata Consulting Engineers, Bombay, May 1988.

8. Project Report - Flue Gas Desulphurisation Plant for Trombay 500 MW Unit 5, Tata Consulting Engineers, Bombay, November 1989.

9. Copy of the Certificate of Inspection by the Government of Maharashtra Irrigation Department for the Mulshi Dam, dated March 29, 1989.



INDIA
TATA ELECTRIC COMPANIES
POWER GENERATION AND TRANSMISSION SYSTEM
PROJECT COMPONENTS:
220kV TRANSMISSION LINE
POWER STATION
SUBSTATION
COMBINED CYCLE
EXISTING SUPPLY AREAS:
TEC
BEST
BSES
110kV TRANSMISSION LINES
TEC 110/22kV RECEIVING STATION
MSEB POINTS OF SUPPLY TO TEC
TEC POINTS OF SUPPLY TO MSEB
POWER STATION
DAMS
RIVERS
BSES
TEC
BORIVLI
KOLSHET
BHIVANDI
AMBARNATH
KALYAN
SALSETTE
MSEB KALWA
Up to 1000 kVA
SAKI
BOMBAY
DHARAVI
CHEMBUR
MAHALAXMI
TROMBAY
PAREL
Up to 250 kVA
CARNAC
BEST
MSEB PANVEL
PANVEL
MATHERAN
Bhivpuri Power Station
Lake Andhra
Khopoli Power Station
Tunnel
Channel
Penstock
Lake Lonavala
Lake Mulshi
BHIRA
For Detail See Inset
KOLAD
ARABIAN SEA
Mula R.
Mutha R.
Kundalika R.
Amba R.
Patalganga R.
Indrayani R.
Ulhas R.
Andra R.
Kalu R.
Thane Creek
Panvel Creek
0 5 10 15 20
KILOMETERS
73°
19°
This map has been prepared by The World Bank's staff exclusively for the convenience of the readers and is exclusively for the internal use of The World Bank and the International Finance Corporation. The denominations used and the boundaries shown on this map do not imply, on the part of The World Bank and the International Finance Corporation, any judgement on the legal status of any territory or any endorsement or acceptance of such boundaries.
Mulshi Dam
Lake Mulshi
Kundalika R.
Forebay Dam
Power Tunnel
Penstocks
New Tunnel
Tail Race Canal
Old Tunnel
Aproach Channels
Bhira Power Station
Diversion Canal
Bhira Tail Race Power Station
MAY 1990
IBRD 22293