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STAFF APPRAISAL REPORT

INDIA

CAMBAY BASIN PETROLEUM PROJECT

March 8, 1984

Energy Department
Petroleum Projects, Division I

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CURRENCY EQUIVALENTS

Currency Unit	=	Rupee (Rs)
Rs 1	=	Paise 100
US$ 1	=	Rs 10.0
Rs 1	=	US$ 0.10000
Rs 1 million	=	US 100,000

MEASURES AND EQUIVALENTS

1 Metric Ton (mt)	=	1,000 Kilograms (kg)
1 Metric Ton (mt)	=	2,204 Pounds (lb)
1 Meter	=	3.28 Feet
1 Kilometer (km)	=	0.62 Miles
1 Cubic Meter (m^3)	=	35.3 Cubic Feet (cft)
1 Barrel (Bbl)	=	0.159 Cubic Meter
1 Metric Ton of Oil (39° API)	=	7.60 Barrels
1 Normal Cubic Meter (Nm^3) of Natural Gas	=	37.32 Standard Cubic Feet (SCF)
1 Kilocalorie (kcal)	=	3.97 British Thermal Units (Btu)
MW	=	1,000 kilowatts
kWh	=	kilowatt-hour
GWh	=	1 Million kWh
Bbl/d	=	Barrels per day
MMCMD	=	Million Cubic Meters per Day
TCF	=	Trillion Cubic Feet
toe	=	Ton of Oil Equivalent
tpd	=	Ton per day
tpy	=	Ton per year

PRINCIPAL ABBREVIATIONS AND ACRONYMS USED

BOP	-	Bomby Offshore Project
DCF	-	Discounted Cashflow
DEA	-	Department of Economic Affairs
EOR	-	Enhanced Oil Recovery
GOI	-	Government of India
HIL	-	Hydrocarbons India Limited
ICB	-	International Competitive Bidding
IDT	-	Institute of Drilling Technology
IOIP	-	Initial Oil in Place
LPG	-	Liquefied Petroleum Gas
LSHS	-	Low Sulfur Heavy Stock
NGL	-	Natural Gas Liquids
OIDB	-	Oil Industry Development Board
OIL	-	Oil India Limited
ONGC	-	Oil and Natural Gas Commission

FISCAL YEAR

April 1 - March 31

INDIA

CAMBAY BASIN PETROLEUM PROJECT

Loan and Project Summary

Borrower: Government of India (GOI)

Beneficiary: Oil and Natural Gas Commission (ONGC)

Amount: US$242.5 million equivalent (including capitalized front-end fee of 0.25%)

Lending Terms: Repayable over 20 years, including five years of grace at the standard variable interest rate.

On-Lending Terms: Government of India (GOI) to ONGC (US$242.5 million): Funds will be onlent to ONGC at a rate of at least 12% per annum; repayment over a maximum of 15 years, including five years' grace. GOI would bear the foreign exchange and interest rate risks.

Project Description: The purpose of the project would be to assist the Oil and Natural Gas Commission (ONGC) in developing its capabilities for optimizing the production of existing, mature oil fields--a new area of technology for India's fledgling oil industry. The project comprises the preparation and implementation of a US$954 million investment program for increasing the production of oil and gas from the onshore Cambay Petroleum Basin located in the State of Gujarat in western India.

Specifically, assistance would be provided in (i) exploration - to delineate, by seismic survey and drilling, the limits of the known producing zones; (ii) development and production - to substantially increase the production of both oil and gas; (iii) enhanced oil recovery - to test alternative technologies for increasing recoverable reserves; and (iv) technical assistance and training to ensure that ONGC staff acquire the requisite skills to successfully implement the new methodologies.

The principal project risks are those normally associated with petroleum exploration and development, i.e., geological and technological. The geological risks include the possibility that oil will not be found in commercial quantities in the deeper zones to be explored. The technology being introduced under the project is a blend of proven, profitable and "leading edge" technology

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in such proportions, and with adequate foreign technical assistance and training, that the risks - both economic and environmental - are acceptable under all reasonably expected adverse scenarios.

Estimated Costs:	(US$ millions)		
	Local 1/	Foreign	Total
Exploration	19.3	61.7	81.0
Development and Production	269.9	319.2	588.8
Enhanced Oil Recovery	2.6	5.0	7.6
Technical Assistance and Training	2.0	5.0	7.0
Total Base Cost	293.5	390.9	684.4
Physical Contingencies	39.7	58.4	98.1
Price	75.3	95.9	171.2
Total Project Cost	408.5	545.2	953.7
Front-End Fee	-	0.6	0.6
Total Financing Required	408.5	545.8	954.3

Financing Plan:	(US$ millions)		
	Local	Foreign	Total
IBRD	-	242.5	242.5
Cofinancing 2/	-	245.0	245.0
ONGC	408.5	58.3	466.8
Total	408.5	545.8	954.3

Estimated Disbursements:

BANK	(US$ millions)						
	FY84	FY85	FY86	FY87	FY88	FY89	FY90
Annual	0.6 3/	35.8	60.6	72.8	36.3	24.3	12.1
Cumulative	0.6	36.4	97.0	169.8	206.1	230.4	242.5

Economic Rate of Return: About 91% for total project.

Financial Rate of Return: About 18% after taxes.

Appraisal Report: No. 4928-IN, dated March 8, 1984.

1/ Includes an estimated US$150 million in duties and taxes.
2/ Including Euro-currency borrowings and suppliers' credits.
3/ Front-end Fee.

INDIA

CAMBAY BASIN PETROLEUM PROJECT

STAFF APPRAISAL REPORT

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This report was prepared by Messrs. Denis T. Carpio, Hannachi Morsli, Akin Oduolowu, Jean-Paul Pinard and Stephen Tisza of the Energy Department.

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DOCUMENTS CONTAINED IN THE PROJECT FILE

1. Chemical Flooding Enhanced Oil Recovery Projects,
   - Cambay Basin (October 26, 1983)
   by Ted M. Geffen - Consultant

2. The Evaluation of the Skills of Workers and their Training Needs
   - Cambay Basin (September 1983)
   by Bruce R. Whalen - Consultant

3. Enhanced Oil Recovery Projects (Heavy Oil) - Cambay Basin
   (August 24, 1983)
   by Philip D. White - Consultant

4. Cambay Basin Petroleum Project Feasibility Study (July 25, 1983)
   by ONGC (Western Region)

5. Feasibility Report - Final Development Plan Kalol Field (March 1983)
   by ONGC (Institute of Reservoir Studies)

6. Cambay Basin Exploration and Development Projects (February 1983)
   by ONGC

7. Laboratory Studies on Steamflooding for Balol Field (February 1982)
   by: ONGC (Institute of Reservoir Studies)

8. Identification of a Suitable Polymer and Polymer Flood Studies
   on Horizon IX & X - Jalora Field (July 15, 1983)
   by ONGC (Institute of Reservoir Studies)

9. In-Situ Combustion Studies for Lanwa Field, Field Pilot Design and
   a Study of Variation in the Parameters Between Lanwa, Balol
   and Santhal Fields (May 1981)
   by ONGC (Institute of Reservoir Studies)

10. Pilot Thermal Flooding Demonstration Project - Balol Field
    (March 1980)
    by ONGC (Institute of Reservoir Studies)

11. Stratigraphy of Cambay Basin at a Glance (August 1981)
    by ONGC

I. INTRODUCTION

1.01 The Government of India (GOI) has requested a Bank loan of US$ 242.5 million equivalent for a petroleum project in the Cambay Basin (the project) located in the State of Gujurat (IBRD Map. No. 17604). The project will be implemented by the Oil and Natural Gas Commission (ONGC), the national oil company. The main objectives of the project are to: (i) increase oil and gas production by about 2 million tons of oil equivalent per year representing about 12% of 1982/83 petroleum imports; (ii) implement enhanced oil recovery (EOR) pilot schemes; and (iii) explore the petroleum potential of deep horizons and the unexplored area in the Gulf of Cambay. These objectives are expected to be achieved by improving ONGC's technical and operational capabilities in drilling and production. Improvements will come partly through training and technical assistance and partly through a shift from force account drilling to contracting.

1.02 The total financing required for the project, which accounts for about 60% of the Cambay Basin investments and about 5% of ONGC's overall investment program during 1984/85-1989/90, is estimated at US$954 million (Rs 9.5 billion) including about US$546 million (Rs 5.5 billion) in foreign exchange. In addition to the proposed Bank loan, ONGC will seek export, buyers' and suppliers' credits for the project; it will also seek during the project implementation period, commercial bank loans for part of its total corporate investments. Part of such borrowings will be utilized in the proposed project. The total co-financing is expected to be about US$245 million. The balance of the financing required will be provided by ONGC.

1.03 The Bank has indicated for some time its interest in reviewing ONGC's onshore operations. Thus, in late 1981, ONGC first mentioned to the Bank the idea of undertaking some pilot enhanced oil recovery schemes for the heavy oil fields in the northern section of the Cambay Basin. Subsequently, the dialogue between ONGC and Bank staff expanded to include the full evaluation of the petroleum production potential of this mature basin as well as the operational and technological priorities to rapidly increase production, modernize operations, and develop a program of optimal oil and gas recovery in the basin. During the course of discussions about ONGC's exploration and investment program in 1982, the concept of a project addressing the main operational and technical problems, as well as the major exploration and development investment opportunities, in the Cambay Basin was developed. Following an identification mission and a preappraisal mission in March 1983 and July 1983, respectively, the project was appraised in September 1983 by a mission consisting of Messrs. Denis T. Carpio (Chief), Hannachi Morsli, Jean-Paul Pinard, Stephen Tisza and Akin Oduolowu of the Energy Department and Mr. Ted Geffen (EOR consultant).

II. - THE ENERGY SECTOR

A. Energy Resources and Consumption

2.01 Commercial primary energy (coal, oil, gas, hydro and nuclear power) accounts for about 46% of total energy consumption in India, with the balance (54%) being derived from non-commercial sources such as firewood and agricultural and animal wastes. Over the past ten years, the growth of energy

consumption in India averaged 4% per annum, which was marginally below GDP growth for the period. Over the same period, commercial energy consumption increased by 5.3% per annum. Per capita consumption of commercial primary energy is about 166 kg of oil equivalent, which is half the average for low-income developing countries. The share of oil products and natural gas in India's commercial primary energy consumption, at about 33%, is low for a developing country, primarily because of the significant use of coal in power generation. Firewood is the most widely consumed fuel in India, accounting for about 65% of total non-commercial energy consumption. Other sources of fuel, such as vegetable and animal wastes, account for the remaining 35% of non-commercial energy consumption. The energy supply in India by primary energy sources is shown in Annex 2.1 and is summarized below.

Table 2.1: Primary Energy Supply in India
(million tons of oil equivalent)a/

	Actual					Estimate	Average Annual Growth Rate (%)	
Fiscal Year	1960/61	1970/71	1975/76	1980/81	1981/82	1982/83	1960/61-1970/71	1970/71-1980/81
Commercial Primary Energy								
Coal & lignite b/	27.8	37.1	50.6	58.4	64.7	67.8	2.9	4.7
Petroleum c/								
Oil	7.9	18.6	23.3	33.6	34.9	32.5	8.9	6.1
Gas	N.A	0.4	0.8	1.1	1.6	1.5	N.A	11.0
Subtotal	7.9	19.0	24.1	34.7	36.5	34.0	9.2	6.2
Hydro & Nuclear Power d/	1.9	6.6	8.6	11.9	11.9	11.6	1.3	7.2
Subtotal	37.6	62.7	83.3	105.0	113.1	113.4	5.2	5.3
Noncommercial Primary Energy f/								
Firewood	48.8	57.8	65.2	N.A.	N.A.	N.A.	1.7	2.5e/
Agricultural waste	13.2	15.6	17.6	N.A	N.A.	N.A.	1.7	2.5e/
Animal dung	12.0	14.2	16.1	N.A.	N.A.	N.A.	1.7	2.5e/
Subtotal	74.0	87.6	98.9	N.A.	N.A.	N.A.	1.7	2.5e/
Total	111.6	150.3	182.2	N.A.	N.A.	N.A.	3.0	3.9e/

a/ Based on the following conversion factors: one ton of oil equivalent (toe) is equal to 2 tons of domestic coal; 5.88 tons of lignite; 0.94 tons of refined petroleum products; 1,235 cubic meters of natural gas; 4,166 kwh of hydro and nuclear power; 2.04 tons of firewood; 2.33 tons of agricultural waste; and 4.54 tons of animal dung.

b/ 99.3% coal and 0.7% lignite in terms of toe in 1982/83.

c/ Natural gas excludes quantities flared and used in field operations. Petroleum supply includes those for fuel as well as for petrochemical feedstocks.

d/ About 94% hydro power and 6% nuclear power in 1980/81. But in 1981/82 and 1982/83 there was no power generation from nuclear plants due to spare parts and maintenance problems. The figures are gross power generation.

e/ Growth rate from 1970/71 to 1975/76 only. The same rate assumed for the 10-year period (1970/71-1980/81).

f/ Non-commercial energy figures are for consumption which are taken as equal to supply.

2.02 Coal is the most abundant indigenous energy resource and the main domestic source of commercial primary energy in India with reserves estimated at about 85 billion tons [1/] equal to about 42 billion tons of oil equivalent (toe), 25 billion tons (about 12 billion toe) of which are proven reserves. Most of the coal is of low to medium quality (3,500 to 5,000 kcal/kg) and is primarily used for power generation. Coal production, which stagnated between 1976/77 and 1979/80 because of power shortages, delays in commissioning new mines, labor difficulties and transportation bottlenecks, has risen substantially from about 104 million tons in 1979/80 to 131 million tons in 1982/83, making India the sixth largest coal producer in the world. However coal production is still about 4 million tons per year less than demand.

2.03 Based on the proven coal and hydro resources, India possesses the potential to increase its power generating capacity. However, due to low capacity utilization, delay in commissioning new thermal plants, lack of essential spare parts for timely maintenance, and poor management, the supply of power has consistently been less than potential demand in recent years. In 1980/81, the estimated deficit (calculated as actual supply compared to potential unrestricted demand) was about 13% despite a growth in power generation of 9% in the same year. If the government can successfully overcome these problems, power generation capacity could reach 50,900MW in 1984/85 and, from 1988/89 onwards, the country's overall average electrical energy requirements may be satisfied, although a peak capacity deficit and regional imbalances would most likely continue until the mid-1990s.

2.04 India also possesses significant reserves of natural gas both onshore and offshore. Proven gas reserves, mostly offshore, are estimated at about 410 billion cubic meters (or 330 million toe), equivalent to about 41% of total estimated hydrocarbon reserves. Gas resources are not yet widely utilized due to lack of market development. However, the importance of gas as an energy source in the industrial sector to substitute for oil is increasingly recognized by the government which is now making concerted efforts to accelerate exploration and development of gas resources (para 3.01).

B. Investments in The Energy Sector

2.05 The energy sector claims a large and increasing share of public investment in India, reflecting the growing concern that inadequate energy supplies may become a serious constraint to economic development. Direct real investment in the power, coal and oil subsectors as a whole grew at an average annual rate of 15% between 1974/75 and 1980/81, while its share in total outlay increased from about 18% in the Third Five-Year Plan to about 27% in the current Sixth Five-Year Plan. This is a major commitment and should accelerate the exploration for and development of India's energy resources. Although the power subsector continues to receive the major share of funds allocated to the energy sector, direct investment in the coal and oil subsectors have increased three to four times between 1974/75 and 1980/81.

1/ These are for reserves in seams greater than 1.2 metres thick and at a depth of less than 600 metres.

2.06 The size and rapid growth of investment in all energy subsectors, especially in power and petroleum, reflect GOI's determined efforts to minimize the adverse economic effects of energy shortages on the one hand, and large oil import bills on the other. Stepped-up investment in this sector has resulted in significant increases in energy production. Domestic crude production has more than doubled from about 8 million tons in 1974/75 to about 21 million tons in 1982/83. Coal production has also increased by over 30% between 1979/80 and 1982/83, while installed capacity in the power sector (utilities) has increased by more than 75% over the past seven years. Nevertheless, inadequate supply of energy has remained a major constraint to India's economic growth. Although considerable indigenous energy resources exist their development has not kept pace with demand; efforts to meet the energy demand of the economy from domestic sources must still be intensified and made a national priority, notwithstanding the encouraging progress made recently in increasing oil production. The momentum of energy investments needs to be maintained in the coal and oil/gas subsectors, and substantially increased in the power sector, in order to eliminate power shortages and prevent the re-emergence of coal shortages by the early 1990s as well as reduce oil imports to a more manageable level of say 30% to 35% of domestic demand. This would mean that the energy sector should continue to absorb a large share of India's investment resources in future development plans.

2.07 The sectoral distribution of energy consumption is shown in Annex 2.2. Industry and transport together account for about 79% of total commercial energy consumption, households 11%, agriculture 6% and all other sectors the remaining 4%, respectively. The industrial sector is the largest (55%) user of commercial energy, accounting for about 75% of coal, 63% of electricity and 19% of petroleum consumption, respectively. The transport sector is the next largest (24%) user of commercial energy, accounting for about 53% of petroleum and 16% of coal consumption, respectively. The household sector accounts for a relatively small share of commercial energy consumption (7% of coal, 19% of petroleum and 10% of electricity).

2.08 The Government is aware that policies and actions are needed for both energy demand management and development of local energy resources. Since 1979 several studies have been undertaken to address both areas and some specific policy decisions and action programs have evolved from these studies. Some of those pertaining to petroleum are discussed in the following chapter.

III. - PETROLEUM SUBSECTOR

A. Petroleum Resources, Production and Consumption

3.01 In India, there are 27 sedimentary basins (Annex 3.1) with a total area of approximately 1.7 million km^2, of which about 1.4 million km^2 (81%) are onshore and the remainder offshore (to a water depth of 200 meters). Commercial petroleum production has been established in only three sedimentary basins, viz., the Upper Assam Shelf in north-eastern India, the Cambay basin in Gujarat, and the Bombay offshore basin which has several petroleum fields, namely, Bombay High, North Bassein (Panna), South Bassein, Heera and Ratnagiri (Ratna). Many of India's potential petroleum-bearing areas are still less than fully explored. Historically, the pace and scope of exploration activity has been uneven and resources have been concentrated on a few promising

areas. Since the discovery of the giant Bombay High field off the West Coast of India in the mid-1970s, India has not made a new major discovery. The ongoing exploration efforts of ONGC, however, have been encouraging and have identified several petroleum-bearing areas which need further exploratory drilling to determine their commercial potential. Indications of petroleum have been found in eight other basins: Krishna-Godavari, Cauvery, Rajasthan, Bengal, Andaman Islands, Himalayan Foothills-Ganga Valley, Tripura Fold Belt and the Assam-Arakan Fold Belt. Furthermore, four other basins are considered prospective on general geological grounds, although hydrocarbons have not yet been discovered. These basins are Saurashtra, Kutch, Konkan-Kerala and Mahanadi. The Krishna-Godavari and Cauvery basins offer the most promising undeveloped potential to date. Estimates of India's potential total recoverable hydrocarbon reserves are 4.5 billion tons of oil equivalent (toe), of which about two-thirds are located offshore and 75% are expected to be in the form of natural gas. Proven and probable recoverable hydrocarbon reserves are currently estimated at 800 million toe of which 470 million tons is oil and the remainder is natural gas (410 billion cubic meters or 330 million toe). Natural gas is becoming increasingly important to the Indian economy following the development of the Bombay High oil field with its associated gas and as a result of the ongoing development of the large offshore South Bassein gas field. Gas consumption is estimated to have reached the equivalent of 1.5 million toe in 1982/83, as compared with 1.1 million toe in 1980/81, and is expected to increase sharply to about 6.8 millon toe by 1989/90.

3.02 As a result of the rapid development of the Bombay High field, crude oil production from domestic reserves has increased steadily over the past 20 years, from about 0.5 million tons in 1960/61 to almost 7 million tons in 1970/71 and an estimated 21 million tons in 1982/83. For 1983/84, domestic production is estimated to about 26 million tons mainly as a result of further development of the Bombay High field. Consumption of crude oil grew at about 6.5% per annum over the past five years, and reached an estimated 40 million tons in 1983/84. In that year imported crude oil accounted for 14 million tons or about 35% of consumption. The estimated import bill for crude oil and petroleum products was about US$4.5 billion for 1983/84 representing 32% of total merchandise imports and 58% of India's merchandise export earnings. By the end of the Sixth Plan period (1984/85), consumption is expected to reach about 44 million tons per year. This would exceed expected domestic production from known petroleum reserves by about 14 million tons per year. Table 3.1 summarizes the consumption and production trends for hydrocarbons.

3.03 While there are good prospects for increasing production from existing fields, offshore as well as onshore, India's dependence on imported oil could increase from a low of 33% in 1984/85 to about 50% in the early 1990s unless new major discoveries are made and developed in the next few years (Annex 3.2). Thus, a concerted effort to accelerate exploration of prospective areas and improve the efficiency of production of existing petroleum resources is of vital importance and is a central objective of Government petroleum policy. In recognition of this need, India is making efforts to attract risk capital by inviting foreign oil companies to assist in exploring for oil, both onshore and offshore; areas in about half of the country's sedimentary basin areas have been offered to private oil companies

Table 3.1: India: Petroleum Production and Consumption Trends

	Actual				Forecast a/	
	1970/71	1980/81 b/	1981/82	1982/83	1984/85	1989/90
Crude Oil (million tons)						
Domestic Production	6.8	10.5	16.2	20.6	29.8	34.2
Net Crude Oil Imports	11.7	16.3	14.5	11.8	11.1	22.5
Net Product Imports c/	0.4	6.9	4.9	4.6	3.4	7.3
Total Consumption	18.9	33.7	36.6	37.0	44.3	64.0
% Self-Sufficiency	36	31	45	56	67	53
Natural Gas (million toe)						
Field Production	1.2	1.9	3.1	3.3	3.3	8.3
Less: Field Uses	0.2	0.2	0.3	0.5	0.5	0.7
Flared Gas	0.6	0.6	1.2	1.3	0.6	0.8
Net Consumption	0.4	1.1	1.6	1.5	2.2	6.8
Total Petroleum Consumption	19.3	34.7	37.2	38.5	46.5	70.8

a/ Production forecasts are based on development of presently known petroleum reservoirs and do not assume new discoveries from the accelerated exploration program.

b/ Domestic crude oil production in 1980/81 was adversely affected by political unrest in Assam. In comparison, domestic production was 11.8 million tons of oil in 1979/80 representing 37% of total oil consumption.

c/ Crude oil equivalent of petroleum products converted at 1.0638 tons of crude per ton of products and gas at 0.81 toe/1000 cubic meters. The trends in the production and consumption of petroleum products are shown in Annex 3.3.

Source: Annex 3.1 and Indian Petroleum and Petro-Chemical Statistics 1982-83.

to participate in exploration under production-sharing contracts (para 3.09). In addition, the investment programs of ONGC and Oil India Limited (OIL), the Government-owned institutions engaged in exploration and development of hydrocarbon resources, have been increased by over 100% in real terms in the current Sixth Five Year Plan (1980/81-1984/85) compared to the previous plan period (para 3.10).

B. Petroleum Pricing

(a) Consumer Prices of Refined Petroleum Products

3.04 Domestic petroleum product and crude oil prices are regulated by the Government, and the Government policy in petroleum pricing has been to consistently set the price of petroleum products at levels designed to ensure efficient use of energy. Retail product prices have been maintained, on average, at or above international levels. At the present time, both the level and structure of petroleum prices in India are considered satisfactory. Current retail prices are summarized in Table 3.2.

Table 3.2: Retail Prices of Petroleum Products.

Products	INDIA Rs/litre a/ Sept. 1983	INDIA US$/gallon C.I.F. Imports	INDIA US$/gallon Retail	Retail in US$/gallon TURKEY d/	Retail in US$/gallon CHINA c/	Retail in US$/gallon USA d/
Gasoline	6.09	1.07	2.31	2.14	1.24	1.12
Kerosene						
(Subsidized)	0.05 b/	—	—	—	—	—
(Unsubsidized)	1.88	1.14	0.71	1.44	1.16	1.59
Diesel Oil	3.20	1.10	1.21	1.44	0.77	1.20
Fuel Oil	2.80	0.75	1.06	0.98	0.16	1.25

a/ These are retail prices in New Delhi, which approximates average prices in India. Prices based on conversion factor of Rs10= US$1.00 and also reflects price changes implemented in September 1983.

b/ There is a dual pricing policy for kerosene introduced in February 1983. 7% of supplies are to be distributed at subsidized prices to cater for the poor households. Purchases at the subsidized price are through official ration coupons. Price increase for unsubsidized kerosene are designed to achieve parity with diesel oil prices and hence minimize diesel adulteration with kerosene.

c/ Current average retail prices.

d/ 1982 average retail prices.

Sources: GOI; Department of Petroleum; World Bank and Annex 3.1.

(b) Producer Prices

3.05 Crude oil selling prices of ONGC and OIL, which were raised in July 1981 from US$6.1 per barrel to US$17.3 per barrel, are lower than international prices but still ensure satisfactory profits for the companies. In 1982/83, ONGC's profit per barrel of oil (US$4/Bbl)[1]/ was in line with the average for international oil companies. The profit is expected to increase to $5 per barrel by 1984/85 at the current level of domestic prices, provided anticipated increases in oil and gas production are realized. The profits provide sufficient cash flow to enable the companies to finance a substantial portion of their investment programs from internally-generated funds (para 6.09). ONGC's and OIL's exploration and development decisions are based on international prices, and hence the lower domestic selling price does not act as a disincentive to exploration and development. Under the production-sharing contracts, foreign oil companies will receive the full international price for their share of production that the Government has the option to purchase.

(c) Natural Gas Prices

3.06 Natural gas is currently sold directly by the producers (ONGC and OIL) to consumers on the basis of long-term contracts that require Government

1/ ONGC's gas production was converted to oil equivalent and included in total oil sold in arriving at this profit per barrel of oil.

approval. Natural gas prices vary according to use and source. On a use basis, gas is priced to be competitive with the energy equivalent price of the alternative fuel for which it is substituting. Offshore gas, which accounts for about 55% of gas sales at present, is priced at between Rs 555 and Rs 2,780/1000 Nm^3 depending on the intended use (US$1.49 and US$7.44 per thousand SCF.). The lower price applies to interruptible supplies to power plants otherwise using coal or high sulphur heavy fuel oil and the higher prices apply to guaranteed supplies to industry and fertilizer plants. On average, ONGC receives about Rs 1428/1000 Nm^3 (US$3.83/1000 SCF)[1/] for offshore gas, which is well above its production and delivery costs and, in energy terms, is in line with the international price of fuel oil. Onshore gas prices are relatively low, but will eventually be priced much higher; ONGC's intention is to price the gas originating in Gujarat closer to the price of offshore gas. For onshore gas from Gujarat, which accounts for about 20% of gas sales at present, the current price is about Rs 355/1000 Nm^3 (US$0.95/1000 SCF). This price is heavily influenced by the low price stipulated in old long-term contracts. ONGC intends to increase this price as contracts are being reviewed or renegotiated, with the ultimate objective of applying the same pricing principle (i.e., competitiveness with alternative fuels) as the one used for offshore gas. Recently ONGC unilaterally increased Gujarat gas prices to the level of offshore gas prices under some contracts that just expired but industrial consumers have successfully challenged ONGC's action in state courts. The matter is now under appeal by ONGC. It is likely that a compromise will be reached which would raise the gas price close to (e.g., about 75%) fuel oil parity (excluding domestic taxes, i.e., CIF basis) over several years (e.g., five years). For onshore gas from Assam, which accounts for about 25% of gas sales at present, the price is about Rs161/1000 Nm^3[1/] (US$0.43/1000 SCF) reflecting the surplus of associated gas which is being flared due to the small size of the market in that isolated region. The average level of gas prices and their expected trend in the near future is currently satisfactory.

C. Subsector Institutions

3.07 In the public sector, two companies, ONGC and OIL, have traditionally undertaken petroleum exploration and production activities. ONGC had, and will continue to have, the largest involvement in the petroleum sector as the principal entity in charge of petroleum exploration and development. OIL is much smaller than ONGC and produces about 3 million tpy of oil, all from Assam. Until recently, it had a license covering only about 2,500 km^2 in Assam and Arunachal Pradesh. The company has explored its license area extensively and has replenished its reserves through steady but small discoveries. Since late 1981, OIL obtained exploration rights in Orissa (the Mahanadi basin), both onshore and offshore, and in areas in Rajasthan.

3.08 The Ministry of Energy is directly in charge of policy making in the petroleum sector. It monitors activities in the sector closely and, *inter alia*, has to vet all the programs and budgets proposed by public sector enterprises. The Oil Industry Development Board (OIDB), a public body created in 1974, provides financing to public sector enterprises in the petroleum production and refining sectors. Its only source of revenues is a cess levied on domestic oil production. The Department of Economic Affairs of the Ministry of Finance is responsible for approving foreign exchange expenditures and for mobilizing foreign exchange resources. Finally, both the Ministry of

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1/ These prices are as of September 1983.

Finance and the Planning Commission review and approve the budget proposals of ONGC and OIL as endorsed by the Ministry of Energy. The attached map (IBRD Map No. 17603) presents the main features of India's petroleum subsector.

D. Petroleum Exploration Policies and Investment Strategy

3.09 The government's current investment program in the petroleum sector contains the following three principal components: (i) to accelerate exploration by both foreign and national oil companies; (ii) to increase production from existing fields, primarily by accelerating the development programs of ONGC and OIL in areas where hydrocarbons have already been discovered; and (iii) to develop the gas pipeline system and gas-using industries (e.g. fertilizer and petrochemical plants) to use more effectively the significant gas reserves currently untapped. In order to encourage foreign oil companies and attract risk capital for exploration, in late 1980, the government offered to international bidders thirty-two blocks, each ranging in size from 10,000 to 30,000 km^2 offshore and onshore. The total area offered, almost 0.9 million km^2, represented about 50% of the country's sedimentary basin area. One production-sharing agreement was signed with a consortium led by Chevron (USA) for an 18,500 km^2 block in the Saurasthra basin offshore Gujarat, north of the Bombay High field. The terms of the production sharing agreement provide for Chevron to drill at least three wells, spending a minimum of US$29 million over a three-year period, at its own risk. Upon commercial discovery, ONGC may assume up to 50% joint venture in future development (without payment of exploration costs), and production will be split according to a scale which escalates with field profitability. Until India achieves self-sufficiency in oil, GOI has the option to purchase Chevron's share of the oil produced at international prices. Chevron has completed the seismic surveys and drilling started in late 1983 after the monsoon season. Meanwhile, invitations to bid on a second round of offerings were issued end-August 1982 to 37 foreign oil companies. The second offering covered about 50 blocks both onshore and offshore, including new areas such as west of the Bombay High field (in 200 m of water) and the outer-shelves of the offshore Krishna-Godavari and Mahanadi basins. Unfortunately this second offering coincided with the worldwide decline in investments for petroleum exploration by the international oil companies which affected most of the developing countries, particularly the oil importing ones. Only a few bids were received in early 1983; discussions are still going on with two of these bidders. It appears that any substantial increase in participation by international oil companies is unlikely to materialize for a few more years. Nonetheless, the first steps in opening up prospective acreage to private oil companies have been initiated; any significant increase in the participation of private oil companies to a level commensurate with India's exploration needs will require not only a turnaround in worldwide exploration activities but also flexible and imaginative approaches in attracting new exploration investment. The ongoing discussions with foreign oil companies will provide a preliminary test. The Indian authorities reiterated during project appraisal the Government's intention to continue its "open-door" policy and to undertake new initiatives after a turnaround in worldwide exploration activities take place. One idea being considered is to have ONGC's subsidiary, Hydrocarbons India Limited (para 4.03), form joint-ventures with both foreign and local private companies to undertake exploration projects. In the meantime however, any accelerated development of India's hydrocarbon potential will depend largely on ONGC's and OIL's ability to undertake and manage large and complex investment programs.

3.10 Following the successful implementation of the initial four phases of development of the Bombay High field as well as the encouraging results of recent exploration activities, GOI has authorized both ONGC and OIL to accelerate their petroleum exploration and development programs. Thus, while the current Plan (1980/81-1984/85) originally earmarked about Rs 33.3 billion in 1980/81 prices for petroleum exploration and development, which represented a 47% real increase above the actual expenditures during the previous five-year period (1975/76-1979/80), ONGC and OIL have responded with a much higher revised budget proposal of about Rs 57.8 billion in 1980/81 prices for exploration and development, most of which has already been approved. The focus of this revised program (para. 4.11) is the accelerated implementation of the fifth and sixth development phases of the Bombay High field, the development of the offshore South Bassein gas field including the related gas transportation infrastructure, further exploratory drilling in the Krishna-Godavari basin, and further exploration and development in the onshore producing areas (i.e. Cambay Basin and Assam).

E. The Bank's Role and Lending Strategy in the Petroleum Subsector

3.11 Most of the Bank's lending operations to India in energy have been in the power subsector (31 Bank/IDA operations for a total of US$3,656 million) and span a period of 34 years. However, the Bank's involvement in the petroleum subsector has grown substantially within the last six years. Four loans have been made to ONGC including two for the development of the Bombay High field[1/] (US$550 million in all); one for exploration in the Krishna-Godavari basin (US$165.5 million)[2/], and another for offshore gas development in South-Bassein (US$222.3 million)[3/]. A loan (US$200 million) has also been made for the modernization of several refineries[4/].

