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MYANMAR:

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ENERGY SECTOR INVESTMENT AND POLICY REVIEW STUDY

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MYANMAR

ENERGY SECTOR INVESTMENT AND POLICY REVIEW

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This report is based on the findings of an energy sector mission that visited Myanmar in November, 1990, and discussions with the Government of Myanmar at an energy symposium held in Yangon in January, 1992. The mission comprised:

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EXECUTIVE SUMMARY

A. Background and Objectives

1. Since the early 1960's, Myanmar has pursued economic policies based on government ownership of economic resources, central direction of the economy, strict government controls and limited interaction with the rest of the world. Beginning in 1974, the government made a number of policy adjustments to revitalize the sagging economy, which, along with external support, helped to temporarily stimulate production. But the partial economic recovery could not be sustained in the absence of structural reforms; and in response to the major deficits and increase in debt service ratio to 36% in 1983, the government cut down drastically on investments and imports. In late 1988, the government took steps towards implementation of market-oriented economic policies aimed at encouraging foreign capital, restructuring state economic enterprises, stimulating private sector participation and liberalizing the domestic and external trade. The Myanmar economy is now in a state of shifting from extreme centralization towards a greater market orientation and these transitions, combined with present political uncertainty, are severely affecting economic performance and investment planning in the energy sector.

2. The energy sector in Myanmar at present faces a critical situation. Modern energy consumption level is one of the lowest in the world even accounting for the low per capita income. There is significant unmet demand because of severe supply constraints. Industrial production is severely handicapped by shortage of energy. At the same time, the existing sources of supply are deteriorating rapidly for a number of reasons including the use of inadequate and obsolete technology, inappropriate policies and weak sector management. The sector is capital intensive, has incurred substantial foreign debts, and in the past has been prevented from providing domestic financial savings to the government because of excessively low pricing of energy. But it today requires substantial investments just to maintain its existing capability for energy supplies, and for the economy to grow rapidly the capital requirements will be all the greater. However, investments are not likely to result in efficient production and utilization of energy resources unless policy reforms are implemented, notably in technology acquisition, energy pricing and financial management of the sector. A much more systematic effort is also essential to evaluate the various domestic resources, whose potential is uncertain because of inadequate assessments.

3. The purpose of this study is to review: (a) the prospects for development of the country's indigenous energy resources including hydro, power, oil, natural gas, coal and biomass; (b) the pricing policy for the energy sector; (c) selected operational issues affecting the efficiency of the energy sector including rehabilitation of power, oil and gas sectors; and (d) management and financial issues facing the major entities in the energy sector. Based on this review, a short, medium and long term strategy for national energy development is suggested.

B. Energy Demand

4. Myanmar has one of the lowest levels of energy consumption in the developing world--0.31 tons of oil equivalent (toe) per capita/yr in 1990. The total use of primary energy in 1990 was 12.3 million toe (or about 250,000 barrels of oil equivalent per day) with primary energy being supplied in the form of fuelwood plus charcoal (76.7%), biomass (6.2%), domestically produced crude oil (5.0%) and imported oil (1.1%), natural gas (8.2%), hydroelectricity (2.7%) and coal (0.2%). In terms of secondary energy the largest consuming sector was household (87.2%), followed by industry (5.6%), transport (3.9%) and other users including fertilizer manufacture (2.3%). There are serious supply restraints which curtail actual consumption of all energy products: at present, electricity is regularly load-shed in all regions of the country; natural gas is insufficient for the gas-fired generation plants, as well as for the fertilizer plants and for industrial use, leading to plants operating at far less than capacity; the availability of petroleum products has dropped precipitously; and rationing is applied even within the government and its state owned enterprises (SEEs). Modern energy consumption has stagnated over the last decade; petroleum products consumption has been squeezed down from 7.6 mmb/yr in 1985 to 4.4 mmb/yr in 1990, kerosene use has declined from 68.7 million gallons (IG) in 1975 to about 2 million gallons in 1990, and electricity growth rate has decreased to only 3.5% per year from the earlier rates of 8%. The potential demand for modern energy is far higher than present sales. This is also reflected in the traditional energy sector where the consumption of fuelwood has increased in the absence of kerosene and there is considerable overcutting in the divisions adjacent to the cities of Yangon and Mandalay.

5. In view of the fact that present energy consumption is severely constrained by the availability of supplies, and considerable uncertainty exists regarding availability and timing of some of the major resources, it is difficult to forecast with any degree of accuracy the future demand patterns for energy. In order to provide an analytical framework for analysis of options, the study used two possible scenarios corresponding with high and low growth rates of GDP. The optimistic scenario assumes a GDP growth rate of 5% but also that a number of essential energy strategy steps are undertaken so that over the period of 1991 to 2005, total modern energy consumption increases at about 5%/yr, with petroleum product consumption at 7.4%/year and electricity at 7.5%/yr. The demand for petroleum products in this scenario would triple from the present consumption of 5.14 mmb, while electricity demand on the interconnected system would increase to 7,207 GWh from the present level of 2,371 GWh. The second forecast also assumes that the basic steps of an energy strategy are undertaken but that the economy grows at the slower rate of 3.0%/yr, with modern energy consumption increasing at the rate of 3.1%/yr, petroleum products at 4.5%/yr and electricity at 4.3%/yr.

C. Domestic Sources of Energy

6. Myanmar has considerable indigenous primary energy potential, which could in the long term meet these demands. As of April 1990, the remaining recoverable proven onshore oil and gas reserves were estimated at 114 mmb and 13[illegible] bcf respectively, while the future discovery potential onshore and offshore is estimated at 800 mmb of oil and 7,000 bcf of gas. The total coal resources in place are estimated at about 200 to 230 million tons. Hydropower resources

are quite substantial, with a theoretical power potential of over 108,000 MW and 366,000 GWh/yr of average energy. Myanmar has a forest area of about 31.6 million ha or 47.5% of the total land area of the country, and this with non-forest trees and agricultural residues provides the potential for substantial and sustainable traditional energy supplies. But Myanmar has not been able to effectively explore and exploit these energy resources in the absence of appropriate technology, adequate financial resources and market-oriented systems and structures.

The Oil and Gas Sector

7. In the oil sector, Myanmar has changed from self-sufficiency to being in a position of significant deficit in a relatively short period. In 1980 production averaged about 10 million barrels per year and stayed around this level until 1985 before starting its deterioration to the current production of about 5 million barrels. Alarming decline rates in the order of 20% per year have been recorded since 1985--much higher than would be expected under normal oil field operating practices. Myanmar had to import about 0.7 million barrels in 1990 to meet its severely curtailed requirements. Current production forecasts indicate a further continuing slide unless major corrective actions are taken.

8. Reduction in oil production is generally due to the advanced stage of depletion of most of the fields, lack of adequate pressure maintenance, faulty well completion and inadequate surface and subsurface equipment. An increase in oil production would require a major rehabilitation effort in all the producing fields as well as delineation and development of the probable and undeveloped proven reserves. The major targets of the above investment programme would be the Mann and Htaukshabin fields where most of the probable and undeveloped proven reserves are expected to be encountered and the above rehabilitation and development programs will need to depend on a first phase data gathering and appraisal program.

9. The situation of natural gas is equally critical. Based on optimistic projections of resources, it was generally believed that Myanmar had ample reserves both onshore and offshore to meet domestic demand for the foreseeable future and to replace the depleting oil reserves. The Bank financed Gas Development project (Cr. 1840-BA) was designed to tap gas from the Payagon field. However, detailed investigations and field performance in 1988 revealed that the onshore gas reserves were inadequate to meet current consumption levels for much beyond 1991. Natural gas supply from the presently developed and proven onshore reserves is forecast to decrease from 33.3 bcf in 1991 to only 1.7 bcf in the year 2000 unless additional reserves are discovered. The decline is projected to be particularly sharp in the Delta and Pyay Embayment areas. In fact, the Delta area is expected to have negligible gas supply in 1991 due to total depletion of Payagon field while in the Pyay Embayment area free gas production is expected to plunge from 13.7 bcf in 1991 to 4.0 bcf in 1995 and to cease completely in 1997. The reduction in gas production would be even sharper if adequate compression is not installed immediately at Shwepyitha, and during the next 18 months, at Ayadaw fields. To arrest this production decline--which is due to the advanced stage of depletion of the known gas reservoirs, drops in well productivity and wellhead pressures--or to reduce it as much as possible, would require additional development and delineation of the unproven gas reserves.

10. The deteriorating oil and gas production situation calls for concerted action. The government has already taken the long overdue step of inviting international oil companies to explore both onshore and offshore areas under production sharing contracts. Myanmar awarded exploration licenses in 1989-90 to ten companies (or groups of companies) on nine onshore and two offshore blocks with a minimum work commitment of 29 wells, with the first wells being spudded in early 1991. Approximately 32 percent of the estimated future discoveries are covered by these licenses (55 percent of the oil potential and 15 percent of the gas potential). The decision to award production sharing contracts to international oil companies in 1989 has stimulated exploration. But it needs to be noted that even an early success would take three to five years to bring to production after the initial discovery.

11. In the short term, Myanmar Oil and Gas Enterprise (MOGE) will need to take urgent steps for the rehabilitation of the existing fields. Increase in oil production will require upgrading of technology, rehabilitation of fields, delineation and development of probable and possible reserves. It is estimated that with an investment of US$668 million, over the period 1991-2005, oil production could be kept at about 9.96 mmb in 1995 and 5.58 mmb in 2005. Onshore gas production from existing fields is, however, unlikely to increase significantly; even with an investment of US$242 million over the period 1991-2005 for rehabilitation and development of probable and possible reserves, gas production is estimated to only attain 23.6 bcf per year in 1995 and then decline to 6.2 bcf per year in 2004. These investments will, however, be productive only if appropriate technology is mobilized by MOGE either directly or through production sharing type contracts from the international oil industry.

12. Offshore Gas Field Development. The only promising prospects are for the development of offshore gas. Substantial gas reserves have been discovered in the Gulf of Moattama 90 km from the shoreline in water depth of about 45 m. While MOGE estimates the proven reserves to be 7 tcf, according to mission estimates, based on wells drilled till date, the total in place reserves are about 5 tcf, of which about 1.6 tcf can be considered to be proven recoverable reserves. The remaining gas potential could be promoted to the proven category following the drilling of 3-5 wells. A level of production of some 75 bcf could be achieved for a period of 15 years from the present proven reserves in the Gulf of Moattama, which could be increased to 150-175 bcf per year if the additional delineation work succeeds in confirming the gas potential of the 3-DA and MOC-8 structures. Preliminary assessments of three alternative schemes for the development of the offshore gas field: minimum development of 3-DA structure for domestic use only, export to Thailand through a pipeline or export of natural gas products such as liquified natural gas (LNG), indicate that the optimum development scheme would be the export of a minimum level of 108 bcf per year of gas to Thailand with a spur pipeline providing about 42 bcf per year to the domestic market. This US$1 billion development scheme, however, depends critically on the level of producible reserves available for export and the availability of external capital and technology. The exploitation of the 3-DA structure for the domestic market, which would include a 90 km submarine pipeline and 180 km onshore pipeline from Moattama to Yangon and require an investment of about US$247 million, could form the first phase of the development scheme thus alleviating the acute energy shortages in the country.

13. Since offshore gas development provides the best hope for the country's energy economy in the short and medium term, it is essential that urgent steps are taken by the government. The development of the offshore gas reserves requires: (a) additional delineation drilling of 3-5 wells to determine the extent of the producible reserves; (b) a reservoir simulation study to evaluate the optimum development plan for the field; (c) a detailed feasibility study to determine the exact routing of the pipeline; and (d) formation of a joint venture which could mobilize the necessary capital and technology.

The Coal Sector

14. The country is estimated to have a total coal resource (proved, probable, possible and potential reserves in place) of 200 to 230 million tons, in numerous deposits mostly of sub-bituminous rank, mainly in the northern regions. The country's two mines produced a total of 38,672 tons in 1989: Kalewa, using underground mining techniques, produced some 12,900 tons and Namma, using open cast mining, produced some 25,800 tons. However, Namma is a short term operation, lacking reserves for any major expansion.

15. The Kalewa deposits are the only significant deposit for consideration for further coal development at the present time, but no serious attempts have been made in the past to develop the mine at a larger scale. However, the high volatile content and good burning characteristics of Kalewa coal make it ideally suited for pulverized fuel or fluidized bed boiler operations, such as for power generation. The knowledge of reserves at Kalewa is presently limited, and reserves estimates range from 26 to 128 million tons of resources, but only about 5 million tons are proven. A mine mouth electricity generation plant of 200 MW would require about 350,000 tons/yr of coal which means that at least some 31.5 million tons of reserves in place should be proven before such a project could go ahead. Therefore, a detailed exploratory drilling program of Kalewa is essential.

The Power Sector

16. Approximately 94% of electrical energy sold by the Myanma Electric Power Enterprise (MEPE) in Myanmar (1,844 GWh in 1990) is provided from 20 interconnected power stations with a combined available capacity of about 400 MW (54% thermal based on gas) and through an interconnected 230/132/66 kV transmission grid system extending some 600 miles from Pathein city, south-west of Yangon, to Kawlin copper mine north of Mandalay. Its associated 33/11/6.6/0.4 kV subtransmission and distribution networks feeding urban, industrial and a few rural loads adjacent to the transmission grid provide service to 10% of the 28 million urban population who live in the main towns and cities of the six principal Divisions of Myanmar. The balance of electrical energy sold by MEPE (94 GWh in 1990) is supplied by numerous isolated diesel and minihydel units scattered throughout the surrounding high country. Fewer than 7% of the estimated nine million rural population in these remote areas, comprising two Divisions and six States, receive electricity and their supplies are usually provided on a restricted 4-12 hours per day basis. These proportions reflect the previous governments electrification policies which have been to promote greater industrial use of power rather than development of the residential or commercial sectors.

17. Electricity Demand. There is a considerable and growing unserved demand in the electricity market at present, both because of load shedding as a result of gas and oil shortages for power generation and because industry itself is short of gas and other inputs and therefore is operating far below capacity. Over the last decade electricity consumption in Myanmar has grown at about 8%/yr on average, but since 1985 the growth rate has fallen to only 3.5%/yr. The average growth over the decade is modest in comparison with growth in many of Myanmar's Asian neighbors, despite Myanmar's low electricity usage (45 kWh/capita in 1990), and low tariffs (0.48 Kyats/kWh). There are no reliable long term projections of power demand presently available but mission estimates that increases in electricity could range from 4.8% to 8.4% over 1990-2010, with the power generation capacity tripling the existing capacity in the low case and increasing to about 2,000 MW in the more optimistic case.

18. Generation Options. The current uncertainty about the availability of the key energy resources makes it difficult to plan for a program of power generation. The availability and volume of natural gas for the power sector plays a particularly important role in any decision on generation expansion to meet the projected increase in demand. Assuming that gas from offshore is available, as is likely if the government makes a concerted effort to attract foreign capital for this purpose, an analysis of generation options using the power sector investment programming package, Energy and Power Evaluation Program (ENPEP), indicates that[1] the economic sequence of utilizing various sources of energy would be:

(a) to utilize natural gas for power generation using combined cycle power plants;

(b) to fill the gap between the growth in electricity demand and the available natural gas resources with power plants using imported fuel;

(c) to replace imported fuel with domestic coal mine-mouth power plants if they are technically and economically viable in light of projected increases in international fuel oil prices; and

(d) to develop hydro resources in conjunction with the combined cycle gas plants depending on the feasibility to develop potential schemes.

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[1] The levelized costs of generation for power plants using various fuel sources at full capacity over a period of 20 years are:

natural gas with combined cycle.....3.41 c/kWh
natural gas with gas turbines.....4.26 c/kWh
natural gas with diesel engine.....4.84 c/kWh
coal-domestic (based on coal price of $25/ton)....4.98 c/kWh
coal-imported (based on coal price of $40/ton)....6.22 c/kWh
hydro (Paunglaung with 40 year life).....7.80 c/kWh
fuel oil in steam generating plant..... 8.06 c/kWh

19. Based on the projections of power demand in the high growth scenario, the least cost development program for Myanmar would be as follows:

YEAR	ADDITIONAL POWER PLANTS	INSTALLED (MW)
1989	EXISTING CAPABILITY	399
1990	THAKETA/YWAMA (Conversion to diesel)	60
1992	REHABILITATION PROGRAM completed	
1994	Convert SHWEDAUNG/MANN to Combined Cycle	71
1995	Convert THAKETA/MYANAUNG to Combined Cycle	52
1996	NEW YANGON Combined Cycle #1	50
1997	YANGON Combined Cycle # 2	50
1998	YANGON Combined Cycle # 3	50
1999	YANGON Combined Cycle # 4 and # 5	100
2000	YWAMA retires	-36
2000	YANGON Combined Cycle # 6	50
2001	YANGON Combined Cycle # 8 # 1	100
2002	YANGON Combined Cycle # 8 # 2	100
2003	PAUNGLAUNG Hydro	280
2004	BALUCHAUNG #3 Hydro	48
2004	Retire THATON/HAMLAMYAING	-47
2005	BILIN Hydro	240
2006	YEYWA Hydro	400
2007	MON CHAUNG Hydro	200
2008	SHWEZAYE Hydro	600
2009	KUN CHAUNG Hydro	84
2010	Retire old GT capacity	-150

20. The least cost development plan would require the rehabilitation of existing plants to increase fuel efficiency and the conversion of Shwedaung, Mann, Myanaung and Thaketa to combined cycle operation adding 160 MW to system capacity by 1995. Subsequently, up to 500 MW of combined cycle plants would also be required for commissioning in stages beginning in 1996 for a total investment in power generation of around US$600 million up to the year 2000. With gas generating plants comprising over 75% of total system capacity, it would be prudent to commission Paunglaung and Bilin hydro plants as the next major capacity increments (520 MW in total) in 2003 and 2005 respectively. Subsequent development prospects would include Yeywa, Mon Chaung and Shwezaye hydro plants.

21. However the uncertainty about gas availability makes it difficult to take a decision about gas based power development at this time. Analysis of the low gas scenario reveals that in the short and medium term, power requirements could only be met by the import of costly diesel oil while steps were taken to hasten the hydro power developments. An alternative that needs evaluation is that of coal fired plants using domestic coal and located at the minemouth, should exploration at Kalewa indicate the presence of a minimum resource of 35 million tons; or imported coal could be used in Yangon. Both options would be considerably more expensive and require a minimum period of time for exploitation. These alternatives underline the need for the government to move urgently to evaluate and develop its offshore gas reserves.

22. Transmission and Distribution Systems. Under normal conditions the new 230/132 kV system would provide MEPE with a secure high voltage grid between the Upper and Lower Myanmar load centers. However bottlenecks caused by limitations in the associated 132/66 kV systems, limit the capability of the 230/132 kV circuits to carry large loads during emergencies and under some circumstances the system can also become inherently unstable resulting in major load shedding. Furthermore during lightly loaded periods the 132 kV system voltage levels can rise in excess of design limits. These aspects of system operations need to be addressed urgently to improve stability of operations,

avoid expensive breakdowns and make better use of available generating capacity.

23. In contrast to transmission developments, there has been little matching investment in the distribution networks which have been generally neglected over the last 40 years. As a result distribution networks throughout Myanmar are in very poor condition and urgently in need of rehabilitation. Losses are high, breakdowns are frequent and poor low voltage conditions commonplace. The major urban networks supplying Yangon and Mandalay being more heavily loaded are in urgent need of reinforcement. The other rural networks are also in poor condition largely because of the unavailability of suitable materials. Distribution system losses, running in excess of 30% of generation in some areas, are worsening the critical demand situation particularly as they increase in intensity during peak periods. The situation is worse than it appears in the low voltage (LV) distribution networks because of the high proportion of load that is supplied from the transmission 66/33/11kV systems. Recent information indicates LV losses actually lie between 30-50% throughout Myanmar clearly requiring urgent action to make best use of the limited generating capacity. Preliminary estimate indicates that some US$250m is required for general rehabilitation and expansion of the distribution networks in the next five to ten years.

24. Rehabilitation and Maintenance of Plants. The suspension of supply and service foreign contracts and financing has created a serious problem with the maintenance of most of MEPE's thermal generating plants and will lead to an accelerated deterioration of plant reliability. Even new units are curtailed due to lack of repairs. A planned effort needs to be undertaken to (i) provide adequate maintenance and operational spare to existing plants; (ii) carry out rehabilitation and overhauling of existing gas turbines sets; (iii) recommission gas turbine sets to burn diesel oil including the provisioning of diesel oil handling and storage facilities; and (iv) expand selected gas turbine installations into combined cycle plants.

25. Rural electrification: Unlike most of its Asian neighbors MEPE has no strategy for expanding its rural electrification program. The number of villages electrified rose from 709 in 1979 to only 751 in 1989. Approximately 20% of MEPE's consumers (9% of total demand) are served by isolated diesel/mini hydel power stations scattered over the 14 Divisions/States of Myanmar. The number of diesel engines has increased from 570 by only 60 since 1985 and the rate of growth of new consumers and consumption in these areas is significantly lower than for the interconnected system. A detailed rural electrification study needs to be carried out to draw up a plan for supply of electricity to the rural and remote communities.

Refinery and Petrochemical Sector Issues

26. Refineries, methanol, urea and Liquefied Petroleum Gas (LPG) plants are all operating at much below their design capacities due primarily to absence of adequate crude oil and gas. The three refineries, with a design capacity of 18.9 mmb per year processed 4.8 mmb in 1990, down sharply from about 9 mmb in 1989, and are operating at 25% of capacity. The 450 tons per day Seiktha methanol plant runs 1 out of 3 months at 60% capacity; two of the urea plants are shut down and total production averages 582 tons per day as against the total plant capacity of 1,272 tons per day, while the LPG plant is operating at 63% capacity due to inadequate gas supplies as well as leaner quality of gas.

27. The shortage of natural gas has severely curtailed the production at Myanmar's four ammonia-urea plants; Sale A, Sale B, Kyunchaung and Kyawzwa. In the year 1990 total urea production was 45% of the installed capacity. The Kyawzwa plant was completely shut down in May 1990. Sale A and Sale B have had enough gas supplies but their production has been limited by a lack of spare parts and equipment problems. In 1989 these urea plants were using from 20% to 100% more gas per ton of urea than their design capabilities and it would therefore be efficient to undertake a debottlenecking study at the same time as the plants were rehabilitated. The fertilizer plants at Sale A and B and at Kyunchaung should be rehabilitated with an investment of US$11 million. Losses in all the plants are significantly higher than those at comparable plants in other countries and there is a need for an operational audit for control of losses and energy conservation.

28. The Seiktha methanol plant has also been starved of natural gas, and it has been operating at minimum capacity, on an intermittent basis, resulting in a total annual production of about 30% of design capacity. As a result production costs of methanol (excluding the cost of gas) are high. The economic options are either to shut down the plant or to run it at a much higher feed rate.

Traditional Energy

29. The biomass fuel resources of Myanmar consist principally of woodfuels (fuelwood and charcoal), but there is also a considerable quantity of agricultural residues that could be used for fuel without adversely affecting soil fertility or animal husbandry. In 1990 woodfuel consumption was estimated to be approximately 28 million air dried tons (adt), equivalent to about 9.4 million toe, and the non woody biomass consumption was 0.9 million toe. However, there is a scarcity of reliable data on the standing stock and sustainable yield of woodfuels and on the quantity of agricultural residues available for fuel. It is estimated that the annual per capita consumption of woodfuels is 0.7 adt and the overall sustainable woodfuel supplies for the country are only about 75% of the 1990 consumption. When woodfuel consumption and sustainable supply are compared on a state/divisional basis, the results show that, despite 45% of the country being covered in forest, there are today serious deficit situations in Central and Lower Myanmar, which by the year 2000 are projected to rise to 8.4 million adt in the woodfuel catchment area supplying the city of Yangon and 7.6 million adt in the area supplying Mandalay. These projected deficits will lead to serious overcutting of the forest particularly in the divisions of Yangon, Magway and Ayeyarwaddy. It is also expected that continuing agricultural encroachment in these areas will exacerbate the destruction of the forests. The large areas of mangroves, that are prime sources of charcoal and fuelwood, are being particularly affected in Ayeyarwaddy Division and, with the depletion of preferred stocks there, Rakhine and Tanintharyi Divisions are now being affected. No studies have been done on the detrimental effect on fish stocks, but continued degradation of the mangroves may adversely affect these as well.

30. Woodfuel development and conservation must, however, be done within the framework of a national woodfuel strategy that considers interfuel substitution. There are several policy and institutional issues that need to be resolved before effective investment can be made in any woodfuel development and conservation program. At present villagers are permitted to grow trees or collect wood for their own use, but are not permitted to sell such wood unless

they obtain a license to cut and royalty is paid to the Forest Department. The current system of establishing quotas for charcoal and fuelwood production is in serious need of revision, particularly for those divisions that are in a sustainable woodfuel deficit situation. The current royalty of kyats 2 per 90 lb bag of charcoal and kyats 5 per stacked ton of fuelwood, equivalent to kyats 6.5 and 10 per adt respectively, are far from representing the economic or financial value of the wood on the stump. Without higher stumpages it would be difficult to justify government investment in woodfuel development programs or to encourage the production of woodfuels by the private sector. Government policy should encourage and support the production of wood for both subsistence and commercial purposes by the private sector, particularly by rural households. The setting of quotas should be rationalized in the context of sustainable supplies, rather than short run feasible supplies.

31. A major woodfuel development program needs to be undertaken and one of the first priorities of the program should be to carry out woody biomass and household energy consumption surveys. For urban areas, the immediate strategy should focus on improved charcoal production and woodstove programs; pilot programs for improved management of deciduous and mangrove forests and a feasibility study for peri-urban plantations. In the rural areas, action should be focused on enhancing the seedling distribution program to the villagers and development of a system of grassroots forestry extension.

D. Energy Pricing

32. A recurring difficulty in evaluating and setting domestic energy prices in Myanmar is the foreign exchange rate situation. Myanmar government have not changed the grossly overvalued exchange rate for more than a decade despite a widening gap between the official and parallel market rates. At present in the parallel market, the value of kyat is nearly one tenth of its official price of 6.2 kyat to the dollar. Maintaining such an overvalued exchange rate leads to inefficiencies in its use, adversely affects incentives to produce, reduces government revenues and results in scarcities. Even assuming an exchange rate of k50/US$, energy prices in Myanmar are extremely low: the present official prices translate into US$2.20/barrel for crude oil, US$0.21/IG for diesel and US$0.32/IG for petrol, which would be some of the lowest diesel and petrol prices in the world - with consequent huge excess demands and lack of supply. Electricity tariffs were revised in 1988 to an average of 0.48 k/kWh but they are still very low by international standards. The existing administrative procedures and technical criteria for setting of energy prices are cumbersome and inadequate and there is a critical need for alternative pricing systems and a clearly defined pricing strategy.

33. There are two key objectives in setting energy prices: they should be sufficient to provide for financial viability of the energy entities and generate sufficiently high surplus to allow the sector to provide a significant part of its future investment program and secondly, the prices should be set at levels which encourage efficient use of energy and avoids wasteful consumption. There are serious problems with current energy prices in Myanmar since they reflect neither the economic supply costs nor the opportunity cost of energy.

34. The present method of cost-plus pricing of crude oil tends to lead to shortages of supply because of the difficulties of fully allowing for the costs of exploration and unsuccessful development, and allowing for changes in the

volume of production, for example following a new discovery, in the unit price calculation. The present low official price of crude oil of 110 kyats/barrel does not provide MOGE with adequate funds for its rehabilitation or development programs. The first critical step in establishing a petroleum pricing strategy is to clarify the method of approach that will be used. It is recommended that the domestic crude oil price should be tied to a suitable international crude oil price, for example a crude oil of similar quality to domestic production and available ex Singapore. The prices of petroleum products could be set on a cost-plus basis using refinery and distribution margins for each product while the price ratios of various products reflect international product prices. These prices would then promote optimal choices among products, discourage waste and eliminate economic subsidies.

35. In the short term since natural gas is in deficit, its price should be at least as high as the estimated cost of onshore gas production, but when Moattama gas is developed there will be a gas surplus and the netback value from exports should become the guideline for pricing domestic gas. The long run incremental supply cost (excluding taxes) of new onshore gas production has been determined at about US$2.42/mcf. The estimated cost of offshore gas from Moattama, when developed for domestic use only is US$1.74/mcf (including a depletion premium), but this is highly conditional upon the low investment costs associated with using the existing Jack-Up rig. The expected netback at Yangon from export of offshore gas to Thailand is evaluated to be about US$2.10/mcf. The price of gas should reconcile the objectives of stimulating both onshore and offshore development, while not raising gas prices too high which would heavily impact electricity tariffs. Therefore, the mission recommends that the gas price should be set in the range between US$2.10/mcf and US$2.50/mcf. In the short term the price should be at the upper end of this range with the prospect of decreasing it in the future when the netback from exports is realized.

36. Electricity rates have been maintained at too low levels for the effective development of this subsector, and even after the recent hike in tariffs, they are still too low to provide for the efficient use of electricity and to provide sufficient internal cash flow for MEPE to sustain its financial integrity. The tariff structure has been oversimplified, by essentially setting all tariffs at the same level, without any blocks for quantity of usage, and with insufficient attention to the costs of providing capacity which is differentiated by the proportion of consumption taken at higher voltage levels and higher losses in each part of the system. In addition, like petroleum prices, electricity tariffs have been kept fixed for excessively long periods of time in spite of domestic inflation and changes in the costs of operating MEPE.

37. The electricity tariff structure and levels should be related directly to the estimated marginal costs of providing service to respective groups of customers, and levels should be revised periodically, with a six monthly adjustment change, in order to adjust for changing fuel prices, domestic inflation and other changes. Basic criteria should be the estimated long run marginal cost (LRMC) of expanding generation, transmission and distribution in order to meet the forecast demand. At the same time average tariffs must provide for satisfactory internal cash flow to MEPE for it to be financially viable on a long term basis, both in terms of sufficient cash flow for the viability and improvement of its operations and contributing to investment requirements, and to provide an adequate rate of return on the capital employed

in the utility. To meet the needs of the electricity demand forecast, the average tariff level will have to be increased from the present 48 pyas/kWh to 68 pyas/kWh in 1992 for MEPE just to maintain an accounting breakeven. In the longer term, the average tariffs should be increased to the LRMC to provide for the necessary investments in the sector.

38. Traditional energy supplies, particularly charcoal also appear to be underpriced, as a result of too low a level of royalties. Over the past decade, although the current kyat price of charcoal has increased, the real price after adjusting for the consumer price index has actually decreased, in spite of serious overcutting of the forests in some regions. The present royalty of k 2/90 lb. bag of charcoal and k 5/stacked ton of fuelwood, equivalent to k 6.5/adt and k 10/adt of fuelwood are estimated to be too low for efficient management of the forests, which would appear to call for rates in the order of k 38/adt of fuelwood.

39. The fact that the kyat is significantly overvalued makes the pricing decision very complex, particularly for petroleum and gas which are or can be substituted for tradeable commodities. This creates an enormous gap between the financial and economic prices which, in turn, results in major distortions. In such cases it is impossible to ignore the economic prices. The energy prices recommended are considerably higher than the existing prices as indicated in the table below. It is suggested that prices be increased in the first step to meet the minimum financial objectives of the energy entities. These should then be gradually increased to the economic level in the next two to three years.

RECOMMENDED ENERGY PRICES IN MYANMAR
(k)

		Prices	
	Existing Prices	First Step at 6.2/US$	Target Minimum at 50/US$
Crude Oil	110/barrel	155/barrel	1250/barrel
Petrol	16.00/IG	22.36/IG	51.43/IG [1]
Kerosene	13.50/IG	15.84/IG	45.26/IG
Diesel	10.50/IG	15.76/IG	43.29/IG
Fuel Oil	8.50/IG	10.63/IG	30.73/IG
Natural Gas	7.50/mcf	15.50/mcf	125/mcf
Coal	365/ton	Domestic price to be tied to international prices with higher royalties if necessary	
Electricity:			
Residential	0.50/kWh	0.83/kWh	5.79/kWh
Services	0.50/kWh	0.61/kWh	4.14/kWh
Industrial	0.40/kWh	0.53/kWh	3.57/kWh
Ave.	0.48/kWh	0.68/kWh	4.72/kWh
Woodfuels/Charcoal Royalties		6.5-10/adt	38/adt

Note:
1. The target petroleum prices shown are net of distribution margins and taxes. The government's tax policy should determine the consumer price levels, but which should be set above these floor amounts, as illustrated in Annex 7.3 (d).

40. All energy prices must be considered together in a policy package and the strategy should also put in place transparent methods for establishing prices and a mechanism for annually reviewing them through the possible creation of an independent Energy Pricing Board.

E. Institutional and Financial Issues

41. Institutional Framework, Coordination and Planning. Policy formulation and planning of the energy sector are the responsibilities of the Energy Planning Department of the Ministry of Energy (MOE) created in April, 1985. The Ministry of Energy is responsible for MOGE, MEPE, MPPE, and MPE. Coal development is under the Ministry of Mines (Mining Enterprise No. 3) while fuelwood and biomass are under the Forest Department (FD) in the Ministry of Agriculture and Forestry.

42. Despite announced government policy, the four energy sector institutions do not enjoy autonomy as corporate entities. While they have operational freedom, their production targets, allocations of production, selling prices, foreign exchange requirements, capital investments and budgets are all determined by MOE and Government of Myanmar (GOM). No planning beyond the following year is being undertaken by the enterprises and by the ministries. There is an absence of defined corporate objectives, project evaluation systems, mechanisms for the setting of prices to ensure adequate cash flow to cover all costs, debt service and future investments and incentive systems to encourage managerial effectiveness. Financial constraints have prevented import of appropriate technology contributing significantly to the poor state of the energy sector. It is recommended that an energy sector financial and investment strategy be drawn up on a regular basis and formally ratified by an Energy Coordinating Committee consisting of the chief executives of the major energy sector institutions and departments and the MOE. All investments in the energy sector which require the commitment of government funds should be in consonance with the approved energy strategy, but the energy sector institutions should have adequate autonomy to implement their investments within the defined objectives.

F. Investment Program

43. A preliminary examination of financial needs of the energy sector shows required investments of about US$2,206 million over the period 1991-2000 with the least cost power generation program requiring about US$985 million. For maintaining energy supply at current minimum low levels over the next three years, there is a need for a minimum investment of about US$362 million for various rehabilitation measures.

INVESTMENTS IN THE ENERGY SECTOR
(US$ million)

SECTOR	1991-2000		1991-1995		1995-2000	
	TOTAL	FOREIGN COST	TOTAL	FOREIGN COST	TOTAL	FOREIGN COST
Coal Sector	6.00	5.00	6.00	5.00		
Oil Sector	1028.50	620.30	828.50	518.30	170.00	102.00
Refinery Sector	136.00	87.00	61.00	44.00	75.00	43.00
Power Sector	984.87	658.00	610.55	418.39	374.31	239.62
Traditional Energy Sector	51.47	12.87	25.74	6.43	25.74	6.43
Total Energy Sector	2,206.84	1,393.17	1,531.79	992.12	645.05	391.05

Source: Mission Estimates (1991)

44. But for these investments to be effective they will need major import of technology. Investments in the oil and gas sector are inadvisable unless appropriate technology is mobilized by MOGE either directly or through production sharing contracts (PSC) for not only new fields but also for rehabilitation and development of existing fields. While some measures have been initiated by the government for foreign company participation both in oil exploration and production, there is considerable scope for the government to increase the private sector participation in the energy sector: in the rehabilitation of oil and gas fields, in development of unproven gas reserves, in coal exploration and production, and in build-own-operate power plants.

45. While additional measures need to be initiated by the government for greater private sector participation in the energy sector, a substantial portion of the foreign exchange needs of around US$1,393 million will also have to be found from bilateral assistance, commercial loans, supplier credits and multinational agencies. The four energy sector institutions have about US$1.0 billion equivalent of outstanding loans which are mostly official development assistance (ODA). For the last three years, about US$90 million in repayments due and about US$50 million in interests due were not made due to foreign exchange difficulties. It will be necessary to resolve these and other macroeconomic issues for the necessary ODA to resume and for commercial and suppliers credits to become available at reasonable terms.

G. National Energy Development Strategy

46. Based on the above analysis of the sector development potential and operational issues, the following strategy for energy development is recommended.

In the short term (1991-1995), since the power sector will face a critical shortage of fuel supplies, an immediate plan needs to be established and implemented to cover the next three to five years of operation:

(a) **Conversion of gas-fired power plants to liquid fuel use** would require arrangements for the procurement of crude oil for refining and supplying sufficient diesel oil for (i) continuous operation of Thaketa and Ywama power plants and for (ii) standby operation of the Shwedaung, Mann, and Myanaung plants. The estimated fuel requirement to maintain operations with minimum load shedding but limited load growth is about one mmb/yr. All of the above stations

should be modified for burning diesel oil/gas; arrangements for transfer and storage of diesel at each site, made and storage and handling facilities commissioned as soon as possible.

(b) **Rehabilitation of power plants:** MEPE must take immediate steps to improve its supply of spare parts and carry out rehabilitation measures at the existing plants.

(c) **Power Distribution loss control:** There needs to be concerted effort to bring the losses down to increase revenue and reduce the incidence of load shedding, by reinstating the activities and strengthening the role of the Loss Reduction Unit.

(d) **Rehabilitation of the onshore oilfields** should be carried out on the highest priority; well production equipment, surface facilities, well completions, drilling of 24 data wells and pressure maintenance schemes should be taken up immediately while water injection schemes could await detailed investigations. The established undeveloped proved and probable oil reserves can be developed at fairly low risk under MOGE management but using international consultants and services companies. The exploration and development of possible reserves should, however, be delayed, and/or given over to international companies on a PSC or similar basis.

(e) **Methanol Plant:** In the short term, given the existing shortages of natural gas, it appears advisable on economic grounds to shut the Seiktha methanol plant. It could be reopened when plentiful gas supplies become available from offshore development and if international methanol prices are high enough in the future to make exports worthwhile.

(f) **Establish Energy Pricing Criteria and an Energy Pricing Board:** It will be essential to initiate a pricing reform in support of the investments which are contemplated in the energy sector. This will necessitate substantial increases in energy prices and thought should be given to the creation of an independent Energy Pricing Board.

47. In the medium term (1996-2000), the future electric power generating capacity should be based on natural gas from offshore if adequate reserves are established.

(a) **The assessment of the total offshore gas reserves** needs to be expedited. This will enable the government to determine the economic viability of the export options and to determine the volume of gas reserves that would be available for the domestic sector. This assessment would require the drilling of 3-5 offshore wells as well as an independent reservoir evaluation based on the latest data.

(b) **The export of gas to Thailand through a pipeline with a spur pipeline to Myanmar** for domestic supply of 42 bcf per year of natural gas provides the most economical option for the country.

The domestic option should be planned as an early phase of development of the export pipeline system. A detailed engineering study of the gas field development and pipeline system needs to be commissioned as well as discussions concluded early with the government of Thailand for possible contractual arrangements.

(c) **Gas field:** Rehabilitation of onshore gas fields should be carried out along with the development of the probable reserves but investments in the exploration and development of possible reserves should be deferred till the total offshore reserves have been determined. An examination needs to be carried out of the relative cost effectiveness of the alternatives of a trunk gas pipeline to transport offshore gas to industries in Central and Upper Myanmar versus the development of probable and possible gas reserves in those areas.

(d) **Conversion of Combustion turbine plants to Combined cycle Plants:** The early conversion of the Thaketa, Mann and Shwedaung plants to combined cycle operation needs to form an essential part of the medium term plan. The priorities for the conversion of the plants would be Ywama, Thaketa, Shwedaung and Mann.

(e) **Coal Exploration:** An exploration drilling program in the Kalewa area, costing about US$5.5 million, is recommended as a first step leading to a possible mining feasibility study for developing Kalewa for a 200 MW mine-mouth electricity generation plant.

(f) **Woodfuels Program:** Steps should be taken immediately to improve the information base of consumption and sustainable supplies.

48. In the long term (2001-2010), the options to increase generation capacity are hydro plants, domestic coal and additional plants based on gas depending on the discoveries made in the intervening period. In view of the long lead times involved in development and utilization of indigenous energy source like hydro, several immediate actions are necessary if timely decisions are to be made:

(a) **Detailed studies of the various hydro options** should be initiated so that investment decisions on hydro power plants can be taken as soon as an assessment of the total gas reserves has been completed so that the volume of gas available for the domestic power sector can be determined.

(b) MEPE also needs to prepare a ten year **transmission and distribution development plan** which should examine the nature of future development with a view to rationalizing a basis for expansion in the urban and rural areas.

(c) MEPE needs to prepare a **rural electrification plan.** MOE should initiate the preparation of a rural energy plan, which combines rural electrification, traditional and renewable energy supplies into integrated development schemes.

(d) For the woodfuels sector, a strategy for sustainable development needs to be prepared including programs of improved management in mangrove and deciduous forests within the Yangon supply area.

I. THE ECONOMY AND ENERGY DEMAND

A. Introduction

1.1 Myanmar's population in 1989 was estimated at 40 million, and growing at the rate of 1.88%/yr.[1] Some 10 million persons are employed in agriculture, comprising 66.2% of the estimated total employment of 15 million. The private sector is almost wholly very small scale, and out of some 40,000 registered private businesses in the country only 13 had more than 50 employees in 1989. Essentially all the large businesses are government owned and operated. Overall, the statistical average GDP per capita is in the range of US$200 to US$300, but its estimation depends critically on the assumed foreign exchange rate. Manufacturing has not emerged as an engine of growth, either for the domestic economy or for exports: manufactured goods account for perhaps 5% of exports, and manufacturing and processing contributed only 9.2% to GDP in 1990. The economy is essentially agrarian, with 50% of GDP derived in agriculture, livestock, fisheries and forestry. In fact agriculture may be considered as the cornerstone of the economy.

1.2 Myanmar is richly endowed with natural resources,[2] which includes minerals, forest and marine resources, in addition to relatively abundant arable land. However, most of these resources, including those known underground resources ranging from oil and natural gas to precious stones, are yet to be properly explored and exploited. There is good potential in most spheres for production and exports if proper economic and financial incentives were provided, and modern technology were available.

1.3 Myanmar has a 30 year history of a planned economy, dating from 1962, and government owns and controls virtually all the larger enterprises in the country, from industrial and manufacturing plants to hotels. Wages and prices of public sector output are determined centrally, and numerous non-price arrangements have been put in place in an attempt to offset or overcome the problems of ignoring market forces and appropriate pricing. The exchange rate has been pegged for more than a decade and the parallel exchange rate is some 8 to 10 times the official rate. Widespread shortages of consumer and industrial goods exist.

1.4 In the mid-1970's, reforms had been implemented to try to revitalize the economy, by focusing investment on mining and import substitution industries, largely financed by foreign loans. This had a stimulating effect and, according to official statistics, GDP grew at close to 6%/yr during the period. But beginning in the early 1980's the situation deteriorated: the external balance of payments account went into a worsening deficit and the government was forced in 1984 to resort to restrictive policies in an attempt to correct it. It reduced domestic investment and cut imports, but this also tended to reduce foreign earnings as a result of shortages of imported inputs needed for the country's exporting industries. The value of exports, two-thirds of which have traditionally been rice and teak, began to deteriorate in 1985, and declined by

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[1] See map IBRD 22977 Union of Myanmar

[2] See map IBRD 22979 Geological Basins

about 40% by 1989. The decline of rice exports was caused by poor producer incentives, shortages of fertilizers and the overvalued exchange rate. International teak prices were also weak in this period. Official imports were drastically restricted starting in 1984 and their value declined some 45% by 1989. The state economic enterprises (SEEs), including the energy SEEs, which were operating during this period at financial losses, were covered by the government through domestic loans financed through money creation, or through foreign loans. The broad money supply was increased at around 19%/yr, and although two 'demonetizations' were carried out in November 1985 and September 1987, when larger banknotes (e.g. 50 and 100 kyat notes) were simply declared void overnight, inflationary pressures eventually spilled over into the economy. In the past two years, the money supply has increased at about 50%/yr. In 1980, the ratio of gross investment to GDP was as high as 21.5%; it dropped to 15.5% in 1985, and last year (1990) was only about 13% of GDP.

1.5 The consistently declining export trend since 1984, the retrenchment of imports, declining capital inflows, and increasing debt service payments caused reductions in domestic investment, shortages of production inputs, and intensified price pressures which overflowed into the 'parallel' market along with a diminution of activities in the formal economy. In 1986 the economy began decreasing in output, and GDP declined in each of the three years up to 1988. The decline in economic activity had a pronounced effect on government revenues, especially because of the decreasing contribution of SEE related revenues. In the past, the SEEs had provided more than 70% of public revenues, but by 1988 this had dropped to 59%. By the year 1989, the contribution of SEE related revenues had fallen by k 2 billion (current kyats) annually.

1.6 The country's foreign debt has risen from about US$2.2 billion in 1983 to around US$4.6 billion at present, of which US$900 million is owed by the energy sector SEEs, i.e, almost 20% of the total sovereign debt. Foreign debt service almost doubled between 1983 and 1987, to reach some US$320 million/yr, close to 90% of the country's foreign exchange receipts. During 1987 the country's official foreign exchange reserves were down to as little as US$50 million at the official exchange rate. GDP had decreased by at least 16% since 1985 and the decline in 1988 was particularly severe: the manufacturing sector showed a plant utilization rate of 30%; consumption of modern energy, except electricity, declined; and the agricultural sector declined by 13% despite normal weather. The government deficit widened from 8% of GDP to about 13%, the money supply expanded by some 33% and inflation rose to 27% according to official statistics. On the parallel market the kyat depreciated to about k 65 to the dollar. The year 1988 was also one of political unrest, shutdowns of industry and general economic disorganization and in October 1988 the new government suspended most debt repayments.

1.7 The State Law and Order Restoration Council (SLORC) government in November 1988, announced a new shift in policy: towards a market orientation. The foreign investment law was partially liberalized; border trade agreements were realized with China, Bangladesh, India and Thailand; export earnings were allowed to be partially (and later fully) retained by private sector exporters for the purpose of purchasing imports; the Companies Act was reintroduced and amended; the Myanmar Chamber of Commerce was reformed (after a period of 26 years); new income tax regulations were introduced with lower tax rates; the production and pricing of agricultural products in the domestic market were mostly decontrolled; the SEEs were instructed to eliminate losses and were given more discretion in pricing and other management matters; and joint ventures were set up between the

government and the private sector. In 1989, MOGE entered nine onshore oil and gas 'participation' contracts with international oil companies, raising a total of some US$45 million in signature bonuses, and opening the door to large international companies. These contracts, in the event of a discovery and subsequent production, provide for much of the contractors' share of oil production to be priced at international oil prices. A number of these changes have meant that more and more transactions in the economy are taking place at the equivalent of international prices using the parallel exchange rate, which is seen by officials in the Ministry of Planning and Finance as a stepwise process towards an eventual liberalization of the currency.

1.8 The government has taken an official stand to encourage private sector participation in economic activities. The privatization of some state-owned farms has been agreed to in principle. However, privatization has been limited so far to returning small sawmills and ricemills to their previous owners before nationalization. In September, 1989 a new state-owned enterprise law was promulgated which redefined and limited the areas to be reserved for the public sector. To increase the profitability of the SEE's, some autonomy was also granted regarding the procurement and sales of products. A decision was also made to transfer all SEE accounts to a consolidated government state fund account. In the process the debts of the SEE's were written off and converted to state equity. This, in fact, was a backtracking on the announced SEE reforms since it put all SEE financial matters under the control of the central budget and had the impact of distancing the SEE managers from the issues of the cost of capital and of obtaining a return on the capital invested in the enterprise.

1.9 Though overall the direction of the government's policies is towards more efficient management of the economy, actions to date have fallen short since some essential steps have not been taken. The main price distortion, the exchange rate, has not been corrected and the government's deficit is increasing. The opening up of trade is still hampered by the multitude of restrictions and regulations. Foreign investment has increased but the domestic private sector still lacks adequate institutional and financial support. The SEEs are caught between having neither the autonomy they need nor the previous direction of central planning. The economic picture in 1990--with an official preliminary estimate of GDP growth of 7.4% for 1990 fiscal year--appears brighter, although it is widely believed that the rate of inflation may be much higher than officially recognized and is almost certainly on the increase. The budget for 1990 depends heavily on a continuing government deficit, partly as a result of increased 'public works' expenditures for things such as city parks and road widening, and the money supply is still increasing significantly. The public sector deficit rose to 14.4% of the GDP. The government has targeted a growth rate of 5.7% for the year to April 1991 but any optimism will have to be conditional on achieving political stability in the country, and realizing further steps towards economically viable policies.

Economic Forecast

1.10 The economy has in the past, according to official statistics, shown that growth rates of the order of 5%/yr are feasible. But for these rates to be achieved in the future will require some major changes in macroeconomic policies and the structural framework of the economy. For purposes of this report two economic growth forecasts have been used: a relatively high economic growth case in which GDP growth is projected at 5%/yr until 1996, and 6.5%/yr thereafter, and a second case in which the growth rate languishes around 3%/yr. The energy

sector, which provides k 580 million/yr in petroleum product taxes and k 800 million in operating surpluses of the SEE's, is critically linked to the economy's performance. The energy sector, in turn, could lead the way in generating financial savings both for the public sector generally, and therefore subsequently for investment in any sectors of the economy, given suitable policies. In fact the energy sector could be a key area where more market oriented and sound financial policies could be re-introduced into the SEEs, and the economy generally. It could be a dynamic force in liberalizing the economy; through raising investment, achieving greater financial viability and efficiency in management of the SEEs, through enhancing relationships between Myanmar enterprises and large international companies, through state-of-art technology transfers and through increasing export earnings.

B. Energy Resources and Production

1.11 Myanmar has diverse sources of indigenous energy. As of April 1990, the remaining recoverable proven oil and gas reserves onshore are estimated at 114 mmb and 139 bcf respectively, while the future discovery potential is estimated at 800 mmb of oil and 7,000 bcf of gas. The total coal resources in place are estimated at about 200 to 230 mtons. Hydropower resources are quite substantial, with a theoretical power potential of over 108,000 MW and 366,000 Gwh/yr of potential energy. However, the development of the hydro resources is relatively costly due to the distance of the better sites from the main transmission grid or their location in insurgency prone areas. Myanmar has a forest area of about 79.5 million acres or 47.5% of the total land area of the country, and this with non-forest trees and agricultural residues provides the potential for substantial and sustainable traditional energy supplies.

