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STAFF APPRAISAL REPORT

ISLAMIC REPUBLIC OF IRAN

POWER SECTOR EFFICIENCY IMPROVEMENT PROJECT

MARCH 3, 1993

Country Department II
Industry and Energy Operations Division
Middle East and North Africa Regional Office

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CURRENCY EQUIVALENT
Currency Unit = Rial (Rl)
(As of February, 1993)

US\$ 1.00	=	Rls 70	<u>/1</u>
Rls 1.00	=	US\$0.0143	<u>/1</u>
US\$ 1.00	=	Rls 1,450	<u>/2</u>
Rls 1.00	=	US\$0.0007	<u>/2</u>
US\$ 1.00	=	Rls 600	<u>/3</u>
Rls 1.00	=	US\$0.00167	<u>/3</u>

WEIGHTS AND MEASURES

BCM (billion cubic meters)	=	35.3 billion cubic feet
GWh (Gigawatt hour)	=	1,000,000 kWh
MBPD	=	million barrels per day
MBTU	=	million British Thermal Units
MTOE	=	million tons of oil equivalent
MW (Megawatt)	=	1,000 kW
One cubic meter	=	264 (U.S.) gallons
	=	35.31 cubic feet
Kilometer (km)	=	0.6214 miles
Metric ton (mt) (1,000 kg)	=	2,205 pounds
tcf	=	trillion cubic feet
TWh (Terawatt hour)	=	1,000,000,000 kWh

GLOSSARY OF ABBREVIATIONS

AIC	=	Average Incremental Cost
CEM	=	Country Economic Memorandum
FSU	=	Former Soviet Union
GDP	=	Gross Domestic Product
HRSG	=	Heat Recovery Steam Generator
ICB	=	International Competitive Bidding
IEPO	=	Iranian Environmental Protection Organization
IPO	=	Iran Power Organization
LRMC	=	Long-Run Marginal Cost
MBPD	=	Million Barrels Per Day
MIS	=	Management Information System
MOE	=	Ministry of Energy
PCB	=	Polychlorinated Biphenyl
PPAR	=	Project Performance and Audit Report
REC	=	Regional Electric Company
SCADA	=	Supervisory Control and Data Acquisition
STG	=	Steam Turbine Generator
TAVANIR	=	Iran Power Generation and Transmission Company
TOR	=	Terms of Reference
TREC	=	Tehran Regional Electric Company
WPA	=	Water and Power Authority
EIRR	=	Economic Internal Rate of Return

GOVERNMENT OF ISLAMIC REPUBLIC OF IRAN
FISCAL YEAR

March 21 - March 20

/1 Official basic exchange rate.
/2 Floating exchange rate.
/3 Competitive exchange rate for a selected list of imports.

STAFF APPRAISAL REPORT
ISLAMIC REPUBLIC OF IRAN
POWER SECTOR EFFICIENCY IMPROVEMENT PROJECT

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ISLAMIC REPUBLIC OF IRAN

POWER SECTOR EFFICIENCY IMPROVEMENT PROJECT

LOAN AND PROJECT SUMMARY

Borrower: Tehran Regional Electric Company

Guarantor: Islamic Republic of Iran

Amount: US\$165 million

Terms: Standard IBRD terms, with 17 years maturity

Project Objectives and Description: The primary objective of the project is to decrease load shedding through a combination of system expansion, efficiency improvement, load management and price adjustments. This would be accomplished through the addition of 200 MW of capacity, by converting the existing gas turbines at Qom to a combined cycle plant; the construction of 400-kV substations and transmission line; distribution equipment; technical assistance and training activities; and price reform measures supported by the project.

Benefits and Risks: Electricity in Iran has been supply-constrained since the end of the war with Iraq. As a result, investments in this sector are a high priority component of the Government's reconstruction program. The Government also intends to use investments in the power sector as a means to attract cofinancing to assist in addressing the substantial capital requirements of reconstruction. The Qom Combined Cycle Plant is an integral component of this least-cost investment plan. The conversion of the Qom gas turbines to combined cycle operations would add about 200 MW of capacity by 1996. This project has been classified as Environmental Category B. The project requires no incremental fuel usage and has minimal water requirements as it uses air cooled condensers. Hence, the environmental impact is minimized. The project risks are mitigated by engaging consultants of international repute who have had experience with similar projects and with the Bank. The risks in achieving the level of outputs forecast are addressed by including operator training as a component of the loan. The financial risks have been minimized by substantial up-front action by the Government on price adjustments. The EIRR for the project is estimated to be 17 percent.

Estimated Project Cost
(US\$ Million)

	<u>LOCAL</u>	<u>FOREIGN</u>	<u>TOTAL</u>	<u>FOREIGN AS % OF TOTAL</u>	<u>% OF BASE COST</u>
I. Qom Component					
- Civil Works	12.2	3.0	15.2	20	5
- Equipment & Materials	36.8	152.2	189.0	81	58
- Transmission Lines & Substations	14.2	66.0	80.2	82	25
- Distribution Equipment	3.1	13.1	16.2	81	5
- Project Management & Owner's Administration	12.1	9.1	21.2	43	6
- Base Cost	78.4	243.4	321.8	76	99
II. TA Component					
- Studies	0.5	3.4	3.8	88	1
- Training	0.2	0.6	0.8	80	0
- Base Cost	0.6	4.0	4.6	87	1
	-----	-----	-----	-----	
Base Project Cost	79.0	247.4	326.3	76	100
Physical Contingencies	7.4	24.2	31.7		
Price Contingencies	6.3	19.0	25.3		
	-----	-----	-----	-----	
Total Project Cost	92.7	290.6	383.3	76	
Interest During Construction (IDC)	0.0	30.6	30.6		
	-----	-----	-----	-----	
Total Project Cost + IDC	92.7	321.1	413.9	78	
	-----	-----	-----	-----	

NOTE: Figures may not add-up as they are rounded to the first decimal place .

Project Financing Plan
(US\$ Million)

<u>SOURCE</u>	<u>LOCAL</u>	<u>FOREIGN</u>	<u>TOTAL</u>	<u>% OF TOTAL</u>
- IBRD	0.0	165.0	165.0	39.9
- Supplier's Credit	0.0	47.8	47.8	11.5
- MOE	0.6	0.0	0.6	0.2 ^{1/}
- TREC	92.1	108.4	200.4	48.4
Total	92.7	321.1	413.9	100.0

NOTE: Figures may not add-up as they are rounded to the first decimal place.

^{1/} Less than one percent.

Estimated Disbursement
(US\$ Million)

	<u>FY94</u>	<u>FY95</u>	<u>FY96</u>	<u>FY97</u>	<u>FY98</u>
- Actual	27.0	58.9	53.6	21.3	4.2
- Cumulative	27.0	85.9	139.5	160.8	165.0
- Percentage	16.4%	52.1%	84.5%	97.5%	100.0%

NOTE: Figures may not add-up as they are rounded to the first decimal place.

This report is based on the findings of an appraisal mission to Iran in January 1992, comprising Messrs. G. Stuggins (Task Manager), C. Woodruff (Senior Financial Analyst), L. Gutierrez (Senior Energy Economist), S. Ouahes (Senior Power Engineer), T. Moore (Consultant), A. Posada (Consultant), U. Chandra (Consultant). The report was updated on the basis of a post-appraisal mission comprising Messrs. V. Bhargava (Mission Leader), R. Mendonca, C. Woodruff, and U. Chandra, which visited Iran in August 1992. Peer Reviewers: Messrs. Peter Cordukes (IENED) and Suman Babbar (CFSPS). The report has been endorsed by Mr. Caio Koch-Weser, Vice President, MNAV, Mr. Ram K. Chopra, Director, MN2DR and Mr. Vinay K. Bhargava, Division Chief, MN2IE.

I. THE ECONOMY

1.1 Iran's economic policies and performance in the last decade were influenced by the revolution in 1979 and by the war with Iraq from 1980 to 1988. During the war years, the economy was subjected to many forms of control and administrative intervention, and economic performance was mixed. A fast rate of GDP growth (averaging 8 percent per year in 1980-85) in the early years was followed by a decline (3 percent per year in 1985-88) and rising inflation (averaging 20 percent per year in 1985-88) due, in large part, to excess money supply created to meet growing public deficits (on average, equal to 8 percent of GDP each year during 1985-88). Following the end of the war in 1988, Iran prepared the First Five-Year Plan (FFYP) spanning 1989-1993. The policy objectives in the FFYP include the progressive elimination of financial imbalances, the decentralization of economic decision-making and the privatization of state enterprises in various parts of the economy.

1.2 Since the inception of the FFYP, the Government has initiated sound policy changes. Additional macroeconomic and sectoral policy reforms nevertheless will be required to consolidate and advance the reform process. A major distortion has been the multiple exchange rate system. In January 1991, the Government reduced the number of rates from seven to three (the official rate of Rials 70/US\$, the competitive rate of Rials 600/US\$, and the floating rate, lately Rials 1450/US\$), and a proposal has now been passed to unify the rates. Other recent policy reforms have included: a large effective depreciation of the rial, especially for non-oil exporters; widespread removal of non-tariff barriers on imports at the floating rate; decontrol of many domestic prices, along with dissolution of price enforcement courts; introduction of a less onerous income tax schedule; steep increases in public utility rates; abolition of credit ceilings; and a decision to permit private nonbank financial institutions.

1.3 Implementation of key reforms has helped to stimulate economic growth and to lower budget deficits. From a low base that ensued from the 1980-88 war, GDP grew an average 7 percent per year during 1989-92. The general government deficit was reduced from 9 percent of GDP in 1988 to an estimated 2 percent in 1992. With lower deficits, the growth of net credit to government and that of broad money declined between 1988 and 1990. This helped to lower inflation from 29 percent in 1988 to around 10 percent in 1990. Since then, however, inflation has edged up to around 20 percent each year in 1991 and 1992.

1.4 The rapid restoration of oil production and export facilities over the past four years, together with the high oil prices reached in 1990, helped Iran's external accounts. The overall balance of payments totalled a positive \$2 billion in 1989-90. In 1991, however, the balance of payments deteriorated sharply as oil prices fell 20 percent while the volume of imports rose 30 percent. This underscores the importance of export diversification for Iran to reduce its vulnerability to oil price fluctuations. Before increasing its output and exports on a sustainable basis, Iran will need to further improve economic incentives and make substantial investments to rehabilitate its productive infrastructure.

Country Dialogue and Bank Strategy

1.5 The reform process has been remarkably successful thus far, and the stage has been set for an acceleration and deepening of reforms to continue developing the economy. The key to efficient growth and longer-term development in Iran is to complete the unification of the exchange rate and price reform and to enhance the role of the private sector. This would need to be accompanied by the corresponding trade reforms, compensatory mechanisms such as wage adjustments and social safety nets, and the mobilization of domestic and external resources to underpin policy reforms, finance development expenditures and strengthen essential public and private sector institutions.

1.6 These steps are an integral part of the Government's plan. The Government has adopted a program of progressive movement towards exchange rate unification and world market prices (including those in the agriculture sector) and elimination of subsidies, notably for agricultural inputs and equipment. Work is also going ahead on the design of a social safety net program.

1.7 Against this background, Bank country strategy aims to: (i) support the Government's economic reform program; (ii) support the rehabilitation of the Iranian economy and human resources development; and (iii) help Iran strengthen its links to the world economic and financial system and re-establish access to international capital markets. To achieve these goals, the Bank program comprises economic and sector work, investment lending, and the mobilization of other international financial resources through cofinancing and technical assistance.

II. THE ENERGY SECTOR

A. Background

2.1 Iran's electricity supply is characterized by widespread load shedding that affects all sectors. In 1989, electricity consumers generally experienced six hours of load shedding per day. Electricity sales since then have grown by about 10 percent per annum, reflecting the growth in both the economy (para. 1.3) and population (estimated at about 3.2 percent per annum). In spite of this, the power utilities have been effective in reducing daily load shedding to about two hours per day, reflecting an estimated supply shortfall of about 1,000 MW. This improvement was accomplished by reconstructing plants and transmission lines, which were damaged in the war with Iraq, and by expanding capacity. In spite of the considerable investments planned, load shedding is expected to persist through at least 1995. As load shedding is estimated to cost the economy more than US\$1 billion per year^{1/}, the Government accords a high priority to eliminating this problem.

2.2 Iran's power system consists of a major 400-kV interconnected system, which supplies electricity to most of the country, and to two isolated systems in eastern Iran (one in Khorasan and the other in Sistan-Baluchistan). The effective generating capacity in the interconnected system was about 11,000 MW as of March 1991 and about 1,000 MW in the isolated systems. The interconnected system is subdivided into two well-developed grids, with weak transmission links between the one in the north and the other in the south. This results in a bottleneck in power transfers from the south to the north, which is currently being addressed by reinforcing the transmission grid. Detailed description of the power system in Iran is presented in Annex 1.1.

2.3 Efficiency issues are being addressed within the sector. Staff in the Ministry of Energy (MOE) have made major improvements in their load forecasting and investment planning analysis and in the process, have helped identify ways to improve efficiency in power production. In addition, energy conservation options are being actively pursued through pricing adjustments and time-of-use tariffs. However, the largest potential impact on power sector efficiency is expected to come from the Government's proposed institutional reform as described in their Statement of Power Sector Development Policy (para. 2.18), which focusses on the corporatization and privatization of the existing entities.

B. Institutional Setting

2.4 Prior to 1965, the power sector consisted of a number of small municipally or privately owned power companies and generating plants associated with industries. In 1965, all of the power companies were nationalized and placed under the control of the newly created MOE. To this day, all power transmission and distribution activities, as well as all generating capacity, except that which is captive to industrial enterprises, remain under the jurisdiction of MOE. Thus, in the absence of independent

^{1/} Based on an estimated 2 TWh per annum of energy unserved valued conservatively at over US\$0.50/kWh.

suppliers, MOE has a virtual monopoly on the supply of electricity to the grid.

2.5 Power Sector Institutions. In addition to MOE, the power sector consists of the Iranian Power Generation and Transmission Company (TAVANIR); 16 distribution companies, established either as Regional Electricity Companies (RECs) or Water and Power Authorities (WPAs); and the Iran Power Organization (IPO). As indicated by the organization chart shown in Annex 2.1, MOE is responsible for many of the day-to-day activities as well as the future development of the sector. The sector enterprises, described below, have limited autonomy and function mainly as administrative subdivisions of the Ministry.

2.6 TAVANIR was established in 1969 to take over and operate the thermal generation and power transmission facilities. TAVANIR currently owns and operates over 90 percent of total thermal power plant capacity, as well as over 80 percent of the national transmission grid. The 16 RECs or WPAs, including the project executing agency, the Tehran Regional Electricity Company (TREC), are responsible for power distribution in their respective regions. RECs vary greatly in size, from TREC with annual sales of about 14,000 GWh, to the Semnan REC, which was recently formed to take over part of the TREC distribution network and has annual sales of less than 1,000 GWh. Though mainly confined to distribution, some RECs have retained transmission and generation facilities or taken over such facilities from TAVANIR. The WPAs operate dams, irrigation systems and hydropower stations, as well as power transmission and distributions facilities.

2.7 IPO was created in 1988 to take over the functions and much of the staff of the power section of MOE. As shown by the organization chart in Annex 2.2, IPO is headed by the Minister of Energy and managed, on a day-to-day basis, by the Deputy Minister of Power. IPO was created to take over responsibility, from TAVANIR and the RECs, for dispatching electric power throughout the national interconnected transmission system. More recently, in response to the Government's decision to cease financing power generation projects directly from the budget, IPO has been empowered to collect financial surpluses generated by the RECs and to oversee the allocation of such surpluses among generation investment projects (para. 2.14). Thus, on a de facto basis, the incomes of the RECs are subject to an effective tax rate of at least 100 percent, which is paid directly, at source, out of receipts from the sale of power. This reorganization has also led to the elimination of the TAVANIR monopoly on the construction of new power plants. TAVANIR does not contribute to IPO as it does not generate surplus funds internally, and, until recently, its investments were funded directly from the budget. Now TAVANIR must compete for IPO funds with other RECs, which are permitted to build their own power plants.

C. Energy Endowment

2.8 Iran's energy resource endowment is considerable, including oil, natural gas, hydropower, coal and solar energy. In January 1987, the National Iranian Oil Company (NIOC) increased its estimate of proven oil reserves to 93 billion barrels; Iran's reserves are now ranked among the five largest in the world. Current production rates of about 3.3 million barrels per day (MBPD) put the oil reserve to production ratio at about 80 years. Of the current oil production, about 2.4 MBPD are exported and 0.9 MBPD are for domestic use. From 1982-1989, domestic petroleum product consumption grew at 6.5 percent p.a., diminishing the exportable surplus. Tempering growth in domestic

consumption and interfuel substitution are key elements in increasing oil and gas exports.

2.9 Iran's gas reserves are considered to be conservatively estimated at 17 trillion cubic meters, second in size only to the Former Soviet Union (FSU) reserves. This estimate is thought to understate Iran's true potential because gas-prone areas have not been the focus of extensive exploration. At 1990 production levels, the gas reserve-to-production ratio was about 400 years, thus indicating considerable potential for accelerating utilization in domestic and export markets. The Government is actively pursuing both of these markets by increasing the supply of gas for power and household use^{1/} and by exports to the FSU. At present, about one billion cubic feet per day of associated gas production is being flared. Given that gas oil is being used by dual-fuel fired gas turbines, for which natural gas is a cost-effective substitute, there is considerable unmet gas demand.^{2/} The Government has assigned a high priority to reduce flaring and has sought Bank assistance for this purpose.

2.10 Iran currently has developed about 1,900 MW of hydroelectric power, representing only a small proportion of its potential, with the Karun and Karkheh Rivers alone estimated to have about 20,000 MW of economically attractive sites. Three sites on the Karun River are in advanced stages of preparation - Karun III, Godar-e-Landr and Karun IV - which would more than triple system hydro capacity.

D. Electricity Demand

2.11 Electricity consumption in Iran increased by 17 percent per annum in the period immediately preceding the war with Iraq (1970-80) and by 10 percent per annum during the war years (1980-88), reflecting strong economic growth, low prices and high population growth. During the post-war period, the annual rate of growth in consumption increased to 11.7 percent, reflecting a rebound in the economy despite large price increases. However, the structure of the growth changed: agricultural, residential and service demands grew less rapidly, while industrial consumption increased substantially (para. 6.1). It is difficult to estimate total demand because of load shedding and the concomitant latent demand. Energy sales increases are expected to remain high while the supply/demand gap is being addressed. However, these rapid energy sales growth rates are unlikely to continue over the medium- to long-term as electricity prices are expected to continue to increase in real terms.

E. Development Plan

2.12 The Government has embarked upon an ambitious investment program with annual capacity increases of about 1,500 MW costing about US\$2 billion (see Annex 1.1). Over the near term, the investment plan focusses on building gas turbine plants to address the load shedding problem. In addition, dual-fueled steam units (using residual fuel from nearby refineries and natural gas) are under construction. Dual-fired steam plants are being built to

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- 1/ The number of cities supplied by the gas grid is expected to double from 100 to 200 during the First Five-Year Plan period.
 - 2/ Gas oil currently is imported because of refinery constraints caused by the war with Iraq.

mitigate the risk of shortfalls in gas production. However, because of the abundance of low-cost natural gas in Iran, gas turbines for peaking and midrange operation and combined cycle units for base load operation are integral components of the least-cost plan.

2.13 The investment planning capabilities in the power sector suffered from a lack of international technical cooperation during most of the 1980s. There are still management and methodological problems that need be addressed to achieve more efficient investment planning. During appraisal, MOE has made major advances in their investment planning analysis through the use of improved load forecasting tools and long-term optimal generation investment planning models. A counterpart team that worked closely with the Bank mission has established the capability to use these analytical tools and will continue to refine the database. The project components are based on the results of these analyses. The energy planning capabilities in MOE will continue to be strengthened under the Energy Sector Development Study (para. 4.7).

2.14 Sector Financing. As sector enterprises have been permitted to import capital goods at the official exchange rate of 70 Rls/US\$ rather than at the competitive rate of 600 Rls/US\$ or the market rate of 1,450 Rls/US\$, the consumer has been the beneficiary of a large capital subsidy. A large implicit subsidy also exists based on domestic fuel prices, which are well below their export values. In 1991, tariffs were set to enable the sector to be financially self-sufficient. IPO levies were established so that the net funds available would enable each REC to break even on a cash basis. RECs, however, collect substantial revenues in the form of consumer connection charges, which are designed to cover some transmission and all distribution investments. Electricity prices are reviewed annually to ensure that tariffs are sufficient to enable IPO levies to fill the generation and transmission financing gap. Hence, the sector is independent of government financial resources.

2.15 In order to reach this high level of self-financing, the average electricity tariff was raised from 3 Rls/kWh to 5.2 Rls/kWh at the beginning of FY89, to 8.5 Rls/kWh at the beginning of FY91, and to 10.3 Rls/kWh as of February 1992. Thus, the average revenue has increased nearly fourfold in only three years. However, the IPO financing plan is flawed in that it makes no provision for financing the increased working capital requirements of the sector, in particular accounts receivable, which can be expected to increase in line with the tariff increase.

F. Sectoral Issues

2.16 Institutional Issues. The Iranian electricity market is typical of the vast majority of power sectors throughout the world in that it is characterized by an absence of competition. The managers of TAVANIR and of the RECs lack autonomy and authority; their accountability is limited, and they are not given appropriate incentives, even though these enterprises are responsible for major investments and are engaged in critically important commercial businesses. The Government intends to redress this problem by, first, commercializing the sector; second, by divesting operations that are not directly related to the delivery of electricity; and, finally, by encouraging private sector participation. Initially, the Government intends to redistribute the assets of the power sector among 9 regional companies (RHCs) which will be created as holding companies. TAVANIR will cease to exist and its generation and transmission assets will be turned over

to the regional holding companies which will also take over the assets of the 16 existing RECs. The RHCs will then rent their assets to 20 individual generating companies and 24 individual distribution companies (one for each of the 24 provinces). The Bank has recommended that the Government consider broadening this policy by eventually transferring the generation and distribution assets to the operating companies which would then be privatized. In this way, generation can be undertaken in a competitive framework, thus increasing the benefits of private sector participation. The Government has agreed, in principle, to explore this avenue further and, with Bank assistance, will study alternate ways (para. 4.7) to induce private sector participation in order that efficiency gains may be realized.

2.17 In spite of the fact that the average salaries are much lower than those available in the private sector, the calibre of the technical staff employed in the electricity sector is high. The technical management of the generation stations, in particular, is of a high standard. However, the institutions themselves are not organized to obtain the most out of the resources they deploy. Management systems are hierarchical and occupationally biased. Financial management is almost nonexistent. There is a preoccupation with technical data and performance standards, and insufficient attention is paid to financial performance. This problem will be addressed by the corporatization of the existing entities, followed by privatization. The increased autonomy of entities, including financial independence, is not only expected to achieve the reforms sought but will better prepare these entities for privatization.

2.18 The proposed project would address the various institutional issues in a number of ways. In particular, the project would support the commercialization of generating plants and RECs and the creation of market competition wherever possible. To this end, the Government has furnished the

Privatization

In 1990 the Government announced it would allow private sector participation in power distribution. In addition, the government would divest its ownership in power utilities that had become involved in non-power related business. At the Bank's suggestion, the Government has agreed to broaden the scope of privatization to include generation. It will also undertake a Commercialization/Privatization Study (see para. 4.7), that addresses the restructuring of the sector in order to eliminate heavy-handed regulation, and thus, create a more competitive market for power sales. The study will also recommend well-defined steps to be taken to increase commercialization and prepare assets for divestiture.

Meanwhile, the following steps will be undertaken prior to the completion of the study: (i) the power utilities accounts will be audited by private auditors to establish internationally acceptable financial statements with separate accounts for each generating station; (ii) the Government will continue to adjust electricity prices to reflect the cost of supply, ensuring full pass-through of input prices; and (iii) utilities will continue to divest non-power business units such as construction, long-term maintenance and ancillary activities like cleaning, food services, building management, etc.

Bank with a Statement of Power Sector Development Policy. The Government intends to undertake the following sector restructuring measures:

- (i) bring energy prices to levels that reflect market prices or the long-run marginal cost of production;
- (ii) commercialize sector enterprises, with all major generating plants, RECs and WPA power sections reorganized into joint-stock companies operating independently on a commercial basis and TAVANIR divesting itself of its power plants;
- (iii) continue to divest ancillary business units so that these units, which currently provide maintenance, construction, engineering, catering and accommodation services, could be privatized and compete with other enterprises;
- (iv) restructure the sector to promote competition among sector enterprises;
- (v) establish a legal/regulatory framework for power enterprises to ensure that monopoly powers are not abused;
- (vi) improve financial transparency and accountability in the sector by requiring enterprises to have their accounts audited by independent and internationally recognized auditors;
- (vii) redefine the role of the Government to limit its activities to advising on sector policies;
- (viii) promote cogeneration schemes by industrial enterprises; and
- (ix) incorporate international environmental standards governing the operation of the sector.

2.19 **Pricing.** Electricity price adjustment proposals are based on an analysis of the financing needs of the sector by MOE. Recommendations on changes to the level and structure of tariffs are based on implementing the Government's policy of full financial independence for the sector; they are forwarded from MOE to the Higher Economic Council for its consideration. The main issues concerning electricity tariffs in Iran are that: (i) electricity rates are distorted by implicit subsidies on foreign exchange and fuel costs; and (ii) the tariff structure does not reflect the costs of supply to each customer class. In 1989, the Government embarked on a major policy change in its approach to pricing in the power sector. It resolved that prices would be set at a rate that would allow the sector to be fully self-financing, requiring little or no transfer from the budget. It has consistently followed this policy. As a result, prices were increased from 3 to 5.2 Rls/kWh in 1989. Furthermore, it was recommended that increased focus on the industrial sector to ensure that price signals would guide new investments and restructuring by providing the basis for determining the optimal capital-labor-energy mix. Taking these recommendations into account, in March 1991, the Government increased average electricity prices by 64 percent, tripling the prices charged to industrial consumers. In February 1992, the Government increased electricity tariffs by about 21 percent and introduced time-of-use pricing so as to reflect the seasonal nature of supply costs. Time-of-day pricing has also been established to reflect the increased cost of supply during peak hours. This incentive system to shift consumption to off-peak

hours will become effective once time-of-use metering is installed. The Government has decided to increase the weighted average tariff by about 65 percent, effective March 21, 1993, for FY93. Despite these increases, the cost recovery is currently estimated to be about 20 percent of the long-run marginal cost at the floating exchange rate of Rials 1450/US\$ and about 50 percent at the competitive exchange rate (para. 1.2).

2.20 Given the paucity of debt financing, pricing is based on a high self-financing capability within the sector. As the Government increases access to capital markets for the sector entities, its stated policy is, over the medium-term, to evolve a pricing strategy based on market principles in which the Government plays a minor role. The principles upon which this strategy would be implemented are to be analyzed in the Commercialization-Privatization Study. The study would include the establishment of a risk-related rate-of-return target that would be adequate to attract private sector financing. Thus, the proposed self-financing ratio targets (para. 5.10) are viewed as a temporary measure until power sector entities are converted into joint-stock companies (para. 2.18). The results of the study and the implementation of a rate-of-return target would form the basis for future Bank involvement in the sector.