3.12 Although ONGC was the main beneficiary of these four loans, each project was designed to address a specific set of issues in the sector. The first Bombay High project aimed at establishing the basis for a sound long-term development program for Bombay High (the most important oil field in India), initiating the early development phases in an effective manner, and introducing ONGC to the financial markets. These objectives were largely fulfilled. The second was aimed at accelerating the development of Bombay High at the time of rapid increase in oil prices. The South Bassein operation sets the initial conditions for the creation and development of gas infrastructure, while the Krishna-Godavari exploration project provides a framework within which ONGC exploration policies as well as the balance between national and private resources can be better assessed. The proposed project aims at improving the efficiency of onshore operations, which though smaller than Bombay High (in terms of oil production) can make a substantial contribution to domestic petroleum supplies. The Bombay High I project was satisfactorily completed and a completion report has already been issued[5/]; disbursement for the Bombay High II project has just been completed.

1/ Loan No. 1473-IN approved in June 1977, and Loan No. 1925-IN approved in December 1980.
2/ Loan No. 2205-IN approved in October 1982.
3/ Loan No. 2141-IN approved in February 1983.
4/ Loan No. 2123-IN approved in April 1982.
5/ Project Performance Audit Report No. 4139, October 13, 1982.

3.13 With regard to oil exploration, India's recent policy of having parallel efforts by national and international oil companies is fully justified and is well focused. While not formally associated with the process, the Bank has been instrumental in increasing the attractiveness of the offerings (the seven proposals received in the 1980 offering were for two blocks added at the suggestion of the Bank). The Bank will continue its dialogue with the Government on this subject to improve the chances of success of future exploration acreage offerings to the private sector. Through its own lending the Bank has, to a considerable extent, also assisted in minimizing the risks of the Krishna-Godavari exploration program by reducing the project area and bringing about a more balanced exploration among the onshore, shallow offshore and deep offshore portions of the project area. The Krishna-Godavari exploration project is the first major basin exploration project undertaken by ONGC. While ONGC has the basic capability to manage this program, Bank involvement in the design of the program, methods of implementation, evaluation of results, and adjustments made to the program, has also benefitted ONGC staff and made them better appreciate the risks involved.

3.14 India's western offshore free and associated gas reserves are quite large, with a production potential equivalent in energy terms to 65% to 80% of the maximum western offshore oil production expected. But these gas reserves are currently underdeveloped, primarily because of difficulties in matching resources with markets. The development of the South Bassein offshore gas field represents a new challenge to ONGC and the government as it is the first major gas development project in India. Unlike crude oil, such a project has to be optimized not only in terms of reservoir considerations, but also in relation to the potential market for natural gas. During the preparation of that project the Bank discussed with GOI, ONGC, and its consultants, the scope of market studies to be carried out and has been instrumental in demonstrating the benefits of a wider utilization of gas. As a result, the main components of that project have been optimized in terms of the anticipated market. This dialogue will continue during project supervision as GOI formulates a long-term gas strategy designed to accelerate the development of free and associated gas reserves, based not only on the use of gas as feedstock in the fertilizer industry but also as boiler and household fuel.

3.15 So far, Bank assistance to the petroleum sector has aimed at accelerating the offshore programs which held the promise of quicker and larger oil/gas production increases. The offshore programs are progressing satisfactorily and now is the time to address the relatively more complex issues of onshore operations. In this regard, the future role of the Bank in India should be to: (i) assist the Government and the national oil companies to establish investment priorities, particularly by bringing the international experience of Bank specialists and consultants to bear on these problems; and (ii) support well-defined projects which will also act as vehicles for managerial and operational improvements, transfer of technology, and further mobilization of financing from commercial sources. In this context, an effective dialogue has been established with ONGC regarding its overall investment plans and strategy. This dialogue can be expected to be maintained through the Bank's continuing presence in key investment areas. These efforts should proceed in parallel through various projects, each addressing one or two specific sets of issues.

3.16 In the case of the proposed Cambay Basin Petroleum Project, the Bank has made a substantial contribution in: (i) modifying and improving the scope of, and the implementation arrangements for, the investment program in the basin; (ii) providing the basis for improving ONGC's oil field operations through training, use of consultants and introduction of appropriate and modern technology, equipment and materials; (iii) suggesting improvements in ONGC's drilling and other operational policies and practices; and (iv) encouraging the Government and ONGC to continue to diversify their sources of foreign exchange financing.

3.17 The Bank has consistently encouraged ONGC to diversify its sources of foreign exchange financing. This effort has been largely successful and ONGC has established itself as a credit worthy borrower in the international financial market. Initially, cofinancing was mostly associated with specific procurement packages using export, buyer's or supplier's credits, although recently ONGC has borrowed increasing amounts of untied funds through Euro-currency borrowings from commercial banks. Of the eleven commercial bank borrowings by ONGC during 1977-83, eight (ranging from US$16 to US$42 million each for a total of about US$232 million) were buyer's credits, that is, were specifically associated with the purchase of major equipment packages (e.g., platforms, jack-up rigs, etc.) and entered into after the procurement award was made. The other three were major Euro-currency borrowings for general corporate purposes (i.e., not earmarked for specific procurement items) and each one was entered into following negotiations/approval of a Bank-financed project. A substantial proportion of these funds were eventually utilized for Bank-assisted projects. The first (US$50 million) followed Bank approval of the Bombay High I Project; the second (US$200 million) followed approval of the Bombay High II Project; and the third (US$400 million) followed approval of the South Bassein Gas Development Project.

IV. THE OIL AND NATURAL GAS COMMISSION (ONGC)

A. Introduction

4.01 The beneficiary of the proposed loan will be the Oil and Natural Gas Commission (ONGC). ONGC was initially formed in 1955 as the Oil and Natural Gas Directorate within the then Ministry of Natural Resources and Scientific Research. In 1959, the Directorate was transformed into a separate statutory body and re-named the Oil and Natural Gas Commission by an act of Parliament. ONGC was to "plan, promote and implement the development of petroleum resources and the production and sale of petroleum products produced by it." ONGC's statutes provide that it is a corporate body with power to acquire, hold and dispose of property. ONGC also has authority to contract and borrow. ONGC has evolved into a full-fledged oil company although its operations are primarily petroleum exploration and production, including the sale of natural gas, and do not include oil refining nor sales of refined petroleum products.

4.02 ONGC is managed by an operating board or commission consisting of a Chairman and not less than two, but not more than eight, Members appointed by the government generally for a period of five years each. At present, the commission consists of the Chairman, six full-time Members (Finance, Materials, Personnel, Exploration, Offshore and Onshore) and two part-time Members (representing the Ministry of Finance and the Ministry of Energy). All

decisions of the commission must be approved by a majority of the Members. The commission sets policies, manages the activities of ONGC, and develops the plans and budgets of ONGC which have to be endorsed by the Ministry of Energy, Ministry of Finance and the Planning Commission before they are sanctioned by Parliament.

4.03 ONGC has established three institutes to support its petroleum operations and one subsidiary to undertake foreign ventures. The first institute, established in 1963, was the Institute of Petroleum Exploration (KDMIPE).1/ This institute presently has a staff of about 800 technical personnel and reviews all exploration proposals, programs and exploratory well locations. The second institute, established in 1977, was the Institute of Reservoir Studies (IRS) which provides technical support in the areas of reservoir engineering, field development planning as well as enhanced oil recovery research and applications. IRS has about 80 technical staff at present. The third institute, established in 1978, was the Institute of Drilling Technology (IDT). This institute has a staff of about 50 technical personnel and is responsible for setting the drilling policies and standards of ONGC, for reviewing and approving well designs and drilling programs, and for training. Finally, ONGC has a subsidiary, Hydrocarbons India Limited (HIL), established in 1964, which undertakes foreign ventures. HIL took a one-sixth share in a production-sharing exploration venture in Iran (1968-1980) and undertook an exploration contract in Iraq (1973-1977). HIL also undertook contract drilling work in Tanzania (1976-1979) and in Iraq (1977-1979). All these ventures are now completed or terminated. While HIL has no foreign venture prospects at this time, it is expected that it will participate in local joint ventures with both foreign and domestic private companies to provide technical support services which ONGC will increasingly need as well as to undertake exploration projects.

4.04 ONGC's organization and operations have expanded rapidly, both in terms of size and complexity, during the last eleven years as shown by the figures in Table 4.1. Most of the growth and diversification was the result of the hydrocarbon discovery in 1974, and subsequent development, of the giant Bombay High offshore oil field.

B. Organization and Management

1. Organization and Management Structure

4.05 ONGC's organization chart is shown in Annex 4.1. At present, ONGC's main exploration, development and production activities are divided among two major groups under the Member Onshore and the Member Offshore respectively. Onshore operations are further sub-divided into three regions, the Eastern Region with headquarters in Nazira (Assam) and covering Assam and the adjacent states; the Western Region with headquarters in Vadodara and covering Gujarat, Rajasthan, Uttar Pradesh and the northern states; and the Central Region with headquarters in Calcutta covering West Bengal, Bihar, Madya Pradesh, Maharashtra and the southern states. The proposed Cambay Basin project will

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1/ Renamed the Keshava Deva Malaviya Institute of Petroleum Exploration (KDMIPE) in 1982.

be under the jurisdiction of the Western Region; the organization chart for this group is shown in Annex 4.2. Offshore operations are grouped into the Bombay Offshore Project (BOP) with headquarters in Bombay. The main administrative and financial functions (planning, procurement and stores, accounting, personnel, computer activities, etc.) and technical support services are centralized in the corporate headquarters at Dehra Dun located about 200 km. north of New Delhi.

4.06 Following the rapid expansion of ONGC during the last eleven years, the offshore/onshore organizational framework has become complex, and currently the overall ONGC structure is beginning to show strains and inefficiencies. With ONGC's growth expected to continue into the 1990's, the issue of organizational efficiency has become a serious concern to ONGC, the government as well as the Bank. A specific proposal to restructure ONGC has been submitted to the Ministry of Energy along the following three concepts: (a) the "common basin" management approach in which specific operations in an entire basin, even those with both onshore and offshore portions or those straddling state boundaries, would be managed by the same unit; (b) the business group or functional approach in which activities would be grouped into similar functions or profit/cost centers rather than by geographical location; and (c) the concentration of ONGC resources and efforts in the basic exploration and production activities with a reduction in ONGC's own participations in areas such as petroleum transportation, drilling equipment and other technical support services which can be provided by contractors. The "common basin" approach has already been introduced and the more substantial organizational restructuring is expected to be implemented within the next year or two. The Bank supports this streamlining of ONGC's organization and will continue to exchange ideas with ONGC on specific operational aspects of its organizational framework.

2. Management Information Systems

4.07 Under the Bank's first project with ONGC (Bombay High I project, para 3.12), the accounting and financial systems of ONGC, as well as the project management and reporting system of BOP, were reviewed by consultants whose main recommendations have since been implemented by ONGC. During the past several years, ONGC has developed adequate management information systems. A comprehensive operational monthly report is prepared by BOP and each of the regional onshore groups, which highlights to ONGC management the status of different activities and enables the commission to take remedial actions whenever the need arises. Some of the major accounting systems (e.g. payroll, budget) have also been recently computerized. This will enable ONGC to close its financial books and prepare its unaudited financial reports as well as prepare its budget much faster than before. Other financial systems (e.g. cash and bank deposit management) are in the process of being computerized. ONGC has submitted timely progress and financial reports to the Bank and no problems are expected in the future. During negotiations, agreement was reached with ONGC that it will provide the Bank with periodic project progress reports (para 5.56) as well as semi-annual unaudited financial reports during project implementation within 45 days after the end of the period covered. ONGC will also be asked to prepare a Project Completion Report within six months after the project is completed or after the proposed loan is completely disbursed.

Table 4.1: ONGC Pattern of Growth (1972/73 - 1982/83)

	ONGC Growth Indicators		
	1972/73	1982/83	% Average Annual Increase
Employment			
Onshore	21,448	29,377	
Offshore (BOP)	20	3,643	
Total	21,468	33,020	4.4
of which: Managerial/Supervisory	2,901	9,232	
Skilled	7,464	13,060	
Clerical and unskilled	11,103	10,728	
Oil Production (million tons)			
Onshore	4.1	5.4	
Offshore	-	13.0	
Total	4.1	18.4	16.2
Gas Production (billion m^3)			
Onshore	0.7	1.1	
Offshore	-	1.8	
Total	0.7	2.9	15.2
Operating Revenue (Rs billions)	0.5	23.6	47.0
Net Income After Taxes (Rs billions)	0.1	6.9	53.0
Total Assets (Rs billions)	2.5	43.1	16.9
Total long-term debt (Rs billions)	0.9	16.1	33.4
of which: Foreign Commercial Sources	Nil	9.0	-
Number of Rigs Owned			
Onshore	32	40	
Offshore	-	6 a/	
Total	32	46	3.7
Drilling			
Number of Wells Drilled: Onshore	61	114	
Offshore	-	64	
Total	61	178	
Meters Drilled (1,000) Onshore	115	224	
Offshore	-	162	
Total	115	386	12.9
Geophysical (Seismic) Surveys (1,000 line-km)			
Onshore	5.6	5.3	
Offshore	-	13.9	
Total	5.6	19.2	13.0

a/ ONGC also used 8 hired offshore rigs.

3. Accounts and Audit

4.08 Each project unit has a Finance and Accounts Section reporting to the Project Manager and to the Member Finance at ONGC's headquarters. The Internal Audit Section is also under the Member Finance, in Dehra Dun, and performs satisfactorily. ONGC's acounts are audited by the government's Comptroller and Auditor General, which is acceptable to the Bank. Starting with the 1981/82 audited financial statements, ONGC included supplemental information covering inflation adjusted accounts as well as reserve (petroleum) recognition accounting. This is indicative of the increasingly sophisticated financial reporting system developed recently and further enhances ONGC's standing in the international financial market. While ONGC's accounts are generally available four months after the end of the fiscal year at the latest, GOI rules and regulations provide that ONGC's audited accounts cannot be made public before they have been approved by Parliament. During negotiations, agreement was reached that the Commission's audited accounts will be submitted to the Bank not later than twelve months after the end of the fiscal year.

4. Insurance

4.09 ONGC has adequate insurance coverage for its existing offshore installation, equipment, vessels, etc., with several insurance companies in India which are reinsured in the international market. Insuring follows the international practice whereby designs are certified by independent agencies. ONGC self-insures onshore petroleum exploration and production facilities, which are relatively less expensive compared to offshore facilities. This is reasonable given the geographic diversity of its onshore activities. ONGC's insurance coverage for its existing facilities is satisfactory.

C. ONGC's Investment Program (1984/85-1989/90)

4.10 ONGC is now on the fourth year of the Five-Year Plan (1980/81-1984/85). This Plan was revised in August 1981 to include the accelerated programs for exploration and for the final development of the Bombay High field. ONGC has also prepared plans covering the second half of the decade and the next twenty years respectively. These plans are in two variants: Variant I has the objective of increasing ONGC's annual oil production to about 45 million tons by 1989/90 while Variant II aims at 60 million tons per year of oil production by 1989/90. Both of these variants are ambitious, given that ONGC's existing reserves, when fully developed, can reach an annual production rate of just about 31 million tons of oil (ONGC's oil production in 1982/83 was about 18 million tons). These plans therefore assume that increased exploration in the early 1980's will yield commercial discoveries which can be brought into production by the end of the decade. The government in principle approved in November 1982, all exploration components as well as the development of presently known reserves proposed in Variant I, but did not approve the speculative portion relating to the development of expected future discoveries. These types of development investment will be proposed by ONGC as the discoveries are actually made. The portion of Variant I approved by the government is known as the Core Plan and its major components are briefly discussed in Annex 4.3. The Core Plan investments over the next six years are summarized in Table 4.2.

Table 4.2: ONGC Investments (1984/85-1989/90) a/

	Rs billion	US$ billion	%
Exploration			
Offshore	31	3.1	16
Onshore	41	4.1	21
Sub-total	72	7.2	37
Development			
Offshore	73	7.3	37
Onshore	46	4.6	24
Sub-total	119	11.9	61
Misc. Items	3	0.3	2
Total	194	19.4	100

a/ Items common to exploration and development, which account for about 35% of the total investments have been allocated 75% to development and 25% to exploration. The proposed Cambay Basin Petroleum project would account for about 5% of the Core Plan investments during this period.

4.11 In the absence of new major discoveries, ONGC's reserves/production ratio will decline from about 23 years at present to only about 12 years by 1989/90. This means that the rate of increase in oil production will begin to slow down after 1984/85, production will peak towards the end of the decade, and then gradually decline thereafter unless new commercial discoveries are made and brought into production within the next five to ten years. Without new discoveries and increased recovery from existing reserves, ONGC would find it difficult to continue to generate the internal resources needed to finance a major proportion of its investment program. Thus, for ONGC to maintain prudent debt/equity and debt service coverage ratios, the government will have to either provide additional equity funds or increase ONGC's selling prices substantially or the program would have to be reduced to match the availability of funds. This emphasizes the importance of seeking major new discoveries in the next few years and justifies the ambitious exploration program which represents about 37% of total investment until the end of the decade. It also emphasizes the need for ONGC to maintain prudent financial policies, particularly with respect to borrowings, until its petroleum reserve base is further increased. ONGC's exploration strategy is to balance the program between areas of lower risk and lower potential with areas of higher risk but with greater potential for discovering large new reserves. During the next six years, about half of the exploration investment will be in producing areas of Assam, Gujarat and offshore Bombay, which in the near term hold promise of modest but more certain additions to reserves. In addition, ONGC will continue the ongoing evaluation of the Krishna-Godavari delta which is the most promising frontier area in India today and which in the medium term could contribute major additions to petroleum reserves.

D. Operating Performance and Challenges

4.12 ONGC is a competent organization which has been able to take increasingly larger responsibilities over a short period of time. Its growth and overall performance during the past decade is impressive as its activities have progressed from relatively small onshore operations and almost complete reliance on in-house capabilities, to large integrated offshore projects requiring sophisticated management, the acquisition of modern technology, and the use of international contractors. But, as indicated earlier, the very fast growth and diversification of activities has caused serious organizational and managerial strains. These have been recognized and are expected to be largely remedied through the proposed restructuring of the organization which would decentralize the operating management while retaining a centralized policy-making system, as well as establish profit or cost centers for control and evaluation purposes. Rapid growth has also introduced serious operational and financial constraints which could adversely affect the implementation of ONGC's accelerated petroleum exploration and development program. The demands of the large offshore operations, which continue to absorb most of ONGC's resources, have led to a relative neglect of onshore operations, stretched ONGC's project implementation capacity, created a shortage of experienced technical staff and brought about a need to mobilize large amounts of foreign exchange resources very quickly. As a consequence, ONGC's onshore operations have suffered from insufficient exploration and development budgets, less experienced technical staff, and grossly inadequate equipment as well as obsolete technology (Annex 4.4). These factors are reflected in the lack of any substantial growth in ONGC's onshore oil reserves and production over the last decade.[1/] The Core Plan investments for the next six years have begun to remedy this imbalance. While still heavily offshore oriented, the Plan reflects a relatively higher proportion of onshore investments particularly for exploration, compared to the last five years.

4.13 In order for ONGC to effectively and efficiently undertake the large investment program and operations envisaged for the rest of the decade, it has to take decisive actions along several fronts. In addition to the organizational re-structuring and larger budget allocations for the onshore operations mentioned earlier, the following are required: (i) to adopt a policy of contracting a substantial proportion of the drilling and technical services in onshore operations (as in the case of offshore operations), not only to complement ONGC's own limited capabilities and act as vehicles for technology transfer, but also to focus more of ONGC's scarce technical manpower and financial resources on the basic exploration and development activities (para 5.34); (ii) to expand and upgrade the training program for oil field workers which is minimal and unsatisfactory at present; (iii) to use technical consultants to help improve onshore operations as is the case in offshore operations; (iv) to replace and upgrade the existing equipment and technology for exploration, drilling, workover and production in onshore operations; (v) to improve field communications in all onshore regional

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1/ Another reason for the lack of growth in onshore production is the political and social unrest in Assam during the last several years which has slowed ONGC exploration and development efforts in the Eastern Region.

operations; and (vi) to continue to diversify the sources of foreign exchange financing, particularly the use of commercial bank loans, while keeping the overall debt/equity ratio and the debt service coverage ratio at prudent levels (para 6.05).

4.14 ONGC has already taken steps along the lines mentioned above and the proposed project will reinforce and emphasize these actions. For example ONGC has adopted an approach of using offshore and onshore drilling contractors for as much as 40%, as well as hiring offshore supply vessels for as much as 65%, of the company's requirements. Similarly, ONGC is already contracting out a major proportion of its offshore technical well services and is also beginning to contract for onshore technical services. In all of these areas, ONGC has encouraged local firms to form joint ventures with experienced foreign firms in order to lower costs and contribute to the technology transfer into the country. The proposed project is also intended to improve ONGC's onshore operations.

V. THE PROJECT

A. Background

5.01 The systematic search for hydrocarbons in the Cambay Basin (IBRD Map No. 17604) was begun by ONGC in the mid-1950's supported by technical assistance supplied by the U.S.S.R.. The first hydrocarbon discovery was made in 1958; however, ONGC did not become aware of the basin's true potential until the discovery of the Ankleshvar field in 1960 (the largest and most productive field in the Cambay Basin). The bulk of the oil reserves established in the basin was discovered between 1960 to 1970, with only minor fields and moderate quantities of oil reserves discovered since then. A total of 1324 wells have been drilled in the basin through 1982, of which 697 are exploratory tests and 627 field development wells. To date, about 170 oil or gas prospects (structures, fault closures, or stratigraphic traps) have been identified, of which 134 have been drilled and 49 established as hydrocarbon bearing (a 36% success ratio).

5.02 As mentioned earlier, ONGC and Bank petroleum staff discussed in 1982 ONGC's petroleum investment program and, in particular, its plans for increasing oil and gas production onshore and offshore. In general, ONGC is expecting offshore areas (i.e. the offshore Bombay Basin) to provide the major portion of the anticipated increase in oil and gas production during the 1980's. Accordingly, the offshore effort was given the preference over onshore operations in the use of the most modern drilling equipment, support facilities and qualified field and technical personnel. As regards onshore areas, ONGC was satisfied with a strategy of first stabilizing and then moderately increasing onshore oil production by approximately 25% over the next seven to ten years. The consequences of ONGC's past investment strategy in the onshore part of the Cambay Basin have been the following:

(a) Hydrocarbon production in the basin is oriented toward the recovery of lighter crudes, leaving the vast in-place reserves of heavier oil[1/] located in the northern parts of the basin undeveloped;

1/ Crude oil of about 18 degrees API gravity and a viscosity range of 100 to 550 centipoise found in the Balol, Lanwa and northern Santhal oil fields.

(b) Approximately 345 potentially producing wells are at present inactive and in need of mechanical repair. However, the current fleet of ONGC workover rigs in the basin is old, inefficient and unable to keep up with the repair load. Lost oil production due to the backlog of wells to be repaired is estimated at about 300,000 to 400,000 tons per year;

(c) A total of about 550 development infill wells are required during the next 3 to 4 years to sustain current levels of production and adequately drain some reservoirs. However, available drilling rigs are outdated and unable to perform this field development task due to excessive breakdowns and maintenance difficulties;

(d) The basin's greatest remaining exploratory potential is beneath the shallow waters of the Gulf of Cambay and the contiguous tidal swept mud flats and shoal areas. However, due to technical and equipment constraints, very little exploration effort was planned in this shallow water/tidal area.

5.03 Following technical discussions with Bank staff and consultants during the project identification, preparation and appraisal process, ONGC has been able to formulate a comprehensive exploration, development and field rehabilitation program which the government has accepted as a high priority undertaking. The most important aspects of this program are incorporated in the proposed project. While this project is partly based on ongoing ONGC investments, a significant portion of the restructured investment program in Cambay is based on new initiatives, identified with the assistance of the Bank. The development of the heavy oil fields, which were discovered in the late 1960's, is a case in point. This development had not been planned by ONGC for this decade due to a misconception (as a result of inferior well design and lack of good reservoir engineering in the early 1970's) that these fields can only be produced by advanced enhanced oil recovery (EOR), i.e., thermal recovery techniques. Thus, ONGC had only planned for some pilot thermal recovery schemes to form the basis for a full scale commercial EOR project during the 1990's. It was for assistance in these pilot EOR schemes that ONGC initially approached the Bank. Subsequently, however, the Bank staff was able to convince ONGC and the government that these heavy oil fields can and should be immediately produced by primary methods using proper well design and artificial lift equipment. The final development plan for the Kalol field, on the other hand, was conceived and proposed by ONGC's staff (with Soviet assistance) but, because the plan relied on extensive utilization of artificial lift equipment in addition to water flooding, which made it complicated and relatively expensive, it did not receive, prior to the involvement of the Bank, the proper priority in ONGC's investment plans due primarily to the resource constraints faced by ONGC and the tendency of favoring offshore investments to onshore investments.

5.04 Although ONGC has extensively and successfully utilized foreign contractor services and consultants for offshore operations, ONGC prefers to undertake, and during the past decade has in fact undertaken, all onshore operations by itself. There has also been very little transfer of experience and technology from the offshore to the onshore operations. Both of these factors have seriously retarded the technological development of onshore

activities. However, a major breakthrough was achieved under the Krishna-Godavari exploration project when ONGC utilized, for the first time in over a decade, foreign drilling contractors and consultants for the deep abnormal high pressure onshore exploration drilling component of that project. ONGC is now appreciating more fully the benefits of hiring foreign drilling contractors for some of the more difficult exploration drilling onshore. Under the proposed project, ONGC will also hire technical consultants as well as foreign drilling and technical well services contractors.

B. Main Characteristics of the Hydrocarbon Fields in the Cambay Basin.

5.05 The Cambay Basin (IBRD Map No. 17604) covers an area of about 56,000 square kilometers and is one of the major petroleum basins in India. Located in the State of Gujarat in northwest India, the basin is a roughly north-south, down-dropped graben (i.e., fault-bounded trench) approximately 400 kilometers in length and 80 kilometers in width. Due to the sand distribution pattern of the main producing sequence, the oil/gas fields are noticeably grouped to the northern and southern ends of the graben with few exploratory locations and producing fields in the central area.

5.06 To date, ONGC has concentrated geophysical, exploratory drilling and field development efforts in the northern tectonic blocks of the Cambay Basin where the search for oil and gas has reached a relatively mature stage. However, the southern and central portions of the basin, including the nearshore tidal and shallow water areas of the Gulf of Cambay, remain relatively untouched and still in an early stage of development.

5.07 Annex 5.1 describes the geology and main petroleum fields of the Cambay Basin. The main characteristics of the hydrocarbon fields in the basin are summarized below:

Table 5.1: Main Characteristics of the Cambay Basin Hydrocarbon Fields

Areal Size of Individual Fields, Square kilometers	2-15
Depth to Producing Zone, meters	500-2000
Age of Producing Zone	Tertiary
Porosity, %	18-30
Permeability, millidarcy	40-3,000
Formation Water Salinities, grams/liter	1,000-30,000
Oil Gravity, API	15-41
Viscosity at Reservoir Temperature, centipoise	0.1-550
Gas Oil Ratio, m^3/m^3	100-30,000

C. Status of Development of the Cambay Basin

5.08 Proved initial petroleum in-place reserves in the Cambay Basin are currently estimated to be about 500 million tons of oil equivalent (toe) of which about 447 million tons is oil and 53 million toe (65.7 billion m^3) is gas. Many of the petroleum pools have small initial in-place reserves of just 1 to 3 million toe. Approximately 140 million toe, or 28% of the proven in-place reserves, is recoverable. Cumulative production up to January 1983 was about 74 million toe — 67 million tons of oil and 7 million toe of gas. The

remaining recoverable reserves are thus about 66 million toe of which about 49 million tons is oil and 17 million toe is gas. Current production averages 8,920 tons per day (3.2 million tons per year) of oil and 2 million m^3/day (0.6 million toe per year) of gas. About one-half of the oil production comes from the Ankleshvar field, the largest and most important petroleum field in the basin. However, this major field has passed its peak productive years and its production has declined from 2 to about 1.5 million tons per year of oil at present. The petroleum reserves and production are distributed as follows:

Table 5.2: Cambay Basin Petroleum and Production

Field Name	Year Disc.	Proved Initial In-Place Reserves: Oil Million Tons	Proved Initial In-Place Reserves: Gas Billion M^3	Current Prod. Rate/day: Oil Tons	Current Prod. Rate/day: Gas M^3
Ankleshvar	1960	113.0		4,000	500,000 450,000 a/
Kalol	1961	51.5		850	600,000 300,000 a/
N. Kadi	1967	43.8		1,130	75,000
Jhalora	1965	26.1		425	-
Sobhasan	1968	24.6		300	-
Sanand	1962	13.0		-	-
Other Fields		175.0		2,215	90,000
Cambay Basin Total:		447.0	65.7 b/	8,920	2,015,000

a/ Non-Associated Gas

b/ About 36.1 billion m^3 (29 million toe) are either non-recoverable or are gas caps and isolated pools that ONGC does not intend to produce in the foreseeable future.

5.09 Of the Cambay Basin total proven initial oil_oin-place (IOIP), approximately 45 million tons are heavy oil (i.e., 18 API gravity or lower and 50 to 550 centipoise viscosity at formation temperature). These heavy oil reserves are essentially associated with one basic, elongated productive feature in the northern end of the basin. These fields are: Santhal, Balol and Lanwa. Estimated proven oil reserves in Santhal are about 40 million tons. Current estimates of proven heavy oil reserves in Balol and Lanwa are only about 5 million tons (IOIP), but both proven and probable reserves are estimated to be about 42 million tons. These estimates are subject to large variations due to the widely scattered well control and inadequate subsurface data until now. However, wells are to be drilled shortly as part of the project to better delineate the heavy oil reserves which are expected to be substantially in excess of current estimates.

5.10 About 25 isolated small oil and gas discoveries in the basin have not been fully evaluated. Furthermore, two interesting recent discoveries are the non-associated gas fields, Dahej and Hazira, which have yet to be fully evaluated with respect to total gas reserves. In addition, there are a number of wells with indicated recorded hydrocarbon accumulations that were not adequately tested or for which completion attempts were inconclusive. ONGC plans to develop most of the isolated oil fields during the next several years and is currently appraising the Dahej gas field.

D. Project Concept and Objectives

5.11 The major concept supporting the Cambay Basin Petroleum Project is that exploration and exploitation investments in a near mature hydrocarbon producing basin, while not anticipated to provide spectacular results, are often among the lower cost and lower risk opportunities available to establish additional proven reserves and markedly increase production levels. However, to achieve this would require a high level of organizational, operational and technical efficiency in all facets of petroleum operations as well as a systematic analysis of investment opportunities and priorities. Unfortunately, ONGC is presently deficient in many of these aspects. At the same time, priority investments cover the full range of petroleum activities, from exploration to enhanced oil recovery. This is because a substantial portion of the basin is still only lightly explored while the existing major producing fields have passed their peak productive years; their declining production must be made up by developing several undeveloped fields, improving production efficiency and preparing for enhanced oil recovery applications. Thus, the main project concept is to define an optimal program of investments as well as a broad program for improving ONGC's operating efficiency, and then design a project to effectively integrate and implement the investment and institutional improvement programs simultaneously in order to realize the substantial economic benefits as early as possible.

5.12 The proposed project thus has four major components with the following specific objectives: (i) exploration -- to pursue the search for petroleum by drilling deeper to less explored prospects, and by acquiring seismic data and hence identifing potential hydrocarbon prospects in the unexplored shallow waters and shoal areas of the Gulf of Cambay; (ii) development and production -- to accelerate the development of undeveloped and underdeveloped oil fields and improve maintenance of wells thereby increasing oil production in the basin by close to 2 million tons per year and gas production by about 142 million m^3 per year (0.12 million toe per year) within six years; (iii) enhanced oil recovery pilot tests -- to increase recoverable reserves by about 20 million tons of heavy oil and 4 million tons of light oil by determining the most appropriate enhanced oil recovery (EOR) method through field pilot schemes; and (iv) technical training and assistance -- to improve the drilling and production efficiency in the basin through training programs, hiring of technical consultants and contractors, as well as introducing new and modern equipment as an integral part of project implementation. The project has already been formally approved by the Public Investment Board (PIB).

E. Project Components

5.13 The project components are discussed in Annex 5.2 and are briefly described below.

1. Exploration Component

5.14 The exploration component has two sub-components, a seismic survey and deep exploration drilling.

a. Seismic Survey

5.15 Approximately 20% of the Cambay Basin is in the Cambay Gulf and covered by current swept shallow waters, tidal mud flats and shoals. To date, this highly prospective area has not been surveyed by ONGC with modern seismic methods due to the lack of specialized geophysical techniques and equipment needed to acquire data in this difficult environment. Only one well has been drilled in the mud flats area, the Aliabet No. 1, which tested oil in the Miocene. The seismic survey included in the project will: (i) help outline the seaward extent of the Dahej structure, a major Eocene gas field discovered in 1979 and currently under appraisal; (ii) delineate possible fault controlled structures (i.e., drillable prospects) in the Gulf similar to the Ankleshvar field; and (iii) help determine the western limits of the hydrocarbon bearing Eocene sands of the Narbada river delta. About 1,750 line kilometers of data will be acquired for this purpose using modern seismic survey techniques. Furthermore, depending upon the successful outcome of the offshore North Tapi No. 1 wildcat, located in the Gulf of Cambay about 75 kilometers southwest of Ankleshvar field, ONGC may propose, in late 1984, to add another 800 line kilometers of seismic survey under the project. This seismic acquisition would be south of the area covered by the 1,750 kilometer program and restricted to the eastern shoreline and saltwater marsh/swamp areas of the Gulf.[1/] The additional cost could be covered from the physical contingencies provided in the cost estimate.

b. Deep Exploratory Drilling

5.16 Most identifiable subsurface/seismic features in the basin have been drilled at least through the main Middle Eocene pay zones (i.e., down to about 3,000 meters). Future production increases from the onshore basin, other than that realized from infill drilling of undeveloped or underdeveloped fields and proposed EOR schemes, must be derived from yet to-be-tested deep prospects including those from reservoirs draped over basement highs located some 4,000 to 5,000 meters deep. The four deep exploration wells included in the proposed project represent the next logical phase in the exploration and exploitation of the basin. These four wells have been designed to primarily test deep prospects in zones which have previously indicated the presence of a hydrocarbon reservoir in other locations where these zones are relatively shallower or have been drilled (unsuccessfully) recently. Successful completion of these wells will provide ONGC with better information on hydrocarbon trends and zones that could potentially yield commercial petroleum reserves to supplant the depletion of existing fields. The four locations proposed for drilling are: (i) Bharkodra, (ii) Jambusar-P, (iii) West Kalol and (iv) South Warosan. These are described in Annex 5.3 and shown in IBRD Map No. 17604.