TABLE 1.1 FINAL ENERGY DEMAND BY SECTOR IN 1990
(mtoe)

	TRADITIONAL ENERGY			MODERN ENERGY					
Sector	Fuel Wood	Charcoal	Biomass Residue	Petroleum Products	Gas	Coal	Electricity	TOTAL ENERGY	Percent
Transport				362.5	0.0		0.0	363	4.0%
Industry			75.9	134.0	194.6	23.6	88.1	516	5.6%
Other				109.8	0.0		19.5	129	1.4%
Fertilizer				0.0	167.1		0.0	167	1.8%
Household	7181.5	535.6	227.8	7.3	0.0		48.3	8000	87.2
TOTAL	7181.5	535.6	303.7	613.5	361.6	23.6	155.9	9175	100.0%
Percentage	78.3%	5.8%	3.3%	6.7%	3.9%	0.3%	1.7%	100.0%	

Note: Secondary energy after all conversion and conversion losses

Source: Energy Balance Tables (1990)

1.12 Myanmar has, however, one of the lowest levels of energy consumption in the developing world--0.31 tons of oil equivalent (toe) per capita/yr in 1990. The total use of primary energy in 1990 was 12.4 million toe (or about 250,000 b of oil equivalent per day) with primary energy being supplied in the form of fuelwood including charcoal (76.7%), biomass (6.2%), domestically produced crude oil (5.0%) and imported oil (1.1%), natural gas (8.2%), hydroelectricity (2.5%) and coal (0.2%). In terms of secondary energy the largest consuming sector was

household (87.2), followed by industry (5.6%), transport (3.9%), and other users including fertilizer manufacture (2.3%).

1.13 Over 82% of total primary energy supply in Myanmar consists of traditional fuels, predominantly fuelwood, some charcoal and other biomass, reflecting the agricultural and rural nature of the majority of economic activities. The vast majority of traditional energy supply is firewood which is gathered on a subsistence basis, and for sale locally in rural areas. The production of charcoal is mostly for supplying the cities of Yangon and Mandalay. Crop residues, such as bagasse, are used seasonally for local steam raising. Quite unlike other developing countries, however, the proportion of traditional energy supply has shown a marginal increase since 1981.

1.14 A number of shifts in the use of primary modern energy fuels have occurred in the economy during the past decade: notably, the consumption of natural gas has increased its importance from 17.8% of primary modern energy in 1981 to 48.2% in 1990. The share of crude oil, consumed now in final form mostly as petroleum products for transportation fuels, has decreased from 72.8% to 35.2%. Hydro electricity has increased slightly from 9.0% to 15.4%. The share of coal has remained small, at around 1% of modern energy. The importance of oil and natural gas in modern energy supplies is evident as together they provide 84.1% of total modern energy. The per capita consumption of energy over the last decade has remained virtually stagnant.

TABLE 1.2 SUPPLIES OF MODERN ENERGY IN MYANMAR
1978 TO 1990

	Crude Oil		Gas	Coal		Elect	TOTAL MODERN	Self
	Prodn	Import/ Export		Prodn	Import/ Export	Prodn (Grid)	ENERGY SUPPLIES	Supply Ratio
	(mmb)	(mmb)	(bcf)	(tons)	(tons)	(GWh)	(mtoe)	%
1978	8.4	-0.8	21.4	28346	96814	677.6	1763.1	102.3%
1979	8.3	-1.1	19.1	11992	64594	690.1	1610.2	106.6%
1980	9.2	-0.7	21.5	13600	45751	1081.3	1858.5	103.5%
1981	8.6	-0.7	25.3	11036	23204	1227.8	1875.5	104.3%
1982	8.2	-0.7	23.9	16836	15917	1394.7	1787.9	104.8%
1983	7.8	-0.5	23.1	28494	20109	1551.8	1758.2	103.1%
1984	7.4	-0.7	22.7	35402	30560	1674.6	1672.6	104.5%
1985	7.8	0.0	29.5	43500	21386	1890.3	2006.4	99.3%
1986	7.0	0.0	35.5	43155	10101	2119.4	2067.6	99.7%
1987	6.0	0.0	40.4	37498	7155	2245.5	2062.6	99.8%
1988	5.1	0.0	41.9	38713	5258	2319.6	1983.7	99.8%
1989	3.6	0.5	39.1	29780	3491	2226.5	1765.4	96.0%
1990	4.4	1.0	38.0	38672	4147	2371.0	1931.3	92.8%
AAG* 1978/1985	-1.1		4.7%	6.3%		15.8%	1.9%	
AAG 1986/1990	-10.6		5.2%	-2.3%		4.6%	-0.8%	
AAG 1978/1990	-5.2		4.9%	2.6%		11.0%	0.8%	

Note: TOTAL ENERGY includes conversion losses in use of oil, gas and coal but only hydro component of electricityto avoid double counting; gas products such as methanol are included in gas. Electricity is amount produced before losses. Imports are given positive sign and exports negative.
* Average Annual Growth.

1.15 After allowing for conversion and other losses, the use of energy at the consumer level shows an even greater preponderance of traditional energy than the

sources of primary energy. Firewood provides close to 90% of traditional energy needs, and the share of charcoal has only increased slightly since 1981, to about 7% at present. One factor leading to the continuing high use of firewood has been the previous governments' policy to phase out the use of kerosene, which was reduced to only about 2 million gallons in 1990. It was previously used extensively for cooking and lighting, especially in rural areas, but also in urban centers. In cities and towns this policy has accelerated the use of electricity for cooking thus aggravating the peak demand. In terms of secondary energy, almost half of modern energy consumption is petroleum products while electricity only provides 13.5% of modern energy needs.

TABLE 1.3 CONSUMPTION OF MODERN ENERGY IN MYANMAR (1978 TO 1990)

	Petroleum Products (mmb)	Gas (bcf)	Coal (tons)	Electricity (Gwh)	TOTAL MODERN ENERGY (mtoe)
1978	6.4	11.8	104611	677.59	1315.8
1979	6.3	14.7	71316	690.09	1361.0
1980	6.7	17.7	48001	762.56	1478.8
1981	6.7	22.0	32102	853.48	1597.4
1982	6.4	20.4	30167	949.69	1517.9
1983	6.9	19.2	40829	1050.15	1552.6
1984	6.8	20.5	59563	1121.50	1590.0
1985	7.6	24.5	61690	1263.63	1816.5
1986	6.6	34.5	49432	1459.53	1952.0
1987	5.8	39.5	45004	1542.98	1990.2
1988	4.7	41.3	34059	1580.09	1882.7
1989	3.6	38.8	24954	1704.28	1664.8
1990	5.1	36.1	44166	1799.60	1814.4
AAG 1978/1985	2.4%	10.9%	-7.3%	9.3%	6.4%
AAG 1986/1990	-7.6%	8.1%	-6.5%	7.3%	-8.1%
AAG 1978/1990	-1.9%	9.7%	-6.9%	8.5%	2.7%

Note: Total includes conversion losses in use of oil, gas and coal but only hydro component of electricity to avoid double counting; gas products such as methanol are included in gas. Electricity is the amount consumed.

C. Energy Consumption

1.16 In each of the modern energy subsectors there are serious supply restraints which curtail potential demand. At present, electricity is frequently load-shed in all regions of the country. In the residential sector new connections to the grid have been markedly slowed down and they are unlikely to keep up with population growth. Natural gas is insufficient for the gas-fired generation plants, as well as for the fertilizer plants. Gas is also in short supply for industrial use; for example, at the Sittaung Paper plant, 90 miles east of Yangon, and in the country's main cement plant. The availability of petroleum product has dropped precipitously, and petrol and diesel are rationed, even within the government and its SEEs. Therefore, in the modern-energy subsectors the present consumption levels are considerably less than would be the case without widespread non-price rationing.

Petroleum Products Consumption

1.17 The consumption of petroleum products has been squeezed down from 7.6 mmb/yr in 1985 to 4.7 mmb/yr in 1990 (including methanol); the use of kerosene has plunged from 68.7 million gallons in 1975, to 4.8 million gallons in 1985,

and to only about 2 million gallons in 1990 while the potential demand is far higher than present sales. Consumption of all petroleum products is controlled through a rationing system, with allocations based on regional and other considerations including vehicle engine capacity, according to government priorities.

TABLE 1.4 REFINED PETROLEUM PRODUCT CONSUMPTION IN MYANMAR, 1980-1990 (million IG)

	1980	1985	1990
Diesel	89.6	102.7	83.8
Petrol and Methanol	70.2	76.3	50.0
Fuel Oil	47.6	49.0	24.6
Kerosene	19.7	4.8	2.2
Ave. Fuel	6.9	6.6	4.6
Other	7.0	33.5	0.5
TOTALS	234.1	266.3	165.7

MPPE estimates that existing potential demand for diesel and petrol might be between 80% and 160% higher respectively, than present consumption (at existing official prices): while this seems a huge excess demand, such levels would only be about 40% and 30% higher than actual consumption in 1984. Some 80% of the diesel market is government purchases, much of which is for government vehicles. In 1989, about 50% of total diesel consumption was for transporcation, followed by some 42% in industry but it seems probable that a large part of the 'industrial' consumption is also actually in transportation. Since the consumer price of diesel, at k 10.50/gal, is 60% lower than the price of petrol, the demand (and actual consumption) of diesel in transportation is growing faster than petrol: at 2.8%/yr in the period between 1980 and 1985--the peak consumption year before rationing became prevalent. Since then, and up until last year, consumption decreased because of supply shortages. Petrol consumption grew at only 1.7%/yr in the same period up to 1985, and has decreased in each year thereafter. The market for petrol, used in cars and light trucks and concentrated some 60% in Yangon, consists about 80% of privately owned vehicles. It has been estimated that up to about 40% of final sales to consumers are made in the black market, where prices run around k 150/gal in Yangon in contrast to the present government controlled price of k 16/gal.

1.18 In recent years some diversification of transportation fuels has been achieved by the introduction of methanol, Liquefied Petroleum Gas (LPG) and some Compressed Natural Gas (CNG) into the transportation market. Initially, the methanol and LPG projects were intended to supply the export market, but domestic requirements are so acute and supplies have not been up to expectations so that most output is consumed in Myanmar. Methanol is blended 80/20 (80% methanol) with petrol, priced at k 11.50/imperial gallon (IG), and sold regionally for some 13,000 specially converted vehicles. About 1400 cars have been converted to run on LPG, priced at k 11.50/IG, and about 350 vehicles to CNG.

Electricity Consumption

1.19 Over the entire decade of the 1980's, electricity consumption in Myanmar has grown at around 8%/yr on average. However, latest statistics show that the growth rate since 1985 has declined markedly to the low level of about 3.5%/yr.

These levels of growth are modest in comparison with the growth rates of electricity in many of Myanmar's Asian neighbors, despite Myanmar's low base of electricity usage (45kWh/capita in 1990). Growth of electricity demands from the domestic sector on the interconnected system over the last five years has occurred even though the connection of new consumers has been restricted, the rate of new connections barely keeping up with the population growth of about 2%/yr. Residential growth is generally thought to reflect increased use of electricity for cooking, resulting from the rising cost of charcoal and the absence of kerosene in the market. Industrial demand on the interconnected system accounted for 50% of consumption in 1990 and it is estimated that over 40% of the industrial electricity demand is in the Magway Division, where the principal industries, namely fertilizer, LPG and cement plants, are located and which compete with MEPE for gas supplies. A similar situation exists in Ayeyarwaddy, Mon and Yangon where it is also evident that electricity demand is suppressed by industrial fuel shortages. Taking into account the recorded electricity consumption figures for large industrial operations for the last three years, it can be deduced that if sufficient gas were available for large industrial operations, electricity demand could quickly increase in the order of 40% above current annual consumption.

TABLE 1.5 ELECTRICITY CONSUMPTION INTERCONNECTED AND RURAL SYSTEMS IN MYANMAR, 1980-1990
(GWh)

	1980	1985	1990
Residential	216.5	373.8	582.4
Industrial	407.4	654.8	1031.6
Bulk (Services)	109.3	195.5	183.1
Others	29.4	39.7	47.3
TOTALS	762.6	1263.6	1844.4

Source: MEPE

1.20 Electricity consumption in the rural areas shows an overall growth of 8%/yr but the electrification ratio has stayed constant at about 6% from 1984-1990. The rural load factor is very low (25-30%) reflecting fuel limitations for generation.

Natural Gas, Coal and Woodfuels Consumption

1.21 The use of natural gas has increased rapidly over the past decade from 10.9 bcf/yr in 1980 to an estimated 36 bcf/yr in 1990, but consumption in fiscal 1991 has been running at only about 33 bcf/yr because of gas production failures.

TABLE 1.6 NATURAL GAS CONSUMPTION IN MYANMAR, 1980-1990
(bcf)

	1980	1985	1990
Electricity Generation	4.1	11.3	19.9
Industry	3.4	4.5	8.0
Methanol/fertilizers/LPG	3.4	5.6	8.0
CNG			0.2
TOTALS	10.9	21.4	36.1

1.22 Coal consumption decreased markedly in the late 1970's but since then it has recovered somewhat.

TABLE 1.7 COAL CONSUMPTION IN MYANMAR, 1980-1990
(mtons)

	1980	1985	1990
Railways	35.2	17.9	1.7
Industry	13.6	13.2	12.9
Iron processing		30.3	25.8
Stock Change	-0.8	0.3	3.8
TOTALS	48.0	61.7	44.2

1.23 It is estimated that the annual per capita consumption of woodfuel is 0.7 adt ($0.9m^3$).

TABLE 1.8 CONSUMPTION OF WOODFUELS IN MYANMAR, 1980-1990
(mill CuT)

	1980	1985	1990
Fuel Wood	12.5	15.9	17.9
Charcoal	0.5	0.8	0.8

D. Forecasts of Energy Demand

1.24 Based on the macroeconomic scenarios and assumed sectoral growth rates, two principal energy demand forecasts and a number of demand sensitivity cases were developed for this report. The Base Case forecast is relatively optimistic and assumes that a number of essential energy strategy steps are undertaken, especially that oil field rehabilitation is accomplished, offshore gas resources are developed so that after 1996 plentiful natural gas is available for the domestic market, and petroleum product, natural gas and electricity prices are rationalized. The forecasts are based on a continuation of low prices being maintained in real terms; the demand would be significantly lower if the energy prices were increased. In the Base Case, over the period to the year 2005, total modern energy consumption is forecast to increase at about 4.8%/yr in the context of economic growth which averages 6%/yr over the period (Table 1.9). Petroleum product consumption increases at 7.4%/yr, and electricity at 7.5%/yr. The second forecast--the Low Case--assumes that the economy grows at the slower rate of 3.0%/yr and modern energy consumption grows at the rate of 3.1%/yr, petroleum products at 4.5%/yr, and electricity at 4.3%/yr. Traditional energy is assumed to grow at the same rate of 21%/yr in both cases since it is tied to the rate of growth of the rural population. The Base Case is summarized in Table 1.9, showing the final consumer demand (secondary energy) for petroleum products in the transportation, industrial and other sectors, coal for industrial uses, etc., and electricity demanded from the interconnected grid and from the isolated rural system. It shows the allocation of natural gas between the power sector and other uses. The critical demands of the electricity sector for diesel and fuel oil are shown to reach about 1 mmb in 1992. These oil requirements are relieved only in late 1995 with the development of the offshore gas reserves.

TABLE 1.9 BASE CASE: MODERN ENERGY CONSUMPTION FORECAST

Year	Petroleum Products		Natural Gas		Coal	Electricity	
	Transport Ind. etc. (mmb)	Elect (mmb)	Industry etc. (bcf)	Elect (bcf)	(mtons)	Grid (GWh)	Rural (GWh)
1990	4.7	0.44	16.2	19.9	44.2	2371	138
1991	4.9	0.78	15.6	19.7	45.0	2552	152
1992	5.3	1.14	9.8	20.1	45.9	2718	158
1993	5.6	0.94	7.7	17.8	46.9	2896	163
1994	5.9	1.00	7.3	15.4	47.8	3087	170
1995	6.3	0.38	21.4	19.7	48.8	3247	174
2000	9.4	0.48	18.1	34.4	53.8	4593	201
2005	14.7	0.41	12.5	35.5	59.4	7207	262
Growth to 2005%	neg	neg	3.9%	2.0%	7.7%	4.4%	

Note: Base Case assumes that Hoattama offshore gas reserves are developed and commence production in late 1995; and onshore oil and gas proved and probable reserves are rehabilitated and developed beginning in 1992. Gas use in industry is the residual supply after allowing for electricity needs.

Source: Mission estimates (1991)

Petroleum Product Demand Forecasts

1.25 The present excess demand for petroleum products has been created to a large degree by the extremely low official prices, and the decline of domestic crude oil production. For some products and markets, like petrol and diesel used for transportation, the excess demand in the official market spills over into the black market where the black market price serves in the end to equilibrate demand with available supplies. In those instances, when the official market breaks down, the black market serves finally to allocate products through a market-determined price. However, the excess demands for fuels such as fuel oil (and diesel) used in the industrial market, or fuel oil and diesel used for electricity generation, are curtailed primarily by simply reducing industrial production or electricity generation. These factors make it difficult to assess present consumption figures for the purposes of forecasting future demand and consumption of petroleum products. The black market prices provide a guideline for prices that might equilibrate the product markets.

1.26 The forecast product growth rates are separately linked to the forecast growth rates of GDP in the economy. Diesel, aviation fuel and other products are linked to industrial GDP; petrol, fuel oil and methanol are linked to total GDP; and kerosene demand is linked to agricultural GDP, in each case through elasticities which have been assigned based on the experience of other less developed countries. The resulting average elasticity of demand for total petroleum products with respect to GDP ranges between 1.3 and 1.7. While no specific kerosene policy base been introduced, kerosene consumption is forecast to grow faster than all other products in each of the forecasts. This follows from the assumption that adequate domestic crude oil supplies are available after 1996 and with prices related to international levels the allocation system becomes redundant, so that kerosene becomes freely available. The Base Case and Low Case forecasts each assume that petroleum product prices are raised to be close to international levels by the end of 1993, and the forecasts show only a gradual pick-up in demand in the period from 1991 to 1996. In the Base Case

after 1996, when it is assumed that new domestic oil supplies will be available and the economy will grow at an average of 6%/yr, total product demand is forecast to increase at slightly more than 9.0%/yr. The Base Case forecast for the main products is summarized below:

TABLE 1.10 BASE CASE FORECAST OF PETROLEUM PRODUCT CONSUMPTION IN MYANMAR, 1991-2010
(million IG)

	1990	2000	2010
Diesel	83.8	188.1	496.8
Petrol	38.1	73.1	174.7
Fuel Oil	24.6	35.8	52.5
Kerosene	2.2	5.5	28.8
Methanol/petrol	11.9	15.3	28.7
Other	5.1	-11.5	29.9
TOTALS	165.7	329.3	811.4

Source: Mission Estimates (1991)

Electricity Demand Forecast

1.27 The country's 40 million population can be considered in two principal electricity service areas comprising: (a) areas served by the interconnected system--the six principal lowland divisions of Yangon, Mandalay, Ayeyarwaddy, Bago, Magway and Sagaing with a population 28 million and including the major urban areas; and (b) rural areas served by isolated systems--the remaining territories comprising Shan, Mon, Kayin, Kachin, Chin and Kayah States together with Tanintharyi and Rakhine divisions with a population 9 million. Industrial, Residential and Services demand are assessed separately. Growth in the urbanized towns supplied by the grid are largely affected by general economic conditions, and by the supply capability of the system. In the rural areas growth is also affected by political and guerilla activity, and by the limited access to these areas by road and waterways to be able to operate and expand existing facilities. Using the results of econometric analysis and analysis of electricity demand in other countries and in relation to the undersupplied electricity market in Myanmar, two principal forecasts have been derived (Table 1.6): a Base Case and a Low Case. The parameters underlying these forecasts are as follows: (a) forecasts of industrial GDP growth rates and relationships to industrial electricity demand growth (industrial GDP elasticity of 1.3); (b) forecasts of services sector GDP growth rates and relationship to other/services electricity demand growth (services GDP elasticity of 1.2); (c) forecasts of urban population growth rates and relationship to residential electricity demand growth (urban population elasticity in the range of 1.6 to 2.6); (d) estimated operational load factors, reflecting the existing and expected load shedding in the system. This load factor is used to estimate the "unserved demand", and it declines in the Base Case from 75% to 67%; the latter level considered to be "normal" for the MEPE system; and (e) estimated loss factors of a technical and non-technical nature, beginning at 21% and 10% respectively and assumed in the Base Case to be reduced through actions by MEPE to the levels of 14% and 2% over the decade to 2001.

TABLE 1.11 SUMMARY OF ELECTRICITY DEMAND FORECASTS 1990-2010
Interconnected Systems

Year	Base Case		Low Case	
	(GWh)	(MW)	(GWh)	(MW)
1989/90	2371	376	2371	376
1994/95	3247	530	2897	446
1999/00	4593	771	3466	573
2004/05	7207	1227	4499	766
2009/10	11653	1985	5995	1021
Av. Growth	8.4%	8.7%	4.8%	5.2%

Isolated Rural Systems

Year	Base Case		Low Case	
	(GWh)	(MW)	(GWh)	(MW)
1989/90	138	61	138	61
1994/95	173	70	162	67
1999/90	201	74	170	68
2004/00	264	89	201	77
2009/10	352	112	242	89
Av. Growth	4.8%	3.2%	2.9%	2.0%

Source: Mission Estimates (1991)

1.28 The Base Case forecast reflects an optimistic scenario where electricity demand on the interconnected system increases by an average of 8.4%. After 1995, it is assumed that growth will accelerate as gas supplies from the offshore Moattama field become available in sufficient volumes to supply demands of both MEPE plants and industry. The Low Case forecast reflects a pessimistic scenario where electricity demand grows at about 4.8% and unsupplied demand persists until the end of the 1990's.

Rural Electrification

1.29 Unlike most of its Asian neighbors, MEPE has no strategy for expanding its rural electrification program. In 1979 the number of villages electrified was 709. It rose to only 751 in 1989. Approximately 20% of MEPE's consumers (9% of total demand) are served by isolated diesel/minihydel power stations scattered over the 14 Divisions/States of Myanmar. The number of diesel engines has increased from 570 by only 60 since 1985 and the rate of growth of new consumers and consumption in these areas is significantly lower than for the interconnected system. The growth in rural systems is forecast at 4.8%/yr in the Base Case and some 3%/yr in the Low Case. It may be noted that some rural growth, as it may be connected to the grid, is assumed to be included in the forecast for the interconnected system.

Traditional Energy Demand Forecast

1.30 Woodfuel consumption is forecast to increase at a continual growth in the order of 2%/yr, composed of 1.95%/yr for urban areas and 2.05%/yr for rural areas in the period to 2000, and 1.9% and 2.0%/yr thereafter, based on a population growth of about 2%/yr with only limited substitution of modern fuels for traditional fuels in the period to the year 2005.

1.31 The objective of this report is to review the prospects for exploitation of the country's energy resources and to formulate medium and long term plans for national energy development during the period 1991-2010. The energy resources of Myanmar are evaluated in Chapter 2. The oil and gas sector, which is the crucial growth subsector in the short and medium term, is reviewed in Chapter 3, while the implications of future hydrocarbon supplies on the refinery and petrochemical sectors are examined in Chapter 4. The development of the power sector is the focus of Chapter 5, while Chapter 6 is devoted to traditional energy supplies. A critical issue in Myanmar has been energy pricing; this is examined in Chapter 7. Concurrently with issues of energy pricing are those of an institutional and financial nature; these are reviewed in Chapter 8. Finally, an energy sector investment program, based on this analysis, is indicated in the final chapter.

II. ENERGY RESOURCES

A. Introduction

2.1 The indigenous modern energy resources of Myanmar include crude oil, natural gas, geothermal, hydro and coal.[1] These reserves are diverse but, based on the exploration effort expended till date, the proved reserves are neither very large nor low cost. There is, however, considerable potential which still needs to be explored effectively if the country is to make optimum use of its resource endowments.

2.2 Myanmar also has an excellent forestry potential which provides for almost 80% of the country's total energy consumption. The indigenous forest potential, however, needs to be carefully husbanded if it is to continue to play an important role in the traditional energy sector. As regards other nonconventional energy resources such as agricultural residues, wind power, solar etc., they could be exploited to make a greater contribution to energy supplies, particularly in helping reduce pressure on fuelwood resources, but in the short to medium term, their contribution is unlikely to be significant.

B. Oil and Gas

2.3 Oil occurrence in Myanmar has been documented and exploited since antiquity from seepages and shallow hand dug wells in the neighborhood of Yenangyaung in Central Myanmar Basin. Intensive exploration for oil, started by Burma Oil Company following the British annexation of Upper Myanmar, resulted in the discovery of the Yenangyaung field in 1886 and other significant oil discoveries along the structural trend of Yenangyat-Chauk-Minbu. The initial discoveries were made by drilling surface anticlines (essentially all topographic highs as well) associated with active oil seeps in the Central Myanmar Basin. This early effort (1886-1940) succeeded in finding some 500 mmb of oil and 290 bcf of gas, mostly at shallow drill depths. The period 1940-62, interrupted by severe damage to wells and field facilities during the second world war and a subsequent flood of the Ayeyarwaddy River, witnessed the costly and time consuming rehabilitation of production facilities and the initiation of exploration in areas removed from the early discoveries. In 1962 the industry was nationalized and all activities absorbed by the national enterprise (MOGE and predecessor organizations). National efforts were quite successful in building upon prior efforts, over 20 discoveries being made by MOGE, and an additional 130 mmb oil and 73 bcf gas were found during the ensuing period (1962-80). In the mid-1970's offshore tracts were awarded to foreign international companies but though a number of wells were drilled, no commercial discoveries were made. In the early 1980's MOGE, with assistance from the Japanese, made several discoveries offshore, the most important of which was the 3-DA gas field in the Gulf of Moattama. Onshore discoveries by MOGE since 1980 have, however, been very modest amounting to about 15 mmb oil and 24 bcf gas, the principal discovery being the Kanni field in the Central Burma Basin immediately south east of earlier finds. Oil and gas production in Myanmar reached a peak of 11.154 mmb/yr in 1984/85 and 41.95 bcf/yr in 1987/88 respectively (Table 2.1).

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[1] See map IBRD 22976 Hydrocarbon Resources

TABLE 2.1 MYANMAR: OIL AND GAS PRODUCTION

Oil Production (barrels per day)

Field	79/80	80/81	81/82	82/83	83/84	84/85	85/86	86/87	87/88	88/89	89/90*
Mann/Minbu	22823	20162	20347	18016	17840	16669	12357	9155	7281	5938	6330
Htaukshabin	198	954	1696	1857	3440	7886	10045	8178	4753	3140	2450
Yenangyaung	3104	3176	3310	3393	3625	3529	3462	3060	2906	2334	2302
Chauk	1020	1039	1003	1052	989	979	947	880	814	622	691
Kanni	0	0	0	0	0	0	52	282	312	886	2660
Others	2973	2283	2271	2406	1861	1496	1108	1105	719	750	759
Total (bpd)	30,118	27,614	28,627	26,724	27,755	30,559	27,971	22,660	16,785	13,670	15,1920
Total (mmb/yr)	10.993	10.079	10.412	9.754	10.131	11.154	10.209	8.234	6.126	4.990	5.534

Gas Production (bcf)

Chauk	3.186	3.060	3.089	2.623	1.978	2.854	4.833	5.887	6.183	5.122	5.209
Ayadaw	3.607	4.942	4.723	5.212	6.683	7.398	5.647	4.180	4.340	4.170	4.606
Htaukshabin	0	0	0	0	0	0	0	1.035	3.043	3.451	1.763
Peppi	0.043	0.014	0.072	0.148	0.005	0.021	0.013	0	0.150	0.983	1.734
Kanni	0	0	0	0	0	0	0	0.090	0.124	0.135	0.824
Shwepyitha	3.623	3.674	3.343	3.316	1.929	2.834	3.581	5.960	7.515	7.174	7.267
Pyi (Prome)	0	0	0	0.752	0.799	1.522	6.953	7.012	6.931	7.384	7.205
Payagon	0	0	0	0	0.175	2.014	3.994	6.873	6.825	6.587	7.402
Others	1.716	2.080	2.344	3.329	3.465	3.691	3.384	3.496	3.540	1.760	*3.500
Subtotal	12.175	13.770	13.571	15.380	15.034	20.334	28.405	34.533	38.651	36.766	39.510
Associated Gas	9.569	11.070	10.166	7.687	7.637	9.117	6.635	5.020	3.264	2.328	*2.000
Total (bcf/yr)	21.744	24.840	23.737	23.067	22.671	29.451	35.040	39.553	41.915	39.094	41.510

Note: *The production drop in 1988/89 was due to unsettled conditions in the country
Source: MOGE *Estimated

2.4 Data available for assessment of future production potential is, however, highly variable in extent and is of limited quality. In the more prolific Central Myanmar Basin most of the data is field specific both in regard to wells and seismic profiles. Well data in the central portion of the Ayeyarwaddy Delta/Offshore Basin is fairly extensive but seismic data is less extensive and of generally poor quality. Important other areas, i.e., eastern or Pegu Ywama area and SW coastal area of the Ayeyarwaddy Delta/Offshore Basin, the SW and highly structured area of the Central Burma Basin, the Eastern Platform, Chindwin and Hukwang Basins, contain very limited seismic information and have been drilled very sparsely. Thus, any assessment of potential involves a few areas with ample data and many areas of no data and requires a high degree of interpretation to mesh these into a rational model.

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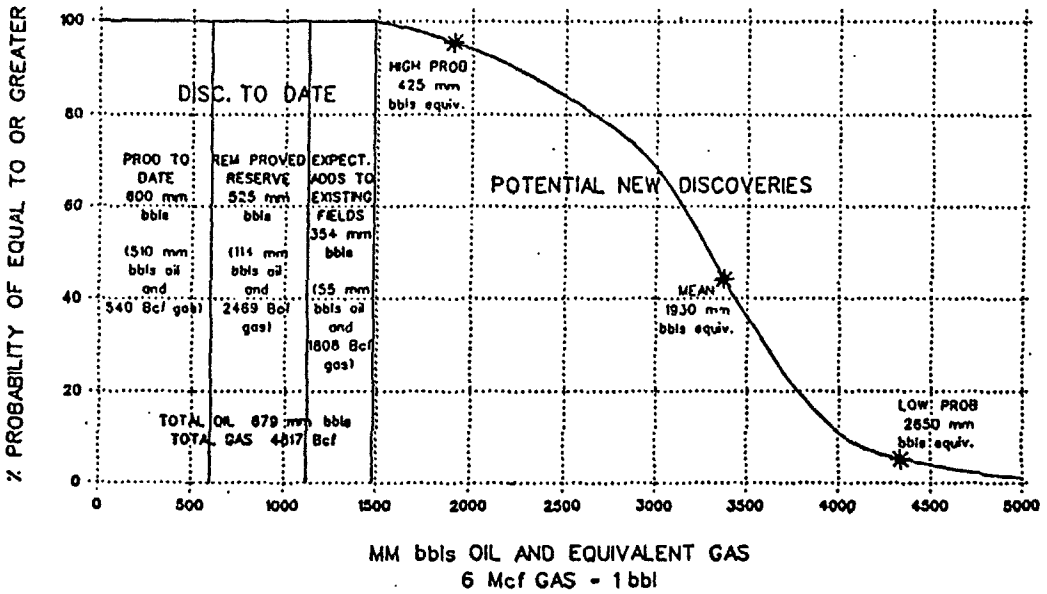
PAST DISCOVERY AND FUTURE POTENTIAL



2.5 Past exploration has already yielded onshore proved and probable recoverable reserves of about 815 million barrels of oil equivalent (mmboe), comprising 679 mmb oil and 817 bcf gas. Substantial gas reserves have been discovered in the Gulf of Moattama 90 kilometers from the shoreline in water depth of about 45 meters; the most important accumulation being a miocene carbonate build up in 3-DA structure and an overlying upper miocene sand sequence in MOC-8 about 5 kilometers away. While MOGE estimates the in-place reserves to be 7 tcf, according to mission estimates, based on wells drilled till date, the recoverable reserves are about 5 tcf, of which 1.6 tcf can be considered to be proved at this time. The remaining gas potential could be promoted to the proven category following the drilling of 3-5 wells of which 2 wells should be drilled in the 3-DA structure. Based on analysis of seven proved and two indicated generic hydrocarbon plays in the five basins comprising the Central Burma Tertiary Trough, the future onshore and offshore discovery potential for Myanmar is estimated to range from 425 mmboe to a maximum of 2,850 mmboe, with a mean expectation of 1930 mmboe (roughly 800 mmb oil and 7,000 bcf gas), of recoverable reserves (Annex 2.1). The prospective areas are the Chindwin and Eastern Platform Basins, which are undergoing their initial exploration by the production sharing contractors (PSC); the shallow marine and bay and marsh area in the SW Ayeyarwaddy Delta/Offshore Basin, where significant additional gas discoveries are possible, both from limestone reservoirs similar to offshore 3-DA and sandstone reservoirs similar to MOC-8; and the SW part of the Central Burma Basin, where Oligocene sandstones and Eocene sandstones may provide significant gas and oil finds.

2.6 Both the estimation of discovered reserves and potential for future discovery are made with a certain degree of uncertainty somewhat peculiar to Myanmar. With only few exceptions the productivity of the reservoirs in Myanmar is well below expectations relative to the same age, depth, and type of reservoir found elsewhere in the world. Thus reservoirs that would yield economic rates elsewhere are sub-economic in Myanmar and the recoverable fraction (% recovery factor) from reservoirs is likewise less than would be normally expected. This could be due to the petrophysics of Myanmar reservoirs being sub-optimal or it could be due to drilling and completion technology of MOGE damaging the reservoirs near the well bore, or perhaps both factors are involved. At least in some situations it is known that volcanic detrital, tuff and the like, adversely affect the reservoir. In most situations it is obvious that MOGE equipment and material are lacking to perform drilling and testing operations in an acceptable fashion. The lack of cores in nearly all and porosity logs in most important reservoirs contribute to the dilemma. The acquisition of this important data on all future wells is essential for estimation of resource potential and for effective reservoir management.

2.7 Myanmar has recently awarded exploration licenses to ten companies (or groups of companies) on nine onshore and two offshore blocks with a minimum work commitment of 29 wells, with the first wells being spudded in early 1991. Approximately 32 percent of the estimated future discoveries are covered by these licenses (55 percent of the oil potential and 15 percent of the gas potential). The decision to award production sharing contracts to international oil companies in 1989 has stimulated exploration; at the very least a number of potentially attractive areas will be subject to exploration for the first time. Given the long time intervals normally required between initial exploration in new areas to the onset of production, even with early success significant contribution to Myanmar oil production is unlikely before 1996. Gas discoveries will require even more time. Thus license awards will do little in the short term to increase oil and gas production in the country.

2.8 MOGE would need to continue its exploration and delineation work in the areas that are not licensed to foreign operators but its exploration program needs to be carried out using the latest technology. Its exploration could also become more efficient (even under existing operating conditions) if more pre-drill seismic is applied. The average of 34 line km per exploratory well is exceedingly low, being about 1/10 of industry norms and a larger seismic effort and fewer wells would surely yield better results. Wells should be drilled with balanced non-damaging mud systems so that well bore gauge is maintained, and full cement coverage obtained; blow-out preventers must be used; mud-logging required on all exploratory and key field wells; high quality mud and additives utilized with efficient mechanism for solids removal from circulated mud; all appropriate cores taken and logs run; high quality cement and cementing equipment procured, with relevant stimulation material and equipment available as required; and appropriate production testing tools and procedures utilized. Even low quality reservoirs can be stimulated to improve productivity and ultimate recovery by improvements in drilling, well completion and production technology.

2.9 Due to the semi-isolation of MOGE from the world petroleum industry over the past several decades, training designed to update capabilities in the use of current technology is needed. Fortunately much of this training can be covered by association with the joint-venture and secondment arrangements in the current licensees. MOGE's current secondment program (one-year rotational basis) is designed to provide exposure and training to the maximum number of people, but it does not provide the opportunity for the foreign companies to absorb these people into their operations or provide for long term contribution to foreign company operations in Myanmar. The current secondment program will be beneficial to MOGE only if they can assemble the resources to launch a strong independent program. Any increase in exploration effectiveness of MOGE is thus critically dependent on import of appropriate technology, upgradation of skills of its trained manpower and absorption of modern oil production techniques through association with joint-venture contractors.

C. Coal

2.10 To date some 15 coal deposits have been identified in Myanmar:[1] two of these, Namma and Kalewa, are presently being mined. The remainder are in several stages of evaluation ranging from explored and evaluated, undergoing exploration, or merely identified and awaiting exploration. There are probably many more coal occurrences which have not yet been tabulated. Data concerning the geology of Myanmar deposits is somewhat dispersed and not easily accessed. Coal beds are known to occur in Miocene, Eocene, Cretaceous, Jurassic and Carboniferous age sediments. More than 90% of known coal reserves are located in the Chindwin Basin and margins; more than 80 percent is Eocene in age, and more than 95 percent is sub-bituminous rank. However, two-thirds of the of the current production is located in the Shan highlands, is of Miocene age and lignite rank.

2.11 Several promising deposits are found along the lower reaches of the Chindwin river as well as in the southern part of the country. In Sagaing division there are three major coalfields: the largest Kalewa coalfield, along side the Chindwin river, also sustains the only underground coal mine in the country. The other two important coal deposits are at Paluzawa-Chaungzon and

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[1] See map IBRD 23051 Coal Deposits

Dathwegyauk further north of Kalewa. The only other deposit of commercial interest is located at Namma near Lashio township in northern Shan State. The coal is lignitic in character; the reserves are limited, estimated to be only 2.8 million tons and one seam which attains a thickness of 50 ft. is being exploited by open-cast method. There are no other deposits in the country which are commercially exploited though some of their reserves are adequate to sustain local energy demand for brick making, steam raising, etc. Occurrence of coal deposits in Myanmar is shown in Table 2.2 below:

TABLE 2.2 ESTIMATED COAL RESOURCES IN PLACE IN MYANMAR

Coal fields	Location	Coal	Estimated Reserves (mmtons)	Category
Dathwegyauk	Sagaing Div.	SB	34	P_4
Paulu zawa-Chaungzon	"	SB	89	P_4
Kalewa	"	SB	5	P_1
			18	P_2
			105	P_3
Kyobin	"	SB	S	
Mahudaung	"	L	1	P_3 & P_4
Thinbaung	"	L	S	P_3
Namma	Shan State	L	2.8	P_2
Samlaung	"	L	1.6	P_2
Si-gyit	"	Not explored		
In-byin (kalaw)	"	SB	S	P_4
Lwegye	"	Not explored		
Kyauktaga	Magway Div.	SB	S	P_3
Myeni	"	SB	S	P_3

SB-Sub-bituminous and L-Lignite;
S-Small deposit, less than 0.5 million, P_1 - proven, P_2 - Probable, P_3 - possible and P_4 - Potential
Approximately one third of these resources might be recoverable, if proven.

2.12 The Kalewa coal deposit was first discovered in 1886 and during the next several decades the Geological Survey of India reported coal occurrences extending more than 115 miles north and south of Kalewa, but other than field mapping very little exploration work was done. During the 1950's, some mine development work was taken up by the Burma Geological Department. This period also coincided with foreign collaboration with Krupp from Germany and Pierce Management Inc. from the USA for the development of the coalfield. Several bulk coal samples were sent abroad for analyses and tests for determining carbonization and briquetting properties of the coal but the results were not very encouraging. In 1956, Powell Duffryn from the UK, was hired for technical advisory services and for opening a coal mine, but that effort was not successful either.

2.13 The Kalewa coalfield, divided by the Myitha river running west to east, is on the Western limb of a major syncline with a consistent North-South strike and an average dip of 45° to the east. Though more than 50 coal seams have been identified, only 5-6 seams attain any minable thickness. The coal seams can be grouped into the Upper and Lower Coal Measures separated by about 1,000 ft. of barren strata. On the north bank of the Myitha river, a small creek (Waye Chaung) runs between the two Coal Measures from north to south and joins the river. The UC coal seam (thickness 10 ft.) in the Upper Coal Measure which is

generally free from shale bands receives the most attention. About 300 ft. above and 300 ft. below the UC seam are two workable seams UA and UD which are 4 ft. and 7 ft. thick respectively. The seams in the Lower Coal Measures are superior in physical structure and hardness, but are generally less in thickness. Two seams LD and LE which are 6 ft. and 3.5 ft. thick respectively are also considered minable. The immediate roof and floor strata of all coal seams generally consist of soft shale or mudstone. A drilling program initiated by Pierce Management Inc. in 1953 together with Mineral Resources Development Corporation (MRDC) of Myanmar put down 22 holes in the Upper Coal Measures and 18 holes in the Lower Coal Measures. All these were located within 2-2.5 miles north of the Myitha river, and no holes were drilled on the south-side. Another hole was drilled in 1971 about one mile north of the previously covered area.

2.14 A scrutiny of the exploration records shows that choice of locations of the boreholes were not always optimal. Many borehole locations, their surface collar level and the elevation of borehole bottom were incorrectly recorded and some borehole logs are missing. Despite these shortcomings, the boreholes established that the major coal seams previously identified from the surface mapping continue up to a depth of about 550 ft. and 770 ft. in the Upper and Lower Coal Measures respectively, below the Waye Chaung floor level. It also indicated that the area covered so far was generally free from major geological problems. Based on the drilling program and past and present mining operations which cover only a small distance north and south of the Myitha river, the reserve lying within this area was first estimated to be 25.9 million tons. This was later revised to 109.8 million tons by MRDC in 1964 which covered additional areas up to 18 miles to the north of the river and 5 miles to the south. Krupp, who worked in Kalewa in 1950's and again in the 1970's has placed the total reserves at 128 million tons (Annexure 2.2).

2.15 Paluzawa-Chaungzon coalfield, located about 18 miles north of Kalewa, seems an extension of the same geological formation. More than 50 coal seam exposures ranging in thickness from 4 inches to 7 ft. were identified, of which only two seams (5 ft. and 7 ft.) attain minable thickness. The strike direction of the strata is north-south with coal seams dipping 25°-45° to the east. Though no boreholes have been drilled, MRDC has estimated that 89 million tons of additional reserves of potential category exist there. Information about Dathwegyauk, 60 miles further north, is very limited but it has a potential reserve of 34 million tons and is reported to have favorable mining conditions. However, the relative inaccessibility of the place makes it unattractive for any mining venture.

2.16 The total coal production in Myanmar reached a peak of 43,500 tons per year (tpy) in FY84 but has dropped to 29,780 tons in FY89. The annual production from Namma mine has varied from 8,000 to 30,000 tons but the present method of mining has only limited prospect due to the high overburden ratio in the future and limited proven reserves. Kalewa, though a small mine with an average production varying from 10,000 to 15,000 tpa, has prospects for future development. The main uses at present of coal are for small scale power generation, mineral processing industries, and sponge iron production, in almost equal proportions.

2.17 The present estimates of coal reserve in Kalewa vary from a low of 26 to a high 128 million tons of proved, probable, possible and potential category up to a very limited depth from the surface. Out of this, only 5 million tons are considered proven. Since the other coalfields are very remotely located, and it is not possible to cheaply transport the coal to major consuming centers, it

seems advisable to concentrate any immediate future production program from the Kalewa coalfield alone.

2.18 But there are two major constraints to the development of Kalewa coal. It has to be transported first by trucks and barge and then by rail to the major consuming centers. This raises the delivered cost of coal from k 350 per ton at the pithead to about k 574 at Monywa.[1] The coal being naturally friable, breaks down into smaller sizes as the number of loading/unloading points increase but the existing demand is for lumpy coal for open grate boilers designed to burn imported lumpy coal which are no longer available. However, no such lumpy coal is required in cement and brick kilns where the use of gas can be easily replaced by coal and for lime kiln, tobacco curing, and for heating and steam raising in miscellaneous industries. The high volatile content, low sulphur content and good burning characteristic of Kalewa coal make it ideally suitable for pulverized fuel and fluidized bed boilers for power generation. If the fine coal could be used near the mine site at Kalewa, it could also solve the transportation and marketing problems of small coal.

Strategy for Growth of Coal Sector

2.19 It is clear that only Kalewa coalfield has adequate reserve to offer reasonable prospect for development as an energy base. The most important use of Kalewa coal could be power generation and it can reasonably sustain 200 MW of power generation. But the knowledge of reserves is inadequate and an exploration program needs to be initiated to determine the minable reserves.

2.20 Detailed exploration of the Kalewa coalfield, both north and south of the Myitha river for a distance of 3-17 km along the strikeline and 350-450 meters. along the slope length needs to be carried out. The area further north including Paluzawa-Chaungzon should be covered only by regional drilling at present. This will provide a firm basis for mine planning and design in the near future and for long-term development of the coalfields. The exploration will involve about 25,000 meters of diamond drilling, partly coring and partly non-coring, and geophysical logging. The estimated cost of such a program is placed at US$5.5 million with the regional drilling an additional US$1-1.5 million dollars. The detailed drilling of the prospective mining blocks will take about two years and regional drilling an additional year.

2.21 Available expertise within the country for detailed coal exploration, mine planning, design, operation and management are very limited. Drilling program may have to be assigned to foreign parties who could undertake the work in collaboration with local geologists and drilling crew. A coal survey laboratory to undertake proximate and ultimate analysis of coal ash analysis, petrography, carbonization tests, etc. would be required at a cost of US$5 million, and a training center would need to be established at site where some theoretical and practical training could be imparted. An alternate possible approach to coal exploration and development would be the invitation of foreign parties to enter into production sharing type contracts with the government.

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[1]Average sale price at Monywa rail head is k750 per ton for lump coal, k365 for run-of-mine coal and k177 for fine coal.

D. Geothermal

2.22 Some 92 areas in Myanmar have been identified as having surface manifestation of geothermal resources. All of these are in the form of hot springs, none show geysering or fumarole activity. The hot spring areas have surface temperatures ranging from 35-65°C and appear to be related to deep-seated faulting rather than Pleistocene or older surface volcanic activity. These lie in 23 different areas: nineteen are associated with the Shan fault system, two with the Thayetma (cross fault) system and two with the Rakhine fault systems. These latter two are associated with mud volcanoes at Chauk and Minbu (Mann field) where undercompacted Eocene Yaw shale has been brought to the surface containing water temperatures representative of several thousand meters of burial. The others are thought to be the result of convection where deeply buried and hot water aquifers leak to the surface along fault planes. The fact that none of the hot springs areas can be directly tied to relatively young volcanism suggests that none can be considered commercially exploitable, either by hot water or steam, for generation of electric power. Lesser uses may of course be feasible.

2.23 The Yinmabin area southwest of Monywa has the highest predicted subsurface temperature 388°C (depth unknown) based on extrapolation of solution temperatures of associated minerals and may be associated with young volcanism. Springs in the Thandaung, Chaungzon, and Kawthaung have the highest surface temperatures, i.e., exceeding 60°C. These four areas appear to warrant priority for future investigation, particularly if low entropy utilization becomes feasible, and any further exploratory work, e.g., electric resistivity surveys and slim-hole drilling, to establish temperature gradients, should begin in these areas.

E. Hydroelectric Power

2.24 Myanmar has an abundance of potential hydropower resources in its river systems which drain the four main basins of Ayeyarwaddy, Chindwin, Thanlwin and Sittaung. The hydro power potential of the country is estimated to be more than 100,000 MW on an installed basis. This potential compares to the present development of 280 MW of installed capacity which represents less than one half of one percent of the country's theoretical potential.

2.25 Although the vast hydro resource is spread widely throughout the country, the existing installations--Lawpita(168 MW), Kinda (56 MW) and Sedawgyi (25 MW)--and those under construction, Baluchaung #1, are close to the main load centers and the power grids of the central region. Many other sites off the grid have been identified and include large hydro and mini-hydro in the central and the outlying regions.

2.26 In 1978 the consultant NEWJEC, under IBRD/UNDP funding, identified various theoretically potential schemes associated with the eight principal rivers flowing through the country and listed 23 previously identified proposed projects (total 5,729 MW) for review and closer examination. Subsequently to date 25 schemes totalling about 9000 MW have been identified by MEPE for further detailed investigation. Since 1981 the development of four schemes have been fully evaluated to the feasibility and/or design stage including Paunglaung (280 MW - Norconsult, Norway 1982), Baluchaung #3 (28 MW - Nippon Koei, Japan 1985), Anyapya (12+9 MW - Hydroplan/Decon/Gopa, Germany 1984), Zawgyi (18 MW - IVO, Finland 1990). The two latter stations are remote from the existing transmission

system and as such are being developed for local use only.

2.27 Paunglaung #2 (280 MW) ranked amongst the best of the original schemes in terms of the cost of energy delivered. It was somewhat costly compared with competing stations and has less live storage capacity. Nevertheless, since Paunglaung was the most accessible site, it was taken to the next stage of development. The consultant Norconsult performed a feasibility study and detailed design of that scheme in 1982 funded bilaterally by the Norwegian government. In 1987 Norconsult, in conjunction with an IDA team of experts reviewed the design. A number of technical issues were resolved before proceeding with the project including the resolution of matters relating to the optimization of the dam height, spillway construction, cofferdam design and diversion floods, rockfill dam slopes, irrigation aspects and operational conditions. As a consequence of resulting changes in the design the revised optimum multipurpose project were estimated at US$492 million. Approximately 16% of the project costs were assigned to providing water supplies to eleven local irrigation schemes to supplement existing supplies from the Yezin damsite. In a subsequent review of the cost estimates in May 1990, Norconsult provided a new estimate of project financing requirements of US$594 million (i.e., US$2120/kW) exclusive of interest during construction. Their revised multipurpose scheme (280 MW, 190m high water level, total storage 680m^3, annual production 941 GWh) also reduced the scope of the irrigation component to serve an area of only 4320 hectares. This minimized the loss of annual energy production to 10 GWh, and correspondingly, reduced the allocation of irrigation costs to about 8% of the total project costs.

2.28 A 240 MW scheme on the Bilin river appears to be one of the best prospects for relatively early development and at estimated costs considerably lower than Paunglaung, primarily due to the smaller dam size. Firm power from Bilin may, however, be more owing to the much larger water storage with mean energy generation estimated at about 880 GWh. But due to the multipurpose nature of the project, there are substantial uncertainties as to the relative economies of Paunglaung and Bilin which can be resolved only by detailed studies. The hydro potential of the country can only be realized by carrying out detailed surveys and feasibility studies for a number of prospective sites.