2.21 In keeping with the commercialization and privatization objectives of the sector, the focus of the pricing policy dialogue has been financial targets. As the current debt burden of entities in the sector is small, financial targets for the near term have centered on achieving a credible financing plan for proposed investments. The proposed 40 percent self-financing ratio starting FY94 (para. 5.10) would ensure adequate internal cash generation to enable entities to maintain the debt/equity ratio needed to encourage increased private sector participation. A Commercialization-Privatization Study, the results of which the Government has agreed to review with the Bank, would assess the risk associated with investments in power projects, relative to other opportunities, to determine the return-on-equity necessary to induce investments from the private sector (para. 5.13). Following the study, the Government intends to put in place a system for market pricing of electricity (para. 2.18).

2.22 Energy Conservation. There is potential for substantial energy conservation in Iran. The first, and most important, step in conserving energy is to make pricing more efficient (para. 2.19). The relatively strong link between long-term price elasticity and demand is expected to result in a much lower growth in electricity consumption. According to the load forecast estimates, the proposed price adjustments would result in a reduction in generation capacity needs of over 2,000 MW by 1998. This would not only result in investment savings in excess of US\$2 billion, but would also dramatically reduce fuel consumption and concomitant air pollution.

2.23 MOE is actively addressing load management options with substantial analytical work already undertaken for the cement industry. A pilot study has considered a two-step approach: imposed restrictions followed by tariff-induced restrictions. MOE has reviewed the load curves of many cement plants and determined an energy management strategy that would reflect time-of-use supply cost considerations. Seminars have been presented to cement plant managers on how this plan would be implemented. For the second stage, the Government has already implemented time-of-use pricing by increasing the tariffs during peak seasons (when air conditioning and heating loads are high) by 50 percent. Time-of-day tariffs will be implemented when

specialized meters are acquired based on the results of the Energy Sector Development Study (para. 4.7).

2.24 Increasing efficiency in generation would be addressed on two fronts: (i) the introduction of new technologies (including combined cycle and cogeneration schemes); and (ii) the rehabilitation of existing plants. The project would directly support the former by introducing a combined cycle plant with thermal efficiencies of about 45 percent, well above the current system efficiency of 32 percent. The Thermal Plant Rehabilitation Study (see para. 4.7) would enable a technical audit of the existing thermal plants, which could be used to determine which investments could best increase plant efficiency and reliability. In addition, the operation of equipment at two major hydroplants, Dez and Karun I, is being reviewed by Electroconsult (Italy) and Lahmeyer (Germany) so that rehabilitation and upgrading can take place.

G. Rationale for Bank Involvement

2.25 The major objectives of Bank assistance strategy in Iran are to: (a) assist the Government implement a sound economic reform program; (b) support the reconstruction and rehabilitation of the Iranian economy and human resources development; and (c) strengthen Iran's access to capital markets. (See Report No. P-5947-IRN, dated February 19, 1993.) The proposed project is in line with items (b) and (c) of the assistance strategy and would assist the Government in formulating an action program consistent with its proposed policy reforms. Specifically, through this project, the Bank would support a rational program of investments and actions, which would enable the supply/demand gap to be reduced and efficiency enhancements to be achieved through restructuring. In addition, the Bank's sector policy dialogue with the Government focuses on the reforms necessary to: (i) enable entities to borrow commercially while increasing private sector participation; and (ii) formulate and implement an energy conservation program.

III. THE BORROWER

3.1 TREC is considered to be one of the best run RECs in Iran. The technical staff are competent and have been effective in maintaining system performance given the constraints they face. The accounting and financial staff have performed well, producing quality reports. The size of staff relative to its sales and customer base compares favorably with similar entities elsewhere. Because of its excellent performance record, other RECs have requested TREC to undertake projects on their behalf. With the reorganization in the sector, (para. 2.7) in which generation has been decentralized, TREC has been selected as the first REC to own and operate a generating plant.

3.2 Statutory Functions. TREC was constituted by legislation enacted in 1964 to produce, transmit and supply electric power in its service area. It currently operates under the Companies Law, which applies to private and publicly owned companies. TREC is the largest of the RECs, accounting for about 27 percent of total electricity sales in Iran. Following the centralization of the sector in 1965, TREC continued to operate the generating plants located on the site of its Tehran headquarters complex and to distribute electricity to the greater Tehran area. However, with the decommissioning of old equipment, total TREC power generation fell from 5,014 GWh in 1986 to 989 GWh in 1991.

3.3 TREC has recently been permitted to build its own power plants, including the gas turbine plant at Qom and the associated combined cycle steam turbine plant proposed for financing under this project. TREC will also build the transmission and substation facilities necessary to connect the plant to the national grid. To accommodate the proposed new generation capacity, a new Generation and Transmission Division has been formed within the company.

3.4 Organization and Senior Management. The TREC internal organization, shown in Annex 3.1, follows the functional pattern of sector enterprises. The board of directors consists of the managing director and two members appointed by the General Assembly. The managing director (who is also the chairman of the board) is appointed for a two-year term, which is automatically renewed unless otherwise decided by the board of directors. Reporting to the managing director are four deputy managing directors. Seven staff functions, including the Inspection, Audit, Planning, Advisory, Security, Administrative and Public Relations Departments advise the managing directors. This organization structure is operating satisfactorily. The team of senior executives that assist the managing director are impressive, well qualified and highly regarded individuals. Financially, the organization seems to be adequately organized, although, as with the sector, commercialization is desirable.

3.5 Ultimate control of TREC is exercised by MOE through the general meeting, at which it is the only shareholder. The general meeting appoints the managing director and consists of a representative of MOE, usually the Minister, and the board of directors. It approves the budget and balance sheet of the company, personnel levels and the operational plan and policy for the forthcoming year. The interests of the owner (the Government) are not represented on the board of directors. This issue will be addressed in the Commercialization-Privatization Study to be carried out under the proposed project (para. 4.7).

3.6 Personnel Policies. The TREC technical staff also appear to be doing an excellent job of operating and expanding the TREC distribution system. TREC, however, shares the problems of TAVANIR and other RECs with respect to the attraction and retention of good staff. Numerous means have been devised to provide nonsalary benefits for staff, ranging from providing the traditional business car and housing loans all the way to hiring a wedding hall.

3.7 Accounts. TREC accounting capabilities appear to be among the best in the power sector in Iran. However, accounting is largely a recording process, and financial information is not routinely used as a basis for managing the various operating departments.

3.8 Recent Organization Developments. In addition to its major expansion in generation activities, TREC has recently divested itself of two ancillary divisions. Tehran Niro (TN), formerly a TREC construction division, was reorganized as a separate registered company under the Companies Law. TN has its own management and makes independent decisions. It is able to offer better and more flexible wages and salaries to its staff. The work that it obtains from TREC is by way of competitive tendering. It specializes in civil and electrical engineering, with more than 2 billion rials of work in hand. TREC holds 49 percent of the shares, with 25 percent held by Ghodss Niroo, a consulting engineering firm, and 26 percent by the Deprived People's Foundation.

3.9 TREC divested itself of its engineering department, which became Moshanir, a government-owned, independent, registered consulting engineering firm that undertakes many engineering tasks for TREC by direct selection rather than by tender. Pymanir, a private construction firm, is the other major associated company whose business is based on open competitive tendering. TREC has shares in three other government companies: SATKAB, a trading and electrical component manufacturing company; Albuaz Industrial Park, a land purchase and infrastructure company; and Kaveh Industrial Park, a land development company. These developments indicate that the concept of a utility dealing with other public and private sector companies under a holding company structure is well established, thus creating the potential for more rapid movement towards the privatization of ancillary functions.

3.10 Institutional Issues. While TREC compares favorably with the other entities in the sector, in many respects it shares some of their institutional problems. Many of these problems will be dealt with in the Commercialization-Privatization Study (para. 4.7), while the maintenance of standards with respect to financial performance and audits will be dealt with through the financial performance conditions of the loans.

IV. THE PROJECT

A. Project Origin, Past Lessons and Project Design

4.1 The Government of Iran requested the Bank to finance a power sector project to address the substantial load shedding problem. As this would be the first Bank-sponsored project in the power sector of Iran in over 15 years, the lending modality, policy framework and project component design were key elements addressed during the appraisal process. Although the need for addressing the supply/demand imbalance is urgent, lessons learned from Bank experience clearly indicate the importance of establishing a policy framework first, with up-front actions on necessary reforms. Policy dialogue has focussed on the Government's Statement of Power Sector Policies (para. 2.18). The project includes two policy analysis studies to help formulate and implement key sector restructuring measures envisaged in the Government's policy. Supply options were considered as a residual of energy conservation, particularly pricing and load management. The Qom conversion to combined cycle component is included in this project because it is an integral component of the least-cost plan, is environmentally friendly and has no resettlement issues. In addition, the executing agency is considered to be among the best in Iran. The environmental aspects of project design have been largely guided by studies from the Environmental Policy and Research Division of the Bank, particularly with regard to the minimization of air pollution from both a regional and global perspective.

B. Project Objectives and Scope

4.2 Given the annual growth in power demand of about 1,000 MW and the persistent load shedding problem, the primary short-term objective of the proposed project is to add about 200 MW of supply capacity. Reducing the supply/demand gap is of particular importance in the context of Iran's reconstruction efforts, as power interruptions constrain growth in downstream sectors. MOE has initiated a number of generation projects including the Qom component. By 1996, about 6,000 MW of new generation capacity is planned to become operational, significantly narrowing the supply/demand gap. Industrial growth over the near term may be considerable when capacity utilization in existing industries increases, necessitating a quick supply response by the power sector. The proposed project is designed to have a relatively short gestation period so that the load shedding problem may be quickly addressed. Additional objectives include upgrading planning capabilities to help ensure the sustainability of project benefits, laying the groundwork for commercialization and setting the stage for attracting private sector participation.

C. Project Description

4.3 The project would consist of the following components:

- (i) the addition of 200 MW of generating capacity by converting the open cycle gas turbine units currently under construction at Qom to combined cycle operation (see Annex 4.1 for a detailed description);

- (ii) the construction of 400-kV substations and transmission lines to transmit power from the Qom combined cycle plant and strengthen the north-south interconnection;
- (iii) the supply of distribution equipment to improve TREC's information, customer billing and collection systems and planning capabilities;
- (iv) technical assistance and consulting services for: (a) an Energy Sector Development Study; (b) a Commercialization-Privatization Study for the power sector; (c) a Thermal Power Plant Rehabilitation Study; and (d) power plant operator training.

4.4 Qom Combined Cycle Component. The Qom combined cycle component would be about 15 km outside of Qom, which is 150 km to the south of Tehran. The four 100 MW (site rating) open cycle gas turbine units currently being installed would be converted to two combined cycle modules, with a total nominal site rating of 600 MW. The addition of heat recovery steam generators (HRSGs) would link each pair of gas turbines with a steam turbine generating unit of about 100 MW (site rating). There are no land or resettlement issues as sufficient land has been acquired for the complete plant. The dual fuel fired gas turbines are being supplied and erected by Mitsubishi Heavy Industries of Japan (MHI) and are expected to be commissioned between May 1993 and July 1993. The primary fuel for the gas turbines would be natural gas with gas oil as the standby fuel. A 15-day reserve capacity of gas oil would be available in a storage tank at the plant site to account for any shortages in gas supply. The 200-MW combined cycle add-on would require no additional fuel. Water requirements would be drawn from wells located about 1 km from the plant site. Tests of these wells indicate that the size of the aquifer is adequate for plant needs without compromising other local needs. The plant would use a dry cooling system (air cooled condensers) to minimize the water supply needs. TREC has carried out an assessment of water supply availability and consumption for the Qom region. Results show that the proposed project would not affect the water supply pattern to the Qom region.^{1/} The gas turbine generating units would be connected to the system via 230-kV transmission lines.

4.5 Substations and Transmission lines. As part of the strengthening of the north-south links of the interconnected system (para. 2.2), a 400-kV substation and a 400-kV transmission line would be built to connect the power plant to the national grid. The Qom substation would be located about 10 km to the southwest of Qom city. The works related to the Qom substation include the 400-kV switchgear, autotransformers, necessary relay protection, AC/DC systems and control measures. Two 400-kV single circuit lines would be connected to this substation - one from the under construction Golpaygan and the other from the existing Jalal substations. On commissioning of the gas turbines, their output would be connected to the interconnected system via

^{1/} Due to water conservation measures in plant design, the combined cycle add-on would require a maximum water supply of 15 l/s to meet cooling water needs (5 l/s) potable, fire fighting and landscaping needs (10 l/s). This is not expected to have any adverse impact on water supply to the Qom region given that Qom city needs (about 160 l/s) are taken from a separate aquifer, and future needs will be met from the Panzdah Khordad reservoir with an 850 l/s supply capacity.

230-kV transmission lines. Once conversion to combined cycle is complete, the power plant output would be connected to the national interconnected system via 230-kV and 400-kV transmission lines to the Qom substation. Work is well in progress for the laying of the 400-kV transmission lines purchased from Romania. Power would be supplied to the Saveh, Qom and Behranf areas through the 230-kV network and to Jalal, Arak, and Golpaygan through the 400-kV network.

4.6 Distribution Equipment. This component covers the promotion of improvements in the information and customer billing and collection systems, and planning analysis of TREC, including engineering services, equipment, software, and support for establishing the necessary systems and procedures.

4.7 Technical Assistance and Training Component. This component would provide assistance to the Iran Power Organization (para. 2.7) to formulate detailed measures for restructuring the power sector in line with the Government's Statement of Power Sector Development Policy (para. 2.18) by providing financing for studies and training, including the following:

- (i) an Energy Sector Development Study that would review indigenous resources, forecast demand, provide least-cost investment plans, determine a feasible financing plan and recommend a price reform program based on economic and financial considerations (see Annex 4.2 for the draft TOR);
- (ii) a Commercialization-Privatization Study that would assist GOI in its efforts to restructure the power sector, encourage private sector participation and improve the efficiency of the present power sector entities (draft TOR included in Annex 4.3);
- (iii) a Thermal Power Plant Rehabilitation Study to upgrade the efficiency of existing thermal plants (see Annex 4.4 for the draft TOR); and
- (iv) operator training for specialized functions, such as gas turbine maintenance and combined cycle plant operation, as well as manpower development programs for engineers, chemists and technicians (see Annex 4.5 for the draft TOR).

D. Project Cost

4.8 The total project cost (as shown in Table 4.1) is estimated to be about US\$414 million, of which 78 percent, amounting to US\$321 million, is in foreign exchange. Costs were converted between Iranian Rials and US Dollars at the floating rate of Rials 1450 to US\$1. All costs were estimated in US Dollars. A summary of estimated project costs for the principal components of the project is shown in Annex 4.6.

Table 4.1: Estimated Project Cost
(US\$ Million)

	<u>LOCAL</u>	<u>FOREIGN</u>	<u>TOTAL</u>	<u>FOREIGN AS % OF TOTAL</u>
Component				
- Qom Conversion to Combined Cycle	49.0	155.2	204.2	76
- Transmission Lines & Substations	14.2	66.0	80.2	82
- Distribution Equipment	3.1	13.1	16.2	81
- Engineering & Project Management	12.1	9.1	21.2	43
- Studies & Training	0.6	4.0	4.6	87
Base Cost (January 1993 prices)	79.0	247.4	326.3	76
Physical Contingency	7.4	24.2	31.7	76
Price Contingency	6.3	19.0	25.3	75
Total Project Cost	92.7	290.6	383.3	76
Interest During Construction (IDC)	0.0	30.6	30.6	100
Total Project Cost + IDC	92.7	321.1	413.9	78

NOTE: Figures may not add-up as they are rounded to the first decimal place.

4.9 The base cost is in January 1993 prices using estimates by Monenco-Iran (para. 4.14) for the Qom combined cycle component; and by IPO for the studies and training components. These estimates were reviewed during post-appraisal and are considered to be reasonable, based upon international comparisons and site conditions in Iran. The detailed cost estimates are shown in Annex 4.7. Physical contingencies have been added at the rate of 10 percent for equipment and civil works for the Qom combined cycle component. Price contingencies have been added to the base cost using the inflation rate projections shown in Table 4.2 below.

Table 4.2: Inflation Projections

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>	<u>1997</u>	<u>1998</u>
Local	23.0	18.1	14.2	12.4	10.6	13.4
Foreign	3.8	1.9	2.7	3.4	3.6	3.6

E. Financing Plan

4.10 The financing plan for the project is summarized in Table 4.3 and is detailed in Annex 4.8. Bank funding would cover the full foreign exchange requirements of the Qom combined cycle add-on, except for civil works, the HRSG packages, the substation and the transmission line interconnector to the grid. Bank financing would also cover the full foreign exchange requirements for the studies, training and for distribution equipment. The Bank loan would be to TREC with a maturity of 17 years, including 5 years grace. TREC would

on-lend US\$4.6 million to IPO for the studies and training components using the same terms as the Bank loan. IPO would bear the full foreign exchange and interest rate risks. Execution of a subsidiary loan agreement, between TREC and IPO, satisfactory to the Bank, would be a condition of loan effectiveness. For the HRSG package, suppliers' credit or export credit agency funding would be requested, with the Bank financing the 15 percent downpayment. TREC would finance 100 percent of the cost for substation and transmission lines and the local costs component of the Qom conversion to combined cycle from its own resources. IPO would finance the local costs associated with the technical assistance component. Given that tariffs would be set on the basis of a minimum self-financing capability of 40 percent, TREC would be able to finance part of the foreign exchange costs from internally generated funds if suppliers' credit was not available from the lowest evaluated responsive bidder. However, all prequalified suppliers for the HRSG package have indicated that they will be able to offer suppliers' credit with their bid. During negotiations, assurances were obtained from TREC on the financing plan, and a suspension clause would be introduced in the loan documents, should adequate cofinancing and/or other arrangement¹ to cover the needed foreign exchange satisfactory to the Bank, not be available in a timely manner.

Table 4.3: Financing Plan

Source	Local	Foreign	Total	% of Total
IBRD	0.0	165.0	165.0	39.9
Supplier's Credit	0.0	47.8	47.8	11.5
MOE	0.6	0.0	0.6	0.2
TREC	<u>92.1</u>	<u>108.4</u>	<u>200.4</u>	<u>48.4</u>
Total	92.7	321.1	413.9	100.0

Note: Figures may not add-up as they are rounded to the first decimal place.

F. Status of Project Preparation

4.11 The detailed engineering design was initiated in November 1991 by Monenco-Iran for the combined cycle add-on at Qom based on a feasibility study previously undertaken by local consultants. Following the review of the engineering design report (Phase I) during appraisal in February 1992, the Government appointed Monenco-Iran to undertake the detailed engineering design, the preparation and issue of bidding documents and bid review (Phase II). Tender documents were issued in February 1993. Retroactive financing of US\$2.0 million would be included to cover the costs of consulting services detailed engineering and tender document preparation.

G. Procurement

4.12 Materials and Equipment. All Bank-financed procurement for the supply and installation of materials and equipment would be in accordance with the Bank's Procurement Guidelines. Bank financing is proposed for the foreign exchange component of the following packages:

1/ The HRSG package would be bid on a supply and finance basis, with the Bank financing the 15 percent down payment. Should the lowest evaluated, technically responsive bid not include financing, TREC would use its own resources to finance the gap.

- (a) the main package for the Qom combined cycle add-on, including the steam turbines and air condensers, electrical systems, instrumentation and controls and the balance of plant equipment;
- (b) the HRSG package for the Qom combined cycle add-on (including embedded materials and steel structures for the civil works package), to be bid upon separately on a supply-and-erect basis; bid documents have requested suppliers' credit financing on an optional basis (para. 4.10), and Bank proceeds would be used for the 15 percent downpayment; and
- (c) the distribution equipment package would include computerized information and customer billing/collection, planning analysis systems equipment, software and engineering services for design and implementation.

Except for small-value items, International Competitive Bidding (ICB) according to Bank Procurement Guidelines would be followed for the above packages. However, miscellaneous items such as water supply, lighting and HVAC would be bid as separate packages common to (a) and (b) under ICB. For performance guarantee reasons, the main package (a) would be procured as a single responsibility contract under ICB on a supply-and-erect basis. The contractors for packages (a) and (b) would be responsible for the detailed engineering design of related civil works and would supply the associated embedded parts. Local contractors are competent and costs of construction are below international market rates. As the size of the civil works package (US\$14.4 million) is too small to attract interest from foreign contractors, it would be procured under Local Competitive Bidding (LCB), but foreign firms may bid if they wish to do so. Such LCB procedures were reviewed and found acceptable to the Bank for the contract.

4.13 Substation. Procurement of the substation and transmission lines are underway using TREC procurement procedures that are similar to the Bank's limited international bidding procedures. The TREC procedures were reviewed by the Bank and found to be satisfactory. TREC would finance 100 percent of the substation and transmission lines package on a supply-and-erect contract. TREC has demonstrated a satisfactory capability for supervising and managing such contracts.

4.14 Technical Assistance. The technical assistance services would follow Bank Guidelines for the Use of Consultants in Bank-financed projects. Bank financing is proposed for the foreign exchange component of the following packages:

- (a) consulting services for the supervision and construction management of the Qom conversion to combined cycle component; and
- (b) consulting services for the studies and training components.

TREC used the services of Monenco-Iran for Phase I (feasibility and engineering design). In the interest of project efficiency, Monenco-Iran would be retained as consultants under the Bank's Guidelines on the use of Consultants to assist TREC in Phase II, i.e., bid document preparation, bid award, construction supervision and commissioning of the project.

4.15 Bidding documents and recommendations for the award of contracts would be prepared by TREC with the assistance of their consultants (para. 4.14). Contracts for goods and works financed under the Bank loan valued at US\$2 million or more would be subject to prior review by the Bank. Three bidding packages for equipment, estimated to cover about 91 percent of the value of Bank-financed equipment and material contracts would be based on ICB. The smaller Bank-financed contracts would be subject to selective post-award review. Local manufacturers would be expected to bid for some categories of equipment for which domestic preference of 15 percent or the corresponding import duty, whichever is less, would be applied in the comparison of bids. All packages are expected to be awarded by November 1993. Procurement arrangements are summarized in Table 4.4 and details are provided in Annex 4.9 (Attachments 1 and 2).

Table 4.4: Procurement Arrangement
(US\$ Million)

	<u>Procurement Method</u>			<u>Total Cost</u>
	<u>ICB</u>	<u>LCB</u>	<u>Other ^{a/}</u>	<u>N.B.F. ^{b/}</u>
Civil Works		14.4		14.4 0.0
Equipment & Materials	223.9 (136.3)			4.1 228.0 (136.3)
Transmission lines & Substations				93.3 93.3
Distribution Equipment	14.0 (14.0)		1.0 (1.0)	3.5 18.5 (15.0)
Project Management & Owner's Admin. ^{c/}			9.5 (9.5)	14.7 24.2 (9.5)
Studies			4.1 (3.6)	4.1 (3.6)
Training			0.8 (0.6)	0.8 (0.6)
Total	<u>237.9</u> <u>(150.3)</u>	<u>14.4</u>	<u>15.4</u> <u>(14.7)</u>	<u>115.6</u> <u>383.3</u> <u>(165.0)</u>

NOTE: Figures in parentheses to be financed by the Bank.

Figures may not add-up as they are rounded to the first decimal place.

^{a/} Shopping and Consulting Services.

^{b/} Non-Bank Financed.

^{c/} Includes US\$2.0 million retroactive financing (para. 4.11).

H. Disbursements

4.16 The proceeds of the loan would be disbursed over a period of five years (FY94-FY98) on the following basis:

- (a) 100 percent of the foreign expenditures for the supply and installation of the main equipment for the Qom combined cycle add-on, except for the HRSG equipment;
- (b) 100 percent of the foreign expenditures for the down payment for the supply and installation for the HRSGs equipment and for the embedded materials and steel structures of the civil works package at Qom;
- (c) 100 percent of the foreign expenditures for the supply and installation of computerized information and customer billing, planning analysis equipment and associated engineering services; and
- (d) 100 percent of foreign expenditures for consulting services, technical assistance and training.

4.17 The disbursement schedule is summarized in Table 4.5 and detailed in Annex 4.10. It generally follows the EMENA (MENA and ECA) power sector disbursement profile adjusted to take into account advance payments made while opening a Special Account and the disbursement against down payments for about 16 percent of the loan amount in the early stages of project implementation. The disbursement schedule is two years shorter than the standard disbursement profile for the power sector as this project is limited to the add-on of equipment to an existing plant. In order to enable prompt payments to be made to the contractors and consultants, the Bank would advance funds, as needed, to the Special Account to be opened in a commercial bank in Iran for a maximum amount of US\$5 million; this would cover the Bank's share of eligible expenditures over a period of 4 months. Payments from the Special Account would only be made for eligible expenditures indicated in the loan agreements. The account would be denominated in US dollars and replenished against withdrawal applications of at least US\$1,000,000. Applications with appropriate supporting documents would be submitted when approximately half of the maximum allocated amount of the account had been spent, or quarterly, whichever occurred first. Disbursement under the project would be made against standard documentation except for contracts for goods and works of US\$50,000 equivalent or less, which would be claimed under Statements of Expenditure (SOE). Related supporting documents for SOE claims would be retained at TREC headquarters and made available for inspection by Bank missions and project auditors. The loan closing date would be June 30, 1998.

Table 4.5: Estimated Disbursement
(US\$ Million)

	<u>FY94</u>	<u>FY95</u>	<u>FY96</u>	<u>FY97</u>	<u>FY98</u>
Annual	27.0	58.9	53.6	21.3	4.2
Cumulative	27.0	85.9	139.5	160.8	165.0
Percentage	16.4%	52.1%	84.5%	97.5%	100.0%

NOTE: Figures may not add-up as they are rounded to the first decimal place.

I. Monitoring and Supervision

4.18 It is estimated that at least 20 staff weeks per year for half yearly supervision missions would be required during the first 2 years of project execution and at least 14 staff weeks per year thereafter. The supervision mission would include a thermal power plant engineer, a procurement specialist (for the initial missions) and a financial analyst. TREC would be responsible for preparing documents for Bank supervision missions, quarterly progress reports to the Bank during project implementation and a Project Completion Report within six months of project completion.

J. Environment

4.19 The Iranian Environmental Protection Organization (IEPO) has been established along the lines of the United States Environmental Protection Agency (EPA) to review environmental matters on behalf of the Government. Fuel usage, and the consequential thermal plant emissions, and water usage are the primary environmental concerns. TREC engaged consultants to undertake an Environmental Analysis (EA) for the Qom project to determine the environmental impact of the plant and recommend an environmental mitigation plan, a summary of which is included as Annex 4.11. As a result of the Bank's review of the EA, TREC agreed to undertake a study of groundwater resources and the impact of the plant on these resources and other potential users. This study was completed in March 1992 and forwarded to the Bank; it indicated that the project would have no adverse impact on competing needs for water resources. The study indicated that the level of pollutants from natural gas use and the increased efficiency associated with combined cycle operations would minimize the environmental impact. Further, dry cooling using air condensers would not have any thermal discharge impact and would use no water for cooling (except for make-up). In addition, general seismicity concerns in Iran, from the point of safety and stability, would be addressed in the design of the project structures. The project is assigned to environmental Category B on the basis that: (a) it has no incremental fuel usage; (b) there are minimal cooling water needs; and (c) there are no resettlement issues.