1/ The 1,750 line-kilometers of survey will consist of about 1,450 line kilometers of "teleseis" over the tidal and shoal area and 300 line-kilometers of shallow water survey. The additional 800 line-kilometers would also utilize the "teleseis" technology. "Teleseis" is a method of seismic data acquisition that utilizes electronic transmitters rather than cables to "connect" the grid of recording stations and can therefore cover larger areas and difficult terrains better than conventional cable systems.

2. Development and Production Component

5.17 The development and production component has four sub-components: (i) the final development or completion of the final development schemes of several light oil fields namely Kalol, North Kadi, South Kadi, Sobhasan and Nawagam; (ii) the initial (primary) development of the heavy oil fields namely North Santhal, Balol and Lanwa; (iii) the rehabilitation of the Cambay gas field, the largest non-associated gas field in the basin; and (iv) improvement of well maintenance (workover) operations to eliminate the substantial backlog of production wells needing repairs, as well as to increase the capacity and quality of well maintenance and workover to cope with the larger number and more complex production wells as a result of the proposed project.

5.18 The final development of the light oil fields primarily involve one or more of the following: infill drilling, introduction of artificial lift equipment (gas lift and sucker rod pumps) and introduction of water injection schemes or expansion of the schemes now in place. The main objective is to increase production to the optimum level as early as possible. A total of about 247 wells will be drilled under this sub-component which will provide an incremental production of about 0.83 million tons per year of oil and about 91 million m^3 per year of gas at peak level. The most important final development scheme involves the Kalol field, which will require about 140 new wells.

5.19 The Balol and Lanwa heavy oil fields, as well as the northern portion of the Santhal field, which together have proven and probable reserves (initial oil in place or IOIP) of about 55 million tons of oil, are not yet developed at present. Primary production using heavy duty pumps is expected to recover about 10% to 12% of the IOIP in North Santhal, 9% in Balol and 5% in Lanwa respectively. The combined heavy oil production under the initial field development scheme will be about 0.75 million tons per year at the peak level. About 287 wells will be drilled in these fields under the project. Enhanced oil recovery based on in-situ combustion is expected to improve the recovery up to about 40% to 50% of the IOIP (para 5.22). Another objective of the primary field development is therefore to condition the reservoirs (i.e., reduce the pressures, etc.) for eventual application of this EOR technique. Under the primary development, the wells will be designed for thermal service and the well spacing will take into account the EOR requirements.

5.20 The Cambay gas field rehabilitation has two objectives: to arrest the rapid decline in gas production caused by progressive abandonment of the old wells (which cannot be repaired) following water enroachment; and to test the apparently "tight" oil formation located below the gas producing zone. The Cambay gas field has been in production since the early 1960's but about one-half (1.5 billion m^3) of the recoverable gas reserves still remain. Gas production has declined substantially to 70,000 m^3/day at present but could fall further to about one-half this level within a few years. Under the project two or three gas wells will initially be drilled using special techniques to take into account the depressed pressures (below hydrostatic) in the gas zone. If successful, additional gas wells (up to about 10) will be drilled to increase gas production to about 140,000 m^3/day. The initial production tests of the lower oil zone conducted by ONGC in the early 1960's were not successful and no other attempt to test or delineate this oil zone has been made since. Under the project 4 wells will be drilled to test

several new well stimulation methods of oil production, and better estimate the reserves and recovery that could be expected.

5.21 At present, about 130 to 150 wells in the Cambay Basin need to be repaired each year which just about matches ONGC's workover capacity. However, there is a backlog of about 345 wells which have been in need of workover for sometime. The resulting lost production is estimated at about 300,000 to 400,000 tons per year of oil. ONGC plans to eliminate this backlog over the next five years through the following: Firstly, workover operations are now proceeding on a 24-hour basis. Secondly, a workover contract was signed last year for two Soviet workover rigs (and crews) to repair 120 wells within a three year period (1983-85). ONGC will handle the other 225 wells during a five-year period (1983-1987). To accomplish this task and keep up with the additional (about 110 wells more per year) and more complex workover jobs that will result from the 548 new development wells to be drilled under the proposed project, ONGC will need to replace most of its existing 23 workover rigs which are very old and, at the same time, increase its fleet to about 30 to 35 workover rigs. Thus, thirdly, the acquisition of ten replacement workover rigs and related equipment (e.g., wireline service units, production logging units), as well as the cost of workover materials and supplies for about 340 wells, are included in the proposed project. Fourthly, ONGC whenever required, will utilize the technical assistance (para 5.26) under the proposed project to help plan and undertake workover operations.

3. Enhanced Oil Recovery (EOR) Component

5.22 Three EOR pilot schemes are included in the proposed project: two thermal EOR pilots in the Lanwa heavy oil field and a polymer chemical flood pilot in the Jhalora light oil field. Bank consultants have recommended these among several proposed by ONGC.

a. In-situ Combustion (Lanwa Field)

5.23 The Lanwa field has the most viscous heavy oil among the oil fields in the basin and will be the first to require a commercial EOR scheme within about 4 to 6 years after primary development. A thermal EOR technique is expected to increase oil recovery to about 45% of the initial oil in place from only about 5% for primary production. The first thermal EOR pilot will use the in-situ combustion technique. The second pilot, which will be started about 18 to 24 months after the first, will use either the steam flood method or the in-situ combustion method depending upon the initial results of the first pilot. The Lanwa pilots, while specific to that field, will also serve as prototypes for the Balol and Santhal pilot in-situ combustion schemes which will follow about one to three years later. The in-situ combustion pilot is expected to run for about four years.

b. Polymer Flood (Jhalora Field)

5.24 The polymer flood pilot at the Jhalora field was recommended because of the adverse mobility ratio and heterogeneous permeability profile of the reservoir. The primary recovery of the Jhalora field is expected to be around 16% with cumulative production from 1977 up to the present already about 6% of the initial oil in place (26.4 million tons). However, oil production has begun to decline as the water cut increased from 20% two years ago to 30% at

present. An EOR scheme will therefore be needed within a few years to reverse the decline in production and increase the recovery factor. The Jhalora polymer pilot is also expected to last about four years and serve as a prototype for the other light oil fields.

4. Technical Training and Assistance Component

5.25 ONGC's field operations in the Cambay Basin have many serious deficiencies and problems. One of the main objectives of the proposed project is to improve ONGC's oil field operations through training, use of consultants and contractors, and introduction of new technology, equipment and materials. Each of these is described briefly below.

5.26 While ONGC has extensive training facilities and programs for managerial and higher level technical staff, it lacks a meaningful training program for field level employees. In the past, oil field workers have learned through informal on-the-job apprenticeship. Last year, ONGC began a modest oil field worker training facility near Ahmedabad in the Cambay Basin. The program consisted of a six-week introductory course plus on-the-job training. The facility has very limited training aids. ONGC, however, has plans to build four or five large training centers around the country. A training consultant attached to the Bank preappraisal mission reviewed ONGC's existing and proposed training facilities and program and recommended a more modest training center for the Cambay Basin, but with a more comprehensive training curriculum. In addition, a major effort will be made to prepare and develop the necessary training materials and train the instructors. This will require the hiring of a training consultant to initially help ONGC organize the planning and implementation of this training program. Training aids will include simulators, laboratory equipment, models and prototypes, closed circuit TV system, etc. The training program will cover basic and advanced courses in all facets of oil field operations (e.g., drilling, production, cementing, various types of logging, pipelines, well stimulation, and instrumentation).

5.27 Technical assistance will also be provided by an expatriate consulting firm to assist in implementing the project and in improving ONGC's field operations. Technical assistance will cover the application and evaluation of EOR methods (in-situ combustion and chemical flooding), training and whenever required may also cover reservoir engineering, drilling practices, mud engineering, workover techniques and formation testing. In addition, the contracts with experienced international contractors for drilling and technical well services (e.g. cementing, logging, production testing) will have provisions for practical training of ONGC personnel.

5.28 The new equipment included in the proposed project is essential towards modernizing and improving the efficiency of ONGC's onshore operations. They are also required for ONGC to effectively undertake its portion of the project's drilling program within a reasonable time. The equipment are for exploration, development and production as follows:

a. coring equipment;
b. three open hole electric logging units;
c. two production logging units;
d. fourteen production wire-line units;

e. seven mud-logging units;
f. five units (each 3 MW) of mobile gas turbine power generators.
g. field radio communications;
h. ten workover rigs (discussed in para 5.21); and
i. seven mobile drilling rigs.

5.29 ONGC presently does not have rig-site equipment to continuously monitor downhole conditions, as well as drilling mud components and hydrocarbons in the drilling fluid system. Also, ONGC rigs presently lack formation coring tools to cut and retrieve the typically unconsolidated and loose sands that predominate in many Cambay Basin fields. State-of-the art electric logging units in the basin are limited in number and, often, important exploratory wells are inadequately evaluated. Reliable and accurate subsurface parameters, which are critical in determining reservoir characteristics and essential in the design and implementation of any secondary or enhanced oil recovery project, are not being measured satisfactorily due to lack of proper logging and other equipment. As part of the project, some critical equipment will be purchased to either provide additional units or as replacement units to cover existing shortfalls and deficiencies.

5.30 Of the 14 drilling rigs operating in the Cambay Basin at present, 12 are obsolete and should have been replaced a long time ago. As part of the project, seven heavy duty mobile drilling rigs will be purchased to drill ONGC's portion of the development wells included in the project. The new rigs will replace the old rigs and should be similar to the contracted rigs (para 5.34); they represent a new technology for ONGC. The rigs will subsequently be used for infill drilling during the commercial scale EOR projects in the heavy and the light oil fields that will follow the pilot schemes in about 5 to 7 years. They will also be used for workover of the deeper wells (2,000- 2,500 m) in the basin (e.g., Kalol). The rigs will therefore be productively used in the project area for at least the next 10 years.

F. Project Implemenation

1. Organization for Project Implementation

5.31 The project will be implemented by ONGC's Western Region. However, the project is a major and complex undertaking which will require logistical and organizational support not presently available in the Western Region. ONGC agreed with the appraisal mission on the general organizational arrangements for project implementation. A separate project implementation unit has just been established. This project unit will have over-all responsibility for the project as well as specific responsibility for procurement, exploration and all activities involving contractors. The existing field organization of ONGC will undertake all force account work which will be coordinated by the project unit. The implementation of the training program for field workers will be mainly the responsibility of the headquarters (Dehra Dun) training department but will be implemented by a regional training unit to be set-up for this purpose. The project unit will have control over the resources needed by the project. ONGC has prepared a project implementation plan and has already appointed the core staff for the

project unit. The remaining support staff will be appointed as needed according to the implementation plan. These arrangements are satisfactory.

2. ONGC and Contractor(s) Work Program

5.32 The seismic acquisition and data processing, and the drilling of the four deep exploratory wells will be performed by international contractors. However, in the past two years, the Government has imposed more strict requirements and clearance procedures (on grounds of national security) for the processing of seismic data by outside contractors. This has delayed some of ONGC's recent seismic surveys. The appraisal mission was assured by ONGC, and this was again confirmed during negotiations, that the necessary clearances will be sought from the Government to process the data by contract. In the unlikely event that this clearance is not granted, alternatives satisfactory to the Bank (e.g. using contractor software and personnel to process the data in ONGC's computers on a priority basis) will be arranged by ONGC.

5.33 The appraisal mission informed ONGC that additional seismic information and geological analyses should be performed for two of the proposed four exploratory wells to determine precisely the most advantageous spudding location. During the pre-appraisal mission, the Bank staff also suggested, and ONGC agreed, that a detailed drilling program and a preliminary completion program should be prepared before each well is spudded. ONGC confirmed its agreement to all these during negotiations. Furthermore, the Bank would review and ascertain that the best available methodology and data had been used in selecting the sites, and that all pre-drilling studies and surveys, as well as drilling plans, have been completed prior to drilling each exploratory well.

5.34 Development drilling under the proposed project will be done partly by foreign drilling contractors and partly by ONGC. About 204 wells will be drilled by international drilling contractors, over a period of 3 years. The drilling program is shown in Annex 5.4. The contracted rigs are expected to act as "pacesetters" for ONGC rigs operating within the same area. The remaining wells, about 344, will be drilled by ONGC using 9 to 10 of its own rigs, including 7 to be purchased under the project. The development drilling load of ONGC has been carefully determined to meet the requirements of efficient and timely project implementation as well as the improvement in ONGC's operating capabilities which is also a key objective of the project. This drilling load is technically acceptable and the most effective alternative for the following reasons: (i) ONGC can, with the technical assistance, new equipment, and improved logistical support included in the project, undertake part of the operations since it has been drilling and producing in the basin for over twenty years where more than 1,300 wells have been drilled thus possessing the requisite basic experience and management capability; (ii) its normal annual drilling work program in the basin is comparable to the initial drilling load under the project and this load has been planned to increase at a reasonable rate during the course of project implementation; (iii) ONGC Western Region would use the same established field management teams and crews to continue the operations after the contractors have completed their tasks under this project; (iv) the transfer of technology and skills in oil field activities such as drilling and workover is better accomplished if ONGC works side by side with the foreign contractors; and

(v) the alternative of contracting a larger portion of the drilling operations would be substantially more costly. The total development drilling cost (excluding materials and consumables) under the proposed arrangements is about US$310 million. This would increase by about US$45 million (15%) if all development drilling and technical well services required under the proposed project were to be contracted.

5.35 During the preparation and preappraisal missions, Bank staff recommended that ONGC change its casing policy for most of the wells to be drilled under the project (and ONGC's onshore operations in general) with respect to the use of a 5 1/4" production casing. Instead, a 7" production casing should be used. ONGC agreed to this and during negotiations it was determined that about 386 development wells and all exploration wells under the project will use a 7" production casing. In addition, ONGC also agreed that for the project only API certified or labeled oil field cement will be used below a depth of 500 meters.

3. Implementation Schedule

5.36 The project schedule is given in Annex 5.5. It is anticipated that development drilling would start during the second half of 1984 and end by early 1990. Exploration drilling would start by late 1985 and be completed by early 1988. The drilling contract along with the other auxiliary technical well services such as wire-line logging and cementing would be procured by the start of 1985 for a period of about 3 years. Procurement of most of the new drilling and workover equipment should start not later than third quarter of 1984 and be fully operational by the beginning of 1986. There should be no difficulty in meeting the completion targets given the lead time being provided for procurement of contractors services, the reasonable work load to be undertaken by ONGC and the use of experienced contractors and consultants. Close coordination would be assured by a Project Manager in charge of the project implementation unit and reporting directly to the regional Group General Manager.

G. Project Cost Estimate

5.37 The total project financing requirement is estimated at about US$954 million, including physical and price contingencies and the front-end fee on the Bank loan. The foreign exchange component is estimated at US$546 million or 57% of the total project cost. The detailed estimated project costs are shown in Annex 5.6 and shown by field and activity in Annex 5.7. They are summarized below:

Table 5.3: Summary of Project Cost

	Rs Million			US$ Million		
	Foreign	Local	Total	Foreign	Local	Total
1. Exploration						
Seismic, Drilling & Technical Well Services	552	142	694	55.2	14.2	69.4
Well Materials & Consumables	65	51	116	6.5	5.1	11.6
Sub-total	617	193	810	61.7	19.3	81.0
2. Development & Production						
Drilling & Tech. Well Serv.	1,024	207	1,231	102.4	20.7	123.1
Well Materials & Consumables	1,522	895	2,417	152.2	89.5	241.7
Force Account (ONGC Departments)	-	524	524	-	52.4	52.4
Rigs, Other Equip. & Surf. Fac.	646	1,070	1,716	64.6	107.0	171.6
Subtotal	3,192	2,696	5,888	319.2	269.6	588.8
3. Enhanced Oil Recovery Pilots						
Drilling Equipment & Consumables	50	26	76	5.0	2.6	7.6
4. Training & Technical Assistance						
Equipment, Materials, Consultants and Supervision	50	20	70	5.0	2.0	7.0
Total Base Cost Estimate	3,909	2,935	6,844	390.9	293.5	684.4
Physical Contingencies a/	584	397	981	58.4	39.7	98.1
Price Contingencies b/	959	753	1,712	95.9	75.3	171.2
Front-End Fee on Bank Loan	6	-	6	0.6	-	0.6
Total Financing Required	5,458	4,085	9,543	545.8 c/	408.5 d/	954.3

a/ At 20% for the exploration and EOR pilot component, 15% for drilling and well materials, and 10% for equipment, assistance and training.

b/ Foreign costs at 7.5% in 1984/85, 7% in 1985/86 and 6% thereafter. Local costs at 7% in 1984/85, 8% in 1985/86 and in 1986/87, and 6% thereafter.

c/ Includes about Rs 289 million (US$28.9 million) of indirect foreign exchange cost for fuel.

d/ Includes about Rs 1500 million (US$150 million) for import duties.

Exchange rate is US$1.00 = Rs 10.00

5.38 The cost estimate of the project was prepared by the Bank and ONGC in April, 1983 and updated in November, 1983. The costs are expressed in late-1983 prices. Prices are in line with the costs experienced in other Bank projects in and outside India and are based on the following: (i) drilling costs for development wells are based on wells of similar depth drilled in the Cambay Basin while drilling costs for the deep exploration wells are based on costs of similar wells in India (i.e., Krishna-Godavari Exploration Project); (ii) seismic survey costs are estimated from comparable shallow water/tidal seismic acquisition in other parts of the world as well as from recent contractor bids for geophysical and data processing submitted to ONGC; (iii) equipment costs are based on figures supplied to the Bank by ONGC and

cross-checked with costs experienced in other Bank projects outside of India; (iv) technical well services (i.e. cementing, electric logging and formation testing) are derived from offshore Bombay High and Krishna-Godavari Project costs adjusted downwards for the onshore operations; (v) enhanced oil recovery (EOR) pilot costs were estimated by consultants; (vi) the expected average cost per man-month for training consultants is estimated at US$8,000 for foreign consultants (30 man-months) and US$1,500 for local consultants (30 man-months), respectively, including travel, subsistence and overhead; and (vii) technical consultants (70 man-months) are expected to average US$10,000 per man-month, including travel, subsistence and overhead. The phasing of project expenditures is shown in Annex 5.8.

H. Financing Plan and Procurement

1. Project Financing Plan

5.39 The proposed project represents about 5% of ONGC's overall investment program of about Rs 194 billion (US$19.4 billion) and about 60% of the Cambay Basin total investments of about Rs 16 billion (US$1.6 billion)[1/] over 1984/85-1989/90. The financing plan of ONGC's overall investment program, discussed in para 6.09, indicates that internally generated funds will finance about 63% of the overall investment program and loans 37%. Of the total borrowings, commercial banks are expected to provide about 63%, while aggregate disbursements from the Bank (including the proposed loan) is estimated to account for another 8%. Thus, Bank loans will finance about 3% of ONGC overall investment, (corresponding to about 7% of the estimated foreign exchange cost) during this period. For the proposed project, the ONGC financing plan is based on the following main consideration: to cover as much of the foreign exchange cost as possible with foreign loans while at the same time have a proportion of loan financing and an average loan maturity consistent with the overall corporate objective of keeping ONGC's future debt/equity ratio, debt service coverage ratio and ability to quickly mobilize large financial resources (in case of a major discovery), in line with western oil industry practices (para 6.06). ONGC is also interested in having a significant Bank involvement in key high priority projects for technical reasons and to help maintain the good financial standing it has developed among foreign commercial lenders following the Bank's first project with ONGC in 1977. On this basis, ONGC intends to seek loan financing for the project in the range of 50% to 55% of the financing required, of which almost one-half would be covered by medium-term (e.g., 6 to 8 years) borrowings from commercial sources.

5.40 Several of the foreign exchange cost items under the project are suitable for financing by eximbank, suppliers or buyers credits. These include artificial lift equipment, wellheads, casings, tubings and accessories, and mobile power generators, which together have an estimated value of about US$194 million. In this context, ONGC's approach to cofinancing, adopted in late 1981, is that major bid packages are tendered using global tendering procedures (i.e., ICB) with a request for financing proposals; the financing offer is optional and is not a condition of bid qualification. Bid evaluation is done by ONGC in accordance with the concept of lowest evaluated bid used by the Bank (i.e., excluding financing offers).

1/ ONGC's overall investment program and investments in the Cambay Basin during 1984/85-1989/90 are discussed in Annex 4.3.

It is only at the Government level just before the final decision to award is taken that the financing proposals are evaluated in conjunction with the commercial bid evaluation. At this time, the possibility exists that a good financing offer from a bidder other than the lowest evaluated bidder is accepted assuming that its combined commercial and financing offer indicates a superior total package. However, practically all bid packages handled by ONGC so far have been awarded to the lowest evaluated bidder because differences in financing amounts and terms offered were not sufficiently significant to affect the decision. In fact, in several cases, the award was given to a bidder who did not offer any financing; in most cases, the financing offers ranged from 40% to 80% of the contract value. The entire amount or the balance, as the case may be, was financed from free foreign exchange or a subsequent commercial bank loan. ONGC will use this as one approach to mobilize suppliers and eximbank credits for the proposed project.

5.41 ONGC is also expected to seek, at various times during the project implementation period, Euro-currency loans, untied to procurement packages, to help finance its overall investment program. The timing of such corporate borrowings will depend on financial market conditions as well as on the foreign exchange financing needs of the company. Parts of these Euro-currency loans are expected to be used towards the financing of the proposed project to the extent needed to cover the direct foreign exchange cost not financed by eximbank, suppliers or buyers credits and the proposed Bank loan. In all, about US$245 million in export credits and commercial bank co-financing is expected for the project. Furthermore, ONGC informed the Bank that during the next two years (1984/85 and 1985/86), commercial borrowings are expected to total about US$400-450 million per year for ONGC as a whole.

5.42 The financing plan for the project is therefore expected to be as follows:

Table 5.4: Project Financing Plan

	US$ million	%
ONGC	466.8	49
Borrowings:		
(a) Export Credits & Commercial Banks[a/]	245.0	26
(b) Proposed Bank Loan[b/]	242.5	25
Total Loans	487.5	51
Total Financing	954.3	100

a/ Commercial loans include eximbank, supplier's and buyer's credits as well as Euro-currency loans.

b/ The expected disbursement profile for the Bank loan is shown in Annex 5.9.

5.43 ONGC's contribution to the project's financing plan would represent about 4% of its internal cash generation during the project implementation period. No problems are expected in mobilizing this amount for the project. However, oil companies in general must be prepared to undertake large development investments within relatively short notice in case of a major discovery. ONGC's financial forecasts do not provide for such unforseen investments which could increase ONGC's financing requirements substantially. The financial forecasts could also be adversely affected by lower

than expected oil recovery factors or slower pace of development due to imprecise geologic information inherent in all petroleum development efforts. During negotiations therefore, agreement was reached with the government that it will provide ONGC, or cause ONGC to be provided with sufficient funds, including authorizing ONGC to seek co-financing to meet ONGC's financial requirements for the project.

5.44 The proposed Bank loan amount of US$242.5 million was determined after considering those items which are not generally financed by suppliers credits (e.g. contractor and consultant services) and which, for technical and quality considerations, are best financed by the Bank (para 5.45). The proposed Bank loan would represent about 25% of the total, and 44% of the foreign exchange, project cost. The loan would be made to GOI with a maturity of 20 years including a five year grace period at the standard Bank variable interest terms including a front-end fee of 0.25%. The Government would onlend the proceeds of the loan to ONGC at an interest rate of at least 12% (in line with GOI loan rates for public sector enterprises) with a maturity of at most 15 years including a five-year grace period. The foreign exchange and the interest rate risks would be borne by the Government. The onlending rate is expected to exceed domestic inflation rates which are not likely to be over 8% annually in the next five years. In general, the onlending terms are reasonable considering that: a significant proportion (14%) of the project investments are for exploration, EOR pilots, and training which will yield benefits only in the long-term; almost one-half of the loan financing is medium-term (6 to 8 years for the commercial loans) which must be balanced by longer-term financing to arrive at an average maturity that would be consistent with ONGC's overall debt service level objectives in light of its increasing capital requirements particularly for long-gestation investment such as exploration; also, additional large investments will be needed after about six to nine years for the commercial-scale EOR applications and for the follow-up exploratory drilling in the Cambay Gulf area. Execution of the Subsidiary Loan Agreement on terms and conditions satisfactory to the Bank would be a condition of effectiveness of the proposed Bank loan.

2. Items Proposed for Bank Financing

5.45 As mentioned earlier, certain items in the project have been determined as high priority for Bank financing and the proposed loan amount was derived on the basis of their cost. These items were selected from those that met the following criteria: (i) items that are not normally financed by export credits; (ii) items most suitable for international competitive bidding (ICB) and involving the minimum (if any) retroactive financing; (iii) items whose technological and quality contents are critical to the technical success of the project, including the technology transfer objectives of the Bank; and (iv) items that will spread the Bank financial involvement throughout the project implementation period as well as across all the major components of the project. Based on these considerations, items listed in the table below were judged the most appropriate for Bank financing. The first three groups of items listed below (contractor and consultant services, training and EOR pilot expenditures) are generally not financed by eximbank or suppliers credits. However, ONGC has been successful in borrowing from the Euro-currency markets for its overall corporate requirements and it would be desirable to progressively reduce the share of Bank financing from the levels of previous projects. It is therefore proposed that the Bank finance about 80% of the cost of contractor services. In the case of the mobile drilling rigs and workover rigs as well as the other equipment to upgrade existing ONGC rigs, which are generally suitable for financing by eximbank or export credits, financial involvement by the Bank is also essential to help ensure that: the

types and specifications of these equipment are appropriate for the project; the procurement will be timely to avoid delays in project implementation; the objective of technology transfer and improvement in ONGC's drilling and workover operations sought by the Bank is achieved as early as possible; and the Bank's financial support is not limited to the activities of contractors, but also covers the major part of the development drilling and workover operations being undertaken by ONGC. The Bank's financial support covering about 50% of the cost of the drilling and workover rigs and 100% of the cost of the other equipment is therefore recommended. In the case of cement, chemicals and additives, it is recommended that the Bank finance all the API type "G" as well as the thermal type of oilfield cement, and critical drilling mud chemicals because of the severe cementing and drilling problems experienced in the Cambay Basin which, in the Bank staff's judgement, are largely the result of using local cement and chemicals which are not certified by the API. Bank financing will help ensure that AP[illegible] [illegible]ade cement and materials are used by ONGC in this project.

Table 5.9: Items Proposed for Bank Financing a/

		Amount Allocated (US$ million)	% of Expenditures to be Financed
1.	Seis[illegible], Drilling and Technical Services Contractors	174.0	80% of expenditures
2.	Consu[illegible]ants and Foreign Training	3.5	100% of foreign exchange expenditures
3.	Equipment and Materials for EOR Pilot and Training	9.0	100% of foreign exchange or local ex-factory expenditures
4.	Mobile Drilling Rigs and Workover Rigs b/	26.4	50% of expenditures
5.	Other Equipment to Upgrade Existing ONGC Rigs and Field Operations c/	15.0	100% of foreign exchange or local ex-factory expenditures
6.	Oil Field Cement and Chemicals	14.0	100% of foreign exchange or local ex-factory expenditures
7.	Front-End Fee	0.6	Amount due
	Total	242.5	

a/ About 10% of the amounts shown for each category will be transferred to an "unallocated" category in the loan documents.

b/ Ten workover rigs and seven heavy duty mobile drilling rigs are included in the project with an estimated total foreign exchange cost of about US$55 million. The procurement of these items may be split with the Bank financing 100% of one package.

c/ These equipment are: special coring equipment; three open hole electric-logging units; two production logging units; fourteen production wire-line service units; seven mud-logging units; and field radio communication facilities.

3. Procurement and Disbursements

5.46 Procurement arrangements are summarized in the table below:

Table 5.6: Procurement Table
(US$ million)

Project Component	Procurement Method ICB	LCB	Other	N.A. a/	Total Cost
1. Exploration					
Seismic, Drill. & Well Services	76.2 (59.9)	14.2	1.7 b/	3.7	95.7 (59.9)
Well Materials & Consumables	7.8 (1.7)	2.8	2.4 c/ (0.3)	3.0	16.0 (2.0)
Sub Total:	84.0 (61.6)	17.0	4.1 (0.3)	6.7	111.8 (61.9)
2. Development & Production					
Drill. & Tech. Well Services	152.7 (118.2)	-	9.4	30.1	192.2 (118.2)
Well Materials & Consumables	193.2 (11.0)	28.6	27.6 d/ (1.0)	76.7	326.1 (12.0)
Force Account	-	-	87.0 b/	-	87.0
Rigs, Equipment & Surf. Facilities	79.0 (35.3)	102.7	2.8 (2.0)	32.7	217.2 (37.3)
Sub-Total:	424.9 (164.5)	131.3	126.8 (3.0)	139.5	822.5 (167.5)
3. EOR Projects					
Drill. Equip. & Consumables	5.0 (5.0)	-	2.7 (2.0)	2.8	10.5 (7.0)
4. Training & Tech. Assistance					
Equip., Consult. & Supervision	1.5 (1.5)	1.9	4.5 (4.0)	1.0	8.9 (5.5)
TOTAL:	515.4 (232.6)	150.2	138.1 (9.3)	150.0	953.7 (241.9)

a/ Customs duties
b/ Force account
c/ Includes fuel (US$1.3 million)
d/ Fuel only

Note: (i) Figures in parenthesis are the respective amounts financed by the Bank; (ii) the front-end fee, US$0.6 million, is not included in the Procurement Table above.

5.47 About US$515 million worth of contractor services, equipment and materials for the project will be procured through international competitive bidding (ICB) and US$150 million worth of equipment, materials and supplies will be purchased using local competitive bidding procedures (LCB) under which foreign firms can also bid. The "other" procurement category includes: (a) equipment and materials to be procured under limited international bidding (LIB), estimated to cost about US$5.8 million; (b) foreign consultants to be hired using Bank guidelines and foreign training of ONGC personnel for which no procurement method applies, together valued at about US$3.5 million; and (c) ONGC force account expenditures (US$ 87 million), direct local purchases from single or limited suppliers, e.g., diesel fuel for drilling (US$28.9 million), as well as the hiring of local consultants, together valued at about US$128.8 million.

5.48 The number of procurement packages to be procured under ICB and LIB procedures will be about 42 as follows:

(a) Contractor Services - About seven packages covering: seismic data acquisition and processing; exploration drilling; development drilling; wire-line electric logging; cementing and drill stem testing; mud logging and mud engineering; and directional drilling (if needed).

(b) Oilfield Equipment - About twelve packages covering: drilling rigs (2); workover rigs; special coring equipment; production logging units; open hole electric logging units; open and cased hole production wire line service units; mud logging units; mobile electric generators; and field radio communication (2).

(c) Well Equipment, Materials and Consumables - About twenty-three packages covering: casing and tubing; drilling and casing bits; wellheads and production christmas trees; artificial lift and production bottom hole equipment; mud products and drilling chemicals (2); floating equipment; oil field cement (3); cement additives (2); liner hangers; EOR equipment (compressors, pumps, etc. - 4 packages); EOR chemicals (polymer, etc. 2 packages); and training equipment (4).

5.49 Items to be financed by the Bank will be grouped whenever possible into contracts valued at US$300,000 or more (CIF basis) and such packages will be procured through international competitive bidding (ICB) in accordance with Bank guidelines. A margin of preference equal to 15% of the C.I.F. bid price of imported goods or the actual customs duties and import taxes, whichever is lower, will be allowed for domestic manufacturers. Similarly, a domestic preference of 7.5% will be allowed for local contractors for works (i.e. drilling and cementing services). Bid packages for equipment and materials costing less than US$300,000 (CIF), or items from a limited number of qualified suppliers, or those whose delivery periods are critical to the timely completion of the project, will be purchased through limited international bidding (LIB) with quotations being solicited from at least four suppliers from three different countries. The total LIB purchasers for equipment and materials will not exceed US$6 million. Consultants for traininng and technical assistance financed by the Bank will be selected in accordance with Bank guidelines. All service and equipment contracts over

US$1 million each (about 15) will be subject to prior Bank review. Bank review will cover 95% of the value of service contracts and about 80% of the value of equipment and materials to be financed by the Bank. Other contracts will be subject to selective post-award review. Retroactive financing for up to US$2 million for expenditures after September 1, 1983 will be allowed to cover costs for consultancy, services and equipment procured after project appraisal.

I. Ecology and Safety

5.50 Coastal seismic data acquisition will take place in a sparsely populated, and lightly utilized area. Geophysical survey lines and subsequent exploratory drilling locations would be selected to avoid close proximity to habitation and water wells. All water aquifers, including surface source water, will be protected by following oil well drilling standards set by the industry. ONGC will contain and clean up any drilling mud and chemical contamination that would originate on the ground surface adjacent to drillsites in holding pits or dump reservoirs. Drilling a number of development wells entails some risk of surface blow-outs and the possibility of fire. The risk is, however, minimized through the use of blow-out preventers and sophisticated equipment introduced in the mud logging unit (which can monitor traces of gas coming out of the hole). The ONGC Western Region, in spite of some inefficiencies in its oil field operations, is quite aware of the risks involved and has for years maintained an excellent safety record.