F. Traditional Energy and Nonconventional Energy Sources

2.29 Myanmar's traditional energy resources--fuelwood, forest and wood residues, and agricultural residues--are plentiful and their potential contribution to the energy picture of the country are discussed in Chapter 6. The non conventional energy resources include solar and wind energy. Limited solar data indicates a modest potential for direct solar radiation in water heating, cooking, driers, solar stills etc. Since average wind velocity is only 4 miles per hour, except for Coco Islands where it reaches 7 miles per hour, wind is more suitable for water pumping than for electricity generation. But work in these areas is still at the experimental stage.

G. Conclusions

2.30 Myanmar's energy resources are plentiful but exploration has been limited. In the absence of adequate surveys, seismic and drilling work, it is difficult to assess the total potential of these resources for commercial production. A

concerted effort needs to be made in the oil, gas, coal, geothermal and hydro sectors to evaluate the total energy potential of the country. This would need mobilization of the latest exploration technology through purchase of appropriate instrumentation and equipment, hiring of experienced international service companies and increased recourse to production sharing type arrangements in all areas of the energy sector.

III. OIL AND GAS DEVELOPMENT

A. Introduction

3.1 Following nationalization in early sixties, the national organization (MOC, now MOGE) was vested with the responsibility to explore and exploit hydrocarbons throughout the country. MOGE succeeded in making a number of commercial discoveries of oil and gas in the Central Basin, the Pyay Embayment, the lower Delta region and in the offshore area of the Gulf of Moattama, including major fields such as Mann, Htaukshabin, Shwepyitha and Pyay on land and the 3-DA structure in the offshore. The capacity of MOGE to continue exploration in new areas, however, drastically reduced during the last decade owing to lack of adequate foreign exchange.

3.2 All the oil and gas reserves discovered in Myanmar to date are encountered in the Tertiary sediments of the Tertiary Geosyncline, which covers nearly half the country. With the exception of Moattama 3-DA structure, where gas was discovered in a Miocene reefal limestone build-up, oil and gas accumulations are encountered in the Oligocene and Miocene inter-bedded clastics which have been deposited over shallow marine lower coastal plains and fluvial environments. Almost all the oil and gas fields on land are situated in the Central Basin and the Pyay Embayment. The Central Basin, which has been more thoroughly studied than any other basin in Myanmar because of its easy accessibility and to early interest attached to its oil seepages, accounts for almost all the oil discovered and produced since the last century; and with the Pyay Embayment, for more than 85% of the gas discovered on land.

B. Onshore Oil and Gas Reserves

3.3 The published MOGE oil and gas reserves estimates date, in the majority of cases, from 1986; the oil reserves estimates for Mann, Htaukshabin and Kanni were revised by IPEC (International Petroleum Engineering Consultants) in 1988, and in 1989 BEICIP of France reviewed the gas reserves of four of the major gas fields on land while Schlumberger carried out a detailed evaluation of gas reserves of the Payagon region in 1989. These evaluations show wide variations when compared to those carried out by MOGE, being generally more pessimistic. While some of the major reasons behind the variations may be the complexity of the structure and the lack of reliable data, it is essential to establish consistent oil and gas reserve estimates that can be reliably used in the production projections and evaluation of development options.

3.4 The initial oil in place (IOIP) estimates carried out by MOGE lead to a total proven reserves of 1,776 mmb: four oil fields; Chauk, Yenangyaung, Mann and Htaukshabin accounting for about 90%. Chauk and Yenangyaung fields have been producing for about a century and are the best geologically known fields, but these two fields are at an advanced stage of depletion. The evaluation carried out by IPEC on Mann and Htaukshabin resulted in a substantially lower IOIP of the order of 30% and 50% respectively, as compared to MOGE estimates. Based on the mission's evaluations, the proven IOIP is estimated at 1,770 mmb, in line with MOGE estimates; while the IOIP in the probable and possible category are estimated at 390 mmb and 1,750 mmb respectively. A major proportion of the probable reserves are likely to be encountered in deeper sands, in the western

flank of Mann, below the 900 meters and in Htaukshabin and the undrilled blocks in Kanni. The possible oil reserves are likely to be encountered in the Lower Oligocene sands of the Pagan/Tuyintaung/Tetma/NST Trend and in the southern extension of the Htaukshabin structure. The proven initial recoverable oil reserves are estimated at 623 mmb, of which about 509 mmb have already been produced, and the unproven reserves are estimated at about 178 mmb. Consequently, the total remaining reserves are 292 mmb, of which only 114 mmb are proven (Table 3.1).

TABLE 3.1 SUMMARY OF MYANMAR OIL RESERVES ESTIMATES
(mmb)

Field/Structure	Initial Oil in Place				Initial Recoverable Reserves				Produced until 1/4/90
	Proven	Probable	Possible	Total	Proven	Probable	Possible	Total	
Mann/Minbu	450	100	50	600	150 (27)	17	4	171	94.1
Htaukshabin	210	150	200	560	40 (15)	15	10	65	16.3
Yenangyaung	540			540	230 (9)			230	216.0
Chauk	400			400	150 (7)			150	145.8
Kanni	40	40		80	14 (4)	7		21	1.5
Pagan/Tetma Trend		100	1500	1600		15	110	125	
Others	120			130	39			39	35.0
TOTAL	1770	390	1750	3910	623 (64)	54	124	801	508.7

Source: Mission Estimates, November 1990

( ) Undeveloped proven reserves.

Note: 1. The recoverable reserves have been estimated assuming that 50% of the probable and 25% of the possible reserves are promoted to proven reserves following delineation.
2. Recovery factors estimated from performance of major sands in existing reservoir.

3.5 Estimates by MOGE of onshore free initial gas in place (IGIP) are 1,320 bcf in the proven category, with three fields (Chauk, Ayadaw and Shwepyitha) accounting for about 63% of the proven IGIP, and 2,047 bcf as unproven (probable and possible), of which 83% are in the possible category. MOGE's gas reserves estimates for onshore areas were reviewed by BEICIP in 1989 and downgraded by 41%. Schlumberger Overseas carried out detailed estimates of the gas and condensate reserves in the Payagon region in 1989 and showed an average reduction of approximately 73% over existing estimates. These large differences are believed to be the result of insufficient structural control of reservoir sands. Volumetric evaluations are rarely verified against estimates based on actual reservoir pressure decline analysis because of the absence of static reservoir pressure measurements. The initial in place free gas reserves in the onshore areas are estimated to be 688 bcf in the proven category and 685 bcf in the unproven category. The total remaining initial recoverable gas reserves are estimated at 628 bcf, while the remaining reserves are 286 bcf, of which only 139 bcf, i.e. less than half, are proven (Table 3.2).

TABLE 3.2 SUMMARY OF ONSHORE FREE GAS RESERVES
(bcf)

Field/Region	Initial Gas in Place				Recoverable Reserves				Produced
	Proven	Probable	Possible	Total	Proven	Probable	Possible	Total	1/4/90
Chauk	190	5	20	215	137	2	4	143	85.7
Ayadaw	143	45	75	263	103	16	13	132	76.6
Htaukshabin	15			15	11			11	9.3
Peppi	15	30	30	75	11	11	5	27	3.0
Kanni	9	15	30	54	6	5	5	16	1.1
Pagan/Tetma			150	150			27	27	
Central Basin	372	95	305	772	268	34	54	356	175.7
Shwepyitha	112	30	80	222	81	11	15	107	55.2
Pyi (Prome)	71		5	76	51		1	52	40.2
Others	58		70	128	42		13	55	36.2
Pyi Embayment	241	30	155	426	174	11	29	214	131.6
Delta (Payagon)	55		100	155	40		18	58	35.5
Total	688	125	560	1353	482	45	101	628	341.8

Source: Mission Estimates, November 1990.

Note: The recoverable reserves have been calculated assuming that 50% of the probable and 25% of the possible reserves are promoted to proven reserves following delineation.

3.6 The mission's evaluations show that:

(a) The estimates of proven oil reserves of MOGE are reasonable.

(b) The gas reserve estimates carried out by MOGE are, however, inconsistent with reservoir performance and are generally optimistic when compared with estimates based on well pressures;

(c) Gas reserve evaluated from well head pressures for Chauk, Ayadaw and Shwepyitha are about 59% of existing estimates;

(d) Gas reserves for Htaukshabin and Peppi fields are significantly lower than the reserves given in MOGE and BEICIP estimates, and Payagon gas reserves are expected to be totally depleted by the end of 1991; and

(e) Ayadaw and Shwepyitha fields have produced more than two thirds of their proven developed reserves and are already on decline.

C. Oil and Gas Field Development

3.7 Annual oil production in Myanmar has fluctuated between 10 and 11 mmb during the period 1979 to 1985--the relative stability of oil production was largely due to intense development drilling in Mann and Htaukshabin fields, (Figure 3.2) which accounted for about 75% of the country's oil production during the period. But oil production has been declining at an average rate of approximately 20% since 1985. The drop in oil production has been particularly drastic from Mann and Htaukshabin where the annual decline rates have attained 23% and 30% respectively.

3.8 The decline in oil production is attributed to several factors:

(a) Depletion of Oil Reserves: Most of Myanmar oil fields are at an advanced stage of depletion: more than 85% of the reserves of Yenangyaung and Chauk have already been produced; Mann field, which presently accounts for more than of 40% of the country's oil production, may also be considered to be mature after 60% of the field's estimated reserves have been produced.

(b) The accretion of oil reserves from new discoveries and their development during the last decade have not been sufficient to offset the oil production decline.

(c) Reservoir Factors: Producing sands are generally complex, contrasted in properties, of limited areal extension due either to their lenticular nature or to compartmentalization by sealing faults. Natural pressure support from the aquifer is expected to be very limited. In addition, the majority of oil pools have been produced for a long time under rock and fluid expansion (depletion drive) which has resulted in a substantial drop of reservoir pressure (due to excessive gas production) and therefore, in severe loss of well productivity.

(d) Pressure maintenance schemes have been implemented at a late stage of a field's life and have been only partially effective due to insufficient replacement of total reservoir withdrawal (oil, water and gas), or due to the discontinuous nature of the producing sands. The geological complexity and reservoir heterogeneity limit the drainage volume attributable to individual wells and severely reduce the sweep efficiency of water flood schemes. Pressure maintenance has been generally restricted to major pools rather than individual sands and, with regards to reservoir characteristics, the schemes are often poorly designed. Water injection is mainly carried out from one or two injectors situated either in the crestal area or down flank in the aquifer, rather than a more appropriate pattern flooding. Sand by sand analysis of water flood performance is difficult due to the general lack of reliable production and pressure data and the difficulty of allocating fluid production and water injection volumes to a given sand.

(e) Formation Damage and Well Completion: The major causes of formation damage are the use of heavy-weight muds, migration of fines, and sand production from unconsolidated sands. The use of heavy- weight muds (relative to formation pressure) and long open hole exposure times, due to low drilling penetration rates, inevitably result in excessive mud filtrate invasion and formation plugging by fines and filtrate cake formation. Most of the well tests carried out on producers from Mann and Htaukshabin indicate very severe formation damage. If formation damage is not removed, using appropriate stimulation, it could cause permanent impairment to well productivity. It should be noted that most of the producers drilled today are brought on production without stimulation owing to the lack of chemicals and equipment. Although most producers have been completed in one major sand, analyses of well histories suggest that

a great number of these producers have poor zonal isolation often resulting in co-mingled production from oil and aquifer sands. Such severe zonal isolation problems are believed to be frequent in Htaukshabin and could be a major reason behind early water production, poor well productivity, low oil recovery and ineffectiveness of water flooding.

(f) Aging of Well and Surface Production Equipment: The great majority of wells do not flow to the surface without artificial lift, most oil production being obtained by reciprocating beam pumps. But single prime movers, well head equipment, sucker rods and down-hole pumps are in short supply and those functioning require constant maintenance. Gas lift applications have been very limited. Long flow lines without check valves, pose major problems such as back pressure on the well head, choking of lines, particularly in fields where surface topography is severe (e.g. Chauk, Htaukshabin and Yenangyaung fields) and wax deposits in well tubing and flow lines lead to well productivity loss.

3.9 Annual free gas production had increased gradually with increasing demand to attain a peak of about 38.65 bcf in FY87, but since then gas production has also been declining at a rate of approximately 3 to 4% due to production decline from Shwepyitha and Payagon fields. Gas production from the Payagon field, which amounted to some 7 bcf/yr over the period 1987/89, has declined very sharply and is expected to cease by the end of FY90. Solution gas production has declined from about 11 bcf in FY80 to about 2 bcf during 1990 mainly due to the decline of oil production and to the decrease in producing gas/oil ratio as a result of depletion of solution gas reserves. Most of the major free gas reserves have produced more than two-thirds of their proven reserves and are expected to start declining rapidly unless efforts are devoted to drill new producers and install additional compression facilities to compensate for the decline of well productivities and well head pressures.

3.10 For an immediate increase of oil and gas production, a major emphasis needs to be placed on the rehabilitation of the producing oil and gas fields. Rehabilitation would need to be carried out progressively to account for present knowledge of the fields, cost and effectiveness of the rehabilitation work envisaged. Based on cost-benefit analysis, it is clear that priority in field rehabilitation should be given to (a) well and surface production equipment; (b) well completions; (c) pressure maintenance schemes; and (d) gas field development.

3.11 More than 95% of oil producers in Myanmar do not flow naturally and are equipped with reciprocating beam pumps: but now pumping units and all critical spare parts are in short supply, resulting in frequent failures and chronic maintenance. The loss of oil production as a result of low operational availability of surface and down hole pumping equipment is estimated to be in the order of 4,500 bpd. Preliminary estimates show that some 150 pumping units, associated spare parts and equipment for servicing, would be required to replace and upgrade the existing pumping units. Surface oil gathering systems, oil treatment facilities, separators, settling tanks and pumps need to be refurbished and expanded.

3.12 Most of the oil fields in Myanmar produce from 10 to 15 major (group) sands of heterogenous petro-physical properties and pressure regimes. Some wells are

also perforated in several sands for co-mingled production. But examination of individual well performance suggests that a large percentage of the supposedly 'single' completion wells are producing from several sands owing to faulty primary cementation. Rehabilitation of well completions would require repair of faulty primary cementations, isolation of watered-out horizons, reentry of abandoned wells and recompletion in lower horizons across liners, well stimulation to remove formation damage, treatment and recompletion of unconsolidated sands for sand control. Rehabilitation of well completions would require testing, production logging and well-by-well analysis to identify faulty completions and design of the needed remedial work-overs, but data available at present is insufficient and unreliable for such analysis. Based on preliminary analysis, rehabilitation of well completion would be needed for about 80 to 100 wells annually.

3.13 About 65 water injection projects have been initiated on Mann and Htaukshabin since 1975. In Mann field, 12 of the 30 implemented projects have resulted in a substantial increase of oil recovery beyond the estimated recovery under natural depletion and the average oil recovery is estimated to be in the order of 35%. But the coefficient of replacement of reservoir withdrawals in sands, where the successful projects are implemented, is a amongst the lowest in the field. Water injection in Htaukshabin needs to be discontinued under its present design. Though the data available on these projects is sparse and unreliable to allow identification of the exact causes of failure, the most probable reasons seem to be: poor design of water injection pattern (very large spacing), limited areal extension and the discontinuous nature of sands, unavailability of high pressure water injection pumps, lower reservoir permeability and unfavorable water-oil mobility ratio. New pressure maintenance schemes should not be undertaken unless performance and causes of failure of the implemented projects have been fully assessed. It is estimated that some 24 new wells need to be drilled on various fields for data gathering. The main target of rehabilitation would be blocks AB and DS in Mann field and most of the blocks in Htaukshabin.

3.14 Rehabilitation of gas fields is really the additional development needed to compensate for the decline of well productivity due to reservoir pressure drop. The projected rehabilitation program, would require the drilling of 40 additional producers on Ayadaw, Chauk, Shwepyitha and Peppi, half of these wells would be needed on Chauk and Ayadaw fields; installation of additional compression capacity to overcome back pressure from the gas evacuation system; it is estimated that 12 compression units would be required over the, next two years, most of them on Shwepyitha and Ayadaw and rehabilitation of the gas evacuation system to remove bottlenecks.

D. Oil Production Forecasts

3.15 Oil production forecasts for the period 1991-2005 are estimated under three cases (Table 3.3). In case A, future oil production has been estimated from existing developed proved reserves without any additional development investment. In case B, rehabilitation of the existing fields is carried out using the latest equipment and technology; in addition investment are also made on the development of proven and probable oil reserves. In case C, production from development of possible reserves is also taken into account, following exploration and delineation of these reserves. (Detailed assumptions underlying the three cases are indicated in Annex 3.1)

TABLE 3.3 MYANMAR OIL PRODUCTION FORECASTS

Rehabilitation of Fields and Development of Unproven Reserves
(mmb)

	90/91	91/92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05
Case A*															
Proven Reserves	4.892	4.244	3.734	2.940	2.359	1.921	1.588	1.300	1.104	0.944	0.807	0.690	0.590	0.500	0.430
Case B															
Rehabilitation			2.400	3.900	4.700	4.300	3.900	3.500	3.050	2.650	2.350	2.100	1.850	1.600	1.350
Undeveloped Proven Probable Reserves				0.500	2.900	5.500	5.500	5.500	5.500	5.500	5.500	5.500	4.800	4.300	3.800
CASE A&B TOTAL	4.892	4.244	6.134	7.340	9.959	11.720	10.988	10.300	9.654	9.094	8.657	8.290	7.240	6.400	5.580
Case C															
Development of Possible Reserves				0.800	2.000	4.600	6.500	6.500	6.500	6.500	6.500	6.500	6.500	6.500	6.500
TOTAL (A+B+C)	4.892	4.244	6.134	8.140	11.959	16.320	17.488	16.800	16.154	15.594	15.157	14.790	13.740	12.900	12.080

Source: Mission Estimates, November 1990

* Assuming no additional development and oil production will continue to decline at the same rate observed since 1985/86.

3.16 As can be seen, production from existing proved reserves without additional investment leads to a cumulative oil production of approximately 28 mmb over the period 1990/91 to 2004/05, but the country's annual oil production would decline from 4.89 mmb in 1991 to 0.43 mmb in 2004/05 (Case A in Table 3). Oil production from the Mann field, which presently accounts for about 40% of the total oil production of Myanmar, would represent about 70% of the country's oil production around the year 2000. But with field rehabilitation, oil production could be increased to close to 6.22 mmb in 1995/6, and the estimated incremental cumulative oil production would be in the order of 38 mmb by the year 2004/05. The development of the probable and undeveloped proven reserves would increase oil production by some 5.5 mmb from 1995/96 through 2001/02, and the incremental cumulative oil production would be about 55 mmb. The major part of possible reserves is believed to be located in the Lower Oligocene sands of the Pagan/Tuyintaung/Tetma/NST oil belt situated about 50 miles to the southeast of Chauk. According to mission estimates, the recoverable possible reserves are about 124 mmb and their development could add up to 6.5 mmb/yr from 1996/97 through 2004/05. Exploration and delineation of possible reserves would require the drilling of some 29 exploration/delineation wells, nine of which will be deep test wells, and about 250 development wells. There is, however, considerable exploration risk involved in this case.

3.17 The investment required for oil field rehabilitation and the additional development of proved and probable reserves is estimated to be about US$698 million over the period 1991/92-2004/05, and the major targets of the above investment would be Mann and Htaukshabin fields where most of the probable and undeveloped proven reserves are expected to be encountered. This rehabilitation and development programs would depend on a first phase data gathering and appraisal program which is projected to include the drilling of 24 wells. The capital expenditure required for the exploration, delineation and development of possible reserves is estimated to be in the order of US$575 million, of which about US$67 million would be needed for initial appraisal and delineation (Table 3.4). The average investment costs for rehabilitation of the oil fields ranges from US$11.20 to 12.10/b (Annex 3.2).

Table 3.4 MYANMAR OIL FIELD REHABILITATION AND ADDITIONAL DEVELOPMENT PROGRAM

Summary of Capital Expenditure (Million US$ 1990)

Year	90/91	91/92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05	Total
Capital Investment																
Rehabilitation		10.00	43.00	43.00	18.00	5.00										119.00
Undeveloped Proven and Probable Reserves			48.00	123.00	138.00	90.00	30.00	30.00	30.00	30.00	30.00	30.00				579.00
SubTotal		10.00	91.00	166.00	156.00	95.00	30.00	30.00	30.00	30.00	30.00	30.00				698.00
Development of Possible Reserves		9.00	37.00	84.00	77.00	81.00	41.00	36.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	575.00
TOTAL		19.00	128.00	250.00	233.00	176.00	71.00	66.00	60.00	60.00	60.00	60.00	30.00	30.00	30.00	1273.00
Wells Required																
Undeveloped Proven and Probable Reserves																
Data Gathering			8	8	8											
Delineation			15	15	15	15										
Development				30	60	40	20	20	20	20	20	20				
Possible Reserves																
Deep Test		3	3	3												
Delineation			5	5	5	5										
Development			10	40	40	40	20	20	20	10	10	10	10	10	10	

Source: Mission Estimates, November 1990

E. Onshore Gas Production Forecasts

3.18 Gas production from the presently developed onshore reserves is expected to decline from 33.3 bcf in 1990/91 to 14.1 bcf in 1994/95 and to 1.7 bcf in the year 2000, implying that the present developed proven reserves will be totally depleted by the end of the century. Gas production declines would be particularly sharp in the Delta and Pyay Embayment areas, while production from the presently developed sands in the Payagon field, the sole producer in the Delta area, are expected to cease all-together in early 1990. In the central region Chauk and Ayadaw are the only structures, from the presently developed fields, to have sufficient reserves that could supply gas until the year 2000; the remaining fields, Htaukshabin. Peppi and Kanni, are also expected to be totally depleted around 1995.

3.19 Any enhancement of onshore gas production would require the rehabilitation of existing gas fields and the development of the unproven reserves. Increase of gas production from the presently developed reserves would depend on how fast the probable and possible reserves are delineated, developed and brought on stream. Given appropriate investments, production from unproven reserves could attain a level of 10 bcf in 1994/95, peak at 13.3 bcf in 1996/97 and decline thereafter to 6.2 bcf in 2004/05 (Table 3.5). However, the additional production expected from unproven reserves would not be sufficient to maintain the present gas production level. The projected delineation and development program would need the drilling of 6 deep test wells, 16 delineation wells and about 77 gas producers. The capital investments (Table 3.6) for rehabilitation of existing gas fields (US$71 million) and for the appraisal and development of unproven reserves (US$171 million) would, however, provide the additional gas at an average incremental cost of US$2.03-2.42/mcf (Annex 3.3). It is likely that exploitation of offshore gas, should the reserves prove to be adequate, despite

a major onshore pipeline. Thus, major investments in onshore exploration should await determination of the offshore resource base would be competitive with domestic supplies from onshore gas reserves.

TABLE 3.5 MYANMAR GAS PRODUCTION FORECAST:
PROVEN AND UNPROVEN RESERVES
(bcf)

ONSHORE AREAS

Region	90/91	91/92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05
Central Region															
Proven	16.1	15.1	13.1	11.3	10.1	8.0	6.4	5.1	3.1	1.7					
Probable		1.0	1.5	2.5	3.5	3.0	3.0	3.0	3.0	3.0	2.7	2.4	2.2	1.7	1.0
Possible				1.5	2.5	3.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	3.6
SubTotal	16.1	16.1	14.6	15.3	16.1	14.0	13.4	12.1	10.1	8.7	6.7	6.4	6.2	5.7	4.6
Pyi Embayment															
Proven	13.7	11.3	8.2	5.9	4.0	2.4	0.7								
Probable		0.5	0.7	1.0	1.5	1.5	1.5	1.2	1.0	0.8	0.6	0.4	0.2		
Possible				1.0	1.5	2.0	3.0	3.0	3.0	3.0	3.0	2.7	2.2	1.6	1.1
SubTotal	13.7	11.8	8.9	7.9	7.0	5.9	5.2	4.2	4.0	3.8	3.6	3.1	2.4	1.6	1.1
Delta															
Proven	3.5														
Probable															
Possible				0.5	1.0	1.5	2.0	2.0	2.0	2.0	2.0	1.4	1.0	0.7	0.5
SubTotal	3.5	0.5	1.0	1.5	2.0	2.0	2.0	2.0	2.0	1.4	1.0	0.7	0.5		
TOTAL Onshore	33.3	27.9	23.5	23.7	24.1	21.4	20.6	18.3	16.1	14.5	12.3	10.9	9.6	8.0	6.2

Source: Mission Estimates (November 1990)

TABLE 3.6 MYANMAR GAS PRODUCTION PROFILE AND PHASING OF CAPITAL EXPENDITURE

Rehabilitation of Fields and Development of Unproven Reserves
ONSHORE AREAS

Production (BSCF)	90/91	91/92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05
Proven	33.30	26.40	21.30	17.20	14.10	10.40	7.10	5.10	3.10	1.70					
Unproven Reserves															
Probable		1.50	2.20	3.50	5.00	4.50	4.50	4.20	4.00	3.80	3.30	2.80	2.40	1.70	1.00
Possible				3.00	5.00	6.50	9.00	9.00	9.00	9.00	9.00	8.10	7.20	6.30	5.20
TOTAL (BSCF)	33.30	27.9	23.50	23.70	24.10	21.40	20.60	18.30	16.10	14.50	12.30	10.90	9.60	8.00	6.20

Summary of Capital Expenditure (MM US$ 1990)

											Total
Rehabilitation	18.00	21.00	14.00	10.00	8.00	71.00					
Unproven Reserves	24.00	31.00	33.00	27.00	16.00	14.00	8.00	6.00	6.00	6.00	171.00
TOTAL	42.00	52.00	47.00	37.00	24.00	14.00	8.00	6.00	6.00	6.00	242.00

Source: Mission Estimates, (November 1990)

F. Moattama Offshore Gas Development

3.20 Substantial amounts of gas reserves have been discovered in the offshore Gulf of Moattama, 90 km from the shoreline in water depth of about 45 m. Gas was discovered in 1974 in well MOC-8 drilled on a bright spot, and the well encountered gas in five of the Upper Miocene sands situated at a depth between 3000 to 3300 ft. The five gas bearing sands total some 120 ft. and their individual thickness vary from 10 to 50 ft. The Moattama 3-DA structure was discovered in 1982, and the first discovery well, 3-DA-XA, encountered a 300 ft.

thick gas column in the Miocene reefal limestone build-up situated at a depth between 4,150 to 4,450 ft. A second well, 3-DA-XC, was drilled in 1983 and encountered gas in the same formation. The 3-DA gas accumulation, well defined by the gas water contact encountered in the two wells and identifiable on seismic profiles, extends over an area of about 35 to 40 sq. km.

3.21 The initial proven gas in place estimates of MOGE for the 3-DA and MOC-8 discoveries are in the order of 5.4 tcf and 1.6 tcf respectively, while the IGIP estimates of several other agencies lead to an IGIP ranging from 3.9 tcf to 5.0 tcf. The seismic and well data relative to 3-DA and MOC-8 discoveries were reviewed by the mission and based on this review and preliminary evaluations, the IGIP potential was estimated at about 5 tcf. Taking into account the simple geometry of the 3-DA structure, the relatively homogeneous reservoir properties and the location of the two discovery wells a total of 1.6 tcf is estimated to be recoverable. It is also estimated that at least two additional delineation wells would be required to confirm the remaining gas potential into the proven category. On the other hand about 90% of the gas potential given for MOC-8 discovery is considered to be unproven and full delineation would require at least an additional three wells.

3.22 The Moattama gas field, even in its present stage of partial delineation, represents a major resource and can be developed rapidly. Gas production potential from the Moattama structure and field development can be evaluated based on the assumption that the proven gas reserves, would be upgraded to about 3.5 tcf following the drilling of 2 more delineation wells on the 3-DA structure and possibly to 4 tcf following the delineation of the bright spot, MOC-8; and that 70% of the recoverable reserves could be produced during a plateau of 15 years and the remaining reserves during field decline. The initial well production rate from 3-DA structure is estimated to be in the order of 35 to 40 mmcf/d, based on well deliverability test results, and initial flowing well head pressure of 1,300 psig. No offshore condensate handling is required as 98% of the Moattama gas is methane; the theoretical liquid yield, based on gas composition, being about 1.5 b/mmcf. Based on the above, the minimum proven plateau gas production rate from the 3-DA structure is estimated at 75 bcf/yr. If, following delineation, the totality of gas reserves is confirmed in the proven category, the gas production plateau rate which could be achieved is estimated at 150 bcf/yr from 3-DA and 25 bcf/yr from MOC-8, during a period of 15 years.

3.23 The three alternate options for the development of offshore gas reserves are: (a) production dedicated to domestic demand only with minimum investments; (b) development oriented towards LNG production and export; and (c) pipeline gas export to Thailand.

(a) The Domestic Option. This option, which could satisfy the short/medium term domestic demand for gas, envisages an annual production of 40-50 bcf using minimum installations on the offshore field. Field installations would comprise MOGE jack up, after rehabilitation, as an early production system, one well platform, and the gas would be evacuated to Yangon area via a 24 inch, 90 Km submarine pipeline and an 18 inch, 180 km onshore pipeline. The US$247 million development, would require some 30 months for completion.

(b) LNG Production and Export. This option assumes that the proven recoverable reserves could support a gas production plateau of about 150 bcf/yr for 15 years, with 125 bcf/yr dedicated to LNG production for export to Japan, Korea, etc., and the remaining 25 bcf/yr for domestic utilization. This implies that a minimum of 3.5 tcf of reserves would be proved following the proposed delineation. Preliminary evaluations indicate that full field development would require one process/drilling platform, two well platforms, drilling the needed number of wells, and a 30 inch pipeline to a liquefaction plant comprising two liquefaction trains having a total capacity of about 2.5 million tons/yr of LNG. It is estimated that shipping of the LNG would require at least two LNG tankers. Preliminary estimates indicate that the total investment required for LNG development would be in the order of US$2,200 million, excluding the investment required for an LNG off-loading terminal, which range from US$100 to US$200 million depending on the water depth and morphology of the shoreline. The time required to complete the above project is estimated at about 5 years following feasibility studies and the tendering phase.

(c) Gas Export to Thailand. Under this option it is assumed tnat a minimum of 108 bcf/yr of the gas produced would be exported to Thailand and 42 bcf/yr would be diverted for domestic utilization. A 350 km, 30 inch submarine pipeline to Kyaikkami and then a 450 km, 30 inch onland pipeline to the Bangkok region would be required, gas for domestic utilization, being diverted through a 150 km, 18 inch pipeline to Yangon region. Preliminary evaluations show that the total investment required for the project would be in the order of US$1,036 million and project could be completed in 3-4 years following the feasibility studies and tendering phase. Land acquisition could present many uncertainties in regard to the time needed for project completion and has to be carefully accounted for from the very early stages.

3.24 Cost estimates, including phasing of construction, indicate that the option for the development of offshore gas for domestic use at a level of about 100 mmcfd is attractive, with an average incremental cost of US$1.24/mcf, at Yangon without royalties or taxes. The alternative of exporting the gas through a pipeline to Thailand is also promising, with an average incremental cost of US$1.38/mcf, for delivered gas to Thailand (without royalties and taxes). The price of gas sold to Thailand could range from US$2.50-3.50/mcf, and therefore this option could give a netback of around US$2.0/mcf, and assuming that some 40 bcf/yr would also be delivered to the domestic market, this would represent the optimum utilization of the offshore gas reserves. The LNG option appears to be the least attractive, incurring very high investment costs and with an estimated cost of US$3.43/mcf for gas delivered to Korea or Japan (without royalties or taxes). (Annex 3.4).

TABLE 3.7 SUMMARY COSTS OF OFFSHORE GAS DEVELOPMENT
(Cost in millions of US$ 1990)

Option	Domestic (100 mmcfd)	Cost	LNG Export (400 mmcfd)	Cost	Gas to Thailand (400 mmcfd)	Cost
Field Development						
Process Platform			1 Platform	120	1 Platform	120
Well Platform	1 platform	18	2 Platforms	36	2 Platforms	36
Jackup Rehabilitation	Dehyd. & Util.	14	Utilities	5	Utilities	5
Drilling & Flowlines	4 Wells	10	20 Wells	50	20 Wells	50
Evacuation						
Offshore Pipeline	90 Km/24 inch	67	250 Km/30 inch	183	350 Km/30 inch	256
					Divertn Yangon	98
Onshore Pipeline	180 Km/18 inch	96	50 Km/18 inch	25	450 Km/30 inch	306
Terminal		10			Compression	30
LNG Tankers			2 Units	550		
Liquefaction Plant			2 Trains	950		
Contingencies		32		288		135
Total Cost		247		2,207 (a)		1,036 (b)

Source: World Bank Mission, (November 1990)

(a) LNG evacuation terminal is not accounted. The cost of such a terminal may range from US$100 to US$200 million depending on water depth and coast line morphology.

(b) Land acquisition for the onland pipeline is not included. This is estimated at about US$30 million based on similar projects in the area.

G. Major Issues in the Oil and Gas Sector

3.25 The major issues in the oil and gas sector can be summarized as follows:

(a) Oil and gas reserve estimates used by MOGE for future production projections are inconsistent with existing field production data. Indeed, the absence of well and core data in adequate quantity and quality, is a major cause of discrepancies in field development projections. It is recommended that a National Reserves Evaluation Board is set up to periodically evaluate the total reserve potential of the country.

(b) Technological Upgrading and Rehabilitation of fields will be a critical determinant in the growth of the hydrocarbon industry in Myanmar. Absence of the right equipment, materials and technology from seismic exploration to field development has led to a high cost of exploration and production on the one hand, and to inefficient practices on the other.

(c) Development of offshore gas reserves provides the best opportunity for renewal of the energy sector. Examination of various alternatives like LNG and petrochemicals export has kept the government from exploring the more realistic and economical options of using it in the domestic economy, especially the power sector, in conjunction with a sizeable pipeline export to Thailand. But the appraisal and delineation of these reserves has yet to be completed.

(d) Resource Mobilization. MOGE has been unable to generate local funds for increased exploration and development due to the extremely low prices for crude oil and gas fixed by the government. But even more critically, very little foreign exchange has been made available for purchase of crucial instrumentation, equipment and services.

H. Conclusion and Recommendations

3.26 The oil and gas sector can once again play a significant role in the energy economy of the country but a clearly articulated policy and strategy needs to be defined and implemented. Major components of this should be:

(a) Rehabilitation of the oilfields onshore should be carried out on the highest priority; well production equipment, surface facilities, well completions and drilling of 24 data wells should be taken up immediately while water injection schemes should await detailed investigations. At the same time the proposed program to develop undeveloped proven and probable reserves should be undertaken. This development is relatively low risk and can be undertaken under MOGE management but only if international consultants and contractors are used. MOGE can alternatively examine using PSC type contracts for rehabilitation and development of some of the fields. But investment in the development of possible reserves are risk investments and it would be advisable to let this work be carried out under production sharing contracts.

(b) The assessment and appraisal of the total offshore gas reserves needs to be expedited as this will enable the government to determine the economic viability of the export options and to determine the volume of gas reserves that would be available for the domestic sector. This assessment would require the drilling of 3-5 offshore wells as well as an independent reservoir evaluation based on the latest data.

(c) The export of gas to Thailand through a pipeline with a spur pipeline to Myanmar for domestic supply of natural gas provides the optimum option for the country and the domestic spur line should be planned as an early phase of development of the export pipeline system. In the event that negotiations with the Thais should fail, offshore gas should be developed for the domestic market only. A detailed study of the gas field development and pipeline system needs to be commissioned as well as discussions initiated with the government of Thailand for possible contractual arrangements.

(d) Onshore gas field rehabilitation should be carried out along with the development of the probable reserves, but investments on the exploration and development of possible reserves should be deferred until the total offshore reserves have been determined. An examination of the relative cost effectiveness of the alternative of trunk gas pipelines to transport offshore gas to industries in the regions 2 and 3 to the development of probable and possible gas reserves in the area, needs to be carried out.

(e) Resource mobilization for the oil and gas sector requires the government to increase the price paid to MOGE for crude oil and gas and also provide adequate foreign exchange resources for carrying out exploration, delineation and production work in the most efficient manner in accordance with international norms in the industry. Investments in the oil and gas sector are inadvisable unless appropriate technology is mobilized by the domestic oil and gas sector entities, either directly or through PSC type contracts for new fields but also for exploitation of discovered fields.

IV. THE REFINERY SECTOR

A. Introduction

4.1 The downstream oil and gas sector in Myanmar has three petroleum refineries, an LPG plant, four fertilizer plants and a methanol plant. Myanmar Petrochemical Enterprise (MPE) has the responsibility for the operation of these plants and it is also responsible for import of crude oil and base stocks for lubricants and for export of petroleum and petrochemical products. The Myanmar Petroleum Products Enterprise (MPPE), is the sole petroleum products and lubricants distributing company in Myanmar, with the exception of some LPG distributed by MPE and CNG sold directly by Myanmar Oil and Gas Enterprise (MOGE). In 1990 the total consumption of petroleum products was about 4.7 mmb, of which 51% was diesel, 30% petrol and only 1% kerosene.

4.2 The three petroleum refineries have a total design capacity of 57,300 b/stream day (18.9 mmb/yr). The Thanlyin refinery (26,000 bpd), located near Yangon, which was heavily damaged during World War II, was rebuilt in 1955, and new units were added later. The refinery has three topping units: topping 1, with 5,700 bpd capacity, and a 1,700 bpd vacuum plant built in 1957; a second topping unit with 14,300 bpd capacity built in 1963, and a third unit with 6,000 bpd added in 1980. In 1986 a 5,200 bpd Coker and a 500 bpd Polymerization unit was built. A 1,400 bpd fractionation unit produces a narrow cut solvent (62/82 C°) out of naphtha that is used for rice oil extraction. Thanlyin also operates a lubricant blending plant, with a capacity of 14,000 tonnes/yr (tpy), and there is a candle production unit, with designed output of 5.2 tonnes/day (tpd). The wax used in this unit is brought by barges from the Chauk Refinery, which was built in 1953. The Chauk plant includes a topping and vacuum unit, with a 6,300 bpd capacity and a wax plant producing 1,500 tonnes/month. The newest refinery, Mann, was built in 1982 and has a 25,000 bpd Topping unit, a 2,800 bpd Semi-regenerative Catalytic Reformer unit, a 5,200 bpd Delayed Coker unit, a Kerosene Hydrodesulfurization unit (3,800 bpd), an LPG Merox treating unit and a Naphtha Merox treating unit. The LPG separation plant at Mann has a design treating capacity of 24 mmcfd of wet natural gas and a design production capacity 60 tpd of Propane and 55 tpd of Butane.

4.3 Crude oil transportation to the refineries is done primarily by MPE with a fleet of 40 tugs and 150 barges, 500 tons each. Additionally, four 1,000 ton tankers are used to supply five coastal depots. The three refineries have access to river loading and unloading facilities. There is also a 10-inch diameter, 300 mile long pipeline connecting Mann and Thanlyin refineries, which was originally used to pump oil, but nowadays is used to transmit gas. Occasionally, crude oil is imported from Australia (Challis), Borneo (Brunei Light) or Indonesia (Attaka). Since the port capacity is limited, large tankers are forced to stay out in the open sea, some 80 miles from the refinery. Crude oil is transshipped using smaller vessels, which can moor at the refinery's jetties, contributing to a significant increase in the cost of imports and exports.

4.4 Petroleum products are distributed by MPPE from the main terminals in bulk to major customers as well as to depots, filling stations and retail shops. MPPE also supplies aircraft needs through nine airport refuelling stations. The

retail distribution system is rather old but it seems adequate for present and medium term needs.

4.5 To distribute the available petroleum products, an allocation system was established in the early 1980's. The Allocation Committee operates at cabinet level and reviews all fuel requests presented by state organizations, cooperatives and private sector consumers. The latter present their requirements through State and Division Councils. Abundant and detailed documentation is required to support petitions in an attempt to detect inflated requests or double counting. Allocations are based on regional considerations as well as other factors, such as vehicle engine capacity and government priorities. A formal procedure to control purchases is established in major towns. Each vehicle, including public sector vehicles, is assigned to a specific filling station and must keep a record book of all purchases.

4.6 Consumer and transfer prices for petroleum crude and products are set by the Government on a cost-plus basis. They were held constant for many years at significantly lower levels than international market values until October 1988, when consumer prices were increased over 4 times and the crude transfer price increased about 3 times: crude oil being raised from k 42.66/barrel to k 110.00/barrel. At a shadow exchange rate of k 50/US$, prices are US$2.20/barrel for crude oil, US$0.32/gallon for petrol and US$0.21/gallon for diesel, which are significantly below international prices; there is also an active unofficial market at price levels much higher than the official rates. Although black market prices are closely monitored by MPPE, reliable estimates of the quantities sold in the black market are not available, but it is said that it includes as much as 40% of final consumer petrol sales.

B. Petroleum Products Consumption

4.7 The refining capacity of Myanmar is adequate for its needs if it is operated at its design capacities. But crude oil and natural gas production have shown a declining trend during the last few years, and the pattern of petroleum products has varied. As shown in Table 4.1, the share in output of diesel has continuously increased from 35% in 1977 to 51% in 1989. Kerosene, on the other hand, has decreased in the same period, from 13% to 1%, as a result of a policy of restricting the production of kerosene established in the mid-1970's. The share of petrol plus methanol/petrol mix has increased slightly from 28% to 30%, and fuel oil has shown a marked decrease from 20% to 15% through natural gas substitution. Jet fuel has maintained a 3% market share. Over the decade the ratio of diesel-plus-kerosene versus petrol has increased significantly from 1.26 in FY77 to 2.2 in FY89.

TABLE 4.1 MAIN PETROLEUM PRODUCTS CONSUMPTION

Product	1977/78 (mb)	1977/78 (%)	1984/85 (mb)	1984/85 (%)	1989/90 (mb)	1989/90 (%)
Petrol	1,789	28	2,144	32	1,089	23
Petrol + M80*	1,789	28	2,144	32	1,429	30
Kerosene	852	13	142	2	63	1
Jet fuel	243	4	143	2	131	3
Diesel	2,248	35	2,843	43	2,391	51
Fuel oil	1,309	20	1,405	21	703	15
TOTAL	6,441	100	6,677	100	4,717	100

* The methanol/petrol mix is 80% methanol (M80).

4.8 LPG is produced in the refineries and in the LPG separation plant, and is distributed mainly in the Yangon area. Actual consumption in 1989 was limited by low production from the LPG separation plant, to 21,000 barrels of propane and 56,000 barrels of butane.

4.9 Some of the recently constructed plants, such as the LPG separation plant and the methanol plant, were intended to use onshore natural gas supplies to generate export products. Unfortunately the reductions in domestic natural gas and crude oil production, combined with less than favorable international market conditions, particularly for methanol, have eliminated these exports, as summarized in the Table 4.2 below.

TABLE 4.2 EXPORTS OF PETROLEUM PRODUCTS
(tonnes)

Product	1986/87	1987/88	1988/89	1989/90	1990 (April-Dec)
Urea	90,326	121,245	60,061	51,000	11,719
Methanol	-	9,111	25,235	6,900	-
Coke	36,496	31,504	29,522	32,700	11,105
Wax	902	1,334	-	955	182
LPG	-	2,585	-	664	-
EXPORT EARNINGS TOTAL US$000	9,306	12,688	11,709	8,904	2,722

C. Supply and Demand

4.10 Since 1984 petroleum product consumption has been supply restricted. Consumption has been limited in most years to the supplies derived from domestic crude production, except in 1989 when some 1 mmb/yr of crude (and some diesel) were imported. Restrictions reached a critical point in 1988 when total sales were at their lowest point in the past ten years. The throughput of the refineries in the period from 1980 to 1986 had been in the range of 8 to 9 mmb/yr, i.e., almost half the design capacity (Figure 2). In 1988, total refining output declined further to 4.5 mmb.

4.11 As a result of supply constraints, the allocation system and the active black market for petroleum products at prices far higher than official prices, it is difficult to assess how demand might be if supplies were available, and what price levels might serve to balance supplies with demand if the markets were

free. In the short term, in addition to suppressed transportation demands, there is a critical demand for diesel and fuel oil in the place of natural gas for power generation and general industry. In the absence of increased domestic production, these needs will have to be met through imported crude oil. Two demand forecasts have been used to examine the issues in the refinery sector: (a) The Low Case, based on relatively low growth in each sector of the economy, shows consumption rising gradually from the actual levels in 1990, at growth rates beginning around 3%/yr and increasing after 1996 to a level of 5.7%; and (b) A High Case developed specially for analyzing potential refinery bottlenecks that might arise in the late 1990's. The High Case uses the consumption levels of 1984 as a basis because that year was the first full year of the allocation system and before the drastic declines in domestic crude oil production which followed. It assumes an average growth rate of 2%/yr would have occurred up until 1990. As a result the "potential" demand in 1990 was estimated to be some 7.44 mmb/yr, or about 45% higher than the actual consumption in that year. The forecast then assumes that demand increases by 2%/yr to 1993, by 3%/yr to the year 2000 and 4%/yr afterwards.

TABLE 4.3 MAIN PETROLEUM PRODUCT DEMAND FORECASTS
(mmb/yr)

	LOW CASE			HIGH CASE		
Products	1995	2000	2010	1995	2000	2010
Diesel	3037	4129	7343	4509	5592	9109
Petrol	1266	1560	2423	2564	2915	3918
Fuel Oil	786	906	1217	877	711	786
Kerosene	240	337	711	872	1076	1671
M80		340	340	340	0	0
TOTALS	5223	7272	12534	8622	10294	15484

Source: Mission Estimates (1991)

Notes: 1. The High Case assumes that petroleum product prices are kept at their existing low official levels, and sufficient products are supplied to fill the resulting high consumer demand.
2. LPG demand is estimated to increase from 21 metric tonnes/day to 48/day.

D. Issues in the Refinery Sector

4.12 In the last five years, refinery utilization has dropped from 50% to 25% of design capacity, resulting in a very inefficient operation. At the present processing rates, either one of the two largest refineries (Thanlyin or Mann) has enough capacity to handle crude oil processing. However, due to logistical, strategic and employment considerations, all three refineries are in operation. The Thanlyin and Mann refineries run continuously while the Chauk plant operates intermittently. At the Thanlyin refinery two topping units and the vacuum units are shut down and the coker and polymerization plants are running intermittently, while at Mann, the kerosene hydrotreating and the reforming units are not operating. The Chauk refinery is in poor condition and its capacity is reduced to approximately 1,300 b/day, just accommodating the present local crude production. Thus, Myanmar's present operational refining capacity is sufficient to process approximately 15 mmb of crude oil/yr. The LPG separation plant is also operating at 63% of capacity with a feed rate of only 15 mmcfd. Natural gas shortages have reduced the throughput and the gas which is available is also leaner than

previously, with a recoverable liquid content of approximately 2.4 mol% against a plant design value of 8.6 mol%.

4.13 There is a generalized scarcity of spare parts in all refineries and rehabilitation is needed in several areas. The lack of spare parts is critical, especially in instrumentation and rotatory equipment. Partial dismantling of some unused units is taking place as an emergency solution. Fuel consumption and losses, reported by MPE as 14% to 18% by weight, are high compared with typical values of other refineries. The causes of such high fuel consumption and losses and the wide range of numbers reported can be numerous: crude received at the refinery gate has variable quantities of water and important measurement errors occur when emulsions, wax separation or water lenses are present; most products are transported in barges in small volume shipments can cause large measurement errors and losses. The low feed rate to the refineries also causes low efficiency in heaters, boilers, measuring instruments and rotatory equipment. Faulty design or operation in oil recovery systems, flare, evaporation, drainage of tanks, and heat and product losses, are also possible sources of losses.

4.14 Though the Low Case demand forecast can be satisfied with the present refineries' configuration and capacity up to the year 2008 without any major modifications, the High Case demand forecast, which has very high petrol and diesel demands in the near term, implies that a surplus of fuel oil would be produced as early as 1996, and by 1997 the surplus would be of the order of 343,000 barrels/yr. The conversion capacity and diesel production capacity would then become critical in this case. Plant configurations for the two largest refineries, Thanlyin and Mann, are very similar from a diesel over fuel oil point of view; coking to Topping capacity ratio is 25.6% for Thanlyin (Topping 1 not included) and 20.8% for Mann. Local crude yields 32% to 35% of long residue so at full capacity there is a surplus of reduced crude for fuel oil production that cannot be fed to the cokers. Diesel and fuel oil productions will depend on the possibility of using coker gas oil as a diesel blending component and on the topping versus coking feed rate. Consequently, the existing refineries' configuration could not satisfy the exact product mix of the High Case demand forecast.

4.15 Methanol. The Seiktha Methanol plant was built in 1986 with a design capacity of 450 tonnes of methanol per day. Unfortunately, from the very beginning there was not enough natural gas to feed the plant. Annual production was 19,807 tons in 1986/87, 39,590 tons in 1987/88, 50,596 tons in 1988/89 and 42,272 tons in 1989/90, the latter being approximately 30% of design capacity. At design capacity the plant needs 15 mmcfd of natural gas, but in FY89 only 10 mmcfd, 100 days/yr were being allocated to the plant and the unit was running at 60% of capacity, intermittently. Frequent start ups and shutdowns and a low feed rate are also detrimental to equipment, decrease its operating life and increase failures and maintenance cost.

4.16 The present shortage of natural gas raises the issue of whether it would be more economical to shut the methanol plant rather than operate it at inefficiently low levels of feed rate. Production cost of methanol are high under low levels of operation; with operating costs given by MPE and natural gas valued at US$2.00/mcf, the estimated production costs of methanol in 1989/90 were approximately US$132/tonne. No capital charges were included, assuming them to be 'sunk' costs. The average methanol price US Gulf Coast for the last twelve years has been approximately US$140/tonne with a maximum of US$230/tonne and a minimum of US$80/tonne. Even at higher production rates and lower production

cost, the use of gas for methanol production must compete with the use of gas in other sectors of the economy, most of which give a higher value for gas. Even if methanol can find an export market this option is only economic if the price of methanol is sufficient to offset the costs of imported crude oil and producing petrol.