4.20 Air Quality. The site for the Qom combined-cycle plant is within the land area approved by IEPO for the construction of the gas turbine plant. The city of Qom, located 15 km away, is predominantly a religious center, and there are no major industrial activities in the area. Currently the only source of NO_x, CO₂ and SO₂ emissions is the low-to-moderate truck traffic on the Tehran-Arak road. TREC would use natural gas with low hydrogen sulphide (3.9 ppm) as a primary fuel for the gas turbines. The combined cycle add-on would use heat from unfired heat recovery boilers installed at the exhaust of the gas turbines and would not require additional fuel. There would be, therefore, no additional emissions resulting from the combined cycle add-on.

4.21 Water Resources. The Qom region is dry and barren with an annual precipitation of less than 150 mm. The plant would use air-cooled condensers to minimize water needs. Water supply requirements would be drawn from two wells located about 0.7 and 1.2 km from the plant site. TREC has completed studies that indicate that adequate water would be available from the wells for plant operation, including boiler makeup, potable, fire fighting and landscaping needs. Well water would be treated for the plant process as well as for potable needs. Plant wastewater would be minimized by recycling and would consist mainly of pretreatment (reverse osmosis) of rejects, including boiler blowdowns, demineralization and condensate plant-polishing regeneration

waters. Rejects would be collected in a settling pond and treated to remove any contaminants; the clean effluent would then be disposed of in a solar evaporator pit after sampling to ensure compliance with environmental requirements. Any organic (oil) waste would be separated prior to the effluent going to the settling pond. Sanitary sewage would be treated in a packaged, biological-type tank on-site.

4.22 Toxic and Hazardous Substance Management. TREC has confirmed that all plant transformers would be oil cooled and would not contain any PCBs. The building codes prohibit the use of asbestos as

construction material. During negotiations, TREC agreed to develop procedures, by March 1993, for normal usage, as well as for emergency spills and the cleanup of hazardous materials, such as transformer coolants, lube oil, etc., based on IEPO (similar to US EPA) guidelines. TREC would use only approved fertilizers and pesticides for landscaping to minimize the contamination of groundwater resources.

4.23 Public Safety. The project structures would be designed for appropriate earthquake loading, based on local geotechnical and seismic data. During negotiations, TREC agreed to develop, by March 1993, procedures and specifications for remedial actions to deal with fires and other emergency situations in conformity with Iranian national standards.

K. Project Management and Implementation

4.24 Project Management. TREC would implement the Qom combined cycle component conversion, and IPO would implement the technical assistance component. TREC has appointed Monenco-Iran to assist in engineering design and bidding document preparation for the conversion of gas turbines at Qom to combined cycle. At present, the Qom site is being readied for the installation of the four gas turbines. The consulting engineering firm of Ghodss Niroo is assisting MHI in the erection and commissioning of the gas turbines. Monenco-Iran prepared the engineering studies for the Qom conversion to combined cycle, which was reviewed during appraisal and found satisfactory. Monenco-Iran would finalize the design, assist TREC in the

Environmental Improvements Through Efficiency

As the title of the project implies, the focus of project design is efficiency improvement. Efficiency improvement goals are expected to decrease the cost of supply (and hence tariff increase requirements) and decrease environmental costs caused by fuel use. The efficiency of many of the gas turbines currently operating in the system is unusually low because of their age and deferred maintenance resulting from the war with Iraq and trade embargoes. About 1,550 MW of gas turbines in operation in the interconnected system have efficiencies of 22 percent or less. The Qom combined cycle plant will allow some of these to be retired and some taken out of service for rehabilitation. The decreased environmental impact is even more dramatic. The Qom plant efficiency is expected to be about 45 percent (relative to a system average of 32 percent) with NO_x and CO_2 effluent expected to be reduced by another 50 percent per kWh produced. The total impact of the project is expected to result in decreased CO_2 emissions of about 0.3 million tons per year.

preparation of bidding documents for the various procurement packages and evaluate bids and contract awards.

4.25 Project Implementation. The project implementation schedule is shown in Annex 4.12 with a project completion date of June 30, 1996. Annex 4.13 shows the reporting requirements and the supervision planned by the Bank. The documents listed in the Annex would assist IPO and TREC in providing the quarterly reports required by the Bank for project supervision. During negotiations, assurances were obtained from TREC that it would take the following measures in a timely manner to achieve the project's objectives:

- (a) continue to employ engineering consultants, satisfactory to the Bank, throughout the project implementation period (para. 4.24);
- (b) comply with environmental standards and adopt an emergency mitigation plan (paras. 4.19, 4.22 and 4.23);
- (c) revalue assets using a methodology acceptable to the Bank; the results of this revaluation would be reported annually as a note to the audited balance sheet for each year starting in FY93 (para. 5.9);
- (d) increase its billing frequency of residential customers to at least every two months by March 30, 1994, with interim bills based on estimated consumptions (para. 5.12);
- (e) ensure the completion of:
 - (i) the Commercialization-Privatization study by June 30, 1994;
 - (ii) the Thermal Power Plant Rehabilitation Study by June 30, 1995; and
 - (iii) the Energy Sector Development Study by June 30, 1994.
- (f) following the joint review of the Commercialization-Privatization Study by TREC, IPO and the Bank, TREC would prepare and review with the Bank, no later than September 30, 1994, an action program for the commercialization of its operations and for an increase in private sector participation in operations, maintenance and financial affairs.

V. FINANCIAL ASPECTS

A. Financial Position of Borrower

5.1 TREC recent financial statements are presented in Annex 5.1. TREC has a very low debt:equity ratio, a high self-financing capability and a good liquidity position. When its payments to IPO are considered as part of its internal cash generation, TREC can demonstrate, for the last two years, a high level of internal cash generation relative to its fixed capital investment. However, the return on fixed assets would be unacceptably low if fixed assets were to be revalued at an estimated unified exchange rate.

Table 5.1: TREC - Financial Coefficients, FY87-91

	FY87	FY88	FY89	FY90	FY91
Return on Sales - %					
- Operating Income	22.9	18.5	38.3	45.7	58.7
- Net Income	15.5	13.2	9.6	17.9	13.4
Return on Assets - % 1/	4.8	3.7	10.0	11.2	24.0
Internal cash generation					
to fixed investment - % 2/	270.1	(47.0)	160.5	116.5	147.3
Debt service coverage					
Debt:equity ratio	19:81	9:91	9:91	8:92	20:80
Current ratio	2.4	4.2	4.6	3.8	3.3
Source: TREC					
1/ Original Cost Basis					
2/ Based on 3 year average for investments					

5.2 Though TREC, the borrower, is legally constituted as an independent entity and functions as such in carrying out its day-to-day operating activities, its current financial structure and recent financial performance is largely the result of decisions taken by MOE. TREC and the other sector enterprises have little control over tariffs, financing strategy or the allocative mechanisms that redistribute operating surpluses.

5.3 The profit and loss statements of sector enterprises do not give an accurate picture of their financial structure and performance since they fail to adequately reflect the cost of capital. First, depreciation charges are inadequate since they are based on the low historic costs of imported capital goods, which were purchased at the overvalued official exchange rate. Therefore, large adjustments would be required if the balance sheets of sector enterprises were to reflect the value of their assets based on either the competitive or free market rate. Second, for reasons discussed below, the reported charges for the use of capital (e.g., interest expenses) are almost negligible.

5.4 The only debts enterprises in the sector owe are to the Government. None of these debts have carried interest charges or are subject

to amortization. During the 1980s, most of the investment in generation and transmission was financed by government contributions from the budget, as the transfer price paid by the RECs to TAVANIR did not permit significant levels of self-financing. Since 1989, the situation has completely changed, with nearly 100 percent of investments being self-financed on a sector-wide basis. In addition, the Government is currently studying ways of changing this by treating some budget transfers as equity and the rest as debt with commercial rates.

5.5 The accounts of the sector enterprises are based on a code of accounts established almost 30 years ago. Though the accounts are detailed and comprehensive, an inflexible use of these codes has often led to an inappropriate classification of balance sheet and income statement items. The statutory published accounting statements do not include a statement of sources and application of funds. The accounts of the sector enterprises have not been subject to timely and regular auditing, although they are periodically examined by the audit branch of the Ministry of Finance. To address this problem, the Ministry of Finance has hired independent private accounting firms to undertake audits on its behalf. Finally, payments to IPO are not treated in the manner normally associated with levies and taxes. Instead, RECs carry the cumulative amount of their IPO contributions as part of their equity reserves, and the difference between levies to IPO and contributions from IPO is carried as an investment on the asset side of their balance sheet. As a result, it may be argued that both assets and reserves are inflated. The role and ownership of IPO will be addressed in the Commercialization-Privatization Study (para. 4.7), while the treatment of IPO levies in TREC accounts will be reviewed by TREC auditors. The Government also proposes to remove the IPO levies and set prices, including transfer prices, based on commercial principles.

5.6 It is significant that there have been no reports from TREC concerning revenue collection problems. Government and industry customers are billed 10 times per year. However, TREC bills its other customers only every third month due to inadequate data processing capabilities. The average collection period for TREC at the end of FY90 was 3.5 months. This suggests that once bills are issued, they are promptly paid. However, it also suggests that as total sales grow, TREC may fall farther behind on its monthly payments to TAVANIR. For example, TREC accounts payable to TAVANIR at the end of FY90 were Rials 0.87 billion, or about 0.4 months of purchases. However, by December 1991, the accounts payable had increased to almost Rials 6.0 billion, or 2.8 months of purchases. Accounts receivable and billing problems are being addressed at the sectoral level with a study to be carried out by internationally experienced consultants and by measures to be undertaken by TREC (para. 5.12). The suggestions made by the study would be implemented on a pilot basis at Khorason REC and, if successful, would be transferred on a later date to other RECs. In addition, consideration is being given by TREC to the establishment of a series of branch offices to assist with revenue collection. The project would finance technical assistance to TREC for improving their billing and collection systems (para. 4.6).

B. Financial Targets

5.7 The foremost principle guiding the establishment of targets was to achieve a level of financial soundness that would be adequate to attract private capital. The financial targets would: (i) establish financing based on commercial principles; (ii) generate adequate funds to finance the investment plan; (iii) maintain a balance sheet that reflects current asset

values; (iv) generate a return on capital sufficient to attract private sector investment; (v) increase discipline in collections and payments; and (vi) adequately provide for debt service.

5.8 The proposed Commercialization-Privatization Study (para. 4.7) is designed to establish financial criteria that would be adequate to attract private sector financing. However, certain actions can be taken prior to the completion of this study to facilitate the transition to private ownership. To establish confidence in the utilities' accounts, TREC agreed during the negotiations, to submit audited financial statements no later than six months after the end of each fiscal year; in addition, TREC agreed to have its accounts and financial statements audited, in accordance with appropriate auditing principles consistently applied by independent auditors satisfactory to the Bank.

5.9 As in most countries, Iran's accounting standards are based on historically valued assets. Given the substantial devaluation expected in the exchange rate over the near term, restating the balance sheet based on current values is important to determine the real return on capital. During negotiations, TREC agreed to revalue its fixed assets using a methodology acceptable to the Bank; the results of this revaluation would be reported annually as a note to the audited balance sheet for each year starting in FY93.

5.10 As a result of the reconstruction program, the persistent load shedding problem and the substantial economic and population growth, investment in the power sector is expected to be unusually high over the near term. The Government is actively addressing this issue by gradually raising tariffs to boost internal cash generation and by seeking outside financing sources for the sector's foreign exchange needs. In order to establish a feasible financing plan, including adequate levels of self-financing, TREC agreed, during negotiations that:

- (a) it would generate, for each fiscal year, after the fiscal year starting in FY94, funds from internal sources equivalent to not less than 40 percent of the annual average of the capital expenditures expected to be incurred by the Borrower for that fiscal year, the previous fiscal year and the next fiscal year (for FY93 the target would be set at 20 percent);
- (b) before November 20 of each fiscal year, TREC would review its financial forecasts for the next fiscal year, with respect to the target set forth in paragraph (a) and would furnish a copy of the review to the Bank; and
- (c) if any such review shows that TREC would not meet the requirements set forth in paragraph (a) for the next fiscal year, the Borrower would promptly take all necessary measures (including adjustments of the structure and levels of prices) in order to meet such requirements.

5.11 In order that TREC can comfortably satisfy its debt service requirements, a debt service coverage target has also been established. During negotiations, the Government and TREC confirmed that, except as the Bank shall otherwise agree, to maintain a debt service coverage ratio, for each fiscal year starting in FY93, of no less than 1.5.

5.12 TREC accounts receivable and accounts payable to TAVANIR are unacceptably high. The practice of billing many of its consumers every three months contributes to this problem. This problem is being addressed by financing under the loan the purchase of computerized information and customer billing/collection systems. To improve the situation, TREC confirmed, during negotiations that:

- (a) it would increase its billing frequency of its residential customers to at least every two months by March 20, 1994, with interim bills based on estimated consumption;
- (b) no later than March 20, 1994, it would take actions to enable it to reduce its accounts receivable to three months' sales equivalent; and
- (c) it would maintain its accounts payable to TAVANIR at an amount no more than the equivalent of two months of its purchases from TAVANIR.

5.13 The above actions are designed to help lay the groundwork for privatization. The Commercialization-Privatization Study would look closely at the structure of the sector, labor, capital and tariffs, institutional autonomy and the regulatory framework necessary for privatization, along with ways to involve private sector participation. During negotiations: (i) the Government confirmed that the results of the Commercialization-Privatization Study would be reviewed jointly by the Bank, and an action plan for implementing the agreed recommendations of the study would be prepared for review with the Bank no later than September 30, 1994; and (ii) TREC would be asked to prepare and submit to the Bank, no later than September 30, 1994, an action plan for commercialization including increased private sector participation in its operations.

C. Projected Financial Performance

5.14 TREC pro forma net income, cash flow and balance sheet statements covering the period FY87-FY97 are presented in Annex 5.1, and the results are summarized in Table 5.2, below. The assumptions used in preparing the financial projections are detailed in Annex 5.2. In particular the assumptions reflect the Government's stated intentions to: (i) remove the exchange rate subsidy (therefore, the projections are based on a floating exchange rate of Rials 1450/US\$ for FY93, adjusted by the differential between the domestic and foreign inflation estimates for subsequent years); (ii) increase electricity tariffs in order to reach LRMC by FY96; (iii) increase fuel prices to either domestic marginal cost or to world price levels by FY98; (iv) convert into debt a portion of the Government's past contributions to investments; and (v) ensure that any future contributions to sector enterprises are provided as loans on commercial terms. On this basis, it is projected that TREC returns on fixed assets will improve due to higher tariffs, but its self-financing ratio will decrease as the large implicit subsidy on foreign exchange expenditures is removed. It is estimated that under the current assumptions, for FYs 1994, 1995 and 1996, annual tariff increases of about 100 percent would be required in order for electricity tariffs to reach LRMC for FY96 while maintaining an internal cash generation ratio of at least 40 percent for FY94 and thereafter. However, the actual size of increase necessary in a given year would depend upon: (a) the unified exchange rate as determined by the market, (b) the actual inflation outcome, (c) the fuel prices, and (d) the investment needs. The combined effect of

these outcomes may call for higher or lower tariff increases. The March 1996 target for achieving the LRMC may need to be reviewed in light of sustainability and social impact of massive tariff increases year after year.

Table 5.2: TREC - Projected Financial Coefficients, FY92-97 with FY91 (actual)

	FY91	FY92	FY93	FY94	FY95	FY96	FY97
Return on Sales - %							
- Operating Income	58.7	56.8	68.4	22.1	38.2	20.3	9.0
- Net Income	13.4	(0.0)	(8.5)	3.2	7.5	2.6	(3.2)
Return on Fixed Assets							
in service -% 1/	23.5	23.1	18.5	7.0	19.7	17.4	6.5
Internal cash generation							
to fixed investment - %	147.3	281.7	110.0	40.1	48.1	52.8	106.8
Debt service coverage 2/				34.5	2.2	2.3	1.6
Debt:equity ratio 3/							
- as stated	0.2	0.2	0.1	1.5	1.3	1.1	1.0
- including quasi equity	0.0	0.2	0.1	1.3	1.1	0.9	0.8
Current ratio	3.3	2.8	3.3	2.5	2.0	1.9	1.8
Tariff Increase							
- nominal	69.4	10.7	50.0	100.5	100.5	100.5	11.5
- real	47.2	(7.5)	(4.3)	66.5	72.8	77.0	0.0
Avg. Tariff/LRMC		0.21	0.20	0.33	0.56	1.00	1.00
1/ Assumes assets are revalued in FY93							
2/ Debt service negligible prior to FY94							
3/ Assumes that 50% of subordinated commercialization loan can be counted as equity.							

5.15 As shown above, if TREC is allowed to increase tariffs to the level of LRMC by FY96, it should be able to comply with the 40 percent internal cash generation target and service the equivalent of US\$532 million in new foreign debt (see Table 5.3), including its share of the Bank loan (i.e., US\$161 million), and still maintain sound balance sheet ratios.

D. Financing Plan

5.16 The sources and applications of funds for TREC over the period FY93-FY97 is presented in Table 5.3, below. In order to finance the generation and transmission components of their investment programs, while maintaining tariffs at or near LRMC levels, it was found that TREC may have to borrow as much as 85 percent of the foreign exchange component of its fixed investments. On this basis, TREC projected sources and application of funds for the period FY93 through FY97 are summarized below.

Table 5.3: TREC - Financing Plan, FY93-97
(US\$ millions)

<u>Sources of Funds</u>	<u>Amt.</u>	<u>%</u>
Cash from Operations	811	65.8
Customer Connection Charges	353	28.6
Less:		
- Debt service	455	(36.9)
- Increase in Working capital	57	(4.7)
	----	----
Internal Cash generation	652	52.9
Other sources		
- IPO	50	4.1
- World Bank Loan	161	13.0
- Other Investment Loans	371	30.0
	----	----
Total sources	1,234	100.0
Applications		
- IPO Levy	145	11.7
- Fixed Assets		
Foreign	625	50.7
Local	241	19.5
Capitalized interest	97	7.9
	----	----
Total Fixed Assets	963	78.1
	----	----
Total Applications	1,108	89.8
Net Cash Flow	126	10.2

5.17 In addition to the World Bank loan, TREC will need to mobilize other investment loans totalling over US\$371 million over FY93-97 period. Shortfalls in the availability of such loans would necessitate that additional revenues be generated from higher tariffs, equity injections or loans from the Government on commercial terms. Given that exchange rate reforms would increase budget flows for exports currently denominated at the official exchange rate, funding prospects from the local capital markets are expected to be substantially increased. Any future dividends would have to be paid out of net cash flow, which is projected to be rather small relative to projected TREC equity capital at the end of FY97 (US\$1.1 billion). The proposed Commercialization-Privatization Study would determine adequate levels for a return-on-equity to attract private capital, and it is possible that implementing the findings of the study could either drive tariffs to levels higher than those projected or, alternatively, require that assets be sold for less than their projected net book value.

E. Insurance

5.18 Since, at present, all sector enterprises are considered to be part of MOE, the sector enterprises self-insure their physical assets. Destruction resulting from war or natural disasters has, in the past, been addressed by the Government. Given the objectives of commercializing and eventually privatizing sector enterprises, insurance options would be addressed in the Commercialization-Privatization Study. As the Government has

already demonstrated its willingness to finance the rebuilding of war damaged facilities, self-insurance is considered to be acceptable, on an interim basis, until the results of the study can be implemented.

VI. ECONOMIC ANALYSIS

A. Demand

6.1 Electricity consumption in Iran increased by 17 percent per year in the period immediately before the war (1970-80). During the war years (1980-88), the growth of electricity consumption declined to 10 percent per annum, with agricultural consumption growing at 23 percent per annum, residential at 13 percent, commercial at 11 percent and industrial at 4 percent. During the post-war period, electricity sales increased 11 percent per annum. However, relative changes occurred among sectoral consumers: agricultural, residential and service demands grew less rapidly than earlier, while industrial consumption grew at a substantially higher rate (see Table 6.1). These rapid growth rates are expected to decline because of electricity price adjustments and the expected decrease of economic growth as the reconstruction program matures. Table 6.1 below presents the demand forecast for the 1991-2000 period under the projected tariff adjustment schedule.

Table 6.1: Annual Growth Rates of Demand

	1970-80	1980-88	1988-91	1991-95	1995-2000
Residential	20.3%	13.4%	11.4%	7.7%	4.6%
Industrial	15.2%	3.7%	12.3%	7.2%	4.5%
Commercial	16.9%	11.3%	9.9%	7.7%	1.7%
Agricultural	19.8%	23.3%	17.8%	6.9%	1.5%
Services	10.2%	11.0%	3.5%	8.4%	9.3%
Total	16.8%	10.4%	11.4%	7.5%	3.8%

Note: The 1991-2000 forecasts corresponds to the "Efficiency Pricing Scenario."

6.2 Several entities forecast electricity demand in Iran (see Table 6.2 for details). However, those prepared by MOE are used for investments as MOE is responsible for system planning. In the First Five-Year Plan, MOE had forecast electricity demand to grow at about 11.9 percent per annum during the 1991-95 period and at 9.4 percent for the 1995-2000 period. MOE forecasts were reviewed and found to be optimistic. Therefore, MOE, with Bank support, has examined alternative forecast methodologies. Several factors have been considered in forecasting demand: (1) the reconstruction program; (2) increasing electricity prices; and (3) the load shedding problem. Given these factors and the uncertainties facing the Iranian economy, alternative demand scenarios were examined. Figure 6.1 presents the growth in demand from 1980 to 1990 and compares the original MOE forecast with the revised forecast for the 1991-2000 period. The efficiency pricing scenario (EPS) assumes rapid increases in rate levels (in real terms) consistent with understandings reached with the Government. Table 6.2 presents the demand growth rates for the different scenarios, along with the GDP growth assumed in the forecasts. The table presents, for comparative purposes, an intermediate case - the business as usual scenario (BAU) - estimating the future demand based on tariff levels that remain constant in real terms.

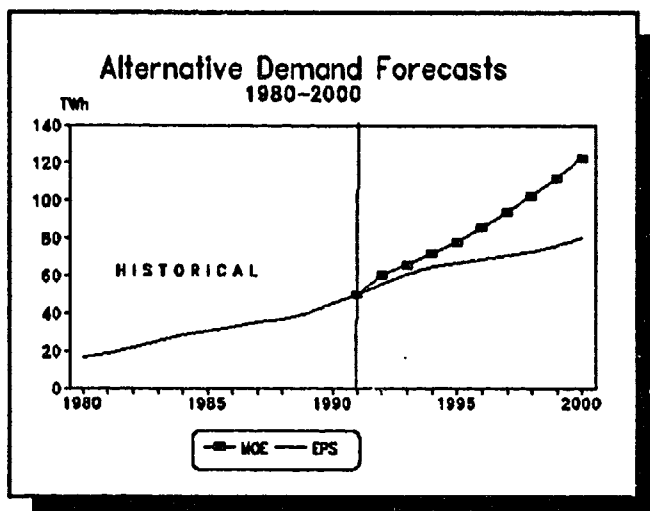


Figure 6.1 Alternative Demand Forecasts

Table 6.2: Alternative Demand and GDP Forecasts

		91-95	95-2000
Alternative Scenarios	MOE	11.9%	9.4%
	BAU	12.6%	9.1%
	EPS	7.5%	3.8%
Demand Growth Rates	Low GDP Growth	6.5%	2.1%
	Base GDP Growth	7.5%	3.8%
	High GDP Growth	9.1%	6.2%
GDP Growth Rates	Low Growth	3.5%	3.6%
	Base Growth	6.0%	6.0%
	High Growth	9.6%	9.5%

6.3 The EPS forecast is lower than the MOE forecast; largely due to the fact that the MOE forecast model does not consider price elasticity effects and assumes an average GDP growth of 8 percent per annum. As the MOE survey has shown, all forecasts consider the entrance of special loads consisting mainly of large new industrial users, several of which are related to the reconstruction effort. The higher demand growth in the first period is explained by the reconstruction effort. Thus, as the reconstruction effort diminishes during the second half of the 1990s, the growth in demand slows as well. A detailed demand forecast is provided in the project file.

B. Least-Cost Analysis

6.4 Based on demand forecasts that consider the projected increase in tariffs, an optimization of the expansion of the generating capacity of the interconnected system was carried out with the WASP model. The financial costs were converted to economic costs by netting out taxes and other domestic transfers and expressing the import content at c.i.f. prices. The costs include all the required investments for the 10-year investment program, as well as the value of the unserved energy due to random outages. The main parameters employed in the least-cost analysis are presented in Annex 6.1. The economic analysis presented in this chapter is based on a foreign exchange rate of Rials 1450 = 1US\$ for 1993.

6.5 The results of the analysis indicate that the Qom project forms part of the least-cost expansion. A sensitivity analysis was carried out with respect to the price of gas. Given that no economic estimate of the cost of gas in Iran is available, an expansion plan with a price of gas of US\$1.50 per MBTU was developed. This sensitivity run showed that as natural gas price declines, fewer combined cycle units become economically feasible; gas turbines then become more attractive until a price of US\$1.50 per MBTU is reached, where future needs are divided between gas turbines and combined cycle options. However, given that the analysis has not quantified the environmental benefits that accrue to combined cycle add-ons (para. 6.6), combined cycle conversions are expected to be more attractive than the other alternatives. Table 6.3 presents the summary of the least-cost exercise.

Table 6.3: Results of Least-Cost Analysis

Plants	1994	1995	1996	1997	1998	1999
Total Plan Cost US\$12,634 million						
Gas Turbines (100 MW)	2					
Gas Turbines (120 MW)	2					
Qom CC (100 MW)		1	1			
Combined Cycle (100 MW)					8	
Shahid Montazeri (200 MW)				2	2	

C. Cost-Benefit Analysis

6.6 A cost-benefit analysis was undertaken using the estimated costs, excluding taxes and duties and price contingencies, and an annual operating and maintenance cost stream equivalent to 2 percent of the capital costs. The Qom component has no incremental fuel costs associated with it as the design is based on a non-refired boiler. As the combined cycle plant would have the highest operating efficiency of all thermal plants in the system, it is assumed to be base-loaded, operating as many hours as it is available. The analysis assumes that the plant would only have a 50 percent plant factor in its first year of operation due to higher than average levels of maintenance for inspection and teething problems. The output is assumed to increase to a

60 percent plant factor in its second year of operation and to a 70 percent factor for the remainder of its first decade of operation. The plant factor is forecast to decline to 60 percent during its second decade of operation and to 50 percent for its last decade. The benefit stream is valued using projected tariffs at the generation level based on meeting the proposed financial targets as a proxy for benefits. The results indicate that the project's ERR is 17 percent. The project also includes an implicit environmental benefit in decreasing CO₂ production from power plants. The estimated annual reduction of CO₂ would be 0.3 million tonnes/year, which would increase the benefits by approximately US\$6 million p.a.^{1/} This benefit has not been included in the economic analysis because of the difficulty in valuing CO₂ reductions.