5.51 The by-products and chemicals used in the EOR schemes have been investigated and their presence is not judged to be a safety hazard or harmful to the environment. The production of hydrogen sulfide (H_2S) is possible with any oil production operation. If H_2S is found to be present in the produced gases in the in-situ combustion pilot, plans are to be made to incinerate the gas and render it suitable for discharge into the atmosphere. The polymer to be used in the EOR chemical flood is not toxic. However, the monomer from which the polymer is made is toxic. It may exist in minute concentrations in a polymer supply. However, the monomer is quite reactive and should disappear quickly. During negotiations, agreement was obtained that ONGC take precautions in line with industry practice to protect workers and the environment during the implementation of the project and during operation of the project facilities.

J. Project Risks

5.52 As described earlier (para 5.11), the major concept supporting the project is that exploration and exploitation investments in a near mature hydrocarbon producing basin are often among the lower cost and lower risk opportunities available to establish additional proven reserves. The infill drilling of undeveloped and underdeveloped fields and the implementation of the EOR pilot schemes, two major components of the project, represent the lower risk opportunities available in the basin. The project's exploration component is more risky but the risks are difficult to quantify. In the case of the seismic program, not enough is known of the subsurface under the shallow waters of the Gulf to permit a statement of unqualified success; similarly, in the case of the exploration drilling program, there is not enough data to perform a meaningful economic risk analysis. Justification for

both these exploratory components rests with an assessment of their technical and geological risks and a judgement of the benefits to be acquired from their successful completion (para 7.01). A summation of these factors as they apply to the exploration component is as follows:

1. Seismic Program

5.53 Seismic recording in the Gulf of Cambay shallow water and tidal environment will require unconventional, advanced recording devices, tools and techniques. The methods to record a seismic program of this type have been performed under similiar conditions throughout the world, and although still considered very specialized, the technical risk factors associated with data acquisition will be minimized by engaging a foreign contractor experienced in this mode of data collection. Geologically, the areas contiguous and nearby to the Dahej gas discovery and associated Ankleshvar features are expected to extend known structures and inferred sandstone reservoirs along established northeast-southwest trends. However, further away from present subsurface well control, the geologic risk rises. Under the waters of the Cambay Gulf and in the remote portions of the tidal-swept areas to the south and to the west, the geologic risk is that the established onshore structural fault trends and the sandstone patterns intepreted for the Narbada delta may not persist. In addition, although Miocene hydrocarbons have been encountered in the Hazira and offshore Tapti locations, seismic and subsurface well control is insufficient to delineate the origin of the reservoir beds or predict the exact position of the inferred structural faulting.

2. Exploratory Drilling

5.54 The technical risks in drilling the four deep exploratory wells is that the holes may not be evaluated and tested effectively due to downhole or mechanical rig problems. The principal causes of this would be high bottomhole temperatures, abnormal formation pressures or impenetrable zones which could not be handled by ONGC's own rig equipment. To reduce these technical risks, it has been decided to employ an expatriate drilling contractor experienced in drilling through and evaluating deep high temperature/pressure exploratory wells. Geologically, the four exploratory wells are primarily designed to test deep prospects in zones which have indicated hydrocarbon reservoirs in prior drilling, and secondarily to evaluate prospects in even deeper less explored stratigraphic intervals. But, due to the limited reliable geologic data about these deep zones, it is difficult at this stage to assign a meaningful risk factor on this drilling.

5.55 It is the conclusion of ONGC and the Bank that the technical risks attached to the exploration component of the project have been reduced by engaging outside international contractors. The geological risks of the seismic program will be justified considering the high probability of identifying additional structures and fault closures in the Gulf. The geological risks assigned to the exploratory drilling can also be justified if new, potentially productive deep zones are identified within the basin.

K. Reporting Requirements

5.56 In order to allow the Bank to reach an informed judgement on the progress of the project, agreement was reached during negotiations that ONGC

will provide the Bank bi-monthly telexes summarizing the exploration drilling status, including casing, cementing, testing and all other auxillary services. Quarterly progress reports covering technical progress of the seismic work, development and exploration drilling, workover, well location preparation, procurement status, and funds committed/spent should also be provided. Interim and final well completion and testing results would be incorporated in the quarterly progress report when these are completed (para 4.07). During negotiations, agreement was reached with ONGC on the formats and contents of the periodic reports to be submitted to the Bank.

VI. - FINANCIAL ANALYSIS

6.01 ONGC's financial and accounting systems, while governed by GOI regulations, are similar to those of a commercial oil company. However, key financial parameters (selling prices, investment programs, external borrowings) are either decided (e.g. oil prices) or subject to review and approval by GOI. Within this framework, ONGC has operated in a responsible and reasonably autonomous fashion. ONGC is in a sound financial position and is expected to remain so in the future.

A. Main Issues and Bank Objectives in ONGC's Finances

6.02 In lending to ONGC the Bank has supported ONGC's policy to rely on internal cash generation, i.e., reasonable profits and depreciation charges, to finance a substantial portion of its financing requirements for capital investments and increases in net working capital. This has been achieved by periodic increases in the price of oil and gas. The Bank has also encouraged ONGC to progressively diversify its sources of external financing. Since 1977/78, ONGC has increasingly utilized commercial sources to finance development expenditures while practically eliminating its reliance on government borrowings or equity contributions (as shown in the table below). After the government raised the crude oil price in July 1981 (para 3.05), ONGC's after-tax profit per barrel of oil (and oil equivalent of gas) has improved from about US$1/Bbl in 1979/80 to about $4/Bbl in 1982/83 and in 1983/84 (estimated) and for the last three years has been in line with the average for the western oil industry (US$3 to 4/Bbl). ONGC's internal cash generation after debt service payments, as a proportion of capital investments has also increased to the level of 50% to 60% in recent years, and is projected to remain at 55% or higher over the next six years. Again, this compares satisfactorily with the western oil industry average of about 70%.[1/] However, unlike large integrated oil companies, ONGC's opportunities for diversifying its reserve base and production are limited and its future profitability will depend largely on the success of current exploration and

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1/ The western (private) international oil companies generally use "off-balance sheet" financing methods, e.g., project financing, to finance some investments, particularly large infrastructure types (e.g., Alaska pipeline). Thus, the large loans associated with these investments do not appear in the company's balance sheet. This improves the reported debt equity ratio (about 20:80 on average) and the reported proportion (about 70%) of investments financed from internal cash generation. On the other hand, ONGC does not use "off-balance sheet" financing methods.

enhanced recovery programs. Therefore, while the Bank will continue to pursue the two objectives of adequate cash generation and diversified borrowings, it will also increasingly monitor ONGC's debt/equity ratio, which could approach prudent limits (i.e., 60:40) within a few years; its capacity to sustain, over an extended period if necessary, its major exploration and development investments, and its ability to move rapidly to finance the early stages of development following any commercial discovery. The Bank will also encourage ONGC to ensure that the blend of maturities and grace periods of its medium and long-term loans result in a reasonable pattern of overall debt service payments.

Table 6.1: ONGC Sources of Long-Term Loans a/

(in Rs billion)

	1976/77	1979/80	1980/81	1981/82	1982/83	1983/84(Est.)
Total Long-Term loans Outstanding at Year-End b/	1.9	3.9	5.9	9.6	16.4	19.4
of which:						
(a) Export Credits & Foreign Commercial Bank Loans	-	0.4	1.4	2.7	9.0	9.8
(b) World Bank Loans c/	-	0.9	1.2	3.1	4.0	5.4
(c) Other Official Foreign Loans c/	-	-	0.1	0.3	0.5	0.9
(d) GOI, OIDB Loans	1.9	2.6	3.2	3.5	2.9	3.3
(a) as % of total	-	10	24	28	55	50
(b) as % of total	-	23	21	32	24	28
(c) as % of total	-	-	2	3	3	5
(d) as % of total	100	67	53	37	18	17

a/ Commercial loans carry maturities of 6-9 year with 1 or 2 years of grace. Government official loans have maturities or 15 years or more with 4 or 5 years of grace.
b/ Including current portion.
c/ Loans made through the government.

B. ONGC - Financial Performance and Forecasts

6.03 ONGC's accounting practices are described in Annex 6.1. Its Income Statements, Balance Sheets and Sources of Funds Statements over 1979/80 - 1983/84 and financial projections over 1983/84-1988/89 are shown in Annex 6.2. The financial projections are based on a number of important assumptions, inter alia, that (i) the price of crude oil and natural gas to ONGC will remain at present levels until 1987/88 when it will be increased by 10% to enable ONGC to maintain an adequate return on its assets and be in a position to finance about 60% of its investment program through cash generation; (ii) all of ONGC's external financing requirements would be met by borrowing so that GOI will no longer be required to provide equity or loan financing; (iii) development investments will be limited to presently known reserves, and no additional production from new oil or gas discoveries was assumed during the period under review; and (iv) exploration investments will cover the full accelerated exploration program approved in the Core Plan (para 4.10). The following table summarizes ONGC's past financial performance and the trends that are expected to develop during the life of the project.

Table 6.2: ONGC: Summary Financial Statements
(Rs billion)

	Actual			Est.	Forecast		
	1980/81	1981/82	1982/83	1983/84	1984/85	1986/87	1988/89
Sales							
Crude Oil (million tons)	9.2	13.2	17.6	22.8	26.8	28.2	29.8
Natural Gas (billion m^3)	1.2	1.6	1.9	2.3	2.7	4.4	7.5
Income & Cash Flow							
Revenues	4.4	13.3	23.6	34.5	40.7	46.7	58.7
Operating Expenses	3.6	6.7	10.9	17.8	22.8	36.6	36.7
Interest & Taxes	0.5	2.8	5.8	7.0	6.6	5.6	7.9
Net Profit	0.3	3.8	6.9	9.7	11.3	4.5	14.1
Internal Cash Generation a/	1.7	4.1	10.0	12.7	17.5	22.0	20.2
Capital Investments	4.3	8.1	13.6	17.7	27.5	37.5	26.6
Debt Service	1.0	1.3	2.0	2.3	3.0	7.6	14.6
Balance Sheet as of March 31							
Current Assets	4.2	8.9	17.0	16.9	18.0	19.6	28.2
Net Fixed Assets In Operation	8.5	11.3	18.1	24.8	43.6	86.3	109.2
Total Assets	14.9	25.0	45.6	55.7	72.8	121.2	148.3
Long-Term Loans b/	5.5	8.5	14.9	16.9	22.7	56.1	51.8
Equity	5.9	9.5	16.1	25.6	36.7	50.4	74.9
Ratios and Indicators							
Debt Service Coverage Ratio c/	2.9	5.7	6.4	7.3	7.3	4.0	2.7
Current Ratio	1.2	1.3	1.2	1.3	1.3	1.3	1.3
Long-term Debt/Equity Ratio	48:52	47:53	48:52	40:60	38:62	53:47	41:59
Profit and Interest Charges as % of Average Assets used in Operation d/	7	28	28	28	25	11	16
Internal Cash Generation as % of Capital Investments	40	51	73	72	64	58	76

a/ Net profit plus depreciation and depletion less principal repayments, dividends and net increase in working capital.
b/ Excluding current portion.
c/ Net profit plus depreciation and interest divided by total debt service.
d/ Assets in operation are current assets plus net fixed assets.

6.04 ONGC's profitability and cash generation has improved considerably since 1981/82 as a result of higher oil prices starting in July 1981 (para 3.05) and, more importantly, higher levels of oil production from the Bombay High field. Oil production doubled from 9.2 million tons in 1980/81 to 18.4 million tons in 1982/83. It is forecast to reach about 27 million tons in 1984/85 and then peak at about 30 million tons by 1988/89 on the basis of all presently known reserves, primarily the Bombay High field. However, while oil production is expected to level off in future years, assets will continue to grow, reflecting ONGC's large investment program which covers equipment acquisition, infrastructure for gas (e.g. transmission lines) and secondary recovery at Bombay High which is intended to maintain production at its peak

level. On the other hand, gas production will increase and provide additional revenues. Nonetheless, the rate of profitability is expected to temporarily decline from about 28% of assets employed in 1982/83 to about 11% in 1986/87 and then gradually improve to 16% by 1988/89. The decline in profits in 1986/87 is primarily an accounting and tax phenomenon. ONGC is expected in that year to start operations of several major facilities and this would allow it to claim investment tax credits through additional depreciation and depletion charges. This would lower reported income and hence, income taxes as well. The cost of these facilities in turn, are transferred from investments under construction to fixed assets in operation in ONGC's balance sheet which initially lowers the reported return on assets. Finally the level of investments in 1985/86 and 1986/87 are expected to be substantially higher than the preceeding or subsequent years and this causes the self-financing proportion to also decline slightly during both these years. Internal cash generation, however, is expected to remain satisfactory at more than 55% of investment requirements but the debt/equity ratio will approach prudent limits within a few years before improving again. The debt service coverage ratio could also gradually fall to about 2.7 times but would still be satisfactory by the end of the decade. The current ratio will remain close to the minimum prudent level but will still be acceptable considering that ONGC uses the "last-in, first-out" (LIFO) inventory valuation method which understates the value of its inventories, and current ratio, during periods of rising prices as is presently the case. Overall, the financial situation projected for the second half of the decade is considered satisfactory but will require close monitoring of key financial indicators.

6.05 ONGC's debt/equity ratio is about 40:60 at present. While this ratio is low compared to other industries, it is higher than that of international oil companies. However, ONGC's debt structure includes large loans from the government as well as foreign multilateral and bilateral loans made through GOI which are longer-term (e.g., 15 years or more), have longer grace periods and therefore, in evaluating ONGC's financial structure, should not be considered on the same basis as commercial borrowings.[1/] Overall, ONGC's financial structure can be considered satisfactory and should remain so if the company continues to follow prudent borrowing practices. At present, ONGC intends to maintain its current ratio at 1.3 times or higher, its debt/equity ratio at not more than 60:40, and to keep such a blend of medium-term (6 to 9 years) commercial loans and longer-term loans (10 to 15 years) that would maintain its debt service coverage ratio at not less than 1.5 times. The Bank supports these objectives and during negotiations, agreement was reached with ONGC that it will follow normally accepted prudent financial practices and to this end shall maintain its current ratio, debt/equity ratio and debt service coverage ratio at satisfactory levels.

6.06 Although generally conservative, the financial projections are based on the premise that the expected increase in oil and gas production from presently known reserves under development is realized and, in particular, that such major development programs as the Bombay High secondary recovery and the development of the South Bassein gas field are implemented on time and produce petroleum at expected levels. The risks that these development

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1/ The major borrowings of ONGC to date are shown in Annex 6-3.

programs will be delayed (particularly the secondary recovery in Bombay High which is the first such undertaking by ONGC and will account for the sustained oil production between 1984/85 and 1988/89), or that the productivity of the reservoirs will be less than expected, do not appear to be high but cannot be ruled out. Finally, the projections already indicate a risk of a potential deterioration in profitability by the late 1980's.

6.07 Because of these risks, agreement was reached during negotiations that: (i) GOI will, from time to time, carry out a review of the prices of crude oil and natural gas paid to ONGC, and shall set such prices at a level needed to enable ONGC, under conditions of efficient operation, to meet its operating expenses and earn a sufficient return after taxes on assets employed in operation, meet its debt service requirements, maintain adequate working capital and finance a substantial portion of its proposed capital investments; and (ii) ONGC will submit annually to GOI an analysis of its financial situation as a basis for setting ONGC's selling prices. Such analysis will include, inter alia, a financial evaluation of the proposed project and of any subsequent commercial-scale EOR investment or other major development investment in the Cambay Basin ; this evaluation will indicate the level of prices required for ONGC to earn a discounted cashflow (DCF) return after taxes of at least 15% on the project and on any related subsequent major developments. Similar covenants were applied under the two Bombay High loans and the South Bassein loan. They have been complied with and led to the major revision of petroleum prices in July 1981.

C. Financing of ONGC Investment Program (1984/85-1989/90)

6.08 ONGC's financing plan over the 1984/85-1989/90 period can be summarized as follows:

Table 6.3: ONGC Financing Plan 1984/85-1989/90

	Rs billion	Percent
Investment Program	194.3	100
(of which foreign exchange costs)	(87.4)	(45)
Financed by		
Internal Cash Generation	122.0	63
GOI Equity Contributions	-	-
Foreign Commercial Borrowings	44.3	23
World Bank Loans	5.9	3
Other Loans	22.1	11

As the above table indicates, internal cash generation from operations is expected to cover an average of 63% of investment requirements during the next six years. Given the risk of a slower than anticipated build-up in revenues, ONGC's decision to maintain a relatively low gearing ratio is advisable and prudent. This is particularly important since, as mentioned earlier, there is also a possibility that, in the event of large discoveries, ONGC would need to seek heavy borrowings to finance additional development costs.

6.09 World Bank funds shown as part of long-term borrowings in the above table reflect expected disbursements under the Krishna-Godavari and South Bassein loans as well as under the proposed loan for the Cambay Basin Petroleum Project. Altogether, Bank disbursements would represent about 8% of

ONGC's additional borrowings and 7% of its foreign exchange needs during the 1984/85-89/90 period. In addition, ONGC is expected to finance about 50% of its future foreign exchange requirements from commercial borrowings. No major difficulties are anticipated in mobilizing such large commercial borrowings, provided ONGC's financial performance remains satisfactory. ONGC's long-term outlook will depend on the success of the exploration and enhanced recovery programs currently being implemented or planned, its success in marketing large quantities of natural gas which is expected to become a significant source of income in the 1990's, and finally on the continuation of the Government's policy of adjusting oil and gas prices periodically within economic limits. The covenants attached to the proposed loan and the continuing dialogue between the Bank and ONGC concerning its investment program and financing plan should help ensure that ONGC's financial situation remains sound in the long-term.

D. Financial Rate of Return of Development Components

1. Financial Rate of Return

6.10 The development and production components (excluding workover) of the proposed project have a combined financial rate of return of about 18% after taxes (Annex 6.4) and a payback period of about 8 years (including the five-year implementation period). Based on present price levels the financial rate of return of the individual development components range from 15% to 26%. Sensitivity analyses indicate that the financial return on these components is sensitive to several risk factors. A 20% increase in capital cost, a 20% decrease in revenues or a one-year delay in production would result in a return of 11%, 12% or 13%, respectively, for the development component taken as a whole, which would still be acceptable. A combination of all these three factors, however, would cause the financial rate of return to drop to 5%. The project's cash generation and debt service capacity immediately following the development of the light oil fields (i.e. 1986/87) will be satisfactory and its cash position (after principal repayments) is expected to be positive at all times. Cash generation, however, is also quite sensitive to the various risk factors. In the case of a 20% increase in capital costs or of a one year delay in production, the project would not be able to service its debt until year 5 (i.e. 1988/89) — two years later than in the base case.

2. Utilization of Heavy Oil

6.11 The total heavy oil production from the Cambay Basin is expected to increase as a result of the project from 0.25 million tons per year at present to at least 1 million tons per year by the end of the decade. Heavy oil production will eventually be two to three times this level once a commercial scale enhanced oil recovery (EOR) scheme is implemented during the 1990s. At present, the Koyali refinery in Gujarat can only absorb about 0.5 million tons per year of heavy oil. However, ONGC is presently constructing a 12" oil pipeline (50km) from Kalol to the Salaya-Mathura crude oil pipeline which would allow transport of light and heavy oil from the northern Cambay Basin to the Mathura refinery in Uttar Pradesh starting in mid-1984. As the Mathura refinery can also handle only a moderate volume of heavy oil at present, the Ministry of Energy has indicated that it will study utilization alternatives for the heavy oil. Given the lead time available (4 to 5 years), no difficulties are expected in utilizing the additional heavy oil production

from the project. Nonetheless, advance planning is essential. Agreement was reached during negotiations to the effect that GOI will (i) undertake a heavy oil utilization study, to be completed by March 1985, and (ii) take the necessary steps to ensure the utilization or sale of the heavy oil from the Cambay Basin.

VII - ECONOMIC JUSTIFICATION

A. Justification for Exploration Component

7.01 ONGC, with the assistance of Soviet experts, has evaluated several times the petroleum potential of the Cambay Basin, more recently in 1978/79. This latest evaluation concluded that roughly up to 40% of potential petroleum resources in the basin, or about 350 million toe of in-place reserves remained to be discovered. A significant proportion of undiscovered petroleum would be in isolated small pools as shown by the pattern of discoveries to date. However, a major proportion is expected to be found, in the Cambay Gulf area as well as in the deeper horizons (4,000-5,500m), in pools that would be economic to exploit. In accordance with these conclusions, ONGC is embarking on a substantial exploration effort in the basin. During 1984/85-1989/90, its overall exploration and appraisal effort in the basin is presently planned to be at least about US$400 million of which about US$112 million will be contributed by the proposed project. Moreover, there is a provision to increase this total to about US$600 million to cover further exploratory as well as appraisal drilling should the exploration component of the proposed project prove encouraging. If this expanded (US$600 million) total effort discovers (and proves) one-quarter of the prognosticated remaining potential, which is a reasonable assumption, and of this about 28% is recoverable (the present basin-wide average recovery factor), then the additional recoverable reserves generated would be about 25 million toe. The incremental finding cost would be about US$24 per toe (US$3.3/Bbl). Development and production costs in the Gulf of Cambay or for the deep reservoirs in the basin, assuming the petroleum reservoirs will be similar in size to the basin average, is not expected to be more than US$25/toe (US$3.5/Bbl). Since the geologic risks are moderate in a mature petroleum basin such as Cambay and the technical risks have been minimized (paras 5.52 through 5.55), the overall economics for further exploration are favorable and justify ONGC's planned exploration effort in the basin.

B. Justification for Enhanced Oil Recovery Pilot Schemes

7.02 The primary development of the heavy oilfields (North Santhal, Balol and Lanwa) is only expected to recover 5% to 12% of IOIP. Nonetheless, the economic rate of return for this primary development is satisfactory at 53% (para 7.06). An EOR scheme, namely in-situ combustion, is expected to increase the recovery rate to about 40%-50% of IOIP. The development and production cost for a commercial scale in-situ combustion scheme in the heavy oil fields will be substantial, but the expected large incremental recovery (30%-40% of IOIP) will more than compensate for the large costs; the economic rate of return for a commercial scale operation is expected to exceed 40%. Thermal EOR techniques (in-situ combustion and steam flood) are commercially proven methods and are expected to be economically viable for the Cambay Basin heavy oil fields. The pilot EOR schemes are primarily to optimize the field design and more precisely determine the incremental recovery, rather than establish the basic economic viability of the process.

7.03 The polymer EOR pilot on the other hand is more speculative because commercial-scale polymer EOR projects are presently risky undertakings. While polymer EOR techniques are technically proven, there are only few commercial applications at present. The main reason for this is the high cost of polymer which would make the technique of marginal economic value if the incremental recovery is only moderate. Thus, in reservoirs where the primary recovery is relatively high and leaves a smaller proportion of IOIP for EOR methods to extract, polymer EOR schemes are not economic at present levels of polymer and oil prices. In the case of the Jhalora field, the primary recovery factor is expected to be about 16% of IOIP, which would indicate a potentially large incremental recovery (15%-25%) for an appropriate EOR method. This could make a commercial-scale EOR scheme economic in the Jhalora field. Thus, the purpose of the polymer pilot is to test the basic economic feasibility of a polymer EOR scheme. Since the pilot will last about four years, commercial-scale application will take place only at the end of the decade or the early 1990's and, by that time, the price of polymer relative to the price of oil is expected to have decreased; this provides added impetus for undertaking the pilot scheme now.

C. Economic Rate of Return of Development Components

1. Economic Rate of Return

7.04 A rate of return has been calculated for the development component (excluding workover) of the project as a whole as well as for each of the four main sub-components included therein: (a) development of the Kalol field; (b) development of other light oil fields (North-Kadi, South-Kadi, Nawagan and Sobhasan); (c) development of heavy oil fields (North-Santhal, Balol and Lanwa); and (d) rehabilitation of the Cambay gas field. The benefits of the project are taken to be the savings from displacement of crude oil and fuel oil imports resulting from the incremental production of crude oil and natural gas respectively. All investment costs are expressed in mid-1983 prices. The base case economic analysis assumes that the economic price of oil and gas will remain constant in real terms during the life of the project. The following parameters were used:

Light oil price:	US$29/Bbl or US$232/ton
Heavy oil price:	US$26/Bbl or US$173/ton
Gas price :	US$162/thousand Nm^3 1/

7.05 At a 10% discount rate, the net present value of the development component is US$1.1 billion. The overall incremental output of crude (14.5 million toe over sixteen years) represents a saving in oil imports of US$2.9 billion at mid-1983 prices. Moreover, the present value of incremental production during the first five years (3.4 million toe) would roughly cover the total economic cost of development activities including physical contingencies.

1/ The economic value of the gas is based on the calorific equivalent of fuel oil. On the basis of US$180 per ton of fuel oil, the equivalent value of the gas is US$162/thousand Nm^3.

7.06 The economic rate of return of the development component as a whole is estimated at 91%, the return on sub-components ranging from 46% to 180% (para 7.07). A high rate of return is not unusual for an oil development project with a long history of sunk costs as is the case here for the light oil fields in North Gujarat, the development of which started in the 1960's (ERR=183%). The economic rate of return for the primary development of the heavy oil fields is lower (53%) but still satisfactory. Returns on tertiary recovery of heavy oil (expected to be implemented during the 1990s) is also expected to be satisfactory.

2. Sensitivity Analysis

7.07 Sensitivity analyses were conducted for several alternative assumptions, including the case where the economic price (i.e. international price) of oil initially declines in real terms then begins to increase by about 2% annually in real terms after 1985. The results, shown in the table below, suggest that the economic rate of return of the project should remain satisfactory under even moderately adverse circumstances. Sensitivity analysis also suggests that the price of oil would have to drop to US$11/bbl for the project to give a return of 20%.

Table 7.1: Economic Rate of Return (percent)

	Sub-components				Total Development Component
	Kalol Field	Other Light Oil Fields	Heavy Oil Fields	Cambay Gas Field	
Base Case	93	183	53	46	91
Sensitivity Analysis					
1. Investment costs up 20%	72	131	44	39	70
2. Investment costs up 50%	53	91	37	31	52
3. Revenues down 20%	67	121	41	36	66
4. Revenues down 50%	34	57	22	20	33
5. One year delay in production	51	72	37	34	50
6. 1 and 5 together	43	61	31	29	43
7. 3 and 5 together	41	58	30	27	40
8. 1, 3 and 5 together	34	49	25	23	34
9. Economic Price of Oil Initially Declines then Increases Annually After 1985[a]	89	165	53	47	87

a/ See Annex 7.1 for details.

VIII. - AGREEMENTS REACHED AND RECOMMENDATIONS

8.01 During negotiations, agreement was reached with the Government that:

(a) it will provide ONGC or cause ONGC to be provided with sufficient funds to meet ONGC's financial requirements for the

project. In this context the Government will authorize ONGC to seek co-financing for the project (para 5.43);

(b) it will onlend the Bank funds to ONGC on terms and conditions satisfactory to the Bank (para 5.44);

(c) it will, from time to time, carry out a review of the prices of crude oil and natural gas to ONGC, which will determine the level of prices required to meet its operating expenses and earn a rate of return on its assets employed in operations sufficient to meet its debt service requirements, maintain adequate working capital, and finance a substantial portion of its proposed capital investments (para 6.07); and

(d) it will undertake a heavy oil utilization study, to be completed by March 1985 and take the necessary steps to ensure the utilization or sales of the heavy oil from the Cambay Basin (para 6.11).

8.02 ONGC confirmed the following during negotiations:

(a) it will obtain Government approval to have a foreign contractor process the seismic data acquired under the project or otherwise make arrangements satisfactory to the Bank for the timely processing of the seismic data (para 5.32);

(b) it will complete all the necessary pre-drilling studies and survey's using the best data and methodology available and then prepare a detailed drilling program as well as a preliminary completion program satisfactory to the Bank, before drilling each exploration well included in the project (para 5.33); and

(c) it will follow the well casing policy, as well as use the type and quality of oil field cement agreed with the Bank for the wells to be drilled under the project (para 5.35).

8.03 The following agreements were reached with ONGC during negotiations:

(a) periodic project progress reports and ONGC financial reports will be submitted to the Bank during the project implementation period; a Project Completion report will also be submitted (paras 4.07 and 5.56);

(b) ONGC's audited accounts will be submitted to the Bank not later than twelve months after the end of the fiscal year (para 4.08);

(c) it will take precautions in line with industry practices to protect workers and the environment during the implementation of the project and during the operation of the project facilities (para 5.51);

(d) it will maintain its current ratio, debt/equity ratio, and debt service coverage ratio at satisfactory levels (para 6.05); and

(e) it will submit each year to the Government a report containing an analysis of the financial situation of ONGC including a financial evaluation of the development components included under the project, which will indicate the level of prices which would be required by ONGC to earn a DCF return after taxes of at least 15% for the development component and any subsequent commercial scale EOR application in the Cambay Basin as well as other major development projects (para 6.07).

8.04 Execution of a subsidiary loan agreement between GOI and ONGC with terms and conditions satisfactory to the Bank would be a condition of loan effectiveness (para 5.44).

8.05 Based on the agreements reached on the points listed above, the project would be suitable for a US$242.5 million loan to GOI for a term of twenty years, including a five-year grace period.

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INDIA

CAMBAY BASIN PETROLEUM PROJECT

Production, Trade and Consumption of Primary Energy a/

	1960/61	1965/66	1970/71	1975/76	1976/77	1977/78	1978/79	1979/80	1980/81	1981/82	1982/83
I. PRODUCTION											
(a) Commercial Primary Energy											
Coal (10^6 tons)	55.7	67.7	73.0	99.7	101.0	101.0	102.0	104.0	116.0	124.9	131
Lignite (10^6 tons)	-	N.A.	3.4	3.0	4.0	3.6	3.2	2.9	3.0	3.0	3.0
Solid Fuels (10^6 toe)	27.8	N.A.	37.1	50.4	51.2	51.1	51.5	52.5	57.5	63.0	66.0
Crude Oil (10^6 tons)	0.4	3.5	6.8	8.4	8.9	10.8	11.6	11.8	10.5	16.2	17.6
Natural Gas (10^6 toe) b/	N.A.	N.A.	0.4	0.8	1.0	1.0	1.3	1.3	1.1	1.6	1.5
Petroleum (10^6 toe) c/	0.5	N.A.	7.2	9.2	9.9	11.8	12.9	13.1	11.6	17.8	19.1
Hydro Power (10^9 kWh) d/	7.8	15.2	25.2	33.3	34.8	38.0	47.2	45.5	46.5	49.6	48.2
Nuclear Power (10^9 kWh) d/	-	-	2.4	2.6	3.3	2.3	2.8	2.9	3.0	N.A.	N.A.
Primary Power (10^6 toe) c/	1.9	3.6	6.6	8.6	9.1	9.7	12.0	11.6	11.9	11.9	11.6
Total Commercial (10^6 toe)	30.2	N.A.	50.9	68.2	70.2	72.6	76.4	77.2	81.0	92.7	96.7
(b) Non-Commercial Energy e/											
Firewood (10^6 tons)	99.6	109.3	117.9	133.1	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Agricultural Waste (10^6 tons)	30.6	33.6	36.3	41.0	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Animal Dung (10^6 tons)	56.6	59.9	64.5	73.0	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Total Non-Commercial 10^6 toe)	74.0	81.2	87.6	98.9	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Total Production (10^6 toe)	104.2	N.A.	138.5	167.1	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
II. IMPORTS											
Crude Oil (10^6 tons)	5.7	6.8	11.7	13.6	14.0	14.5	14.7	16.1	16.2	14.5	11.8
Refined Petroleum Products (10^6 toe)	2.4	2.7	1.1	2.4	2.8	3.0	4.1	4.8	7.5	4.9	4.6
Petroleum (10^6 toe)	8.1	9.5	12.8	16.0	16.8	17.5	18.8	20.9	23.7	19.4	16.4
Coking Coal (10^6 tons) g/	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	1.1	1.0	1.9	2.0
Total Imports (10^6 toe) c/	8.3	N.A.	13.0	16.4	N.A.	N.A.	N.A.	21.7	24.7	21.3	18.4
III. EXPORTS											
Refined Petroleum Products (10^6 toe)	0.2	0.4	0.3	0.2	0.1	0.1	0.1	0.1	Nil	0.1	0.9
International Bunkers (10^6 toe)	0.6	N.A.	0.7	0.9	0.9	0.7	0.7	0.8	0.6	0.6	0.6
Coal (10^6 tons)	N.A.	N.A.	0.5	0.5	0.5	0.5	0.3	Nil	0.1	0.2	0.2
Total Exports (10^6 toe) c/	0.8	N.A.	1.2	1.2	1.2	1.0	1.0	0.9	0.7	0.9	1.7
IV. APPARENT CONSUMPTION (10^6 toe) f/											
Solid Fuels c/	27.8	N.A.	37.1	50.6	N.A.	N.A.	N.A.	53.2	58.4	64.7	67.8
Petroleum c/	7.9	N.A.	19.0	24.1	25.7	28.5	30.9	33.1	34.7	36.5	34.0
Primary Power	1.9	3.6	6.6	8.6	9.1	9.7	12.0	11.6	11.9	11.9	11.6
Sub-total Commercial	37.6	N.A.	62.7	83.3	N.A.	N.A.	N.A.	97.9	105.0	113.1	113.4
Non-Commercial	74.0	81.2	87.6	98.9	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Total Consumption	111.6	N.A.	150.3	182.2	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Self-Sufficiency (percent)											
Petroleum	6	N.A.	38	38	38	41	42	40	33	49	56
Commercial Primary Energy	80	N.A.	81	82	N.A.	N.A.	N.A.	79	77	82	87
Total Primary Energy	93	N.A.	92	92	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
MEMORANDUM ITEM: Gross Power Generation (10^9 kWh)											
Generation by Utilities	26.9	33.0	55.8	79.2	88.3	91.3	102.6	104.6	119.2	130.9	139.5
Self-Generation by Industry	3.2	3.8	5.4	6.7	7.3	7.6	7.6	8.2	N.A.	N.A.	N.A.
Total Power Generation	20.1	36.8	61.2	85.9	95.6	98.9	110.2	112.8	N.A.	N.A.	N.A.

a/ Based on the following conversion factors: one ton of oil equivalent (toe) equals: 2 tons of domestic coal; 5.88 tons of lignite; 1.39 tons of imported coking coal; 0.94 tons of refined petroleum products and international bunkers; 1,235 cubic meters of natural gas; 4.166 kWh of primary power; 2.04 tons of firewood; 2.33 tons of agricultural waste; and 4.54 tons of animal dung.

b/ Natural gas production excludes quantities flared and used in field operations.

c/ Data that is not available at present have been estimated in arriving at total figures of selected years (i.e. 1960/61, 1970/71 and 1980/81).

d/ Gross power generation.

e/ Non-commercial energy production figures are not available and the figures above are estimated consumption, which are taken as equal to supply.

f/ Apparent consumption equals production plus imports less exports. It does not take into account changes in stock levels.

g/ Demand for coking coal estimated to increase at 6.1% per annum (1981-1989).