4.17 Urea. Myanmar has four urea plants: Sale A built in 1970 with a production design capacity of 205 tpd; Sale B, built in 1984, with a design capacity of 260 tpd; Kyunchaung, built in 1972, with a design capacity of 207 tpd; and Kyawzwa built in 1985 to produce 600 tpd of urea, and this plant is 10% to 15% more efficient than the older units. The shortage of natural gas has severely affected the production of urea. Kyawzwa urea plant was completely shut down in May 1990. Sale A and Sale B have enough natural gas available but their production is limited by a shortage of spare and equipment problems. Sale B is shut down due to compressor failures. In FY89, 192,000 tons of urea were produced, 45% of installed capacity; 141,000 tonnes were used locally and 51,000 tonnes were exported. The maximum historical urea consumption was close to 300,000 tonnes in FY85 while Myanmar's potential requirements of urea have been estimated at 480,000 tonnes. The key issue is the shortage of natural gas but production is also hampered by a lack of spare parts, a need for plant rehabilitation and the low efficiency of operations.

E. Investment Profile

4.18 The total investments that need to be made in the refinery and petrochemicals sector are summarized in Table 4.4. Estimates of crude oil supply forecasts show that domestic sourcing of crude--and, therefore, of petroleum products--will be less costly than international sourcing at projected world oil prices. The investments in the sector are primarily directed at rehabilitation and efficiency improvements in the existing installations in the short and medium term.

TABLE 4.4 INVESTMENTS IN THE REFINERY SECTOR (US$ million-1991 prices)

	1991-------2000		1991--------1995		1995-------2000	
	Total	Fixed Costs	Total	Fixed Costs	Total	Fixed Costs
Spare parts	6.00	6.00	6.00	6.00		
Rehab/Chaulk/Thanlyn	4.00	3.00	4.00	3.00		
Rehab tug fleet	50.00	25.00	10.00	7.00	40.00	18.00
Modernization/distribution	5.00	4.00	5.00	4.00		
Loss control/efficiency	25.00	18.00	5.00	4.00	20.00	14.00
Yangon depot	20.00	10.00	20.00	10.00		
Mann refinery	15.00	11.00			15.00	11.00
Rehab fertilizer plants	11.00	10.00	11.00	10.00		
TOTAL SECTOR	136.00	87.00	61.00	44.00	75.00	43.00

Source: Mission Estimates (1991)

F. Conclusions and Recommendations

4.19 Improvement in the refinery and petrochemical sector requires action on a number of issues:

(a) Utilization of Spare Capacity. At present there is more than enough refining capacity for domestic crude oil, and even with crude imports to serve the domestic products market, the Thanlyin refinery will be running at a low feed rate for several years. Marginal refining costs for refineries in such a condition are usually low and MPE could offer convenient refining services if a suitable client could be located. Important factors in refining service contracts are the refining fee and the products slate that the refinery can offer in return for the crude oil to be refined. Total yield tends to set the refining fee but the closer the individual product yields are to the client's needs, the better. Sometimes no refining fee is charged and the refining profit is realized in the form of products which are retained. The Thanlyin refinery has spare coker capacity that can increase the distillate yields to be offered, but it would be essential to have efficient offloading of crude to the refinery and shipping of products from Thanlyin. To accomplish any service refining deals it would first be necessary to solve the problem of high losses and fuel use. The costs of such losses could easily be as high or larger than the refining fee, thus making the deal a loser. In spite of these problems it is worthwhile to undertake a market survey, looking for a niche that could be supplied competitively.

(b) Rehabilitation and Efficiency Audit. Considering the fuel use and estimated losses, it is recommended to perform an operational loss and energy audit. The audit is a tool that the refinery can use to compare present operational conditions with theoretical yields, losses and fuel use. Objectives for reducing losses and fuel use can therefore be established, and procedures can be put in place to accomplish them. Investments to improve efficiency can then be measured on a realistic financial basis. Finally, programs should be devised to train and encourage personnel to improve loss control and energy conservation. The loss and energy audit should be part of an overall plant loss and energy management program. A debottlenecking study might also be considered to improve efficiency.

Rehabilitation is needed in Thanlyin topping 1, jetties, utilities, water separation and the oil recovery system. The Chauk refinery is in poor shape but its rehabilitation is not a high priority item. Action has also to be taken to assure that critical spare parts are available to the refinery operations, perhaps by permitting MPE to retain part of foreign exchange that it earns.

(c) Increasing Diesel Yield. Even with the present refinery configuration, there are various processing alternatives to improve the diesel yield. At present, only up to 5% of coker gas oil is being blended with diesel, because of instability of the blend at higher levels. With appropriate analytical methods, the use of additives, and good quality control the amount blended could be

increased without detrimental effects on product quality. Diesel specifications for boilers, stationary and marine low speed diesel engines, gas turbines, etc., could be made less stringent than specifications for diesel used in vehicles and high speed diesel engines, and a heavier diesel oil could be produced and distributed. To handle two types of diesel can increase distribution and handling costs and therefore it would be advantageous for consumption of the new product to be concentrated in a few areas. Coker gas oil, if properly hydrotreated, is a good diesel blending component, and a hydrotreating unit could be built at Mann refinery where the reforming unit could supply the hydrogen required.

(d) Refinery Investment Alterratives. In the context of the High Case demand forecast, a number of investment alternatives were examined, including refinery modifications and partial or full import of distillate products. The most economic alternative was for increasing the conversion capacity of the refineries, consist of a 2,000 bpd hydrotreating unit for Coker gas oil, to start up in 1996/97 and a revamping of the Mann refinery Coker to increase its capacity by 25%, by 2003/04 at a total investment of US$15 million.

(e) Fuel Oil Surplus. The export market for fuel oil is very competitive and the netback from the sale of relatively small cargoes is not likely to provide better economics than investments in refinery conversion facilities or other processing modifications. Other ways of dealing with a potential fuel oil surplus are to produce new types of fuel oil if a market could be found for them. Intermediate fuel oils (IFO) are being used in other countries as fuel for low rpm marine diesel engines, and the Myanmar fuel oil characteristics, such as low metals' content, could have a competitive edge. Domestic as well as foreign ships can be supplied with IFO. It must be stressed, however, that potential refining problems which are related to the required mix of products, reflect in part the petroleum product taxation and pricing policies followed. A relatively low consumer price for diesel versus petrol will encourage its use in transportation and if natural gas is available the demand for fuel oil will stagnate. A consequence may therefore be the need for additional refinery investment which could otherwise be avoided through higher diesel prices.

(f) Methanol Production. Production costs of methanol (excluding the cost of gas) are high and the economic options are either to shut down the plant or to run it at a much higher feed rate. In the short term, with acute shortages of natural gas, it appears advisable to shut the plant. It could be reopened when plentiful gas supplies are available from offshore and if international methanol prices rise in the future to make export economical.

(g) Urea Production. An estimated investment of US$11 million is needed to rehabilitate Sale A, Sale B and Kyunchaung to bring them back to normal operating conditions. In 1990, urea plants used 20 to 100 percent more natural gas per tonne of urea than the design value. As in the case of the refineries and considering the natural gas shortage, there is a strong rationale for improving energy efficiency. As a complement of the rehabilitation projects, an

efficiency operating audit and a debottlenecking study are recommended.

(h) Transportation of Crude Oil and Distribution of Products. Thanlyin is an important distribution center and is the only point of import and export of petroleum and petrochemical products. Consideration should be given to formulating a technical-economic feasibility study for improving the transportation networks serving the Thanlyin refinery.

(i) Institutional Strengthening. MPE staff, although of high quality, have a need for more frequent contact with current information and techniques for efficient refinery operation and management, and product marketing. More contact with international refinery operations is especially recommended. Their computer infrastructure should be markedly improved, to allow for more complex analytical techniques to be applied in refinery operations, where they are particularly well suited. Refineries programming and optimization, alternative project evaluation, crude oil purchasing evaluation, and natural gas usage should be optimized with the help of linear programming models and similar techniques.

V. POWER SECTOR DEVELOPMENT PROGRAM

A. Introduction

5.1 From an operational generation capacity of about 400 MW approximately 94% of electrical energy sold (1,730 GWh in 1990) by MEPE is provided from an interconnected 230/132/66 kV transmission grid system.[1] This extends some 600 miles from Pathein city, south-west of Yangon, to Kawlin copper mine north of Mandalay. Its associated 33/11/6.6/0.4 kV subtransmission and distribution networks feeding urban, industrial and a few rural loads adjacent to the transmission system provide service to 10% of the 28 million population, who live in the main towns and cities of the six principal Divisions of Myanmar. The balance of electrical energy sold by MEPE (100 GWh in 1990) is supplied by numerous isolated diesel and minihydel units scattered throughout the surrounding high country. Fewer than 7% of the rural 9 million population in these remote areas, comprising two Divisions and six States, receive electricity, and their supplies are usually provided on a restricted four to twelve hours per day basis.

5.2 Over the entire decade of the 1980's electricity demand in Myanmar has grown just over 8% per year on average, limited largely by supply constraints. The growth rate since 1988, however, has slowed down considerably as shown in Table 5.1 below. The relative proportion of consumption by the domestic sector has remained fairly constant at about 30% of total, with industrial and bulk consumers making up the balance. Industrial consumption has been curtailed by about 40% over the last three years largely due to the shortage of gas both as a raw material and as a source of power. Table 5.1 also shows that losses in the distribution system have been steadily increasing from 21% of total generation in 1980 to 27% in 1989. Overall growth in power demand has also been modest in comparison with many of Myanmar's Asian neighbors, in spite of Myanmar's low base of electricity usage (45 kWh/capita in 1990).

B. Generation System

5.3 At present MEPE has 20 interconnected power stations capable of supplying the grid with a combined rated capacity of 661 MW. The actual firm capacity is only about 400 MW due to various limitations at each station,but this is expected to increase to around 562 MW when the ongoing rehabilitation work is completed in 1993.[2] In 1990, 54% of electricity generation to the interconnected system was provided by thermal units (primarily gas-fired combustion turbine sets), whilst 46% was provided from hydro sources. An analysis of the trends (Annex 5.1 (b)) shows the increase in dependency on gas fired generating plant going from 24% of production in 1980 to 55% in 1989. Even though there is now overcapacity in the system, production is severely limited by rationing of gas and diesel oil supplies for the combustion turbines; and by limitations in water storage capacity coupled with inadequate rainfall to operate the hydro stations effectively.

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[1] see map IBRD 22974 Power System

[2] A summary of the interconnected system generating plant is shown in Annex 5.2 giving details of the status of each station after committed reinstatement works are completed.

TABLE 5.1 ANNUAL SUMMARY OF GENERATION AND SALES IN GWH 1980-1990

	Generation						Sales					Losses				
Year	Hydro	Gas	Steam	Diesel	Purchase	Total	Domes	Indus	Bulk	Others	Total	Gen	Trans	Dist	Other	Total
1979/80	725.15	262.68	37.50	47.19	8.77	1081.29	216.52	407.41	109.25	29.38	762.56	28.02	43.21	226.18	21.32	318.73
1980/81	725.15	375.55	79.10	46.26	6.72	1227.81	242.29	457.10	122.23	31.86	853.48	32.40	50.81	262.04	29.08	374.33
1981/82	915.38	350.41	75.84	47.69	5.36	1394.68	281.38	498.70	132.68	36.93	949.69	44.32	67.05	309.36	24.26	444.99
1982/83	964.47	453.85	75.71	44.64	13.10	1551.77	315.82	551.81	144.81	37.71	1050.15	45.44	92.64	338.62	24.92	501.62
1983/84	992.63	549.76	72.42	41.83	17.94	1674.58	340.59	585.35	157.61	37.95	1121.50	42.08	83.49	399.55	27.96	553.08
1984/85	1011.49	765.27	49.99	43.45	20.09	1890.29	373.75	654.76	185.46	39.66	1263.63	32.28	89.81	477.36	27.21	626.66
1985/86	1003.48	996.38	55.00	41.66	22.85	2119.37	408.66	882.34	128.48	40.05	1459.53	47.18	81.74	501.94	28.98	659.84
1986/87	1042.61	1075.68	80.91	31.84	14.42	2245.46	436.95	918.75	145.96	41.32	1542.98	45.12	91.84	527.61	37.91	702.48
1987/88	1023.71	1208.74	61.37	20.35	5.44	2319.61	481.08	904.35	153.66	41.00	1580.09	46.75	137.68	516.62	38.47	739.52
1988/89	934.89	1228.44	39.41	17.91	5.80	2226.45	500.10	737.75	149.68	40.68	1428.21	42.34	114.65	608.10	33.51	798.24
1989/90	1143.91	1292.44	25.19	24.34	7.83	2509.00	570.39	804.87	183.15	42.24	1600.65	47.38	128.42	680.10	37.16	893.06
1990/91	1193.24	1226.00	27.60	23.22	7.50	2477.56	627.40	862.00	199.63	45.24	1734.27	50.05	136.05	519.26	37.93	743.29
SUMMARY OF GROWTH RATES OVER THE DECADE																
1980/85	8.0%	21.3%	3.4%	-2.2%	25.6%	11.6%	11.7%	9.6%	11.3%	6.0%	10.3%	4.4%	16.9%	15.7%	3.3%	14.3%
1985/90	1.1%	10.1%	-12.6%	-24.4%	-24.4%	4.6%	8.4%	1.4%	0.5%	1.0%	3.3%	4.8%	9.6%	6.9%	5.8%	7.1%
1980/90	3.5%	18.6%	-4.9%	-0.6%	-0.6%	8.6%	9.47%	8.1%	3.45	5.2%	7.9%	3.7%	10.3%	11.0%	5.2%	10.1%

Thermal Generation Facilities

5.4 MEPE has nine combustion turbine generating stations with a combined capacity of 280 MW. They are supplied with gas from three separate pipeline networks associated with the following gas fields: (i) in the Delta area at Payagon; (ii) in the Pyay area at Shwepyitha and Pyay and; (iii) in the Central Basin area at Mann and Chauk/Ayadaw. Each of the networks has different supply and demand characteristics thereby restricting MEPE in operating its generating plant in accordance with requirements of the interconnected system. Two steam generating thermal plants, totalling 30 MW, use locally supplied fuel oils from refineries at Thanlyin, Chauk and Mann (Thanbayargan). Some fuel oil is also imported (by end 1990 the government will have imported about 1 mmb of oil). MEPE also own and operate a large number of isolated diesel engines scattered throughout the 14 States/Divisions of Myanmar. Diesel plants comprise 644 sets with a combined capacity of about 100 MW. It is understood that only 50% are in good operating condition; their operation is also curtailed by fuel shortages. Coal was an important fuel for steam generating thermal power stations in the past but is no longer used. Coal imported from India was used for power generation in Yangon for over 50 years; coal fired plants were in operation at Ahlone (three 10 MW units), Ywama (three 10 MW units) but they are obsolete and were recently shut down. There is still a very old steam generating plant with four 550 kW units in operation at Kalewa coal mine which is both uneconomic and difficult to operate.

5.5 Outside MEPE control there is approximately 280 MW of installed steam generation, gas combustion turbine, diesel, and biomass fuelled generating capacity generally in small unit sizes. Of these a total of 214 MW is operated by industrial/commercial organizations under the control of the following Ministries: No.1 Industry (82 MW), No.2 Industry (12 MW), Energy (57 MW), Mines (37 MW), Fisheries (10 MW), and Trade (16 MW). Cogeneration facilities (i.e. generating equipment producing heat and electricity largely for industrial use) are in operation in Thaton (MEPE); Thanlyin (MOE); in Yenangyaung, and Chauk (MOGE); and in Lashio and Namtu (Myanmar Bawdwin Corp).

Hydro Generation

5.6 Existing major hydro plants are located in the eastern hill country between Yangon and Mandalay at Kinda (56 MW), Sedawgyi (25 MW), and Lawpita (168 MW). Kinda and Sedawgyi have relatively small reservoirs and catchments and consequently limited capability during the dry season. The Baluchaung river system which supplies Lawpita provides a regulated flow from the Mobye dam in both wet and dry season. Under an ongoing rehabilitation program it will have a cascade pair of plants in operation by 1992 (Lawpita and Baluchaung #2 (28 MW)); a third upstream plant (Baluchaung #3 (48 MW)) is proposed for the mid 1990's. There are also 16 minihydel sets with a total capacity about 4 MW, three are located in remote areas of the Chin state, the remainder not too distant from existing 33/11 kV interconnected networks. Eight of the minihydel stations have been constructed with imported equipment (costing about 3-4,000$/kW), and are working satisfactorily. The remainder have been designed by MEPE; they are equipped with turbines built locally, and generators converted from old diesel plants. Although much lower in cost, typically 1-2,000$/kW they are giving some trouble in operation. MEPE also have plans for the development of a number of new sites including seven minihydel units, and two smaller hydropower projects: Zawgyi (two 8 MW units) near Taunggyi, and Anyapya multipurpose project (9.3 MW) in the Tanintharyi Division near Dawai.

5.7 The government of Thailand has recently expressed an interest in the development of hydro schemes on its borders with Myanmar at Nam Mesai (25 MW), and at Klong Kra (40 MW). Both schemes are however in remote areas of Myanmar, too far to be considered for connection into the national grid and intended for local development and export of power to Thailand. Accordingly they are not considered in MEPE's generation expansion plan.

Transmission and Distribution

5.8 MEPE's high voltage transmission system is in good operating condition much of which having been recently constructed under the IDA Power Project (Cr. 1245-BU). This comprises some 2,980 circuit km of 230/132 kV transmission, 1,233 circuit km of 66 kV subtransmission, 674 MVA of 230/132 kV grid substation capacity and 630 MVA of 66/33/11 kV primary substation capacity. [A summary of the existing and committed transmission lines and substations is given in Annexes 5.3 (a) and (b)]. Distribution networks comprise some 4,300 km of medium voltage (33/11 kV) lines, 4,300 km of low voltage (230/400 V), an estimated 800 MVA of distribution transformer capacity, and associated services for MEPE's 630,000 consumers. Up to date summary details of distribution plant and network details are not available, perhaps reflecting the low priority given by MEPE to this important part of their operations. The 230/132 kV grid extends 600 km across the lower and upper valley regions of Myanmar to interconnect the three principal systems: the Lawpita hydro system, and the gas based Pyay-Myanaung and Mann systems. The work to build the new grid was carried out in conjunction with a Kreditanstalt fuer Wiederaufbrau (KfW) funded project which included the construction of a 230 kV line between Thazi and Toungoo (to evacuate power from the proposed hydro station at Paunglaung). IDA also approved in 1987 an extension of the original Power project scope to enable MEPE to extend the grid by building some 66 kV subtransmission lines to reinforce supplies in the Yangon distribution network. Under normal conditions the new 230/132 kV systems would provide MEPE with a secure high voltage backbone grid interconnecting the Upper and Lower Myanmar load centres. However bottlenecks caused by limitations in the associated 132/66 kV systems, limit the capability of the 230/132 kV circuits of carrying large loads during emergencies. Under some circumstances the power system can also become inherently unstable; the condition occurs three to five times a year and inevitably results in major supply disruptions. Furthermore during lightly loaded periods the 132 kV system voltage levels rise in excess of design limits; for example at Thazi 230/132 kV substation voltages sometimes rises as high as 151 kV.

5.9 In contrast to the transmission investment program, there has been little matching investment in distribution which has been generally neglected over the last 40 years. As a result distribution networks throughout Myanmar are in very poor condition and urgently in need of rehabilitation. Losses are high, breakdowns are frequent and poor voltage conditions commonplace. The major urban networks supplying Yangon and Mandalay being more heavily loaded are in urgent need of reinforcement. The other rural networks are also in poor condition largely because of the unavailability of suitable materials. While sales have gone up at 8%/yr in the past decade, high voltage (HV) transmission line length have increased at 6%/yr, but medium (MV) and low voltage (LV) distribution line length have hardly changed, as shown Table 5.2. The loading on the distribution networks has therefore increased significantly over the same period.

Table 5.2 COMPARISON OF GROWTH OF HV MV AND LV SYSTEMS

Circuits (kilometers)	1977	1985	1990	Average Annual Increase
HV (230/132/66 kV)	753	1149	1720	6.0%
MV (33/11 kV)	2641	3085	3159	1.0%
LV (230/400 V)	4096	4265	4311	0.3%
Sales (GWh)	628	1263	1844	8%
Consumers (000s)	449	563	628	2.6%
Loading Indicators				
Ratio MV/LV lines	1.53	1.38	1.36	
MV GWh/km	238	409	583	7%
LV GWh/km	153	296	427	8%
LV Consumers/km	109	132	145	2%

5.10 Yangon, the largest distribution division in Myanmar accounting for 40% of demand, is supplied by a generally underground 33/6.6 kV primary system, and 230/400 V low voltage secondary networks. More recently overhead 11 kV networks have been introduced but this is not very extensive. Parts of the low voltage network use overhead (copper conductor) lines to serve domestic and street lighting services. Over 50% of the network was constructed before 1965 and about 10% of the cables were installed before 1940. Not surprisingly all the cables are badly overloaded, giving rise to poor service voltage conditions, and/or continuing failures. Frequent complaints of low voltages (as low as 60% of the contractual requirement) at small industrial and commercial premises confirm the situation. Upgrading work, carried out in recent years, has been done on a piecemeal basis with scant regard for longer term considerations. The distribution networks in Mandalay, the second largest city which accounts for about 20% of demand, is in better condition than Yangon but with similar problems characterized by high losses, unsatisfactory reliability and poor service voltage conditions. The Mandalay network and networks in most other areas in Myanmar are similar in design, being primarily overhead 11/0.4 kV networks supplied from 132/33 kV substation via several 33/11 kV primary substations. However, in contrast with Yangon and Mandalay, there is little or no detailed planning being undertaken in the other Divisions/States. It is notable that Bago, Magway and Sagaing Divisions have experienced the highest growth rates in Myanmar over the last five years and in all probability need considerable investment to improve their network.

C. Demand Forecast

5.11 Based on an analysis of sectoral demands using demographic and economic data (see para 1.24 and 1.27), two power demand forecasts were used for this report. The Base Forecast reflects an optimistic scenario assuming that MEPE will be able to minimize load shedding and maintain a modest level of growth until 1995. After 1995 it is assumed growth will accelerate as gas supplies become available in sufficient volumes to supply demands of both MEPE plants and industry. The Low Forecast reflects a pessimistic scenario wherein unsupplied demand will persist for some time at present levels at least until after 2000 when hydro capacity can be brought into service. Under the base case scenario, electricity generation in the year 2010 is predicted at 11,653 GWh in the interconnected system and 352 GWh in the isolated rural systems; while under the low forecast, demand is projected at about half that of the

base case--5,995 GWh in the interconnected system and 242 GWh in the isolated rural systems.

Table 5.3 SUMMARY OF LOAD FORECASTS 1990-2010

Year	Interconnected System Base Forecast (GWh)	Base Forecast (MW)	Low Forecast (GWh)	Low Forecast (MW)
1989/90	2371	376	2371	376
1994/95	3247	530	2897	446
1999/90	4593	771	3466	573
2004/00	7207	1227	4499	766
2009/10	11653	1985	5995	1021
Ave. Growth	8.4%	8.7%	4.8%	5.2%

Year	Isolated Rural Systems Base Forecast (GWh)	Base Forecast (MW)	Low Forecast (GWh)	Low Forecast (MW)
1989/90	138	61	138	61
1994/95	173	70	162	67
1999/90	201	74	170	68
2004/00	264	89	201	77
2009/10	352	112	242	89
Ave. Growth	4.8%	3.2%	2.9%	2.0%

D. Generation Investment Plan

Thermal Generation Options

5.12 The timely development of the natural gas resources in Myanmar will be critical to MEPE's development strategy over the next decade. Gas based power plants should form the base of its generation plan. Two gas supply scenarios are conceivable (para 3.18): a high gas scenario in which approximately 40-45 bcf/yr of gas is available for 25 years after the Moattama field is developed; and a limited gas scenario in which the current level of production (33 bcf/yr) declines slowly up to 2000. This assumes rehabilitation of the existing onshore fields.

Table 5.4 GAS SUPPLY SCENARIOS
(bcf/yr)

Scenario	1990	1995	2000	2005	2010
High gas	33	35	40	40	45
Limited gas	33	23	14	6	0

For the high gas scenario an overland pipeline would be required from Moattama to supply onshore facilities in the Delta area and then to the Pyay area by interconnecting pipelines, and possibly up to the Central Basin area. In the meantime gas supplies from existing onshore fields would be provided at a minimum level in order to maintain plant operations at present generation levels. In addition, to sustain growth in the short term, both Thaketa and Ywama stations would have to be fired with imported diesel oil for base load operation. Moattama gas supply, assumed to become available in late 1995, would be adequate to enable MEPE to fully utilize existing plants and to

develop a balanced least cost gas/hydro generation expansion (para. 5.17). For the limited gas scenario, expansion of the pipeline network would not be viable. The operation of existing power plants would need to be rescheduled. At the same time the Pyay area gas supply decreases from 13 bcf/yr to 4 bcf/yr would necessitate delivery of bulk diesel oil supplies from the Chauk and Thanbayargan refinery to Mann, Shwedaung and Myanaung generating stations.

5.13 The coal reserves in Kalewa (para 2.19), are the only significant deposit for consideration for further coal development in steam based power plants at the present time. The high volatile content and good burning characteristic of Kalewa coal, however, make it ideally suitable for pulverized fuel and fluidized bed boilers for power generation. It is possible that a production operation with a capacity of some 500,000 tons/yr would be feasible, probably in three smaller mines and could either be laterally along the slopes or through sinking shafts. New mines could be brought into production as and when the demand arises. It would take three to four years to get on a power plant stream. A preliminary estimate of costs of coal production are between US$25 and US$30/ton, and the investment for the mine would be about US$45 million.

Hydro Generating Options

5.14 From a large number of potential hydro sites which could be considered for development (para 2.26), seven schemes were identified by MEPE in 1988. They include: Bilin, Shwezaye, Htamanthi, Yeywa, Mon Chaung, Kun Chaung. As indicated in Table 5.5, the best prospects aside from Paunglaung, in terms of lowest capital cost/kW, lowest levelized generation costs (LGC) and proximity to the grid are: Bilin in Mon State about 100 km from Yangon; Yeywa about 50 km from Mandalay; and Kun Chaung near Bago. Bilin is considered the most attractive scheme and preliminary investigations by Norconsult in 1982 indicate that better live storage may be developed there at lower cost than at Paunglaung Regrettably however the Bilin site is located in a "brown area" i.e. not yet free of insurgent activity and it may be difficult at the present time to carry out a thorough site investigation. Two other schemes are also under investigation: Saingdin Falls (15 MW first stage of 75 MW final development proposed in 1953), and Nam Mesai (25 MW) both of which are considered too far from the grid and therefore not included in the plan. In September 1990, MEPE initiated new feasibility studies for Bilin and Kun Chaung; when the results of this work is available, the relative positions of these schemes should be reviewed in the list of potential plants.

Table 5.5 SUMMARY OF COMPARATIVE HYDRO CHARACTERISTICS

Site	Installed Capacity (MW)	Storage Capacity (Mcu.m)	Annual Energy (GWh)	Capacity Factor (%)	Capital Costcosts ($US/kW)	LGC (c/kWh)
Baluchaung #3	48	828	338	80.4%	33335.77	
Paunglaung	280	690	911	37.1%	23758.95	
Bilin	240	10600	1000	47.6%	19005.65	
Yeywa	400	2602	1402	40.0%	15675.48	
Mon Chaung	200	7802	700	40.0%	315810.98	
Kun Chaung	84	1666	350	47.6%	20666.06	
Htamanthi	1200	39180	5270	50.1%	28507.96	
Shwezaye	600	1604	2000	40.0%	331911.55	

Notes
1. Capital costs exclude interest during construction and are based on original estimates by NEWJEC and increased prorata with current estimate for Paunglaung.
2. The estimate of LGC is based on a 40 year plant life assuming a 12% interest rate.

Least Cost Generation Development Plan

5.15 Modelling studies of the least cost generation expansion plan were performed using the Energy and Power Evaluation Program (ENPEP)[1]. The plan includes: (i) existing plants; (ii) committed projects, e.g. Baluchaung #2 which is under construction; (iii) Conversion of Shwedaung, Mann, Myanaung, and Thaketa, to combined cycle operation in order to increase fuel efficiency from approximately 20% to 38% whilst simultaneously increase output by up to 47%; and (iv) retirement of older or inefficient units including Ywama, Thaton and Mawlamyaing. Possible options include (i) up to 500 MW combined cycle plants (in 50-100 MW units depending on system size at the time of commissioning); (ii) 300 MW steam station with multi fuel capability for coal/oil/gas burning; (iii) 200 MW minemouth plant near Kalewa; (iv) various hydro stations; (v) a station comprising up to either eight 12 MW medium speed diesel power plants or four 25 MW low speed diesel units with facilities for gas burning when gas becomes available. Feasible sites for thermal plant or combined cycle plants would be: Thaketa, Ahlone and Kyaiklat. These sites are close to the main load centre (Yangon), and have access to port facilities. Plants would be designed with the aim of eventually using gas from the offshore Moattama field. Prospective thermal station sites could be considered in the location of existing plants. However, further development at Mann, Myanaung, Shwedaung and Ywama would depend on the overland development of the gas pipeline networks. This would depend on when Moattama gas is available for use in the Central Basin, and of the competing requirement by the industrial sector. No further development at Kyunchaung is likely, but the station would normally be operated for peaking purpose.

5.16 To obtain an overview of the options for generating electricity, the table below shows the LGC of different thermal plant, at capacity factors (CF) corresponding to peak load and base load operation. The gas turbine and combined cycle plants are estimated to be lowest cost options, mainly as a result of the relatively low price of gas, of US$2.00/mcf which as a domestic fuel is assumed to remain constant over a 20 year period.

Table 5.6 LEVELIZED COST OF THERMAL GENERATION

Plant Type	Capacity	Fuel	Peaking LF=.2 (c/kWh)	Base LF=.8 (c/kWh)
Gas Turbine	50	Gas	7.88	5.01
Combined Cycle	50	Gas	7.92	3.43
	50	Diesel	12.22	7.23
Steam 100 MW	100	Imported Coal	21.35	4.69
Steam 50 MW	50	Coal (Kalewa)	19.56	5.33
Steam	50	Fuel Oil	17.58	8.41
Diesel Engine	12	Diesel	20.71	9.49

[1] ENPEP is the PC version of the WASP - Wien Automatic System Planning: software used by utilities in utilities under the auspices of the International Atomic Energy Agency.

5.17 A least cost expansion plan based on the official exchange rates was derived for Myanmar for the base case of high power demand and high gas availability and is summarized in Table 5.7 and Annex 5.7. The results show that the plan would require (i) the conversion of Shwedaung, Mann, Myanaung and Thaketa to combined cycle operation adding 140 MW to system capacity by 1995; (ii) use of diesel oil at Thaketa and Ywama but change over to gas in 1996; (iii) gas supplies at the other plants remaining at present levels even though output would be increased; (iv) construction of a new 250 MW combined cycle plant for commissioning beginning in 1996 with the first 50 MW unit; and (v) after 1999 a further 250 MW combined cycle plant would be necessary probably using larger unit sizes--100 MW--to take advantage of economies of scale. At that time gas fired combined cycle generating plant would comprise over 75% of total system capacity leaving MEPE vulnerable to supply problems even if more gas is found. The prudent approach, would be therefore to commission Paunglaung and Bilin hydroelectric stations as the next major capacity increments (520 MW in total). Subsequent hydro development prospects would include Mon Chaung, Yeywa, and Shwezaye hydro plants. The order in which these are commissioned however would depend on the findings of future feasibility studies to determine the likely costs of development.

Table 5.7 LEAST COST DEVELOPMENT PROGRAM

High Power Demand-High Gas Availability

Reserve Year (%)	Generation Capacity Increase	Fuel	Generating Capacity Incrs (MW)	Total (MW)	System Peak (MW)
1990	Existing Peak Generating Capability			399	3760%
1991	Thaketa/Ywama Gts to use diesel	Diesel	60	459	45918%
1992	Rehabilitation Program completed	-		562	41426%
1994	Convert Shwedaung/Mann to Combined Cycle	Gas	71	633	48923%
1995	Convert Thaketa/Myanaung to CC	Gas	71	633	53023%
1996	New 50 MW Combined Cycle Yangon C-C#1	Gas	50	735	56623%
1997	Additional Yangon C-C A#2	Gas	50	785	60523%
1998	Additional Yangon C-C A#3	Gas	50	835	65621%
1999	Additional Yangon C-C A#4&5	Gas	100	935	71124%
2000	Ywama Steam Turbine retired	Gas	-36	935	77118%
	Additional Yangon C-C A#6	Gas	50	949	77111%
2001	New 100 MW Combined Cycle Yangon C-C B#1	Gas	100	1049	84919%
2002	Additional Yangon C-C B#2	Gas	100	1149	92220%
2003	Paunglaung	Hydro	280	1429	101529%
2004	Baluchaung #3	Hydro	48	1477	111624%
	Retire Thaton/Hawlamyaing Plants	-	-47	1430	14%
2005	Bilin	Hydro	240	1670	122826%
2006	Yeywa	Hydro	400	2070	148735%
2007	Mon Chaung	Hydro	200	2270	148734%
2008	Shwezaye	Hydro	600	2870	163843%
2009	Kun Chaung	Hydro	84	2954	180339%
2010	Retire Oldest Combustion Turbines	-	-150	2804	198629%

Sensitivity Analysis

5.18 In the event that there is limited offshore gas available for electricity generation, conversion of existing combustion turbines in combined cycle remains feasible. However, as on-shore gas supply declines, there would be a shift of fuel to imported diesel oil and additional capacity would have to come from steam plants. Two alternative scenarios were examined to test the

sensitivity of the base case in the period 1991-2000 under the new conditions. The results are summarized in Annex 5.4 (c). For the base case forecast scenario assuming that Kalewa coal field development proves to be feasible in the next two years, then a 200 MW minemouth plant would be implemented, with a first 50 MW unit ready for commissioning in 1996. Later on, a 300 MW coal fired station would be installed near Yangon using imported coal. Alternatively, in the event that the domestic coal option is not feasible, the proposed steam plants would be located near Yangon and dual-fired using imported heavy fuel or coal depending on the market price of these fuels. In the long term, the next additions would come from the hydro plants. For the low scenario of demand, the conversion process would be delayed along with the decision regarding the appropriate fuel for steam plants. The commissioning of the first unit would be required only in 1999.

5.19 For the above program energy production and fuel consumption, including the requirement for rural diesel generation, are shown in Annex 5.1 and summarized below. Gas consumption shows a gradual increase after Moattama gas is brought onshore following the development of the field. Fuel oil usage is terminated after 2000 when the Thaton and Mowlamyaing plants are retired. After 1995 diesel oil is largely used only to meet the electricity demands of the rural sector.

TABLE 5.8(a) ENERGY GENERATED FOR THE BASE CASE SCENARIO (GWh)

Generating Station	1991	1995	2000	2005	2010
Gas Turbines/Comb. Cycle	1313	1821	3372	3705	5331
Diesel/Steam Plant	456	223	263	263	352
Hydro	1091	1546	1546	4226	6993
TOTAL	2860	3594	5181	8194	12677

TABLE 5.8(b) ANNUAL FUEL CONSUMPTION 1990-2010

	1991	1995	2000	2005	2010
Gas (bcf/yr)	19.65	19.67	34.40	35.49	51.15
Fuel Oil (bbl/yr)	0.10	0.10	0.13	0.00	0.00
Diesel (bbl/yr)	0.78	0.28	0.32	0.41	0.56

The investment requirements for the base case covering the additional generation capacity commissioned before the year 2000 are detailed in Annex 5.7. Their preliminary cost estimates are summarized as follows.

Table 5.9 POWER SECTOR INVESTMENTS

	(US$ million)		
	Foreign	Local	Total
1) Rehabilitation of existing plants (including provision for oil handling facilities)	93.03	52.57	145.61
2) Conversion of existing plants to combined cycles	128.90	43.00	171.00
3) Installation of new 300 MW combined Cycle plant near Yangon	195.60	84.00	279.60
TOTAL INVESTMENT	417.53	179.57	596.20

5.20 Based on studies currently being carried out by MOE there appears to be potential for new cogeneration schemes associated with the refineries, paper mills, fertilizer plants, textile factories, and in food processing. The introduction of such schemes would provide dual benefits; they would make more efficient use of gas that is available and would reduce electricity demand on the interconnected system.

E. Transmission and Distribution Development

5.21 To match the generation expansion program, the transmission system will need to be continually reinforced and extended in the 1990's as the loadings increase. The few bottlenecks that now exist will need to be addressed along with the planning of extensions to individual substations to meet the forecast demand. The Load Dispatch Centre (LDC) will also need to increase its monitoring capability to cover all outstations and eventually introduce remote control facilities. This will necessitate the installation of alternative communications facilities, using either microwave or fibre optics links carried on the existing tower circuits. It will also involve considerable rewiring work at the outstations (power stations, substations, administration and operation centres) to install suitable exchanges and associated outstation equipment. The transmission expansion plan would also be designed to (i) transmit power from new generating plants, (ii) reinforce transmission and substations to meet load growth, and (iii) allow for modest expansion of the distribution networks. The scope of work together with preliminary cost estimates, excluding local taxes and interest during construction, is summarized below and detailed in Annex 5.5.

TABLE 5.10 TRANSMISSION DEVELOPMENT PLAN

Project	Base Cost Estimate (US$ Millions)		
	Foreign	Local	Total
132 kV Interconnection with Thaton System	8.62	6.56	15.18
Yangon 66 kV Reinforcement Project	24.25	19.83	44.08
Upgrading System Control Facilities	11.23	5.01	16.24
Ayeyarwaddy 66 kV Subtransmission	5.78	4.21	9.99
Monywa/Mandalay/Kyunchaung 132 kV project	14.73	10.98	25.71
General Substation Uprating program	16.08	11.07	27.15
TOTAL TRANSMISSION DEVELOPMENT	80.69	57.66	138.35

5.22 With regard to distribution, the only comprehensive planning study covering the needs was performed in 1985 under GTZ funding from the Federal Republic of Germany in the form of a Master Plan for future development of the Yangon network. It proposed that MEPE replace the 6.6 kV system by 11 kV as soon as feasible, and gradually uprate the 33 kV networks to 66 kV. In 1986 Norconsult, from Norway, also prepared a conceptual plan for the implementation of a 66 kV network. In 1988, EPDC, Japanese consultant, prepared yet another report for the rehabilitation of the Yangon distribution network which recommended a development program costing approximately 50,000 million yen (US$330 million). The report's estimate of the work still needed to rehabilitate the Yangon system is based on the design concepts set out in the Norccnsult report. The scope of work involved will extend the current 66 kV construction program with a view to completing the voltage upgrading program and associated distribution by 1996.

5.23 MEPE distribution designs need to be updated to improve operational reliability and reduce investment costs. Savings can be effected by rationalizing the use of the different voltage classes throughout Myanmar. In Yangon the use of 33/11/6.6 kV systems should be phased out in favour of 66/11 kV as soon as feasible. Consideration should be given to the greater use of overhead lines, in preference to underground cables which are generally in use at present for MV and LV feeders. The long term cost of overhead lines can be reduced through the use of more efficient concrete pole designs, by replacing LV copper conductors, and MV Aluminum Carbon Steel. Reinforced (ACSR) conductors by all aluminum conductors, and by making other design improvements, particularly with regard to connection and isolating devices, in accordance with modern practice.

5.24 Special attention should be given to improving the design of low voltage distribution systems. Distribution transformer sizing needs to be reviewed to improve the utilization of existing LV circuits. In many cases transformers are too large for the associated LV networks resulting in overloading and poor voltage conditions. In many urban and rural areas the greater use of LV "bundled" (insulated) conductors should be considered to reduce tampering and improve reliability of supply. Bundled conductor systems are now in widespread use throughout South East Asia; their overall costs have become competitive with conventional bare conductor systems, they are easier to install and suited to densely populated urban environments. A review of metering practice would also be beneficial with the aim to rationalize the practice of dual metering for domestic consumers and to replace most of the older and inaccurate types of meters.

5.25 With regard to commercial operation of the distribution networks, most accounting and billing functions are done manually throughout Myanmar. MEPE are currently installing a pilot computerized billing system in Yangon area, to improve the efficiency of metering and bill collection. Modern computerized billing systems offer considerable advantages over manual billing operations, not only with regard to improvement of financial operations of the utility, but also with regard to their monitoring capability. Data available to management through billing system can be designed, in conjunction with other technical data bases, to provide essential information about consumers, organization efficiency, and status of plant. To get the most effective use from MEPE computer billing system its expansion needs therefore to be planned carefully. In particular it would be necessary to perform a thorough review of existing organizational procedures to support computerized billing and make changes to standard forms and collection and billing procedures to handle the flow of information.

5.26 Based on above, preliminary estimates of costs for distribution construction and rehabilitation, excluding local taxes and interest, are shown below and detailed in Annex 5.6:

TABLE 5.11 DISTRIBUTION DEVELOPMENT PROGRAM

	(US$ Millions) Foreign	Local	Total
Yangon 11/0.4 kV Rehabilitation	37.74	19.30	57.04
Mandalay Division	12.61	7.28	19.89
New Towns Project	10.88	6.50	17.38
Urban Division/States	43.51	26.01	69.52
Rural Division/States Towns	43.51	26.01	69.52
Rural Electrification	11.52	5.52	17.04
TOTAL	159.78	90.63	250.41

F. Investment Profile

5.27 The consolidated investment needs of generation, transmission and distribution in the least cost expansion plan for the base case scenario, for projects commissioned before 2000, are estimated to cost US$658 million in foreign exchange matched by US$681.6 million in local funds, including 356.2 million in taxes and duties. The components are summarized below and detailed in Annex 5.7. Expenditure in the latter part of the decade should also include development costs for the hydro projects which are commissioned after 2000.

TABLE 5.12 INVESTMENTS IN POWER SECTOR
(Excluding Taxes and Duties)

	1991-2000 Total (m$)	1991-2000 Foreign Cost (m$)	1991-1995 Total (m$)	1991-1995 Foreign Cost (m$)
Rehabilitation	145.61	93.03	145.61	93.03
Generation	450.50	324.50	255.70	188.10
Transmission	138.35	80.69	76.60	43.74
Distribution	250.41	159.69	132.00	93.52
TOTAL	984.86	658.00	610.55	418.39

G. Marginal Costs of Supply

5.28 The estimated long run marginal cost (LRMC) for 1990-2000, reflecting the lower capital costs of the combined cycle expansion component, and the estimated LRMC for 1990-2010, reflecting the higher investment costs of subsequent hydro expansion, for the base case were calculated. The results are indicated in Table 5.13. Two sets of values are shown for each level of supply (i) a value in US currency (c/kWh) reflecting the opportunity costs of capital and operations as used in the ENPEP analysis; and (ii) a value in Myanmar currency (k/kWh) computed by converting all foreign costs at the exchange rate of 50k/US$ and making no adjustment to local costs as detailed in Annex 5.8. The latter value indicates the magnitude of the increase in tariff that would be necessary to be able to finance future investments. On the basis of these marginal costs of power, the existing tariff would be inadequate. Therefore, a new tariff level would need to be put into effect to cover MEPE medium term investment requirements. The design of an appropriate tariff structure would also need to take into account the characteristics of MEPE consumers to provide incentives for increased efficiency in the use of electric power.

Table 5.13 ESTIMATED LONG RUN MARGINAL COSTS OF MEPE SYSTEM

Level of Supply	Energy Costs			
	1990-2000		1990-2010	
	(c/kWh)	(k/kWh)	(c/kWh)	(k/kWh)
Generation	2.7	1.05	4.9	1.97
Transmission	3.0	1.17	5.3	2.12
Subtransmission	3.8	1.47	6.7	2.68
Medium Voltage	4.8	1.82	7.9	3.14
Low Voltage	8.7	3.33	11.1	4.40
Ave. Cost of Supply	6.5	2.48	9.0	3.58

H. Issues in the Power Sector

5.29 The major issue in the power sector is the lack of planning. The situation has been exacerbated by lack of planning in the past to deal with contingency situation that has arisen because of fuel shortfalls for power generation. Lack of planning also affects the deterioration of distribution networks which have become grossly overloaded. Indeed investment in the power sector has fallen well behind the needs estimated in the Bank's 1985 Energy Sector Review. For the ten year period 1985-1994 estimated capital expenditure was to have been US$1,666 million. In fact very little has been expended in accordance with the original budget even though demand has more than doubled in the last decade. The largest investment in the last five years has flowed from IDA first lending operation to the sector (Cr. 1245-BU) approved in June 1982 but only recently completed. Other significant recent investment was financed by Overseas Development Administration from the United Kingdom (33/11 kV substations), Overseas Economic Cooperation Fund of Japan (Thaketa power station, Lawpita rehabilitation), and Kreditanstalt fuer Wiederaufbau of Germany (KfW) (Kinda project). Whilst planning is at a standstill, even 'committed' projects have been postponed and critical preparatory work needed to formulate plans for further investment has been put on hold. Key projects and investigative work for (i) conversion of Shwedaung and Mann power stations to Combined Cycle operation; (ii) rehabilitation of Yangon distribution system; (iii) construction of Baluchaung #3 hydro project; (iv) provision of spares to maintain operations at Myanaung, Ywama, and Kyunchaung power stations; (v) feasibility study of the six next ranked hydro schemes; and (vi) an overall Sector Development Study, have all been delayed.

5.30 The principal issue with regard to generation is the critical gas and oil fuel supply situation. Gas use for electricity generation expanded by 18% annually on average over the last ten years. Since 1989 supply has been curtailed and now gas production from existing fields is declining very quickly. In the long term, gas should continue to play an important role in power generation provided its price remains competitive, and more importantly provided MOGF can guarantee adequate supplies. MEPE, however, consumes gas very inefficiently in open cycle combustion turbine sets. Their typical operating efficiencies ranging between 18-24% is normally acceptable for peaking duty but not for base load. Performance can be improved considerably to obtain efficiencies up to 38%, by installing heat recovery and steam generating equipment for combined cycle operation. Two such heat recovery units are already installed at Ywana generating station. However, they are not yet in operation, awaiting rehabilitation of the steam turbine equipment.

5.31 Generation by hydro-electric power stations lacks a comprehensive plan for its development. Although Myanmar has considerable hydro-electric potential (para 2.24), very few of the potential schemes have been fully evaluated particularly with regard to power sector requirements. For example, the two recently completed schemes, Kinda and Sedawgyi, have been primarily developed for their irrigation capability and do not make a significant contribution to power supply. Recently however the government announced its plan to accelerate the program of hydro development giving priority to a number of schemes that have been considered for some time. Extra benefits of developing Myanmar's hydro resources, above those from electricity generation, would be hydro's potential reliability, downstream irrigation benefits, and local employment created through major construction of dams and other civil works. However hydro power development requires considerable investment and long lead times for its planning and construction, and it is essential that alternative schemes are properly evaluated and prioritized early for development.

5.32 Generation by coal fired power plant also appears to be an option that has not been explored. A coal fired plant could be sited in the lower Delta area in a location where imported coal supplies can be delivered. Such a station could be provided with facilities to burn gas when offshore supplies becomes available. The possibility of a minemouth coal fired station at Kalewa should not be overlooked, but exploratory drilling would be needed to prove its feasibility notably with regard to reserves, before this prospect could be considered seriously.

5.33 The principal issue with regard to distribution is the high level of losses which results in considerable loss of revenue and waste of generation resources. MEPE statistics show losses have not improved from 35% in 1984 when a pilot Loss Reduction Program was undertaken under the IDA Power Project. Indeed the situation is similar to many systems in Asia at a stage when they were characterized by relatively high system losses largely as a consequence of rapid growth in demand. These have however been brought down from 30-35% over a 5-10 year period with little effort. Average overall losses for Indonesia, Sabah/Sarawak, and the Philippines, for example, now range between 20-22%. Experience in Thailand indicates these can be reduced even further by concerted effort; as a result overall distribution loss levels remain 6% in Bangkok city, and 8% throughout the Provincial Electricity Authority largely rural service areas. It is clear, therefore, that with adequate planning and commitment by management, losses in the Myanmar system could also be reduced significantly.

5.34 As shown in Annex 5.9, from 1981 to 1988, residential tariffs in Myanmar were higher than industrial tariffs which reflected the higher costs of serving the low voltage residential sector. Tariffs were increased overall in 1988 but they were set almost equal for the residential and industrial sectors. As a result, the flat tariffs offer little incentive for consumers to reduce their demand on the system. Energy based tariffs have little relationship with the cost of supply, offering therefore minimum scope for efficiency improvements.

TABLE 5.14 AVERAGE REVENUES

	1981-82		1988-89	
	kWh Sales (%)	Rev. (%)	kWh Sales (%)	Rev. (%)
Residential (LV)	30	46	35	42
Industrial (HV)	53	32	52	42
Bulk (MV)	14	16	10	11
Others	4	6	3	4

5.35 Unlike most of its Asian neighbors, Myanmar has no strategy for expanding its rural electrification program. In 1979, the number of villages electrified was 709. It rose to only 751 in 1989. Approximately 20% of MEPE's consumers (9% of total demand) are served by isolated diesel/mini hydel power stations scattered over the 14 Divisions/States of Myanmar. The number of diesel engines has increased from 570 in 1985 by only 60 to date. The rate of growth of new consumers and consumption in these areas is significantly lower than for the interconnected system. The government is now pressing for extension of existing distribution networks throughout Myanmar to provide power to a number of proposed new towns created by its relocation policies. For the four new towns near Yangon, for example, MEPE estimates that the respective loadings by 2000 would be as follows: New Dagon 16 MW, Shwepyitha 5 MW, Pale 8 MW and Hlaing Thay 6 MW. However, there is little associated infrastructure in place in the new towns and prospects for growth may be optimistic. In the event that the projects are implemented as planned, there will be further strain on the critical power supply situation in Yangon.

5.36 In contrast to other ministries in Myanmar, and certainly in contrast with comparably sized power utilities in Asia, MEPE staff have an inadequate working environment including poorly maintained office buildings, furniture and operating equipment (vehicles, tools); inadequate facilities such as computers, copying equipment, technical and administrative support materials (e.g. drafting, filing, workspace etc); and absence of training programs and facilities. Although a new head office complex is under construction in Yangon, the problem is particularly acute in MEPE's distribution divisions where the most urgent attention should be focused. For an organization with a budgeted revenue of 900 million kyats in 1989/90 little has been spent on important institutional measures to improve MEPE's overall efficiency.