D. Risks

6.7 The main risks associated with the project are: (a) failure to continue with electricity price reform; (b) market growth below that forecast; and (c) cost overruns. If electricity prices are only increased to 80 percent of LRMC at the generational level (estimated at 4.5 US cents/kWh), the EIRR would drop to 14 percent. As noted in para. 5.14, the estimated amount of tariff increases that would be necessary to attain LRMC by March 1996, is large (about 100 percent for each of the next three years). There is a genuine risk that such large increases may not be socio-economically sustainable - the Government's commitment notwithstanding. Under such circumstances, the target date may be extended and the gap between the domestic tariffs and the LRMC may close slower than expected. However, the sensitivity analysis shows that to bring the EIRR down to 10 percent, prices at the generation level would have to be less than 2.8 US cents/kWh. Given the Government's demonstrated commitment to reform, this appears to be a low risk. The risk that market growth will be less than anticipated is also expected to be small. The demand forecast used for the least-cost analysis and the cost-benefit analysis is conservative and the lowest of all analyses undertaken to date. However, should the demand growth not develop as forecast, the implementation schedule for gas turbine plants can be varied to respond to changes in demand. In addition, much of the equipment for committed plants are to be supplied from countries suffering from substantial internal turmoil (Former Soviet Union and Eastern Europe). This is likely to delay the implementation of other generating plants, further emphasizing the need for the project. Hence the risk of slower than forecast demand growth is manageable. Should project implementation be delayed by one year, the EIRR would be 15 percent. The project cost would have to increase by more than 61 percent to result in an EIRR of less than 10 percent. Given that the design is based on standard equipment, which is readily available and for which there are numerous suppliers, the likelihood of such a cost overrun is small.

1/ This benefit is based on a conservative estimate of the economic value of CO₂ reduction of US\$20/tonne.

VII. AGREEMENTS REACHED DURING NEGOTIATIONS AND RECOMMENDATIONS

7.1 During negotiations, the Government agreed that it would:

- (a) enable TREC to fulfill its financial targets (paras. 5.10 and 5.11); and**
- (b) review the Commercialization-Privatization Study jointly with the Bank and develop an action plan for implementing the agreed recommendations of the study for review by September 30, 1994 (para. 5.13).**

7.2 During negotiations, TREC agreed on the following:

- (a) it would cover the foreign exchange needs, with cofinancing or other arrangements, should the proposed suppliers' credit not be available in a timely manner (para. 4.10), failure to do so would be a cause for suspension of disbursements;**
- (b) TREC would take all actions necessary to carry out a Project Implementation Plan satisfactory to the Bank (para. 4.25);**
- (c) to support the commercialization process, independent auditors would be employed to audit TREC accounts, and this audit would be furnished to the Bank no later than six months after the end of each fiscal year (para. 5.8);**
- (d) TREC fixed assets would be revalued and would be reported annually as a note to the audited balance sheet for each year starting in FY93 (para. 5.9);**
- (e) TREC would produce, for each fiscal year, funds from internal sources equivalent to not less than 20 percent of the three-year rolling average of its capital expenditures for FY93 and 40 percent for FY94 and thereafter (para. 5.10);**
- (f) TREC would maintain a debt service coverage ratio, for each fiscal year starting in FY93, of no less than 1.5 (para. 5.11);**
- (g) that by no later than March 20, 1994, TREC would increase its billing frequency for its residential consumers to at least every two months, and that by no later than March 20, 1994, TREC would take actions to enable it to reduce its accounts receivable to three months' sales equivalent and its accounts payable to TAVANIR to no more than the equivalent of two months of purchases (para. 5.12); and**
- (h) that by no later than September 30, 1994, TREC would furnish to the Bank its action plan for increasing commercialization and initiating private sector participation in its operations (para. 5.13).**

7.3 Execution of a subsidiary loan agreement, between the Borrower and IPO, satisfactory to the Bank, would be a condition of loan effectiveness (para. 4.10).

7.4 Subject to the above agreements, the proposed project is suitable for a Bank loan of US\$165.0 million to the Government of the Islamic Republic of Iran. The loan would be for a term of 17 years, including a five-year grace period, at the Bank's standard variable interest rate.

ISLAMIC REPUBLIC OF IRAN
POWER SECTOR EFFICIENCY IMPROVEMENT PROJECT
STAFF APPRAISAL REPORT

DETAILS OF THE POWER SYSTEM IN IRAN

Introduction

1. The power sector consists of three electrically isolated systems: (i) the interconnected system (ICS); (ii) the Khorazan system (KS) in the northeast; and (iii) the Sistan-Baluchistan system (SBS) in the southeast. The ICS supplies electricity to most of the country, as indicated in the table below.

<u>System</u>	<u>1991 Peak Demand (MW)</u>	<u>Installed Capacity End FY90 (MW)</u>	<u>1991 Estimated Load Shedding (MW)</u>
ICS	10,137	12,650	1,000
KS	920	1,320	0
SBS	136	305	0

2. After the end of the war with Iraq in 1988, the power sector entities have been busy reconstructing assets that were destroyed. The technical staff have done an excellent job in rebuilding plants, especially in light of the limited access to spare parts resulting from trade sanctions. The war also took a toll on system reliability as major maintenance programs were deferred. The thermal plant rehabilitation will be the focus of a study (para. 4.7, Annex 4.4 for draft TOR).

3. Generation planning has been somewhat ad hoc based on independent feasibility studies, which do not properly address the dynamic problems of integrated system development. MOE has acquired the WASP computer program^{1/} and is in the process of strengthening its data base required to determine a least-cost plan. Initial analyses have been reviewed and improvements are being made. A major review and upgrade will be undertaken under the Energy Sector Development Study (para. 4.7, Annex 4.2 for draft TOR).

4. The backbone of the transmission system consists of 5,946 circuit km (1991) of 400-kV lines and 14,361 circuit km (1991) of 230-kV lines. The transmission system is currently inadequate. Plants in the southwest are run below capacity while load is shed in the northwest. This bottleneck is expected to be minimized as the balance of regional supply and demand is addressed. The transmission constraint not only causes load shedding but also

^{1/} WASP (The Wien Automatic Simulation Program) was developed in the 1970s by the International Atomic Energy Agency (IAEA) and is widely used by power utilities to determine least-cost generation investment plans by explicitly emulating the stochastic nature of operation of alternative system plans and minimizing the sum of investment and operating costs using dynamic programming.

does not allow for least-cost system operation. The limited short-circuit capacity of the substation is a major problem that constrains system operation. Some of these problems are currently being addressed by the addition of transmission and substation capacity, but these are short-term solutions. Long-term development of the transmission grid will have to be addressed in a future National Grid Study. In addition, the feasibility of interconnecting the two isolated systems (KS and SBS) to the ICS, and its optimal timing, will also have to be assessed.

Power Sector Background

5. Electricity supply in Iran started with many small municipally or privately owned power companies with generating plants that were operated by industries. Tehran alone had 30 small companies and Tabriz had 6. The Ministry of Water and Power was created in 1964, and the public electricity supply facilities were nationalized in 1965. Industries retained their captive power plants. In 1965 the sector was small, at about 400-MW total load, with the largest steam plant being the 50 MW Tarasht plant in Tehran. The power system grew rapidly after nationalization; by 1970 the country's total generating capacity was about 2,100 MW, including 700 MW of captive industrial plant.

6. However, even in its early years of development, the sector suffered from poor quality service. A 1971 Bank energy sector review noted there were voltage and frequency reductions, load shedding of roughly 10 percent at peak load and the overloading of generators. The causes of the poor service were a high rate of load growth coupled with an inability to plan and commission plants in time to meet the expanding electricity demand. The power supply problems were aggravated by the lack of an interconnected system to share generating reserve capacities and to coordinate hydro and thermal plant outputs and integrated maintenance programs. System interconnection was greatly assisted through the north to south 400-kV transmission lines installed in the mid-1970s under Bank financing (Loan 856-IRN).

7. The Bank's past participation in the development of the power sector, through loans totalling US\$201 million, is summarized as follows:

- Loan 247-IRN for US\$42 million in 1960 financed the Dez multipurpose project with four 65 MW units (later increased to eight) in Khuzestan Province and created the Khuzestan Water and Power Authority.
- Loan 716-IRN for US\$160 million in 1970 financed the rehabilitation and expansion of distribution facilities on the TREC system.
- Loan 856-IRN for US\$51 million to TAVANIR in 1972 financed 400-kV and 230-kV lines to connect the 1,000 MW Karun I hydro plant then under construction, to interconnect the Fars area, and to strengthen the north-south transmission.
- Loan 1001-IRN for US\$58 million to TAVANIR in 1974 financed 400 MW of gas turbines and a 400-kV line between Arak and Tehran.

Installed Generating Capacity in 1991

8. The demand for electricity in Iran has grown almost 10-fold over the past 20 years, and today the demand is still supply-constrained. In 1991 the total installed generating capacity (based on nameplate ratings) was 14,276 MW, of which about 90 percent was in the interconnected system. Thermal plants (steam, gas turbine, diesel) made up 87 percent of total capacity as shown below.

<u>Plant type</u>	<u>MW</u>	<u>%</u>
Gas turbine	3,402	23.9
Steam	8,255	57.8
Hydro	1,915	13.4
Diesel	704	4.9 ^{1/}
Total	14,276	100.0

9. The number of individual generating units at the country's three power systems totalled 242 units (55 plants) in 1991, excluding diesel plants. The details of plant locations and unit arrangements are shown as Attachments to this Annex (Attachments 1 and 2).

Generation Capacity Operation

10. The available generating capacity is being operated very effectively by TAVANIR and the RECs, in spite of capacity limitations and difficulties in arranging outages for maintenance. The plants are being operated at high plant factors to maximize energy delivery to the system and thus minimize load shedding. In 1990 the average plant factors on the ICS and KS were as follows:

<u>System</u>	<u>Plant Type</u>	<u>Annual Plant Factor %</u>
ICS	Steam	79.8
	Gas Turbine	52.2
	Hydro	78.8
KS	Steam	93.7
	Gas Turbine	80.7

11. This exceptionally high utilization record for available capacity results not only from system overload but also from an effective performance monitoring program at the national control center for power operations. All unit outages and their causes are recorded and plant operators are urged to achieve high utilization through competition and an award system, including the regular reporting of the performance and achievements of each plant. Annual availability factors for the highest individual units (96.9 percent for steam, 99.8 percent for hydro and 98.3 percent for gas turbines) were reached

^{1/} Diesel accounts for less than 1 percent of energy.

in 1990. However, maintenance is being neglected in the interest of maximizing output. Additional capacity is urgently needed to permit maintenance, to eliminate load shedding and to establish a margin of generating capacity reserve.

Suppressed Power Demand

12. The electricity supply is being restricted about 10 percent on a capacity basis and 3 percent on an energy basis. The unserved energy demand was estimated to be about 2000 GWh in 1991, representing an economic loss of US\$1 billion based on an economic worth assumed to be US\$0.50/kWh. The causes of the power shortages are a mixture of inadequate generating capacity reserve, transmission limitations, fuel shortages and water limitations at hydro plants. However, the overriding cause is the eight-year war with Iraq and the resulting delays in planning and installing additional generation, transmission and fuel facilities in time to meet the growing demand for electricity.

Transmission System

13. Iran is a large country stretching 200 km west to east and 1,600 km north to south. The long distances require a large transmission grid even though most of the population is concentrated in the western and northern areas. Consequently, the light load in the eastern and central areas has not warranted, to date, the linking of the two isolated systems in the east to the interconnected system in the west. The existing 400-kV transmission comprises 118 lines totalling 14,361 circuit Kms. There are only two 400-kV north-south transmission paths, and the capacity of these lines is inadequate to handle the power flows required to balance load areas in the north and generation sources in the south. An overall National Grid Study is required to address this problem.

**CAPABILITY OF EXISTING POWER PLANTS ON THE
NATIONAL INTERCONNECTED SYSTEM IN 1991
(Installed Nameplate Capacity)**

GAS-TURBINE POWER PLANTS		STEAM POWER PLANTS	
	Units * MW		Units * MW
RAY	13*28	SHAHID SALIMI (NEKA)	4*420
	18*21	SHAHID MONTAZER-GHAEM	4*156
	3*75.5	SHAHID BEHESHTI	2*120
	6*21	BESAT	3*82.5
SHAHID MONTAZER-GHAEM	1*21	SHAHID FIROZI-TARASHT	4*12.5
SHAHID BEHESHTI	2*55	ISFAHAN	2*37.5
BESAT	21+2*53		1*120
SHAHID FIROZI (TARASHT)	2*11		2*320
RASHT	2*23.5	SHAHID MONTAZERI	4*200
ISFAHAN	15+19	STEEL MILL	2*12.5
STEEL MILL	1*18		1*60
HESA	3*19		1*55
BAKHTARAN	2*28	RAMIN	2*315
DOROOD	2*26	MADHAJ	1*145
MADHAJ	2*30	TABRIZ	2*387
NEKA (SHAHID SALIMI)	2*137+1*30	BANDAR-ABBAS	4*320
SHIRAZ	2*21.5	ZARAND	2*30
	1*9.5	SAR-CHESHMEH COPPER	2*9
	1*18	TOTAL STEAM	7523.5
	1*50	HYDRO POWER PLANTS Units * MW	
	3*11.5	SHAHID ABBAS-POUR	4*250
BUSHEHR	3*22.5	DEZ	8*65
TABRIZ	2*28	SEFID ROOD	5*17.5
SOOFIAN	4*21	AMIR-KABIR	2*45.5
OROMIEH	2*26	LATIAN	2*22.5
GHARA-MALEK (TABRIZ)	2*13	ARAS	2*11
TRACTOR MANUFACTURING	2*8	ZAYANDEH ROOD	3*18.5
BANDAR-ABBAS	2*21.5	MAHABAD	2*3
SAR-CHESHMEH	5*18	KALAN	2*38.5
YAZD	4*20	DOROODZAN	2*5.5
COAL PROCESSING	1*30	TOTAL HYDRO	1915
TOTAL GAS-TURBINE	2702	GRAND TOTAL	12650.5
DIESEL POWER PLANTS	510		

**CAPABILITY OF EXISTING POWER PLANTS ON THE
NATIONAL ISOLATED SYSTEM IN 1991
(Installed Nameplate Capacity)**

**KHORASAN REGIONAL ELECTRIC
COMPANY**

POWER PLANT	TYPE	UNITS & CAPACITY MW
TOOS	STEAM	4*150
	GAS T.	1*6
MASHHAD	STEAM	2*60 1*12
	GAS T.	2*72.5 2*17 1*22
	GAS T.	6*21.5
	GAS T.	6*21
SHARIATI	GAS T.	6*21.5
SHIRVAN	GAS T.	6*21
GHAEN	GAS T.	2*20.5
SOUTH KHORASAN	DIESEL	85
TOTAL		1320

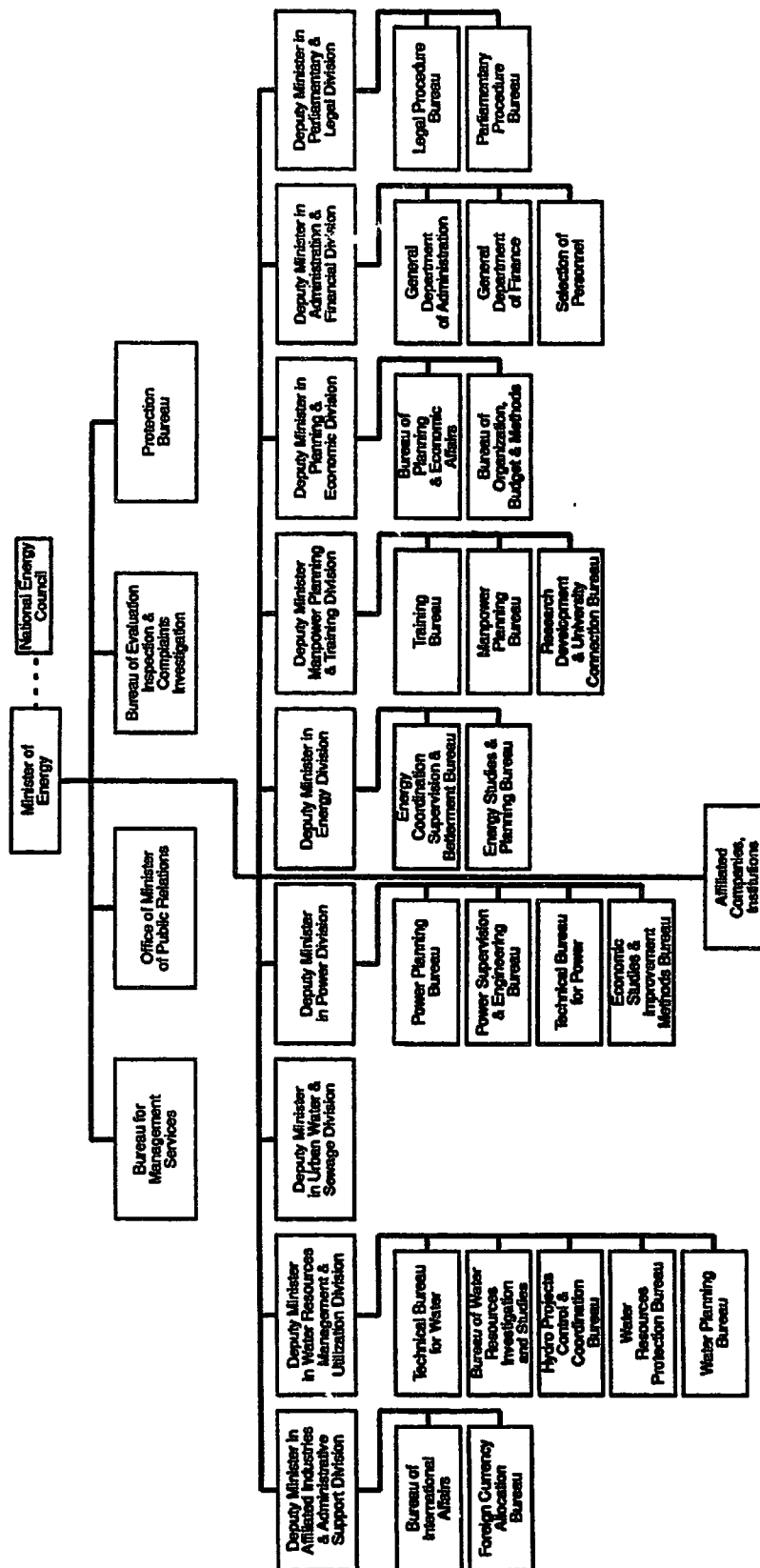
**SISTAN & BALUCHISTAN
REGIONAL ELECTRIC COMPANY**

POWER PLANT	TYPE	UNITS & CAPACITY MW
ZAHEDAN	GAS T.	3*19.5
CHABAHAR (KONARAK)	GAS T.	6*23
SISTAN & BALUCHISTAN	DIESEL	109
TOTAL		305.5

**TOTAL NATIONAL
CAPABILITY OF POWER PLANTS
IN 1991**

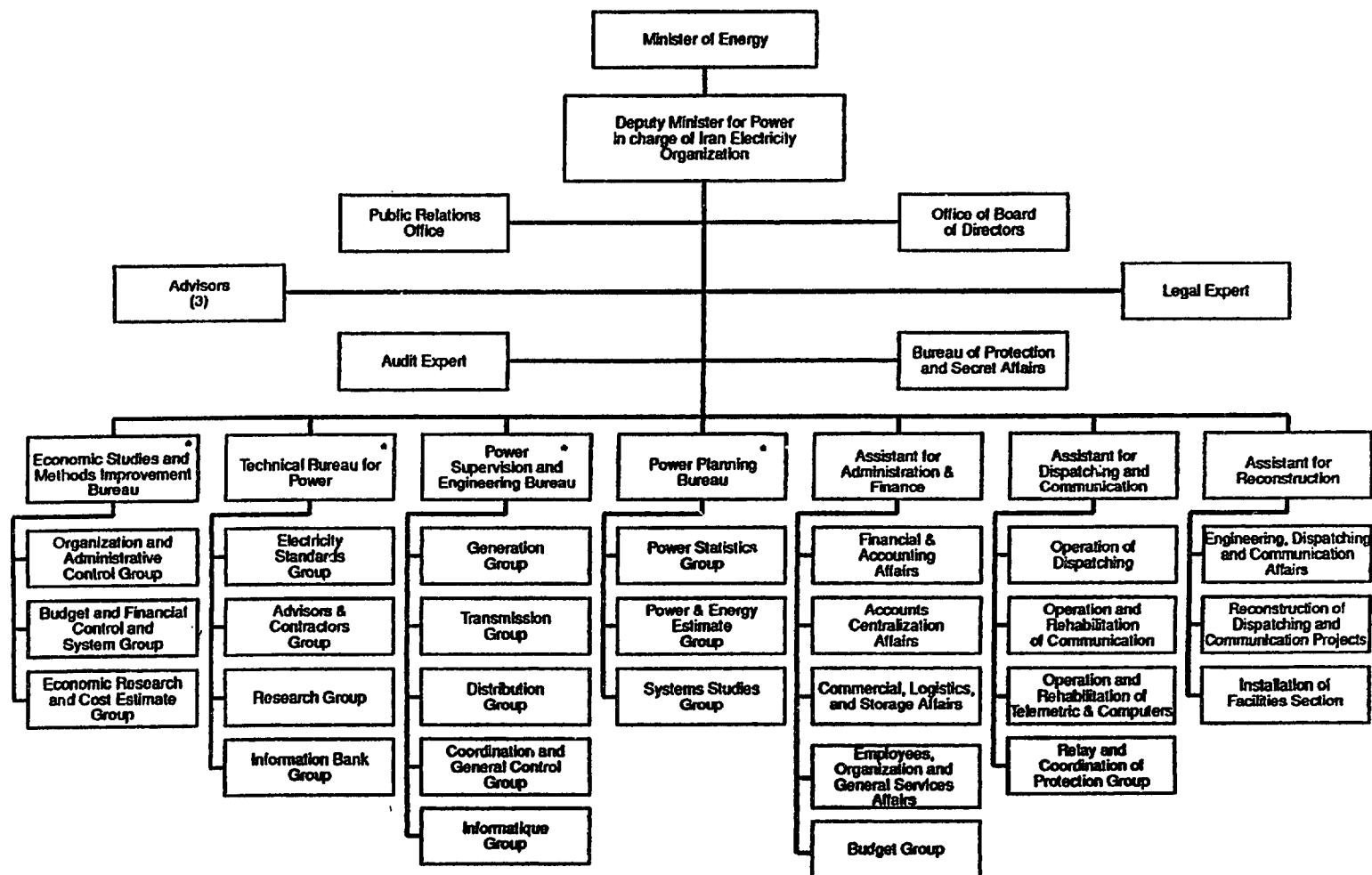
INTERCONNECTED SYSTEM	MW
	12650.5
KHORASAN NETWORK	1320
SISTAN & BALUCHISTAN NETWORK	305.5
TOTAL	14276

MOE ORGANIZATION CHART



E/MWS3076

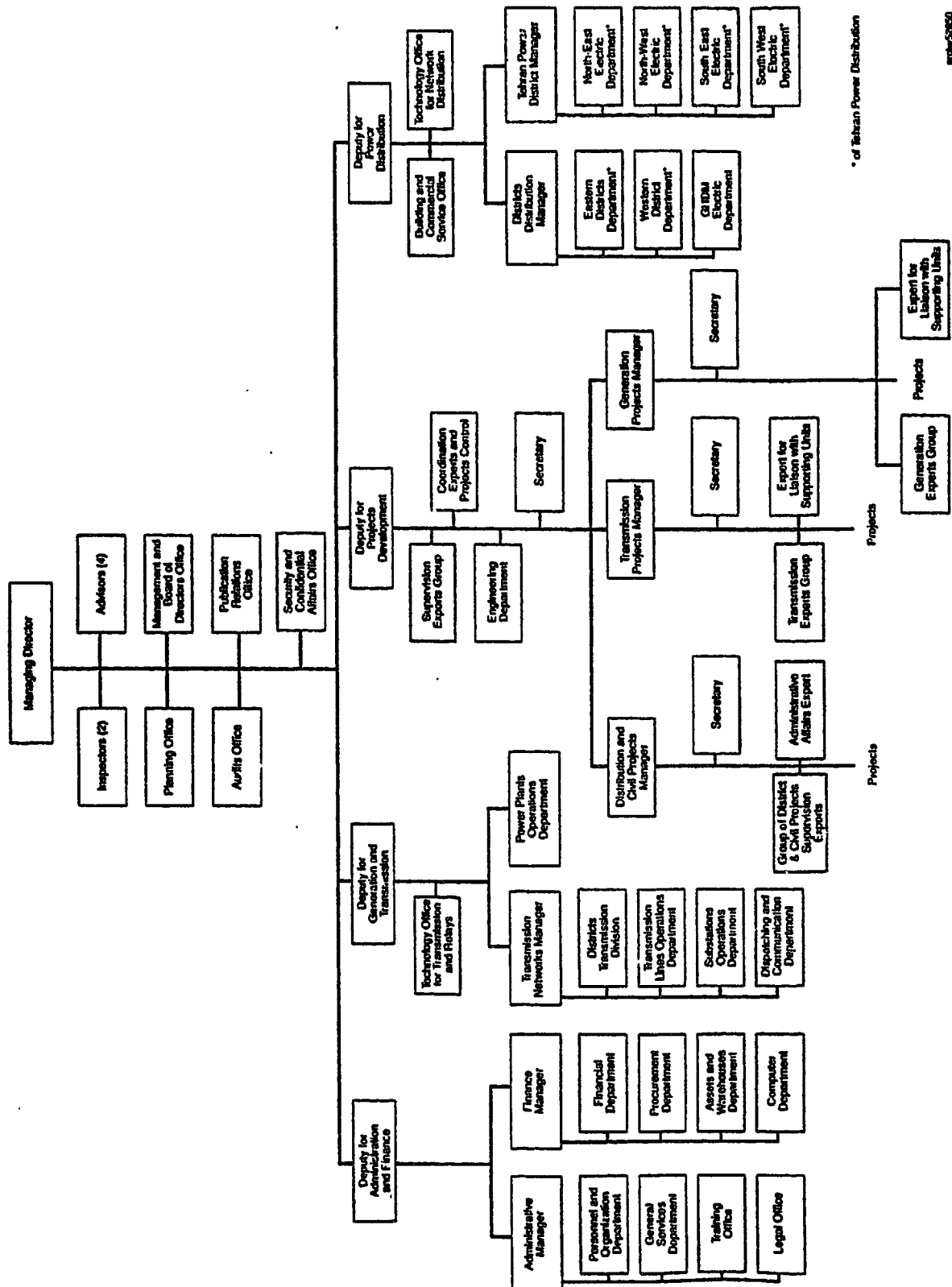
IRAN POWER ORGANIZATION CHART



* The Salaries of the employees in these departments are paid by IEO although they are under the Ministry of Energy.