Sources: Working Group of Energy Policy (1979); Indian Petroleum and Petrochemicals Statistics (1981/82 1982/83); Annual Coal Statistics (1982); Central Electricity Authority; Economic Situation and Prospects of India (Report no. 38972-IN, March 1982); Bank staff estimates.

Energy Department
March 1984

ANNEX 2.2

INDIA

CAMBAY BASIN PETROLEUM PROJECT

Sectoral Distribution of Energy Consumption

YEAR/SECTOR		Million Tons of Oil Equivalent				
		Oil[a/]	Electricity[b/]	Coal[a/]	Total	%
1980/81: [c/]	Household	4.5	2.2	2.4	9.1	11.2
	Agriculture	1.8	3.4	-	5.2	6.3
	Industry	4.6	13.7	27.0	45.3	55.5
	Transport	12.6	0.6	5.9	19.1	23.4
	Others	0.4	1.9	0.6	2.9	3.6
	Total	23.9	21.8	35.9	81.6	100.0
1970/71:	Household	4.3	0.9	2.0	7.2	13.7
	Agriculture	0.7	1.1	-	1.8	3.4
	Industry	1.7	8.3	15.6	25.6	48.9
	Transport	7.3	0.3	8.0	15.6	29.8
	Others	1.0	1.1	0.1	2.2	4.2
	Total	15.0	11.7	25.7	52.4	100.0
1960/61:	Household	2.5	0.4	1.7	4.6	14.9
	Agriculture	0.4	0.2	-	0.6	1.9
	Industry	1.1	2.8	9.5	13.4	43.4
	Transport	2.7	0.1	8.6	11.4	36.9
	Others	-	0.5	0.4	0.9	2.9
	Total	6.7	4.0	20.2	30.9	100.0

a/ Excluding quantities used for power generation and for oil, excluding non-energy use (e.g. feedstock for fertilizers, etc.).

b/ Estimated electricity consumption at the consumer level (gross power generation less internal power plant uses transmission and distribution losses).

c/ Provisional.

Sources: Working Group on Energy Policy (1979); Indian Petroleum and Petrochemicals Statis (1980/81); Annual Coal Statistics (1981).

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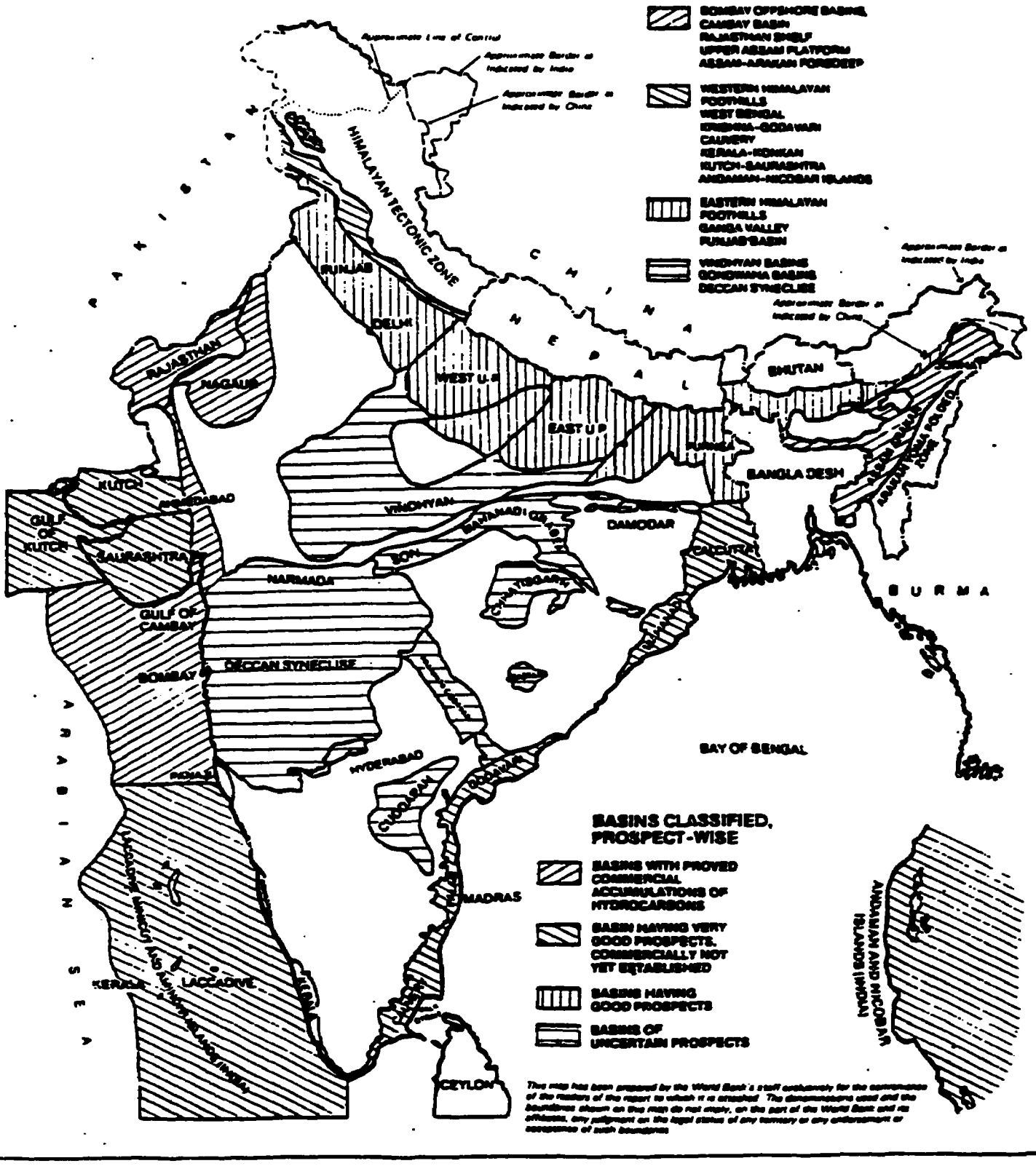
INDIA
CAMBAY BASIN PETROLEUM PROJECT

SEDIMENTARY BASINS OF INDIA



INDIA

CAMBAY BASIN PETROLEUM PROJECT

India Petroleum Summary
(volume in million tons)

	1978/79	1979/80	1980/81	1981/82	1982/83	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90
Crude Production	11.63	11.77	10.51	16.20	20.59	25.79	29.84	30.11	31.22	32.10	32.82	34.15
ONGC-Offshore	3.31	4.42	4.99	7.95	12.30	16.96	20.1	20.17	20.52	20.62	20.35	20.75
ONGC-Onshore-Gujarat	4.24	3.77	3.81	3.41	3.13	3.60	3.90	4.10	4.50	4.90	5.50	6.00
ONGC-Onshore-Assam	1.36	1.32	0.42	1.80	2.15	2.25	2.80	2.84	3.20	3.58	3.99	4.40
Oil India Limited	2.67	2.22	1.24	3.00	3.01	2.98	3.04	3.00	3.00	3.00	3.00	3.00
Crude Imports	14.66	16.12	16.25	14.52	11.76	10.19	11.10	13.00	15.3	17.0	21.3	22.5
Crude Invent. & Losses	(0.32)	(0.42)	(0.88)	(0.57)	(0.40)	(0.72)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)
Refinery Throughput	25.97	27.47	25.84	30.15	31.95	35.26	40.84	43.01	46.42	49.00	54.02	56.55
Product Production	24.19	25.83	24.12	28.18	29.71	32.79	37.98	39.90	43.17	45.57	50.24	52.59
Product Import	3.88	4.48	7.06	4.92	4.59	4.50	3.36	3.64	3.25	3.90	4.81	7.29
Products:												
Domestic Availability	28.07	30.31	31.29	33.10	34.30	37.29	41.34	43.54	46.42	49.47	55.05	59.88
Domestic Consumption	28.24	29.88	30.89	32.52	34.32	36.89	39.66	42.64	45.83	49.27	52.97	56.94
Inventory & Losses	-	0.33	0.40	0.58	0.98	0.40	1.68	0.90	0.59	0.20	2.08	2.94
Imports:												
Volume	14.66	16.12	16.25	14.52	11.76							
Unit Value (US$/Ton)	104.03	167.99	261.07	271.17	274.12							
Value (US$ Millions)	1,525	2,708	4,242	3.938	3,224							
Crude Imports:												
Volume	3.88	4.72	7.25	4.92	4.59							
Unit Value (US$/Ton)	135.22	283.42	333.19	331.72	349.85							
Value (US$ Millions)	525	1,338	2,416	1,632	1,606							
POL Import (US$ million)	2,050	4,046	6,657	5,570	4,830							
Crude Equivalent	18.79	21.14	23.96	19.74	16.64							
Memo: OPEC Av. Price (US$/BBL)												
(Calendar Year	18.60	30.50	34.20	33.00	33.00							
(Fiscal Year)	14.33	21.58	31.43	33.90	33.00							
Fiscal Year Index	0.46	0.69	1.00	1.08	1.05							

Source: ONGC; Ministry of Petroleum, Chemicals and Fertilizers

Energy Department

March 1984

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Production and Consumption of Petroleum Products
(Million Tons)

	Actual							Forecast		
	1975/76	1976/77	1977/78	1978/79	1979/80	1980/81	1981/82	1982/83	1983/84	1984/85
Production										
Light Distillates	3.63	3.82	4.05	4.30	4.46	4.10	5.14	5.77	5.90	7.13
LPG	0.33	0.36	0.38	0.40	0.41	0.37	0.41	0.59	0.62	0.78
Petrol	1.28	1.34	1.42	1.52	1.51	1.52	1.61	2.12	2.16	2.59
Naphtha	1.91	1.99	2.12	2.26	2.42	2.12	3.00	2.95	3.01	3.62
Others	0.11	0.13	0.13	0.12	0.12	0.09	0.12	0.12	0.12	0.14
Middle Distillates	10.77	11.23	12.08	12.48	13.08	12.12	14.14	16.67	16.87	20.15
Kerosene	2.44	2.58	2.45	2.51	2.54	2.40	2.91	3.51	3.66	4.50
Jet Fuel/Aft	0.93	0.98	1.08	1.18	1.10	1.00	1.01	1.34	1.34	1.58
High Speed Diesel	6.29	6.40	7.13	7.35	7.98	7.37	9.05	10.10	10.21	12.18
Light Diesel Oil	0.95	1.09	1.22	1.23	1.23	1.11	0.95	1.39	1.33	1.51
Others	0.16	0.18	0.20	0.21	0.23	0.24	0.22	0.32	0.32	0.38
Heavy Ends	6.43	6.38	7.09	7.42	8.26	7.91	8.92	9.93	9.59	10.93
Fuel Oil	5.08	4.73	5.33	5.65	6.35	6.12	6.95	7.55	7.21	8.12
Lub Oil	0.34	0.37	0.41	0.49	0.49	0.43	0.41	0.55	0.54	0.62
Bitumen	0.70	0.95	0.99	1.10	1.10	1.08	1.29	1.48	1.50	1.79
Others	0.31	0.33	0.36	0.32	0.32	0.28	0.27	0.35	0.33	0.39
Total	20.83	21.43	23.22	24.20	25.79	24.12	28.20	32.36	32.36	38.21
Consumption										
Light Distillates	3.60	4.04	4.23	4.57	4.46	4.38	5.14	5.20	5.68	5.93
LPG	0.34	0.37	0.39	0.41	0.41	0.40	0.49	0.65	0.46	0.85
Petrol	1.28	1.32	1.39	1.50	1.49	1.52	1.60	1.53	1.58	1.64
Naphtha	1.84	2.20	2.29	2.51	2.41	2.32	2.93	2.86	3.17	3.26
Others	0.14	0.15	0.16	0.15	0.15	0.14	0.12	0.16	0.17	0.18
Middle Distillates	11.65	12.65	13.77	15.19	16.32	17.01	17.79	19.34	21.13	23.09
Kerosene	3.10	3.32	3.63	3.96	3.87	4.21	4.70	4.52	4.82	5.22
Jet Fuel/Aft	0.90	0.96	1.04	1.15	1.14	1.13	1.12	1.33	1.46	1.62
High Speed Diesel	6.60	7.11	7.74	8.65	9.80	10.33	10.78	12.18	13.27	14.59
Light Diesel Oil	0.88	1.08	1.16	1.22	1.27	1.13	1.03	1.29	1.35	1.44
Others	0.17	0.18	0.20	0.21	0.24	0.21	0.21	0.22	0.22	0.22
Heavy Ends	7.20	7.40	7.54	8.50	9.10	9.40	9.39	10.84	11.44	12.10
Fuel Oil	5.78	5.73	5.84	6.67	7.08	7.42	7.20	8.17	8.54	8.95
Lub Oil	0.44	0.45	0.48	0.54	0.57	0.59	0.60	0.60	0.63	0.67
Bitumen	0.69	0.88	0.91	0.94	1.07	1.08	1.30	1.50	1.65	1.83
Others	0.29	0.34	0.31	0.34	0.38	0.31	0.29	0.57	0.62	0.65
Total	22.45	24.10	25.54	28.24	29.88	30.79	32.32	35.58	38.25	41.12

Source: ONGC; Ministry of Petroleum, Chemicals and Fertilizers.

Energy Department
March 1984

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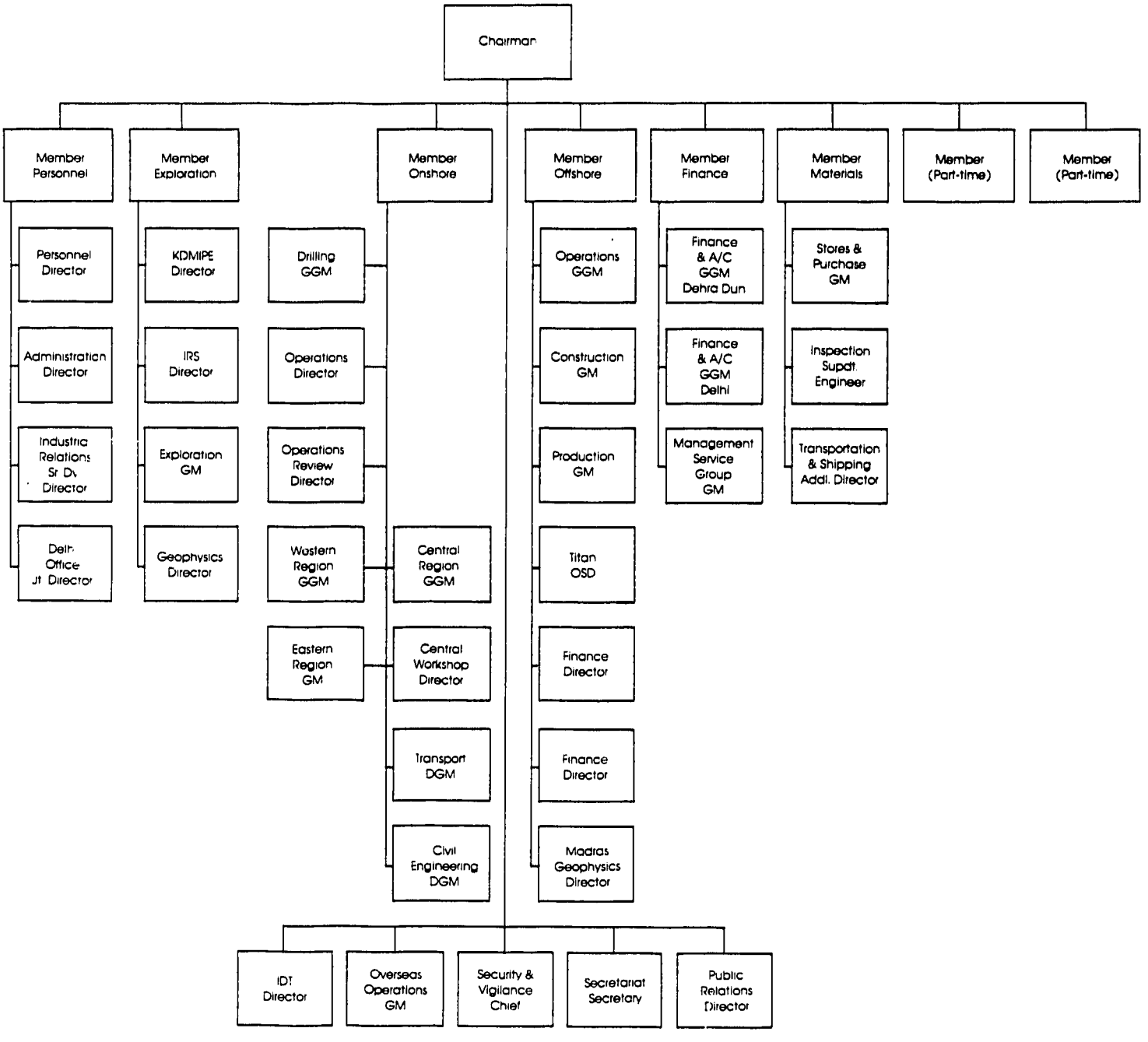
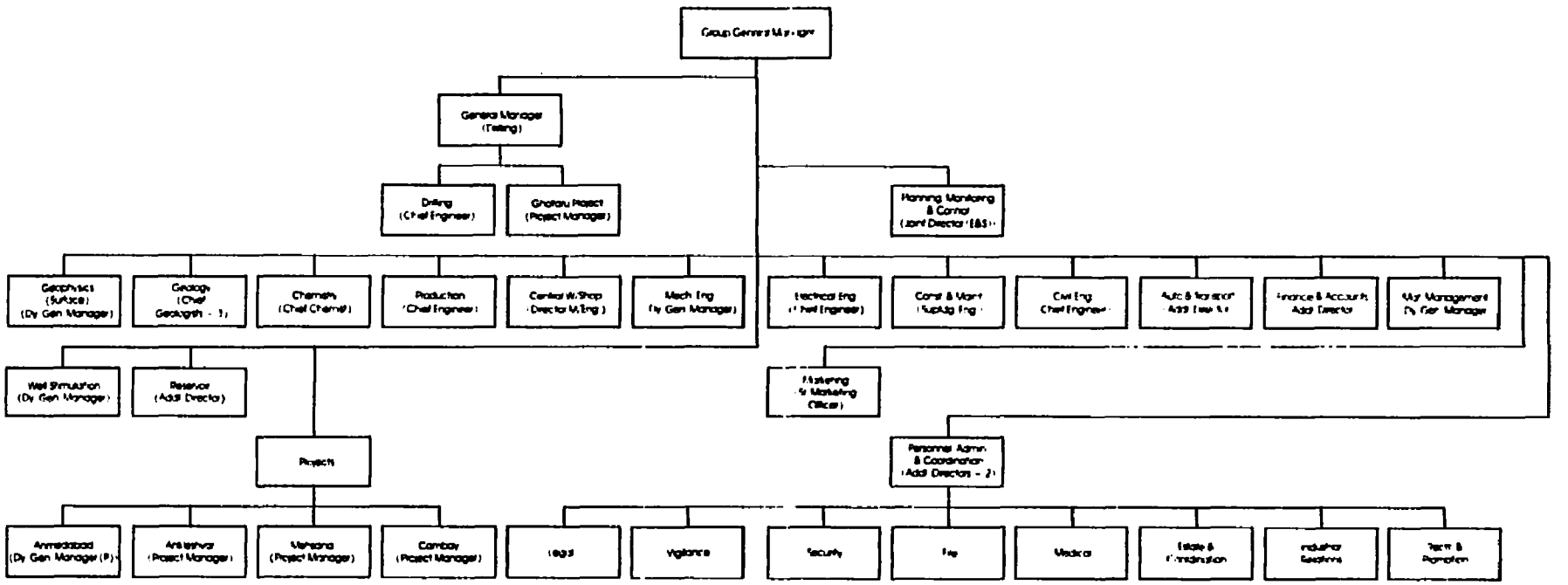
CAMBAY BASIN PETROLEUM PROJECT
ONGC
Organization Chart



Energy Department
December 1983

ANNEXURE 4.2

INDIA
CAMBAY BASIN PETROLEUM PROJECT
Organizational (Function_l) Set-Up of Western Region



Energy Department
December 1983

Arvind Bora - 2/7/98

INDIA

CAMBAY BASIN PETROLEUM PROJECT

ONGC Investment Program

Background

1. ONGC is now in the fourth year of the five-year plan period 1980/81-84/85. The initial plan document (June 1980) provided for expenditures of approximately Rs 40 billion (at 1980 prices). It was revised in August 1981 and again in August 1982 in order to incorporate the accelerated programs for exploration and the final development of the Bombay High field; outlays were increased accordingly to Rs 71 billion (at current prices). The production target over the plan period was increased from 51.3 million tons of crude oil to 91.6 million tons.

2. In March 1982, ONGC completed a 10-year conceptual planning exercise over the period 1980/81-89/90 where two scenarios are presented: Variant I has an annual production objective of 46.5 million tons of crude oil by 1989/90, while Variant II has an objective of 60.5 million tons annually in the same year. Since ONGC's existing reserves cannot sustain a production rate above 30 million tons per annum, both scenarios assume that increased exploration expenditures would yield commercial discoveries which will start producing in the second half of the 1980's.

3. ONGC recognizes that in order to accelerate its exploration program during the seventh plan period (1985/86-89/90), additional exploration and development expenditures will have to be incurred between 1983/84 and 1984/85 so that when the seventh plan begins, it will have adequate materials and equipment, trained personnel and resources to achieve its objectives. One should note, however, that the Government has not yet approved ONGC's recommendations. In November 1982 the Government approved, in principle, all the exploration components as well as the development of presently known reserves proposed in Variant I, but did not approve the speculative portion of the development investments dealing with future (expected) discoveries. These types of development investments will be proposed by ONGC as the discoveries are actually made. The GOI-approved plan is now known as the Core Plan. This Core Plan has been used for the purposes of the financial projections over the period 1982/83-1989/90. The investment program which appears at the end of this Annex has been used as an input for the financial projections (Annex 6.1). It should be considered as the broad outline of an expenditure program which could be, at relatively short notice, significantly altered, for instance, on account of reservoir studies (which would lead to additional investments in producing areas) or commercial discoveries.

Exploration

a. Onshore

4. The Western Region includes the Cambay, the Rajasthan, the Saurashtra and the Kutch basins; but only the Cambay basin has been fairly well explored. The region's recoverable oil reserves are estimated at 113.6 million tons as of 1/1/82 (51.5 million tons as of 1/1/81). The exploration

strategy adopted here is to: (i) locate extensions of prospects already delineated; (ii) identify subtle traps in different basement blocks on the basis of sophisticated seismic work and geological modelling; and (iii) explore new areas such as the shoal project in the Cambay Gulf, Kutch, Saurashtra and Rajasthan. Deeper prospects in the existing known areas are also to be drilled. During the period 1982/83-1987/88, ONGC plans to carry out about 22,230 line-km of seismic surveys and drill 200 wells (about 490,000 meters).

5. The Eastern Region (Assam, Nagaland, Meghalaya, etc.) is considered very prospective. Recoverable oil reserves were estimated at 61.4 million tons as of 1/1/82 (50.0 million tons as of 1/1/81). More than 40 prospects identified from seismic and geological surveys are yet to be drilled. Virgin areas such as Dansiri Valley, Naga Hills, and the north bank of Brahmaputra are planned for drilling. 14,600 line-km of seismic surveys are planned during the 1982/83-87/88 period, together with 156 exploratory wells (altogether 580,000 m).

6. In the Central Region, which comprises the balance of the onshore area, no commercial discoveries have been made so far, but a number of attractive prospects have been identified, including the basins of Bengal, Krishna-Godavari and Cauvery. ONGC also plans to initiate exploration efforts in new areas (Himalayan foothills -- Ganga Valley) and is in the process of acquiring modern equipment for that purpose (digital seismic units, equipment designed for desert conditions, etc.). 47,900 line-km of seismic surveys are now proposed in the 1982/83-87/88 period, together with 186 exploratory wells (744,000 m).

b. Offshore

7. Offshore exploration activities have given very encouraging results in recent years. In 1981, a new structure known as B-57 has been discovered south-east of the Bassein field. On the east coast, oil has been discovered for the first time in a new structure in the Palk Straits known as PH-9. Offshore recoverable oil reserves are estimated at 345.8 million tons as of 1/1/82 (328.3 million tons as of 1/1/81). The objective of the exploration program here is to complete the seismic reconnaissance and semi-detailed surveys of most of the promising areas, and extend the same to the continental slope and deeper areas offshore. For this purpose, about 165,000 line-km of seismic surveys and 219 exploratory wells (719,000 m) are proposed in the 1982/83-87/88 period.

Development

a. Onshore

8. Primary production for many of the fields in the Western Region is declining, and sophisticated secondary and tertiary recovery techniques (water flooding, polymer injection, thermal in-situ combustion, gas injection) will be needed to maintain production. Contracts have been signed with the USSR to assist in work-over operations, and with Nowasco of Canada to provide advanced technology for well stimulation, acidization and fracturing. 226 development wells are proposed during the 1980/81-1984/85 plan period (326,000 m). For the period 1984/85-1989/90, the investment program for the Western Region is

about US$1.6 billion, including the proposed Cambay Basin Petroleum Project (US$954 million).

9. In the eastern Region, an accelerated production program aiming at producing 4.1 million tons by 1985/86 is underway. 273 wells (815,000 m) are proposed for the 1982/83-87/88 period.

b. Offshore

10. The accelerated offshore production program includes the further development of Bombay High and the development of new structures such as Ratna (R-12), Heera (B-37/38), Bombay High East and Panna (North Bassein). In addition, the South Bassein offshore gas field will be developed. CFP (France) has been retained for the reservoirs studies and development of Bombay High and neighboring fields. 341 development wells (789,000 m) are proposed during the 1982/83-87/88 period.

Research and Development

11. Three institutes for research and development function within ONGC; the Institute of Petroleum Exploration (IPE) and the Institute of Drilling Technology (IDT), both at Dehra Dun, ONGC's headquarters, and the Institute of Reservoir Studies (IRS) at Ahmedabad. These institutes support ONGC's activities both onshore and offshore. IPE primarily frames the exploration strategy, reviews exploration programs, and prepares reserves estimates. IDT aims at improving the drilling technology. To that effect, it develops tools, carries out research in indigenous development of mud chemicals and cement additives; it also supervises and monitors key exploratory wells projected for deeper targets. IRS establishes drilling plans for various discovered fields, monitors the behavior of producing reservoirs, carries out economic studies and investigates enhanced recovery methods.

12. ONGC is now considering establishing an Offshore Technology Research Institute in Bombay, which will be active in offshore oil exploration, development, production and transportation, and upgrades ONGC's know-how in offshore technology, deep water techniques, etc.

Source: ONGC.

Energy Department
January 1984

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CAMBAY BASIN PETROLEUM PROJECT

Investment Program
(Million Rupees)

	1982/83	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90
I. OFFSHORE								
A. Exploration								
Surveys	144	246	281	93	98	104	113	122
Drilling	1,909	1,855	1,972	2,931	3,191	4,692	5,801	6,783
Capital Items	1,733	700	1,034	739	751	721	679	601
Sub-total	3,786	2,801	3,287	3,763	4,040	5,517	6,593	7,506
B. Development								
Development Expenses	1,535	8,531	11,709	23,334	15,158	6,554	1,461	2,021
Capital Items	5,197	2,099	3,103	2,217	2,254	2,162	2,037	1,804
Sub-total	6,732	10,630	14,818	24,551	17,412	8,716	3,498	3,825
Total Offshore	10,518	13,431	18,099	28,314	21,452	14,233	10,091	11,331
II. ONSHORE								
A. Exploration								
Surveys	194	366	495	837	900	642	531	571
Drilling	641	1,218	2,172	3,153	4,070	5,007	6,779	8,412
Capital Items	451	367	1,115	1,979	1.720	1,007	1,155	932
Sub-total	1,286	1,951	3,782	5,969	6,690	6,756	8,465	9,915
B. Development								
Development Expenses	434	1,068	1,867	4,524	3,690	4,013	3,931	3,933
Capital Items	1,361	1,103	3,347	5,937	5,162	3,321	3,466	2,796
Sub-total	1,785	2,171	5,214	10,461	8,852	7,334	7,397	6,729
Total Onshore	3,071	4,122	8,996	16,430	15,542	14,090	15,862	16,644
III. INSTITUTES AND R&D	32	113	367	500	550	550	600	600
TOTAL	13,621	17,666	27,462	45,244	37,544	28,873	26,553	28,575

Note: Capital items have been allocated 75% to development and 25% to exploration.

Source: ONGC

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March 1984

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CAMBAY BASIN PETROLEUM PROJECT

ONGC Operations in the Cambay Basin

Drilling

Drilling activity in the Western Region consists mainly of development wells of shallow depth. ONGC Western Region (WR) drills 60 to 70 wells per year of which 6 or 7 are exploration wells and the remaining development wells. ONGC-WR owns and operates 16 land drilling rigs. Fourteen of these are of Russian build and design, one is of Romanian build and design and one is Indian built of US design. Most of the Russian rigs are very old, ranging from 15 to 23 years, and of a very low efficiency, taking at least twice as long to drill a well compared to a new modern rig. ONGC's yearly average drilling performance is of a low level — 5 to 6 wells of 1,600-meter depth per rig in development and 1 to 2 wells of 3,000-meters depth per rig in exploration.

The Russian rigs, as well as the Romanian one which was delivered in 1978, are diesel mechanic and of inadequate design. Their mechanical system offers little flexibility and availability, resulting in continuously disrupted operations. Mud processing is also of poor design. The mud solids control equipment is virtually nonexistent and mud treatment equipment completely ineffective. ONGC's operating efficiency is further hampered by the absence of infrastucture and logistical support. All this leads to a low drilling penetration rate, poor cement job and finally to a well of poor quality, which may need to be worked over sooner than its normal producing life.

Drilling Services

All specialized well drilling services are performed by ONGC. These services include mud engineering, mud logging, electric logging, cementing, formation drill stem testing and production testing with all other related operations. The equipments used for these services are very old and completely worn out, except for electric logging for which 2 US made units have just been received and will be operating shortly.

Mud Engineering

The mud system normally used by ONGC-WR is of a fresh water bentonite lignosulfonate type for which most of the products and chemicals are produced locally. No rig mud laboratories are available and the field mud test kits are incomplete. As observed in the field, most of the time mud engineers use inadequate or incomplete equipment for measuring mud properties. This may explain why, although the mud is of a water base type, its properties are not properly controlled. As observed, solids content is very high and the specific gravity often much higher than actually needed. This leads to subsequent problems such as a low drilling penetration rate, poor cement job and formation damage. Formation damage appears to be very critical in the Cambay gas field.

Mud Logging

ONGC's rigs in the Western Region, including those used in exploration, are not equipped with mud logging units. Rig personnel use an old-fashioned device for drilling control and geological monitoring. Modern mud logging equipment would assist rig personnel in continuously and automatically monitoring various bottom-hole parameters during drilling. As a result, geological surveillance would be more accurate and easier. On the other hand, without mud logging units, drilling data acquisition is minimal and sometimes unreliable.

Electric Logging

ONGC's well logging equipment in the Western Region is Russian-made and old. The system is composed of two trucks, one containing the electric wireline winch and associated gears and the other logging instruments and controls. Logging tools and instruments in these units are reported to be of poor accuracy and useless when the hole temperature exceeds 120°F, which happens quite often in the Western Region. Except for a few basic tools, most required tools are lacking. These existing units can be used as tools for correlation purposes but are not effective guides in locating pay zones. However, ONGC is well aware of the limitation of its equipment and has just received two US-made units which will be in operation shortly with technical assistance from the supplier. These two technically advanced units will cover most of the exploration needs and will help in drilling the complicated development wells.

Cementing

Most of the cement jobs are not successful. In addition to the use of inadequate cementing equipment, cementing operations are done with Portland construction cement which is well known for its poor results when used in oil or gas wells. As opposed to electric logging where ONGC is now introducing up-to-date equipment, cementing services are still performed with substandard units of very low performance. These units are Romanian and Russian made, old and worn out. Each unit is equipped with a single pump, mounted on a truck. Bulk cement tanks are carried out on trucks of 15 to 20 ton capacity. The system cannot perform continuous cement slurry mixing and pumping, which is essential to maintaining proper slurry parameters.