I. Conclusions and Recommendations

Generation Development

5.37 In the short term, MEPE should take immediate steps to improve its power supply situation. Generating units are curtailed due to lack of repairs and/or fuel, or they are on extended outage due to lack of spare parts. Limitations in gas supplies however provide the main cause for concern and an immediate plan should be established and implemented to cover the next three to five years of power supply. This would involve the following steps:

(a) Procure crude oil for refining and supplying sufficient diesel oil in order to (i) maintain continuous operation of Thaketa and Ywama power plants; (ii) ensure standby operation of the Shwedaung, Mann, and Myanaung plants; and (iii) satisfy minimum needs of the rural

sector. For these plants diesel requirement could be as high as 740,000 bbl per year. In addition, steam plants at Thaton and Mawlamyaing will require up to 400,000 bbl per year of fuel oil.

(b) Prepare, as soon as possible, all of the above stations for burning either diesel oil or gas, arrange for transfer and storage of diesel at each site, and commission or rehabilitate fuel oil storage and handling facilities.

(c) Design and implement early conversion of the Thaketa, Mann and Shwedaung plants to combined cycle operation. This would add 103 MW to the system and reduce gas consumption by up to 50%. Likewise conversion of the Myanaung plant should also be considered within 12 months after reviewing the fuel supply situation.

5.38 In the medium term, the critical issue is related to the availability of gas. MEPE cannot afford the risk of waiting to decide whether gas would become a long term viable source of fuel for its least cost combined cycle development. In its own interest, MEPE must take steps to investigate alternative generation options. At this stage, the most likely candidates for the 1990's are steam plants burning either fuel oil, or coal, depending on availability, and hydro. However, more investigation work is needed to establish the costs and risks of development, as well as the infrastructural support, needed to develop the resources.

5.39 For the longer term MEPE must prepare an optimal development plan to exploit its hydro resources. Specific planning should begin immediately for large hydro generation projects which generally have long incubation periods.

5.40 To promote generation in the private sector three situations deserve to be encouraged by MEPE: (i) where an industry has a continuous demand for steam for process heating, cogeneration, with its higher thermal efficiency than conventional thermal power plant, makes it economically more attractive; (ii) where a plant produces waste (such as sugar mill bagasse, saw mill waste, rice husks etc.) that can be used as fuel; and (iii) where a local resource (such as a hydro site, a coal mine, a geothermal reservoir or peat deposit) can be developed to meet a specific industrial requirement.

Transmission and Distribution Development

5.41 MEPE needs to prepare a ten year transmission and distribution development plan. This should examine the nature of future development with a view to rationalizing design procedures to reduce costs. It should also include a review of tariffs and a strategy for rural electrification to maximize the return on investment in the power sector.

5.42 There is considerable scope to reduce losses and to increase electricity conservation. A concerted effort by MEPE management to bring losses down is essential in order to increase revenues and reduce the incidence of load shedding. This can be done by reinstating the activities and strengthening the role, of the Loss Reduction Unit that was established under the IDA Power Project.

VI. TRADITIONAL ENERGY SECTOR

A. INTRODUCTION

6.1 The biomass fuel resources of Myanmar consist principally of woodfuels (fuelwood and charcoal), but there is also a considerable quantity of agricultural residues that could be used for fuel without adversely affecting soil fertility or animal husbandry. A major portion of the woodfuel resource is present in the forests of the country, but trees along road sides, around fields and within village compounds also contain significant quantities of fuel. However, there is a scarcity of reliable data on the standing stock and sustainable yield of woodfuels. There is also no reliable data on the quantity of agricultural residues available for fuel.

6.2 In 1989/90, woodfuel consumption in Myanmar[1] was estimated to be approximately 27 million air dry tons (adt), equivalent to 9.3 million tons of oil equivalent (toe), representing about 82% of the total energy consumption for the country. In 1982/83 woodfuels and non-woody biomass provided 86% of the energy consumed in the household and small/cottage industry sector and it is estimated that approximately the same situation exists today. In the rural areas, fuelwood is used almost exclusively for household cooking with a limited amount of agricultural residues in the form of cotton and pigeon pea stalks being reportedly used in the Dry Zone areas of Sagaing and Mandalay Divisions. Fuelwood is also widely used in a variety of small/cottage industries, such as jaggery boiling, brick making, pottery and cheroot production; while substantial quantities of agricultural residues are also used, including ground nut shells, ziziphus fruit shells, rice husks, and sesame stalks. Urban areas consume approximately 25% of the woodfuels primarily for household cooking and heating. Charcoal, although representing only 5% of the woodfuels consumed, is primarily sold in urban centers. As a result of this relatively concentrated demand, its increasing sales are an important cause of mangrove forest degradation.

6.3 Although Myanmar is endowed with considerable vegetation cover, including 31.6 million ha of closed high forest (47.5% of land area)[2], there has been a steady degradation and depletion of this over the last several decades due to clearing for agriculture, both settled and shifting, and collection of wood for fuel. As Table 6.1 shows, there has been a steady decline in the percentage of land area covered by forests: between 1925 and 1975, there was an estimated annual average depletion rate of 175,000 ha per year, but in the period 1975 to 1980, this rate appears to have jumped to 700,000 ha per year according to some estimates. There is some correlation between the above depletion rates and the depletion of mangrove forest in Ayeyarwady Division. There is also a correlation between the cessation of kerosene supplies for household energy use in the mid 1970s and the sharp rise in forest depletion: between 1961/62 and

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[1] Myanmar is divided into 14 territorial forestry regions which correspond with the administrative divisions. These are subdivided into 48 township groups, previously known as forest divisions. There are 232 townships, each headed by a township officer.

[2] See map IBRD 22978

1975/76, charcoal consumption rose at an average annual rate of 5%, but between 1974/75 and 1982/83 consumption rose by an average of 16% with increases of 20 and 35% respectively in each of the first two years of this period. Fuelwood consumption between 1967/88 and 1973/74 rose at an average annual rate of 0.35%, but between 1973/74 and 1983/84, this rate averaged 4%. There may also be some correlation between the increased depletion of forests in the second half of the 1970s and increased agricultural activities.

TABLE 6.1 DEPLETION OF FOREST COVER

Year	Forest Cover (%)
1925	65.8
1958	57.2
1975	52.7
1980	47.3

Source: Pe Thein, 1990 and FD, 1989.

6.4 The deteriorating forest situation is shown in Table 6.2 where between 1975 and 1980, a total of 6.37 million acres of closed forest were lost as was 2.63 million acres of degraded forest. In the same period, the area affected by shifting cultivation increased by 0.41 million acres in closed and 2.64 million acres in degraded forests.

B. THE RESOURCE BASE

6.5 As in the case in most other countries, there has been little effort made to estimate, with some degree of reliability, the standing stock and annual sustainable yield of wood fuel in Myanmar. Estimates have been made of the standing stock of commercial timber, but until the current national forest inventory, much of the resource data was out of date and often the reliability was suspect. Estimates for the woodfuel supply area for each administrative division were made by the mission using forest class maps prepared from 1980 satellite imagery. Within each division, the areas of the four forest classes as shown in Table 6.3 (Closed Forest, Closed Forest Affected by Shifting Cultivation, Degraded Forest and Degraded Forest Affected by Shifting Cultivation) were considered in relation to their distance from urban centers and rural population concentration. It should be emphasized that these estimates are rough, but are the best available at the present time. It will be observed that only 20% of the closed forest in included in the woodfuel supply area reflecting the fact that much of the closed forest is relatively remote from woodfuel consumption centers. It is, however, possible that woodfuels could be available from more of these closed forests if they became more economically accessible and the management prescriptions were changed to include the cutting of non-teak species for commercial purposes and fuel.

TABLE 6.2 THE CHANGING AREA SITUATION BETWEEN 1975 AND 1980
('000 acres)

State or Division	Year	Closed Forest	Cl.Forest affected by shift cult.	Degraded Forest	Deg.Forest affected by shift cult.	Non Forest	Total
Chin	1975	2703	2030	1178	2500	487	8,898
	1980	2408	1575	1368	2898	650	8,899
Ayeyarwady	1975	1347	0	1300	0	6035	8,682
	1980	1233	0	1004	0	6445	8,682
Kachin	1975	15766	3066	54	559	2557	22,002
	1980	13977	3622	245	922	3237	22,003
Kayin	1975	2634	1813	281	1436	1343	7,507
	1980	2575	1986	355	1356	1235	7,507
Kayah	1975	1041	771	465	289	330	2,896
	1980	758	808	401	457	476	2,900
Magway	1975	1700	103	4611	13	4648	11,075
	1980	1666	193	3331	478	5408	11,076
Mandalay	1975	1872	600	1203	246	5229	9,150
	1980	1451	559	1015	403	5722	9,150
Mon	1975	352	313	697	432	1245	3,039
	1980	277	220	425	476	1640	3,038
Bago	1975	3525	269	1288	221	4383	9,686
	1980	3625	336	757	567	4453	9,738
Yangon	1975	284	0	49	57	2123	2,513
	1980	211	28	80	63	2131	2,513
Sagaing	1975	11785	2967	1996	104	6532	23,384
	1980	10089	3222	2087	299	7685	23,382
Shan	1975	8156	11067	2154	11782	5341	38,500
	1980	7091	10838	1909	11737	6926	38,501
Tanintharyi	1975	7041	846	927	1260	637	10,711
	1980	6762	835	757	1726	631	10,711
Rakhine	1975	4362	771	1047	349	2559	9,088
	1980	4121	804	779	495	2889	9,088
TOTAL	1975	62,568	24,616	17,250	19,248	43,449	167,131
TOTAL	1980	56,244	25,026	14,513	21,877	49,528	167,188

Source: FD

TABLE 6.3 ESTIMATES OF WOODFUEL SUPPLY AREAS BY DIVISION/STATE ('000 acres)

Division/ State	Forest Cover Classes: Closed Forest	Cl. For. Affected by Shift. Cult.	Degraded Forest	Deg/ For. Affected by Shift. Cult.	Total
Ayeyarwady	1233	0	1004	0	2237
Yangon	210	28	80	63	381
Bago	3625	300	756	568	5249
Shan	450	7587	1909	8800	18746
Rakhine	2470	804	780	495	4549
Mandalay	1200	560	1015	402	3177
Sagaing	720	3010	2088	300	6118
Mon	83	220	425	476	1204
Taninthanryi	1400	835	755	1730	4720
Chin	480	1575	1370	1450	4875
Kayah	30	810	400	455	1695
Kayin	750	1990	355	1355	4450
Kachin	700	3620	245	920	5485
Magway	1400	194	3330	478	5402
TOTAL	14751	21533	14512	17492	68288

Source: FD and Mission estimates

6.6 Very rough estimates of the standing stock of woodfuels within the woodfuel supply areas were obtained by using commercial wood volume estimates available from the National Forest Inventory and other FD estimates and then applying a factor, based on experience in similar countries, to obtain the amount of wood available for fuel. Table 6.3 shows the estimated average standing commercial volume for each of the four forest classes derived from the National Forest Inventory together with a factor that represents the ratio of total above-ground woody biomass to commercial woody biomass. The standing stock of wood available for fuel from roadside, village and farm trees was estimated at an average of 1.2 adt per household (0.24 adt/capita) for non-dry zone areas and 0.4 adt per household for dry zone. This took into account that only 40% of the wood present would be used for the fuel; the rest being for house building, shade, fencing and other purposes. The standing stock of woodfuel that is present as sawmilling waste was estimated as 50% of the volume of commercial wood. The total standing stock of woodfuel in 1990 is estimated at 1123 million air dry tons (adt) from a supply area of about 68.29 million acres (ac).

TABLE 6.4 VALUES USED IN ESTIMATING STANDING STOCK OF WOODFUELS

Forest Class	Vol. of Stan.Stk. (HCT/ac)	Ratio of Total Woody Biomass to Comm. Wood	Woodfuels Available (adt/ac)
Closed Forest	29	1.5	25
Closed Forest Affected by Shifting Cultivation	10	1.5	8
Degraded Forest	5	1.8	4
Degraded Forest Affected by Shifting Cultivation	1	2.0	1.4

Source: Mission estimates based on Natural Forest Inventory and FD estimates.

C. SUSTAINABLE YIELD OF WOODFUELS

6.7 Estimates of the sustainable yield of woodfuels are based on the mean annual increment (MAI) or growth of the forest, plantations and scattered trees. But there are no reliable data on these growth rates, in fact, it seems few such measurements have been made in Myanmar forests. In the absence of reliable growth data the mission applied estimates based on experience in other countries with similar geoclimatic conditions for growth rates for the various forest classes as shown below. Based on this data the total sustainable yield that could be harvested annually has been evaluated at about 21.46 million adt. About 85% of this stock is available from forests and plantations with the balance coming from non-forest trees in and around villages and farms.

TABLE 6.5 ESTIMATED GROWTH RATES FOR FOREST CLASSES

Forest Class	MAI (%)	Total MAI (adt/ac)	Woodfuel MAI (adt/ac)
Closed Forest	2.5	1.50	0.5
Cl.For.Shift.Cult.	3.0	0.65	0.2
Degraded Forest	5.0	0.45	0.2
Deg.For.Shift.Cult.	4.0	0.1	0.05
Plantations	20.0	3.0	0.6
Plantations (Dry Zone)	12.0	1.5	0.3

Source: Mission estimates (1990)

6.8 At this point, only a limited quantity of agricultural residues are used for energy and most of this is used in small/cottage industries, although the sugar industry uses bagasse as a fuel in its sugar mills. But it is likely that agricultural residue fuels will become increasingly important in divisions/states where woodfuels are or will be in short supply. Agricultural residues represent a substantial fuel resource, although care should be taken to only include those supplies that are surplus to higher economic values uses such as cattle fodder and manure to maintain agricultural land fertility.

6.9 Table 6.6 summarizes the estimates for the sustainable supply of woodfuel and non-woody biomass (agricultural residues) available for fuel by division and state in 1990. The former includes wood from the four forest classes plus sawmill residues and wood for fuel from roadside, village and farm trees as well as plantations. Thus while the total standing stock in 1990 is estimated at 1,123 million adt, the total sustainable yield that could be harvested annually has been evaluated at about 21.46 million adt for woodfuels and 5.624 million adt for crop residues.

TABLE 6.6 ESTIMATES OF WOODFUELS STANDING STOCK AND SUSTAINABLE YIELD, 1990
(million adt)

Division/State	Standing Stock	Sustainable Yield				
		Forests	Sawmill Residues	Roadside, Farm & Village Trees	Total Yield	Crop Residues
Ayeyarwaddy	62.7	0.96	0.08	0.22	1.26	1.3960
Yangon	11.9	0.18	0	0.22	0.40	.5120
Bago	177.1	2.60	0.03	0.53	3.16	1.1012
Shan	164.4	3.05	0.01	0.52	3.58	.3540
Rakhine	130.5	1.87	0.02	0.30	2.19	.2930
Mandalay	70.5	1.14	0.01	0.13	1.28	.6060
Sagaing	91.5	1.64	0	0.13	1.77	.5440
Magway	87.2	1.61	0.01	0.11	1.73	.3290
Mon	11.7	0.23	0	0.21	0.44	.2370
Tanintharyi	83.7	1.29	0.03	0.12	1.44	.0740
Chin	55.9	1.04	0	0.01	1.05	.0470
Kayah	16.8	0.33	0	0.02	0.35	.0250
Kayin	69.2	1.10	0	0.17	1.27	.1020
Kachin	89.7	1.43	0.01	0.12	1.56	.0930
TOTALS	1122.6	18.41	0.20	2.79	21.46	5.6242

Source: Mission Estimates (1990)

D. CONSUMPTION AND DEMAND

6.10 Data on woodfuels consumption is also scarce and unreliable, based mainly on limited surveys carried out by the FD. The mission used these estimates as well as estimates made by several other agencies and its own very limited sample to arrive at a current annual per capita consumption figure for woodfuels of 0.7 adt (0.9 m^3). It was difficult to see a clear difference between rural and urban consumption, but more definitive data may indeed show such a distinction. There was also some indication that the consumption could vary considerably by region, with the Dry Zone in central Myanmar possibly having figures as low as 0.2 to 0.4 adt per capita.

6.11 In 1990, it is estimated that the total woodfuel (fuelwood and charcoal) consumption was 28 million adt, which, compared to an estimated 23 million adt consumption in 1980 represents 2% average annual increase. The non-woody biomass consumption is estimated to have increased from 900,000 tons in 1980 to 1.5 million tons in 1990, an average annual increase of 5.2%, indicating the increasing use of this resource for energy, particularly in fuelwood deficit areas such as the dry zone, where it is thought that there is increasing substitution of fuelwood with crop residues. The major share (21 million adt or 75%) of the woodfuels consumption is in rural households where fuelwood is usually collected and burnt on a subsistence basis. Charcoal is not generally used in the rural areas, and very little in the way of non-biomass energy is consumed. In Yangon, the major woodfuel used in charcoal, although some fuelwood is consumed by households as well as by tea shops and sidewalk eating establishments. But most of other urban centers appear to use fuelwood almost exclusively (Annex 6.3).

6.12 While information on fuelwood and charcoal demand is limited, there appears to have been a significant increase in consumption shortly after kerosene supplies were curtailed in the mid 1970's. Charcoal and fuelwood consumption jumped in growth from a few percent per year to between 20% and 30%

per year in 1975 and 1976. Coincidentally, the reported harvest of mangroves increase markedly.

6.13 Projections of woodfuel consumption were based solely on population projections without any allowance for conservation or fuel substitution as there seemed to be little chance of this occurring at least in the medium term. These projections (Table 6.7) indicate that the overall sustainable woodfuel supply for the country is only about 75% of the 1990 woodfuel consumption and even with the addition of crop residues that could be available for fuel, there is still an overall energy biomass supply-demand gap of some 2.5 million adt. When woodfuel consumption and sustainable supply is compared on a state/divisional basis the results show that, despite 45% of the country being covered in forest, there are serious deficit situations in Central and Lower Myanmar that are leading to depletion and degradation of the forest resource and the attendant ecosystem. The former region is associated with the Dry Zone, i.e. Mandalay Division, the southern half of Sagaing Division and much of Magway Division. The latter is comprised of Ayeyarwaddy, Yangon and Bago Divisions, but with the former two being particularly affected. Urban demand in Yangon is a major problem, but the high rural population as well as urban demand in Ayeyarwaddy is also putting a strain on the woodfuel supplies.

6.14 There are two main areas that have inter-divisional transportation of woodfuels. The first of these is the Yangon woodfuel supply catchment that has Yangon city as the focal consumption point. Woodfuels, particularly charcoal, are currently transported from all these outlying Divisions to Yangon. In the Dry Zone, there is transport of wood from Sagaing Division to Mandalay City, while towns in the northwest of Magway Division obtain woodfuels from southern Chin Division. The trade between divisions/states in woodfuels, particularly charcoal, is likely to increase over the next 10 years. In 1990 the mission estimated that some 2.5 million adt of wood equivalent of woodfuels was traded with the major share of this (1.8 million) being imported into Yangon. By 2000, woodfuel trade is projected to be about 3.5 million adt with approximately 2.2 million adt being imported by Yangon. By then an increasing quantity (0.7 million adt) is also projected to be imported by Mandalay.

6.15 Table 6.7 shows the wood balance situation through 2000 to 2005. For those divisions that are overcutting this will result in a reduction in the standing stock and sustainable woodfuel yield. The extent of this reduction, and hence the exact sustainable yield in future years, is difficult to predict as the overcut areas are not necessarily lost completely. Regeneration from seedlings and coppice can and often does occur, perhaps quite vigorously, if the areas are protected over the first few years after cutting. On the other hand, however, areas may be repeatedly cut over a relatively short period of time so that regeneration is destroyed or severely degraded while some areas will undoubtedly be lost to agricultural encroachment.

TABLE 6.7 PROJECTIONS OF WOODFUEL CONSUMPTION, TRADE AND NET SURPLUS/DEFICIT BY DIVISION/STATE
For the years 1990, 2000 and 2005 (million adt)

Division/ State	Sustain. Yield Woodfuel	Internal Consump	Export	Import	Net Surplus/ Deficit	Crop Residue Fuel	Crop Residue Consump	Biomass Surplus/ Deficit
1990								
Ayeyarwaddy	1.26	3.99	1.20	0.10	-3.83	1.40	0.13	-2.56
Yangon	0.40	2.70		1.80	-0.50	0.51	0.46	-0.45
Bago	3.16	3.12	0.20		-0.16	1.01	0.15	0.70
Rakhine	2.19	1.63	0.20		0.36	0.29	0.05	0.60
Shan	3.57	2.98			0.59	0.35	0.09	0.85
Mandalay	1.28	3.79		0.40	-2.11	0.61	0.20	-1.70
Sagaing	1.77	3.19	0.40		-1.82	0.54	0.17	-1.45
Magway	1.73	2.64	0.20	0.20	-0.91	0.33	0.11	-0.69
Mon	0.44	1.35			-0.91	0.24	0.04	-0.71
Tanintharyi	1.43	0.74	0.10		0.59	0.07	0.02	0.64
Chin	1.05	0.30	0.20		0.55	0.05	0.01	0.59
Kayah	0.35	0.14			0.21	0.02	0.00	0.23
Kayin	1.27	0.85			0.42	0.10	0.02	0.50
Kachin	1.56	0.74			0.82	0.09	0.04	0.87
TOTALS	21.46	28.16	2.50	2.50	-6.70	5.61	1.49	-2.58
2000								
Ayeyarwaddy	0.86	4.51	1.00	0.30	-4.35	1.40	0.50	-3.45
Yangon	0.31	3.46		2.20	-0.95	0.51	0.38	-0.82
Bago	3.11	3.58	0.70		-1.17	1.01	0.40	-0.56
Rakhine	2.21	1.84	0.40		-0.03	0.29	0.20	0.06
Shan	3.62	3.36	0.10		0.16	0.35	0.37	0.14
Mandalay	1.08	4.37		0.70	-2.59	0.61	0.48	-2.46
Sagaing	1.56	3.68	0.60		-2.72	0.54	0.41	-2.59
Magway	0.86	3.01	0.10	0.30	-1.95	0.33	0.33	-1.95
Mon	0.40	1.32			-1.16	0.24	0.17	-1.02
Tanintharyi	1.50	0.83	0.30		0.37	0.07	0.09	0.35
Chin	1.23	0.34	0.30		0.59	0.05	0.04	0.60
Kayah	0.36	0.15			0.21	0.02	0.02	0.21
Kayin	1.30	0.95			0.35	0.10	0.11	0.34
Kachin	1.64	0.85			0.79	0.09	0.10	0.78
TOTALS	20.04	32.45	3.50	3.50	-12.41	5.61	3.60	-10.40
2005								
Ayeyarwaddy	0.59	4.71	1.00	0.30	-4.82	1.40	0.80	-4.22
Yangon	0.21	4.30		2.40	-1.69	0.51	0.51	-1.69
Bago	3.05	3.85	0.70		-1.50	1.01	0.51	-1.00
Rakhine	2.21	1.96	0.50		-0.25	0.29	0.29	-0.25
Shan	3.63	3.75	0.10		-0.22	0.35	0.35	-0.22
Mandalay	0.99	4.74		0.70	-3.08	0.61	0.61	-3.08
Sagaing	1.42	3.95	0.60		-3.13	0.54	0.54	-3.13
Magway	0.06	3.34		0.30	-2.98	0.33	0.33	-2.98
Mon	0.38	1.59			-1.21	0.24	0.27	-1.24
Tanintharyi	1.55	0.95	0.50		0.07	0.07	0.07	0.07
Chin	1.35	0.36	0.30		0.77	0.05	0.05	0.77
Kayah	0.36	0.17			0.19	0.02	0.03	0.18
Kayin	1.31	1.06			0.25	0.10	0.10	0.25
Kachin	1.68	0.94			0.74	0.09	0.09	0.74
TOTALS	18.72	35.67	3.70	3.70	-16.95	5.61	4.55	-15.89

6.16 The reduction in standing stock because of overcutting exacerbates the woodfuel balance situation in the Central and Lower Myanmar divisions to the point where it is projected that by 2005, Magway will have almost exhausted its stock of woodfuel while Yangon and Ayeyarwaddy will only have approximately 50% of the standing stock it had in 1990, with a corresponding decrease in sustained yield of woodfuels. It is expected that continuing agricultural encroachment will further exacerbate the woodfuel supply situation in the deficit areas.

6.17 The woodfuel deficit situation in Central and Lower Myanmar is projected to worsen by the year 2000. In the six divisions/states supplying the Yangon catchment the consumption is projected to rise to 200% of the sustained yield with a combined deficit of 8.4 million adt. By 2005, with a decreasing resource base in Ayeyarwaddy, Yangon, Bago and Magway consumption is projected to be 250% above sustained yield with a combined deficit of 11.5 million adt. In the Dry Zone the woodfuel consumption in 2000 is projected to rise to 11 million adt. That is 7.6 million adt (320%) above the sustainable yield. By 2005 the deficit is projected to rise to about 9.5 million adt.

6.18 The per capita consumption of crop residues is bound to increase, particularly in the Dry Zone rural areas. It is projected that by 2000 an average of 10% of the biomass consumed would be crop residues; 3.6 million tons. By 2005 crop residue use as fuel is projected to rise to 4.5 million tons, with not only rural industries but many households using a greater proportion of agricultural residues for fuel. Some increase in crop residues available for fuel could occur with potential increases in crop production, but this is not possible to estimate at present.

E. INVESTMENTS, INSTITUTIONAL AND POLICY ISSUES

6.19 Any substantial woodfuel resource development should be preceded by both an assessment of the biomass available in the more critical areas and a survey of household energy consumption. Present estimates indicate that the two problem areas, the Dry Zone and Lower Myanmar will have biomass deficits of 8.4 and 7.3 million adt in 2000. This would require the growing of approximately 4.5 million acres of trees dedicated for fuel in the Dry Zone [1], a program of 450,000 acres a year for ten years or considerably more if multipurpose plantings are established. In lower Myanmar (Bago, Yangon and Ayeyarwady Divisions) a total 1.4 million acres of woodfuel plantings would be required or 175,000 acres over a eight year period. This scale of plantings is clearly beyond the capacity of the FD and, in any event, much of the deficit relates to rural areas where fuelwood is not traded to any extent. Improved forest management may increase productivity by an additional 0.3 adt/ac/yr which would mean a management program over 22.3 million acres in the Dry Zone and there is only an estimated 10 million acres of accessible forest. In Lower Myanmar an increase in productivity of 0.6 adt/ac/yr may be achieved requiring 10.8 million acres to be brought under management, again more than the accessible forest for woodfuels extraction.

6.20 Based on the information that is available, the approach to alleviating sustainable woodfuel shortages in the short term should be one that considers both supply and demand side options and within the context of both the rural and urban consumer for those areas considered to have serious woodfuel shortages. For urban areas the immediate strategy for investment (Table 6.8) should be an improved charcoal and wood stove program, principally with the provision of technical assistance; a pilot program for improved management of deciduous and mangrove forests to enhance the production of woodfuels and other forest products; species and provenance trials for woodfuel and multipurpose trees and shrubs within woodfuel impoverished areas; a feasibility study for peri-urban plantations; and at the same time every effort must be made to achieve a reasonable degree of substitution with kerosene, gas or electricity. In rural areas action should initially be focused on localized shortages through enhancing the seedling distribution program to villagers; assistance in the development of village nurseries; developing a system of 'grassroots' forestry extension that will assist villagers to grow and manage trees while understanding and acting on the villagers' concerns and priorities related to forestry.

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[1] A mean annual increment (MAI) of $7m^3$ or 4.5 adt/ha/yr (1.8 adt/ac/yr) is assumed for the Dry Zone and $20m^3$ or 13 adt/ha/yr (5.2 adt/ac/yr) for Lower Myanmar.

TABLE 6.8 COST OF INVESTMENTS FOR WOODFUEL DEVELOPMENT AND CONSERVATION

Item	Cost US$ million	Duration (months)
Biomass Assessment	0.42	16
Household Energy Survey	0.20	10
Improved Stove Program	0.22	18
Improved Charcoal Production	0.20	24
Improved Forest Management (Pilot)	0.50	36
Species and Provenance Research	0.11	36
Plantation Feasibility	0.04	2
Plantation Program (200,000 ac)	44.90	96
Seedling Program	2.88	48
Develop Extension System	2.00	48

Source: Mission Estimates (1990)

6.21 But there are several policy and institutional issues that need to be resolved before effective investment can be made in any woodfuel development and conservation program. These include:

(a) The Growing and Harvesting of Trees for Commercial Purposes by Villagers. At present villagers are permitted to grow trees or collect wood for their own use, but are not permitted to sell such wood unless they obtain a license to cut and a royalty is paid. In order for Myanmar to overcome its woodfuel deficit problems and the associated forest degradation it will be necessary to adopt a policy that encourages and supports the production of wood for both subsistence and commercial purposes by the private sector, particularly the rural households. For villagers to have the incentive to grow woodfuels and other wood products for the urban market the legislation might be altered to permit the sale of wood grown by these people. The same rationale applies to allowing the sale of wood products from forests that would be managed by villagers, although in this case care has to exercised so that the cutting is controlled and limited to designated management areas, possibly with some form of extraction permit as is currently issued to charcoal manufacturers, but without the same fee. The policy direction is to provide incentives, not disincentives, for popular participation in the production of wood for fuel and other purposes.

(b) Nonsustainable Woodfuel Quotas. The current system of establishing quotas for charcoal and fuelwood production is in serious need of revision, particularly for those divisions that are in a sustainable woodfuel deficit situation. The quotas, which are based on very rough approximations of sustainable cut for these and other forest products, are established each year in discussions with the Planning Department of the Ministry of Finance and Planning. These quotas are the upper limit for production of a traded wood product in each division and, despite the fact that it is recognized that the quotas set for charcoal and fuelwood are far above any sustainable rates, the quotas are raised each year to meet anticipated increases in consumption.

(c) Woodfuel Stumpages. The current royalty of k 2 per 90 lb bag of charcoal and k 5 per stacked ton of fuelwood, equivalent to k 6.5 and 10 per adt respectively, are far from representing the economic or financial value of the wood on the stump. The mission estimates that a stumpage of k 38 per adt of wood for fuel is required currently to cover the costs of wood available through managing existing forests. A stumpage of between k 54 and k 142 would be needed to cover the cost of wood for fuel from dedicated woodfuel plantations depending upon the site conditions and resultant yield potential. Without higher stumpages it is difficult to justify government investment in woodfuel development programs or to encourage the production of woodfuels by the private sector.

(d) Continuing Agricultural Encroachment. The decline in the percentage of land area covered by forest and the increase in forest affected by shifting cultivation are indicative of the continuing encroachment and destruction of forest for agricultural purposes. In fact, in line with evidence in several other countries, it is suspected that clearing for agriculture in Myanmar is the major cause of forest degradation and depletion. Such destruction also reduces the resource base of woodfuels exacerbating a deficit situation in Central and Lower Myanmar. Unless such agricultural encroachment is stopped or at least regulated on a meaningful land use basis that considers the need for wood products as well as ecological and soil/water protection needs, plans and programs for woodfuel resource development and conservation will be frustrated.

(e) Forestry Department Strengthening. The Forestry Department is likely to have some staff deficiencies if it were to undertake a major woodfuel development program within the public estate; however, they lack the manpower and training for developing and conserving woodfuels, particularly within the private sector.

F. CONCLUSIONS AND RECOMMENDATIONS

6.22 Central and Lower Myanmar have insufficient woodfuels and non-woody biomass to support the current and projected consumption of such fuels on a sustainable basis even allowing for transport across divisional or state boundaries. The continued overcutting of the forest resource to supply woodfuels and agricultural encroachment in these areas is having an increasingly detrimental effect on the environment. The large areas of mangroves, that are prime sources of charcoal and fuelwood, are being particularly affected in Ayeyarwaddy Division and, with the depletion of preferred stocks there, Rakhine and Tanintharyi Divisions are now being affected. No studies have been done on the detrimental effect on fish stocks, but continued degradation of the mangroves must adversely affect these.

6.23 Interventions to alleviate the woodfuel supply deficit in Central and Lower Myanmar from both an urban and rural point of view involve both

conservation as well as resource development and management. However, any action taken should be within the overall energy context with special consideration being given to interfuel substitution, perhaps when the oil fields have been rehabilitated, with kerosene, without which it will be difficult to overcome the woodfuel shortages and the associated environmental degradation. Woodfuel development and conservation should be done within the framework of a national energy strategy, with the problem being clearly defined using reliable data on woodfuels supply and demand at least for the identified problem areas. The interventions will need the support of legislation that recognizes the role played by woodfuels in both the forestry and energy sectors and the need for private sector involvement in woodfuel development and conservation. Finally, to be effective in planning and implementing such interventions the Forestry Department should be strengthened.

VII. ENERGY PRICING

A. INTRODUCTION

7.1 Recent policy shifts by the government, towards liberalization of the economy provide an opportunity for more rational and flexible energy pricing so that it can make an important contribution to government's fiscal and budgetary objectives. The shortage of public finance has been identified as a major constraint in energy sector development. Appropriate pricing policies can help to relax this constraint both directly--by taxing energy consumers whose demand is price inelastic and whose incomes are high--and indirectly by enabling the SEE's to self finance a larger share of their investment program. A main cause of domestic energy shortages has been the persistently low and inflexible energy prices over a considerable period of time: the shortages in petroleum products being handled by rationing at official prices and tolerating a black market, and in electricity by frequent load-shedding. This problem is critical to economic growth because ultimately the supply gap is met through curtailment of economic production and socio-economic welfare.

7.2 The basic problems in energy pricing in Myanmar are: (a) present price levels are much too low to induce energy conservation, to promote efficient energy decisions, to provide funds to the energy SEEs, to provide adequate taxes to government, and to cover the costs of supplies; (b) all the modern energy prices have been much too inflexible, being kept fixed over several years in spite of domestic inflation, changes in the costs of energy supply and other significant changes elsewhere in the economy; (c) the administrative procedures and technical criteria for setting prices are cumbersome and lacking; and (d) some of the relative prices appear to be out of line in view of the country's needs and difficulties.

7.3 There are also associated problems which accompany the basic problems of pricing; the energy SEEs lack satisfactory autonomy to make effective use of pricing policy; the government itself is operated extensively on a non-cash basis and needs reform for pricing to be effective, and foreign exchange policies severely limit the potential effectiveness of energy pricing policies. Therefore any serious consideration of pricing reform overlaps with important issues of institutional organization and management within the energy SEEs and in government operations. This chapter reviews the current status of energy prices in the main sectors of the economy, both in terms of the relation to economic costs and in terms of their net impact on government financial resources.

7.4 A recurring difficulty in evaluating and setting domestic energy prices in Myanmar is the foreign exchange rate situation. Myanmar government has not changed the grossly overvalued exchange rate for more than a decade despite continuous appreciation of the kyat and a widening gap between the official and parallel market rates. At present in the parallel market, the value of kyat is nearly one tenth of its official price of 6.2 kyat to the dollar. Maintaining such an overvalued exchange rate leads to inefficiencies in its use, adversely affects incentives to produce, reduces government revenues and results in scarcities. Table 7.1 gives a comparison of energy prices in some South Asian countries which demonstrates that Myanmar's prices, at the real exchange rate, are considerably lower than those of its neighbors.

Assuming an exchange rate of k 50/US$, the present official prices translate into US$2.20/barrel for crude oil, US$0.21/gal for diesel and US$0.32/gal for petrol, which would be some of the lowest diesel and petrol prices in the world, and electricity tariffs, which were revised to an average of k 0.48/kWh in 1988, would be 0.9¢/kWh, which are very low by international standards.

TABLE 7.1 COMPARISON OF ENERGY PRICES FOR SELECTED FUELS IN SOUTH ASIA

		MYANMAR at k6.2/$	atk50/$	INDIA 1990	THAILAND 1990	PHILIPPINES 1990	VIETNAM 1989	CIF YANGON PRICES 1990	Ratio of Domestic to CIF Prices
Crude Oil	$/b	17.70	2.20	14.80				25.00	0.09
Gasoline	$/IG	2.58	0.32	3.80	1.60	3.01	0.82	1.03	0.31
Kerosene	$/IG	2.18	0.27	0.98	1.51	1.21	0.64	0.91	0.30
Diesel	$/IG	1.69	0.34	0.60	1.38	1.21	0.61	0.87	0.39
Fuel Oil	$/IG	1.37	0.27	1.10	0.64	0.87	0.33	0.61	0.44
Natural Gas	$/mcf	1.21	0.15	4.20	2.80			2.00	0.08
Coal	$/ton	59.00	7.30	29.00	58.00	62.00	8.2-10.30	39.00	0.19
Electricity Tariffs	¢/kWh								
Residential		8.00	1.00	1.5-3.8	5.50	6.10	2.10		
Services		8.00	1.00	3.5-9.4	7.90	8.60	6.40		
Industrial		6.00	0.80	2.1-9.3	7.20	7.60	3.10		
Average		7.70	0.96	2.6-5.1	6.90	8.10	2.40		

7.5 There are two key objectives in setting energy prices: they should be sufficient to provide for financial viability of the energy entities and generate sufficiently high surplus to allow the sector to provide a significant part of its future investment program, and, secondly, the prices should be set at levels which encourage efficient use of energy and avoids wasteful consumption. There are serious problems with current energy prices in Myanmar since they reflect neither the economic supply costs nor the opportunity cost of energy; and there is a critical need for an alternative pricing structure and a clearly defined pricing strategy.

B. CRUDE OIL AND PETROLEUM PRODUCTS PRICES

7.6 As shown in Table 7.2, the price of crude oil had remained virtually unchanged in Myanmar from 1980 to October 1988, and in addition prices were only increased slightly during the 1970's, in spite of the increases in international oil prices in that period. As a result, mounting losses were incurred by MOGE. Finally, in an effort to reform the situation, prices were reestablished at higher levels by the government in October 1988, when the price of crude was increased from k 42.66/barrel to k 110.00/barrel, and natural gas from k 2.10/mcf to k 7.50/mcf. The consumers' prices for petrol, kerosene, diesel, fuel oil and aviation fuel were also kept fixed between 1975 and October 1988. Furthermore, in the period 1982 to 1988, petrol, diesel and fuel oil were handed over to MPPE at the same price it had to sell products to the consumer, thus denying MPPE any margin to cover its operating or other costs. This led to the running down of MPPE's previously accumulated financial reserves. Eventually each of the

petroleum operators, MOGE, MPE and MPPE were accumulating debts.

7.7 The prices of both crude oil and petroleum products are supposed to be set on an accounting cost-plus basis, for crude oil ex-MOGE, for products ex the refineries (MPE), and for sale on a cost plus basis to the consumer, by MPPE. Presently, the hand-over price of crude from MOGE to MPE is k 1[illegible] per barrel; MPE then prorates its costs to each product in relation to the value of sales and adds a commodity tax; for example, diesel is handed over to MPPE at k 7.6/IG; MPPE then adds its costs plus a 5% sales tax to determine the final official consumer's price, for example k 10.50/IG for diesel. Price markup and tax details are shown in Annex 7.2. By all accounts the setting of petroleum product prices in Myanmar has been a ponderous and uncertain process. No clear procedures and scheduling for price adjustments exist, and methods of pricing are not well-defined, and the mandate for recommending and implementing price changes is not focused in one place.

7.8 At the same time as maintaining low official prices the market continues to be regulated through an allocation system, but since 1984 the government has tolerated an active black market in all the petroleum products, in which prices have been far higher than official levels. In November 1990, for example, the black market price of petrol was between k 150/gal and k 160/gal, being about 10 times the official price. One result of this situation has been a significant loss of potential government tax revenues, perhaps in the order of k 1 billion/yr, because commodity and sales taxes on petroleum products are related to official prices and not to the black market prices. As well as the obvious incentives for theft and other illegal activities, the past system of low petroleum product prices plus allocation has led to serious misallocation of financial resources, notably by under investment in crude oil and natural gas development, and by significant losses of fiscal funds for the government.

7.9 Efficiency and fiscal objectives can only be met through higher and more flexible prices for all petroleum products. Simultaneously, a balance must be struck with social objectives such as the provision of low-cost public transportation. The method of cost-plus pricing of crude oil tends to lead to shortages of supply because of the difficulties of fully allowing for the costs of exploration and unsuccessful development, and allowing for changes in the volume of production, for example following a new discovery, in the unit price calculation. Excessively low prices of oil and oil product prices contributes to excess demands and lack of supply. The present cost-plus system for establishing product prices also has several limitations: refining cost allocations among products is arbitrary and can lead to distortions--for example since MPE gets a higher profit margin on fuel oil than diesel, it has a higher incentive to produce fuel oil and also the profitability of conversion units is reduced. The price of diesel on world markets is usually between 10% and 15% less than petrol, and therefore the relative official prices of petrol and diesel in Myanmar appear to be out of line with each products' value. Although this is a taxation policy, the relative prices tend to cause a shift towards diesel consumption, which could in the future, cause an imbalance of product mix in the refineries.

TABLE 7.2 CRUDE OIL AND REFINED PETROLEUM PRODUCTS TRANSFER PRICES 1975-1990

(ky = kyats, b = barrel, IG = Imperial Gallon)

	----MOGE TO MPE----		----------MPE TO MPPE---------			----------MPPE TO CONSUMERS----------						
						Fuel Aviation					Fuel Aviation	
	Crude Oil		Petrol	Superior kerosene	Diesel	Oil	Turb Fuel	Petrol	Superior kerosene	Diesel	Oil	Turb Fuel
Year	Ky/b	Ky/b	Ky/b	Ky/b	Ky/b	Ky/b	Ky/b	Ky/b	Ky/b	Ky/b	Ky/b	Ky/b
1975	29.05	0.83	3.03	2.08	1.95	1.41	2.61	3.50	2.50	2.50	1.90	2.61
1976	29.05	0.83	3.05	2.10	1.97	1.43	2.61	3.50	2.50	2.50	1.90	2.61
1977	30.10	0.86	3.05	2.10	1.97	1.43	2.61	3.50	2.50	2.50	1.90	2.61
1978	30.10	0.86	3.05	2.10	1.97	1.43	2.61	3.50	2.50	2.50	1.90	2.61
1979	37.80	1.08	3.05	2.10	1.97	1.43	2.61	3.50	2.50	2.50	1.90	2.61
1980	40.60	1.16	3.05	2.10	1.97	1.43	2.61	3.50	2.50	2.50	1.90	2.61
1981	40.60	1.16	3.05	2.10	1.97	1.43	2.61	3.50	2.50	2.50	1.90	2.61
1982	42.70	1.22	3.50	2.41	2.50	1.90	3.00	3.50	2.50	2.50	1.90	3.00
1983	42.70	1.22	3.50	2.41	2.50	1.90	3.00	3.50	2.50	2.50	1.90	3.00
1984	42.70	1.22	3.50	2.41	2.50	1.90	3.00	3.50	2.50	2.50	1.90	3.00
1985	42.70	1.22	3.50	2.41	2.50	1.90	3.00	3.50	2.50	2.50	1.90	3.00
1986	42.70	1.22	3.50	2.41	2.50	1.90	3.00	3.50	2.50	2.50	1.90	3.00
1987	42.70	1.22	3.50	2.41	2.50	1.90	3.00	3.50	2.50	2.50	1.90	3.00
1988+	110.00	3.14	11.80	10.00	7.60	6.00	10.00	16.00	13.50	10.50	8.50	13.50

Note: 1988 Prices Effective 20-10-88, and still apply in early 1991.

Recommendations on Pricing of Crude Oil and Petroleum Products

7.10 While the historical and expected future costs of crude oil and natural gas exploration, development and production are not good guidelines for the setting of price levels, they do provide important information for determining whether to invest in future oil and gas exploration and development. Provided that the fully-accounted-for costs are less than the cost of importing crude oil or petroleum products for which domestic production would substitute, investment in domestic production is economically attractive and should be undertaken. The estimated cost of exploration and development investment for possible oil reserves has been determined to be about US$12/barrel, and for proven and probable reserves between US$11/barrel and US$12/barrel. Such costs plus an allowed cost for operations, storage, transportation and delivery to domestic refineries of about US$5/barrel, provide an estimate of the full-cycle cost of domestic crude oil supply. On the basis of these estimates, and after analysis of the actual historical costs incurred by MOGE, the long term supply cost (without taxes or royalties) of domestic crude oil is estimated to be about US$17/barrel (i.e., about k 850/barrel at the shadow exchange rate of k 50/US$). This is a critical finding for investment purposes because it means that investment in domestic crude oil supply has a high probability of being economically successful in light of forecasts of future international crude oil prices. From the perspective of domestic pricing policy it means that crude oil prices should never be lower than US$17/barrel, or k 850/barrel.

7.11 There are essentially two ways in which domestic prices for petroleum products could be tied to international prices: (a) phase in the domestic crude oil price at the refinery gate equal to the price of imported crude, delivered to the refinery (i.e., about US$25/barrel equivalent to about k 155/barrel at the official exchange rate or as high as k 1,250/barrel at an estimated shadow exchange rate of k 50/US$), or (b) set oil product prices (ex-taxes) equal to imported product prices, at the consumer level. Following the first approach would provide to MOGE a cash flow (in domestic funds or in equivalent US$ at a foreign exchange rate of k 50/US$) which should be adequate to pay for the oil field rehabilitation which is critically needed, and any surplus funds would provide a return on MOGE's invested capital or flow back to the Central Fund or possibly be captured by government through a higher royalty on MOGE's crude production. Consumer prices would be increased indirectly through passing forward the increased crude price to the refineries and thence to the consumer. Under the second approach, consumer product prices would be increased directly, taxes would be added, and increases in the cash flow to MPPE would occur, and thence to MPE and to MOGE. Such a 'netback' arrangement would, however, necessitate the imposition of restrictions over the revenues to be retained by MPPE and MPE.

7.12 A clearly defined, explicit long term strategy of relating domestic oil prices to international oil prices, at a realistic exchange rate, should be implemented. The mission recommends that domestic crude oil price should be tied to a suitable international crude oil price, for example a crude oil of similar quality to domestic production and available ex-Singapore. Prices would be set every six months, after an assessment by an independent Energy Pricing Board. With the existing price arrangements the cost of imported crude does not flow through to the official petroleum product prices; the cost is simply carried on the government accounts, and the crude is in effect transferred to MPE at the official price. In the future, import costs should be carried by MPE and they should become reflected in product prices each time that product prices are

revised. The government should set up an "Oil Price Stabilization Fund" showing the amounts which were not passed forward into product prices, or conversely if international oil prices were to decline then this fund would show a surplus until the next revision of prices. The price of petroleum products would still be set on a cost-plus basis, however, using refinery and distribution cost margins for each product which would reflect the international product price relatives ex-Singapore. The objective is that these prices should promote optimal fuel choices, discourage waste and eliminate economic subsidies, i.e., the weighted average price of all petroleum products should be at least equal to the weighted average of their border prices.

TABLE 7.3 ILLUSTRATIVE BUILD-UP OF PETROL PRICE, BASED ON US$25/barrel CRUDE OIL

	(kyats/Gallon)		
	at k 6.2/US$	at k 50/US$	at k 50/US$[2]
Refinery			
- Crude oil cost	4.43	35.74	35.74
- Cost of Refining and Admin Expenses[2]	2.03	2.93	10.63 [2]
- Profit Margin (5% on costs)	0.32	1.89	2.32
- Commodity Tax[1]	10.98	37.77	10.98
MOE hand-over price	17.76	77.43	59.67
Distribution			
- Distribution Costs[2]	3.06	3.06	8.47 [2]
- Profit Margin (2% on costs)	0.42	1.61	1.36
- Sales Taxes (5%)	1.12	4.32	3.66
Price to Consumer			
TOTAL including Taxes	22.36	86.43	73.16
TOTAL without Taxes	10.26	44.34	58.52
	Annex 7.3(a)	Annex 7.3 (d)	

1/ Commodity Tax under the exchange rate of k 6.2/US$ is kept at the present rate, which is 170%. This results in 10.98. In moving to the exchange rate of k 50/US$, commodity tax is retained at k 10.98 in column 3, and set at 100% in column 2.
2/ Refining and distribution costs under the exchange rate of k 50/US$ have been adjusted to correspond to the revaluation considering that all foreign exchange accounting will be done by the enterprises at the exchange rate as used for determining prices.

7.13 Assuming that an international crude oil price of US$25/barrel delivered ex-Yangon pertains, Table 7.3 illustrates the range of consumer prices of petrol under various assumptions of tax rates and refinery and distribution costs. The minimum prices, which should reflect the international price relativities, are the estimated opportunity values of petroleum products at Yangon as given below:

TABLE 7.4 ESTIMATED OPPORTUNITY VALUE OF PETROLEUM PRODUCTS
(based on Singapore product prices)

	Gulf Crude in Yangon	Products in Yangon			
		Petrol	Kerosene	Diesel	Fuel Oil
Price per barrel of Crude	25	36	32	30	21
Yangon Prices in $/IG	-	1.03	0.91	0.87	0.61
in k @ k 6.2/US$		6.38	5.61	5.37	3.81
in k 50/US$		51.43	45.26	43.29	30.73

Note: Transportation costs of crude are estimated at $5/barrel ex-Dubai and of products at $3/barrel ex-singapore, landed in Yangon. These product prices exclude local distribution costs and taxes.

On this basis, the minimum prices at an exchange rate of k 50/US$ (excluding taxes) of kerosene, diesel oil, fuel oil and premium petrol would be k 45.26/IG, k 43.29/IG, k 30.73/IG and k 51.43/IG respectively. The government's taxation policy should determine the price level to be set above these floor amounts taking into account other socio-economic objectives.

7.14 The price increases which are contemplated are obviously substantial and a possible first step towards such a pricing regime could be to adopt the opportunity value criteria, using the international oil price as the guideline, but to use the official foreign exchange rate. This would suggest a modest increase of petrol prices to k 22.36/IG, as illustrated in the first column of Table 7.3. It will be seen that except for the change in crude oil cost to correspond to border parity, the present formula for the price build up is retained and the commodity and sales taxes as well as the profit margins are left at existing percentages. Proceeding on the same basis, the prices for aviation fuel, kerosene, diesel oil and heavy fuel oil work out to k 18.32/IG, k 15.84/IG, k 15.76/IG and k 10.63/IG respectively. Although the price levels would be far below the desirable minimum it would at least be a constructive step in the right direction. A further step which could be considered is to prorate the refinery and distribution costs of the different products in line with typical relative product prices in Singapore. In subsequent price revisions where the objective is to move closer to the real exchange rate, the commodity tax might be at a lower percentage for the petroleum products.