EX/P50024A

TREC ORGANIZATION CHART



* of Tehran Power Distribution

enp-52850

ISLAMIC REPUBLIC OF IRAN
POWER SECTOR EFFICIENCY IMPROVEMENT PROJECT
STAFF APPRAISAL REPORT

PROJECT DESCRIPTION

Qom Conversion to Combined Cycle

1. Under this component, the four 100-MW (site rating) open cycle gas turbine (GT) units currently being installed would be converted into two combined cycle (CC) modules providing an additional total capacity of 200 MW. Under this scheme, unfired heat recovery steam generators (HRSGs) would be installed at the exhaust of each GT unit. Using the heat from exhaust gases of GT units, two HRSGs would produce enough steam to operate a steam turbine generator (STG) unit of about 100 MW capacity. Hence the total capacity of the 2 CC modules would be 600 MW gross (588 MW net) when power consumed by the auxiliaries has been deducted. The expected overall efficiency (net, low heating value) would be about 45 percent, compared to 32 percent for the open cycle mode. The scheme would be operated as a base load station with an expected capacity utilization factor of no less than 70 percent.

2. Installed Capacity and Configuration. The Qom power plant was designed to operate initially as a simple cycle gas turbine generating station with four Mitsubishi MW-701 industrial type units, with provisions for the future addition of two more units. The commissioning of the first four units is scheduled between May-July 1993. The gas turbines are designed to fire natural gas or gas oil fuel (distillate) with the following guaranteed performance:

<u>Ambient Conditions</u>	<u>ISO conditions</u>	<u>Site Conditions</u>
Temperature	15 C°	31 C°
Elevation	Sea Level	1,022 mete
Relative Humidity	60%	42.5%
Inlet/Exhaust Losses	101.6/76.2 mmH ₂ O	101.6/76.2 H ₂ O
Turbine Exhaust Temperature	515 C	528 C
Exhaust Flow	452 kg/s	373 kg/s
Gas Turbine Rating	128.58 MW	100.6 MW

Taking into account the performance of gas turbine units and the steam cycle equipment, as well as investment and O&M costs, a configuration of 2 GT + 2 HRSGs + 1 STG has been adopted. Dry cooling with air cooled condensers has been selected to minimize water consumption.

3. Location and Land. The Qom power plant is located approximately 15 km west of the city of Qom, which is about 150 km south of Tehran. The gas turbine plant is a walled 800 m x 800 m area immediately south of the Tehran-Arak road. TREC owns the plant site and during appraisal construction work for the 4 x 100 MW gas turbine was well underway. The area available is adequate for the installation of the combined cycle add-on. Access to the site is via the two-lane paved road from Qom. Equipment and material delivery for this project would be via sea to Persian Gulf ports and then inland by road or by rail. Railroad tracks pass within 200 m of the site.

4. Site Conditions. The site is on a level terrain formed of conglomerate and well-consolidated soils. Geotechnical and seismic data for the proposed site are available from the investigations made for the Gas Turbine Power Station in 1989 and 1991. The 1991 report was commissioned in response to the discovery of collapsible soils in the foundation deposits during site rough grading. This particular aspect is being addressed in the engineering phase and would include further site investigations and laboratory tests and analyses. Available seismic data show the design ground acceleration at the site to be 0.18g. The Qom region is dry and barren with an annual precipitation of less than 150 mm. Water requirements for the gas turbine plant would be drawn from two wells located about 0.7 km and 1.2 km south of the plant site. To minimize additional water supply needs, the combined cycle add-on would use air cooled condensers limiting water consumption to the HRSGs make-up requirements (about 5 l/s). TREC has completed studies that indicate that adequate water will be available from the wells for the plant operation including potable, fire fighting and landscaping needs. Water from the well is highly mineralized and will be treated to make it suitable for use in the HRSGs.

5. Fuel Gas Supply. There would be no additional fuel requirement from the combined cycle add-on. The primary fuel for the GT would be natural gas, and the stand-by fuel would be gas oil (distillate). A 15-day storage capacity is being constructed under the gas turbine contract. The gas requirement for the 600-MW scheme for an average daily generation of 9.5 GWh at 70 percent capacity utilization factor would be 1.94¹ million cubic meters per day based on a heat rate (net, low heating value) of 1893 kcal/kWh. The National Iranian Gas Company is contractually obligated to start supplying natural gas by March 1994. The extension of the IGAT II pipeline and the commissioning of the Kangan gas refinery is expected to be finalized by the end of 1993 to enable the gas needs to be met.

6. Transmission of Power. The two steam turbine generating units would be connected to the 230-kV substation and the four outgoing lines being constructed under the gas turbine contract. By the time the combined cycle add-on would be commissioned, a 400-kV substation and two outgoing lines would be constructed at the Qom site and would be connected to the 230-kV substation through two 500-MVA transformers.

7. Staff and Staff Colony. A housing colony is being constructed for the gas turbine plant. The combined cycle plant would require 67 additional staff, including 7 full time instructors to provide a training program on an on-going basis. There is ample space to construct residential accommodations for additional staff within the existing colony.

8. Technical Features. The combined cycle add-on would include the following features. (a) The HRSG for each unit would be an unfired, double pressure (specific HP and LP values to be optimized during engineering), horizontal/vertical gas flow type with a self-supporting stack; steam for a

¹/ At 100 percent capacity utilization factor, the average daily generation would be 13.6 GWh, and the (maximum) fuel requirement would be 2.77 million cubic meters per day.

deaerator would be from a dedicated evaporator in the HRSG to improve efficiency; a multi louver type or single flap diverter type inlet damper would be installed at the base of the gas turbine bypass stack to direct the exhaust gas either to the atmosphere for simple operation of the GT or to the HRSG for operation in the combined cycle mode. (b) Steam from two HRSGs would be supplied to a condensing non reheat through main steam piping; the steam entry to the turbine would be through a set of emergency stop and control valves; the turbine control system would be of the electro-hydraulic type with hydro-mechanical system as a back-up; 100 percent HP and LP bypass systems for dumping the HP and LP steam to the condenser during start up and turbine trip conditions would be provided; the turbine would be provided with an air cooled condenser; two 100 percent mechanical vacuum pumps would be provided for the evacuation of the air from the condenser. (c) The generator would be a two pole 3-phase, 13.8-kV, 50 Hz, 120 MW nominal rating (at 0.8 p.f.) with a totally enclosed water/air cooled rotor and stator; the excitation system would include a brushless exciter, pilot exciter, static rectifier amplifier and automatic voltage regulator. (d) The power from the scheme would be evacuated through an oil immersed two winding outdoor type step-up transformer with a nominal ratio of 13.8-kV to 230-kV, which would be connected to the 230-kV substation under construction; on-load taps would be provided and the transformer would be rated to carry maximum generator load at 0.8 p.f. with cooling to limit the maximum winding temperature rise to a value consistent with the expected ambient temperature. (e) The auxiliary systems would comprise water treatment, circulating water, auxiliary cooling water, heating, ventilating and air conditioning, service water, potable water, fire alarm and protection, power station electrical supply, protection, control and monitoring, compressed air, communication, safety, grounding and lightning protection, emergency generation and related systems.

Transmission Lines and Substation

9. The main transmission network in Iran consists of overhead transmission lines and substations operated at 400-kV, 230-kV and 132-kV. In addition, 66-kV and 63-kV overhead distribution lines and distribution substations are in service through the electric companies in different regions. Further, in some parts of Iran 33-kV, 20-kV, 11-kV and 6-kV distribution lines are also employed in distribution networks. The lengths of 400-kV, 230-kV, 132-kV and 66/63-kV transmission lines (in circuit kms) are given below.

<u>Year</u>	<u>400-kV</u>	<u>230-kV</u>	<u>132-kV</u>	<u>66/63-kV</u>
1991	5,946	14,361	n.a.	n.a.
1990	5,618	10,971	8,532	18,202
1989	5,618	10,530	8,144	17,310
1984	4,318	8,266	5,605	11,732
1980	1,833	6,297	4,699	6,735

10. To meet the increasing lengths of transmission lines, a growing number of transformer substations have been installed. According to the latest available statistics (1990), MOE is operating 1,352 transformers with a total output capacity of 53,759 MVA, whereas in 1982 MOE was operating 703 transformers with a total output capacity of 25,763 MVA.

11. The Qom substation and transmission line component would enable the evacuation of power from the plant to the 400-kV national grid. On commissioning the open cycle plant, the output would be connected to the interconnected system via the 230-kV transmission lines. The 400-kV project at Qom is mainly being taken up to strengthen the north-south interconnection. At present, the plants in the southwest are run below capacity while load shedding is quite common in the northwest.

12. With the conversion to combined cycle operations at Qom, plant output would be connected to the national interconnected system via 230-kV and 400-kV transmission lines. The substation would be located about 10 km to the south-west of Qom city. The works related to this substation include 400-kV switchgears, autotransformers, necessary relay protection, control systems and related auxiliaries. Two 400-kV single circuit lines would be connected to the Qom substation--one from Golpaygan and the other from Jalal, both existing substations. Operations are underway for the laying of the 400-kV transmission lines purchased from Romania. Power would be supplied to the following areas: Saveh, Qom and Behranf through the 230-kV network and Jalal, Arak and Golpaygan through the 400-kV network.

ISLAMIC REPUBLIC OF IRAN
POWER SECTOR EFFICIENCY IMPROVEMENT PROJECT
STAFF APPRAISAL REPORT

DRAFT TERMS OF REFERENCE
ENERGY SECTOR DEVELOPMENT STUDY

A. Objectives

1. The purpose of this study is to assist the Government of Iran in preparing a comprehensive policy strategy for the development of the energy sector. The study would include the following activities:

- historical analyses and forecasts of energy balances by primary sources, secondary energy forms and consuming sectors;
- a review of the energy resource base of Iran, its current and planned production and export potential;
- demand forecasts by fuels (petroleum products, natural gas, coal and electricity), taking into account different economic and price scenarios;
- an assessment of energy pricing policies and institutional mechanisms with specific proposals for improvement;
- a review of fuel producing, transport and distribution facilities;
- an assessment of fuel prices, taxes, transport costs, distributive margins and opportunity costs, pointing out distortions and inefficiencies;
- an assessment of investment requirements and alternative sources of finance for the power sector over the next 10 years.
- an analysis of the macroeconomic impact of the energy sector, particularly with reference to the current account and budget;
- an analysis of the environmental impact of energy use;
- the development of a pricing policy that reflects economic costs and financing needs, including taxation policies on energy to reflect environmental impact and the impact on downstream sectors; and
- the training of counterparts in the models developed and used in this analysis.

2. To this end, consultants will review the available information -- previous and ongoing studies to assess their relevance and potential contribution to the preparation of this study. Consultants should maintain close contact with the responsible entities preparing other energy studies so as to have consistent data and avoid any duplication of efforts.

B. Scope of the Study

3. The study will assess the resource needs (fossil fuels, hydro power, investment capital and management resources) and the possible financial sources for developing future energy needs.

4. The study will review the available macroeconomic data concerning population, capital formation, gross national product, per capita income, oil trade, exchange rate policy and industrial, commercial, transport, agricultural and services activities. The relationship between these variables and sectoral market variables, such as price and cost, will be studied to determine alternative scenarios for demand forecasts by type of fuel, explicitly modelling interfuel substitution prospects. Thus, the effect on the demand and supply of alternative energy prices and macro economic scenarios will be evaluated.

5. An evaluation of energy resources, their opportunity costs and potential uses will be made to determine the most economic sources of supply to satisfy domestic needs. Hydro resources (existing and proposed) will be reviewed explicitly, taking into account the seasonality of water availability and the stochastic nature of its supply. Recommendations for modelling these aspects of hydro resources will be specifically identified.

6. The study will examine fuel prices, their composition and opportunity costs. Both the level and structure of pricing distortions will be examined, and concrete proposals will be advanced to overcome them. The institutional setup will be examined to recommend a transparent pricing mechanism that responds in a timely manner to changes in opportunity costs. The impact on the budget and the current account balance of recommended pricing changes will be assessed.

7. The study will examine the investment programs of the power sector, explicitly taking into account environmental concerns and critically reviewing investment options in determining a least-cost plan for the next 10 years. The consultant will leave behind an analytical tool and the database to enable the counterpart team to undertake feasibility studies of proposed investments. The WASP III model should preferably be used for the least-cost generation expansion analysis).

8. Following the review of the reference demand forecast and least-cost expansion program for the power sector, the study will evaluate the marginal economic costs of power generation, transmission and distribution at different places, times and voltage levels to different consumer categories over the time-frame specified and compare them with the existing tariff structure and rates. Based on the results of this analysis, the consultant will make a first set of proposals for changing the existing tariff system so that the incentives (and disincentives) it provides to consumers correspond more closely to the schedule of marginal costs derived. These proposals would take into account, among others, the need for the utilities to secure an adequate rate of return on net assets in operation and any income distribution objectives (e.g., subsidizing poorer consumers) to which the electricity tariffs may be required to contribute.

9. The study will determine the most economic combination for meeting the demand for energy up to 2010 on the basis of the least economic cost (investments, fuel cost and O&M). A price reform strategy will be developed focussing on level and structure of prices and the speed of implementation of price reforms. The impact on macroeconomic balances, environment and poverty will be explicitly identified. Based on the results of the investment

program, recommendations on training, research and development will be addressed.

C. Reporting Requirements

10. The study will consist of the following reports:

- an Inception Report, to be reviewed by GOI and the Bank, summarizing the findings on data availability; ways to improve data reporting and access to information; the relevance of available studies; the organization and schedule of future work; and the use of counterpart personnel and local services;
- a Draft Final Report describing the work performed and the findings, policy recommendations and action plan (including implementation plan and timetable) proposed by the study; and
- within 30 calendar days of the receipt of comments from GOI and the Bank on the Draft Final Report, a Final Report incorporating all suggestions and recommendations deemed appropriate.

D. Iranian Participation

11. The GOI has appointed the Iran Power Organization (IPO), an energy agency of the Ministry of Energy, to be the responsible counterpart for the study. This agency will have the high-level support needed to access to the data for the study; the computing resources needed to process the information; and the staff needed to perform the analytical work.

E. Timetable

12. Key dates in the timetable for the study are planned as follows:

Start-Up:	30 June 1993
Inception Report:	30 August 1993
Draft final Report:	30 March 1994
Final Report:	30 May 1994

ISLAMIC REPUBLIC OF IRAN
POWER SECTOR EFFICIENCY IMPROVEMENT PROJECT
STAFF APPRAISAL REPORT

DRAFT TERMS OF REFERENCE
COMMERCIALIZATION-PRIVATIZATION STUDY

Background

1. The Government of Iran (GOI) is restructuring the electric power sector in order to promote, wherever possible: (i) competition among power sector enterprises; (ii) private sector participation in the operation of power generation and distribution facilities; and (iii) co-generation by industrial enterprises.
2. All facilities in the power sub-sector are currently Government-owned and until recently all operations were controlled by the Iran Power Organization (IPO) which is in effect the electric power branch of the Ministry of Energy (MOE). In the past, the main responsibility for the generation and transmission of electricity belonged to the Iran Power Generation and Transmission Company (TAVANIR), while the distribution function was carried out by 16 Regional Distribution Companies (RECs). The Tehran Regional Electric Company (TREC) is the largest distribution entity in the Iranian interconnected electricity system. IPO's mandate also includes the responsibility for the new National Dispatch Center.
3. As of October 1991 the installed capacity of existing power plants was 12,650 MW of which 7,523 MW from steam power plants, 3,212 MW are from gas-turbine plants and 1,915 MW from hydro plants. Most of the hydro plants are operated by the Kuzestan Water and Power Authority (KWPA). By 1989, Iran was experiencing about 6 hours of load shedding per day. Demand for electricity since then has grown by about 10 percent per annum, reflecting the growth in the economy (GDP growth for 1990 was estimated to be about 10 percent) and population (estimated at about 3.2 percent per annum). In spite of this, the power sector enterprises (PSEs) have been effective in reducing load shedding to rotating blackouts generally lasting about two hours per day as a result of an estimated supply shortfall of about 600 MW. This improvement was accomplished by reconstructing plants and components of the network damaged in the war with Iraq and by installing gas turbines. In spite of an ambitious power investment plan, the MOE forecasts that about 360 MW of load shedding is expected by the end of the second five year plan (March 1998).
4. The Iranian energy market (with monopolies at all levels) is characterized by an absence of competition. The organization structure, as it exists, appears to be conventional and reasonably logical.
5. Electricity prices are far less than the estimated long run marginal cost of supply. The current average tariff of about 10.3 Rls/kwh does not reflect the full cost of supply. Meeting the long run marginal cost of supply would require that electricity prices be about five to six times their current rate. In summary, the most notable drawbacks of the present

legal and institutional framework are: (a) absence of competition and management accountability; and (b) absence of a clear set of rules and principles regulating the entities in the sector.

Purpose and Objectives

6. GOI wants to improve the present organizational and regulatory arrangements in order to establish efficiency through competition and effective regulation, increase the accountability of management, ensure corporate autonomy for the power utilities, encourage a more commercial approach to production and distribution, and mobilize greater resources for efficient sector expansion. First, steps were taken to promote the divestiture of ancillary functions such as consulting, construction and maintenance. Then, in 1992, GOI undertook steps to commercialize existing PSEs, with all major generating plants and RECs reorganized into joint-stock companies including 24 Regional Distribution Companies (RDCs) which will operate their respective distributions systems under a 5 year lease agreements, 9 regional holding companies which will own the power plants located in their respective regions and 20 enterprises to operate the individual power plants under a 5 year lease agreements. These changes represents the first steps towards decentralization, commercialization and privatization (partial privatization through employee share ownership) of the sector. The next phase will involve development of an appropriate regulatory framework, tariff reforms, and eventually access to the capital markets.

7. The main purpose of the study is to propose a strategy and a blueprint for reducing the Government's involvement in the power sector while increasing the sector's efficiency by completing the commercialization of the PSEs and promoting the participation of the private sector. This will enable the sector to: (i) become financially autonomous, thus reducing the burden imposed on Government's finances; (ii) develop decentralized and privately owned utilities; and (iii) eventually support, a competitive and sustainable process of development. The objectives of the study are to prepare a long term strategy for the institutional development of the sector with public as well as private participation and to produce a blueprint for carrying out the sector restructuring. This will require:

- (a) development of alternatives for regulation and private sector participation based on evaluation of options taking into account experience in other countries that implemented reforms in the power sector;
- (b) preparation of a blueprint for the implementation of the strategy chosen by GOI;

- (c) preparation of a draft regulatory framework (including a new or amended Electricity Law) that would enable efficient and reliable supply of electricity at least cost, attract foreign and local private capital, and promote environmentally sound operation; and
- (d) preparation of a program to privatize generation and distribution businesses and to promote private investment in new facilities.

Scope of Work

8. Phasing of the study. Phase I would include (a) a review of the existing power sector organization, legal framework and regulatory arrangements; (b) evaluation of the options for restructuring the sector to achieve the Government's objectives; and (c) proposal for a sector restructuring strategy for a suitable institutional and regulatory framework. Following Government's approval of the strategy, phase II would develop and prepare a blueprint (phased implementation action plan) for commercializing and then privatizing the existing PSEs. Phase III would comprise the implementation of the action plans, which would require the preparation of a new legal framework and regulatory arrangements, completion of the establishment of the power companies on a fully commercial basis and subsequently facilitate greater involvement of the private sector.

Phase I - Diagnosis and Evaluation of Institutional Options

9. For phase I of the study, the consultant(s) will be expected to perform the following tasks:

- (a) review the current status of the power sector based on available studies and information from other sources, including:
 - (i) the functions and operational performance of the existing PSEs, including their legal status and organization;
 - (ii) the financial position and performance of the existing PSEs, including the condition of their assets;
 - (iii) the human resources and management of the existing PSEs;
 - (iv) the current laws and institutional arrangements governing the operation of the power sector; and
 - (v) the relative roles of other existing producers/distributors of power in Iran such as captive power, industrial estates, cogeneration, cooperatives and village electric organizations.
- (b) Based on experience in other countries and taking into account the Government's objectives, evaluate alternative organizational structures and regulatory arrangements for the Iranian power

sector and provide the Government with analyses and recommendations concerning:

- (i) the extent of vertical or horizontal integration needed to achieve the Government's objectives;
 - (ii) the feasibility and scope for competition and sound regulation in generation and supply;
 - (iii) the ownership options for generation, transmission, and distribution;
 - (iv) the regulatory arrangements required for each alternative institutional and ownership structure;
 - (v) the pros and cons of different alternatives for institutional organization and regulation;
 - (vi) the commercial principles for tariff setting which will be implemented through a separate regulatory body to encourage efficient allocation of resources, energy conservation and financial self-sufficiency;
 - (vii) the appropriate principles for pooling and dispatching in the power systems;
 - (viii) the appropriate means of responding to the needs of consumers and to potential abuses of natural monopolies; and
 - (xix) the regulatory role of the state and the autonomy of the utilities, particularly for setting prices, salaries and employment conditions and procurement.
- (c) based on (a) and (b), propose a sector restructuring strategy including the appropriate organizational and ownership structure for the power sector and an appropriate regulatory framework; and
 - (d) propose an organizational structure, budget, charter and functions for the regulatory Authority.

Phase II - Development of Organizational Structure and Regulatory Framework.

10. For phase II of the study, the consultant(s) will be required to perform the following tasks:

- (a) after MOE selects a restructuring strategy structure based on the results of phase I of the study, develop and prepare detailed blueprint (timetables and action plans) for creating new and restructuring existing entities while defining:

- (i) the organizational structure and functions of the entities in the power sector, including those for system operation, load dispatch and regulation;
 - (ii) the separation of finances including the transfer of existing assets and liabilities to new entities;
 - (iii) detailed specifications for adopting a fully new commercial approach including application of international accounting and auditing standards; and
 - (iv) staffing implications, including any issues with respect to: pay and conditions, pension arrangements, redundancy provisions, union representation and make appropriate recommendations.
- (b) subsequently, prepare a strategy and action plan for completing the processes of corporatization and privatization the existing entities (e.g., reorganization of the entities into autonomous companies responsible for their investments and operating decisions);
- (c) based on the agreed strategy for restructuring the power sector, provide a detailed outline of the required regulatory regime. In doing so, it would be necessary to define:
- (i) the institutional arrangements necessary to administer the sector entities;
 - (ii) the relationship of the regulatory institution(s) to existing governmental entities;
 - (iii) the functions of the regulatory institution(s), including the role in rate making, provision of reliable supply, system and least cost investment planning, competitive selection of generating investment projects, licensing, dispatching, maintenance of quality of service, safety, protection of the environment, and dispute resolution;
 - (iv) detailed guidelines and procedures for each of the foregoing functions. In particular, identify the criteria, periodicity, participants and procedures to be involved in rate making and investment proposals;
 - (v) model articles of incorporation/statutes for new joint-stock companies; and
 - (vi) the rights and obligations of the power sector or portions thereof (e.g., generating companies, transmission companies, and distribution companies) vis-a-vis the new regulatory institution(s), to other

governmental entities, to private sector projects, and to the public.

- (d) propose a strategy and action plan to modify the existing legislation and procedures as required in order to implement the recommended regulatory framework, including the drafting of the new/amended laws and regulations, which concerns the regulatory framework;
- (e) prepare a strategy and action plan to privatize the generation and distribution businesses and to promote private investment in new facilities; and
- (f) the restructuring for privatization of the electricity industry, including transfer of assets, liabilities and employees, contractual arrangements or other commercial arrangements, management development/training needs, etc. (e.g., ESOP, offer and share, sales to investors (bidding), customer ownership (consumer deposits). (This should include preliminary estimations of the value of the entity).

Phase III - Implementation ^{1/}

11. For phase III of the study, the consultant(s) would be required to include in the report of phase II a proposal for assistance in implementing the agreed strategy and action plans of phase II.

Organization of the Study

12. The study would be conducted by a consulting firm with extensive practical experience in the restructuring, regulation and privatization of public enterprises, including the energy sector. The firm should have access to the following areas of substantive expertise either in-house or through sub-contractors or associates:

- (a) power sector regulation, pricing and costing;
- (b) utility operation and maintenance;
- (c) commercial aspect of power wheeling and exchange;
- (d) personnel management;
- (e) utility demand forecasting;

^{1/} The key steps which should be followed in the implementation process are: (a) establishment of the legal framework; (b) completing the commercialization of the sector; (c) corporatization of the existing entities; and (d) privatization of the sector.

- (f) investment banking related to privatization of the power sector;
- (g) legal aspects of power regulation, corporatization, and private participation; and
- (h) local and international accounting and legal practices.

13. It is expected that the consultant(s) would work closely with the MOE. If required, the MOE will request assistance from representatives of other concerned ministries and agencies.

14. Throughout the study the consultant(s) should report to the MOE. The consultant(s) may also have direct communication with the Bank.

Deliverables and Timetable

15. The study should be performed in the following phases:

- (a) Phase I. The consultant(s) should prepare a report proposing a sector restructuring strategy with an executive summary of not more than 10 pages. The draft report should be completed within 90 days and following review by MOE and the Bank (30 days), the final report would be submitted within 30 days of receipt of MOE's and the Bank's comments. Approval by MOE of the report is planned in no more than 60 days.
- (b) Phase II. Once the MOE has selected a strategy, the consultant(s) should prepare a report with a detailed blueprint and action plans that includes the proposed functions, organization guidelines and procedures necessary to implement the framework recommended in phase I. This report should not exceed 50 pages in length, excluding attachments and provide an executive summary of not more than 10 pages. Organizational charts and tables summarizing the material should be included. Any financial models used for financial projections would be subject to review by MOE and the Bank. The draft report on the detailed institutional, organizational requirements for the recommended power sector structure and the appropriate regulatory regime would be submitted in 60 days. Allowing the review by MOE and the Bank (30 days). The final report on detailed requirements for the proposed structure would be presented within 30 days following receipt of comments. Approval by MOE of detailed requirements and regulatory regime for the recommended structure would be expected within 60 days.
- (c) Phase III. The Consultant(s) should include in the report for phase II, a proposal for services in assisting in implementing the agreed recommendations of phase II.

16. For phases I and II, the Consultant(s) should submit fifteen (15) copies of the draft report and thirty (30) copies of the final report to MOE and five (5) copies of the draft report and ten (10) copies of the final report to the Bank. Monthly progress reports should be forwarded to MOE and Bank. It is expected that the assignment would start in June 1993, with a target completion date of June 1994.

Budget and Fees

17. The Consultant(s) should propose a fixed fee for phases I and II of the study. Details should be provided for each of the Consultant(s) proposed to undertake the work, their experiences, and a tentative work program showing the number of days each would work and the fees to be charged for each consultant. The proposal should include allowances for international travel and subsistence, preparation of interim and final reports, legal documents, office supplies, and transportation in Iran.

Implementation of Recommendations

7. Following MOE agreement on the recommendations submitted, the consultant should prepare the terms of reference, technical specifications and bidding documents for the equipment to be purchased and services to be performed for the implementation of the recommendations.