Formation Testing

No formation drill stem testing (DST) is carried out while drilling due to lack of the necessary equipment. For this reason, even exploratory wells are not adequately tested while drilling. The way the wells are evaluated is actually rather surprising: in exploration, after the well has been drilled and if electric logs indicate an interesting zone, the hole is cased and perforated. A compressor is then used to inject air through the annulus between the tubing and the casing, thus reducing the hydrostatic pressure on the reservoir. The pressure differential so created causes an influx of oil or gas from the reservoir into the well. In this manner, no bottom hole data can be acquired. In addition to the high risk of total casing collapse and blow out, the procedure may fail to stimulate petroleum flow and it should be of no surprise if critical errors are made on the final judgement regarding

the absence of petroleum. This method is also regularly applied in development wells for production testing.

Work-Over

To date there are more than 345 development wells that need to be worked over, which affects oil production susbstantially. These wells are estimated to have a production potential of 3,000 to 4,000 tons of oil per year. In addition to the present work-over backlog, one can assume that the number of wells in need of work-over will increase by 140 to 150 each year. In comparison the present work-over capacity of ONGC Western Region is about 120 wells per year.

Work-Over Rigs

ONGC Western Region owns and operates 23 work-over rigs. In addition, two truck-mounted work-over rigs have been contracted from the USSR. Most of ONGC's rigs are very old (15 to 17 years) and have reached the end of their useful life. Their average performance, including the two under contract with the USSR, is of a very low level. Work-over activity is further hampered by the absence of infrastructure and logistical support. Well repairs that seem too complicated (fishing, casing and bottom hole equipment deterioration) are not carried out due to limitations to the rigs' capability and condition. About 140 wells of such complicated work-over jobs have been left behind. The authorities of ONGC-Western Region are aware of the need to acquire new equipment. Four new US-made self-propelled work-over rigs are expected to arrive in the Cambay Basin early this year.

Organization

ONGC Western Region appears to have a well-conceived organizational structure. A regional management committee based in Baroda sets operational plans, elaborates programs and coordinates field requirements. It is organized on a functional basis with the following groups: production, geology, drilling, maintenance, finance, administration and stores, and supply. Project managers, based in the fields (e.g., Anklewsvar, Ahmebabad, Cambay), supervise the implementation of programs. The field management team is said to have a high level of delegation of authority over operations. Sometimes, however, a communication gap appears to exist between the field team and higher level authority.

Personnel

Operational personnel involved in discussions with Bank staff were very knowledgeable. In fields visited by the Bank mission the overall working atmosphere was good, despite mechanical problems and the inadequacy of the equipment. Field personnel seem well organized and appear to perform according to normal oil field practice. Most of the engineers occupying key operational positions were apparently well aware of ONGC Western Region operating problems.

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March 1984

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CAMBAY BASIN PETROLEUM PROJECT

Geology of the Cambay Basin and Hydrocarbon Resource Potential

A. General Geology

1. The Cambay Basin came into existence at the close of the Mesozoic period with development of tensional down faulting along its margins accompanied by large scale volcanic activity. Later, Tertiary sands and shales, principally of Paleocene and Eocene ages, filled the basin. The depositional environment of these Tertiary sediments range from shallow marine at the base becoming deeper marine to continental as basin fill progressed. The southern half of the basin was cut by east-northeast and west-southwest trending lateral faults activated primarily during and since the Miocene epoch. Structures in the Cambay Basin are of two basic types: (i) horst and graben tensional fault blocks (including tilted marginal fault blocks at the edge of the basin) unaffected by lateral movements in the northern portion of the basin and (ii) compressional folds associated with lateral movements in the southern portion of the basin.

2. The marine Cambay Black Shale of Paleocene-Eocene age, is considered as the main source rock for the hydrocarbons encountered in the Cambay Basin. Secondary source rocks are the shallow marine to fresh-water interbedded shales of the Eocene deltaic intervals (Kalol Formation and equivalents). In addition, even the relatively low organic content Miocene shales of southern Cambay Basin are now considered to be the source rocks for the important gas deposits now being established in the offshore of the Cambay Basin.

3. Reservoir rocks in the Cambay Basin are primarily deltaic sandstones of Middle Eocene age, deposited by two distinct advancing delta fronts: (i) the southern Narmada delta and its distributaries which enter from the east-northeast adjacent to the present course of the Narmada River and (ii) in the north, the Sabarmati delta, which enters from the north-northeast. To the north, the Narmada delta sands appear to extend as far as the Mahsagar River. However, the southern limit of the sands is not well known due to the lack of adequate number of wells drilled into the subsurface so far. The northern Sabarmati delta sands extend as far south as Ahmedabad. Lenticular, shaly pre-delta sandstones are found at the base of the Tertiary within the marine Cambay Shale. Sandstone reservoirs of Mio-oligocene and younger geologic age, associated with a possible delta system have been found at the southern end of the basin and into the Bombay offshore area. Likewise, minor pay has been penetrated in sideratic marls, fractured shales and coal beds in the non-marine portion of the northern delta.

4. The base of the Tertiary is marked by a thick basalt (Deccan Trap) of varying thickness, currently interpreted to be in excess of 1000 meters. The existence of pre-Trappean Mesozoic sediments in the subsurface of the Cambay Basin is uncertain. Scattered and incomplete surface exposures along the eastern margins of the basin indicate the presence of pre-Tertiary continental-laccustrine sands and shales (clastics) as well as shallow water

marine limestones. Attempts have been made to project hydrocarbon source and reservoir rocks into the basin beneath the Deccan Trap basalts; however, Pre-Trappean sediments could have been removed by erosion during possible post-Mesozoic uplift and faulting phase of the basin. Although prenetrated in some of the wells, the Deccan Trap has not been drilled through in order to ascertain the existence of sediments beneath the basalts.

B. Hydrocarbon Reserves Potential

5. Large in-place reserves remain to be discovered in the Cambay Basin. A joint ONGC/Soviet study group in 1978/1979 concluded that the in-place hydrocarbon reserves in the basin could be as large as 850 million toe of which about 500 million toe has been discovered so far. Data at hand supports that these estimated reserves are significant and can be economically exploited from a wide range of geologic prospects onshore, and more significantly, offshore under the Gulf of Cambay. The remaining prospects onshore involve deep potential hydrocarbon zones beneath currently producing fields as well as in isolated wells with shows not adequately tested to rank as discoveries. Additional prospective features, both shallow and deep, exist onshore in the basin's central block where, due to ONGC's preconceived concepts regarding the areas low potential and poor reservoir sand development, have experienced only limited exploratory drilling. The basin's greatest potential, however, lies offshore along the tidal/transition zone and beneath the shallow waters of the Cambay Gulf. A series of structures associated with faulting are seen at the seaward extension of the basin at Hazira and Dahej, projecting outward to North Tapti, Central Tapti and South Tapti. All but North Tapti have been drilled and proved to be hydrocarbon bearing. The South and Cental Tapti features, on the basis of one field discovery each, are tentatively credited with 40 million tons of condensate and 62 billion cubic meters of gas. The Hazira and Dahej gas/condensate discoveries, while not assigned reserves at this time, are expected to extend into the offshore and could be of significant magnitude.

Energy Department
March 1984

INDIA

CAMBAY BASIN PETROLEUM PROJECT

Project Components

1. The proposed project has four major components with the following specific objectives: (i) exploration -- to pursue the search for petroleum by drilling to deeper untested stratigraphic zones, and to acquire seismic data and hence identify potential hydrocarbon prospects in the unexplored shallow waters and shoal areas of the Gulf of Cambay; (ii) development and production -- to accelerate the development of undeveloped and underdeveloped oil fields and improve well maintenance, thereby increasing oil production in the basin by close to 2 million tons per year and gas production by about 142 million m^3 per year (0.12 million toe per year) within six years; (iii) enhanced oil recovery pilot tests -- to increase recoverable reserves of the heavy oil fields by determining the most appropriate enhanced oil recovery (EOR) method through field pilot schemes; and (iv) technical training and assistance -- to improve the drilling and production efficiency in the basin through training programs, hiring of technical consultants and contractors, as well as by introducing new and modern equipment as an integral part of project implementation.

A. Exploration Component

2. The exploration component has two sub-components, a seismic survey and deep exploration drilling.

1. Seismic Survey

3. Approximately 20% of the Cambay Basin is in the Cambay Gulf and covered by current swept shallow waters, tidal mud flats and shoals. This area requires the application of high resolution and modern seismic methods. To date, this highly prospective area has been neglected for lack of specialized geophysical techniques and equipment needed to acquire data in this difficult environment. Only one well has been drilled in the mud flats area, the Aliabet No. 1, which tested oil in the Miocene. The seismic survey included in the project will: (i) help outline the seaward extent of the Dahej structure, a major Eocene gas field discovered in 1979 and currently under appraisal; (ii) delineate possible fault controlled structures (i.e., drillable prospects) in the Gulf similar to Ankleshvar field; and (iii) help determine the western Eocene sand limits of the Narbada prograding delta. This seismic survey is designed to acquire 1,750 line kilometers of data: 300 line kilometers in shallow waters of the Gulf of Cambay and 1,450 line kilometers using "teleseis" technique over the tidal and shoal areas. Furthermore, depending upon the successful outcome of the offshore North Tapi No. 1 wildcat, located in the Gulf of Cambay about 75 kilometers southwest of Ankleshvar field, ONGC may propose in late 1984, to add another 800 line kilometers of seismic survey under the project. This would be acceptable. The additional seismic survey would be south of the area covered by the 1,750 kilometer program and restricted to the eastern shoreline and saltwater marsh/swamp areas of the Gulf. It is expected that the "teleseis" method of acquisition would also be used for this extension. The prime objectives of

this additional coverage would be to: (i) secure nearshore subsurface data to resolve the size and prospectiveness on the Hazira Well No. 1 Miocene gas discovery of 1969; (ii) determine the southern sand limits of the Eocene Ankleshvar sands of the Narbada delta and possibly determine the hydrocarbon source for the thick deltaic Miocene sands recently discovered to be petroleum-bearing on the offshore Tapti structures; and (iii) search for fault controlled structures and traps in the Gulf, which are expected to parallel the northeast-southwest trend as currently mapped in the Ankleshvar, Hazira and offshore Tapti areas.

4. The seismic survey (data acquisition and processing) will be undertaken by an international contractor. However, in the past two years, the Ministry of Defense has imposed more strict requirements and clearance procedures for the processing of seismic data by outside contractors. On the other hand, ONGC's existing computer facility has a backlog of about 4 to 5 years of seismic data for processing and could not be expected to process the data to be collected under the project in a timely or satisfactory manner. A new computer is on order but is not expected to be operational for another two years. The mission was assured by ONGC that the necessary clearances will be sought from the Ministry of Defense to process the data by contract. However, in case this request is denied by the Government, ONGC, in consultation with the Bank, will make satisfactory arrangements for processing the data expeditiously within India. The options available are:

(i) using a foreign contractor with software compatible with ONGC's computer system to process the data in India;

(ii) allowing the contractor selected through ICB to process the data in India on its own computer; and

(iii) ONGC processing the data on a priority basis, in its computer center if the quality of the processing s found to be comparable.

2. Exploratory Drilling

5. Most identifiable subsurface/seismic features in the basin have been drilled at least through the main Middle Eocene pay zones (i.e., down to about 3,000 meters). Future production increases from the onshore basin, other than that realized from the infill drilling of undeveloped or underdeveloped fields and proposed EOR schemes, must be derived from yet to-be-tested deep (i.e., 4,000 to 5,000 meters) stratigraphic zones and reservoirs drapped over basement highs. The four stratigraphic (parametric) exploration wells proposed by ONGC represent the next logical phase in the exploration and exploitation of the basin. These four wells have been designed to primarily penetrate the maximum stratigraphic section to the economic basement (Deccan Trap), evaluate deep Lower Eocene lenticular sandstones and formulate depositional concepts for the encased reservoirs within the Cambay shale. Furthermore, these wells have been site-selected, where possible, to encounter potentially productive shallower (i.e. 3,000 to 4,000 meters) zones pinching out up-dip against structure or trapped against sealing faults which occur frequently in the basin. Successful completion of these wells will provide ONGC with additional information on the new basinal hydrocarbon trends and pay targets to potentially supplant the expected depletion of existing fields.

The four locations proposed for drilling are : (i) Bharkodra, (ii) Jambusar-P, (iii) West Kalol and (iv) South Warosan (IBRD Map No. 17602)

6. The mission informed ONGC that additional seismic information and geological analyses should be performed for two of the proposed four wells to optimize the spudding location. ONGC agreed to do these. During the pre-appraisal mission, the Bank staff also suggested, and ONGC agreed, that a detailed drilling program and a preliminary completion program approved by the Bank would be prepared before each well is spudded. At present, only a highly summarized one-page prognosis, the General Technical Order (GTO), is prepared which is not satisfactory. ONGC confirmed that before each exploration well is drilled, Bank approval will be obtained by ONGC for the specific location. Furthermore, a detailed drilling program as well as preliminary completion program satisfactory to the Bank will be prepared.

B. Development and Production Component

7. The development and production component of the project consists of four sub-components: (i) the final phase or completion of the development schemes of several light oil fields namely Kalol, North Kadi, South Kadi, Sobhasan and Nawagam; (ii) the initial (primary) development of the heavy oil fields namely, North Santhal, Balol and Lanwa; (iii) the rehabilitation of the Cambay gas field, the largest non-associated gas field in the basin; and (iv) improvement of well maintenance (workover) operations to eliminate the substantial backlog of production wells needing repairs, as well as to increase the capacity and quality of well maintenance and workover to cope with the increasing number and complexity of production wells as a result of the proposed project.

1. Final Development of Light Oil Fields

8. a. Kalol Field. The field is located at about 13 kms NE of the town of Ahmedabad. It has an areal extent of 15 sq km. The field is highly faulted and has about 10 pay zones identified as horizons 2 to 12, with horizons 9 and 10 being the main oil producing zones. Horizons 5, 11 and 12 are poorly developed and not consistent in all the wells. Average porosity of the field is about 20-22%, average permeability 20-150 milli darcies, oil saturation about 65-70% and the average thickness of each producing zone is 4 to 5 meters. The field was discovered in 1960 and commercial production started in 1964. The maximum oil production was attained in 1977/78, peaking at 358.527 tons (or 2.69 million barrels). The overall cummulative oil production since 1964 is 3.54 million tons of oil with 1600 million m^3 of gas. This represents about 7% of initial oil in-place and 31% of estimated recoverable reserves. The field is currentlyy producing about 850 tons of oil per day (or 6300 BOPD) and 31.5 mmcf of gas per day, consisting of 600,000 m^3 of associated gas and 300,000 m^3 of dry gas. The oil flows freely with an oil viscosity of 1.4 centipoise at formation temperature.

9. About 210 wells have been drilled in this field so far, consisting of 124 wells classified as oil wells, 31 as gas wells, 9 as water injection wells for pressure maintenance, and 24 wells as abandoned wells (dry holes or technical problems). Of the 124 oil wells, 52 wells are still producing, 5 are

awaiting surface line connection, while 67 are closed-in and in need of work-over. Of the 31 gas wells, 20 are producing, 7 closed-in due to excessive water infiltration and 4 wells are awaiting surface line connection.

10. The main objectives of the Kalol field final development program are to: (i) increase the ultimate oil recovery factor from 21% based on existing techniques and facilities to about 30% of the initial oil in-place; (ii) increase the annual production rate which has declined from 358,527 tons in 1977/78 down to 184,296 tons in 1981/82, to about 640,000 tons per year by 1987/88; and (iii) to increase the associated and free gas production from about 65 million m^3 per year at present to 248 million m^3 per year by 1987/88. These are to be achieved through infill drilling, introduction of artificial lift equipment (gas lift and sucker rod pumps) and expanding the water injection schemes now in place. A total of 135 new wells, equipped with artificial lift equipment, will be drilled under contract for this purpose. Of these 135 wells, 108 will be drilled as oil producers and 27 will be designed to be switched over to water injection wells after about 2 to 3 years of production. The peak incremental production due to the final development plan is about 455,704 tons of oil and 183 million m^3 of gas per year in 1988/89.

11. b. North Kadi Field Located about 51 kms NW of Ahmedabad, the field was put on production in 1969. It has proven reserves (initial-oil-in-place) of about 44 million tons. Total cummulative production so far is about 3 million tons of oil (20.6 million barrels). This total production represents about 6% of the estimated initial oil-in-place or 19% of estimated recoverable reserves. Current production rate is 1200 tons of oil per day (8640 BOPD) and 7500 m^3 per day of gas (2 to 6 mmcf). The average porosity is about 28%, permeability is about 1000 milli darcies and average thickness of producing formation is 8 meters.

12. There are 137 wells already drilled consisting of 105 oil wells, 3 gas wells, 9 pressure observation and disposal wells, 9 plugged or abandoned wells, and 11 awaiting further production testing. Of the 105 oil wells, 32 wells are to be produced by an artificial lift system, including gas lift. An additional 12 wells are currently being drilled. Optimization studies by ONGC indicate that the production rate can be raised to 838,000 tons per year through a total of 171 wells. Under the proposed project therefore, 59 wells with artificial lift equipment are included for the final development of this field.

13. c. South Kadi Field The field is located about 40 km NW of Ahmedabad and was discovered in the early 1960's. The average reservoir thickness is 4 meters, average permeability and porosity is 20 to 50 milli darcies and 39% respectively. Cummulative production before shut-in was 280,000 tons of oil (or 2.1 million barrels) equivalent to 17% of initial oil in-place and 39% of recoverable reserves. The estimated oil reserves in the field is about 1.6 million tons (or 12.16 million barrels). 6 wells have been drilled so far but these are currently shut-in due to high gas-oil ratio of about 3000 m^3/ barrel. This field is now proposed to be exploited by water flood using an inverted 5-spot pattern with a total of 6 producers and 5 injectors. The maximum production envisaged is about 67,525 tons per year (of which 40,500 tons is the incremental output due to the project) by 1986/87. Additional recovery is expected to be about 25% of the initial oil in place.

One injector well is already being drilled and the other 10 wells are included in the proposed project. All production wells (6) will be equipped with artificial lift equipment.

14. d. Sobhasan Field The field is located close to the town of Mehsana. It is the northernmost producing field in the Cambay Basin with proven reserves (initial-oil-in place) of about 14 million tons. It was discovered and put into production in 1969. There are 3 main producing zones (S_1, S_2 and S_3) with an average reservoir thickness of 12 meters. Average reservoir porosity is estimated as 29% and average permeability at 500 milli darcies. Total cummulative is about 1 million tons of oil (7.3 million barrels). This is equivalent to 7% of initial oil in place. Current daily production is about 300 tons of oil (or 2190 BOPD). There are 58 wells drilled in the Sobhasan field. 42 of these are oil wells, 2 are gas wells, 5 are observation wells, 4 are dry wells, while 5 wells are awaiting further production testing. The final development program for the field consist of drilling a total of 73 wells in order to raise the production rate to about 238,000 tons per year. The additional 31 wells will be drilled as part of the proposed project.

15. e. Nawagam Field The field is about 19 km south of Ahmedabad. It was discovered in 1962 and put on production in 1967. To date, 2.8 million tons (or 20.6 million barrels) of oil have been produced. This is about 10% of the initial oil in-place (estimated at 27 million tons), and 44% of the estimated recoverable oil reserves. The current average daily production is about 300 tons of oil per day (or 2200 BOPD). Oil saturation is estimated at 70%, average porosity 20% and average permeability about 25 to 100 milli darcies. ONGC estimates that an additional 17% of the original oil in-place can be recovered if the field continues in its present state; however, with an accelerated program of water injection, the recovery rate could be increased to 26%. 79 wells have been drilled in the Nawagam field; 59 oil wells, 4 water injection wells, 10 abandoned wells and 6 awaiting further production testing. Of the 59 wells, 32 are still producing (27 on artificial lift) while 27 are shut-in due to mechanical problems and require workover. However, based on recent reservoir stimulation studies done by ONGC, it is envisaged that an increase in production by 200 tons per day could be achieved for the next 6 years in the field, if 11 of the existing oil wells are converted to water injection wells (2 wells have already been so converted). In order to offset production losses and ensure more uniform drainage, an additional thirteen in-fill wells with artificial lift will be required. Six wells are currently being drilled and the other seven are included in the proposed project.

2. Initial Development of Heavy Oil Fields.

16. Description of Heavy Oil Field. The "heavy oil" fields situated in the northern part of the basin are confined to the elongated oil bearing feature discovered along the eastern flank of the Mehsana horst. This structure is stratigraphically controlled by an abrupt upward wedging out of Middle Eocene sandstones against the rising flanks of the Mehsana horst block. Although on the same trapping environment, these fields have been functionally separated by increasing oil viscosities and corresponding drop in gas/oil ratio (GOR). From south to north, the fields are Santhal, Balol and Lanwa. Santhal at the south end of the field produces a 50 centipoise oil at

a reservoir temperature of 70°C. Balol field in the middle, produces oil with viscosity of 100 centipoise at 70°C. The Lanwa field, at the northern end of the elongated field reservoir, produces oil with a viscosity of 550 centipoise at 70°C. The average depth to the pay reservoir in all the fields is about 1000 meters.

17. Heavy crude oils are generally similiar in origin to conventional crudes, but they are the result of a different evolution. With respect to the Santhal, Balol and Lanwa fields, the difference in the viscosities can be explained by:

(i) Loss of light ends as a result of dismigration either upwards or laterally, or due to evaporation through poor seals. Filtration, physical segregation and leeching with meteoric water is also a possibility; and

(ii) Biodegration as a result of a continuous leeching process by the ingress of meteoric waters. The leeching process indaecs bacterial attack and changes the chemical composition of the oil which is reflected in a lower wax content heavier crude.

18. a. Santhal Field This field is located five miles (8 kilometers) southwest of the town of Mehsana. It is the southernmost field discovered on the east flank of the Mehsana horst block. The producing Santhal feature is contiguous to the North Kadi field, separated from it to the north by a slight structural reentrant. The producing formation in the Santhal field is a clean, unconsolidated sandstone of Middle Eocene age, the Chatral member of the Kadi Formation. The sand development shows progressive thinning northward from Santhal field, becoming restricted to increasingly shallower levels in the subsurface. Porosities in the field range between 30% to 32%, and permeabilities are 1.5 to 2 darcy.

19. The Santhal field has proven oil reserves (initial oil in place) of about 40 million tons of which about 65% is located in the southern portion of the field. The field was put on production in 1974 but only the southern portion of this field has so far been developed by ONGC. The field has an active water drive. So far 41 wells are producing with a combined production of about 239,000 tons of oil per year. Cumulative production as of March 1983, was about 0.4 million tons or about 1% of the initial oil in place. The development scheme for the field envisages a total of 125 wells, 76 in the southern section and 44 in the northern section. ONGC is now expected to complete the development of the southern section by 1984/85. The initial development of the northern section (44 wells) is included in the proposed project and is expected to provide a peak incremental production of about 241,000 tons per year by 1988/89. The wells will be equipped with artificial lift equipment. Primary recovery in the North Santhal field is expected to be about 10-12% of the initial oil in place.

20. b. Balol Field The Balol field has estimated reserves (proved and probable) of about 25 million tons of oil. Gravity of the crude is 13° API and viscosity is about 100 centipoise at 70°C. This field is not yet on production. To date, 15 exploration wells have been drilled, of which 5 were abandoned, 6 were oil-bearing and 4 need additional testing and are expected to be oil-bearing. The primary development plan envisaged under the proposed

project involves a total of about 109 wells, all equipped with artificial lift equipment. Six wells are to be drilled in 1984/85 to obtain good core samples to improve reservoir data analysis, further delineate the field, test the well and completion design, and obtain some production history. The main drilling program will commence in 1986/87. This schedule would also permit the infrastructure and surface facilities to be installed before implementation of the development drilling program. Balol and Lanwa (and also North Santhal) are the fields selected for thermal enhanced oil recovery (EOR) pilot methods and one of the purposes of the primary development of the fields is to condition the reservoirs (i.e., reduce pressures, etc.) for eventual application of EOR techniques. Primary recovery in the Balol field is expected to be about 9% of the initial oil in place. EOR (i.e., in-situ combustion) is expected to improve the recovery to about 40% to 50%. For the primary development, the wells will be designed for thermal service and well spacing will take into account the eventual EOR well spacing.

21. c. Lanwa Field The Lanwa field is located at the northern end of the Santhal-Balol-Lanwa feature, and has estimated oil reserves (proved and probable) of about 17 million tons (initial oil in place). Six exploration wells have so far been drilled, of which two were abandoned, two wells produced oil (with sucker rod and pumps and gravel pack) and two remain to be tested but are expected to produce oil. Because the casing design and sucker rod pump used in the two producing wells were too small for the type of oil and depth involved, the pumps failed and production from these wells ceased after about six weeks. The wells produced about 9 tons of oil per day during the test period. Based on the oil and reservoir characteristics, as well as the tests described above, a properly designed well and pumping system should produce oil from this field at economic rates. Under the project, about 134 wells equipped with artificial lift equipment are to be drilled for the primary field development. Twelve of these wells will be drilled during 1984/85 and 1985/86 to better delineate the field and improve reserve estimates and other field data. The other 122 wells will be drilled during 1987/88-1989/90 to smooth out the drilling program during the implementation period. Primary recovery is expected to be only about 5% of the initial oil in place. But, as in the case of Balol, Lanwa is well suited for thermal EOR recovery (i.e., in-situ combustion) and about 45% of the initial oil in place is expected to be recovered with this EOR technique. Again, primary development will take into account the field development pattern (well design and spacing) for the eventual EOR project.

3. Cambay Gas Field Rehabilitation

22. The Cambay gas field was the first petroleum field discovered in the Cambay Basin in the late 1950's. It is geologically sited on the southern sandstones and shales above an eocene sequence. The deepest well in the field was drilled to 3333m, penetrating about 1000m of Paleocene sands and conglomerates. The reservoir has two main hydrocarbon zones--an upper zone (1,600 m.) containing gas and a lower zone (2,000 m.) containing oil. The gas zone has been produced since the early 1960's, but about half (1.5 billion m^3) of recoverable reserves still remain to be extracted. A total of 55 gas wells have been drilled but about 20 have been abandoned due to water encroachment. Another 10 will be similarly abandoned within about one year and the remainder will probably also have to be abandoned within five to seven years. Because the wells are old and poorly cemented they cannot be worked

over. Gas production has been declining and is now about 70,000 m^3/day and could fall further to about one-half this rate within a few years. The field can be rehabilitated, however, and after discussion with Bank staff, ONGC suggested drilling initially, about 4 oil wells to: (a) test various well stimulation techniques to produce the oil; and (b) better estimate the oil reserves and recovery that could be expected.

23. The Cambay field sub-component will therefore consist of: (i) rehabilitation of the field by drilling about 10 new gas production wells using advanced drilling techniques to take into account the depressed pressures (below hydrostatic) in the gas zones; and (ii) evaluation and testing of the various stimulation methods to commercially produce the apparently tight oil formation in the lower pay zone for which about 4 wells will be needed. With the new gas wells, production is expected to increase to about 140,000 m^3/day.

C. Enhanced Oil Recovery (EOR) Component

24. Three EOR pilot schemes are included in the proposed project: two thermal EOR pilots in the Lanwa heavy oil field and a polymer chemical flood pilot in the Jhalora light oil field. Bank consultants have recommended these among several proposed by ONGC.

25. a. In-situ Combustion Pilot at Lanwa Field The Lanwa field has the most viscous heavy oil and will be the first field to require a commercial EOR scheme within about 4 to 6 years after primary development. A thermal EOR technique is expected to increase oil recovery to about 45% of the initial oil in place from only about 5% achieved through primary production. The first thermal EOR pilot will use the in-situ combustion technique. The second pilot, which will be started about 18 to 24 months after the first, will use either the steam flood method or the in-situ combustion method depending upon the initial results of the first pilot. The Lanwa pilots, while specific to that field, will also serve as a prototypes for the Balol and the Santhal pilot in-situ combustion schemes which will follow one to three years later. The in-situ combustion pilot is expected to last about four years.

26. b. Polymer Flood (Jhalora Field) The polymer flood pilot at the Jhalora field was recommended because of the adverse mobility ratio and heterogeneous permeability profile of the reservoir. The primary recovery of the Jhalora field is expected to be around 16% with cumulative production from 1977 up to the present already about 6% of the initial oil in place (26.4 million tons). However, oil production has begun to decline as the water cut increased from 20% two years ago to 30% at present. An EOR scheme is therefore needed within a few years to reverse the decline in production and increase the recovery factor. The Jhalora polymer pilot is expected to last about four years and recover an additional 15% to 25% of the initial-oil-in-place. It will also serve as a prototype for the other light oil fields.

27. c. Ankleshvar Field The Ankleshvar oil field is the largest petroleum field in the Cambay Basin. It was discovered in 1960 and covers an area of about 25 km^2 with an estimated 113 million tons of initial-oil-in-place (IOIP). It produces a high quality oil (47 API) from eleven sandstone pays (S_1 to S_{11}) of middle to upper Eocene age at an average depth of about 1140 meters. The current oil production is about 1.5 million tons per year, down from the peak of 3 million tons achieved in 1968. About two thirds of

the production comes from three zones (S_2, S_3 and S_4). Cummulative production by August 31, 1983 was about 50.4 million tons and the remaining recoverable reserves is about 9.8 million tons (equivalent to 6.5 years of production). The expected ultimate recovery factor is high (53% of IOIP) primarily due to the good characteristics of the producing oil sands which make the oil and water mobility about equal in the reservoir.

28. The reservoir has a natural water drive and was placed on water injection (into the water table) for pressure maintenance in 1963 shortly after production started. Despite the advanced stage of water injection, the average producing water cut is still only 40%.

29. The status of the wells in the field are as follows:

			Number
Production Wells			196
Of which:	Producing Oil	90	
	Waiting for Work Over[a/]	84	
	Flooded-Out	15	
	Producing Gas	7	
Injection Wells			29
Abandoned (dry holes and technical problems)			21
Total Wells Drilled			246

a/ About 35 of these wells will be placed on artificial lift (gas lift, sucker rod pumps, or Reda pumps).

30. The Ankleshvar field is close to depletion having produced almost 84% of its recoverable reserves on the basis of existing productin technologies. To evaluate the potential of increasing the ultimate recoverable reserves (53% IOIP at present), ONGC is studying advanced EOR techniques (e.g., micellar/polymer flood) through laboratory experiments. These studies will be supported by the EOR consultants to be provided under the project.

D. Technical Assistance and Training Component

31. ONGC's field operations in the Cambay Basin suffer from many serious deficiencies and problems. One of the main objectives of the proposed project is to improve ONGC's oil field operations through training, use of consultants and contractors, and introduction of new technology, equipment and materials. Each one of these is described briefly below.

32. While ONGC has extensive training facilities and programs for managerial and higher level technical staff, it does not have a meaningful training program for field level employees. In the past, oil field workers learn through informal on-the-job apprenticeship. Last year, ONGC began a modest oil field worker training facility near Ahmedabad in the Cambay Basin. The program consisted of a six week introductory course plus on-the-job training. The facility has very limited training aids. ONGC, however, plans to build four or five large training centers around the country. A training consultant with the Bank preappraisal mission reviewed ONGC's

existing and proposed training facilities and program. The consultant recommended a more modest training center for the Cambay Basin, but with a more comprehensive training curriculum. In addition, a major effort will be made to prepare and develop the necessary training materials and train the instructors. This will require the hiring of a training consultant to initially help ONGC organize the planning and implementation of this training program. Training aids will include simulators, laboratory equipment, models and prototypes, closed circuit TV system, etc. The training program will cover basic and advanced courses in all facets of oil field operations (e.g., drilling, production, cementing, various types of logging, pipelines, well stimulation, and instrumentation).

33. In addition to the training programs for field level employees included under the project, technical assistance will be provided by an expatriate consultant firm to assist in implementing the project and improving ONGC's field operations. Technical assistance will cover the application and evaluation of EOR methods (in-situ combustion and chemical flooding), and as required, also engineering, drilling practices, mud engineering, workover techniques and formation testing. Experienced international contractors in drilling and technical well services (e.g. cementing, logging, production testing) will be utilized for a substantial portion of the project in areas where ONGC lacks sufficient expertise and capacity in order to implement the project within a reasonable period. These service contracts will have provisions for practical training of ONGC personnel.

E. Equipment for ONGC Drilling Operations

a. Technical Well Services Equipment

34. Some of the drilling procedures currently being practiced in the Cambay Basin are suboptimal due to ONGC's use of inefficient and outdated rigs. Also, downhole penetration rates are often decreased by frequent drilling difficulties (i.e. high bottomhole temperatures, hole enlargements caused by formation caving and sloughing, and low formation pressure zones). In spite of many trials with water-base muds, ONGC Western Region has not been able to select a drilling fluid compatible with the high temperature and low pressure zones it encounters. Oil-base muds cannot be tested at the drill-site due to the poor design of the mud circulating system on ONGC's outdated rigs. All these factors have resulted in wells of poor quality and low productive capacities. However, these problems can be traced to the lack of adequate drilling equipment and materials.

35. The new equipment included in the proposed project is essential towards modernizing and improving the efficiency of ONGC's onshore operations. It is also required for ONGC to effectively undertake its portion of the project's drilling program within a reasonable time. Equipment to be acquired will be for exploration, development and production as follows:

a. coring equipment;
b. three open hole electric logging units;
c. two production logging units;
d. fourteen production wire-line units;
e. seven mud-logging units;
f. five units (each 3 MW) of mobile gas turbine power generators;
g. field radio communications;
h. ten workover rigs; and
i. seven mobile drilling rigs.