7.15 Price increases are expected to have only a limited effect on total industrial production costs, as energy accounts for a relatively small proportion of the cost of production of most industrial operations. In addition, in Myanmar, most of the rural population and the poor rely primarily on biomass and the other traditional fuels. Another expected positive result of rational pricing, is likely to be institutional change for better management both within the energy SEEs and in government bodies such as MOE and the Department of Planning and Finance. The self-financing ratios of the energy SEE's would improve. Overall, the impact of higher and more flexible crude oil and petroleum product prices are expected to be positive, and most important they are expected to reduce the gap between petroleum product supply and demand within all sectors of the economy so that eventually the allocation system could be abandoned and the black market eliminated.

C. NATURAL GAS

7.16 The pricing of natural gas must address the dynamics of supply and demand. To reduce an excess supply, the price of gas can be set as low as feasible, i.e., at the level of the estimated long run supply cost, with the objective of promoting the use of gas through substitution for petroleum products in existing markets and through creating new markets for gas such as its use in electricity generation or as a feedstock for example for the manufacture of urea and methanol, while allowing just high enough a price to sustain supply. The long run cost of supply can therefore be viewed as a minimum price for gas. On the other hand, if natural gas is in deficit the gas price should be set as high as feasible in order to discourage its use through substitution for example by fuel oil, to induce conservation, and to stimulate its domestic supply. Therefore the energy equivalent value of petroleum products such as fuel oil indicate a maximum price that might be considered for gas. If natural gas is exported, there are two implications: the netback from the export must be greater or equal to the

estimated long run supply cost of gas (otherwise the export would not be economic), and, this being the case, the netback value of the gas would indicate the appropriate price for domestic gas.

7.17 For pricing natural gas in Myanmar there are three criteria which establish a range as a guideline for prices in the longer term: (a) if the development and export of offshore gas is economical, financeable and is in fact realized or if it is assumed to be realizable, the export netback value of gas (calculated to Yangon) would indicate the appropriate level for gas prices; (b) if gas is in deficit, the substitute petroleum product energy equivalent value (fuel oil or possibly diesel as used in the power sector) indicates the maximum price; and (c) the estimated long run supply cost of gas indicates the minimum price that should be set.

7.18 On the basis of estimates of capital and operating costs and assuming energy prices stated in Annex 7.1(g), the netback values of gas in the domestic market were estimated as part of a Gas Utilization Study (1991) and are given in Table 7.5. Gas use for power generation provides the best valourization of gas in all scenarios; and all gas applications have netback values higher than marginal costs of supply, except new fertilizer and CNG plants. The export netback value of gas is estimated at about US$2.10/mcf, based on fuel oil replacement value in power plants ex-Bangkok of US$3.50/MMBTU.

TABLE 7.5 US$/MMBTU

Power	4.18-4.95
Manufacturing	5.09-5.14
Refinery	4.58-4.77
Paper Manufacturing	3.99-4.07
Cement	3.65
Methanol	2.61-2.92
CNG	2.21
Fertilizer	1.23-1.66

Notes:
1. Netback values of gas, is considered to be representative of the benefits of gas utilization, is defined as the fuel replacement value or as the price of gas which makes its use as feedstock economically viable.
2. Netback values were evaluated for seven sectors--fertilizer, cement, paper, methanol, CNG, industries and LPG.
3. The distribution pipeline costs for manufacturing have not been included in the netback values--hence, net benefits will be lower than for the power sector.

7.19 The investment and operating cost programs to produce incremental onshore and offshore natural gas have been described in detail in Chapter III. On the basis of these estimates, and assuming a discount rate of 12% per year, the long run incremental cost of future gas supplies (i.e., average incremental cost or AIC) have been calculated. In the case of developing Moattama offshore gas for the Thai market, it is estimated that the economic supply cost would be around US$1.88--2.0/mcf depending on onshore pipeline costs and location of the power plants using the gas. The estimates for onshore gas include an exploration component. In the case of offshore gas, exploration costs are treated as 'sunk costs' and a depletion premium is added to the development and operating costs which represents the estimated discounted cost of replacing the Moattama offshore reserves through further offshore exploration. The long run incremental cost (excluding royalties and taxes but including exploration) of new onshore gas production has been determined to be about US$2.42/mcf (delivered to Yangon). The estimated cost of gas from Moattama, when developed and delivered for

domestic use at 40 bcf/yr and using the existing Jack-Up rig, is US$1.24/mcf, delivered to Yangon excluding royalties and taxes. This is highly conditional upon the low investment costs associated with the rig. Adding a depletion premium of US$0.50/mcf brings the estimated economic supply cost to about US$1.74/mcf, ex-city gate Yangon.

Recommendations for Gas Pricing

7.20 Bearing in mind all the complexities and uncertainties involved, a good deal of judgement is required in establishing the price of gas. The future prospects for gas development, the difficulty that MOGE would have in quickly deploying a rapid inflow of local funds, and the impact of high gas prices on electricity tariffs suggests that prices should not be raised right up to the level of petroleum product equivalent straight away. On the other hand, it would not be strategic, in the short term, to price gas at less than the estimated long run cost of onshore supplies, because if the offshore option were to fail or be significantly delayed it is essential to have onshore supplies, and there is also a chance that they might turn out to be larger than presently expected. This suggests a price of at least US$2.42/mcf. Since the estimated cost of offshore gas developed for the domestic market is US$1.74/mcf, the suggested US$2.42/mcf price would hold out the promise for any joint venture partners in offshore development to deliver gas into the domestic market at a profit. The prospect for profit will be a necessary ingredient for the participation of private sector partners, and for the project's financeability. Any excessive profits can be recaptured by government through an efficient royalty arrangement. Thus, a price in the order of US$2.42/mcf, which is slightly less than 60% of the energy equivalent value of fuel oil (CIF Yangon) would appear to reconcile the objectives of stimulating both onshore and offshore developments, while not raising gas prices too high which would heavily impact electricity tariffs and might be a problem for the government later if the PSCs' discover and produce gas, or if the short term high domestic price might tend to inhibit a gas export deal. In the longer term, if a gas surplus is realized, the export netback value of gas, estimated at about US$2.10/mcf, becomes the relevant guideline and it may therefore be strategic at a later date to reduce the gas price in the domestic market, in order to stimulate its use (Table 7.6). The mission recommends that the gas price should be set in the range between US$2.10/mcf and US$2.50/mcf; in the short term at the upper end of this range with the prospect of slightly decreasing the price in the future when the netback from exports is realized.

TABLE 7.6 INDICATORS FOR SETTING NATURAL GAS PRICE IN MYANMAR

	US$/mcf	k/mcf		
		at k 6.2/US$	at k 50/US$	
PRICING TO MARKET:				
Short Term (gas deficits)				
Equivalent Value of diesel	5.50	34	275	Max
Equivalent value of fuel oil	4.18	26	209	
Long Term (potential gas surplus)				
Value in methanol manufacture	2.60	16	130	
Value in CNG Manufacture	2.21	14	110	
Netback Value of Exports	2.12	13	106	*
PRICING BY COSTS:				
Short Term (gas deficits)				
Cost of onshore gas	No short term increase in output possible.			
Long Term (potential gas surplus)				
Cost of onshore gas	2.42	15	121	Min
Cost of offshore gas	1.74	11	87	*

* will depend on the price which is realized for gas delivered to Thailand which is assumed here to be US$3.50/mcf and on the actual costs of development and transmission from Moattama to the point of sale. These prices and costs are particularly uncertain.

Source: Mission Estimates (1991)

D. ELECTRICITY TARIFFS

7.21 Over the period from 1979 to 1988, there were few revisions of electricity tariffs and the average revenue per kWh sold ranged from k 0.25/kWh to k 0.30/kWh. Presently, the average revenue is k 0.48/kWh, equivalent to only 0.09¢/kWh at an exchange rate of k 50/US$. In real price terms, electricity tariffs have decreased over the past 10 years in spite of the nominal tariff hikes in 1984 and 1988. Myanmar tariffs are also exceptionally low in comparison with tariffs in other countries of South East Asia. For example, tariffs in Thailand average the equivalent of about 6.9¢/kWh. The tariff structure is simple in its design, which presumably reflects both the fact that MEPE has inadequate funds to install more complex metering, and that estimates have not been made of the respective long run marginal costs for each type of service. Tariffs are now recommended to government by MOE, after consultation with MEPE. The basis has been cost-plus in an accounting sense, and tariffs have not been used as a means of effecting demand management.

TABLE 7.7 MYANMAR ELECTRICITY PRICES IN 1990

CONSUMER CATEGORY	UNIT	PRICE
General Purpose	Pyas/kWh	50.00
Residential Power	Pyas/kWh	50.00
Small Power	Pyas/kWh	50.00
Industrial	Pyas/kWh	45.00
Large Industrial	Pyas/kWh	40.00
Bulk	Pyas/kWh	45.00
Street lighting (Minimum 40 Watts)		
- 40 Watts	ky/Mon	8.00
- Every Additional 10 Watts	ky/Mon	2.00
Department		At cost

Source: MEPE

7.22 The issues of electricity pricing have essentially three components: (a) tariff levels have been maintained at too low levels for the effective development of this subsector, and even after the hike in tariffs in October 1988 they are still too low to provide for the efficient use of electricity, and to provide sufficient internal cash flow for MEPE to sustain its financial integrity and raise at least part of the funds needed for the investment required in generation, transmission and distribution in the future; (b) the tariff structure has been oversimplified, by essential setting all tariffs at the same level, without any blocs for quantity of usage, and with insufficient attention to the costs of providing capacity to some customers; and (c) like the petroleum prices, electricity tariffs have been kept fixed for excessively long periods of time in spite of domestic inflation and changes in the costs of operating MEPE.

7.23 The existing average tariff of k 0.48/kWh (effective from November 1988), already appears not adequate to cover the financial costs of MEPE of 1991. During 1992-94, as gas availability further declines, more diesel and fuel oil will have to be used, while gas prices have also been recommended to be slightly more than doubled, thus causing large increases in fuel costs. Assuming that the additional fuel will be imported and GOM will supply the fuel to MPPE at normal consumer prices, but with commodity and sales tax exemptions, it will be necessary to raise the electricity tariffs: a 40% increase of the average tariff to bring it to k 68.2 Pyas/kWh before the end of 1991 will still result in a financial loss situation during 1991 and 1992, but MEPE losses would stand to be made up over the next three years (Annex 8.2). The position will be more bleak if the more realistic shadow exchange rate of k 50/US$ is applied. As with petroleum products, the artificially low exchange rate seriously biases the calculation of costs for purposes of efficiently pricing energy.

7.24 The average tariff should at the minimum be sufficiently high to assure the financial viability of MEPE. The revenue requirement should cover <u>all</u> costs and it should include a rate of return on assets commensurate with the capital structure of the utility, allowing for the debt and equity mix on the balance sheet. Depreciation allowances should also be included, sufficient to replace the assets. Therefore, depreciation should be calculated on the up-to-date revalued assets. There is also a case for the revenue requirement to include an allowance for the funding, or partial funding, of future investments by the utility. The tariff structure and levels should be related directly to the estimated marginal costs of providing service to respective groups of customers. Basic criteria in this respect are the estimated long run marginal cost (LRMC) of expanding generation, transmission and distribution in order to meet the forecast demand. The short run marginal costs may also be relevant because in the short-term, the marginal generation, for example, for Yangon, is by diesel-fired units.

<u>Recommendations for Electricity Tariffs</u>

7.25 The estimated costs of electricity generation, transmission, and distribution are shown in Table 5.13. They depend, of course, on the forecast opportunity costs of fuels and financial capital, in the context of the generation plan developed in the Base Case forecast of electricity demand and these costs provide a guideline for tariffs.

TABLE 7.8 PROPOSED TARIFFS (K/KWh)

	First Stage Existing Tariffs	Proposed Tariffs[1]	Long Run Proposed Tariffs based on LRMC[2] 1990-2000	1990-2010
Residential	0.50	0.83	3.56	5.79
Services	0.45	0.61	2.54	4.14
Industrial	0.45	0.53	2.10	3.57
Average	0.48	0.68	2.87	4.72

1: Based on financial viability of MEPE
2: LRMC based on exchange rate of k 50/US$

Source: Mission Estimates (1991)

7.26 Apart from the obvious significance of the exchange rate assumption, it is clear that the marginal costs at low voltage, serving the residential sector, are substantially higher than at medium and high voltages serving the other two sectors. Therefore, on a cost basis the residential sector tariff should be some 60% to 70% higher than industrial tariffs. On the basis of long run marginal costs, using the official exchange rate, and to ensure the financial viability of MEPE, the industrial, service sector and residential tariffs need to be raised some 8-33 pyas/kWh as given in Table 7.8. In the short run, the average tariffs need to be increased from k 0.48/kWh to k 0.68/kWh in order to ensure financial viability of MEPE; but in the longer term, the average tariffs should increase to the LRMC to provide for necessary investments in the power sector.

7.27 To obtain the desired degree of flexibility, it is essential that an annual review procedure should be established with explicit criteria for setting tariffs. A clear procedure for establishing the annual revenue requirement should also be established. Marginal costs should be estimated and updated annually in order to act as guidelines for setting tariffs in each service sector and for setting the levels of bloc tariffs in each sector. Two bloc tariffs should be considered, with higher tariffs in the second bloc, and the second bloc might be set equal to the marginal cost of diesel generated power. Capacity charges for industry should also be increased. It is recommended that a study of tariffs be undertaken so that electricity prices can be set on a sound, long term basis.

E. COAL PRICES

7.28 Coal prices are set on an average cost-plus accounting basis, including the relatively low cost operation at Namma and the higher cost at Kalewa.

TABLE 7.9 SELLING PRICE OF COAL IN 1989

	k/ton	At Location
Kalewa Coal		
Run-of Mine Coal	365	Monywa
Lumpy Coal	715	Mine Site
	750	Monywa
Coal Fines	177	Monywa
Namma Coal		
Run-of Mine Coal	260	Leshio
Washed Fines	207	Pyay-Oo-Lwin Iron & Steel Plant

Source: Mining No. 3 (1989)

Recommendations for Coal Pricing

7.29 The price of coal should be established in relation to the cost of imported coal of comparable quality, and allowing for internal transportation costs. This would provide the incentive for the mines to develop efficiently when coal is in demand domestically and when it can be mined at less cost than imported coal. If necessary, coal royalties could be used to recapture profits for government.

F. TRADITIONAL ENERGY AND PRICES

7.30 Prices for fuelwood and charcoal vary considerably depending on location, local urban demand, the quantity of the sale, and the quality of the charcoal. Yangon City has the highest charcoal prices ranging from kyats 4.00 to 6.70 per viss while fines and dust may be obtained from some outlets for kyats 2.50 per viss, the good quality charcoal from dense mangrove or deciduous forest species sells for kyats 5.00 to 6.70 per viss. Outside Yangon City charcoal prices are generally lower and in areas where supplies are easily accessible, for example, Magway and Bago Division, prices are lower. Mandalay Division (south of Mandalay City), however, has higher prices due to increasing shortages of wood.

TABLE 7.10 CHARCOAL RETAIL PRICES

Location	Charcoal Price (kyats/viss)
Yangon City:	
Charcoal from Ayeyarwaddy	4.00 - 6.70
Charcoal from Tanintharyi	4.50 - 5.00
Charcoal from Bago/Magway	2.50 - 6.00
Yangon Division Town	3.00 - 3.40
Bago Division West	3.60
Bago Division East	1.20 - 2.60
Magway Division	1.80 - 2.50
Mandalay Division	2.00 - 4.70
Ayeyarwaddy Division (Pathein)	4.10 - 4.40

Source: Mission estimates (1990)

7.31 Fuelwood is the principal fuel for rural households where it is usually collected on a subsistence basis from nearby forests, although in some cases it may be purchased by the villagers. It is also the principal fuel for the majority of urban households outside Yangon City who purchase the fuelwood from retail outlets. As shown in the table below, there is an even greater variation in fuelwood prices than charcoal prices even in the same areas.

TABLE 7.11 FUELWOOD RETAIL PRICES

Location	Price (kyats/ADT)
Yangon City	500 - 1700
Yangon Division Town	310 - 700 (kyats 150/ADT for sawdust)
Pyay Town	220
Bago Division East	95 - 1570
Magway Division	60 - 440
Mandalay Division (south)	115 - 1120
Mandalay City	340

Source: Mission estimates (1990)

Recommendations on Pricing

7.32 In the markets for charcoal and fuelwood there are many suppliers, wholesalers and retailers, and unlike the other energy subsectors, prices are determined essentially by the interplay of supply and demand. However, the evidence that charcoal prices have declined in real terms over the past decade combined with the fact that prices jumped up earlier in 1990 when sustainable-cut limits were temporarily placed on supplies, suggests that prices are lower than would be consistent with long term sustainable supplies.

7.33 Traditional energy supplies, particularly charcoal, thus appear to be underpriced as a result of too low a level of royalties. The present royalty of k 2 per 90 lb bag of charcoal and k 5 per stacked ton of fuelwood is equivalent to k 6.5 and k 10 per ADT of fuelwood, assuming a 14% conversion rate from wood to charcoal. These rates are estimated to be too low for efficient management of the forests, which would appear to call for rates in the order of k 38 per ADT of fuelwood.

7.34 In the non-Dry Zone areas, charcoal from plantations or managed forests close to Yangon or in the Ayeyarwaddy Division have relatively low supply costs, and such an increase in royalty rate could be absorbed mainly through a reduction in the profitability of forest cutting and only partly through retail price increases. On the other hand, the supply of charcoal from western Bago and southern Magway Divisions which has higher supply costs would tend to be curtailed, leading eventually to upward pressure on retail prices. Overall, a higher royalty would address the problem of overcutting; it would tend to reduce supplies, raise retail prices and dampen consumer demand.

G. CONCLUSIONS AND RECOMMENDATIONS

7.35 It is clear that all energy prices must be considered together in a policy package, otherwise unwanted substitution will take place or certain segments of the population and economy will be adversely and unfairly impacted. There are strong direct links between energy prices, for example the prices of fuel oil and diesel directly affect the costs of electricity generation which must be passed on to the consumers in the form of higher electricity tariffs. The recommended prices shown in Table 7.12 are considerably higher than existing prices and one means for phasing increases into the economy would be to first use the existing official foreign exchange rate and in the future if the official rate is not changed, to adjust prices into line with a realistic shadow exchange rate.

7.36 The pricing strategy which has been developed has stressed the importance of first putting in place effective methods for establishing prices and a systematic means of annually reviewing them. Creating institutional mechanisms such as an independent Energy Pricing Board should be examined as part of this pricing strategy.

TABLE 7.12 RECOMMENDED ENERGY PRICES IN MYANMAR

	Existing Prices	Prices	
		First Step at 6.2/US$	Target Minimum at 50/US$
Crude Oil	110/b	155/b	1250/b
Petrol	16.00/IG	22.36/IG	51.43/IG [1]
Kerosene	13.50/IG	15.84/IG	45.26/IG
Diesel	10.50/IG	15.76/IG	43.29/IG
Fuel Oil	8.50/IG	10.63/IG	30.73/IG
Natural Gas	7.50/mcf	15.50/mcf	125/mcf
Coal	365/ton	Domestic price to be tied to international prices with higher royalties if necessary	
Electricity:			
Residential	0.50/kWh	0.83/kWh	5.79/kWh
Services	0.50/kWh	0.61/kWh	4.14/kWh
Industrial	0.40/kWh	0.53/kWh	3.57/kWh
Average	0.48/kWh	0.68/kWh	4.72/kWh
Woodfuels/Charcoal Royalties	6.5-10/ADT	38/ADT	

Note: 1/ The target petroleum prices shown are net of local distribution costs and taxes. The government's tax policy should determine the consumer price levels, but which should be set above these floor amounts.

VIII. INSTITUTIONAL, FINANCIAL ISSUES AND INVESTMENT PROGRAM

A. INSTITUTIONAL AND FINANCIAL ISSUES

8.1 All modern energy activities are carried out by four SEEs under the MOE: MOGE is responsible for exploration, drilling and production of oil and gas; MPE operates three refineries, four fertilizer plants, a methanol Plant and an LPG extraction unit; MPPE is entrusted with the marketing and distribution of petroleum products throughout the country, down to retail outlets; and MEPE fulfills the objectives and purposes of development of electric supply and distribution; development, promotion and search for hydro electric power resources; electric supply for industries, commercial users and others in bulk and retail. The coal sector is managed by Mining Enterprise No. 3. Each of these enterprises is headed by a Managing Director who is assisted by Directors in charge of departments (Annex 8.1). In addition, the traditional energy sector is handled as a departmental undertaking in the Ministry of Agriculture and Forestry.

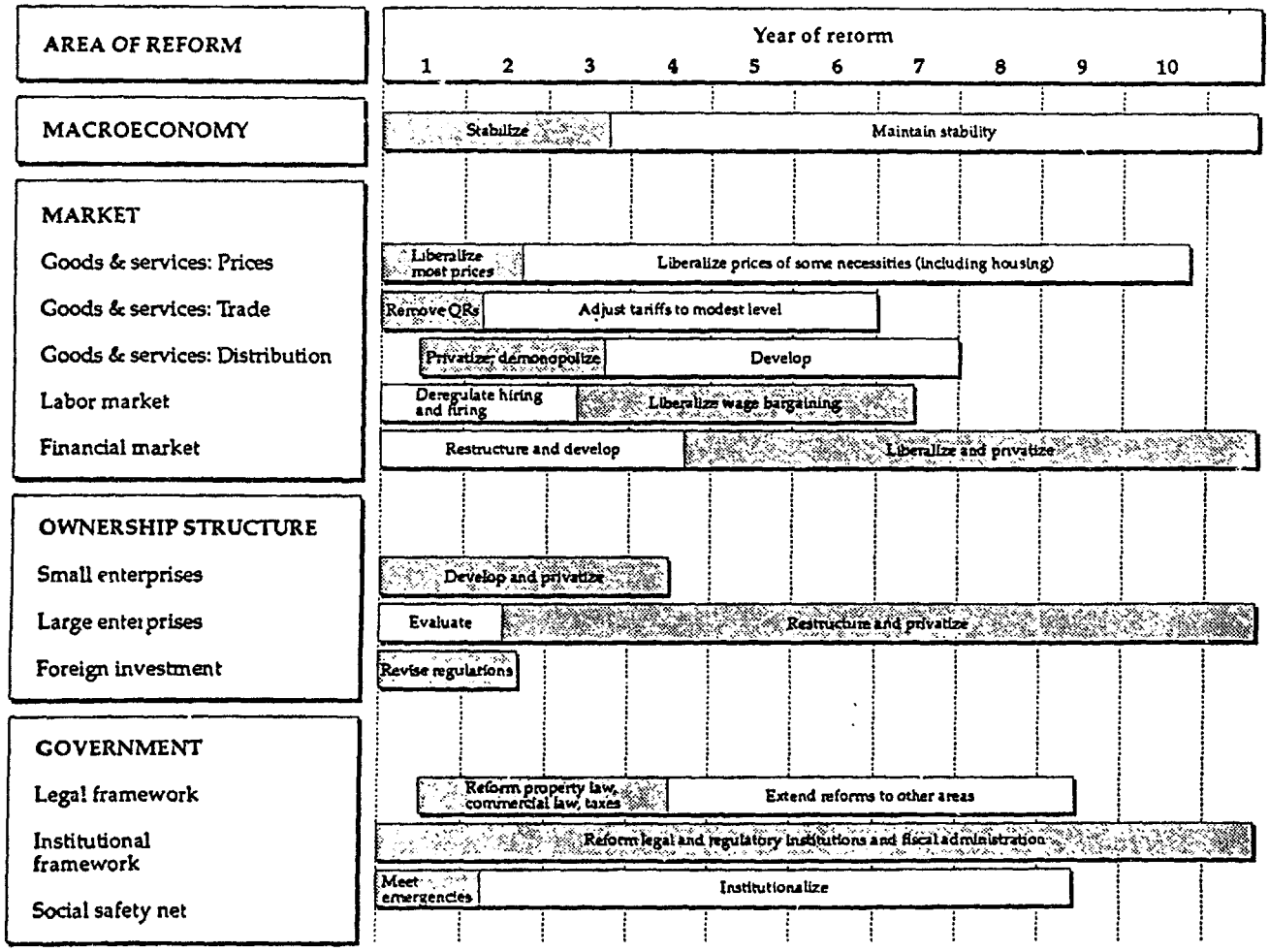
8.2 Until 1988, the SEEs then known as 'State Corporations,' lacked autonomy and accountability, and in an environment of administered prices which over the years increased far too slowly, felt discouraged as profits were eroded due to rising costs and accelerating debts. The current government placed the reforming of the SEEs high on its agenda and at the outset the government announced its intention to decentralize decision making and to give autonomy to the SEEs in procuring their inputs, allocating their production, and deciding the prices of their products. From October 1988, prices of petroleum products, in consultation with the concerned SEEs were raised four to five times and of electric power about 1.5 times so that the SEEs would not make losses on their revenue operations. From April 1, 1989 SEEs were relieved of all their domestic bank debt through conversion to state-owned equity. Simultaneously all SEE operations were brought under the umbrella of the central budget. The budgets of the energy enterprises, divided into the categories of current, capital, and loans and investments, and into domestic and foreign currency, are coordinated in MOE and then consolidated in the Ministry of Finance and Planning for Cabinet approval while the receipts and payments of the SEEs are handled through a common State Fund Account, including foreign currency. But profits are not permitted to be retained with the SEE's and are surrendered to the government as contribution. These arrangements were intended to free the SEEs of financial concerns so that they could focus wholly on production related matters, but have had instead the impact of curtailing the financial autonomy of the SEE's.

8.3 In practice, it is questionable whether the SEEs enjoy more autonomy than in the past. All pricing of energy is still controlled by the government and the mechanisms are inadequately reflective of the autonomy required in a market oriented system. The current local currency expenditure and revenue budgets proposed by SEEs appear to have easy passage with the governmental authorities scrutinizing it. But foreign exchange constraints in the economy and the priorities enjoyed by some other sectors for allocation of foreign exchange result in the energy SEEs obtaining only a minor proportion of their needs, although it is demonstrable that if longer term economic considerations were reckoned with, the priorities would be reversed. Procurement powers delegated

to SEEs have no practical utility in the absence of adequate foreign exchange releases and the extant tight control on how the releases are applied. One other area where autonomy was to prevail was in allocation of products by the SEEs. The serious gap between energy demand and supply and the need to protect essential and/or weaker sections of the community have, however, led the government to retain allocation of energy within MOE. The apex structure of each enterprise having a wholly in-house set up, leaning on the Energy Planning Department of MOE for advice on many a matter of operations, is also not reflective of decentralized administration. SEEs do not have long-term plans other than Government approved annual programs to guide them. Deviations from annual programs or the taking up of any work which is essential but has a long-term impact, therefore lead to 'ad hoc' approvals from MOE.

8.4 To implement the policy directions of a move towards a market oriented system, greater autonomy and decentralization in the energy enterprises are required. Delegation of adequate financial powers, setting up of SEE planning units and co-ordination among the energy enterprises are some of the major requisites for implementation.

The phasing of reform



Source: World Development Report 1991, World Bank
Note: Shading indicates intensive action. QRs - quantitative restrictions

Autonomy

8.5 It is necessary that the perception be created that energy enterprises have an existence of their own, relatively independent of the government, so that suppliers of credit, investors and lenders feel encouraged to deal with the enterprises. Experience in other countries has demonstrated that commercial enterprises in the State sector are successful if only the government provides them with broad mandates and targets, otherwise leaving them alone to manage their business, but reviews performance at periodic intervals. The primary ingredients for autonomy are (a) establishment of the SEEs as full corporate entities with independent boards of directors and all the powers of commercial corporations, (b) operation outside the centralized government budgeting process, (c) right of retention of earnings (d) access to foreign exchange loans or other foreign exchange payments, and (e) responsibility for price setting, wage and salary determination and employment conditions, subject to an independent authority.

8.6 The SEEs should be granted autonomy and responsibility in managing their assets. The government needs to appoint a Board of Directors drawing most members part time from outside of the particular enterprise including a few eminent public persons. The SEE's should also have the right to issue shares to institutional investors or to individuals. In addition the shareholders should be allowed to transfer ownership to others. The SEEs must be taken out of the jurisdiction of the conventional budget and essentially given financial autonomy. To be autonomous organizations, they must begin and remain financially viable. At present, the SEEs do not have their own surplus funds with which to establish themselves independently. To inject working capital the government would have to subscribe an initial paid-up capital, which might simply be set at the value of net assets. This amount would be represented on the balance sheet in the form of shares, and dividends would be expected to be paid in due course. The SEEs must have the right to maintain funds for capital and operating expenditure out of their own income. Repair and maintenance and depreciation expenditures should be provided in the accounts and the corresponding cash flows should be retained in the enterprises. A provision for a development fund for future investments should also be allocated out of annual profits after deducting taxes and duties. Procuring raw materials and controlling investment resources must be under the authority of the SEEs. They should also be granted the right to recruit and retain qualified personnel on salaries and wages, and under competitive working conditions with the private sector, by freeing them from civil service restraints on hiring and firing. It is realized that the reorganization of the enterprises as corporate entities with sufficient autonomy will involve time and phasing. It is, however, recommended that a start be made for defining the new structure and the rights and obligations to be bestowed on the entities. Other steps may follow in quick successions over a period of three or four years.

Financial Systems

8.7 Financial autonomy is basic to the process of making SEE's autonomous entities. Under the present system, the SEEs have to surrender their income to the State Central Fund (SCF) and they can acquire current and capital expenditure from SCF, but all expenditures are subject to budget control. This gives little financial responsibility to the SEEs. As a result the SEEs are not sufficiently profit oriented and they have only few incentives for reducing costs. Although the oil SEEs could generate sufficient resources for their needs as a result of

rational pricing, at present investment funds may be held back by the budget process, especially if macroeconomic pressures become severe. Reliance on budgetary transfer has adverse effects on the autonomy and operation of all the state economic enterprises. It is recommended that no enterprise should be subject to the government budget process. A satisfactory pricing policy should be enunciated for each enterprise and implemented, preferably overseen by an independent authority.

8.8 A core problem is the scarcity of foreign exchange. Shortages of imported spare parts and of raw materials are affecting capacity utilization. It is interesting to note that an export retention scheme is applied to the private sector, under which the foreign exchange proceeds may be retained for purchasing officially recognized imports. The benefits of a similar scheme should be available to the energy SEEs also, especially MOGE and MPE, which already earn foreign exchange. Further the energy enterprises could be permitted to buy from authorized dealers foreign exchange with their kyat income at free equilibrium exchange rates.

8.9 One of the major obstacles to the expansion of oil and oil product supply is the lack of sufficient domestic and foreign financial resources within the concerned SEEs. Due to inadequate financial resources, investment in exploration and development drilling has been cut back and that in turn has led to the dwindling of production and low operating incomes. The low official oil and oil product prices are other major factors causing the present financial constraints within MOGE. Recent liberalization of the economy was supposed to permit pricing flexibility for all the SEEs, but the SEEs still have to put up their price proposals to MOE where they are considered and may be further recommended to cabinet. The low official petroleum prices cannot generate the cash flow to meet domestic investment requirements of the oil SEEs. The mobilization of adequate domestic financing is important and it may be one of the means for attracting external capital inflows. Since more than 50% of the total oil SEEs' investments is in foreign exchange, mobilization of foreign exchange is of critical importance for development of the sector.

8.10 The policy of keeping official energy prices low has also led to inadequate transfer of financial resources to the Government. Even with the underpricing of energy outputs it was of little benefit to the consumer because supplies fell far short of demand. In addition, considerable quantities of oil products are siphoned away from the official to the unofficial black market, where prices are a multiple of the official prices, and the profiteering is paid for by the consumer.

8.11 In the past, the profit margins of the oil SEEs have declined, in part because of inflation, and in part because of costing methods. Costing practices applied by these enterprises have undervalued certain cost elements; depreciation is charged at historical rather than at replacement values and imported materials are costed at the overvalued official exchange rate. In addition to the introduction of rational pricing, the energy SEEs must look to cost reductions to enhance their profitability.

Planning

8.12 Planning for expansion must be a vital element for each of the enterprises. Strong planning units should be set up in each of the SEE's, minimally to prevent decline in production and optimally to meet demand growth in the most cost

effective manner. Specific mention is made in this context of two issues which were highlighted when IDA Credit 1245-BA was extended to MEPE in 1982 for transmission lines, namely the need to develop the nucleus of a planning directorate into an effective planning unit and to reduce system losses from 32% in 1981 to a targeted 20% in 1987. Studies for both were undertaken and financed under the Credit. The situation today is that planning is suspended and system losses are at about the same level as in 1981. Corporate planning is an essential component of an efficient SEE operations and in its absence suboptimal decisions and investments are likely.

Coordination of Energy Strategy and MOE

8.13 Coordination among the energy enterprises is facilitated by the Energy Planning Department in (EPD) MOE. Also the Managing Directors meet with the Minister in committee frequently. If the enterprises function with the kind of autonomy recommended, a qualitative change in the role of EPD as well as in the agenda of the coordinated committee will need to take place. The new focus will be on the strategies for energy supply in the longer term and on the investments to be taken up and approved. EPD will play a supportive role to the enterprises, provide advice to the energy coordination committee and ensure that policy and investment decisions of the committee are given effect to. Considering that coal, woodfuel and biomass are also important resources, though not falling within the purview of the four energy enterprises under MOE, the coordination committee would be well advised to include representation in respect of these resources also, so that the energy policy for the country is duly integrated.

8.14 A critical component in the country's energy strategy has to be its pricing policy. All energy prices should be considered together in a policy package, and a mechanism for annually reviewing them needs to be set up. It is recommended that thought be given to the creation of an independent Energy Pricing Board as a quasi-judicial body for this purpose.

8.15 Besides the major organizational and system changes indicated above, there are certain specific changes that need to be made in the various energy enterprises.

MOGE

8.16 As its activities in the future will become more complex and involve sophisticated technology, e.g., rehabilitation of declining oil and gas fields, development of offshore gas, enhanced oil recovery, etc, new skills and expertise from staff would be called for. Training of staff in modern technology should, therefore, be a high priority for MOGE. MOGE has before its recommendations of consultants made in February 1990 for infrastructural and institutional development; these require careful study and implementation. Some of the recommendations worth emphasis are the strengthening of the Production Directorate by establishing a Production and Reservoir Engineering Unit, a Petroleum and Production Engineering Unit and an Enhanced Recovery Engineering Unit. As fields go through rehabilitation, maintenance will become an important function and so it should be delinked from Engineering/Construction Directorate with decentralization to sites.

8.17 Reserve estimation (proven, probable and possible) of oil and gas has to be done with adequate precision since investment decisions in the hydrocarbon

subsector are largely influenced by these estimates. A National Reserves Evaluation Board, consisting of geoscientists and reservoir engineers from MOGE, EPD and universities with the necessary independence should be set up. The Board should also be free to obtain the assistance of international consultants/ agencies in the review of the reserves estimates on a periodic basis.

8.18 The technical and financial relationships between MOGE and foreign oil companies exploring and eventually producing oil/gas have to be evolved with care to the mutual advantage of all the parties. Management Commirtees established for administering the PSCs and comprising representatives of MOGE/government and the contractor underpinned by various subcommittees have got off to a satisfactory start. MOGE would be well advised to take full advantage of the training provisions in the contracts, particularly in areas where expertise will be required in the future and among others in engineering of surface facilities and pipelines, well drilling, logging, testing and cementation. MOGE should send or cross-post senior technical and management personnel to these companies, in order to gain experience in the international oil business. This is not to suggest that MOGE should not have training arrangements other than under the provisions of the PSCs. Indeed these are necessary as MOGE has to catch up with modern technology in a number of skills. In all new schemes for rehabilitation or development, MOGE must build in training in-house using experts employed for implementing the schemes as part time trainers and also seek other means to acquire expertise.

8.19 MOGE will have surplus staff due to reductions in the volume of its operations: the number of rigs working is about half of the 45 at an earlier time, and oil and gas production have declined. While activities could gather pace in the future, provided investments are made, in the meanwhile MOGE could set up servicing companies as subsidiaries, for example for seismic surveying, drilling, construction of surface facilities and pipelines, maintenance of equipment to effectively use the surplus staff. These companies could provide the PSC's with sorely needed services and support as well.

8.20 MOGE needs to focus special attention on acquisition of modern oil technology in its operations. An effective method is to employ international consultants and contractors for specialized tasks; but a more efficient means would be increasing areas where joint ventures with private interests can operate, particularly where highly complex technologies are needed.

MPE

8.21 MPE has experienced and good quality professional and technical personnel but they lack adequate exposure to modern technology and innovations. Expertise in areas such as system planning and operation optimization, process engineering, non-destructive inspection, safety, instrumentation, loss control and energy conservation needs to be updated through regular training programs.

8.22 MPE does not have a marketing unit. A better knowledge, perhaps through greater co-ordination with MPPE, of the likely future needs of the domestic market needs would be beneficial to its operating and planning efforts. Equally important is the knowledge of the international market. It would be beneficial for its export operations to have people in permanent contact with foreign markets either directly or through an agent in Singapore or other similar trade centre.

8.23 The existing computer infrastructure at MPE is very limited. An upgrade to help in refineries programming and optimization, alternative project

evaluation, crude oil purchasing evaluation, natural gas usage using LP models and techniques is urgently indicated.

MPPE

8.24 MPPE too needs a better computer system. Since it is marketing all petroleum products except for LPG and CNG, the question arises why it should also not market these two products. There appear to be technical advantage in all marketing specialization resting in one enterprise. MPPE may, however, spin off operation of retail outlets and movement of products from subterminals to private ownership and management so that the private sector is directed into these small size activities where much capital does not have to be put up. But such privatization may have to go hand in hand with rationalization of petroleum product prices.

MEPE

8.25 With a sanctioned staff strength of 15,418 including 739 officers, MEPE staffing appears too liberal, when compared to utilities in the area, yielding the following ratios--consumer/staff in distribution, 42; grid staff/substation, 67; and staff/power station, 175. There is scope for reduction in the number or at least for holding down increases until the volume of power generated and distributed grows adequately. In addition as technological changes happen, technical competence and skills of the manpower should be raised and training of professional staff kept under constant attention.

8.26 MEPE is currently installing a pilot computerized billing system in Yangon. Although this system is being installed primarily to improve efficiency of metering and bill collection, it also provides MEPE with the opportunity to address basic problems. To get the most effective use from the system, its implementation needs to be undertaken carefully. In order to take up a thorough review of the organizational procedures to support computerized billing and to make changes to standard forms and collection and billing practices, MEPE should seek assistance preferably from a neighboring utility.

8.27 Power distribution to 600,000 consumers is a major function of MEPE, and consideration should be given to establishing two semi-autonomous entities under separate chief engineers: one for the National Grid and System Control and the other for States and Divisions. In addition to its normal operating staff, each entity should have its own planning, accounting, material purchases and administration. As an initial step, it is suggested that the respective operations could be segregated under separate deputy chief engineers.

B. INVESTMENT STRATEGIES

8.28 Under the conditions prevailing in Myanmar with severe energy shortages, suppressed demand, stagnation and uncertainties the focus has to be on the contingencies of the short term of next four years and on pressing to best advantage whatever resource is at hand. Nevertheless, a perspective view of the longer term has to be kept so that strategies are consistent and investments dovetail from one period to the next. Unless investment programs are immediately initiated, the short term (1991-1995) will be characterized by further abrupt declines in production of natural gas and crude oil, aggravating the prevailing situation of under capacity operation of power stations, refineries and

petrochemical plants, of consequent scarcity of power and of petroleum and petrochemical products.

8.29 The short term (1991-95) strategy should focus on rehabilitation of existing facilities and on relatively low risk investments:

(a) The most critical action to be taken is rehabilitation of the onshore oilfields, first by drilling of 24 data wells, improving well and surface production equipment, next by well completions and then by improving pressure maintenance schemes. These and other ancillary measures, to rehabilitate the developed proved reserves require an outlay of about US$119 million over the next five years and are estimated to yield a production of 11 million barrels of oil during 1991-1995 and 26.7 million barrels during 1996-2005.

The established undeveloped proved and probable reserves can be developed for production with fairly low risk and it is therefore recommended that this should also be done under the management of MOGE but using international consultants and service companies. The investments required are US$399 million in the period up to 1995, and US$150 million thereafter, with an expected incremental oil production over the entire period of 54.8 million barrels.

The proving up of possible oil reserves, however, carries more risk and should be delayed until later, and/or given over to international oil companies on a PSC or similar basis.

(b) To develop the Moattama offshore gas reserves it is essential as a first step to assess the reserves more completely. This will require the drilling of 3 to 5 delineation wells at a cost of US$10-15 million, with the objective of establishing whether proven recoverable reserves can be increased from the present 1.6 tcf to 5 tcf or more. The best economic option for Myanmar would appear to be that about 42 bcf/yr of offshore gas should be dedicated to domestic markets and the remaining production of between 108 bcf/yr and 133 bcf/yr should for export to Thailand by pipeline. Assuming that the offshore gas fields will be developed under a production sharing contract, or under some joint venture arrangement with private sector companies, the minimum investment that would be required from Myanmar would be for the pipeline to Yangon, the cost of which will be of the order of US$173.0 million. Such a pipeline has to be laid in an early phase of offshore gas development, as soon as the production profile is determined, so that gas can flow to Myanmar by 1995/96;

(c) In the event that export of offshore gas does not fructify for whatever reasons: reserves not exceeding 1.6 to 2 tcf or failure to enter into a contract for export, the imperatives for offshore gas field development for domestic supply remain. Capital expenditure of US$247 million is required for drilling production wells, installing platforms and laying a pipeline to Yangon. Thus, a project for exploitation wholly for domestic utilization should be planned on a fall back basis and kept ready for implementation;

(d) In view of the shortage of natural gas, there will be an increasing need to fire diesel and fuel oil for power generation. The gas turbines at Thaketa, Ywama, Shwedaung, Mann and Myanaung must be made operable on diesel. Facilities for diesel fuel handling and storage must be constructed, and oil supply must be secured. Continuous operation of Thaketa and Ywama and standby operation at the other plants are seen to be necessary. In order to reduce load shedding to a minimum, diesel requirements for power generation are placed at about 700,000 barrels/year. In addition, fuel oil at about 350,000 barrels/yr will also be required at Thaton and Mawlamyaing plants. Until domestic crude oil production can be increased this will involve an import of crude oil of over 1 million barrels/yr for refining, specifically for the power sector at a cost of about US$25 million.

(e) Many combustion turbine units are operating beyond their inspection and maintenance schedules. Foreign inspection, replacement of parts and servicing cannot be further delayed without jeopardizing their future operation. Steam turbine plants and units are also in poor condition mainly due to lack of repairs, lack of proper water treatment and use of heavy oil firing in some boilers. An allocation of US$145.6 million for a power plant rehabilitation program is recommended.

(f) The least cost power development program to meet the Base Case demand forecast requires the conversion of Shwedaung, Mann, and Thaketa from open to combined cycle operation during 1993-1995. This will increase the output from the three existing stations by 103 MW maintaining the present level of fuel consumption. Although the economic cost of uprating is marginally lower than the option of building a new plant, it is prudent to delay a decision to invest further in combined cycle plants until the gas supply situation is clear.

(g) An important means of increasing power availability is the reduction of losses, mainly at the distribution level. Statistics show that losses have not been reduced from 35% in 1984 when a pilot loss reduction program was undertaken with assistance from consultants under the first IDA power project. Reactivation of the Loss Reduction Unit in MEPE with a specific mandate to show results is an 'investment' which has good potential for dividends.

(h) The refineries under MPE are operating at 25% capacity for want of crude oil. Nevertheless, Thanlyin and Chauk refineries need some urgent rehabilitation involving about US$4 million. MPE has also to renovate many of its tugs and an initial expenditure of US$5 million starting with four tugs seems necessary. Both MPE and MPPE have several miscellaneous modernization investments to make by way of instrumentation, safety appliances, control systems, computers etc. A total of US$5 million for the purpose will be a modest provision to make until 1995. MPPE is also committed to a new depot for petroleum products at Yangon at a cost of US$20 million.

8.30 For the medium term investments in the period 1996-2000, major studies and investigations will have to begin as soon as possible:

(a) Producing onshore gas fields are in decline and production is decreasing rapidly. To arrest the decline, or reduce it as much as possible, additional development and delineation wells and compression are essential. A five year program to rehabilitate and develop proved and probable gas reserves is estimated to cost US$137.5 million.

The exploration and development of possible gas reserves is estimated to require US$66.50 million in the first 5 years and US$20.00 million in the following 5 year period, and as with oil exploration and development, it is recommended that these investments should be financed through PSC contracts or similar arrangements.

(b) Offshore gas will be available first in the lower delta region. The expected speedy economic development in that region combined with the near absence of onshore gas in the area will place a heavy demand on the offshore gas. At the same time, the upper delta has potential for fast economic growth, and it too will have a lack of onshore gas and so consideration may be given to a gas pipeline from Yangon to that region. A pipeline route and engineering survey would need to be undertaken;

(c) Even if offshore gas is developed, the forecast growth of electricity demand will lead to a stage when gas supplies will become stretched to the limit and for this and other reasons it becomes prudent to invest in the country's hydro resources. Hydro facilities are forecast to be needed by the year 2003, and the initial steps for planning these should begin immediately. In addition, as information unfolds MEPE should reassess its generation options including the possibility of a domestic coal based power plant. The delineation of the coal field in Kalewa at a cost of US$6.0 million and commissioning of a feasibility study for a minemouth based power plant is recommended;

(d) MEPE also needs to prepare a ten year transmission, and distribution development plan. On occasion overloads have already occurred on the new 230/132 kV transmission systems, between the Upper and Lower Myanmar load centres caused by limitations on the associated 132/66 kV systems. Instability in the power system has also occurred, leading to major load shedding now and then. On the distribution side, investments have been minimal for years with the result that the networks are in poor condition throughout Myanmar. A scheme to replace the 6.6 kV system in the city of Yangon with 11 kV and to upgrade 33 kV networks to 66 kV has made little progress. The Mandalay distribution system is in a relatively better state, but it is also characterized by high distribution losses. Investments in the distribution upgradation are estimated at US$250.4 million;

(e) MEPE needs to evolve an integrated strategy for rural electrification. Rural electrification is both a way of enhancing national unity, of such critical importance to the country's future

and a way of nurturing rural economic development and the agricultural sector;

(f) MPE should undertake an operational loss and energy audit of the refineries, to identify possible investment opportunities to increase plant efficiency. A debottlenecking study might also be considered. Both of these studies should employ the assistance of international consultants; and

(g) Assuming that the constraint of crude oil supply is lifted, resulting in a higher growth in petroleum product demand than forecast in the Base Case, MPE's refineries might need some investment to increase conversion capacity in order to offset a possible imbalance of product mix, particularly excess fuel oil. The situation should be monitored and if necessary plans could be drawn up for a hydrotreating unit for coker gas oil, to be commissioned at Mann in 1996/97 or alternatively for a mild hydrocracker and a vacuum unit to start up in 1996/97 at an estimated investment of US$15 million.

8.31 In the medium term, the core program during 1996-2000 would consist of the following:

(a) The next stage of developing the oilfields would be for MOGE to explore, delineate and develop possible oil reserves in the event no foreign oil companies showed an interest in undertaking this work. The investments are placed at US$575 over ten years with US$288 million being in the first five years. The likely incremental production is estimated at 65 million barrels with 3 million barrels being discovered in the first five years.

(b) In the event that offshore gas were not available, the development of possible onshore gas reserves would be imperative. It would require an investment of about US$86.5 million over a ten year period and is expected to yield an incremental gas supply of 86.3 bcf over a ten year period.

(c) Assuming offshore gas is developed, the construction of a pipeline from Yangon to the Pyay area would probably be economic at an estimated costs of US$50 million.

(d) On the basis of the least cost power expansion plan, new combined cycle plants in the vicinity of Yangon of 500 MW have to be commissioned in stages, the cost of which is placed at US$450.5 million over the period 1991-2000. Given the gestation period of at least three years for combined cycle plants and about 10 years for hydro, investments will, however, have to commence long before 1996.

(e) The transmission system is in reasonable condition but will need some expansion in this period, estimated to cost US$138 million. The work of upgrading the distribution system has to be taken up in earnest, with an investment of US$250.4 million.

(f) Projects for conservation of energy as a sequel to the carrying out of energy audits in refineries may call for an adequate outlay.

8.32 The long term, beyond 2000 also should receive attention if only in the context of planning. Large scale power plants are called for in the optimum generation plan for the period between 2000 and 2010, including 300 MW of combined cycle plants and 1852 MW of hydro. The first major hydro plant is required to be on stream in 2003, and thus detailed engineering studies for various hydro sites will need to be completed by 1995.

C. INVESTMENT PROFILE

8.33 Details of the investment profile needed in the quinquennial until 1995 and until 2000 are given in Annex 8.3, and are summarized in the Table below:

TABLE 8.1 INVESTMENT PROFILE
(US$ Million-1991 prices)

Short Term (1991-95)	Foreign	Local	Total
Rehabilitation of proven oil reserves	71	47	119
Development of probable oil reserves	239	159	399
Rehabilitation of proven onshore gas reserves	43	28	71
Development of probable gas reserves	40	27	67
Rehabilitation of Power Stations	93	53	146
Conversion to combined cycle/new GT's	188	68	256
Transmission systems	44	33	77
Distribution systems	94	39	133
Rehabilitation of Refineries	9	1	10
Renovation of river tugs	7	3	10
Modernization/distribution/efficiency/logs control	8	2	10
Petroleum Product Depot at Yangon	10	10	20
Gas Pipeline Moattama-Yangon (for Moattama offshore gas)	125	48	173
Coal Exploration	5	1	6
Fertilizer Rehabilitation	10	1	11
Traditional Energy Sector	6	20	26
TOTAL	994	540	1534
Medium Term (1995-2000)			
Development of proved and probable oil	91	60	150
Development of proved and probable gas	12	8	20
Combined cycle power plants near Yangon	136	58	194
Transmission system improvements	37	25	62
Distribution system improvements	66	52	118
Refinery energy conservation investment	14	6	20
Hydrotreating at Mann refinery	11	4	15
Renovation of Tugs	18	22	40
Traditional Energy Sector	6	20	26
TOTAL	391	254	645

Notes:
1. Maintenance and operational requirements for operations are not include in the above.
2. Purchases of fuel like diesel oil/imports of crude oil are also not reflected in the table.
3. Taxes and duties are not included.
4. Moattama gas field development costs are not included as it is expected that this would be done by PSC's.
5. Development of oil and gas reserves could also be done under PSC type agreements.
6. Investments in the traditional energy sector are estimated at US$51.5 million, depending upon the first stage of data collection, pilot projects.