Reports

8. The consultant should submit to MOE the following reports:
- (a) a preliminary report within 45 days after visiting each power plant or facility to be reviewed by the Bank and MOE, dealing with the following topics:
 - (i) performance evaluation (para. 3);
 - (ii) performance targets (paras. 4-5);
 - (iii) recommendations to improve performance (paras. 6-8);
 - (b) a final report within 30 days of receipt of comments from the Bank and MOE on the preliminary reports; and
 - (c) terms of reference, specifications and bidding documents for selected works to be performed.

Electric Power Company Assistance

9. The power generating companies would assist the consultant in the performance of this assignment by providing the following:
- (a) in-country transportation and access to all thermal power stations;
 - (b) a description of each thermal unit to be evaluated, including turbine inlet steam conditions, exhaust pressure and water cooling temperatures and boiler characteristics;
 - (c) design and guarantee criteria, including efficiency and output, for boilers and turbines and heat balance for each plant;
 - (d) unit performance test results (carried out during commissioning);
 - (e) operating logs and records as required to evaluate performance, including fuel gas analysis, feed water treatment and fuel cost analyses; and
 - (f) qualified engineers to accompany and assist the consultant during plant visits.

Duration of Services

10. The MOE would appoint one of its subsidiaries to be the responsible counterpart for the study. The said company would be expected to work in close coordination with the involved power generating companies. The consultants are required to include in their proposals, project schedules defining the completion of the study on this basis. It is expected that the assignment would start in July 1993, with a target completion date of June 1995.

ISLAMIC REPUBLIC OF IRAN
POWER SECTOR EFFICIENCY IMPROVEMENT PROJECT
STAFF APPRAISAL REPORT

DRAFT TERMS OF REFERENCE
THERMAL POWER PLANT IMPROVEMENT PROJECT STUDY

Introduction

1. The purpose of this study is to assist the Ministry of Energy (MOE), in evaluating the performance of its existing thermal plants and to make recommendations concerning improvements to thermal efficiency and unit availability. The objective is to achieve the lowest cost operation of the power generation system consistent with adequate service.
2. To this end, the consultant should establish target heat rates (kcal/kWh) for each unit and plant. Target heat rates should be developed using design conditions modified to accommodate actual field conditions. In a like manner, the consultant should establish target unit availability. The consultant should comment on the system economic operation should the focus of this be targets, or should identify elements of inefficiency where component upgrading would be useful considering fuel, operation (particularly plant turn-down ratio) and maintenance costs. The consultant should make recommendations to bring the actual system performance in accordance with established targets.

Scope of work

3. Evaluation of Performance. The consultant would review any existing reports analyzing plant operation, visit each power station as listed in Attachment 1 and evaluate actual operation procedures and the condition of each unit in the station. A written report of the evaluations would be submitted including, but not limited to, the following considerations:

- (a) combustion efficiency and flame characteristics;
- (b) flue gas analysis and/or exhaust conditions;
- (c) condenser and heat transfer conditions;
- (d) the utilization of station auxiliaries;
- (e) operating procedures, including the fuel/air ratio, the cleaning of burner tips, spinning reserve, unit loading, cooling the water supply from an overall system operation context, make-up of water supply;
- (f) operational and preventative maintenance of plants;

- (g) unit and station thermal efficiency, availability and capability, electrical plant auxiliary consumption and losses, proper daily report systems, annual test schedules;
- (h) analysis of individual unit forced-outage rates as experienced since commercial operation, with a view of identifying chronic problem areas and potential remedies;
- (i) operator training and availability of operation manuals;
- (j) maintenance programs and availability of maintenance manuals;
- (k) the adequacy and suitability of spare parts;
- (l) fuel characteristics and cost; and
- (m) the economic dispatch of thermoelectric units.

4. Establishment of Performance Targets. The consultant would establish targets to be used by the Power Generating Companies plant staff and management to evaluate efficiency and performance of the power generation plants. The target would be developed for each generating unit and for each power station as listed in (Attachment 1). The targets should consist of the following:

- (a) thermal efficiency targets expressed in kcal/kwh; and
- (b) availability targets expressed in hours/month.

5. The thermal efficiency target developed by the consultant would be based upon design and guarantee criteria but modified to reflect actual field conditions. The consultant would consider the following:

- (a) condition and age of the unit;
- (b) ambient conditions; and
- (c) instrumentation and controls.

6. Recommendations to Improve Performance. The consultant would evaluate unit and plant performance and make appropriate recommendations to improve performance and operation so that the project objective--least-cost system operation--may be achieved. Recommendations would be made by considering the following:

- (a) items listed as (a) through (m) in paragraph 3 above; and
- (b) modifications to plant and units such as the replacement of existing burners, additional instrumentation and heat exchanges. Any recommendations concerning plant modifications should include a cost estimate and the expected benefits of related works.

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THERMOELECTRIC POWER PLANTS TO BE VISITED

	<u>Power Plant</u>	<u>Installed Capacity</u> (MW)	<u>Location</u>
1.	Besat (Steam)	3 x 82.5 MW	Tehran
2.	Montazer-Ghaem (Steam)	4 x 156.25 MW	Tehran
3.	Ray (Gas-Turbine)	1241.6 MW	Tehran
4.	Bandar-Abbas (Steam)	2 x 315 MW	Hormozgan
5.	Esfahan (Steam)	2 x 31.5 + 120 + 2 x 37.5 MW	Esfahan
6.	Tabriz (Steam)	2 x 387 MW	Azarbaijan
7.	Lushan (Steam)	2 x 120 MW	Tehran
8.	Mod-Haj (Steam)	2 x 145 MW	Khuzestan
9.	Ramin 192 (Steam)	2 x 135 MW	Khuzestan

ISLAMIC REPUBLIC OF IRAN
POWER SECTOR EFFICIENCY IMPROVEMENT PROJECT
STAFF APPRAISAL REPORT

DRAFT TERMS OF REFERENCE
POWER PLANT OPERATOR TRAINING

General

1. The power subsector is government-owned and is controlled by the Ministry of Energy (MOE).
2. The Power Generating Companies (PGC)^{1/} operates most of the thermal power stations in Iran. As of October 1991, the installed capacity of existing power plants within the national interconnected system was 12,650 MW, of which 7,523 MW are from steam power plants, 3,212 MW are from gas turbine plants and 1,915 MW are from hydro plants. Most of the hydro plants are operated by the Kuhzestan Water and Power Authority (KWPA).
3. MOE is planning to commission about 3,110 MW of new plants within 1993, and plans to install an additional 11,730 MW by the end of 1998. In addition, the Tehran Regional Electric Company (TREC) proposes to install its first combined cycle unit by 1995.
4. To avoid major breakdowns and increase plant efficiency and availability, extensive maintenance in existing thermal plants needs to be carried out. Further, the build-up of capacity of open cycle gas turbines, to be converted later to combined cycle operation based on system needs, will exacerbate PGC's maintenance and operation capabilities. The availability of gas turbines has been a problem in the past. Hence, the Government is keenly interested in bringing gas turbine reliability up to industry practice standards. In addition, due to the low cost of natural gas in Iran, combined cycle plants are only attractive if they can be base loaded with plant factors exceeding 70 percent. Therefore, it is necessary to formulate and adopt an adequate preventive maintenance program to assure the long-term, reliable and efficient operation of PGC combined cycle and gas turbine generation. Training requirements would also have to be assessed.

Objectives

5. The principal objectives of the study are to:
 - (a) determine MOE's needs regarding steam and gas turbine maintenance facilities and operational staff over the next 10 years;

^{1/} Until recently, the Iran Power Generation and Transmission Company (TAVANIR) was responsible for all the thermal generation in Iran.

- (b) identify equipment and tool requirements and define a manpower development program to enhance MOE capabilities in carrying out such a program; and
- (c) provide training in Iran and abroad for engineers and technicians. The purchase of a simulator to train operators for combined cycle plants would need to be assessed.

Scope of work

6. The scope of the work is:

- (a) review MOE's existing capabilities and assess what is needed to operate and maintain present and future gas turbine, combined cycle and thermal power stations;
- (b) propose a suitable organization to handle maintenance activities, centralized or otherwise, including crews, tools and workshop equipment and facilities, keeping in mind government options for privatization in the power sector, taking note of TAMIRAT-NIRO, the existing maintenance company of TAVANIR; and
- (c) propose and implement a training program for Iranian (technicians/engineers) in Iran and abroad, including the number and qualifications of trainees needed, as determined in consultant reports.

General Requirements

7. The consultants would be expected to work closely with MOE and the companies affiliated with MOE. An inception report would be issued no later than 45 days after the start of the assignment.

8. Monthly progress reports would be submitted by the consultants to MOE by the middle of each month summarizing project progress during the previous month and outlining the work performed, personnel movement, problems encountered and actions taken, forecasts and actual accomplishments, special requests or recommendations and budget status, appropriately illustrated by graphs and photographs. These reports would constitute an important means of monitoring the project, and, therefore, at the start of the project, consultants be required to obtain IBRD approval of the format they intended to use.

9. The consultant reports and all correspondence and other communications would be in English language (MOE would arrange for any translation if required).

10. The consultants would work closely with counterpart staff assigned by MOE and would be expected to work in close cooperation with them under the supervision of a MOE senior official specifically appointed.

11. MOE would provide the following direct local support for project activities:

- (a) counterpart professionals for all field personnel; and
- (b) transportation services for field missions within Iran.

12. MOE would be responsible for making arrangements for administrative, secretarial and other local support staff. The consultants would be responsible for living accommodations, educational facilities and medical services for all personnel assigned to Iran.

Work Program

13. The consultants would provide technical manuals, reference books, calibration and test equipment and instruments to be purchased through the MOE account. All such manuals, equipment and instruments would become the property of MOE upon completion of the contract.

14. It is expected that the assignment would take 18 months, starting in December 1993 with a target completion date of June 1995.

ISLAMIC REPUBLIC OF IRAN
POWER SECTOR EFFICIENCY IMPROVEMENT PROJECT
STAFF APPRAISAL REPORT

SUMMARY OF PROJECT COST

	(RI Billion)			(US\$ Million)			%
	Local	Foreign	Total	Local	Foreign	Total	
I. GOM Component							
Civil Works	17.69	4.35	22.04	12.20	3.00	15.20	20
HRSG & Auxiliaries	13.98	64.38	78.36	9.64	44.40	54.04	82
Steam Turbine & Air Condensor	20.23	102.23	122.45	13.95	70.50	84.45	83
Electrical System	7.11	27.55	34.66	4.90	19.00	23.90	79
Instrumentation & Controls	1.71	14.21	15.92	1.18	9.80	10.98	89
BOP Equipment	10.37	12.33	22.69	7.15	8.50	15.65	54
Transmission line & Substation	20.59	95.70	116.29	14.20	66.00	80.20	82
Distribution Equipment	4.43	19.00	23.43	3.06	13.11	16.16	81
Eng. Proj. Mgmt. & Own. Admin.	11.90	11.75	23.65	8.21	8.10	16.31	50
Project Preparatory Studies	5.66	1.45	7.11	3.90	1.00	4.90	20
Base Cost	113.66	352.94	466.60	78.39	243.41	321.79	76
Physical Contingencies	10.80	35.15	45.95	7.45	24.24	31.69	
Price Contingencies	9.07	27.11	36.18	6.26	18.69	24.95	
Subtotal I	133.53	415.19	548.72	92.09	286.34	378.43	76
II. TA Component							
Energy Sector Development Study	0.22	1.96	2.18	0.15	1.35	1.50	90
Sect. Corptzn. & Pvtzn. Study	0.29	2.25	2.54	0.20	1.55	1.75	89
Thermal Plants Rehabilitation Study	0.15	0.65	0.80	0.10	0.45	0.55	82
Operator Training for GT/CCP	0.22	0.87	1.09	0.15	0.60	0.75	80
Base Cost	0.87	5.73	6.60	0.60	3.95	4.55	87
Price Contingencies	0.06	0.40	0.47	0.04	0.28	0.32	
Subtotal II	0.93	6.13	7.06	0.64	4.23	4.87	87
TOTAL PROJECT COST (I+II)	134.46	421.32	555.79	92.73	290.57	383.30	76
Interest During Construction	0.00	27.51	27.51	0.00	30.57	30.57	
TOTAL FINANCING REQUIRED	134.46	448.84	583.30	92.73	321.14	413.87	78

ISLAMIC REPUBLIC OF IRAN
POWER SECTOR EFFICIENCY IMPROVEMENT PROJECT
STAFF APPRAISAL REPORT
DETAILED PROJECT COST TABLE

	1993			1994			1995			1996			1997			(In US\$ Million)		
	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total
I. GOM Component																		
(i) Civil Works																		
Civil Works	0.60	0.13	0.73	3.57	0.90	4.47	5.95	1.50	7.45	1.79	0.43	2.24	0.00	0.00	0.00	11.90	3.00	14.90
Duties & Taxes	0.02	0.00	0.02	0.09	0.00	0.09	0.15	0.00	0.15	0.05	0.00	0.05	0.00	0.00	0.00	0.30	0.00	0.30
Subtotal	0.61	0.13	0.76	3.66	0.90	4.56	6.10	1.50	7.60	1.83	0.43	2.28	0.00	0.00	0.00	12.20	3.00	15.20
Physical Contingencies	0.06	0.02	0.08	0.37	0.09	0.46	0.61	0.15	0.76	0.18	0.05	0.23	0.00	0.00	0.00	1.22	0.30	1.52
Price Contingencies	0.03	0.01	0.03	0.22	0.05	0.28	0.55	0.14	0.69	0.22	0.06	0.28	0.00	0.00	0.00	1.03	0.25	1.28
Total (i)	0.70	0.17	0.87	4.25	1.04	5.29	7.26	1.79	9.05	2.24	0.53	2.79	0.00	0.00	0.00	16.45	3.55	18.00
(ii) MRO & Auxil.																		
Supply & Erection	0.00	0.00	0.00	1.43	12.22	13.65	2.38	20.33	22.71	1.13	9.64	10.77	0.26	2.22	2.48	5.20	44.40	49.60
Duties & Taxes	0.00	0.00	0.00	1.22	0.00	1.22	2.03	0.00	2.03	0.96	0.00	0.96	0.22	0.00	0.22	4.44	0.00	4.44
Sub Total	0.00	0.00	0.00	2.65	12.22	14.87	4.41	20.33	24.74	2.09	9.64	11.73	0.48	2.22	2.70	9.64	44.40	54.04
Physical Contingencies	0.00	0.00	0.00	0.27	1.22	1.49	0.44	2.03	2.47	0.21	0.96	1.17	0.05	0.22	0.27	0.96	4.44	5.40
Price Contingencies	0.00	0.00	0.00	0.16	0.74	0.90	0.40	1.84	2.24	0.26	1.18	1.44	0.08	0.05	0.13	0.90	3.82	4.71
Total (ii)	0.00	0.00	0.00	3.08	14.18	17.26	5.25	24.20	29.46	2.56	11.78	14.34	0.61	2.49	3.10	11.50	52.66	64.16
(iii) Steam Turbine & Air Condensor																		
Supply & Erection	0.00	0.00	0.00	1.90	19.40	21.30	3.16	32.27	35.43	1.50	15.30	16.80	0.33	3.53	3.87	6.90	70.50	77.40
Duties & Taxes	0.00	0.00	0.00	1.94	0.00	1.94	3.23	0.00	3.23	1.53	0.00	1.53	0.33	0.00	0.33	7.05	0.00	7.05
Sub Total	0.00	0.00	0.00	3.84	19.40	23.24	6.39	32.27	38.66	3.03	15.30	18.33	0.70	3.53	4.22	13.95	70.50	84.45
Physical Contingencies	0.00	0.00	0.00	0.38	1.94	2.32	0.64	3.23	3.87	0.30	1.53	1.83	0.07	0.35	0.42	1.40	7.05	8.45
Price Contingencies	0.00	0.00	0.00	0.23	1.18	1.41	0.58	2.93	3.51	0.37	1.88	2.25	0.11	0.08	0.19	1.30	6.06	7.36
Total (iii)	0.00	0.00	0.00	4.46	22.52	26.97	7.60	38.43	46.03	3.70	18.71	22.41	0.88	3.95	4.83	16.64	83.61	100.25
(iv) Electrical Systems																		
Supply & Erection	0.00	0.00	0.00	0.83	5.23	6.05	1.37	8.70	10.07	0.65	4.12	4.78	0.15	0.95	1.10	3.00	19.00	22.00
Duties & Taxes	0.00	0.00	0.00	0.52	0.00	0.52	0.87	0.00	0.87	0.41	0.00	0.41	0.10	0.00	0.10	1.90	0.00	1.90
Sub Total	0.00	0.00	0.00	1.35	5.23	6.58	2.24	8.70	10.94	1.06	4.12	5.19	0.25	0.95	1.20	4.90	19.00	23.90
Physical Contingencies	0.00	0.00	0.00	0.13	0.52	0.66	0.22	0.87	1.09	0.11	0.41	0.52	0.02	0.10	0.12	0.49	1.90	2.39
Price Contingencies	0.00	0.00	0.00	0.08	0.32	0.40	0.20	0.79	0.99	0.13	0.51	0.64	0.04	0.02	0.06	0.46	1.63	2.09
Total (iv)	0.00	0.00	0.00	1.57	6.07	7.63	2.67	10.36	13.03	1.30	5.04	6.34	0.31	1.07	1.37	5.85	22.53	28.38
(v) Instrumentation & Controls																		
Supply & Erection	0.00	0.00	0.00	0.06	2.70	2.75	0.09	4.49	4.58	0.04	2.13	2.17	0.01	0.49	0.50	0.20	9.80	10.00
Duties & Taxes	0.00	0.00	0.00	0.27	0.00	0.27	0.45	0.00	0.45	0.21	0.00	0.21	0.05	0.00	0.05	0.98	0.00	0.98
Sub Total	0.00	0.00	0.00	0.32	2.70	3.02	0.54	4.49	5.03	0.26	2.13	2.38	0.06	0.49	0.55	1.18	9.80	10.98
Physical Contingencies	0.00	0.00	0.00	0.03	0.27	0.30	0.05	0.45	0.50	0.03	0.21	0.24	0.01	0.05	0.05	0.12	0.98	1.10
Price Contingencies	0.00	0.00	0.00	0.02	0.16	0.18	0.05	0.41	0.46	0.03	0.26	0.29	0.01	0.01	0.02	0.11	0.84	0.95
Total (v)	0.00	0.00	0.00	0.38	3.13	3.51	0.64	5.34	5.99	0.31	2.60	2.91	0.07	0.55	0.62	1.41	11.62	13.03

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I. GOM (cont'd)	1993			1994			1995			1996			1997			(In US\$ Million) 1993-97		
	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total
(vi) BOP Equipment																		
Supply & Erection	0.00	0.00	0.00	1.73	2.34	4.07	2.88	3.89	6.78	1.37	1.84	3.21	0.32	0.43	0.74	6.30	8.50	14.80
Duties & Taxes	0.00	0.00	0.00	0.23	0.00	0.23	0.39	0.00	0.39	0.18	0.00	0.18	0.04	0.00	0.04	0.85	0.00	0.85
Sub Total	0.00	0.00	0.00	1.97	2.34	4.31	3.27	3.89	7.16	1.55	1.84	3.40	0.36	0.43	0.78	7.15	8.50	15.65
Physical Contingencies	0.00	0.00	0.00	0.20	0.23	0.43	0.33	0.39	0.72	0.16	0.18	0.34	0.04	0.04	0.08	0.72	0.85	1.57
Price Contingencies	0.00	0.00	0.00	0.12	0.14	0.26	0.30	0.35	0.65	0.19	0.23	0.42	0.06	0.01	0.07	0.67	0.73	1.40
Total (vi)	0.00	0.00	0.00	2.28	2.71	5.00	3.90	4.63	8.53	1.90	2.26	4.15	0.45	0.48	0.93	8.53	10.08	18.61
(vii) Transmission line & Substation																		
Supply & Erection	2.28	19.80	22.08	3.42	29.70	33.12	1.90	16.50	18.40	0.00	0.00	0.00	0.00	0.00	0.00	7.60	66.00	73.60
Duties & Taxes	1.98	0.00	1.98	2.97	0.00	2.97	1.65	0.00	1.65	0.00	0.00	0.00	0.00	0.00	0.00	6.60	0.00	6.60
Sub Total	4.26	19.80	24.06	6.39	29.70	36.09	3.55	16.50	20.05	0.00	0.00	0.00	0.00	0.00	0.00	14.20	66.00	80.20
Physical Contingencies	0.43	1.98	2.41	0.64	2.97	3.61	0.36	1.65	2.01	0.00	0.00	0.00	0.00	0.00	0.00	1.42	6.60	8.02
Price Contingencies	0.19	0.88	1.07	0.39	1.81	2.20	0.32	1.50	1.82	0.00	0.00	0.00	0.00	0.00	0.00	0.90	4.19	5.09
Total (vii)	4.88	22.66	27.54	7.42	34.48	41.90	4.23	19.65	23.87	0.00	0.00	0.00	0.00	0.00	0.00	16.52	76.79	93.31
(viii) Distribution Equipment																		
Supply and Installation	0.00	0.00	0.00	0.52	3.93	4.46	0.87	6.55	7.43	0.26	1.97	2.23	0.09	0.66	0.74	1.75	13.11	14.85
Duties & Taxes	0.00	0.00	0.00	0.39	0.00	0.39	0.66	0.00	0.66	0.20	0.00	0.20	0.07	0.00	0.07	1.31	0.00	1.31
Sub Total	0.00	0.00	0.00	0.92	3.93	4.85	1.53	6.55	8.08	0.46	1.97	2.42	0.15	0.66	0.81	3.06	13.11	16.16
Physical Contingencies	0.00	0.00	0.00	0.09	0.39	0.48	0.15	0.66	0.81	0.05	0.20	0.24	0.02	0.07	0.08	0.31	1.31	1.62
Price Contingencies	0.00	0.00	0.00	0.04	0.18	0.22	0.07	0.29	0.36	0.02	0.09	0.11	0.01	0.03	0.04	0.14	0.58	0.72
Total (viii)	0.00	0.00	0.00	1.05	4.50	5.55	1.75	7.50	9.25	0.52	2.25	2.77	0.17	0.75	0.92	3.50	15.00	18.50
(ix) Engg. Proj. Mgt. & Own. Adm.																		
Mgmt. & Admin.	1.11	1.21	2.33	1.85	2.03	3.88	1.85	2.03	3.88	1.48	1.62	3.10	1.11	1.21	2.33	7.40	8.10	15.50
Duties & Taxes	0.12	0.00	0.12	0.20	0.00	0.20	0.20	0.00	0.20	0.16	0.00	0.16	0.12	0.00	0.12	0.81	0.00	0.81
Sub Total	1.23	1.21	2.45	2.05	2.03	4.08	2.05	2.03	4.08	1.64	1.62	3.26	1.23	1.21	2.45	8.21	8.10	16.31
Physical Contingencies	0.12	0.12	0.24	0.21	0.20	0.41	0.21	0.20	0.41	0.16	0.16	0.33	0.12	0.12	0.24	0.82	0.81	1.63
Price Contingencies	0.05	0.05	0.11	0.12	0.12	0.25	0.19	0.18	0.37	0.20	0.20	0.40	0.20	0.03	0.23	0.77	0.59	1.35
Total (ix)	1.41	1.39	2.80	2.38	2.35	4.73	2.44	2.41	4.86	2.01	1.98	3.99	1.56	1.36	2.92	9.80	9.50	19.29
(x) Project Prep. & Related studies																		
Consultancy Services	3.12	0.80	3.92	0.78	0.20	0.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.90	1.00	4.90
TOTAL I	10.10	25.02	35.13	27.64	91.19	118.83	35.75	114.31	150.06	14.54	45.17	59.71	4.05	10.65	14.70	92.09	286.34	378.43

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II. TA Component	1993			1994			1995			1996			1997			(In US\$ Million)		
	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total
(i) Energy Sector Development Study																		
Consultancy Services	0.02	0.14	0.15	0.06	0.54	0.60	0.06	0.54	0.60	0.02	0.14	0.15	0.00	0.00	0.00	0.15	1.35	1.50
Price Contingencies	0.00	0.01	0.01	0.00	0.03	0.03	0.00	0.04	0.05	0.00	0.02	0.02	0.00	0.00	0.00	0.01	0.09	0.11
Total (i)	0.02	0.14	0.16	0.06	0.57	0.63	0.06	0.58	0.65	0.02	0.15	0.17	0.00	0.00	0.00	0.16	1.44	1.61
(ii) Sector Corporatization-Privatization Study																		
Consultancy Services	0.02	0.16	0.18	0.08	0.62	0.70	0.08	0.62	0.70	0.02	0.16	0.18	0.00	0.00	0.00	0.20	1.55	1.75
Price Contingencies	0.00	0.01	0.01	0.00	0.03	0.04	0.01	0.05	0.06	0.00	0.02	0.02	0.00	0.00	0.00	0.01	0.11	0.12
Total (ii)	0.02	0.16	0.18	0.08	0.65	0.74	0.09	0.67	0.76	0.02	0.17	0.19	0.00	0.00	0.00	0.21	1.66	1.87
(iii) Thermal Plants Rehabilitation Study																		
Consultancy Services	0.02	0.07	0.08	0.03	0.11	0.14	0.04	0.18	0.22	0.02	0.09	0.11	0.00	0.00	0.00	0.10	0.45	0.55
Price Contingencies	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.01	0.02	0.00	0.01	0.01	0.00	0.00	0.00	0.01	0.03	0.04
Total (iii)	0.02	0.07	0.09	0.03	0.12	0.15	0.04	0.19	0.24	0.02	0.10	0.12	0.00	0.00	0.00	0.11	0.48	0.59
(iv) Operator Training for GT-CCP																		
Consultancy Services	0.02	0.06	0.08	0.08	0.20	0.34	0.04	0.15	0.19	0.02	0.09	0.11	0.00	0.00	0.00	0.15	0.60	0.75
Price Contingencies	0.00	0.00	0.00	0.00	0.02	0.02	0.00	0.01	0.02	0.00	0.01	0.01	0.00	0.00	0.00	0.01	0.04	0.05
Total (iv)	0.02	0.06	0.08	0.08	0.32	0.40	0.04	0.16	0.20	0.03	0.10	0.13	0.00	0.00	0.00	0.16	0.64	0.80
TOTAL II	0.07	0.43	0.50	0.25	1.66	1.91	0.24	1.61	1.85	0.09	0.52	0.61	0.00	0.00	0.00	0.64	4.23	4.87
TOTAL PROJECT COST	10.17	25.46	35.63	27.89	92.85	120.74	35.99	115.92	151.91	14.63	45.69	60.32	4.05	10.65	14.70	92.73	290.57	383.30
VI. Interest During Construction																		
IDC	0.00	0.97	0.97	0.00	5.65	5.65	0.00	14.10	14.10	0.00	9.85	9.85	0.00	0.00	0.00	0.00	30.57	30.57
TOTAL FINANCING REQUIRED	10.17	26.43	36.60	27.89	98.50	126.39	35.99	130.02	166.01	14.63	55.54	70.17	4.05	10.65	14.70	92.73	321.14	413.87

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DETAILED FINANCING PLAN

Project Element	IBRD	Supplier Credit	MOE	TREC	TOTAL
I. QOM Component					
Local				92.09	92.09
Foreign	160.77	47.78		77.79	286.34
IDC				30.57	30.57
	-----	-----	-----	-----	-----
Sub Total	160.77	47.78	0.00	200.45	409.00
II. TA Component					
Local			0.64		0.64
Foreign	4.23				4.23
	-----	-----	-----	-----	-----
Sub Total	4.23	0.00	0.64	0.00	4.87
TOTAL					
Local	0.00	0.00	0.64	92.09	92.73
Foreign	165.00	47.78	0.00	77.79	290.57
IDC	0.00	0.00	0.00	30.57	30.57
	-----	-----	-----	-----	-----
TOTAL FINANCING	165.00	47.78	0.64	200.45	413.85
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DETAILED PROCUREMENT TABLE

	(US\$ million)			
	Procurement Method			

	I C B	L C B	Other a/ NBF b/	Total Cost
Civil Works		14.45		14.45
HRSG & Auxiliaries	64.16 (7.90)			64.16 (7.90)
Steam Turbine & Air Condensor	103.81 (84.14)			103.81 (84.14)
Electrical System	28.38 (22.53)			28.38 (22.53)
Instrumentation & Controls	13.03 (11.62)			13.03 (11.62)
BOP Equipment	14.49 (10.08)		4.12	18.61 (10.08)
Transmission line & Substation			93.31	93.31
Distribution Equipment	14.00 (14.00)		1.00 (1.00)	18.50 (15.00)
Project Management & Owner's Administration c/			9.50 (9.50)	19.29 (9.50)
Project preparatory studies			4.90	4.90
Studies			4.07 (3.59)	4.07 (3.59)
Training			0.80 (0.64)	0.80 (0.64)
	-----	-----	-----	-----
TOTAL	237.86 (150.28)	14.45	15.38 (14.73)	383.30 (165.00)
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Note:

Figures in parentheses to be financed by the Bank.

a/ Shopping and Consulting Services

b/ NBF = Non-Bank Financed

c/ Includes US\$2.0 million retroactive financing (para 4.11)

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EXCERPTS FROM ENVIRONMENTAL ASSESSMENT

Policy, Legal and Administrative Framework

1. Regulatory Policy and Requirements. Under the current regulatory structure, a private enterprise or a government agency interested in developing an industrial facility such as a power plant has to acquire an approval from the Iranian Environmental Protection Organization (IEPO) for the construction and operation of the facility. This approval is based on a preliminary project description submitted by the developer. IEPO reviews this information and issues an approval letter if the project development would not result in any major, adverse environmental impact. If IEPO review indicates any potential adverse environmental and/or social impact as a result of the proposed development, IEPO requires an acceptable environmental impact statement (EIS) prior to the start of construction.