36. ONGC presently does not have any rig-site equipment to continuously monitor downhole conditions and the parameters of drilling mud components and hydrocarbons in the drilling fluid system. Also, ONGC rigs presently lack formation coring tools to cut and retrieve the typically unconsolidated and loose sands which predominate in many Cambay Basin fields. State-of-the art electric logging units in the basin are limited in number and often important exploratory wells are inadequately evaluated. Reliable and accurate subsurface parameters are also critical in determining reservoir characteristics and essential in the design and implementation of any secondary or enhanced oil recovery project. As part of the project, ONGC will purchase mudlogging units, downhole coring equipment, electric logging trucks and cable tools, production logging units and wire-line service units. This ancillary equipment package will either provide additional units or replacement units to cover existing shortfalls and deficiencies in field facilities.

37. Of the 14 drilling rigs operating in the Cambay Basin at present, 12 are obsolete and should have been replaced a long time ago. As part of the project, 7 heavy duty mobile drilling rigs will be purchased to drill ONGC's portion of the development wells included in the project. The new rigs will replace the old rigs and should be similar to the contracted rigs; they represent a new technology for ONGC. The rigs will subsequently be used for infill drilling in the commercial-scale EOR projects in the heavy and the light oil fields that will follow the pilot schemes in about 5 to 7 years. They will also be used for workover of the deeper wells (2,000- 2,500 m) in the basin (e.g., Kalol). The rigs will therefore be productively used in the project area for at least the next 10 years.

38. During the preparation and preappraisal missions, Bank staff recommended that ONGC change its casing policy for wells to be drilled under the project (and ONGC's onshore operations, in general) with respect to the use of a 5 1/4" production casing. Instead, a 7" production casing should be used. ONGC agreed to this change during the appraisal mission. In addition, ONGC also agreed that for the project only API certified or labeled oil field cement be used. During negotiations, agreement was reached with ONGC that at least 386 wells will be designed with 7" production casings and only API certified cement or equivalent will be used below 500 meters depth.

39. Some components of the project, particularly the extensive use of artificial lift equipment, will increase the electrical power requirements in ONGC's Cambay Basin operations tremendously. Unfortunately, there is a shortage of power (about 10% for at least over the next several years) in the State of Gujarat. At present ONGC does not generate any power of its own and relies exclusively on the State grid. This is unusual for an oilfield operation, particularly one such as the Cambay Basin with its widely distributed oil fields located in an area suffering from power shortage and in which ONGC has substantial gas production as well as several isolated oil fields with small quantities of associated gas (which is being flared). ONGC has therefore included in the proposed project 5 units of mobile gas turbine power generators (each 3 MW). These units will be initially installed in Kalol (3) and in Anklesvar (2), the two major oil fields in the basin. The units to be installed in Kalol will be a part of a cogeneration plant to generate power and steam by recovering the turbines' exhaust heat.

40. One of ONGC's more obvious deficiencies in field operations is the lack of modern radio communications. The introduction of new base radio stations at selected office support and supply depots in addition to numerous side band mobile units in vehicles and field locations is proposed. This radio communication network will help alleviate the huge amounts of down-time spent waiting for supplies or maintainence at rig sites and coordinate the movement of materials and personnel throughout the field.

41. b. Improvement of Field Workover Operations Each year, about 130 to 150 wells in the Cambay Basin need repairs (i.e., workover), which just about matches ONGC's workover capacity. However, there is a backlog of about 345 wells which have been in need of workover for sometime now, the resulting lost production being estimated at about 300,000 to 400,000 tons per year of oil. The types of repair work required are as follows: servicing, testing and downhole formation stimulation (120 wells); completion with artificial lift equipment (75 wells); fishing (i.e., recovering broken tools, metal, etc.) and casing repair (60 wells); cement squeeze for water shut off (35 wells); cement squeeze for various water channeling behind the casing (30 wells) and gravel pack and sand consolidation (25 wells).

42. Well workover techniques used by ONGC, although acceptable by oil industry standards, are not producing satisfactory results due mainly to the age and obsolescence of the workover rigs which are 15 to 17 years old, worn out and inefficient. Until recently, well-site scheduling time was inadequate as most of the workover operations were carried out only during daylight hours. Thus, the average productivity of workover rigs was low, typically about 6 to 6.5 wells per rig per year. ONGC is taking several steps to improve this situation. Firstly, workover operations are now proceeding on a 24-hour basis. Secondly, a program has started to eliminate the backlog over the next five years: A workover contract was signed last year for two Soviet workover rigs (and crews) to handle 120 wells during three years (1983-85). This contract work started slowly and is already behind schedule. ONGC will handle the other 225 wells during the next five years (1983-87). To accomplish this task and keep up with the additional and more complex workover jobs (about 110 per year) that will result from the 548 new development wells to be drilled under the proposed project, ONGC will need to replace most of its existing 23 workover rigs which are very old and, at the same time, increase its fleet to about 30 to 35 workover rigs. Thirdly, ONGC has ordered four self propelled, mechanical drive type of workover rigs and four modern cementing units to be used with these rigs to be delivered in 1984. In addition, two wireline logging units were acquired recently. With these new facilities, workover operations are expected to improve substantially in 1984 but will still fall short of the field requirements. Therefore, under the proposed project, additional equipment, namely 10 trailer or truck-mounted workover rigs, two production logging units and 14 production wireline service units will be purchased. Fourthly, ONGC will utilize whenever needed technical assistance available under the proposed project to help plan and undertake workover operations.

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CAMBAY BASIN PETROLEUM PROJECT

Description of Exploration Wells

1. The four stratigraphic (parametric) exporatory wells proposed by ONGC are: (i) Bharkodra, (ii) Jambusar-P, (iii) West Kalol and (iv) South Warosan. These exploratory tests have been selected to penetrate the maximum stratigraphic section to the economic basement (Deccan Trap), evaluate deep Lower Eocene lenticular sandstones and formulate depositional concepts for the encased reservoirs within the Cambay shale. Further, where possible, the drill-sites have been adjusted to provide shallower, secondary pay objectives. Successful achievement of these objectives will present ONGC with new trends and hydrocarbon targets within the Cambay Basin.

2. Two of the four exploratory tests may require a change in location and proposed total depth. These two are: (i) Jambusar and (ii) West Kalol. The location and deep Mesozoic objectives of Jambusar-P, should be re-evaluated on the basis of the results of the interpretation on 3 additional seismic lines of 20 kilometers each to be acquired by ONGC. Two seismic lines of about 20 kilometers each will be shot on the west flank of the Kalol field to further tie the West Kalol exploratory test to the two previous deep wells: K-236 and K-221. No further subsurface evaluation or seismic acquisition is required on the Bharkodra and South Warosan locations. A summary of the four exploratory wells is as follows:

(i) Bharkodra

Location:	In the southern sector of the Cambay Basin, near the mouth of the Mahisagar River, about (60 kilometers west of the town of Baroda.
Proposed Depth:	4000 meters (13,125 feet) or Deccan Trap
Geological Objective:	Primary objectives are Paleocene Olpad trapwash deposits, encountered as gas productive but not tested on the Devla No. 1. Secondary objectives are Lower Eocene Ankleshvar deltaic sandstones expected updip of the Devla No. 1. The Devla No. 1 is located about 13 kilometers south.

(ii) Jambusar - P

Location:	In the southern section of the Cambay Basin, about 55 kilometers south-southwest of the town of Baroda.
Proposed Depth:	5500 meters (18,050 feet)
Geological Objective:	Primary objectives are to test the existence and hydrocarbon potential of the Mesozoic sediments beneath the Deccan Trap basalts.

Secondary objectives are to penetrate a lower Eocene structure on the rim edge of the Broach Syncline. The Lower and Middle Eocene sandstones have been tested as productive in the Dablea, Gajera and Matar areas.

Prognosis: Final location and proposed depth to the Mesozoic may be modified on the basis of the three seismic lines of 20 kilometers each to be recorded by ONGC.

(iii) West Kalol

Location: In the northern section of the Cambay Basin, on the western flank of Kalol field.

Proposed Depth: 4500 meters (14,765 feet) or Deccan Trap.

Geological Objective: Primary objectives are to test the Cambay Shale oil sands found productive but not completed in the two deep Kalol field west flank wells. Secondary objectives are Lower Eocene sands expected to wedge-out along the western flank of the structure.

Prognosis: Location and proposed depth may be altered subsequent to the two additional seismic lines to be acquired by ONGC.

(iv) South Warosan

Location: In the northern section of the Cambay Basin, about 15 kilometers south of the town of Mehsana.

Proposed Depth: 4000 meters (13,125 feet) or Deccan Trap.

Geological Objective: Primary objectives are the Cambay Shale lenticular sandstones found productive in the Linch, South Kadi and Jotana areas. Secondary objectives are deeper Cambay "spill-over" sands on a paleo shelf connecting the South Warosan and Jotana areas.

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CAMBAY BASIN PETROLEUM PROJECT
SEISMIC SURVEY AND DRILLING PROGRAM

Activities	Year	1984				1985				1986				1987				1988				1989				1990				No. Wells	Aver. Depth
	Quarter	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4		
A. EXPLORATION																															
Exploration Drilling										1		1			1		1													4	5,000 m
Contractor																															
Seismic Acquisition																															
Contractor					500 km				500 km				750 km																		
Seismic Processing																															
Contractor						1750 Line km																									
B. DEVELOPMENT																															
Kalol Light Oil Field																															
Contractor							44				44				44															132	1,600 m
ONGC																				8										8	1,600 m
Sobhasan Light Oil Field																															
ONGC				9			6				13				3															31	1,600 m
N Kadi Light Oil Field																															
ONGC				8			12				25				14															59	1,100 m
S Kadi Light Oil Field																															
ONGC				5			5																							10	2,100 m
Nawagam Light Oil Field																															
ONGC				4			3																							7	2,000 m
Cambay Gas Field																														10	1,600 m
ONGC							3				3				3				3				2							4	2,100 m
Santhal Heavy Oil Field																															
ONGC							10				15				10				9											44	1,100 m
Balol Heavy Oil Field																															
Contractor											36				36															72	1,100 m
ONGC				6															10				21							37	1,100 m
Lanwa Heavy Oil Field																															
ONGC				6			6								40				40				42							134	1,100 m
Total Development Wells:																															
Contractor				–			44				80				80				–				–							204	–
ONGC				38			45				56				70				70				65							344	–
Total Rigs:																															
Contractor				–			4				7				7				–				–								
ONGC				7			8				9				9				9				9								

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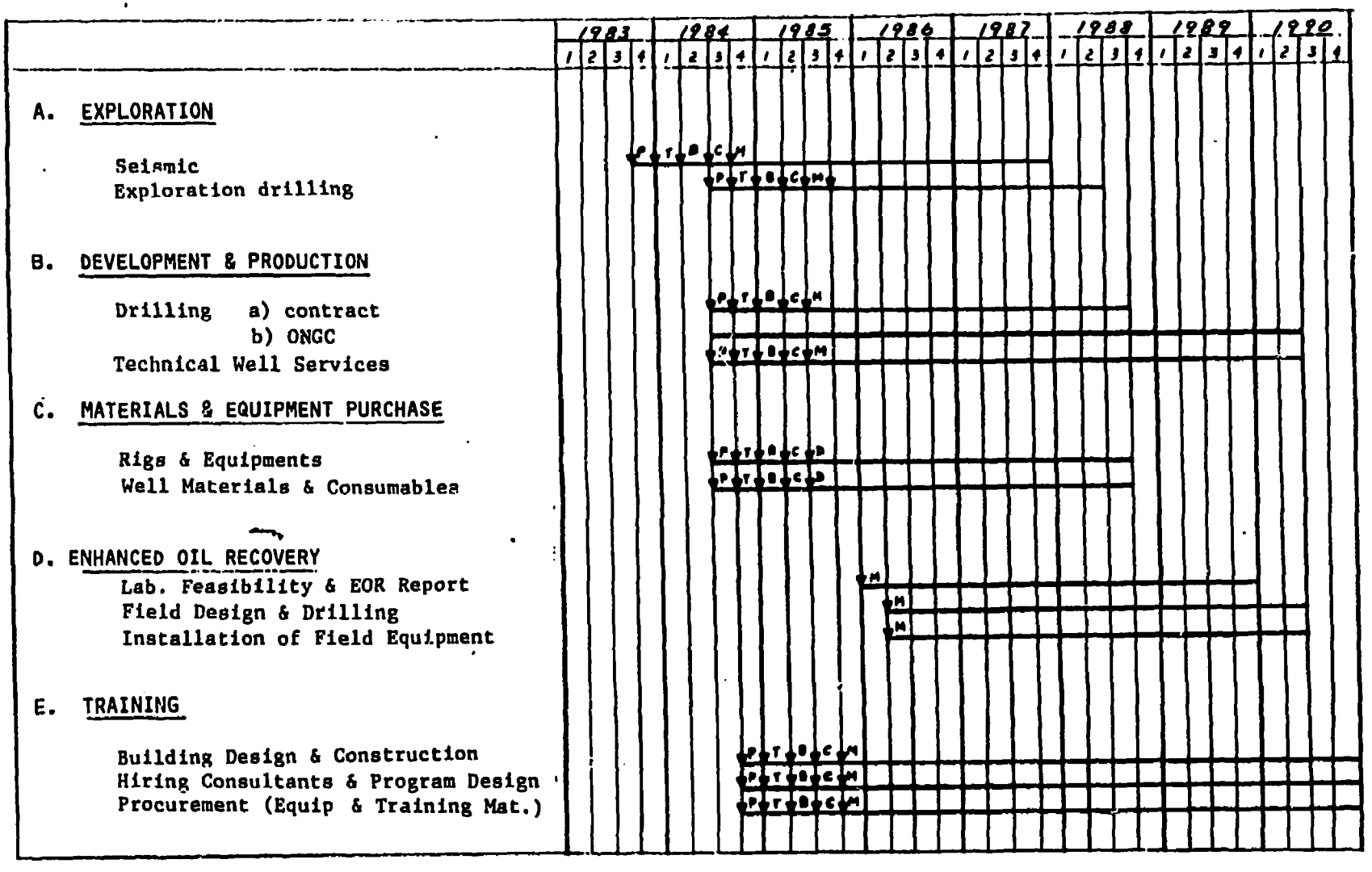
CAMBAY BASIN PETROLEUM DEVELOPMENT PROJECT

IMPLEMENTATION SCHEDULE



▼P Bid Preparation
▼T Tender Documents
▼B Bids Due
▼C. Contract Award
▼D Material & Equipment Delivery
▼M Mobilization/Commencement of Award

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CAMBAY BASIN PETROLEUM PROJECT

Project Cost Estimates
(Rs Million)

	Foreign	Local	Total
I. EXPLORATION			
Seismic, Drilling and Well Services	552.0	141.4	693.4
(Seismic)	(360.0)	(90.0)	(450.0)
(Drilling	(116.0)	(40.8)	(139.4)
(Well Services)	(76.0)	(10.6)	(104.0)
Well Materials and Consumables	64.8	51.4	116.2
(Casing)	(27.3)	(15.0)	(42.3)
(Wellheads)	(2.4)	(1.2)	(3.6)
(Cement and Chemicals)	(14.6)	(27.5)	(21.9)
(Rig Fuel)	(7.9)	(1.4)	(9.3)
(Others)	(12.6)	(6.3)	(39.1)
Sub-total	616.9	192.8	809.7
II. DEVELOPMENT AND PRODUCTION			
Drilling and Technical Well Services	1,049.2	272.1	1,321.3
(Drilling)	(629.4)	(189.6)	(819.0)
(Well Services)	(419.8)	(82.5)	(502.3)
Well Materials and Consumables	1,497.0	791.8	2,288.8
(Casing)	(575.4)	(305.0)	(880.4)
(Wellheads)	(142.8)	(69.8)	(212.6)
(Cement and Chemicals	(102.0)	(108.5)	(210.5)
(Rig fuel)	(161.5)	(28.5)	(190.0)
(Sucker Rod Pumps and Gas Light)	(279.1)	(139.6)	(418.7)
(Others)	(106.2)	(55.4)	(161.6)
(Work-Over Equipment, Materials, Supplies for 340 wells)	(130.0)	(85.0)	(215.0)
Force Account -	-	562.3	562.3
Rigs, Equipment & Surface Facility	646.0	1,070.0	1,716.0
(Rigs and Other Equipment)	(556.0)	(863.0)	(1,419.0)
(Power generators)	(90.0)	(207.0)	(297.0)
Sub-total	3,192.2	2,696.2	5,888.4
III. EOR PROJECTS			
Drilling Equip. and Consummables	50.0	26.0	76.0
IV. TRAINING AND TECH. ASSISTANCE			
Equip., Consult. and Supervision	50.0	20.0	70.0
TOTAL BASE COST	3,909.1	2,935.0	6,844.1
Physical Contingencies	584.0	397.4	981.4
Price Contingencies	959.0	752.8	1,711.8
Front-end fee	6.0	-	6.0
TOTAL COST	5,458.1	4,085.2	9,543.3

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CAMBAY BASIN PETROLEUM PROJECT

Project Cost Summary by Field and Activity

	Rs Million			US$ Million		
	Foreign	Local	Total	Foreign	Local	Total
1. Exploration Component						
Seismic Survey	360	90	450	36.0	9.0	45.0
Deep Drilling	257	103	360	25.7	10.3	36.0
Sub Total:	617	193	810	61.7	19.3	81.0
2. Development & Production Component						
Kalol Field	1,027	423	1,450	102.7	42.3	145.0
Light Oil Fields	318	343	661	31.8	34.3	66.1
Heavy Oil Fields	991	703	1,694	99.1	70.3	169.4
Cambay Gas Field	80	72	152	8.0	7.2	15.2
Rigs and other Equipment	536	863	1,399	53.6	86.3	139.9
Power Generators	90	207	297	9.0	20.7	29.7
Field Communication	20	-	20	2.0	-	2.0
Work-Over (340 wells)	130	85	215	13.0	8.5	21.5
Sub-Total:	3,192	2,696	5,888	319.2	269.6	588.8
3. EOR Pilot Component						
Lanwa Field	35	18	53	3.5	1.8	5.3
Jhalora Field	15	8	23	1.5	.8	2.3
Sub Total:	50	26	76	5.0	2.6	7.6
4. Tech. Training Component						
Tech. Train. & Assist.	50	20	70	5.0	2.0	7.0
Total Base Cost:	3,909	2,935	6,844	390.9	293.5	684.4
Physical Contingencies a/	584	397	981	58.4	39.7	98.1
Price Contingencies b/	959	753	1,712	95.9	75.3	171.2
Front-End Fee, Bank Loan	6	-	6	0.6	-	0.6
Total Project Cost:	5,458	4,085	9,543	545.8	408.5	954.3

a/ At 20% for the exploration and EOR pilot component, 15% for drilling expenses and 10% for equipment, assistance and training.

b/ Foreign costs at 7.5% in 1984/85, 7% in 1985/86 and 6% thereafter. Local costs at 7% in 1984/85, 8% in 1985/86 and 1986/87, and 6% thereafter.

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CAMBAY BASIN PETROLEUM PROJECT

Phasing of Expenditures
(In Million Rupees)

	1984/85	1985/80	1986/87	1987/88	1988/89	1989/90	Total
1. EXPLORATION							
Seismic Survey	225.0	112.5	112.5	-	-	-	450.0
Exploration Drilling	134.9	134.9	89.9	-	-	-	359.7
Sub-total	359.9	247.4	202.4	-	-	-	809.7
2. DEVELOPMENT AND PRODUCTION							
Kalol Field	-	467.7	467.7	467.7	47.0	-	1,450.1
Other Light Oil Fields	187.8	179.3	220.4	44.9	-	28.6	661.0
Heavy Oil Fields	59.8	81.8	384.9	579.0	308.8	280.0	1,694.3
Cambay Gas Field	-	38.0	38.0	38.0	38.0	-	152.0
Rigs & Equipment	-	1,292.3	423.7	-	-	-	1,716.0
Work-Over	36.0	40.0	43.0	46.0	53.0	-	215.0
Sub-total	283.6	2,099.1	1,577.7	1,175.6	443.8	308.6	5,888.4
3. EOR PROJECTS	15.2	60.8	-	-	-	-	76.0
4. TRAINING & TECHNICAL ASSISTANCE	14.0	14.0	14.0	14.0	14.0	-	70.0
TOTAL BASE COST	672.7	2,421.3	1,794.1	1,189.6	457.8	308.6	6,844.1
Physical Contingencies	119.0	313.2	257.3	177.7	67.9	46.3	981.4
Price Contingencies	63.4	406.2	462.6	414.7	196.0	168.9	1,711.8
Front-end Fee	6.0	-	-	-	-	-	6.0
TOTAL	861.1	3,140.7	2,514.0	1,782.0	721.7	523.8	9,543.3

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CAMBAY BASIN PETROLEUM PROJECT

Estimated Schedule of Disbursement 1/
(US$ million)

IBRD Fiscal Year and Quarter		Amount Disbursed	Cumulative Amount	Cumulative %
1983/84	IV	0.6	0.6	-
1984/85				
	I	5.2	5.8	2
	II	8.8	14.6	6
	III	9.6	24.2	10
	IV	12.2	36.4	15
1985/86				
	I	12.1	48.5	20
	II	14.5	63.0	26
	III	17.0	80.0	33
	IV	17.0	97.0	40
1986/87				
	I	17.0	114.0	47
	II	19.4	133.4	55
	III	21.8	155.2	64
	IV	14.6	169.8	70
1987/88				
	I	12.1	181.9	75
	II	7.2	191.6	79
	III	7.3	L98.8	82
	IV	7.3	206.1	85
1988/89				
	I	7.3	213.4	88
	II	7.3	220.7	91
	III	4.8	225.5	93
	IV	4.9	230.4	95
1989/90				
	I	7.2	237.6	98
	II	4.9	242.5	100

1/ This disbursement profile essentially conforms with the statistical profile as of February 1984 for 72 Bank/IDA energy projects (e.g. petroleum, refineries, energy conservation, etc. but excluding power projects) approved from FY73 up to FY83.

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CAMBAY BASIN PETROLEUM PROJECT

ONGC Accounting Principles

Unit of Accounting

1. The Unit of Accounting is an area covered by a license or lease. Extension in the area covered by a separate license or lease is treated as an independent area though contiguous. If a certain portion of a license or lease is surrendered or declared as producing and the balance portion continues under exploration, related costs are segregated and amortized or depleted.

Exploration

2. Geological and geophysical survey costs are charged in each year of account.

3. All exploratory drilling costs are initially accumulated and each year's expenditure is amortized equally over 15 years. If and when an area is determined to be unsuccessful and the license is surrendered, the related balance costs shown on the balance sheet (net of accumulated amortization) is expended against income in three equal annual installments. Any further adjustments in the cost due to accruals, etc., are reckoned equally in the balance period after the surrender of the area. In case an area is declared successful, the balance costs are transferred to the Producing Property Account.

Oil and Gas Producing Properties

4. Oil and Gas Producing Properties include exploratory drilling costs and costs incurred in development. Since the Unit of Accounting is an area covered by a license or lease, all drilling costs incurred in that area are transferred from exploration to Producing Property Account, net of amortization already charged under exploration. Producing properties are created when regular production starts from the field regardless of the level of production. Once producing properties are created the depletion is charged equally over 10 years. Subsequent development costs are depleted in such a manner that total costs are charged against income in the balance period of 10 years from the date of commencement of regular production. Development costs after 10 years are charged against income in the year of expenditure.

Research and Development

5. Research and Development costs other than acquisition of capital assets are charged against income as incurred.

Depreciation

6. Plant, equipment and other capital items are stated at cost and depreciated using a diminishing balance method at the rates set forth in the

Income Tax Act and Rules except for Research and Development Equipment which is depreciated using a straight-line method in 5 equal annual installments.

7. Depreciation on fixed assets deployed in drilling activity is initially capitalized as part of exploration or development costs and amortized or depleted as stated above. Depreciation relating to production and transportation activities is debited against income of the year.

Prior Period Adjustments

8. All prior period adjustments for income and expenditure relating to production and transportation activities are stated in the second part of the Profit and Loss Account.

Inventories

9. Stocks of crude oil from CTF point onwards in saleable condition not taken note of up to 1980-81 have been stated at direct cost starting in 1981-82. The change in the accounting policy was due to the accummulation of high stocks which resulted from increased production and the insufficient capacity of the domestic refineries. This policy will be adopted hereafter. Gas stocks in pipelines are not taken note of since they cannot be measured.

10. Inventories of stores and spares and assets for replacement, etc., are stated at historical cost. The "last-in, first-out" (LIFO) method of inventory valuation is used for costing purposes.

Foreign Currency Transactions

11. All expenditures incurred and liabilities undertaken in the form of loans drawn and/or other liabilities are accounted for at the exchange rate prevailing on the day of the transaction. No year-end adjustment for changes in the foreign exchange rates in respect of outstanding liabilities were taken note of until the Accounting Year 1980-81. Considering, however, the substantial fluctuations in foreign exchange rates, particularly that of U.S. Dollar, year-end liabilities have been rewritten using the mean rate of exchange prevailing at the close of business on 31st March, 1982. The difference arising out of such adjustment and changes in the value of the cash balance and certain adjustable advances held abroad have been adjusted to the relevant head of account wherever feasible, otherwise, to the Profit and Loss Account.

Provisions

12. Provisions are set up for all known and probable liabilities resulting from activities.

Jobs in Progress

13. Workshop jobs in progress and unallocated expenditure are not amortized until these are complete or identified to exploration or development.

Retirement Benefits

14. Gratuity is provided in respect of all employees taking 15 days salary as payable for each completed year of service and this provision is charged against income.

Interest Charges

15. All interest charges are expended during the year of accrual.

Taxes

16. Taxes are provided on income as determined after providing for amortization and depletion in accordance with the agreement with the Government u/s 42 of the Income Tax Act, 1961. For tax purposes total depreciation charged, whether allocable to production and transportation, exploration or development, is reckoned as an expense item charged against income during the year.

Subsidies and Grants

17. Receipts on this account are accounted for on a cash basis. The expenditure incurred on the projects covered by subsidies and grants are, however, accounted for on a normal accrual basis and expended during the year of expenditure.

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CAMBAY BASIN PETROLEUM PROJECT

ONGC FINANCIAL STATEMENTS
INCOME STATEMENTS
(MILLION RUPEES)

	ACTUAL			PROVISIONAL	FORECAST					
	1980/81	1981/82	1982/83	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90
OPERATING REVENUES										
OFFSHORE	2,757	8,156	16,909	26,000	31,061	32,929	35,275	41,346	43,370	45,583
ONSHORE	1,626	5,147	6,697	8,466	9,657	10,194	11,459	13,778	15,303	16,735
TOTAL OPERATING REVENUES	4,383	13,303	23,606	34,466	40,718	43,123	46,684	55,124	58,673	62,318
OPERATING EXPENSES										
OFFSHORE										
OPERATING COSTS	402	752	927	1,383	1,639	1,830	2,338	2,444	2,478	2,576
SALES TAX/ROYALTY/CESS	486	1,740	3,115	7,257	8,763	9,282	9,904	10,892	11,550	12,214
DEPRECIATION/DEPLETION	1,325	1,823	3,741	4,446	6,938	11,377	15,257	13,422	10,792	10,296
SUBTOTAL	2,213	4,315	7,783	13,081	17,340	22,489	27,499	26,758	24,820	25,086
ONSHORE										
OPERATING COSTS	293	560	623	518	604	650	720	790	895	990
SALES TAX/ROYALTY/CESS	521	995	1,273	2,470	2,823	2,968	3,268	3,593	4,004	4,388
DEPRECIATION/DEPLETION	661	864	1,225	1,647	2,040	4,255	5,120	5,779	6,917	8,175
SUBTOTAL	1,475	2,419	3,121	4,635	5,467	7,873	9,108	10,162	11,816	13,553
OPERATING INCOME										
OFFSHORE	544	3,841	9,126	12,919	13,721	10,440	7,726	14,588	18,550	20,497
ONSHORE	151	2,728	3,576	3,831	4,190	2,321	2,351	3,616	3,487	3,182
TOTAL OPERATING INCOME	695	6,569	12,702	16,750	17,911	12,761	10,077	18,204	22,037	23,679
OTHER INCOME	118	22	-	-	-	-	-	-	-	-
TOTAL INCOME	813	6,591	12,702	16,750	17,911	12,761	10,077	18,204	22,037	23,679
LESS-INTEREST	477	861	873	1,027	1,461	3,230	5,570	6,913	7,160	6,976
TAX	-	1,975	4,900	6,000	5,120	-	-	565	744	1,670
NET PROFIT	336	3,755	6,929	9,723	11,330	9,531	4,507	10,726	14,133	15,033
OPERATING RATIOS (%)										
OFFSHORE	80.3	54.9	46.0	50.3	55.8	68.3	78.1	64.7	57.2	55.0
ONSHORE	90.7	47.0	46.6	54.7	56.6	77.2	79.5	73.8	77.2	81.0
COMBINED	84.1	50.6	46.2	51.4	56.0	70.4	78.4	67.0	62.4	67.0
RATE OF RETURN ON NET FIXED ASSETS (%):										
OFFSHORE	11.1	58.0	85.3	80.3	55.4	27.6	15.9	26.5	32.3	35.3
ONSHORE	6.0	82.7	89.3	71.6	44.5	13.6	8.5	9.5	7.4	5.7
COMBINED	9.4	66.2	86.4	78.1	52.4	23.3	13.2	19.6	21.1	20.8
ROR ON ASSETS USED IN OPERATION (%)										
	7.3	28.0	28.2	28.0	24.8	17.4	10.6	15.4	16.3	15.3

PETROLEUM PROJECTS DIVISION 1
ENERGY DEPARTMENT
March 1984

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INDIA
CAMBAY BASIN PETROLEUM PROJECT

ONGC FINANCIAL STATEMENTS
SOURCES & APPLICATIONS OF FUNDS
(MILLION RUPEES)

	ACTUAL			PROVISIONAL	FORECAST					
	1980/81	1981/82	1982/83	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90
FUNDS PROVIDED FROM OPERATIONS										
OPERATING INCOME	495	6,549	12,702	16,750	17,911	12,761	10,077	18,204	22,037	23,679
DEPRECIATION	1,986	2,687	4,966	6,093	8,978	15,637	20,377	19,201	17,709	18,471
SUBTOTAL	2,681	9,236	17,668	22,843	26,889	28,393	30,454	37,405	39,746	42,150
DEDUCTIONS:										
DIVIDENDS	204	214	274	274	274	274	274	274	274	274
DEBT SERVICE: PRINCIPAL	474	417	1,111	1,265	1,511	1,656	1,987	3,669	7,415	10,492
INTEREST	477	861	873	1,027	1,461	3,230	5,570	6,913	7,160	6,976
INCOME TAX	-	1,975	4,900	6,000	5,120	-	-	545	744	1,670
WORKING CAPITAL INCREASE (EXCLUDING CASH)	(85)	1,664	622	1,606	1,056	1,714	664	4,509	3,981	3,247
SUBTOTAL	1,070	5,131	7,780	10,172	9,422	6,874	8,495	15,930	19,574	22,659
ADDITION:										
OTHER INCOME	118	22	-	-	-	-	-	-	-	-
FUNDS AVAILABLE FOR INVESTMENT	1,729	4,147	9,888	12,671	17,467	21,519	21,959	21,475	20,172	19,491
INVESTMENT PROGRAM	4,274	8,105	13,621	17,666	27,462	43,244	37,544	28,873	26,553	28,575
BALANCE TO BE FINANCED	2,545	3,958	3,733	4,995	9,995	23,725	15,585	7,398	6,381	9,084
FINANCED BY:										
GOI EQUITY CONTRIBUTIONS	55	-	-	-	-	-	-	-	-	-
BORROWINGS	2,484	4,065	7,645	3,512	7,463	23,635	15,495	7,308	6,291	8,994
OIDB GRANTS	-	-	-	30	100	100	100	100	100	100
OTHERS	-	14	-	-	-	-	-	-	-	-
TOTAL OUTSIDE FINANCING	2,539	4,079	7,645	3,542	7,563	23,735	15,595	7,408	6,391	9,094
INCREASE (DECREASE) IN CASH	(6)	121	3,912	(1,453)	(2,432)	10	10	10	10	10
CUMULATIVE CASH	30	151	4,063	2,610	178	188	198	208	218	228
DEBT SERVICE COVERAGE	2.9	5.7	4.4	7.3	7.3	5.8	4.0	3.5	2.7	2.3

PETROLEUM PROJECTS DIVISION 1
ENERGY DEPARTMENT
March 1984

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INDIA
CAMBAY BASIN PETROLEUM PROJECT

ONGC FINANCIAL STATEMENTS
BALANCE SHEETS
(MILLION RUPEES)