D. FINANCIAL REQUIREMENTS

8.34 The energy sector's resource mobilization requirements are far greater than any other sectors. Because of the magnitude of these investments, the cost to the nation of either (a) a failure to optimize investments; or (b) an inefficient utilization of assets, can be extremely high. The recommended investment profile is directed at efficient utilization of existing resources and assets and at a least cost power expansion program.

8.35 The total investment needs in the period 1991 to 1995 are US$1,532 million (1991 US$), with a foreign component of US$992 million; and in the period 1996 to 2000 are US$645 million, with a foreign component of US$391 million. This assumes that offshore gas development will be done under a production sharing contract, or other joint venture arrangement, with financing from contract partners and only minimal investments from Myanmar. In the context of examining how the funds needed for investments would be available to the four energy sector enterprise, financial statements incorporating the prices now recommended (first step) have been prepared and are contained in Annex 8.3. Table 8.2 presents a summary of the cash flow for the years 1991-95.

TABLE 8.2 ENERGY ACTIVITIES: MOGE, MEPE, MPE & MPPE
CASH FLOW DURING FY1991-1995

	(k million)	Equivalent (US$ million) at 50k/US$
Sources		
Net income before interest on foreign loans, state taxes, levies and state takes of profits	9868	197.4
LESS state taxes, as above	9269	185.4
Add Depreciation	3389	67.8
Internal cash generation	3988	79.8
GOM Equity contribution	4006	80.1
New foreign loans/investments	5256	847.8
TOTAL SOURCES	13250	1007.70
Application		
Construction requirements	9498	430.8
Debt service on foreign loans	3552	572.9
Changes in working capital	200	4.0
TOTAL APPLICATION	13250	1007.7

8.36 It is interesting to note that the total of state taxes, levies and takes in the five years equals the GOM equity contributions and the new foreign loans/ investments. With the shadow exchange rate in operation, the necessity for moving to the target minimum energy prices becomes paramount as the first step prices will not provide adequate revenues to cover the construction and debt service requirements. But the serious constraint is the availability of foreign exchange.

8.37 Given Myanmar's foreign currency constraints and the fact that the four energy enterprise have had to defer repayments of foreign loans and interest to the extent of US$150 million as at July 15, 1990, the outlook for finding the foreign currency requirements for the future are clouded. The silver lining is that the government has in the last two or three years taken significant action to improve the foreign trade regime and to encourage foreign investments. The response to invitations to explore for oil and gas in new areas of the country

has been significant. Moattama offshore gas development presents an opportunity for financing through a PSC or similar arrangement. For onshore oil and gas development the government and the energy SEEs must also pursue with vigor any openings to attract financing. Foreign investment interest could probably be attracted to the exploration and development of possible reserves, and perhaps to enhanced oil recovery schemes. It is also possible that new power stations such as the combined cycle units could be installed under build-operate-transfer type contracts (BOT) and/or other supplier credit arrangements. As for resumption of bilateral assistance, macroeconomic policies are presently the major constraint, which with determined effort by the government, could be relieved.

ANNEX 1.1

GDP BY SECTOR IN MYANMAR (Billion, '87 kyats)
1976 to 1990

YEAR	AGRICULTURE	INDUSTRY	OTHER	TOTAL
1976	21.2407	3.9835	14.6983	39.9225
1977	22.3873	4.2963	15.6247	42.3083
1978	23.5061	4.7054	16.5517	44.7632
1979	25.3375	5.0182	17.4064	47.7621
1980	26.6774	5.3924	18.1782	50.2480
1981	29.4359	5.8856	19.0879	54.4094
1982	31.7013	6.3163	19.9544	57.9720
1983	33.5999	6.7386	20.9157	61.2542
1984	35.2461	7.0069	21.7365	63.9895
1985	36.8006	7.6638	22.9664	67.4308
1986	37.8373	8.0298	24.1805	70.0476
1987	38.0288	7.5269	23.7531	69.3088
1988	36.1888	7.0663	23.1143	66.3694
1989	31.5700	5.9870	21.1250	58.6820
1990	34.9400	6.9000	21.1800	63.0200

ANNEX 1.2 (a)

ENERGY BALANCES IN MYANMAR, in 1990

(Natural Units)

	TRADITIONAL ENERGY			MODERN ENERGY												
										Electricity		Petroleum Products				
	Fuel-Wood	Charcoal	Biomass Residue	Crude Oil	Gas	Coal	Hydro	Mini Hydro	Purchased Power	Grid	Isolated	Diesel	Petrol	Kero	Av F	F Oil	Other
GROSS SUPPLY	M Cu T	M Cu T	MT	MMB	BCF	MT	GWH	GWH	GWH	GWH	GWH	MMIG	MMIG	MMIG	MMIG	MMIG	MMIG
Production	23536		2206	4.437	40.1	38.0	1113.9	30	5.5								
Field Use and Losses			-299		-4.0												
Imports				0.7		1.6						11.7					
Primary Exports																	
GROSS SUPPLY AVAILABLE	23536		1907	5.097	36.1	39.6	1113.9	30	5.5			11.7					
CONVERSION																	
Charcoal Production	-1406	857															
Power generation					-3.7	-0.05	1143.9	-30	7.83	2510	131.7	-2.3					
Petroleum Refining				-3.8	-2.6							83.8	38.1	2.2	4.6	24.6	18.4
Methanol/LNG					-0.2								1.7				
Conversion Losses	-4223	-43	-1150	-1.3	-19.2	-3.09	-2475	-58									
Trans/distr Losses										-753	-39.5						
NET SUPPLY AVAILABLE	17908	814	757	0.0	10.4	36.5	-217	-58	13	1757	92	93.2	39.8	2.2	4.6	24.6	18.4
Secondary Exports (coke)																	-12.5
NET DOMESTIC CONSUMPTION	17908	814	757		10.4	36.5				1757	92	93.2	39.8	2.2	4.6	24.6	5.9
CONSUMPTION BY SECTOR																	
Transport					0.0	0.7				0	0	52.7	37.4	0.0	4.0	3.5	5.7
Industry			189		5.6	35.7				993	52	22.4	2.0	0.2	0.1	10.9	0.2
Other					0.0					220	12	18.1	0.4	0.0	0.5	10.2	0.0
Fertilizer					4.8					0	0	0.0	0.0	0.0	0.0	0.0	0.0
Household	17908	814	568		0.0					545	29	0.0	0.0	2.0	0.0	0.0	0.0
TOTAL	17908	814	757		10.4	36.5				1757	92	93.2	39.8	2.2	4.6	24.6	5.9
SOURCES OF DATA	IPEC	IPEC	IPEC	IPEC & MOG	IPEC & BEICIP & EST	MOE & BEICIP	IPEC	WB85	MOE & MPPE	EST	EST	MOE+MP	MOE	MOE	MOE	MOE	MOE
CONVERSION TO 000TOE	0.401	0.658	0.401	136.430	28.039	0.647	0.084	0.084	0.084	0.084	0.084	3.744	3.357	3.647	3.647	3.838	2.000

ANNEX 1.2 (b)

ENERGY BALANCES IN MYANMAR, in 1990

(THOUSAND TOE)

	PRIMARY ENERGY									SECONDARY ENERGY								TOTALS
	TRADITIONAL ENERGY			MODERN ENERGY														
	Fuel-Wood	Charcoal	Biomass Residue	Crude Oil	Gas	Coal	Hydro	Mini Hydro	Purchased Power	Electricity Grid	Electricity Isolated	Petroleum Products Diesel	Petrol	Kero	Av F	F Oil	Other	
GROSS SUPPLY																		
Production	9437.6		884.6	605.4	1125.0	24.6	314.2	7.4	0.5									12399
Field Use and Losses			-119.9		-112.5													-232
Imports				90.0		1.0						43.7						135
Primary Exports																		0
GROSS SUPPLY AVAILABLE	9437.6	0.0	764.7	695.4	1012.5	25.6	314.2	7.4	0.5			43.7						12202
% All Primary Energy	76.7%	0.0%	6.2%	5.7%	8.2%	0.2%	2.6%	0.1%	0.0%			0.4%						100%
% Modern Energy				33.1%	48.2%	1.2%	15.0%	0.4%	0.0%			2.1%						100%
CONVERSION																		
Charcoal Production	-563.7	563.7																0
Power generation					-105.0	-0.03	-105.6	-2.5	-0.5	211.6	11.1	-8.6						0
Petroleum Refining				-524.4	-72.9							313.8	127.8	8.1	16.9	94.3	36.8	0
Methanol/LNG					-5.7								5.7					0
Conversion Losses	-1693.2	-28.2	-461.0	-171.0	-467.3	-2.00	-208.6	-4.9										-3036
Trans/distr Losses										-63.5	-3.3							-67
NET SUPPLY AVAILABLE	7180.7	535.5	303.7	0.0	361.6	23.60	0.0	0.0	0.0	148.1	7.8	348.9	133.5	8.1	16.9	94.3	36.8	9199
%	78.1%	5.8%	3.3%	0.0%	3.9%	0.3%	0.0%	0.0%	0.0%	1.6%	0.1%	3.8%	1.5%	0.1%	0.2%	1.0%	0.4%	100%
Secondary Exports (coke)																	-25.0	-25
NET DOMESTIC CONSUMPTION	7181.5	535.6	303.7		361.6	23.6				148.1	7.8	348.9	133.5	8.1	16.9	94.3	11.8	9175
CONSUMPTION BY SECTOR																		
Transport					0.0					0.0	0.0	197.5	125.5	0.1	14.7	13.4	11.4	363
Industry			75.9		194.6	23.6				83.7	4.4	83.7	6.8	0.8	0.5	41.8	0.4	516
Other					0.0					18.5	1.0	67.7	1.2	0.0	1.7	39.1	0.1	129
Fertilizer					167.1					0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	167
Household	7181.5	535.6	227.8		0.0					45.9	2.4	0.0	0.0	7.3	0.0	0.0	0.0	8000
TOTAL	7181.5	535.6	303.7		361.6	23.6				148.1	7.8	348.9	133.5	8.1	16.9	94.3	11.8	9175
% All Secondary Energy	78.3%	5.8%	3.3%	0.0%	3.9%	0.3%				1.6%	0.1%	3.8%	1.5%	0.1%	0.2%	1.0%	0.1%	100%
% Modern Energy					31.3%	2.0%				12.8%	0.7%	30.2%	11.6%	0.7%	1.5%	8.2%	1.0%	100%

ANNEX 1.3

PRODUCTION AND CONSUMPTION OF GAS AND CRUDE OIL IN MYANMAR 1978 to 1990

YEAR	Natural Gas		Crude Oil	
	Gross Prod	Mktble Cons	Gross Prod	Refin Cons
	mmcf/yr		mmb/yr	
1978	21.41	11.85	9.56	8.40
1979	19.14	14.67	9.99	8.30
1980	21.53	17.72	11.02	9.22
1981	25.26	22.00	10.11	8.60
1982	23.85	20.38	10.44	8.21
1983	23.13	19.17	9.79	7.84
1984	22.67	20.51	10.17	7.44
1985	29.45	24.51	11.20	7.79
1986	35.54	34.48	10.25	6.99
1987	40.45	39.49	8.27	5.98
1988	41.91	41.28	6.17	5.12
1989	39.09	38.81	4.84	3.62
1990	41.51	36.10	5.55	4.40

ANNEX 1.4

CONSUMPTION OF MAIN PETROLEUM PRODUCTS (Million IG) in MYANMAR
1978 to 1990

	Petrol	Kero	Av Fuel	Diesel	Fuel Oil	Coker GasOil	HFO	Propane	Butane	LPG	TOTAL
1978	62.6	29.8	8.5	78.5	45.7	0.0	0.0	0.0	0.0	0.0	225.0
1979	64.8	22.7	7.1	80.7	46.4	0.0	0.0	0.0	0.0	0.0	221.7
1980	70.2	19.7	6.9	89.6	47.6	0.0	0.0	0.0	0.0	0.0	234.1
1981	72.5	12.0	6.8	87.7	55.0	0.0	0.0	0.0	0.0	0.0	234.0
1982	71.4	4.3	6.6	88.4	54.3	0.0	0.0	0.0	0.0	0.0	224.9
1983	70.0	5.4	6.9	96.9	50.8	10.0	0.0	0.0	0.0	0.0	240.0
1984	71.6	5.3	6.8	93.2	48.6	10.6	1.2	0.0	0.0	0.2	237.4
1985	76.3	4.8	6.6	102.7	49.0	1.8	25.0	0.0	0.0	0.0	266.3
1986	68.9	2.0	6.8	99.9	43.9	6.7	0.3	0.0	0.0	1.4	229.8
1987	65.6	0.8	5.7	79.7	41.1	4.4	0.0	4.9	0.9	1.1	204.2
1988	51.7	0.2	4.0	68.3	35.1	0.0	0.0	1.8	2.1	2.7	166.0
1989	34.3	0.9	3.8	66.2	17.9	0.0	0.0	1.6	2.1	0.0	126.9
1990	38.1	2.2	4.6	83.8	24.6	0.0	0.0	0.2	0.3	0.0	153.8

Note: years are fiscal year

ANNEX 1.5

PRODUCTION AND CONSUMPTION OF COAL IN MYANMAR (tons/year)

YEAR	PRODUCTION OF COAL			CONSUMPTION OF COAL				Apparent Stock Change
					Imports			
	Kalewa	Namma	Total	Total coal+coke	Coal	Coke	Total Coal	
1978	12696	15650	28346	112827	88598	8216	104611	12333
1979	6065	5927	11992	77020	58890	5704	71316	-434
1980	13600	0	13600	58565	35187	10564	48001	786
1981	8070	2966	11036	39480	15826	7378	32102	-5240
1982	8750	8086	16836	34[illegible]2	11182	4735	30167	-2149
1983	12204	16290	28494	47071	13867	6242	40829	1532
1984	13652	21750	35402	64928	25195	5365	59563	1034
1985	13200	30333	43533	65207	17869	3517	61690	-288
1986	12600	30555	43155	55361	4172	5929	49432	-2105
1987	16442	21056	37498	50038	2121	5034	45004	-5385
1988	15400	23313	38713	37489	1828	3430	34059	6482
1989	13600	16180	29780	26864	1581	1910	24954	6407
1990	12915	25757	38672	46571	1742	2405	44166	-3752

Notes: year is fiscal year (end)

SOURCE: Industry No 3 and MOE

ANNEX 1.6

ELECTRICITY CONSUMPTION IN MYANMAR (GWh/yr)

Fiscal Year	BULK	INDUSTRY	RESIDENTIAL	OTHER	TOTAL
1976	81.2	288.8	159.6	26.4	556.0
1977	81.3	346.4	174.2	26.4	628.2
1978	82.8	378.8	188.4	27.7	677.6
1979	88.5	373.5	200.3	27.7	690.1
1980	109.3	407.4	216.5	29.4	762.6
1981	122.2	457.1	242.3	31.9	853.5
1982	132.7	498.7	281.4	36.9	949.7
1983	144.8	551.8	315.8	37.7	1050.1
1984	157.6	585.4	340.6	37.9	1121.5
1985	195.5	654.8	373.8	39.7	1263.6
1986	128.5	882.3	408.7	40.1	1459.5
1987	146.0	918.8	437.0	41.3	1543.0
1988	153.7	904.4	481.1	41.0	1580.1
1989	167.9	962.9	529.5	44.0	1704.3
1990	183.1	1031.6	582.4	47.3	1844.4

SOURCE: MEPE

ANNEX 1.7(a)

SUMMARY OF BASE CASE MODERN ENERGY CONSUMPTION FORECAST

	PETROLEUM PRODUCTS		NATURAL GAS		COAL	ELECTRICITY		TOTAL
	Transport Ind etc	Electricity	Industry etc	Electricity		Grid	Rural	MODERN ENERGY
	mmb	mmb	bcf	bcf	mtons	GWh	GWh	mtoe
1990	4.7	0.4	16.2	19.9	44.2	2371.0	138.2	1848.6
1991	5.0	1.1	15.6	19.7	45.0	2552.0	152.0	1913.4
1992	5.3	0.9	9.8	20.1	45.9	2717.8	157.6	1858.5
1993	5.6	1.0	7.7	17.8	46.9	2895.7	163.5	1758.4
1994	5.9	0.4	7.3	15.4	47.8	3086.7	169.6	1742.0
1995	6.3	0.4	21.4	19.7	48.8	3247.3	173.5	2228.9
1996	6.6	0.4	35.1	21.9	49.7	3419.5	177.7	2732.5
1997	7.2	0.4	29.3	24.3	50.7	3654.3	183.1	2733.5
1998	7.9	0.4	23.8	27.5	51.7	3908.8	188.8	2772.6
1999	8.6	0.4	18.4	30.7	52.8	4236.4	194.8	2823.4
2000	9.4	0.5	18.1	34.4	53.8	4593.3	201.2	3046.1
2001	10.3	0.5	11.9	38.4	54.9	4982.3	208.0	3121.0
2002	11.2	0.5	6.3	43.5	56.0	5413.7	220.3	3258.4
2003	12.3	0.5	9.5	39.9	57.1	5954.3	233.5	3411.7
2004	13.4	0.4	5.1	43.6	58.3	6550.2	247.5	3566.3
2005	14.7	0.4	12.5	35.5	59.4	7207.1	262.4	3747.1
2006	16.1	0.4	10.7	36.3	60.6	7931.3	278.2	3943.5
2007	17.6	0.5	9.1	37.9	61.8	8729.8	295.0	4190.0
2008	19.3	0.5	9.2	37.8	63.1	9610.5	312.9	4459.5
2009	21.2	0.5	2.2	44.8	64.3	10582.0	331.9	4757.3
2010	23.2	0.6	-4.2	51.2	65.6	11653.7	352.1	5086.2
AAG 1990-1995	5.8%	-2.9%	5.7%	-0.2%	2.0%	6.5%	4.7%	3.8%
1996-2005	8.9%	0.8%	-5.2%	6.1%	2.0%	8.3%	4.2%	5.3%
1990-2005	7.8%	-0.5%	-1.7%	3.9%	2.0%	7.7%	4.4%	4.8%

ANNEX 1.7 (b)

SUMMARY OF LOW CASE MODERN ENERGY CONSUMPTION FORECAST

	PETROLEUM PRODUCTS		NATURAL GAS		COAL	ELECTRICITY		TOTAL
	Transport Ind etc	Electricity	Transport Ind etc	Electricity		Grid	Rural	MODERN ENERGY
	mmb	mmb	bcf	bcf	mtons	GWh	GWh	mtoe
1990	4.7	0.4	16.2	19.9	44.2	2371.0	138.2	1848.6
1991	4.9	0.8	15.6	19.7	45.0	2484.1	149.6	1896.9
1992	5.1	1.1	9.8	20.1	45.9	2589.1	152.9	1825.6
1993	5.3	0.9	7.7	17.8	46.9	2699.4	156.4	1707.3
1994	5.5	1.0	7.3	15.4	47.8	2815.3	160.0	1670.7
1995	5.7	0.4	21.4	19.7	48.8	2897.3	161.3	2135.7
1996	5.9	0.4	35.1	21.9	49.7	2984.2	162.9	2615.3
1997	6.2	0.4	29.3	24.3	50.7	3076.1	164.5	2571.5
1998	6.6	0.4	23.8	27.5	51.7	3173.3	166.3	2560.0
1999	6.9	0.4	18.4	30.7	52.8	3316.4	168.3	2553.1
2000	7.3	0.5	18.1	34.4	53.8	3466.9	170.3	2710.6
2001	7.7	0.5	11.9	38.4	54.9	3625.1	172.6	2711.8
2002	8.1	0.5	6.3	43.5	56.0	3791.4	179.2	2765.9
2003	8.6	0.5	9.5	39.9	57.1	4013.6	186.1	2824.5
2004	9.0	0.4	5.1	43.6	58.3	4249.2	193.2	2872.1
2005	9.5	0.4	12.5	35.5	59.4	4499.1	200.7	2932.6
2006	10.1	0.4	10.7	36.3	60.6	4764.1	208.4	2993.6
2007	10.7	0.5	9.1	37.9	61.8	5045.3	216.4	3087.8
2008	11.3	0.5	9.2	37.8	63.1	5343.5	224.7	3186.2
2009	11.9	0.5	2.2	44.8	64.3	5659.9	233.4	3291.8
2010	12.6	0.6	-4.2	51.2	65.6	5995.6	242.4	3405.1
AAG 1990-1995	3.7%	-2.9%	5.7%	-0.2%	2.0%	4.1%	3.1%	2.9%
1996-2005	5.3%	0.8%	-5.2%	6.1%	2.0%	4.5%	2.2%	3.2%
1990-2005	4.8%	-0.5%	-1.7%	3.9%	2.0%	4.4%	2.5%	3.1%

ANNEX 1.8

SUMMARY OF PETROLEUM PRODUCT FORECASTS (million barrels per year)

YEAR	BASE CASE			LOW CASE			HIGH CASE for refinery analysis only		
	Gen Use	Elect Use	Total	Gen Use	Elect Use	Total	Gen Use	Elect Use	Total
1989/90	4.74	0.44	5.18	4.74	0.44	5.18	7.00	0.44	7.44
1990/91	4.98	0.78	5.76	4.88	0.78	5.66	6.88	0.78	7.66
1991/92	5.27	1.14	6.41	5.07	1.14	6.21	6.76	1.14	7.90
1992/93	5.58	0.94	6.52	5.27	0.94	6.21	7.19	0.94	8.13
1993/94	5.91	1.00	6.91	5.47	1.00	6.47	7.38	1.00	8.38
1994/95	6.27	0.38	6.65	5.69	0.38	6.07	8.24	0.38	8.62
1995/96	6.65	0.39	7.04	5.92	0.39	6.31	8.48	0.39	8.87
1996/97	7.25	0.40	7.65	6.23	0.40	6.63	8.73	0.40	9.13
1997/98	7.90	0.42	8.32	6.57	0.42	6.99	9.08	0.42	9.50
1998/99	8.62	0.42	9.04	6.92	0.42	7.34	9.47	0.42	9.89
1999/00	9.42	0.45	9.87	7.30	0.45	7.75	9.84	0.45	10.29
2000/01	10.28	0.46	10.74	7.70	0.46	8.16	10.26	0.46	10.72
2001/02	11.24	0.48	11.72	8.12	0.48	8.60	10.68	0.48	11.16
2002/03	12.28	0.47	12.75	8.57	0.47	9.04	11.15	0.47	11.62
2003/04	13.44	0.41	13.85	9.04	0.41	9.45	11.69	0.41	12.10
2004/05	14.70	0.41	15.11	9.55	0.41	9.96	12.20	0.41	12.61
2005/06	16.09	0.44	16.53	10.09	0.44	10.53	12.69	0.44	13.13
2006/07	17.62	0.47	18.09	10.66	0.47	11.13	13.21	0.47	13.68
2007/08	19.31	0.49	19.80	11.26	0.49	11.75	13.77	0.49	14.26
2008/09	21.16	0.52	21.68	11.90	0.52	12.42	14.34	0.52	14.86
2009/10	23.20	0.56	23.76	12.58	0.56	13.14	14.92	0.56	15.48
PAA 1990 TO 1995	5.8%	-2.9%	5.1%	3.7%	-2.9%	3.2%	3.3%	-2.9%	3.0%
1996 TO 2005	8.9%	0.8%	8.6%	5.3%	0.8%	5.1%	4.0%	0.8%	3.9%
1990 TO 2000	7.1%	0.2%	6.7%	4.4%	0.2%	4.1%	3.5%	0.2%	3.3%
1990 TO 2005	7.8%	-0.5%	7.4%	4.8%	-0.5%	4.5%	3.8%	-0.5%	3.6%
1990 TO 2010	8.3%	1.2%	7.9%	5.0%	1.2%	4.8%	3.9%	1.2%	3.7%

ANNEX 1.9

SUMMARY OF ELECTRICITY DEMAND FORECASTS

	INTERCONNECTED SYSTEMS				RURAL SYSTEMS				TOTAL DEMAND AND SALES			
	BASE CASE DEMAND		LOW CASE DEMAND		BASE CASE DEMAND		LOW CASE DEMAND		BASE CASE		LOW CASE	
YEAR	Gen Load	SALES	Gen Load	SALES	Gen Load	SALES	Gen Load	SALES	DEMAND	SALES	DEMAND	SALES
1989/90	2371	1636	2371	1636	138	94	138	94	2509	1730	2509	1730
1990/91	2552	1761	2484	1714	152	99	150	97	2704	1860	2634	1811
1991/92	2718	1902	2589	1812	158	104	153	101	2875	2006	2742	1913
1992/93	2896	2056	2699	1917	163	110	156	105	3059	2165	2856	2021
1993/94	3087	2222	2815	2027	170	115	160	109	3256	2338	2975	2136
1994/95	3247	2403	2897	2144	174	121	161	113	3421	2524	3059	2257
1995/96	3419	2599	2984	2268	178	128	163	117	3597	2727	3147	2385
1996/97	3654	2850	3076	2399	183	135	165	122	3837	2986	3241	2521
1997/98	3909	3127	3173	2539	189	143	166	126	4098	3271	3340	2665
1998/99	4236	3431	3316	2686	195	152	168	131	4431	3583	3485	2818
1999/00	4593	3767	3467	2843	201	161	170	136	4795	3927	3637	2979
2000/01	4982	4135	3625	3009	208	171	173	142	5190	4306	3798	3150
2001/02	5414	4547	3791	3185	220	181	179	147	5634	4728	3971	3332
2002/03	5954	5002	4014	3371	234	191	186	153	6188	5193	4200	3524
2003/04	6550	5502	4249	3569	248	203	193	158	6798	5705	4442	3728
2004/05	7207	6054	4499	3779	262	215	201	165	7469	6269	4700	3944
2005/06	7931	6662	4764	4002	278	228	208	171	8209	6890	4973	4173
2006/07	8730	7333	5045	4238	295	242	216	177	9025	7575	5262	4415
2007/08	9611	8073	5344	4489	313	257	225	184	9923	8329	5568	4673
2008/09	10582	8889	5660	4754	332	272	233	191	10914	9161	5893	4946
2009/10	11654	9789	5996	5036	352	289	242	199	12006	10078	6238	5235
Growth to 1995	6.5%	8.0%	4.1%	5.6%	4.7%	5.3%	3.1%	3.7%	6.4%	7.9%	4.0%	5.5%
1996 to 2005	8.3%	9.7%	4.5%	5.8%	4.2%	5.9%	2.2%	3.8%	8.1%	9.5%	4.4%	5.7%
1990 to 2000	6.8%	8.7%	3.9%	5.7%	3.8%	5.5%	2.1%	3.8%	6.7%	8.5%	3.8%	5.6%
to 2005	7.7%	9.1%	4.4%	5.7%	4.4%	5.7%	2.5%	3.8%	7.5%	9.0%	4.3%	5.6%
to 2010	8.3%	9.4%	4.7%	5.8%	4.8%	5.8%	2.8%	3.8%	8.1%	9.2%	4.7%	5.7%

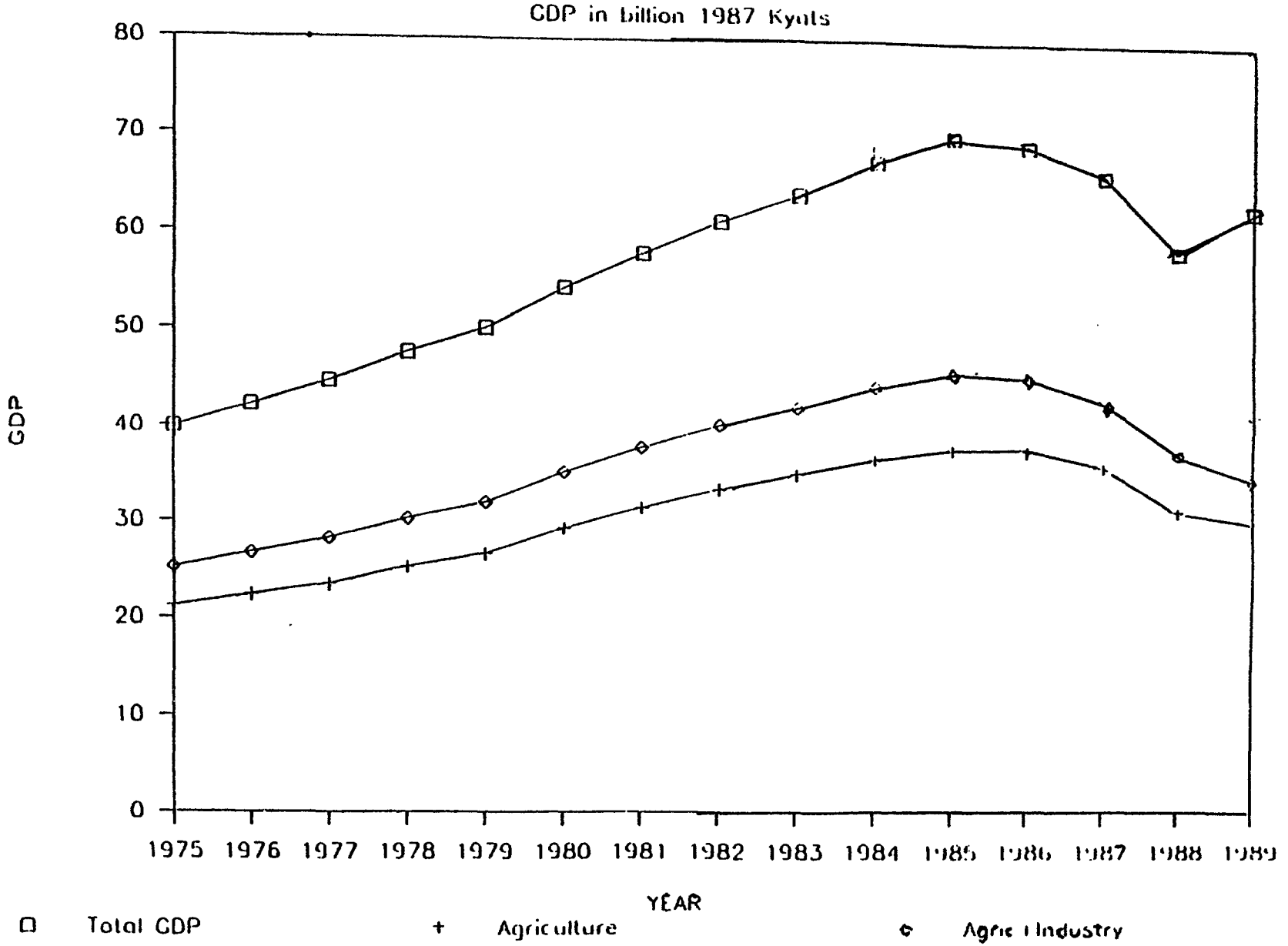
ANNEX 1.10

SUMMARY OF (FREE) GAS SUPPLY FORECASTS FOR DOMESTIC MARKET, BCF per year

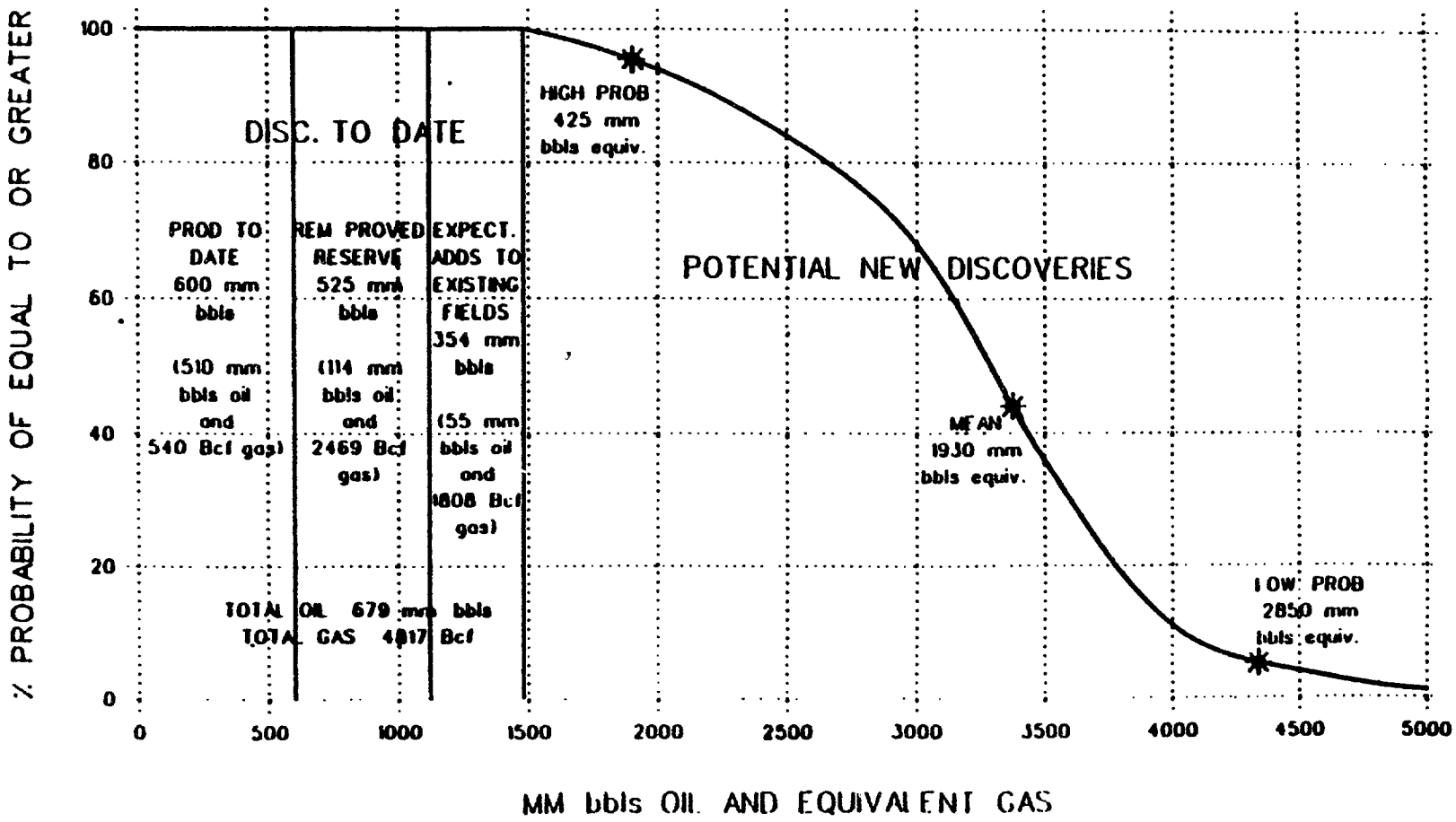
	BASE CASE			LOW CASE			HIGH CASE		
	Onshore	Offshore	Total	Onshore	Offshore	Total	Onshore	Offshore	Total
1990	33.0		33.0	33.0		33.0	(incl poss)		33.0
1991	33.3		33.3	33.3		33.3	33.3		33.3
1992	27.9		27.9	26.4		26.4	27.9		27.9
1993	23.5		23.5	21.3		21.3	23.5		23.5
1994	20.7		20.7	17.2		17.2	23.7		23.7
1995	19.1	20.0	39.1	14.1		14.1	24.1	20.0	44.1
1996	14.9	40.0	54.9	10.4		10.4	21.4	40.0	61.4
1997	11.6	40.0	51.6	7.1		7.1	20.6	40.0	60.6
1998	9.3	40.0	49.3	5.1		5.1	18.3	40.0	58.3
1999	7.1	40.0	47.1	3.1		3.1	16.1	40.0	56.1
2000	5.5	45.0	50.5	1.7		1.7	14.5	45.0	59.5
2001	3.3	45.0	48.3	0.0		0.0	12.3	45.0	57.3
2002	2.8	45.0	47.8	0.0		0.0	10.9	45.0	55.9
2003	2.4	45.0	47.4	0.0		0.0	9.6	45.0	54.6
2004	1.7	45.0	46.7	0.0		0.0	8.0	45.0	53.0
2005	1.0	45.0	46.0	0.0		0.0	6.2	45.0	51.2
2006		45.0	45.0	0.0		0.0	5.0	45.0	50.0
2007		45.0	45.0	0.0		0.0	5.0	45.0	50.0
2008		45.0	45.0	0.0		0.0	5.0	45.0	50.0
2009		45.0	45.0	0.0		0.0	5.0	45.0	50.0
2010		45.0	45.0	0.0		0.0	5.0	45.0	50.0
AAG to 2000	-18.1%		4.7%	-28.1%		-28.1%	-8.8%		6.7%
to 2005	-22.2%		2.3%	-100.0%		-100.0%	-11.3%		3.1%
to 2010	-100.0%		1.6%	-100.0%		-100.0%	-9.5%		2.2%

Note: Associated gas production is now about 2 bcf/yr and could increase depending on oil field rehabilitation

GDP IN MYANMAR, 1975 to 1989/90



UNION OF MYANMAR
OIL AND GAS
PAST DISCOVERY AND FUTURE POTENTIAL



ANNEX 2.1

MYANMAR

PAST DISCOVERY AND FUTURE POTENTIAL FOR OIL AND GAS

Notes:

(a) The vertical axis indicates the degree of certainty of various quantities of recoverable oil and gas (not in-place reserves).

(b) The horizontal axis indicates the amount at various levels of certainty.

(c) The graph portrays the entire spectrum of possibilities for Myanmar from that which has already been produced to the amount that may exist, although with low probability of occurrence.

(d) The graph indicates that some 1479 mmb of oil and equivalent gas (bbls oe) have been found with 100% certainty which includes 600 mmboe produced to date, 525 mmboe proved remaining reserve, and 354 mmboe expected additions to proved reserve; the boundary between expected additions and undiscovered potential is rather more fuzzy than sharp;

(e) Undiscovered potential is represented by a curve ranging from a near certain (95% chance) of 425 mmboe additional being discovered (bringing total oe to 1904 mmb), a mean chance (44%) of 1930 mmboe additional being discovered (bringing total oe to 3383 mmb); and an outside chance (5%) that 2850 mmboe or more additional will be found (bringing total to 4329 mmboe or higher).

(f) Note that of discovered 1479 mmboe, 46% is oil and 54% is gas, while expectations for new discoveries average 35-40 oil and 60-65% gas.

ANNEX 2.2

ESTIMATE OF RESERVES AT KALEWA

	Proven (P1)	Probable (P2)	Possible (P3)	Total
(a) Pierce Management Inc. (1954)				
Upper Coal Measure	-	-	13.7	13.7
Lower Coal Measure	2.7	3.7	5.8	12.2
Total	2.7	3.7	19.5	25.9
(b) MRDC, 1964				
North of Myitha River				
Upper Coal Measure	1.9	2.1	40.5	44.5
Lower Coal Measure	2.7	3.7	7.5	13.9
South of Myitha River				
Upper Coal Measure	-	12.0	17.3	29.3
Lower Coal Measure	0.8	-	21.3	22.1
Total	5.4	17.8	86.5	109.8

Source: Coal Committee Report, 1967.

Note: The coal reserve of the areas which have been drilled and which lie above the Waye Chaung level is considered as measured or proven (P1) reserve. The reserve which lies between Waye Chaung level and 400 feet below is designated as probable (P2), whereas that lying between 400 feet and 800 feet below is taken as possible (P3) reserve. Similarly, in the areas where exploration consisted of outcrop examination and field mapping only without drilling, the reserve above the Waye Chaung level is classified as probable (P2). The reserve between the creek level and 400 feet below it is regarded possible (P3) whereas that between 400 feet and 800 feet below is classified as potential (P4).

ANNEX 3.1

OIL PRODUCTION FORECAST - BASIC ASSUMPTIONS

(a) Future oil production from Myanmar fields for Case A has been evaluated based on the following assumptions.

Oil production from the major oil fields would continue to decline at a rate similar to that experienced since 1985/86.

Rehabilitation of pressure maintenance schemes, well completion and production surface facilities will not be carried out.

Additional development of undeveloped proven reserves are not undertaken.

(b) Future oil production profile for Case B assumes field rehabilitation development of undeveloped proven and probable reserves:

Renewal and optimization of surface pumping equipments.

Upgrading and optimization of surface production facilities and flowline network.

Drilling of 24 key wells for data gathering in the developed sands. These key wells would also be part of the projected delineation program of probable reserves.

Extensive workover programs to repair well completions, to shut-off water producing zones and prevent sand production.

Optimization of the present pressure maintenance schemes.

Drilling of approximately 60 wells to delineate the undevelopment proven and probable reserves. These delineation wells would then be completed as producers or injectors whenever possible.

Drilling of some 190 wells to bring the above mentioned reserves on full production and maintain an oil production plateau of 5.5 mmb/yr for about 7 years.

Installation of the associated well equipment and surface facilities for oil, gas and water treatment for production as well as pressure maintenance.

(c) Future oil production profile for Case C assumes successful exploration, delineation and development of oil reserves in the possible category.

ANNEX 3.2 (a)

OIL PRODUCTION FROM PROVED, PROBABLE AND POSSIBLE RESERVES
MILLIONS OF BARRELS PER YEAR

End Year	Proved Reserves		Probable Reserves	Possible reserves		
	Ouput without Rehab.	Increment with Rehab.	Increment fr added Dev drill.	Increment from Exloration drilling	TOTALS	Incremental Supply
1991	4.892	-			4.892	
1992	4.244				4.244	
1993	3.734	2.400			6.134	2.40
1994	2.940	3.900	0.500	0.800	8.140	5.20
1995	2.359	4.700	2.900	2.000	11.959	9.60
1996	1.921	4.300	5.500	4.600	16.321	14.40
1997	1.588	3.900	5.500	6.500	17.488	15.90
1998	1.300	3.500	5.500	6.500	16.800	15.50
1999	1.104	3.050	5.500	6.500	16.154	15.05
2000	0.944	2.650	5.500	6.500	15.594	14.65
2001	0.807	2.350	5.500	6.500	15.157	14.35
2002	0.690	2.100	5.500	6.500	14.790	14.10
2003	0.590	1.850	4.800	6.500	13.740	13.15
2004	0.500	1.600	4.300	6.500	12.900	12.40
2005	0.430	1.350	3.800	6.500	12.080	11.65

PV Barrels at 12%	61.23	56.78	Millions
PV Barrels at 10%	84.73	66.25	Millions

ANNEX 3.2 (b)

INVESTMENT COSTS FOR OIL PRODUCTION FROM PROVED, PROBABLE AND POSSIBLE RESERVE

(Million dollars)

	Proved & Developed Reserves		Undeveloped Proved & Probable		Possible Reserves		
	Ouput without Rehab.	Increment with Rehab.	Invest in added Drill	Other Capital	Drill	Capital	TOTALS
1991							0
1992		10			3	6	19
1993		43	23	25	18	19	128
1994		43	53	70	46	38	250
1995		18	83	55	45	32	233
1996		5	55	35	45	36	176
1997			20	10	20	21	71
1998			20	10	20	16	66
1999			20	10	20	10	60
2000			20	10	10	20	60
2001			20	10	10	20	60
2002			20	10	10	20	60
2003					10	20	30
2004					10	20	30
2005					10	20	30

SUM	1273
PV $Mill at 12%	637.38
PV $Mill at 10%	706.37

Investment costs per Incremental barrel (PV basis) @ 12% 11.23 US$/B

Investment costs per Incremental barrel (PV basis) @ 10% 10.66 US$/B

ANNEX 3.3

ONSHORE NATURAL GAS PRODUCTION, AND ESTIMATED GAS SUPPLY COSTS

TABLE 1 of 1

MYANMAR - ALL REGIONS

End Year	ESTIMATED PRODUCTION (bcf/Yr)				CAPITAL INVESTMENT (Mill US$) IN				
					Proven Reserves	Unproven Prob & Poss Reserves			Prob & Poss Operating Costs
	Proven	Prob.	Poss.	Total		Wells	Surface Facil	Total Invest	
1991	33.3	0.0	0.0	33.3					
1992	26.4	1.5	0.0	27.9	18.0	22.0	2.0	24.0	0.7
1993	21.3	2.2	0.0	23.5	21.0	29.0	2.0	31.0	1.5
1994	17.2	3.5	3.0	23.7	14.0	29.0	4.0	33.0	2.6
1995	14.1	5.0	5.0	24.1	10.0	23.0	4.0	27.0	3.4
1996	10.4	4.5	6.5	21.4	8.0	12.0	4.0	16.0	4.4
1997	7.1	4.5	9.0	20.6		12.0	2.0	14.0	4.7
1998	5.1	4.2	9.0	18.3		6.0	2.0	8.0	4.7
1999	3.1	4.0	9.0	16.1		6.0		6.0	4.7
2000	1.7	3.8	9.0	14.5		6.0		6.0	4.7
2001	0.0	3.3	9.0	12.3		6.0		6.0	4.7
2002	0.0	2.8	8.1	10.9				0.0	4.2
2003	0.0	2.4	7.2	9.6				0.0	3.8
2004	0.0	1.7	6.3	8.0				0.0	3.4
2005	0.0	1.0	5.2	6.2				0.0	3.1
PV SUMS	97.1	19.2	30.4	146.8	47.9	89.4	11.6	101.0	19.2

Assumed Interest Rate 12.00%

Supply Cost at the Field for new gas ; PV basis at 12.00% 2.42 US$/MCF

Avge. Supply Cost for all gas @ field; PV basis at 12.00% 1.40 US$/MCF

* this includes 38.7c/MCF for operating costs of old gas which is the same as estimated for new gas, and ignores all sunk costs associated with existing reserves.