2. IEPO has the authority to inspect the project operation anytime for compliance and can shut down a plant if specific regulations relative to air emission, water/sewage discharge and noise pollution are violated. In practice, IEPO cooperates with the operator to ensure compliance with the regulation. IEPO also acts as the forum for complaints regarding the operation of the plant from any affected party, nongovernmental organizations (NGOs) or the public. IEPO permits power plant siting based on regional development needs and criteria as well as potential impacts to existing and planned residential, commercial and industrial developments.

Baseline Data

3. Project Setting. The city of Qom is predominantly a religious community with a few light industrial plants located outside the city. The Qom Combined Cycle Conversion Project (QCCP) would be located approximately 15 km west of the city of Qom in the Tehran province. The project is located on the Tehran-Arak road approximately 150 km south of Tehran. TREC has contracted with Mitsubishi Heavy Industries (MHI) of Japan for the supply, installation and commissioning of 4 dual fired simple cycle gas turbine units each with a capacity of 100 MW. Civil works are in progress at the site, and the commissioning of the units is scheduled between May 1993 and July 1993.

4. Generation from the gas turbines would be fed into the interconnected electric transmission system via a new 230-kV line now under construction. The plant would be connected at the plant substation to the 400-kV transmission system being constructed by the Ministry of Energy (MOE) as part of the strengthening of the national north-south link. A dedicated gas pipeline is under construction by Iranian National Gas Company (INGC) for the gas turbine plant and should be completed by July 1993. Until that time, the gas turbines would use gas oil as fuel.

5. Land Use. The area surrounding the plant is undeveloped, dry, waste land. The nearest development is a grain silo and flour mill located 1.5 km from the site, on the road to Qom. The area along the road is not designated for industrial development. According to IEPO, no residential development would be permitted close to the plant.

6. TREC has acquired sufficient lands to locate the QCCP and the associated structures adjacent to the gas turbine plant. The entire plant area has been cleared and regraded. Subsurface investigations indicate the principal characteristic of the soil is its collapsible structure when allowed free access to water. The collapse of this loose soil may also be induced by seismic activity. TREC and its engineering consultants has conducted additional geotechnical investigations to ensure adequate design of the project structures.

7. Air Quality. It is expected that existing ambient NO_2 concentrations at ground level would be around $8 \mu\text{g}/\text{m}^3$ as suggested in the Bank guidelines. TREC has conducted air quality modelling of the gas turbine plant exhaust and has estimated that the incremental annual average ambient NO_2 concentrations at ground level using gas oil would be $40.4 \mu\text{g}/\text{m}^3$. The expected SO_2 emissions from such operations have not been estimated by TREC. Assuming a background SO_2 level of $3 \mu\text{g}/\text{m}^3$ (Bank guidelines), and a 60 percent plant factor for the 400 MW gas turbine units, an average uncontrolled SO_2 emission rate of less than 20 tons/day (TPD) is estimated for the low sulphur gas oil operation. This level of emission should not have a significant impact on the air quality in the area and is expected to result in ambient ground level concentrations within IEPO limits.

8. With natural gas firing, the incremental annual average ambient NO_2 concentrations at ground level due to the gas turbine plant would be reduced to $30.4 \mu\text{g}/\text{m}^3$ over background levels. SO_2 emissions would almost be completely eliminated. TREC is taking steps to accelerate the commissioning of the gas pipeline to cut the high operating costs associated with gas oil as well as to lower emissions from the stack.

9. Water Resources. The Qom region is dry and barren with an annual precipitation of less than 150 mm. The Qom river, located approximately 1.5 km south of the plant perimeter wall, is not conducive to the development of local surface water resources and, therefore, obtains water from groundwater resources, the extraction of which is controlled by the Qom Water Authority. The city of Qom with a population of 300,000 meets its estimated water demand of 825 l/s ($2979 \text{ m}^3/\text{hr}$) from groundwater resources. To augment the supply, the Pandzdah Khordad dam and reservoir is being constructed on the Qom river 50 km south of the site near the town of Delijan.

10. TREC has developed two wells to supply raw water to the gas turbine plant. The wells are located 0.7 km and 1.2 km south of the existing plant perimeter wall. The wells are approximately 140m deep with a static water level about 42m below ground surface. Bed rock is estimated to be at a depth of between 150m and 170m. The gas turbine plant would require approximately 15 l/s ($1,300 \text{ m}^3/\text{day}$), of which over 60 percent is for irrigation.

11. Wastewater and Solid Waste Management. Wastewater from the gas turbine plant would consist of water treatment plant reject and domestic sewage. The treatment plant reject would be neutralized and charged into a solar evaporator pit. The sewage water would be treated in a packaged anaerobic biological plant with a capacity of 30 m³/day. The effluent from the sewage treatment plant would meet the standards required by IEPO and would be used for irrigation. TREC would dispose of the plant sludge in an IEPO approved landfill.

12. Toxic and Hazardous Substances Management. TREC has confirmed that all gas turbine plant transformers are solid cooled and would not contain any PCBs. The building codes now prohibit the use of asbestos as construction material. TREC would store approximately 10,000 tons of gas oil in 2 surface tanks to supply 2 weeks of fuel requirement. TREC would design a fire fighting system comprising ring mains, pressure gages and fire hoses. TREC would also monitor the leakage of oil from these storage tanks using a scheme of gravel drains alongside the tanks to detect any leakage. The drains would be monitored regularly for traces of oil. Typically, soil is used to sponge any oil leaks. TREC would develop procedures for day-to-day usage as well as any emergency spill cleanup of hazardous materials such as transformer coolants, lube oils, etc. TREC would use only approved fertilizers and pesticides for landscaping to minimize any contamination of groundwater resources. TREC proposes to implement manufacturer-recommended maintenance procedures to prevent exposure to toxic gases leaking from the boilers.

13. Noise Pollution. The gas turbine plant design would be such as to meet the IEPO regulations for ambient noise levels (70 dB for general activity in an industrial area). Noise level in the vicinity of drive equipment would meet appropriate IEPO standards, which would conform to the Bank's guidelines (not more than 90 dB). TREC would provide workers with ear protection to prevent exposure to excessive noise while working near drive mechanisms.

14. Natural Resources Protection. The project area has already been cleared of all vegetation as part of the gas turbine development. TREC would obtain a letter from IEPO confirming that no endangered plant or animal species migrate through the plant site and that the project would have no impact on such species. TREC has agreed to landscape the plant area and maintain a green ring of kefir trees around the plant. TREC would use indigenous species and dry landscaping to reduce water consumption. IEPO uses US EPA guidelines to minimize avian hazards from stacks and transmission line towers. MOE would follow IEPO guidelines when designing and constructing the project transmission lines.

15. Historical, Cultural and Aesthetic Resources. No historical or cultural artifacts were reported found during the land clearing and preparation activities for the gas turbine project. Excavation for the QCCP would be carried out in the area already disturbed and graded for the gas turbine plants.

16. Socioeconomic Setting. The gas turbine plant would be a significant employer in the area with around 300 operators and white-collar workers. IEPO expects that the plant would ensure a more reliable power

supply from the Panzdah Khordad reservoir, would have a significant, positive socioeconomic impact and would provide an incentive for light industrial activity along the Tehran-Arak road.

17. Public Safety. Heavy construction activities could potentially cause accidents at the site. TREC would institute a site construction safety plan in consultation with the contractor to ensure adequate protection to construction as well as operation workers. The general public would not be admitted to the construction site. TREC would design the project structures for appropriate earthquake loading based on local seismic data. The project stacks would be the tallest structures in the area (50 m). TREC would obtain appropriate clearances and would install lights to warn aircraft of the stacks. Similar warning systems would be installed on the highest transmission towers if required. TREC has agreed to develop procedures and specifications for remedial actions to address emergency situations arising from pipeline fires, storage tank fires and tanker oil spills.

Environmental Impact

18. Land Use. No significant impact to existing land use is expected during construction. The location of QCCP offers the least impact to land use in the area since all ground-disturbing activities were carried out as part of the gas turbine project. No additional land for project structures or right-of-way for project gas pipeline or transmission lines would be required.

19. Air Quality. Monenco Consulting Engineers (Canada) has designed the stack height for the QCCP using dispersion modeling based on US EPA models that incorporate Gaussian dispersion formulas. The results from modeling the gas turbines and the HRSG operation for the QCCP indicate that the annual arithmetic mean ambient NO_2 concentrations at ground level would not exceed $33 \mu\text{g}/\text{m}^3$ when firing gas and $46 \mu\text{g}/\text{m}^3$ when firing gas oil over background levels. The incremental concentrations over those predicted for the gas turbine operations alone would be 3 and $6 \mu\text{g}/\text{m}^3$, respectively (see Tables 4.11.1 and 4.11.2). These concentrations would be felt at a distance of about 1.5 km downwind from the plant. The maximum concentrations near the city of Qom under similar conditions would be approximately $15 \mu\text{g}/\text{m}^3$ and $25 \mu\text{g}/\text{m}^3$, respectively. These levels are within the IEPO limits and are considered acceptable.

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PROCUREMENT IMPLEMENTATION MONITORING SCHEDULE

Package	Issue of Bid Packages	Bid Opening	Submission of Evaluation Report	Signing of Contract	LC Opening	Expected Completion
HRSQ Island	Mar 93	Jun 93	Sep 93	Nov 93	Nov 93	Feb 96
ST/G Island	Mar 93	Jun 93	Sep 93	Nov 93	Nov 93	Mar 96
Civil Contract	Jan 94	Mar 94	Apr 94	Jul 94	N/a	Jul 95
Engineering & Project Management				Apr 93	Jun 93	Jul 96
Distribution Equipment:						
- Consulting Services				Jun 93	N/a	Jun 95
- Works	Nov 93	Feb 94	Mar 94	Apr 94	N/a	Jun 95

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LOAN DISBURSEMENT SCHEDULE

Bank Fiscal Year Quarter Ending	Quarterly Disbursement (US\$ million)	Cumulative Disbursement	Disbursement as a % of Total
FY 1994			
September 30, 1993	2.30	2.30	1.40%
December 31, 1993	2.30	4.60	2.79%
March 31, 1994	11.22	15.82	9.59%
June 30, 1994	11.22	27.03	16.38%
FY 1995			
September 30, 1994	11.22	38.25	23.18%
December 31, 1994	11.22	49.47	29.98%
March 31, 1995	18.21	67.68	41.02%
June 30, 1995	18.21	85.89	52.05%
FY 1996			
September 30, 1995	18.21	104.10	63.09%
December 31, 1995	18.21	122.32	74.13%
March 31, 1996	8.58	130.90	79.33%
June 30, 1996	8.58	139.48	84.53%
FY 1997			
September 30, 1996	8.58	148.06	89.73%
December 31, 1996	8.58	156.64	94.93%
March 31, 1997	2.09	158.73	96.20%
June 30, 1997	2.09	160.82	97.46%
FY 1998			
September 30, 1997	2.09	162.91	98.73%
December 31, 1997	2.09	165.00	100.00%

Table 4.11.1. Project Air Quality Parameters ($\mu\text{g}/\text{m}^3$)

Parameter	Current Value	IEPO Limits	Bank Guidelines
Ambient Values:			
Avg. Annual NO ₂ Concentrations	8 ¹	100	100
Max. 24-hr Avg. NO ₂ Concentration	8 ¹	250	none
Avg. Annual SO ₂ Concentrations	3 ¹	80	80
Max. 3-hr SO ₂ Concentrations	3 ¹	1,000 ²	1,000 ²
Stack Emissions Average SO ₂ (TPO)			<50
Annual NO ₂ Emissions ²	--	none	none
Annual SO ₂ Emissions ²	--	none	none
Annual CO ₂ Loading ²	--	none	none

1/ Assumed Bank Guidelines.

2/ In 1000 tons.

Table 4.11.2: Expected Air Quality Measurements ($\mu\text{g}/\text{m}^3$)

Parameter	Value with GTs only (gas firing)	Value with GTs only (gas oil firing)	Value with QCCP (gas firing)	Value with QCCP (gas oil firing)
Ambient Values:				
Avg. Annual NO ₂ Concentrations	38	48	41	54
Max. 24-hr Avg. Concentrations	-- ³	-- ³	179	--
Avg. Annual SO ₂ Concentrations	existing ³	50 ^{4,5}	existing ³	859 ⁴
Max. 3-hr SO ₂ Concentrations	existing ³	859 ^{4,6}	existing ³	859 ⁴
Stack Emissions				
Average SO ₂ (TPO)		20		
Annual NO ₂ Emissions	2.4	5.2 ⁴	2.4 ⁸	-- ⁴
Annual SO ₂ Emissions	trace	10.5 ⁴	10.5 ⁸	-- ⁴
Annual CO ₂ Loading	1,860	1,860 ⁴	1,860 ⁸	-- ⁴

1/ Assumed Bank Guidelines.

2/ In 1000 tons.

3/ Data not available.

4/ Not applicable to the project, which uses natural gas as a primary fuel and gas oil as a standby fuel.

5/ Estimates without modeling.

6/ Project value is for 1/2 hour average.

7/ Max. 24-hr inside project fence.

8/ QCCP does not use any more fuel than gas turbines alone, and, hence no additional emissions.

20. **Water Resources.** Water is in short supply in the region. The plant would use air cooled condensers to minimize water needs. Preliminary designs indicate that the maximum raw water requirement for the plant would be 2,200 m³/day including 1,300 m³/day for the gas turbine plant. Raw water from the wells is brackish with a total dissolved solids (TDS) content in the range of 5,000 ppm. Table 4.11.3 below shows the plant water balance.

21. TREC has completed studies that indicate that adequate water (maximum of 2,200 m³/day or 25 l/s) would be available from the two wells for the plant operation, including potable, fire fighting and landscaping needs. The aquifer supplying these wells is reported to be separate from that supplying the city. The Qom Water Authority has approved a long-term groundwater extraction of 3,020 m³/day (35 l/s) by TREC for the development. There is a reasonable indication that sufficient water would be available for the plant operation. The Monenco report, however, does not confirm the available sources. Instead, the report enumerates alternative supply sources available in the area, which may be tapped by TREC if necessary. TREC should

submit to the Bank a letter from the Qom Water Authority confirming that no long-term impact to the Qom water supply or the local area would result from QCCP abstraction. Alternatively, TREC should make a firm commitment to develop alternative resources to assure long-term plant water supply.

Table 4.11.3: Plant Water Balance (all figures in m³/day)

Supply System	Quantity	Treatment
Process - HRSG makeup	950	Pretreatment, desalting, demineralization
Potable water	50	Pretreatment, desalting, demineralization
Service water	380	Pretreatment, desalting, demineralization
Pretreatment reject	110	None
Desalting plant reject	630	Pretreatment
Demineralizer backwash requirement	40	Pretreatment, desalting
Demineralizer plant reject	40	Pretreatment, desalting

Total Raw Water	2,200	

<u>Drainage System</u>		
Total treatment plant reject	780	No treatment; evaporated in solar pond
Domestic sewage	50	Treated and used for irrigation
Oil waste	60	Treated and used for irrigation
Boiler Blow-down and clean service water	1,270	Recyclable
Backwash system	40	Recyclable

Total	2,200	

22. Wastewater and Solid Waste Management. Wastewater from the boiler area, rejects from pretreatment, desalting plant and demineralized plant would be collected in a settling pond and neutralized. Clean effluent would have greater TDS content than would be permissible by IEPO and would be disposed of in a solar evaporator pit. Dry sludge would settle in the pond at the rate of less than 1 m/yr. The deposit would be excavated and removed to an approved landfill once every few years. This practice is acceptable to IEPO and would not cause any impact. Wastewater from areas where oil contamination or leakage may occur would be collected through a separate pipe system, which would pass through an oil separator unit. Oil would be collected and recycled

or disposed of and regulated by IEPO. Clean water would be discharged to the plant agricultural (landscaping) pond.

23. All domestic sewage would be collected into the existing piped system and treated anaerobically in a biological treatment plant. TREC has agreed to incorporate provisions in the final design of the facility for monitoring, collecting and treating any leakages from the gas oil storage tanks to ensure no contamination of groundwater. This should provide adequate protection to the groundwater resources. Sludge from water and sewage treatment plants would be disposed of at regular intervals in an approved landfill designated by IEPO. TREC has agreed to dispose of residual sludge from gas oil firing as regulated by IEPO. IEPO generally follows US EPA guidelines, and, therefore, the practice would satisfy the Bank's guidelines.

Mitigative Measures

Resource	Mitigative Measure
Land Use	TREC to develop appropriate specifications to ensure optimal use of available land and minimize land clearing activities.
Air Quality	TREC to collect baseline data; monitor baseline pollutant concentrations for several months; provide air quality model analysis and modify stack design if necessary to meet IEPO NO ₂ concentration limits; and specify methods to minimize fugitive dust during construction.
Water Resources	TREC to provide letter from Qom Water Authority stating no impact of water withdrawal for QCCP on local users; reassess design to conserve water; alternatively, commit to alternative sources of water for long-term plant needs.
Wastewater and Solid Waste Management	TREC to develop equipment and design specifications to IEPO limits or raw water concentrations for pollutants.
Toxic and Hazardous Substances Management	TREC to develop equipment and design specifications as well as disposal procedures for QCCP, similar to existing practices.
Noise Abatement	TREC to develop equipment and design specifications to meet IEPO standards.
Natural Resources	TREC to develop design construction specifications to ensure minimal clearing of vegetation and the careful disposal of spoils.
Historical and Cultural Resources	TREC to include provisions in construction specifications for consultation with IEPO should significant artifacts be found during excavations.
Socioeconomic Impacts	TREC to ensure construction traffic does not affect local traffic.
Public Safety	TREC to ensure appropriate design of project structures to withstand seismic loading; develop procedures to include QCCP operation in its emergency fire fighting plans; and continue its staff training on safety at the work place.
Monitoring	TREC to develop environmental monitoring program in consultation with IEPO, NGOs and the general public.
Training	TREC to establish an environmental unit and train personnel to ensure the implementation of IEPO requirements.

Monitoring, Management and Training

24. Environmental Monitoring. TREC has proposed a regular, noncontinuous environmental monitoring program to measure ambient ground level NO₂ concentrations and plant water and sewage discharges, as well as noise levels in the plant area. In addition, TREC should monitor NO₂ concentrations at ground level at a station that, based on modeling studies, would suffer the greatest environmental impact from the plant. TREC should consult with IEPO to determine the location of the station.

25. TREC would sample and analyze plant water supply and sewage discharges on a weekly basis. The sampling locations should include representative raw water supply and sewage discharge, as well as water treatment plant discharge points. TREC should test the effluent for temperature, pH, total dissolved solids, nitrates, chlorides, phosphates, sulfates and other parameters that may be of concern to IEPO in the local area, to ensure that no pollutants are higher than those found in raw water or IEPO limits, whichever is greater.

26. Project Training Needs. TREC has proposed to include well-defined technical training for operators for installation, operation and maintenance as part of the equipment supply contract.

27. It is recommended that a short training program be instituted for the environmental monitoring unit to emphasize the need for monitoring, the value of the data to be collected and the interpretation and use of the data to address potential issues or complaints arising from plant operation. A public information and interaction mechanism should be developed as part of these training programs to ensure that the project avoids or minimizes any unforeseen negative impact, as well as enhances its usefulness to the community in which it operates.

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PROJECT IMPLEMENTATION SCHEDULE

COMPONENT	FY93				FY94				FY95				FY96				FY97			
	I	II	III	IV	I	II	III	IV	I	II	III	IV	I	II	III	IV	I	II	III	IV
I. QOM COMPONENT																				
Civil Works																				
Prepare & issue bid documents																				
Open, evaluate & award contract																				
Design and erect structures																				
Heat Recovery Steam Generator Island																				
Prepare & issue bid documents																				
Open, evaluate & award contract																				
Supply and erect																				
Commission																				
Steam Turbine Generator Island																				
Prepare & issue bid documents																				
Open, evaluate & award contract																				
Supply and erect																				
Commission																				
Transmission Line and Substation																				
Prepare & issue bid documents																				
Open, evaluate & award contract																				
Supply and erect																				
Commission																				
Distribution Equipment																				
Consulting Service (feasibility)																				
Prepare & issue bid documents																				
Open, evaluate & award contract																				
Supply and install																				
Commission																				

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PROJECT IMPLEMENTATION SCHEDULE

COMPONENT	FY93				FY94				FY95				FY96				FY97			
	I	II	III	IV	I	II	III	IV	I	II	III	IV	I	II	III	IV	I	II	III	IV
II. TECHNICAL ASSISTANCE																				
Energy Sector Development Study																				
Short list consultants																				
Prepare & issue proposals																				
Open, evaluate & award contract																				
Expected completion date																				
Commercialization-Privatization Study																				
Short list consultants																				
Prepare & issue proposals																				
Open, evaluate & award contract																				
Expected completion date																				
Thermal Plant Rehabilitation Study																				
Short list consultants																				
Prepare & issue proposals																				
Open, evaluate & award contract																				
Expected completion date																				
Operator Training for GT-CCP																				
Short list consultants																				
Prepare & issue proposals																				
Open, evaluate & award contract																				
Expected completion date																				

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POWER SECTOR EFFICIENCY IMPROVEMENT PROJECT
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PROJECT MONITORING GUIDELINES AND SUPERVISION PLAN

Project Monitoring Guidelines

1. The monitoring guidelines indicate the broad requirements and supplement the Borrower's obligation according to the Loan and Project Agreements. These requirements could be modified if needed. Records would be maintained giving planned and actual achievements, to be reviewed annually for the following:

- (a) installed and derated capacity in MW for each of the power stations according to types (thermal, gas, hydro);
- (b) energy capabilities in GWh/year by each power station;
- (c) maximum demand in MW and energy generated in GWh by each power station;
- (d) fuel consumed in mt/m³ by fuel type in each power station;
- (e) number of consumers and sales in GWh by consumer categories;
- (f) transmission and distribution (line) losses;
- (g) planned and forced outages (by classification) in power stations and in the transmission and distribution network;
- (h) monthly maximum demand in MW (gross) for the interconnected system;
- (i) quality of supply to the consumers (number of interruptions, durations classified according to cause and voltage conditions at the consumer end);
- (j) annual system load duration curve for the interconnected system;
- (k) plant and load factors and plant availability; and
- (l) MOE investment plan and annual budget by activity in local and foreign costs.

Project Implementation

2. Records would be maintained showing the original schedule against actual achievements to be supplied to the Bank at agreed regular intervals on the following aspects:

- (a) procurement action by bid packages (bid specifications, bid invitation, opening of bids, bid evaluation, award of contract, signing of contract and contract process as amended from time to time);
- (b) physical progress according to project components and contracts (highlighting critical activities and bottlenecks);
- (c) actual project costs and expenditures (local and foreign) and estimated remaining expenditure (local and foreign) projected quarterly through project completion;
- (d) disbursement schedule (for Bank loans as well as other loans);
- (e) information on problems encountered during implementation (including major mishaps) and expected impact on commissioning schedules; and
- (f) minutes of meetings and progress reports by consultants.