	ACTUAL			PROVISIONAL	FORECAST					
	1980/81	1981/82	1982/83	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90
ASSETS										
CURRENT ASSETS										
CASH	30	151	148	148	178	188	198	208	218	228
ACCOUNTS RECEIVABLE	543	2,026	3,216	2,547	2,926	3,103	3,307	3,612	3,877	4,048
STAFF ADVANCES	150	155	235	385	505	605	705	805	905	1,005
INVENTORIES	2,254	3,037	4,005	4,413	5,013	5,493	6,103	6,693	6,873	7,133
OTHERS	1,193	3,550	9,361	9,362	9,344	9,334	9,324	12,878	16,354	19,090
SUBTOTAL	4,192	8,919	16,985	16,875	17,966	18,923	19,637	24,196	28,227	31,524
PROPERTY, PLANT & EQUIPMENT										
OFFSHORE										
GROSS ASSETS	9,420	13,772	24,934	33,554	53,687	77,915	102,112	119,233	130,981	141,816
LESS ACCUMULATED DEPRECIATION	3,563	6,375	10,925	15,371	22,309	33,686	48,943	62,365	73,157	83,453
OFFSHORE NET ASSETS	5,857	7,397	14,009	18,183	31,378	44,229	53,169	56,868	57,824	58,363
ONSHORE										
GROSS ASSETS	8,830	13,516	15,561	19,780	27,391	41,294	57,771	72,942	88,675	105,406
LESS ACCUMULATED DEPRECIATION	6,177	9,574	11,495	13,142	15,182	19,437	24,557	30,336	37,253	45,428
ONSHORE NET ASSETS	2,653	3,942	4,066	6,638	12,209	21,857	33,164	42,606	51,422	60,178
TOTAL NET PROPERTY, PLANT & EQUIPMENT	8,510	11,339	18,075	24,821	43,587	66,086	86,333	99,474	109,246	118,541
WORK IN PROGRESS: OFFSHORE	1,146	4,299	4,463	9,274	7,240	11,326	8,581	5,693	4,036	4,532
ONSHORE	804	223	1,977	1,993	3,745	6,772	6,437	5,856	6,585	6,898
TOTAL	1,950	4,522	6,440	11,267	10,985	18,098	15,018	11,549	10,621	11,430
LONG-TERM INVESTMENTS	250	250	4,145	2,692	250	250	250	250	250	250
TOTAL ASSETS	14,902	25,030	45,645	55,655	72,788	103,357	121,238	135,469	148,344	161,745
LIABILITIES & SHAREHOLDER EQUITY										
CURRENT LIABILITIES										
CURRENT PORTION LONG-TERM DEBT	417	1,111	1,265	1,511	1,656	1,987	3,669	7,415	10,492	12,450
OTHER CURRENT LIABILITIES	3,049	5,982	13,409	11,693	11,718	10,951	10,991	11,031	11,071	11,111
SUBTOTAL	3,466	7,093	14,674	13,204	13,374	12,938	14,660	18,446	21,563	23,561
LONG-TERM DEBT	5,957	9,597	16,131	18,378	24,330	46,309	59,817	63,456	62,332	60,834
LESS CURRENT PORTION	417	1,111	1,265	1,511	1,656	1,987	3,669	7,415	10,492	12,450
SUBTOTAL	5,540	8,486	14,866	16,867	22,674	44,322	56,148	56,041	51,840	48,384
SHAREHOLDER EQUITY										
CAPITAL	3,429	3,429	3,429	3,429	3,429	3,429	3,429	3,429	3,429	3,429
RESERVE	2,467	4,022	12,676	22,135	33,311	42,668	47,001	57,553	71,512	86,371
SUBTOTAL	5,896	9,451	16,105	25,584	36,740	46,097	50,430	60,982	74,941	89,800
TOTAL LIABILITIES & SHAREHOLDER EQUITY	14,902	25,030	45,645	55,655	72,788	103,357	121,238	135,469	148,344	161,745
DEBT:DEBT PLUS EQUITY	48:52	47:53	48:52	40:60	38:62	49:51	53:47	48:52	41:59	35:65
CURRENT RATIO	1.2	1.3	1.2	1.3	1.3	1.5	1.3	1.3	1.3	1.3

PETROLEUM PROJECTS DIVISION 1
ENERGY DEPARTMENT
March 1984

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INDIA

CAMBAY BASIN PETROLEUM PROJECT

Schedule of Long-Term Loans Outstanding
(as of March 31, 1983)

	Balance (Rs million)	Maturity	Grace Period	Interest (%)
A. Local Loans				
Government of India	326.4	9 yrs.	5 yrs.	9.75
Hydrocarbons India Ltd.	301.5	9 yrs.	5 yrs.	9.75
Oil Industry Development Board	2,240.6	15 & 9 yrs.	2 yrs.	4.5, 9.75 & 10.25
Subtotal	2,868.5			
B. Foreign Loans				
IBRD - Bombay High I	1,038.7	20 yrs.	3 yrs.	10.25
- Bombay High II	2,993.0	20 yrs.	5 yrs.	10.75
OPEC I	103.7	20 yrs.	3 yrs.	10.25
II	149.0	20 yrs.	5 yrs.	10.75
Subtotal	4,284.4			
Commercial Loan I	223.1	7 yrs.	3 yrs.	1 % above LIBOR
Commercial Loan II	2,008.0	7 yrs.	2 1/2 yrs.	3/8th of 1% abv. LIBOR
Commercial Loan III	301.2	7 yrs.	2 1/2 yrs.	3/8th of 1% abv. LIBOR (at Singapore)
Commercial Loan IV	4,016.0	8 1/2 yrs.	4 yrs.	
Export/Suppliers Credits:				
Japan Consortium 1/	274.5	5 1/2 yrs.	6 months	7.5
ENI Credit - Italy 1/	0.5	10 1/2 yrs.	6 months	6
EKS - Norway	339.3			8.5
Hitachi Zosen (Japan)	540.9			6
ECICS	442.8	9 yrs.	20 months	11.75
EXIM Bank of USA	192.7	7 yrs.	3 yrs.	10.75
KFW Loan	207.0			5.375
BNP France I	90.1			10.6
BNP France II	30.9			10.6
BNP France III (R-12)	130.7			8.25
Yen Loan (R-12)	226.8			11
Yen Loan (KVX project)	231.0			3/8th of 1% abv. LIBOR
Subtotal	9,255.5			
TOTAL	16,408.4			

1/ Included accumulated interest.

Energy Department
March 1984

INDIA

CAMBAY BASIN PETROLEUM PROJECT

FINANCIAL RATE OF RETURN AFTER TAXES
(IN MILLION OF 1983 INDIAN RUPEES)
BASE CASE

	INCR. PROD. OIL (MT)	INCR. PROD. GAS (MMCM)	NET REV.		CAPITAL COSTS	PROFIT AFTER TAXES	CASH GENER.	PRINC. REPAYM.	CUMUL. CASH (NET)	CASH FLOW (FOR IRR)
1984/85	46.2	-	44.4	-	284.7	(261.5)	23.2	-	23.2	(241.9)
1985/86	262.5	14.2	261.4	-	1,812.4	(1,659.3)	75.1	-	98.3	(1,593.1)
1986/87	675.6	42.5	677.6	-	1,582.2	(1,200.3)	369.6	-	467.9	(959.6)
1987/88	1,106.4	63.7	1,105.8	-	1,255.4	(547.9)	725.6	202.3	991.2	(215.9)
1988/89	1,349.7	84.9	1,353.7	-	409.1	553.5	977.0	288.7	1,679.5	873.8
1989/90	1,479.1	90.1	1,481.4	-	349.4	785.2	1,151.6	483.0	2,348.1	1,060.1
1990/91	1,418.9	90.8	1,424.2	-	(41.9)	1,145.6	1,154.9	483.0	3,020.0	1,394.2
1991/92	1,336.1	85.5	1,341.0	-	-	1,124.7	1,132.1	483.0	3,669.1	1,269.1
1992/93	1,208.6	86.9	1,219.8	-	-	467.5	473.5	156.7	3,985.9	590.9
1993/94	1,080.2	88.2	1,097.3	-	-	389.9	394.6	156.7	4,223.8	492.4
1994/95	971.4	90.6	994.5	-	-	355.1	358.9	156.7	4,426.0	437.2
1995/96	870.9	85.9	894.9	-	-	321.6	324.7	156.7	4,594.0	383.4
1996/97	781.8	75.6	802.1	-	-	291.0	293.4	156.7	4,730.7	332.5
1997/98	708.5	60.2	721.3	-	-	265.3	267.2	156.7	4,841.2	286.7
1998/99	638.9	49.1	646.9	-	-	242.3	243.8	156.7	4,928.3	243.7
1999/2000	573.4	33.1	573.1	-	-	211.2	212.5	-	5,140.8	212.4

RETURN ON INVESTMENT = 17.536%

CASH GENERATION = PROFIT AFTER TAXES
+ AMORTIZATION & DEPRECIATION

CASH FLOW (FOR IRR) = NET REVENUE - CAPITAL COSTS
-VARIABLE COSTS - TAXES

PETROLEUM PROJECTS DIVISION 1
ENERGY DEPARTMENT
March 1984

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CAMBAY BASIN PETROLEUM PROJECT

KALOL FIELD
FINANCIAL RATE OF RETURN AFTER TAXES
(IN MILLION OF 1983 INDIAN RUPEES)
BASE CASE

	INCR. PROD. OIL (MT)	INCR. PROD. GAS (MMCM)	REVENUE	ROYALTIES AND SALES TAX	NET REV.	CAPITAL COSTS	OPER COSTS	DEPR. AND AMORT.	INTER.	PROFIT BEFORE TAXES	TAXES	PROFIT AFTER TAXES	CASH FLOW	CASH FLOW (FOR IRR)
1985/86	61.5	14.2	95.6	27.0	68.6	537.9	32.4	537.9	37.0	(538.7)	-	(538.7)	(0.8)	(501.7)
1986/87	184.7	42.5	287.0	80.7	206.3	644.6	32.4	636.0	81.3	(543.4)	-	(543.4)	92.6	(470.7)
1987/88	277.0	63.7	430.3	120.9	309.4	537.9	32.4	539.6	110.2	(372.8)	-	(372.8)	101.8	(260.9)
1988/89	369.3	84.9	573.6	161.3	412.3	54.0	32.4	55.4	101.1	223.4	-	223.4	176.8	325.9
1989/90	391.7	90.1	608.5	171.1	437.4	(5.5)	32.4	1.1	81.7	322.2	-	322.2	167.5	410.5
1990/91	376.1	90.8	587.6	164.6	423.0	-	32.4	0.9	62.2	327.5	-	327.5	172.6	390.6
1991/92	354.1	85.5	553.2	155.0	398.2	-	32.4	0.7	42.7	322.4	-	322.4	167.3	365.8
1992/93	316.9	86.9	503.2	139.7	363.5	-	32.4	0.6	36.6	293.9	19.9	274.0	225.8	311.2
1993/94	287.7	88.2	464.1	127.7	336.4	-	32.4	0.4	30.5	273.1	157.7	115.4	67.0	146.3
1994/95	261.3	90.6	429.7	117.1	312.6	-	32.4	0.4	24.4	255.4	147.5	107.9	59.5	132.7
1995/96	231.8	85.9	385.5	104.3	281.2	-	32.4	0.3	18.3	230.2	132.9	97.3	48.8	115.9
1996/97	206.6	75.6	342.9	93.0	249.9	-	32.4	0.2	12.2	205.1	118.4	86.7	38.1	99.1
1997/98	190.8	60.2	309.2	84.9	224.3	-	32.4	0.2	6.1	185.6	107.2	78.4	29.8	84.7
1998/99	172.9	49.1	275.9	76.4	199.5	-	32.4	0.1	-	167.0	96.4	70.6	21.9	70.7
1999/2000	154.0	33.1	237.4	67.0	170.4	-	32.4	0.1	-	137.9	79.6	58.3	58.4	58.4

RETURN ON INVESTMENT = 14.590%

CASH FLOW = NET REVENUE - VARIABLE COSTS
- DEBT SERVICE - TAXES

CASH FLOW (FOR IRR) = NET REVENUE - CAPITAL COSTS
-VARIABLE COSTS - TAXES

PETROLEUM PROJECTS DIVISION 1
ENERGY DEPARTMENT
March 1984

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CAMBAY BASIN PETROLEUM PROJECT

OTHER LIGHT OIL FIELDS
FINANCIAL RATE OF RETURN AFTER TAXES
(IN MILLION OF 1983 INDIAN RUPEES)
BASE CASE

	INCRIMENT. OIL PRODUCT. (MT)	REVENUE	ROYALTIES AND SALES TAX	NET REV.	CAPITAL COSTS	OPER COSTS	DEPR. AND AMORT.	INTER.	PROFIT BEFORE TAXES	TAXES	PROFIT AFTER TAXES	CASH FLOW	CASH FLOW (FOR IRR)
1984/85	46.2	63.5	19.1	44.4	215.9	0.6	215.9	14.9	(187.0)	-	(187.0)	28.9	(172.1)
1985/86	160.0	219.8	66.3	153.5	610.5	4.6	578.1	56.8	(486.0)	-	(486.0)	92.1	(461.6)
1986/87	325.3	447.0	134.6	312.4	253.5	10.1	260.0	74.3	(32.0)	-	(32.0)	228.0	48.8
1987/88	437.1	600.6	180.9	419.7	51.6	13.2	56.8	70.4	279.4	-	279.4	276.8	355.0
1988/89	437.1	600.6	180.9	419.7	-	13.2	4.1	62.5	340.0	-	340.0	281.1	406.6
1989/90	355.1	487.9	147.0	340.9	32.9	13.2	36.2	51.8	239.8	89.1	150.7	91.9	205.8
1990/91	295.5	406.0	122.3	283.7	(13.3)	13.2	2.7	39.9	228.0	131.7	96.3	4.0	152.2
1991/92	274.7	377.4	113.7	263.7	-	13.2	2.1	28.0	220.5	127.3	93.2	0.3	123.3
1992/93	220.4	302.8	91.1	211.7	-	13.2	1.7	24.0	172.9	99.8	73.1	42.8	98.8
1993/94	175.9	241.7	72.8	168.9	-	13.2	1.4	20.0	134.4	77.6	56.8	26.2	78.2
1994/95	140.1	192.5	57.9	134.6	-	13.2	1.1	16.0	104.4	60.3	44.1	13.2	61.2
1995/96	126.1	173.3	52.2	121.1	-	13.2	0.9	12.0	95.1	54.9	40.2	9.1	53.1
1996/97	113.5	155.9	47.0	108.9	-	13.2	0.7	8.0	87.1	50.3	36.8	5.5	45.5
1997/98	102.2	140.4	42.3	98.1	-	13.2	0.5	4.0	80.5	46.5	34.0	2.5	38.5
1998/99	92.0	126.4	38.1	88.3	-	13.2	0.4	-	74.8	43.2	31.6	(0.1)	32.0
1999/2000	82.8	113.8	34.3	79.5	-	13.2	0.4	-	66.0	38.1	27.9	28.3	28.3

RETURN ON INVESTMENT = 26.052%

CASH FLOW = NET REVENUE - VARIABLE COSTS
- DEBT SERVICE - TAXES

CASH FLOW (FOR IRR) = NET REVENUE - CAPITAL COSTS
-VARIABLE COSTS - TAXES

PETROLEUM PROJECTS DIVISION 1
ENERGY DEPARTMENT
March 1984

INDIA

CAMBAY BASIN PETROLEUM PROJECT

HEAVY OIL FIELDS
FINANCIAL RATE OF RETURN AFTER TAXES
(IN MILLION OF 1983 INDIAN RUPEES)
BASE CASE

	INCREMENT. OIL PRODUCT. (MT)	REVENUE	ROYALTIES AND SALES TAX	NET REV.	CAPITAL COSTS	OPER COSTS	DEPR. AND AMORT.	INT.	PROFIT BEFORE TAXES	TAXES	PROFIT AFTER TAXES	CASH FLOW	CASH FLOW (FOR IRR)
1984/85	-	-	-	-	68.8	1.0	68.8	4.7	(74.5)	-	(74.5)	(5.7)	(69.8)
1985/86	41.0	56.3	17.0	39.3	664.0	5.1	618.4	50.4	(634.6)	-	(634.6)	(16.2)	(629.8)
1986/87	165.6	227.5	68.6	158.9	684.1	12.5	673.9	97.4	(624.9)	-	(624.9)	49.0	(537.7)
1987/88	392.3	539.0	162.3	376.7	665.9	20.7	677.1	133.4	(454.5)	-	(454.5)	144.7	(309.9)
1988/89	543.3	746.5	224.8	521.7	355.1	25.2	364.0	142.4	(9.9)	-	(9.9)	230.5	141.5
1989/90	732.3	1,006.2	303.1	703.1	322.0	26.3	329.1	124.5	223.2	-	223.2	320.1	354.8
1990/91	747.3	1,026.8	309.3	717.5	(28.6)	26.3	5.7	95.4	590.1	-	590.1	363.6	719.8
1991/92	707.3	971.8	292.7	679.1	-	26.3	4.6	66.4	581.8	-	581.8	354.2	652.8
1992/93	671.3	922.4	277.8	644.6	-	26.3	3.7	56.9	557.7	89.2	468.5	396.3	529.1
1993/94	616.6	847.2	255.2	592.0	-	26.3	2.9	47.4	515.4	297.6	217.8	144.8	268.1
1994/95	570.0	783.2	235.9	547.3	-	26.3	2.3	38.0	480.7	277.6	203.1	129.5	243.4
1995/96	513.0	704.9	212.3	492.6	-	26.3	1.9	28.5	435.9	251.7	184.2	110.2	214.6
1996/97	461.7	634.4	191.1	443.3	-	26.3	1.5	19.0	396.5	229.0	167.5	93.1	188.0
1997/98	415.5	570.9	172.0	398.9	-	26.3	1.2	9.5	361.9	209.0	152.9	78.2	163.6
1998/99	374.0	513.9	154.8	359.1	-	26.3	1.0	-	331.8	191.6	140.2	65.3	141.2
1999/2000	336.6	462.5	139.3	323.2	-	26.3	0.8	-	296.1	171.0	125.1	125.9	125.9

RETURN ON INVESTMENT = 15.630%

CASH FLOW = NET REVENUE - VARIABLE COSTS
- DEBT SERVICE -TAXES

CASH FLOW (FOR IRR) = NET REVENUE - CAPITAL COSTS
-VARIABLE COSTS -TAXES

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CAMBAY BASIN PETROLEUM PROJECT

SENSITIVITY ANALYSES - FINANCIAL RATE OF RETURN

Cases		FRR after Taxes
1. Base Case		18
Sub-components:	Kalol field	15
	Other light oil fields	26
	Heavy oil fields	16
2. Capital Costs up 20%		11
3. Revenues down 20%		12
4. Production delayed by one year		13
5. Combination of 2 and 3		7
6. Combination of 2 and 4		8
7. Combination of 3 and 4		9
8. Combination of 2, 3 and 4		5

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CAMBAY BASIN PETROLEUM PROJECT

DEVELOPMENT DRILLING COMPONENT
ECONOMIC RATE OF RETURN
(IN MILLION OF 1983 INDIAN RUPEES)
BASE CASE

	QUANTITIES		TOTAL	COSTS		CASH
	OIL	GAS	REVENUE	INVESTMENT	VARIABLE	FLOW
1984/85	46.2	-	107.2	241.7	1.6	(136.1)
1985/86	262.5	14.2	607.8	1,545.9	42.1	(980.2)
1986/87	675.6	48.9	1,548.8	1,341.4	57.9	149.5
1987/88	1,106.4	76.5	2,458.9	1,063.7	69.2	1,326.0
1988/89	1,349.7	110.5	2,989.3	372.7	75.1	2,541.5
1989/90	1,479.1	128.5	3,206.8	294.3	77.6	2,834.9
1990/91	1,418.9	141.9	3,080.2	(32.1)	77.6	3,034.7
1991/92	1,336.1	134.0	2,898.8	-	77.6	2,821.2
1992/93	1,208.6	133.0	2,622.7	-	77.6	2,545.1
1993/94	1,080.2	132.0	2,355.6	-	77.6	2,278.0
1994/95	971.4	132.2	2,130.9	-	77.6	2,053.3
1995/96	870.9	125.4	1,920.6	-	77.6	1,843.0
1996/97	781.8	113.1	1,724.2	-	77.6	1,646.6
1997/98	708.5	95.8	1,553.4	-	77.6	1,475.8
1998/99	638.9	82.9	1,395.4	-	77.6	1,317.8
1999/2000	573.4	65.2	1,237.0	-	77.6	1,159.4
PRESENT VALUE	-	-		3,612.6	486.6	10,833.9

RETURN ON INVESTMENT = 91.401%

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CAMBAY BASIN PETROLEUM PROJECT

KALOL FIELD COMPONENT
ECONOMIC RATE OF RETURN
(IN MILLION OF 1983 INDIAN RUPEES)
BASE CASE

	INCR. PROD.					
	OIL (MT)	GAS (MMCM)	REVENUE	CAPITAL COSTS	OPER COSTS	CASH FLOW
1985/86	61.5	14.2	165.7	441.8	32.4	(308.5)
1986/87	184.7	42.5	497.4	531.8	32.4	(66.8)
1987/88	277.0	63.7	745.8	441.8	32.4	271.6
1988/89	369.3	84.9	994.3	45.4	32.4	916.5
1989/90	391.7	90.1	1,054.7	(4.6)	32.4	1,026.9
1990/91	376.1	90.8	1,019.7	-	32.4	987.3
1991/92	354.1	85.5	960.0	-	32.4	927.6
1992/93	316.9	86.9	876.0	-	32.4	843.6
1993/94	287.7	88.2	810.4	-	32.4	778.0
1994/95	261.3	90.6	753.0	-	32.4	720.6
1995/96	231.8	85.9	677.0	-	32.4	644.6
1996/97	206.6	75.6	601.8	-	32.4	569.4
1997/98	190.8	60.2	540.2	-	32.4	507.8
1998/99	172.9	49.1	480.6	-	32.4	448.2
1999/2000	154.0	33.1	410.9	-	32.4	378.5

RETURN ON INVESTMENT = 93.350%

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CAMBAY BASIN PETROLEUM PROJECT

OTHER LIGHT OIL FIELDS
ECONOMIC RATE OF RETURN
(IN MILLION OF 1983 INDIAN RUPEES)
BASE CASE

	INCR. OIL PROD. (MT)	REVENUE	CAPITAL COSTS	OPER COSTS	CASH FLOW
1984/85	46.2	107.2	183.9	0.6	(77.3)
1985/86	160.0	371.2	516.0	4.6	(149.4)
1986/87	325.3	754.7	215.2	10.1	529.4
1987/88	437.1	1,014.1	43.4	13.2	957.5
1988/89	437.1	1,014.1	-	13.2	1,000.9
1989/90	355.1	823.8	28.2	13.2	782.4
1990/91	295.5	685.6	(10.2)	13.2	682.6
1991/92	274.7	637.3	-	13.2	624.1
1992/93	220.4	511.3	-	13.2	498.1
1993/94	175.9	408.1	-	13.2	394.9
1994/95	140.1	325.0	-	13.2	311.8
1995/96	126.1	292.6	-	13.2	279.4
1996/97	113.5	263.3	-	13.2	250.1
1997/98	102.2	237.1	-	13.2	223.9
1998/99	92.0	213.4	-	13.2	200.2
1999/2000	82.8	192.1	-	13.2	178.9

RETURN ON INVESTMENT = 183.091%

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CAMBAY BASIN PETROLEUM PROJECT

HEAVY OIL FIELDS
ECONOMIC RATE OF RETURN
(IN MILLION OF 1983 INDIAN RUPEES)
BASE CASE

	INCR. OIL PROD. (MT)	REVENUE	CAPITAL COSTS	OPER COSTS	CASH FLOW
1984/85	-	-	57.8	1.0	(58.8)
1985/86	41.0	70.9	559.6	5.1	(493.8)
1986/87	165.6	286.3	565.9	12.5	(292.1)
1987/88	392.3	678.3	550.0	20.7	107.6
1988/89	543.3	939.4	298.8	25.2	615.4
1989/90	732.3	1,266.1	270.7	26.3	969.1
1990/91	747.3	1,292.1	(21.9)	26.3	1,287.7
1991/92	707.3	1,222.9	-	26.3	1,196.6
1992/93	671.3	1,160.7	-	26.3	1,134.4
1993/94	616.6	1,066.1	-	26.3	1,039.8
1994/95	570.0	985.5	-	26.3	959.2
1995/96	513.0	887.0	-	26.3	860.7
1996/97	461.7	798.3	-	26.3	772.0
1997/98	415.5	718.4	-	26.3	692.1
1998/99	374.0	646.6	-	26.3	620.3
1999/2000	336.6	582.0	-	26.3	555.7

RETURN ON INVESTMENT = 53.318%

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CAMBAY BASIN PETROLEUM PROJECT

CAMBAY GAS FIELD REHABILITATION
ECONOMIC RATE OF RETURN
(IN MILLION OF 1983 INDIAN RUPEES)
BASE CASE

	INCR. GAS PROD. (MMCM)	REVENUE	CAPITAL COSTS	OPER COSTS	CASH FLOW
1985/86	-	-	28.5	-	(28.5)
1986/87	6.4	10.4	28.5	2.9	(21.0)
1987/88	12.8	20.7	28.5	2.9	(10.7)
1988/89	25.6	41.5	28.5	4.3	8.7
1989/90	38.4	62.2	-	5.7	56.5
1990/91	51.1	82.8	-	5.7	77.1
1991/92	48.5	78.6	-	5.7	72.9
1992/93	46.1	74.7	-	5.7	69.0
1993/94	43.8	71.0	-	5.7	65.3
1994/95	41.6	67.4	-	5.7	61.7
1995/96	39.5	64.0	-	5.7	58.3
1996/97	37.5	60.8	-	5.7	55.1
1997/98	35.6	57.7	-	5.7	52.0
1998/99	33.8	54.8	-	5.7	49.1
1999/2000	32.1	52.0	-	5.7	46.3

RETURN ON INVESTMENT = 45.938%

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CAMBAY BASIN PETROLEUM PROJECT

Annual Petroleum Price Change Index

	Crude Oil Price	
Year	US$/bbl	Index
1983	1.0000	29.0
1984	0.9515	27.6
1985	0.9282	26.9
1986	0.9487	27.5
1987	0.9660	28.0
1988	0.9865	28.6
1989	1.0070	29.2
1990	1.0275	29.7
1991	1.0480	30.3
1992	1.0690	30.9
1993	1.0904	31.5
1994	1.1124	32.1
1995	1.1343	32.8
1996	1.1571	33.4
1997	1.1804	34.1
1998	1.2037	34.8
1999	1.2280	35.5
2000	1.2527	36.2
2001	1.2774	36.9
2002	1.3030	37.7
2003	1.3291	38.4

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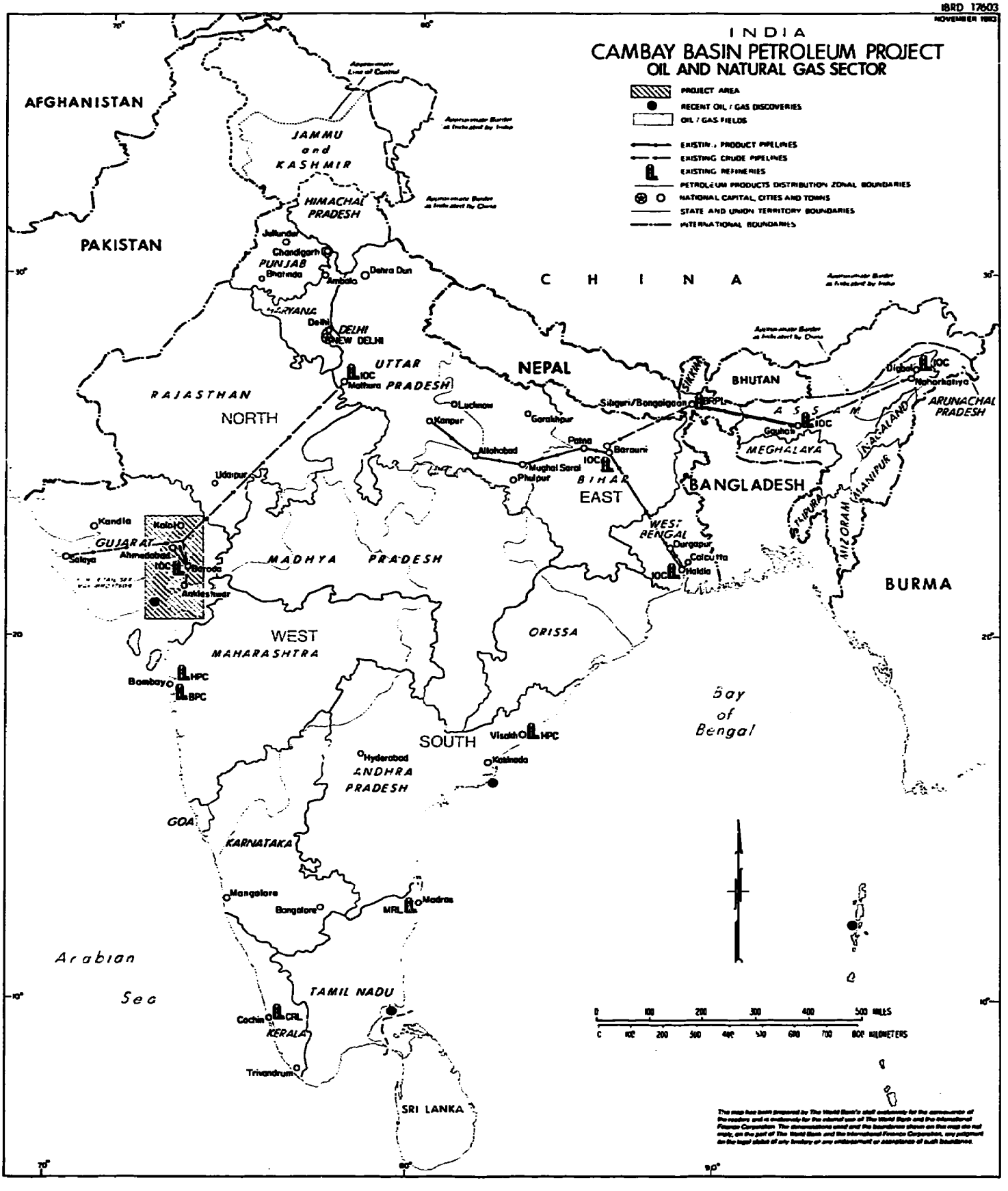
CAMBAY BASIN PETROLEUM PROJECT
OIL AND NATURAL GAS SECTOR



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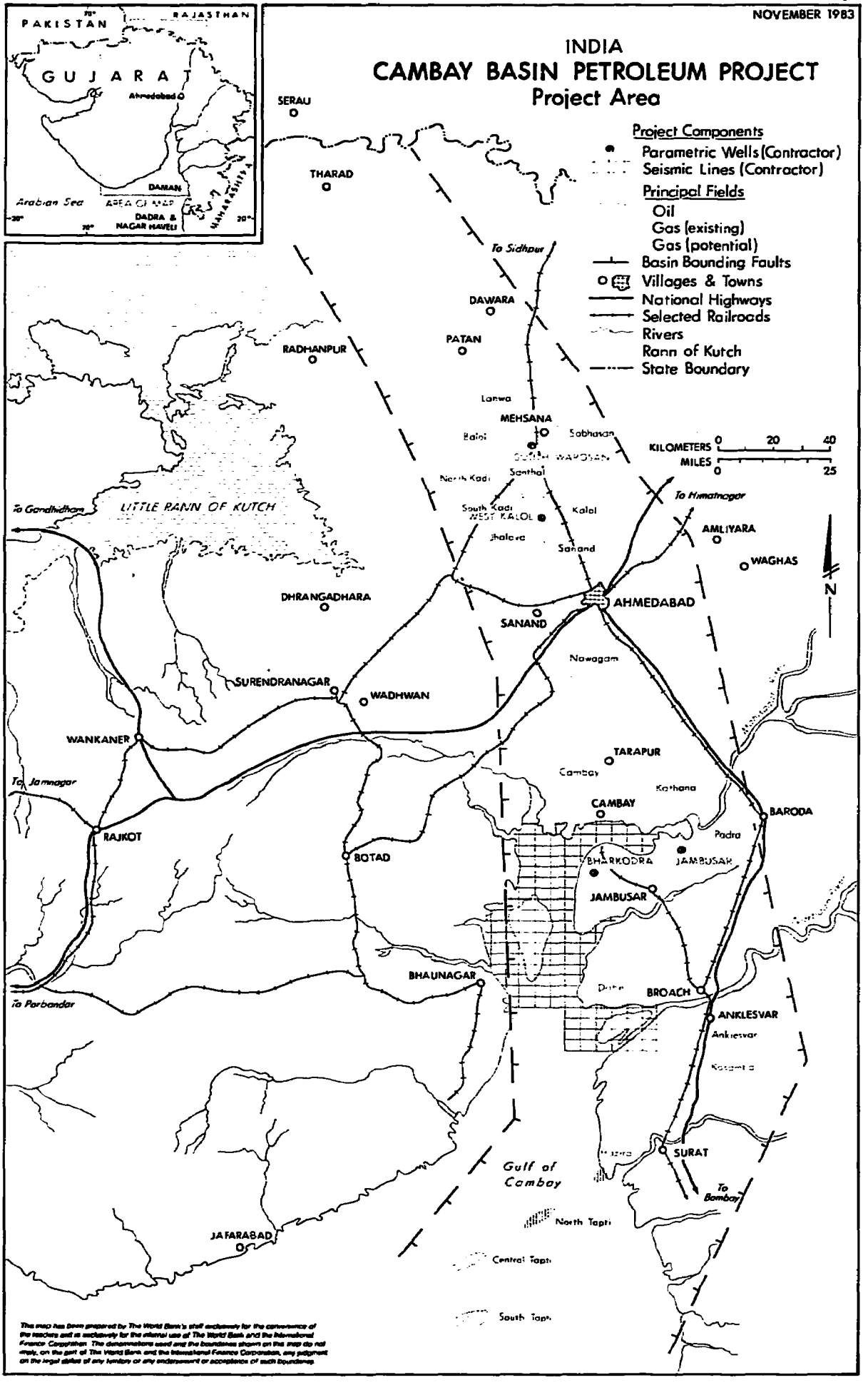
Project Area



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