Project Supervision

3. The proposed Bank supervision missions and their composition would be as follows:

<u>Mission</u>	<u>Composition</u>	<u>Proposed Dates</u>
Project Launch Mission	Power Engineer Financial Analyst Procurement Engineer	February 1993
Project Supervision	Power Engineer Financial Analyst Procurement Engineer	Twice/year 1993-1994
Project Supervision	Power Engineer Financial Analyst	Twice/year 1995-1997

IRAN - Power Sector Efficiency Improvement Project
TREC - Income Statement FY87 to FY97
(Rials billions)

Item	Actual					Projected					
	FY87	FY88	FY89	FY90	FY91	FY92	FY93	FY94	FY95	FY96	FY97
Gross Generation - GWh	3	1	1	1	5	50	3,500	3,392	3,604	3,478	3,803
Purchased Energy - GWh	11,915	10,918	12,265	13,414	14,218	15,970	14,100	15,538	16,183	16,942	17,257
Energy Sales - GWh	10,209	9,678	11,070	11,808	12,661	14,564	16,000	17,368	18,153	18,734	19,321
Energy Sales Growth - %	6.9	5.2	14.4	6.7	7.2	15.0	9.9	8.55	4.52	3.20	3.14
Losses - GWh	1,710	1,241	1,197	1,607	1,139	1,311	1,440	1,563	1,634	1,686	1,739
Losses - %	14.3	11.4	9.8	12.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
No. of Customers (000's)											
- Beginning of year			2,034	2,212	2,345	2,523	2,613	2,703	2,793	2,883	2,973
- new subscribers			178	133	177	90	90	90	90	90	90
Average Tariff - Rls/kWh	4.29	4.26	5.85	6.29	10.66	11.80	17.70	35.48	71.13	142.58	158.92
Increase - %											
- nominal								100.5	100.5	100.5	11.3
- real								66.5	72.8	77.0	0.0
Average Purchase Price - Rl/kWh	2.02	2.07	2.16	2.03	2.23	2.80	2.80	26.70	44.00	120.00	154.00
Revenues											
- Sales of electricity	43.8	41.2	64.7	74.3	134.9	171.9	283.2	616.2	1,291.2	2,671.1	3,070.6
Other revenues	4.3	4.0	4.4	4.9	9.2	16.6	20.9	26.0	31.2	36.5	41.9
Total	48.1	45.2	69.2	79.2	144.2	188.5	304.1	642.2	1,322.4	2,707.5	3,112.5
Electricity purchases	24.1	22.6	26.5	27.2	31.9	44.7	39.5	414.9	712.1	2,033.1	2,657.6
Generating Costs	0.0	0.0	0.0	0.2	0.2	0.7	17.4	37.2	48.6	59.4	103.1
Gross Margin	24.0	22.6	42.6	51.7	112.2	143.0	247.3	190.2	561.7	615.1	351.8
Operating Expenses											
transmission	incl.	incl.	incl.	0.7	1.4	1.9	8.3	10.8	13.1	15.4	17.6
distribution	incl.	incl.	incl.	8.0	9.3	12.8	15.5	20.2	24.5	28.7	33.0
customer accounts	incl.	incl.	incl.	2.0	3.9	5.4	4.5	5.9	7.1	8.3	9.6
sales expense	incl.	incl.	incl.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
admin. and general	incl.	incl.	incl.	8.5	17.0	19.8	15.0	19.6	23.7	27.8	31.9
other	17.0	18.2	20.1	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	17.0	18.2	20.1	19.5	31.6	40.0	43.3	52.1	60.4	68.4	76.2
Gross Operating Profit	7.0	4.4	22.5	32.2	80.6	103.0	204.0	138.1	501.3	546.6	275.6
Interest											
Commercialization loan							0.0	0.0	245.9	200.4	170.5
World Bank Loan							0.0	0.8	17.0	26.2	28.6
Other Investment loans							0.0	1.8	20.2	51.1	87.2
less capitalized portion							0.0	(2.7)	(20.6)	(54.3)	(53.9)
net interest expense					0.0	0.0	0.0	5.7	259.7	214.7	232.4
Depreciation	0.0	0.0	0.0	4.6	20.6	9.9	85.3	112.0	142.3	172.4	249.6
Amortization						0.0	0.0	0.1	0.6	4.3	9.3
Income from Operations	7.0	4.4	22.5	27.6	60.0	93.2	118.6	20.3	98.7	155.3	(215.8)
Other Income	0.4	1.6	1.5	1.6	1.3	0.0	0.0	0.0	0.0	0.0	0.0
Income before levies and taxes	7.5	5.9	24.0	29.2	61.4	93.2	118.6	20.3	98.7	155.3	(215.8)
PO levy	0.0	0.0	17.4	15.0	42.0	93.2	144.6	0.0	0.0	0.0	0.0
Income taxes						0.0	0.0	0.0	0.0	83.9	(116.5)
Net Income	7.5	5.9	6.6	14.1	19.4	(0.0)	(26.0)	20.3	98.7	71.4	(99.3)
Loss on Transfer of Fixed Assets	(0.0)	(0.0)	(0.0)	8.8							
Change in earned surplus	7.5	5.9	6.6	5.4	19.4	(0.0)	(26.0)	20.3	98.7	71.4	(99.3)

IRAN - Power Sector Efficiency Improvement Project
TREC - Cash Flow Statement FY87 to FY97
(Rials billions)

Sources of Funds	Actual					Projected					
	FY87	FY88	FY89	FY90	FY91	FY92	FY93	FY94	FY95	FY96	FY97
Cash From Operations											
- Net profit	7.5	5.9	6.6	5.4	19.4	(0.0)	(26.0)	20.3	98.7	71.4	(99.3)
- Depreciation	4.2	3.9	4.1	4.6	20.6	9.9	85.3	112.0	142.3	172.4	249.6
- Amortization						0.0	0.0	0.1	0.6	4.3	9.3
- Interest						0.0	0.0	5.7	259.7	214.7	232.4
- IPO levy	0.0	0.0	17.4	15.0	42.0	93.2	144.6	0.0	0.0	0.0	0.0
- Customer connection charges	7.5	8.9	11.8	16.0	31.9	36.0	40.0	58.5	99.3	190.9	408.9
- Total	19.2	18.7	39.9	41.0	113.9	139.0	244.0	196.6	600.6	653.7	801.0
Less:											
- Debt service											
Interest						0.0	0.0	5.7	259.7	214.7	232.4
Principal											
- Commercialization loan						0.0	0.0	0.0	0.0	0.0	116.5
- World Bank Loan						0.0	0.0	0.0	0.0	26.5	28.6
- Other investment loans						0.0	0.0	0.0	6.3	37.4	107.5
- Other	1.0	0.7	0.4	0.6	0.0	0.0	0.0	0.0	4.4	9.2	9.2
Total	1.0	0.7	0.4	0.6	0.0	0.0	0.0	5.7	270.4	287.7	494.1
- Increase in Working capital	(17.5)	25.7	0.9	5.6	42.9	3.4	(6.3)	32.6	86.6	121.6	(123.4)
Internal Cash generation	35.6	(7.7)	38.6	34.8	71.0	135.6	250.2	158.3	243.6	244.4	430.3
Other sources											
- IPO	0.0	0.0	0.0	10.0	11.4	9.5	50.0				
- World Bank Loan						0.0	21.2	98.9	140.0	60.6	0.0
- Other Investment Loans											
foreign currency					0	0.0	0.0	171.0	147.0	179.3	210.4
local currency	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.8	47.8	0.0	0.0
- Total	0.0	0.0	0.0	10.0	11.4	9.5	71.2	313.8	334.8	240.0	210.4
Total sources	35.6	(7.7)	38.6	44.8	82.3	145.1	321.5	472.1	578.4	484.4	640.7
Application of Funds											
- Fixed Assets											
Foreign	incl	incl	incl	incl	incl	11.9	67.4	343.3	390.8	284.9	210.4
Local	incl	incl	incl	incl	incl	63.1	65.2	108.2	133.3	98.2	78.0
Capitalized Interest					0.0	0.0	2.7	20.6	54.3	85.4	53.9
Total	12.9	15.8	20.3	36.1	33.3	75.1	135.3	472.1	578.4	468.5	342.3
IPO levy	0.0	0.0	17.4	15.0	42.0	93.2	144.6	0.0	0.0	0.0	0.0
Total Applications	12.9	15.8	37.6	51.2	75.4	168.3	279.9	472.1	578.4	468.5	342.3
Net Cash Flow	22.7	(23.5)	1.0	(6.3)	7.0	(23.2)	41.6	0.0	0.0	15.9	298.4
Ratios											
Internal cash generation	270.1	(47.0)	160.5	116.5	147.3	281.7	110.0	40.1	48.1	52.8	106.8
Debt service coverage								34.5	2.2	2.3	1.6
Return on Fixed Assets in Servi	7.7	4.7	22.2	15.8	23.5	23.1	18.5	7.0	19.7	17.4	6.5

IRAN - Power Sector Efficiency Improvement Project
TREC - Balance Sheet FY 87 to FY97
(Rials billions)

	Actual					Projected					
	FY87	FY88	FY89	FY90	FY91	FY92	FY93	FY94	FY95	FY96	FY97
Assets											
Current Assets	30.2	6.7	5.7	12.0	24	0.7	42.2	42.2	42.2	58.1	356.5
- Cash and notes											
- Accounts receivable	23.8	24.6	25.9	21.9	65.9	83.9	70.8	128.4	269.0	556.5	639.7
- Customers	(1.1)	3.6	17.6	6.8	52.9	52.9	52.9	52.9	52.9	52.9	52.9
- Other											
Total	22.7	28.2	43.4	28.7	118.8	136.8	123.7	181.2	321.8	609.3	692.6
- Inventories											
Fuel	21.1	19.6	27.3	32.9	33.9	22.5	3.4	8.0	10.9	13.8	32.1
Materials							30.3	38.9	46.4	53.9	61.4
Total	21.1	19.6	27.3	32.9	33.9	22.5	33.8	46.9	57.4	67.6	93.5
Total	73.9	54.5	76.5	73.6	176.5	159.9	199.6	270.4	421.5	735.0	1,142.5
- Total	3.7	4.5	4.6	4.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Employee housing loans	45.8	47.1	54.3	74.4	44.2	44.2	44.2	44.2	44.2	44.2	44.2
Advance payments & LCs											
Fixed Assets											
- Electric Plants at Cost	92.1	91.6	95.4	107.4	121.8	219.6	1,706.4	2,139.9	2,846.6	3,447.5	4,992.8
In service	21.1	20.9	22.9	31.2	54.0	31.2	335.8	783.8	1,187.5	1,512.6	820.9
Under construction	113.2	112.5	118.3	138.8	175.7	250.8	2,042.2	3,023.7	4,034.2	4,960.1	5,813.7
Total	(29.5)	(30.2)	(33.6)	(38.0)	(46.3)	(56.2)	(584.1)	(878.1)	(1,149.7)	(1,469.1)	(1,878.7)
- Accumulated Depreciation	83.7	82.2	84.7	100.6	129.4	194.6	1,456.1	2,145.6	2,884.4	3,491.0	3,935.0
- Net fixed Assets					0.0	0.0	2.7	23.3	77.0	158.2	202.7
- Capitalized interest	0.0	0.0	17.4	22.4	30.7	114.4	209.0	209.0	209.0	209.0	209.0
- Net contributions to IPO	20.5	35.8	36.9	47.1	37	37	37	37	37	37	37
- Other Assets											
Total	227.5	224.2	274.3	322.7	427.3	559.7	1,960.2	2,739.0	3,682.6	4,684.0	5,580.0
Total Assets											
Liabilities and Equity											
Current Liabilities	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
- Notes payable	2.7	2.4	4.0	7.3	9.8	9.8	9.8	9.8	9.8	9.8	9.8
- Associated companies	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
- Taxes	27.4	10.1	12.3	11.6	43	46	51	89	153	330	562
- Accounts Payable					0	0.0	0.0	10.7	46.5	46.5	46.5
- Current portion of long t	30.4	12.9	16.8	19.3	53.4	56.6	61.0	109.8	210.2	386.4	618.8
Total											
Long Term Debt						0.0	0.0	1,165.4	1,165.4	1,165.4	1,048.8
- Commercialization loan						0.0	21.2	135.3	297.9	359.3	354.1
- World Bank Loan					0	0.0	0.0	183.6	352.4	530.9	673.1
- Other foreign currency loans					0.0	0.0	0.0	43.8	87.2	78.0	68.9
- Other local currency loan	1.6	1.3	0.9	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Total	1.6	1.3	0.9	0.6	0.6	0.6	21.8	1,528.8	1,903.4	2,134.3	2,145.5
- Total					0.0	0.0	0.0	10.7	46.5	46.5	46.5
- less current portion	1.6	1.3	0.9	0.6	0.6	0.6	21.8	1,518.1	1,856.9	2,087.7	2,099.0
- Net long term debt	4.3	4.3	4.4	4.5	16.6	16.6	16.6	16.6	16.6	16.6	16.6
Other Liabilities											
Capital	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
- Capital stock	56.5	42.5	42.1	54.4	45.2	45.2	45.2	45.2	45.2	45.2	45.2
- Invest. of Government	69.3	93.9	92.9	108.9	140.7	176.7	216.7	275.3	374.6	565.5	974.5
- Customer contributions	0.0	0.0	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
- Other Paid-in Capital			17.4	32.4	48.8	142.0	286.6	286.6	286.6	286.6	286.6
- IPO payments											
- Revaluation reserve					0.0	0.0	1,216.2	1,564.3	1,921.4	2,317.3	2,722.5
Gross reserve							0.0	(1,165.4)	(1,165.4)	(1,165.4)	(1,165.4)
Less stock dividend					0.0	0.0	1,216.2	398.9	756.0	1,151.9	1,557.1
Net reserve					0.0	0.0	0.0	(27.8)	(79.4)	(142.3)	(204.9)
- Exchange loss	65.5	69.3	73.6	86.4	105.7	105.7	79.7	100.0	198.7	170.1	170.9
- Earned surplus											
Total	191.3	205.7	242.2	298.3	356.7	485.9	1,860.8	1,094.5	1,599.0	2,193.3	2,845.6
Total	227.5	224.2	264.3	322.7	427.3	559.7	1,960.2	2,739.0	3,682.6	4,684.0	5,580.0
Total Liabilities & Equity											
Ratios											
- current	2.4	4.2	4.6	3.8	3.3	2.8	3.3	2.5	2.0	1.9	1.8
- debt to equity	0.19	0.09	0.09	0.08	0.20	0.15	0.05	1.50	1.30	1.14	0.96
- debt to equity and quasi equity						0.15	0.05	1.31	1.07	0.91	0.75

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ASSUMPTIONS FOR FINANCIAL PROJECTIONS

A. Basis of Projections

1. Financial projections up to and including FY97 have been made for TAVANIR as well as for TREC. Projections for TAVANIR were prepared in order to establish an appropriate price for the power that TREC purchases from TAVANIR. For the purpose of the projections, this price is assumed to be the price required in order to permit TAVANIR to achieve an internal cash generation ratio of 20 percent in FY93, and 40 percent thereafter. The projections also incorporate several policy proposals including:

- (i) the elimination of the subsidy for investment costs by pricing imported capital goods based on rapid exchange rate projections.
- (ii) electricity tariff increases that would, by the beginning of FY96, bring electricity tariffs and transfer prices to levels that reflect LRMCs;
- (iii) fuel price increases that would, by the beginning of FY98, bring domestic fuel prices to levels that reflect world prices for petroleum products or domestic marginal costs for natural gas;
- (iv) explicit recognition of the cost of capital employed;
- (v) the conversion of equity, which currently yields no direct return to the Government, to debt, yielding a rate of interest that is positive in real terms;
- (vi) the annual adjustment of fixed asset values and depreciation costs in order to reflect current replacement costs;
- (vii) the recognition, following commercialization but prior to privatization, that sector enterprises need to generate adequate financial performance coefficients as presented in Section B of this chapter; and
- (viii) the taxation of sector enterprises as soon as tariffs reach LRMC levels.

B. Inflation Rates and Exchange Rates

2. The projections for inflation rates and exchange rates are given in Table 5.2.1 below. The exchange rate at which the sector accesses foreign exchange is assumed to go from 70 Rials/US\$ in FY92 to 1450 Rials/US\$ in FY93 and then to change according to the differential between local and foreign inflation thereafter.

E. Balance Sheets

11. **Accounts Receivable.** TREC accounts receivable, currently 3.5 months of equivalent sales, are expected to increase at the same rate as sales through FY92, then decline in FY93 to 3 months' equivalent sales and then to 2 months' equivalent sales in FY94 and thereafter.
12. **Fuel inventories** are expected to increase from current levels as fuel costs increase. Other stocks are expected to increase with the cost of other consumables.
13. **Accounts Payable.** Accounts payable, as of March 20, 1991, are expected to grow each year by an amount equal to one twelfth of the incremental cost of fuel and other consumables.

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ECONOMIC ANALYSIS

1. The first stage of the economic analysis examined whether the project formed part of the most economic expansion of electricity supply. The second stage verified whether there were enough economic benefits to justify the commitment of resources to the project.

Least-Cost Analysis

2. Based on the demand forecasts that considered the projected tariff adjustments needed to align them with LRMC, the WASP model was used to find the optimal investment plan for generating capacity in the interconnected system. The input data were reviewed and adjusted where needed to make them more realistic. The costs include a 50¢ per kWh charge for the unserved energy due to random outages in supply. The main parameters employed in the least-cost analysis are presented in Table 6.1.1 below.

Table 6.1.1: Main Parameters of the Least-Cost Analysis

Main Parameters	US\$ of 1991
Basic Natural Gas Price (US\$/million BTU)	2.00
Fuel Oil Price (US\$/ton)	65.00
Gas Oil Price (US\$/bbl)	24.00
Capital Cost Steam Power Plant (US\$/kW)	1,012.00
Capital Cost Gas Turbines (US\$/kW)	509.00
Capital Cost HRSG (US\$/kW)	880.00
Period of the Analysis (Years)	1991-2000
Discount Rate (%)	10.0

3. MOE plans that the Shahid Montazeri plant extension to be supplied by the FSU will be operational by 1996. However, these units would take about five years to bring into operation under normal circumstances, and considering the problems in the FSU, delays are to be expected. Thus, the input information that describes the committed generating expansion program in the WASP program was modified to reflect a likely delay in the commissioning of these plants.

Cost-Benefit Analysis

4. A cost-benefit analysis was undertaken using the estimated costs, based on the current floating rate of 1,450 Rls/US\$, excluding taxes and duties, and an annual operating and maintenance cost stream equivalent to 2 percent of the capital costs. The Qom component has no incremental fuel costs associated with it as the design is based on a non-refired boiler. As the combined cycle plant would have the highest operating efficiency of all thermal plants in the system, it is assumed to be base-loaded, operating as many hours as it is available. The analysis assumes that the plant would only have a 50 percent plant factor in its first year of operation due to higher than average levels of maintenance for inspection and teething problems. The output is assumed to increase to a 60 percent plant factor in its second year of operation and to 70 percent for the remainder of its first decade of operation. The plant factor is forecast to decline to 60 percent during its second decade of operation and to 50 percent for its last decade. The benefit stream is valued using forecast tariffs at the generation level (based on the results of maintaining the proposed financial targets) as a proxy for benefits. The results indicate that the project's EIRR is 17 percent. The project also includes an implicit environmental benefit in decreasing CO₂ production from power plants. This benefit has not been included in the economic analysis. However, as the estimated annual reduction of CO₂ would be 0.3 million tonnes/year, the benefits would increase by approximately US\$6 million p.a.¹

1/ This benefit is based on a conservative estimate of the economic value of CO₂ reduction of US\$20/tonne.

Cost-Benefit Analysis of Oom Combined Cycle Component

Fiscal Year	Capital Cost (US\$ M)	O&M Cost (US\$ M)	Total Cost (US\$ M)	Energy Genr. (GWh)	Value (US\$ M)	Net Benefits (US\$ M)
1993	3.39		3.39			(3.39)
1994	61.79		61.79			(61.79)
1995	99.99		99.99			(99.99)
1996	47.38	1.12	48.50	219.00	4.05	(44.45)
1997	12.12	3.37	15.49	788.40	35.18	19.69
1998		4.49	4.49	1226.40	55.19	50.69
1999		4.49	4.49	1226.40	55.19	50.69
2000		4.49	4.49	1226.40	55.19	50.69
2001		4.49	4.49	1226.40	55.19	50.69
2002		4.49	4.49	1226.40	55.19	50.69
2003		4.49	4.49	1226.40	55.19	50.69
2004		4.49	4.49	1226.40	55.19	50.69
2005		4.49	4.49	1226.40	55.19	50.69
2006		4.49	4.49	1051.20	47.30	42.81
2007		4.49	4.49	1051.20	47.30	42.81
2008		4.49	4.49	1051.20	47.30	42.81
2009		4.49	4.49	1051.20	47.30	42.81
2010		4.49	4.49	1051.20	47.30	42.81
2011		4.49	4.49	1051.20	47.30	42.81
2012		4.49	4.49	1051.20	47.30	42.81
2013		4.49	4.49	1051.20	47.30	42.81
2014		4.49	4.49	1051.20	47.30	42.81
2015		4.49	4.49	1051.20	47.30	42.81
2016		4.49	4.49	876.00	39.42	34.93
2017		4.49	4.49	876.00	39.42	34.93
2018		4.49	4.49	876.00	39.42	34.93
2019		4.49	4.49	876.00	39.42	34.93
2020		4.49	4.49	876.00	39.42	34.93
2021		4.49	4.49	876.00	39.42	34.93
2022		4.49	4.49	876.00	39.42	34.93
2023		4.49	4.49	876.00	39.42	34.93
2024		4.49	4.49	876.00	39.42	34.93
2025		4.49	4.49	876.00	39.42	34.93
Total	224.66	125.81	354.97		1343.93	993.01

EIRR = 17% NPV = 121 US\$ Million

Note:

- (1) Costs are for generation only as transmission benefits cannot be estimated.
- (2) Benefits are based on tariffs at the generation level.
- (3) NPV calculated at 10% opportunity cost of capital in Iran.

MAP SECTION

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SELECTED DOCUMENTS AND DATA AVAILABLE IN THE PROJECT FILE

Ghom Combined Cycle Power Plant Feasibility Study prepared by Monenco Iran in association with Monenco Consultants Limited, Canada, January 1992.

Qom Power Station Water Supply Study prepared by Sazand-Ab Company, Tehran, Iran, March 1992.

Environmental Assessment of Power Sector Efficiency Improvement Project prepared by Ebasco Environmental, Arlington, VA, USA, February, 1992.

Environmental Assessment of Power Sector Efficiency Improvement Project submitted by Tehran Regional Electric Company (TREC), Tehran, Iran to The World Bank, May 1992.

Iran - Reconstruction and Growth (in Two Volumes), Volume I: Main Report and Volume II: Annexes and Statistical Appendix, World Bank Report No. 9072-IRN, July 1991.

Other reports and documents

Consultant's Report (Engineer - Mr. Posada) of the Preparation/Identification mission for the Power Sector Efficiency Improvement Project, August 1991.

Consultant's Report (Energy Economist - Mr. Bridgeman, ACRES, Canada) of the Preparation/Identification mission for the Power Sector Efficiency Improvement Project, August 1991.

Consultant's Report (Engineer - Mr. Warnock, Monitor International, Scotland, U.K.) of the Pre-Appraisal Mission for the Power Sector Efficiency Improvement Project, November 1991.

Consultant's Report (Hydro-Engineer - Mr. Posada) of the Appraisal Mission for the Power Sector Efficiency Improvement Project, February 1992.

Economic Analysis including demand forecast and cost/benefit analysis.

Project cost and financing model including disbursement profiles and procurement arrangements.

Various financial and accounting statements and Annual Reports.

Tables showing the tariff schedules before and after March 1992.

Table 5.2.1: Projections for Inflation Rates and Exchange Rates

	FY91	FY92	FY93	FY94	FY95	FY96	FY97
G-5 MJV Prices							
- Percent Change	2.10	4.30	3.80	1.90	2.70	3.40	3.60
Local Prices							
- Percent Change	19.6	20.0	23.0	18.1	14.2	12.4	10.6
Projected Exchange Rate							
Theoretical							
- Beginning of year	835	978	1,450	1,718	1,991	2,214	2,407
- End of year	978	1,125	1,718	1,991	2,214	2,407	2,570
- Mid year	907	1,052	1,584	1,855	2,103	2,311	2,488
Actual/Projected	70	70	1,450	1,855	2,103	2,311	2,488
1/ Source: MN2CO.							
2/ Source: IEC.							

C. Fixed Asset Revaluation and Refinancing

3. Asset Revaluation. Based on an analysis of actual TAVANIR capital expenditures in local and foreign currency over the period FY85 through FY90, and taking into account international and local inflation rates during the period and the assumptions regarding exchange rate movement, the current value of TAVANIR net fixed assets on March 20, 1991 was estimated to be at least 2.8 times the reported book value at that date. This factor was also assumed for TREC. Current values of fixed assets were then calculated for each year through FY97 and were taken onto the projected balance beginning in FY93, at which time a revaluation surplus was established.

4. It is assumed that by the end of 1993 the revaluation surpluses would be converted, in whole or in part, into commercialization loans, carrying floating rates of interest that would be positive in real terms. The loan (which is considered to be quasi-equity), would not, in any case, cause TREC's adjusted debt:equity ratio (with 50% of the loan considered to be equity) to exceed 1.5. The loan would be established only when TREC is capable of servicing at least the interest cost, and a grace period of two years would be provided before principal would be serviced. Thus, a loan, amounting to US\$628 million equivalent, would be established at the end of FY 94 and amortized over ten-years. The rate of interest on the loans is assumed to be equal to the rate of inflation in the previous year plus a spread of 3.0 percent. The term of the loan would be 12 years. It is assumed that the loans would be administered, on behalf of the Government, by IPO and that the interest and principle payments received would be recycled to finance investments in the sector.

D. Income Statements

5. Sales Revenues. Energy sales are expected to increase from the 1990/91 levels as projected by the WASP model. Through FY96, actual selling prices will be driven by the covenanted level of internal cash generation.

6. Power Purchases. Projections of TREC purchases of power are derived by subtracting TREC projected generation, as determined by the WASP model, from the forecast of power sales and losses. The price of purchased power, currently Rials 2.80 per kWh, is expected to remain unchanged during FY93 and then increase rapidly to around 92% of LRMC by FY96 so that TAVANIR would also obtain a level of internal cash generation of at least 40 percent in FY96 and thereafter.

7. Fuel Consumption and Costs. Fuel consumption by TAVANIR and TREC is based on projections by the WASP model. For gas turbines it is assumed, based on actual results in 1989/90, that in 1991/92 23 percent of the energy input required is being supplied by gas-oil; the energy supplied by the generating stations is based on the WASP model results. Fuel price projections are shown in Table 5.2.2 below.

Table 5.2.2: Projected Fuel Prices

		1992	1993	1994	1995	1996	1997	1998
Fuel Price - \$US								
Gas Oil	l	0.151	0.162	0.171	0.183	0.218	0.254	0.290
Heavy Fuel Oil	l	0.068	0.072	0.077	0.082	0.098	0.114	0.130
Natural Gas	m3	0.037	0.038	0.039	0.040	0.041	0.048	0.055
Petroleum	BBL	17.3	18.5	19.6	20.9	25.0	29.1	33.1
Fuel Price - Rls								
Gas Oil	l	15	29	53	81	115	300	780
Heavy Fuel Oil	l	8	17	28	41	55	139	349
Natural Gas	m3	5	12	19	28	39	76	147

1/ Source: World Bank.

8. Salaries and other operating expenses are expected to increase from current levels in line with increases in sales and local inflation. An exception is the operating and maintenance cost of the TREC Qom power station, which has been estimated on the basis of 2 percent of the initial capital cost and adjusted for inflation.

9. Sector enterprises calculate depreciation at various rates depending on the expected life of the asset in years (i.e., steam plants, 25; gas turbines, 20; transmission systems, 33.33; despatch centers and miscellaneous other assets, 6.67). For simplicity of calculation, the projections for depreciation expenses are based on an average life of 20 years.

10. Interest Expense. It is assumed that the investment loans, whether foreign or domestic, would be denominated in US\$ and carry terms typical of those offered by export credit agencies for long-term credit. Thus, the assumed terms are an interest rate of 8 percent, a grace period of three years and an amortization period of seven years, with the Borrower carrying the exchange rate risk. Commercialization loans in rials carry a floating rate (see para. 4).

POWER SECTOR EFFICIENCY IMPROVEMENT PROJECT