ANNEX 3.4 (a)

DEVELOPMENT OF MARTABAN OFFSHORE GAS FIELD for DOMESTIC USE ONLY

INVESTMENTS in million of US$ (1990)

Year	Process Complex	Jackup Platform	Drilling	Pipeline and Terminal	Compress	Insure	Continge	Operate Costs 28c/mcf	Production MMCF/D	Production BCF/YR	TOTAL Cash Flow Costs
1			1	17			3		0	0	21
2		7	10	62			13		0	0	92
3		7	17	94			16		0	0	134
4								10	100	37	10
5								10	100	37	10
6								10	100	37	10
7								10	100	37	10
8								10	100	37	10
9								10	100	37	10
10								10	100	37	10
11								10	100	37	10
12								10	100	37	10
13								10	100	37	10
14								10	100	37	10
15								10	100	37	10
16								10	100	37	10
17								10	100	37	10
18								10	100	37	10
19								10	100	37	10
20								10	100	37	10
21								9	90	33	9
22								8	81	30	8
23								7	73	27	7
24								7	66	24	7
25								6	59	22	6
							TOTALS		TCF/$Mill	0.8	458
							PV OF PRODUCTION AND COSTS		BCF/$Mill	195	242

AVERAGE COST OF GAS ON PV BASIS AT 12% in US$/MCF 1.24

ANNEX 3.4 (b)

DEVELOPMENT OF MARTABAN OFFSHORE GAS FIELD LNG PRODUCTION

INVESTMENTS in million of US$ (1990)

Year	Process Complex	Liquifact and Terminal	Field Develop	Pipeline	LNG Tankers	Insure	Continge	Operate Costs 92.5c/mcf	Production MMCF/D	Production BCF/YR	TOTAL Cash Flow Costs
1		50	15	20			13		0	0	98
2		100	30	55			28		0	0	213
3		300	115	80			74		0	0	569
4		300	51	53			60	20	60	22	484
5		200			275		70	25	75	27	570
6		150			275		65	81	240	88	571
7								135	400	146	135
8								135	400	146	135
9								135	400	146	135
10								135	400	146	135
11								135	400	146	135
12								135	400	146	135
13								135	400	146	135
14								135	400	146	135
15								135	400	146	135
16								135	400	146	135
17								135	400	146	135
18								135	400	146	135
19								135	400	146	135
20								135	400	146	135
21								122	360	131	122
22								109	324	118	109
23								98	292	106	98
24								89	262	96	89
25								80	236	86	80
							TOTALS		TCF/$Mill	2.7	4894
							PV OF PRODUCTION AND COSTS		BCF/$Mill	605	2075

AVERAGE COST OF GAS ON PV BASIS AT 12% in US$/MCF 3.43

ANNEX 3.4 (c)

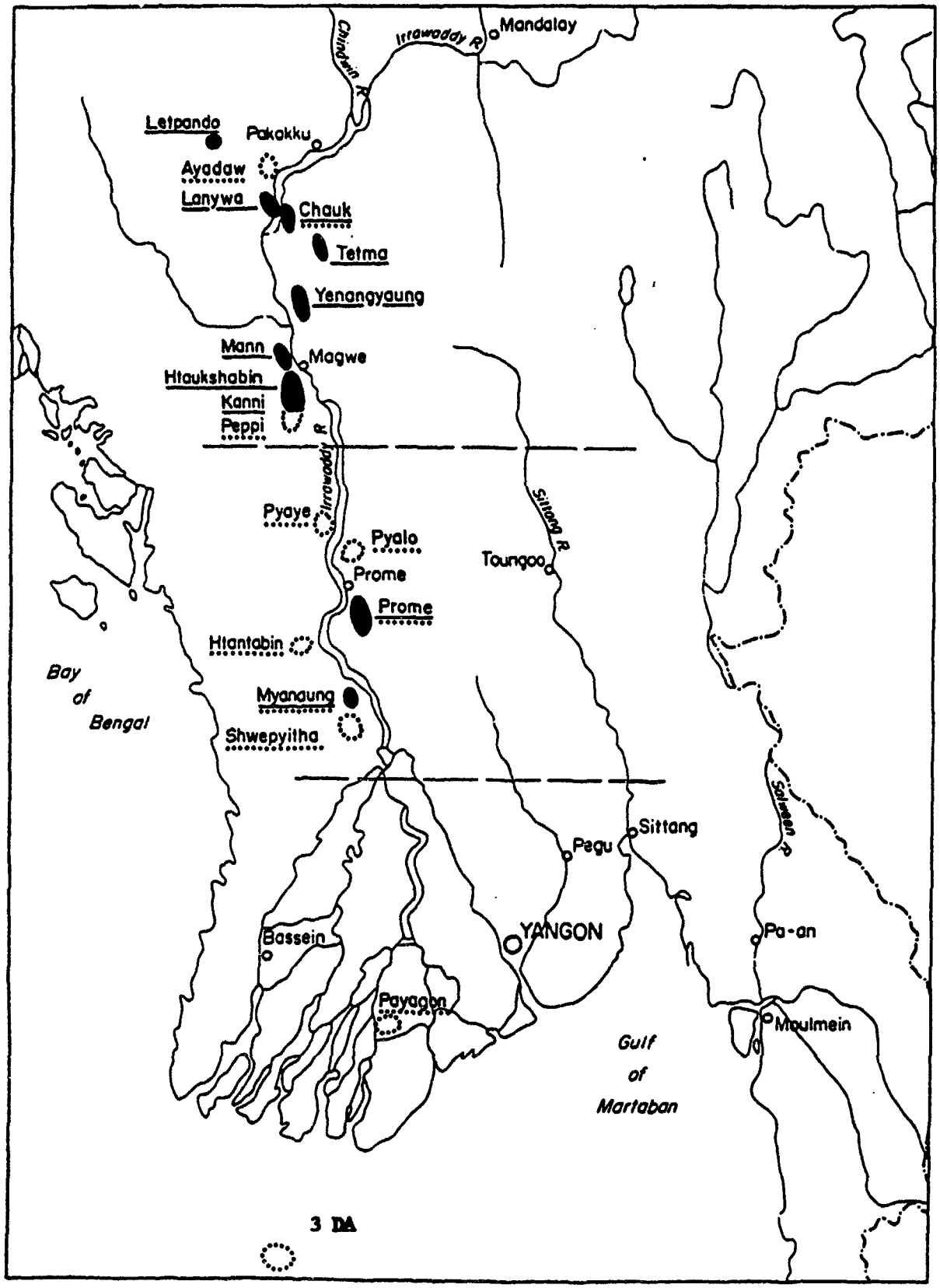
DEVELOPMENT OF MARTABAN OFFSHORE GAS FIELD GAS EXPORT TO THAILAND

INVESTMENTS in million of US$ (1990)

Year	Process Complex	Field Develop	Pipeline	Compress	Insure	Continge	Operate Costs 25c/mcf	Production MMCF/D	Production BCF/YR	TOTAL Cash Flow Costs
1		15	70			15		0	0	100
2		30	200			35		0	0	265
3		115	300			60		0	0	475
4		51	120			25	10	115	42	206
5							20	220	80	20
6							37	400	146	37
7							37	400	146	37
8							37	400	146	37
9							37	400	146	37
10							37	400	146	37
11							37	400	146	37
12							37	400	146	37
13							37	400	146	37
14							37	400	146	37
15							37	400	146	37
16							37	400	146	37
17							37	400	146	37
18							37	400	146	37
19							37	400	146	37
20							37	400	146	37
21							33	360	131	33
22							30	324	118	30
23							27	292	106	27
24							24	262	96	24
25							22	236	86	22
		TOTALS						TCF/$Mill	2.9	1749
		PV OF PRODUCTION AND COSTS						BCF/$Mill	678	933
		AVERAGE COST OF GAS ON PV BASIS AT 12% in US$/MCF								1.38

Figure 3.1

OIL AND GAS FIELDS



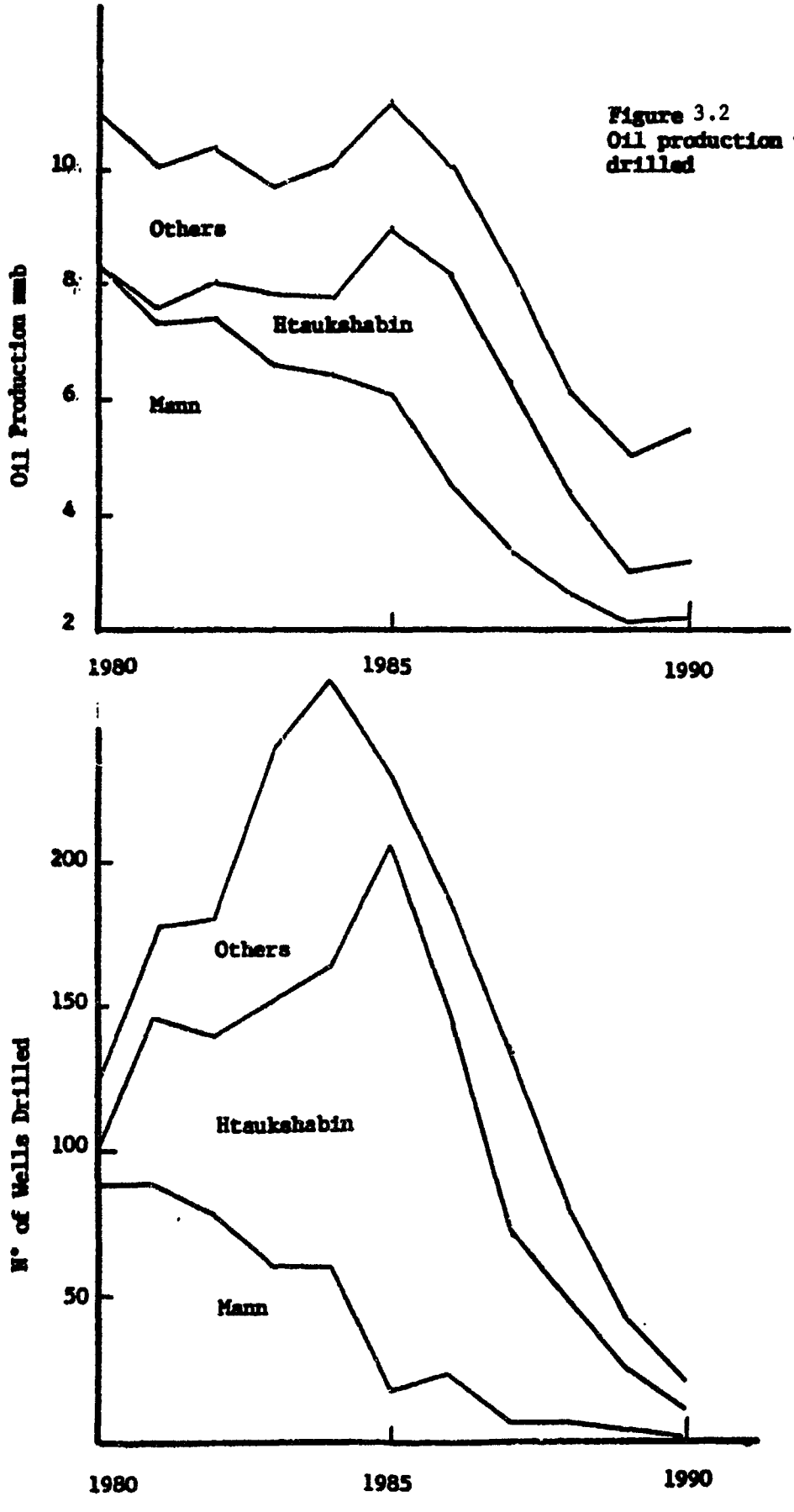
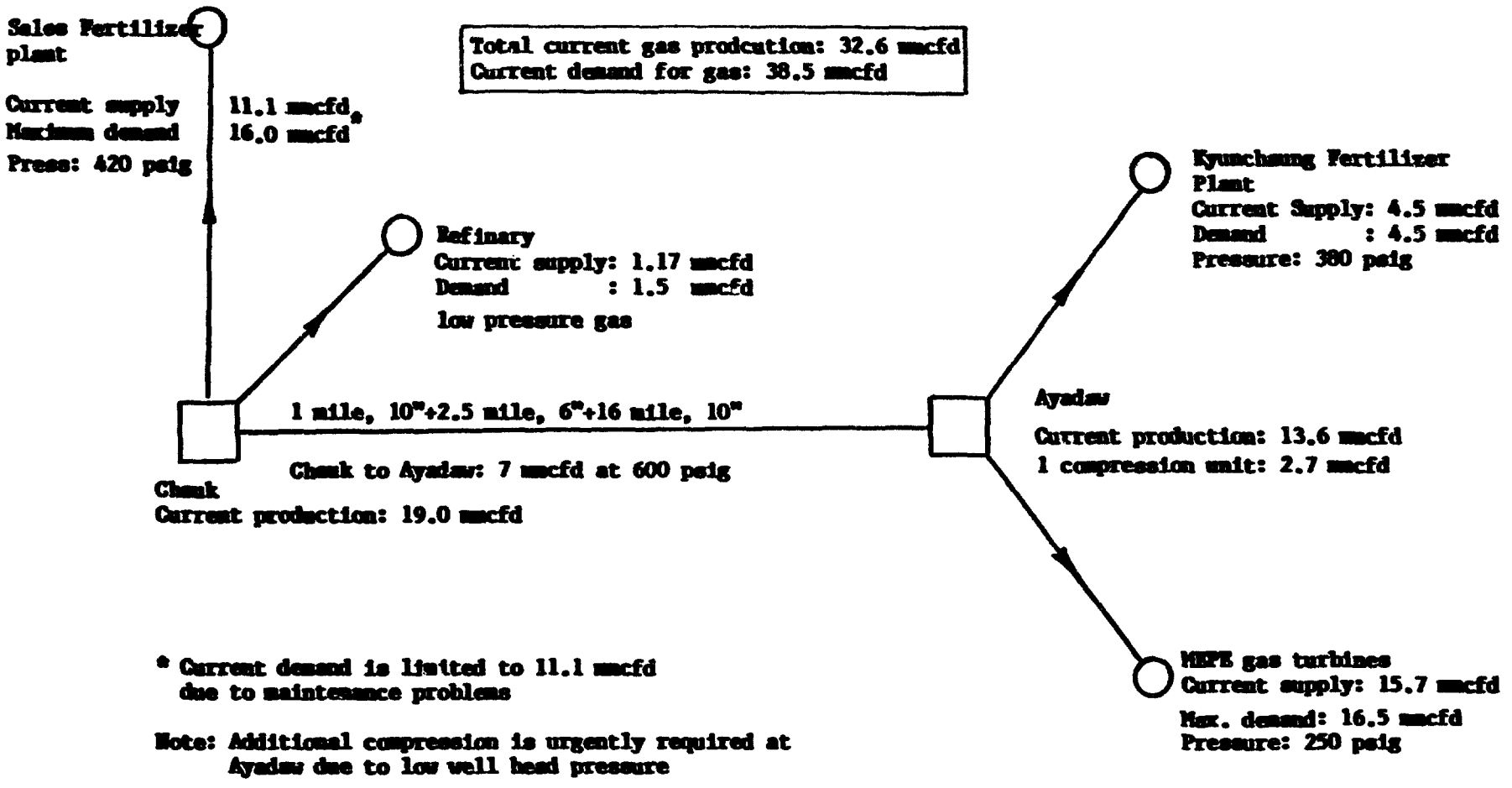


Figure 3.2
Oil production v.s. N° of wells drilled

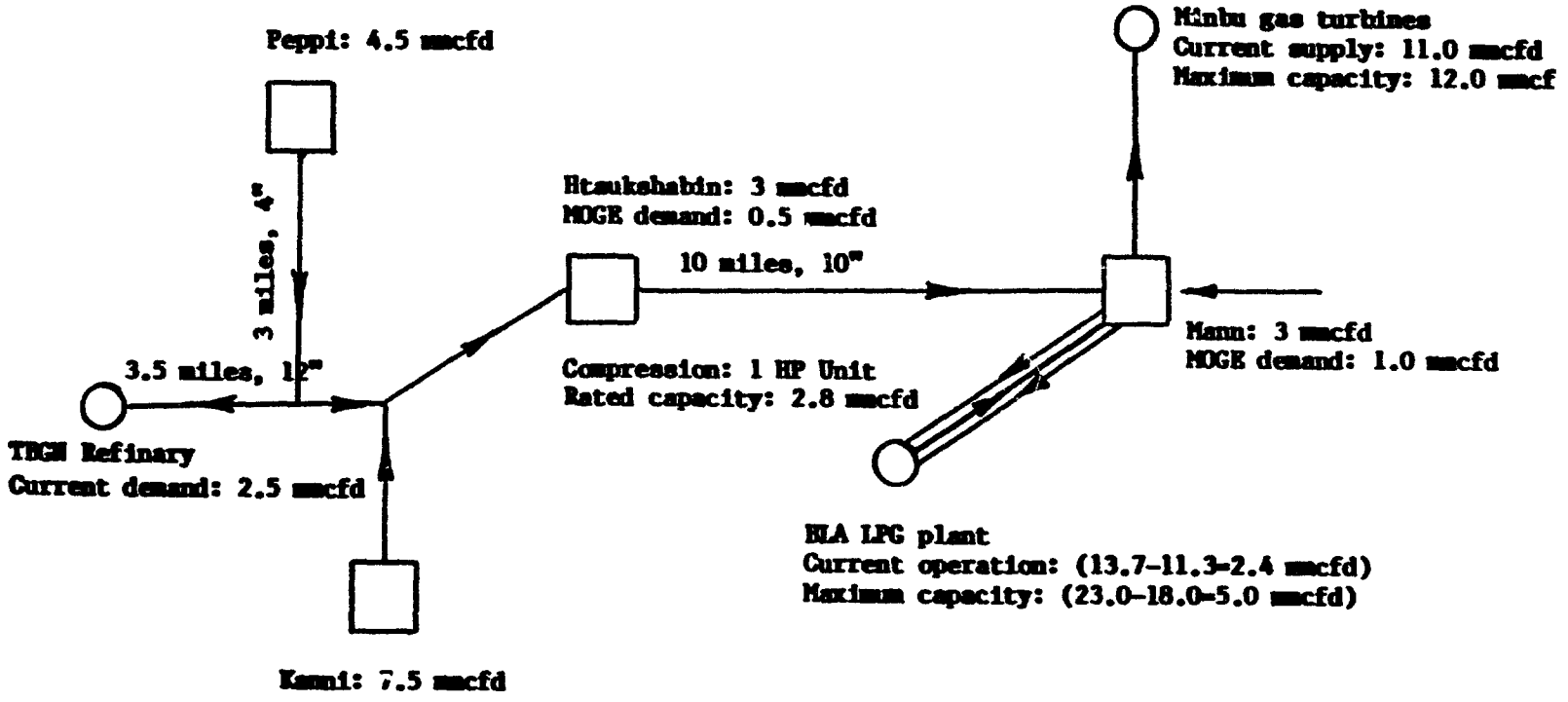
CHAUK-AYADAW



* Current demand is limited to 11.1 mmcfd due to maintenance problems

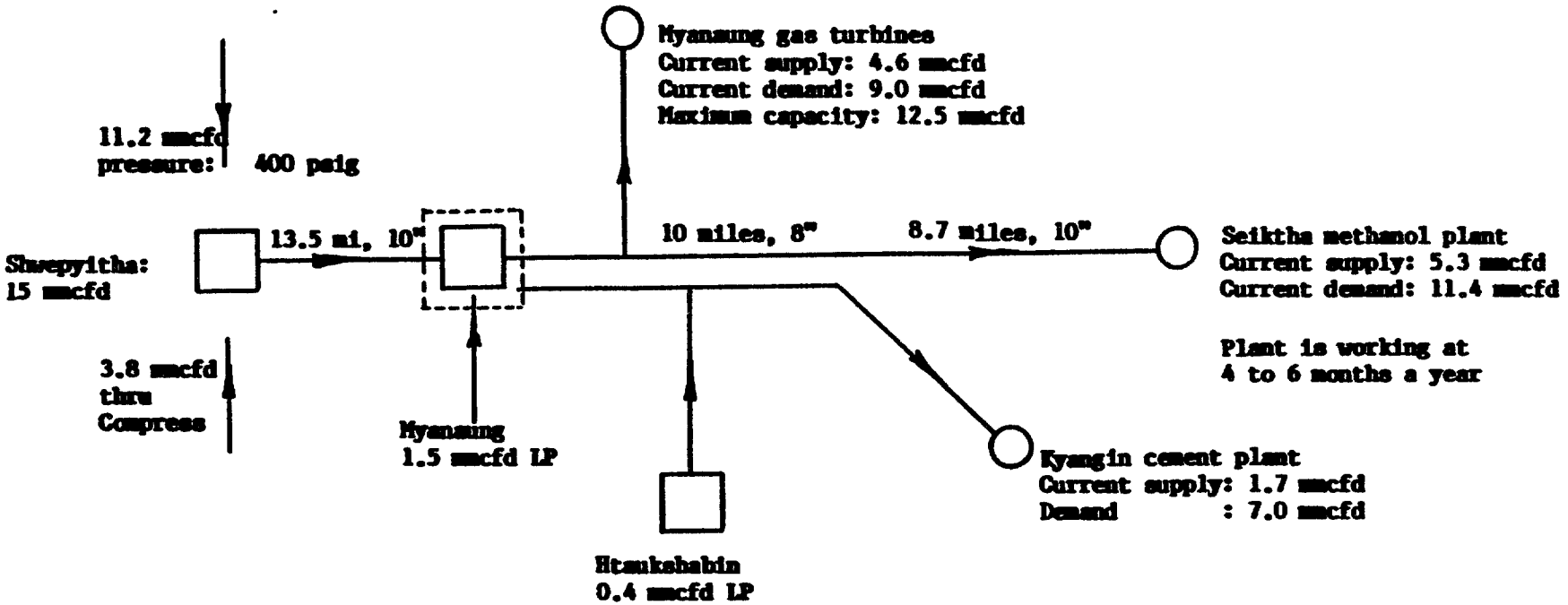
Note: Additional compression is urgently required at Ayadaw due to low well head pressure

MANN-HTAUKSHABIN-PEPPI-KANNI



Current gas production: 18.0 mmcfd
Estimated current demand: 21.0 mmcfd

MYANAUNG-SHWEPYITHA-SEIKTHA



Current gas production: 17.0 mmcfd
Estimated current demand: 30 mmcfd

YANGON-PYI-KYAUZMA

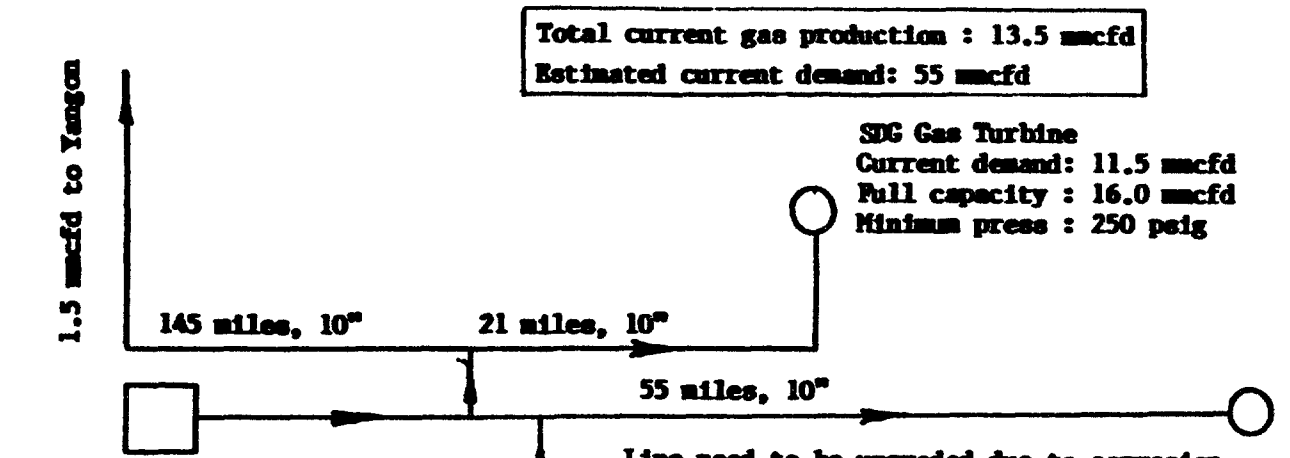
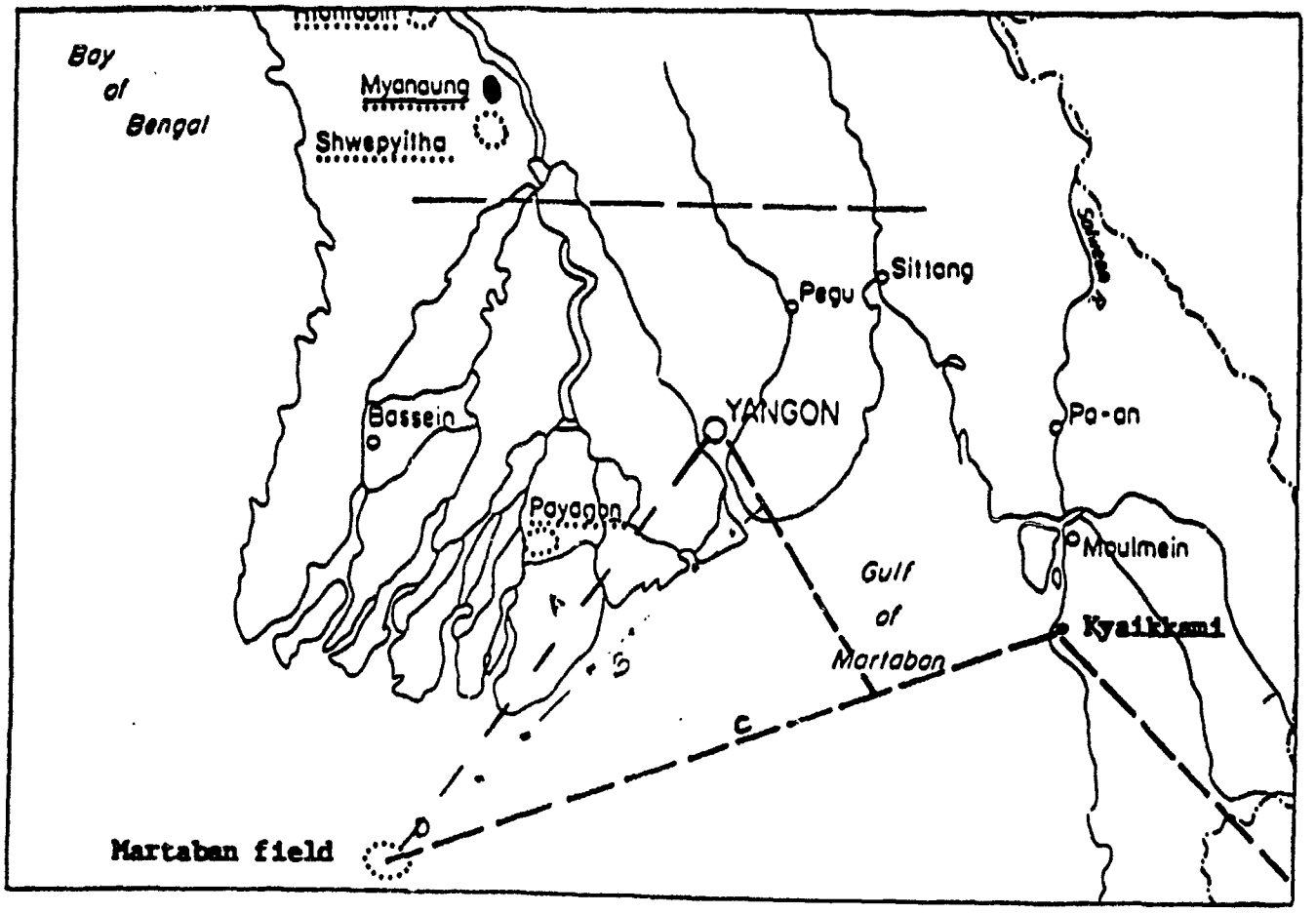


Figure 3.4

DEVELOPMENT OF MARTABAN GAS FIELD

(A. Domestic Option, B. LNG Export, C. Gas Export to Thailand)



ANNEX 4.1

MPE PLANT MAIN CHARACTERISTICS

	Plant	Capacity	Unit	Year of Completion	Process Design	Personnel
REFINERIES						
Thanlyin						2,300
	Topping 1	5,700	bbpd	1,957	Foster W.	
	Topping 2	14,300	bbpd	1,963	Foster W.	
	Topping 3	6,000	bbpd	1,980	MHI	
	Vacuum 1	1,700	bbpd	1,957	Foster W.	
	Coker	5,200	bbpd	1,986	UOP	
	Polimerizat.	500	bbpd	1,986	UOP	
	SBP	1,400	bbpd			
	LPG Merox				UOP	
	Lube Blending	14,000	Ton/year			
	Candle Fact.	5	Ton/day			
Chauk						830
	Topping	6,300	bbpd	1,953		
	Vacuum					
	Wax plant	1,500	Ton/month			
Mann						1,470
	Topping	25,000	bbpd	1,982		
	Reformer	2,800	bbpd	1,982	UOP	
	Coker	5,200	bbpd	1,982	UOP	
	HDS	3,800	bbpd	1,982	UOP	
	LPG Merox					
	Napht.Merox					
Fertilizers						
	Sale A	205	MT/day	1,970	Stamicarbon	(A+B) 770
	Sale B	260	MT/day	1,984	Stamicarbon	
	Kyunchaun	207	MT/day	1,972	Stamicarbon	600
	Kyawzwa	600	MT/day	1,985	UHDE	830
Methanol						550
	Seikthe	450	MT/day	1,986	Lurgi	
LPG						350
	Minbu	24	MMscf/day	1,987		

SOURCE: MPE

ANNEX 4.2

PRODUCTION/DISTRIBUTION STATISTICS - ALL REFINERIES AND LPG EXTRACTION PLANT

ITEM	UNIT	1986-87		1987-88		1988-89		1989-90	
		Production	Distribution	Production	Distribution	Production	Distribution	Production	Distribution
Crude Oil	BBL	5,970,629	5,979,000	5,111,755	5,113,547	4,737,318	4,470,502	4,809,720	4,777,929
PRODUCT									
Propane	BBL	25,942	25,200	72,907	52,374	45,739	37,302	31,009	21,255
Butane	BBL	20,692	9,808	81,778	46,629	60,096	40,839	42,653	55,879
Total LPG	BBL	46,633	35,008	154,685	99,002	105,836	78,140	73,662	77,134
Gasoline	BBL	1,888,722	1,887,427	1,514,800	1,485,804	1,154,404	1,063,974	1,165,374	1,187,102
Kerosene	BBL	14,114	18,400	504	574	51,878	29,841	34,246	49,566
Diesel Oil	BBL	2,301,857	2,302,743	2,127,431	2,112,190	1,962,751	1,971,215	2,405,003	2,396,885
Fuel Oil	BBL	1,089,623	1,121,566	915,111	917,824	513,261	540,199	483,947	531,417
Jet Fuel	BBL	148,457	163,057	173,673	173,809	141,597	113,757	154,190	154,013
Spec. Boil. Point	BBL	27,057	25,143	16,372	17,833	11,973	11,982	15,295	15,045
TOTAL	BBL	5,516,464	5,553,344	4,902,576	4,807,037	3,941,700	3,809,108	4,331,718	4,411,163
Petroleum Coke	MT	44,977	40,820	38,003	37,699	30,060	25,266	32,025	41,459
Paraffin Wax	MT	3,203	2,518	2,350	2,382	555	1,001	2,511	2,626
Lubricants	BBL	80,543	80,429	65,310	65,389	53,542	53,605	54,001	54,001

SOURCE: MPE

ANNEX 4.3

PRODUCT EXPORTS
(Kyats in Thousands)

PRODUCT	UNIT	1986-87	1987-88	1988-89	1989-90
UREA	MT	90326	121245	60061	51000
	KS	47888	65378	44490	32146
	KS/MT	0.53	0.54	0.74	0.63
	% of Production	30	38	28	27
PETROLEUM COKE	MT	36496	31504	29522	32700
	KS	12342	9761	11387	14159
	KS/MT	0.34	0.31	0.39	0.43
	% of Production	81	83	98	102
METHANOL	MT		9111	25235	6900
	KS		5064	22571	3613
	KS/MT		0.56	0.89	0.52
	% of Production		23	50	16
LPG	MT		2585		664
	KS		778		400
	KS/MT		0.30		0.60
PARAFFIN WAX	MT	902	1334		955
	KS	2120	4027		3912
	KS/MT	2.35	3.02		4.10
	% of Production	28	57		38
TOTAL	KS	62350	85008	78448	54230
	1000 US$	9306	12688	11709	8094

NOTES: Last consignment price (FOB)

Urea - US$121.50/MT
Methanol - US$ 77.00/MT

SOURCE: MPE

MYANMAR ENERGY STRATEGY
PETROLEUM PRODUCT DEMAND

H4: BASE CASE, high economic growth
ALL OIL PRODUCTS

H4: BASE CASE, high economic growth ALL OIL PRODUCTS

NOTE: SCENARIO 4, HIGH ECONOMIC GROWTH OF 5.5%; PLENTIFUL OFFSHORE GAS SUPPLY; OIL REHABILITATION IS UNDERTAKEN, GIVING ADEQUATE DOMESTIC CRUDE BY 1996, ASSUMING REVISED PRODUCT PRICES. METHANOL PRODUCTION/CONSUMPTION INCREASES WITH TOTAL GDP AFTER 1996. ACCELERATION OF KEROSENE DEMAND AND LESS FUEL OIL DEMAND

	GDP Growth Rates				GDP elast		Long-Run Price Elast
	1989-91	1992-96	1997-2011	Link to	1991-96	97-2011	
Agriculture	2.3%	4.3%	6.0%	KEROSENE	1.10	3.00	0.6
Mining	4.6%	8.2%	8.5%				
Industry	7.0%	7.3%	8.5%	D/AVG/O	1.00	1.20	0.6
Services	3.8%	4.9%	6.5%				
Total GDP	3.3%	5.0%	6.5%	PETROL	1.10	1.40	0.7
				FUEL OIL	0.80	0.60	0.6
				METHANOL	0.00	1.00	0.6
	Population Growth						
Urban	3.0%	3.0%	3.0%				
Rural	1.6%	1.6%	1.6%				
Total	1.9%	1.9%	1.9%				

FISCAL YEAR	PETROLEUM PRODUCT DEMAND, in Mill gallons									DEMAND GROWTH
	DIESEL	PETROL	FUEL OIL	Kerosene	Methan/ Petrol	AV FUELS	OTHER	TOTAL MM Gall	MM B/Yr	%/Yr
1989/90	83.8	38.1	24.6	2.2	11.9	4.6	0.5	165.7	4.7	
1990/91	89.7	39.5	25.2	2.3	11.9	5.0	0.5	174.1	5.0	5.0%
1991/92	96.2	41.7	26.3	2.4	11.9	5.3	0.6	184.3	5.3	5.9%
1992/93	103.2	43.9	27.3	2.5	11.9	5.7	0.6	195.2	5.6	5.9%
1993/94	110.8	46.4	28.4	2.6	11.9	6.1	0.7	206.8	5.9	6.0%
1994/95	118.9	48.9	29.5	2.7	11.9	6.6	0.7	219.2	6.3	6.0%
1995/96	127.5	51.6	30.7	2.8	11.9	7.1	0.8	232.4	6.6	6.0%
1996/97	140.5	56.3	31.9	3.4	12.7	7.8	0.8	253.4	7.2	9.0%
1997/98	154.9	61.4	33.2	4.0	13.5	8.6	0.9	276.4	7.9	9.1%
1998/99	170.7	67.0	34.5	4.7	14.4	9.5	1.0	301.6	8.6	9.1%
1999/00	188.1	73.1	35.8	5.5	15.3	10.4	1.1	329.3	9.4	9.2%
2000/01	207.3	79.8	37.2	6.5	16.3	11.5	1.1	359.7	10.3	9.2%
2001/02	228.4	87.0	38.6	7.7	17.4	12.7	1.2	393.0	11.2	9.3%
2002/03	251.7	94.9	40.2	9.1	18.5	13.9	1.3	429.6	12.3	9.3%
2003/04	277.4	103.6	41.7	10.7	19.7	15.4	1.5	469.9	13.4	9.4%
2004/05	305.7	113.0	43.3	12.6	21.0	16.9	1.6	514.1	14.7	9.4%
2005/06	336.9	123.3	45.0	14.9	22.3	18.7	1.7	562.8	16.1	9.5%
2006/07	371.2	134.5	46.8	17.6	23.8	20.6	1.9	616.3	17.6	9.5%
2007/08	409.1	146.7	48.6	20.7	25.3	22.7	2.0	675.2	19.3	9.6%
2008/09	450.8	160.1	50.5	24.4	27.0	25.0	2.2	740.0	21.2	9.6%
2009/10	496.8	174.7	52.5	28.8	28.7	27.5	2.4	811.4	23.2	9.6%
2010/11	547.5	190.6	54.5	34.0	30.6	30.3	2.6	890.1	25.5	9.7%
Avge PAA	9.3%	8.0%	3.9%	13.9%	4.6%	9.3%	8.1%	8.3%		

H4: BASE CASE, high economic growth
ALL OIL PRODUCTS

FISCAL YEAR	TOTAL OIL PRODUCTS CONSUMPTION PER CAPITA		PROPORTION OF SALES							
	POP mill	GALL/YR/ PERSON	DIESEL	PETROL	FUEL OIL	Kero	Methan Petrol	AV FUELS	OTHER	TOTAL
1989/9	40.12	4.13	50.6%	23.0%	14.8%	1.3%	7.2%	2.8%	0.3%	100.0%
1990/91	40.90	4.26	51.5%	22.7%	14.5%	1.3%	6.8%	2.9%	0.3%	100.0%
1991/92	41.70	4.42	52.2%	22.6%	14.2%	1.3%	6.5%	2.9%	0.3%	100.0%
1992/93	42.51	4.59	52.9%	22.5%	14.0%	1.3%	6.1%	2.9%	0.3%	100.0%
1993/94	43.33	4.77	53.6%	22.4%	13.7%	1.3%	5.8%	3.0%	0.3%	100.0%
1994/95	44.18	4.96	54.2%	22.3%	13.5%	1.2%	5.4%	3.0%	0.3%	100.0%
1995/96	45.04	5.16	54.9%	22.2%	13.2%	1.2%	5.1%	3.0%	0.3%	100.0%
1996/97	45.91	5.52	55.5%	22.2%	12.6%	1.3%	5.0%	3.1%	0.3%	100.0%
1997/98	46.81	5.91	56.0%	22.2%	12.0%	1.4%	4.9%	3.1%	0.3%	100.0%
1998/99	47.72	6.32	56.6%	22.2%	11.4%	1.5%	4.8%	3.1%	0.3%	100.0%
1999/00	48.64	6.77	57.1%	22.2%	10.9%	1.7%	4.6%	3.2%	0.3%	100.0%
2000/01	49.59	7.25	57.6%	22.2%	10.3%	1.8%	4.5%	3.2%	0.3%	100.0%
2001/02	50.56	7.77	58.1%	22.1%	9.8%	2.0%	4.4%	3.2%	0.3%	100.0%
2002/03	51.54	8.34	58.6%	22.1%	9.3%	2.1%	4.3%	3.2%	0.3%	100.0%
2003/04	52.54	8.94	59.0%	22.0%	8.9%	2.3%	4.2%	3.3%	0.3%	100.0%
2004/05	53.56	9.60	59.5%	22.0%	8.4%	2.5%	4.1%	3.3%	0.3%	100.0%
2005/06	54.60	10.31	59.9%	21.9%	8.0%	2.6%	4.0%	3.3%	0.3%	100.0%
2006/07	55.67	11.07	60.2%	21.8%	7.6%	2.8%	3.9%	3.3%	0.3%	100.0%
2007/08	56.75	11.90	60.6%	21.7%	7.2%	3.1%	3.8%	3.4%	0.3%	100.0%
2008/09	57.85	12.79	60.9%	21.6%	6.8%	3.3%	3.6%	3.4%	0.3%	100.0%
2009/10	58.98	13.76	61.2%	21.5%	6.5%	3.6%	3.5%	3.4%	0.3%	100.0%
2010/11	60.13	14.80	61.5%	21.4%	6.1%	3.8%	3.4%	3.4%	0.3%	100.0%

L2: LOW CASE, low economic growth ALL OIL PRODUCTS
NOTE: SCENARIO 1, LOW ECONOMIC GROWTH OF 3%/ YR; CONTINUED SHORTAGES OF GAS SUPPLY
OIL REHABILITATION IS UNDERTAKEN, GIVING ADEQUATE DOMESTIC CRUDE BY 1996, ASSUMING
REVISED PRODUCT PRICES. METHANOL PRODUCTION/CONSUMPTION REMAINS CONSTANT
AFTER 1996. ACCELERATION OF KEROSENE DEMAND AFTER 1996

	GDP Growth Rates				GDP elast		Long-Run Price Elast
	1989-91	1992-96	1997-2011	Link to	1991-96	97-2011	
Agriculture	1.6%	2.5%	2.5%	KEROSENE	1.10	4.00	0.6
Mining	3.3%	4.5%	4.5%				
Industry	4.0%	5.1%	5.1%	D/AVG/O	1.00	1.30	0.6
Services	2.1%	3.0%	3.0%				
Total GDP	2.0%	3.0%	3.0%	PETROL	1.10	1.50	0.7
				FUEL OIL	0.80	1.00	0.6
				METHANOL	0.00	0.00	0.6
	Population Growth						
Urban	3.0%	3.0%	3.0%				
Rural	1.6%	1.6%	1.6%				
Total	1.9%	1.9%	1.9%				

FISCAL YEAR	PETROLEUM PRODUCT DEMAND, in Mill gallons									DEMAND GROWTH
	DIESEL	PETROL	FUEL OIL	Kerosene	Methan/ Petrol	AV FUELS	OTHER	TOTAL MM Gall	MM B/Yr	%/Yr
1989/90	83.8	38.1	24.6	2.2	11.9	4.6	0.5	165.7	4.7	
1990/91	87.2	38.9	25.0	2.2	11.9	4.8	0.5	170.6	4.9	2.9%
1991/92	91.6	40.2	25.6	2.3	11.9	5.1	0.5	177.2	5.1	3.9%
1992/93	96.3	41.6	26.2	2.4	11.9	5.3	0.6	184.2	5.3	3.9%
1993/94	101.2	42.9	26.8	2.4	11.9	5.6	0.6	191.5	5.5	4.0%
1994/95	106.3	44.3	27.5	2.5	11.9	5.9	0.6	199.1	5.7	4.0%
1995/96	111.8	45.8	28.1	2.6	11.9	6.2	0.7	207.0	5.9	4.0%
1996/97	119.2	47.9	29.0	2.8	11.9	6.6	0.7	218.0	6.2	5.3%
1997/98	127.1	50.0	29.9	3.1	11.9	7.0	0.7	229.7	6.6	5.4%
1998/99	135.5	52.3	30.7	3.4	11.9	7.5	0.8	242.1	6.9	5.4%
1999/00	144.5	54.6	31.7	3.8	11.9	8.0	0.8	255.2	7.3	5.4%
2000/01	154.1	57.1	32.6	4.1	11.9	8.5	0.9	269.2	7.7	5.5%
2001/02	164.3	59.6	33.6	4.5	11.9	9.1	0.9	284.0	8.1	5.5%
2002/03	175.2	62.3	34.6	5.0	11.9	9.7	0.9	299.6	8.6	5.5%
2003/04	186.8	65.1	35.6	5.5	11.9	10.3	1.0	316.3	9.0	5.6%
2004/05	199.2	68.1	36.7	6.0	11.9	11.0	1.0	334.0	9.5	5.6%
2005/06	212.4	71.1	37.8	6.7	11.9	11.8	1.1	352.7	10.1	5.6%
2006/07	226.4	74.3	39.0	7.3	11.9	12.5	1.2	372.6	10.7	5.6%
2007/08	241.5	77.7	40.1	8.0	11.9	13.4	1.2	393.8	11.3	5.7%
2008/09	257.5	81.2	41.3	8.9	11.9	14.3	1.3	416.2	11.9	5.7%
2009/10	274.5	84.8	42.6	9.7	11.9	15.2	1.3	440.1	12.6	5.7%
2010/11	292.7	88.6	43.8	10.7	11.9	16.2	1.4	465.5	13.3	5.8%
AAG to 2000	5.6%	3.7%	2.6%	5.5%	0.0%	5.6%	5.0%	4.4%		
2005	5.9%	3.9%	2.7%	7.0%	0.0%	5.9%	5.0%	4.8%		
2010	6.1%	4.1%	2.8%	7.7%	0.0%	6.1%	5.0%	5.0%		

L2: LOW CASE, low economic growth
ALL OIL PRODUCTS

FISCAL YEAR	TOTAL OIL PRODUCTS CONSUMPTION PER CAPITA		PROPORTION OF SALES							
	POP mill	GALL/YR/ PERSON	DIESEL	PETROL	FUEL OIL	Kero	Methan Petrol	AV FUELS	OTHER	TOTAL
1989/9	40.12	4.13	50.6%	23.0%	14.8%	1.3%	7.2%	2.8%	0.3%	100.0%
1990/91	40.90	4.17	51.1%	22.8%	14.7%	1.3%	7.0%	2.8%	0.3%	100.0%
1991/92	41.70	4.25	51.7%	22.7%	14.4%	1.3%	6.7%	2.9%	0.3%	100.0%
1992/93	42.51	4.33	52.3%	22.6%	14.2%	1.3%	6.5%	2.9%	0.3%	100.0%
1993/94	43.33	4.42	52.8%	22.4%	14.0%	1.3%	6.2%	2.9%	0.3%	100.0%
1994/95	44.18	4.51	53.4%	22.3%	13.8%	1.3%	6.0%	3.0%	0.3%	100.0%
1995/96	45.04	4.60	54.0%	22.1%	13.6%	1.2%	5.7%	3.0%	0.3%	100.0%
1996/97	45.91	4.75	54.7%	22.0%	13.3%	1.3%	5.5%	3.0%	0.3%	100.0%
1997/98	46.81	4.91	55.3%	21.8%	13.0%	1.4%	5.2%	3.1%	0.3%	100.0%
1998/99	47.72	5.07	56.0%	21.6%	12.7%	1.4%	4.9%	3.1%	0.3%	100.0%
1999/00	48.64	5.25	56.6%	21.4%	12.4%	1.5%	4.7%	3.1%	0.3%	100.0%
2000/01	49.59	5.43	57.2%	21.2%	12.1%	1.5%	4.4%	3.2%	0.3%	100.0%
2001/02	50.56	5.62	57.9%	21.0%	11.8%	1.6%	4.2%	3.2%	0.3%	100.0%
2002/03	51.54	5.81	58.5%	20.8%	11.5%	1.7%	4.0%	3.2%	0.3%	100.0%
2003/04	52.54	6.02	59.1%	20.6%	11.3%	1.7%	3.8%	3.3%	0.3%	100.0%
2004/05	53.56	6.23	59.6%	20.4%	11.0%	1.8%	3.6%	3.3%	0.3%	100.0%
2005/06	54.60	6.46	60.2%	20.2%	10.7%	1.9%	3.4%	3.3%	0.3%	100.0%
2006/07	55.67	6.69	60.8%	19.9%	10.5%	2.0%	3.2%	3.4%	0.3%	100.0%
2007/08	56.75	6.94	61.3%	19.7%	10.2%	2.0%	3.0%	3.4%	0.3%	100.0%
2008/09	57.85	7.19	61.9%	19.5%	9.9%	2.1%	2.9%	3.4%	0.3%	100.0%
2009/10	58.98	7.46	62.4%	19.3%	9.7%	2.2%	2.7%	3.5%	0.3%	100.0%
2010/11	60.13	7.74	62.9%	19.0%	9.4%	2.3%	2.6%	3.5%	0.3%	100.0%

ANNEX 4.4(e)

HIGH DEMAND FORECAST ASSUMPTIONS

The High Case has 1984/85 as base year considering that it is the last year before oil production started to decline. Total annual consumption was increased by 5% to take partially into account the kerosene suppressed demand. An average growth rate of 2% was used for the years 1984/85 to 1993/94, 3% for the next five years and 4% assumed from then on. Scenario B has 1989/90 as base year and demand growth rate start at 2.9%, gradually increasing up to 5.7% in 2009/10.

Assumptions for High Case

The following assumptions have been made to develop Scenario A:

- Domestic oil production will increase to a level of approximately 10 MMBBL per year by 1996.
- Demand will depend on what market can bear at a given retail price.
- Kerosene production is no longer restricted.
- Methanol mix (M80) is considered as part of the gasoline market since its consumption is easily reversible.
- Methanol is preferably exported, being used as fuel only when gasoline is scarce.
- Short term fuel needs for power generation has not been considered. They will have to be supplied with the present refining capacity or by imports. Natural gas production will return to historical levels before any refining investment plans have been executed.
- LPG production will depend on refinery operating mode. All LPG will be used in the domestic market.
- Wax will continue to be produced at Chauk refinery at today's rates.
- Coke production will have no limitations other than refining optimization. All production is to be exported.
- All other specialty products are included in the product with the closest related fuel values.

ANNEX 4.4(f)

PETROLEUM PRODUCTS DEMAND FORECAST

High Case for Refinery Analysis

	GASOLINE		KEROSENE		DIESEL		FUEL OIL		TOTAL	
YEAR	DEMAND MBBLS	GROWTH %	DEMAND MBBLS	GROWTH %	DEMAND MBBLS	GROWTH %	DEMAND MBBLS	GROWTH %	DEMAND MBBLS	GROWTH %
1984-85									7,011	2.0
1993-94	2,514	2.0	838	4.0	4,357	3.5	670	1.0	8,379	3.0
1994-95	2,564	2.0	872	4.0	4,509	3.5	677	1.0	8,622	3.0
1995-96	2,616	2.0	906	4.0	4,667	3.5	683	1.0	8,873	3.0
1996-97	2,668	3.0	943	4.5	4,831	5.0	690	1.0	9,131	4.0
1997-98	2,748	3.0	985	4.5	5,072	5.0	697	1.0	9,502	4.0
1998-99	2,830	3.0	1,029	4.5	5,326	5.0	704	1.0	9,890	4.0
1999-00	2,915	3.0	1,076	4.5	5,592	5.0	711	1.0	10,294	4.0
2000-01	3,003	3.0	1,124	4.5	5,872	5.0	718	1.0	10,717	4.0
2001-02	3,093	3.0	1,175	4.5	6,165	5.0	726	1.0	11,158	4.0
2002-03	3,186	3.0	1,228	4.5	6,474	5.0	733	1.0	11,619	4.0
2003-04	3,281	3.0	1,283	4.5	6,797	5.0	740	1.0	12,101	4.0
2004-05	3,380	3.0	1,341	4.5	7,137	5.0	747	1.0	12,605	4.0
2005-06	3,481	3.0	1,401	4.5	7,494	5.0	755	1.0	13,131	4.0
2006-07	3,585	3.0	1,464	4.5	7,869	5.0	763	1.0	13,680	4.0
2007-08	3,693	3.0	1,530	4.5	8,262	5.0	770	1.0	14,255	4.0
2008-09	3,804	3.0	1,599	4.5	8,675	5.0	778	1.0	14,855	4.0
2009-10	3,918		1,671		9,109		786		15,483	

FIG 1 PETROLEUM PRODUCTS DISTRIBUTION

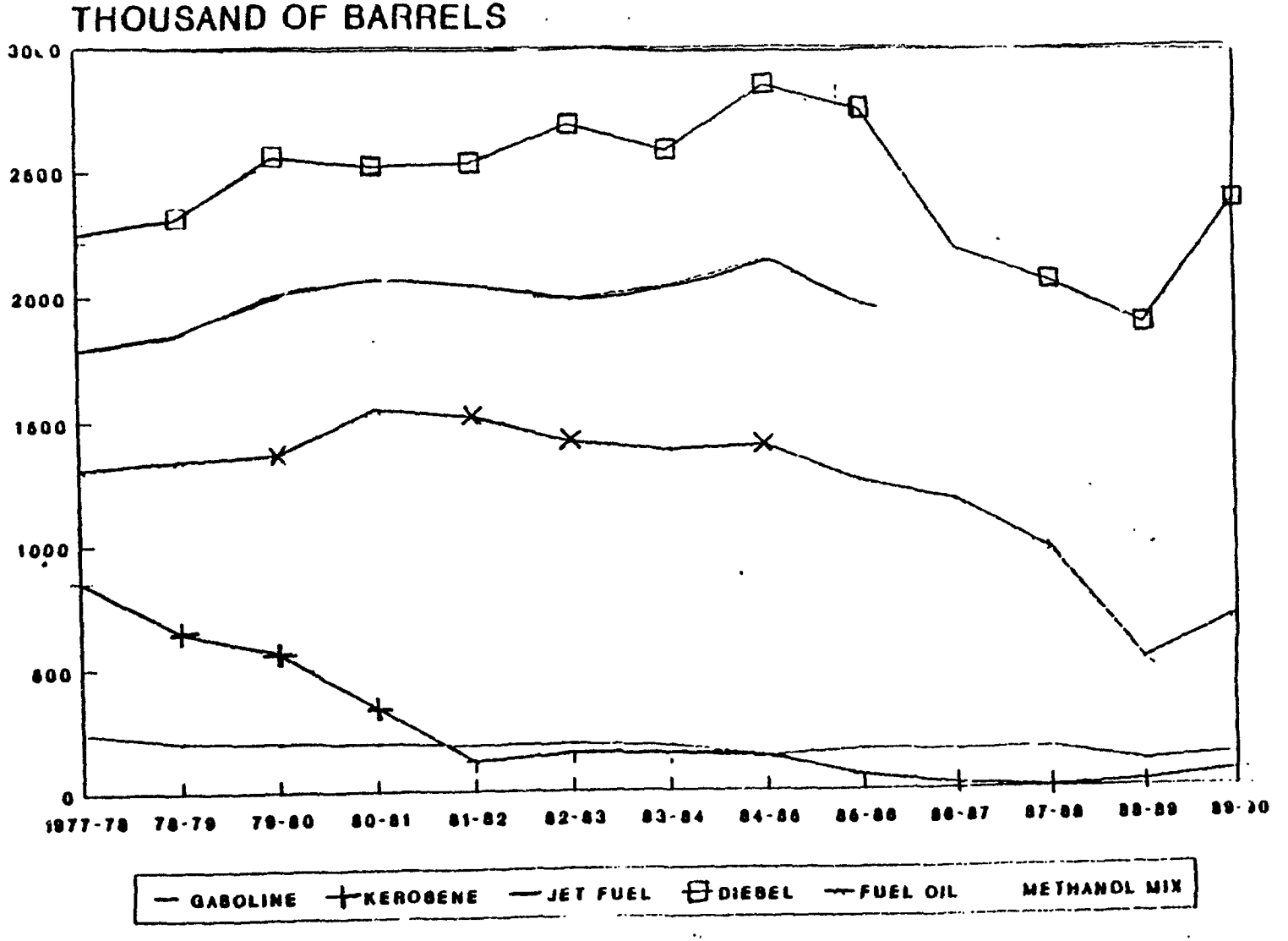
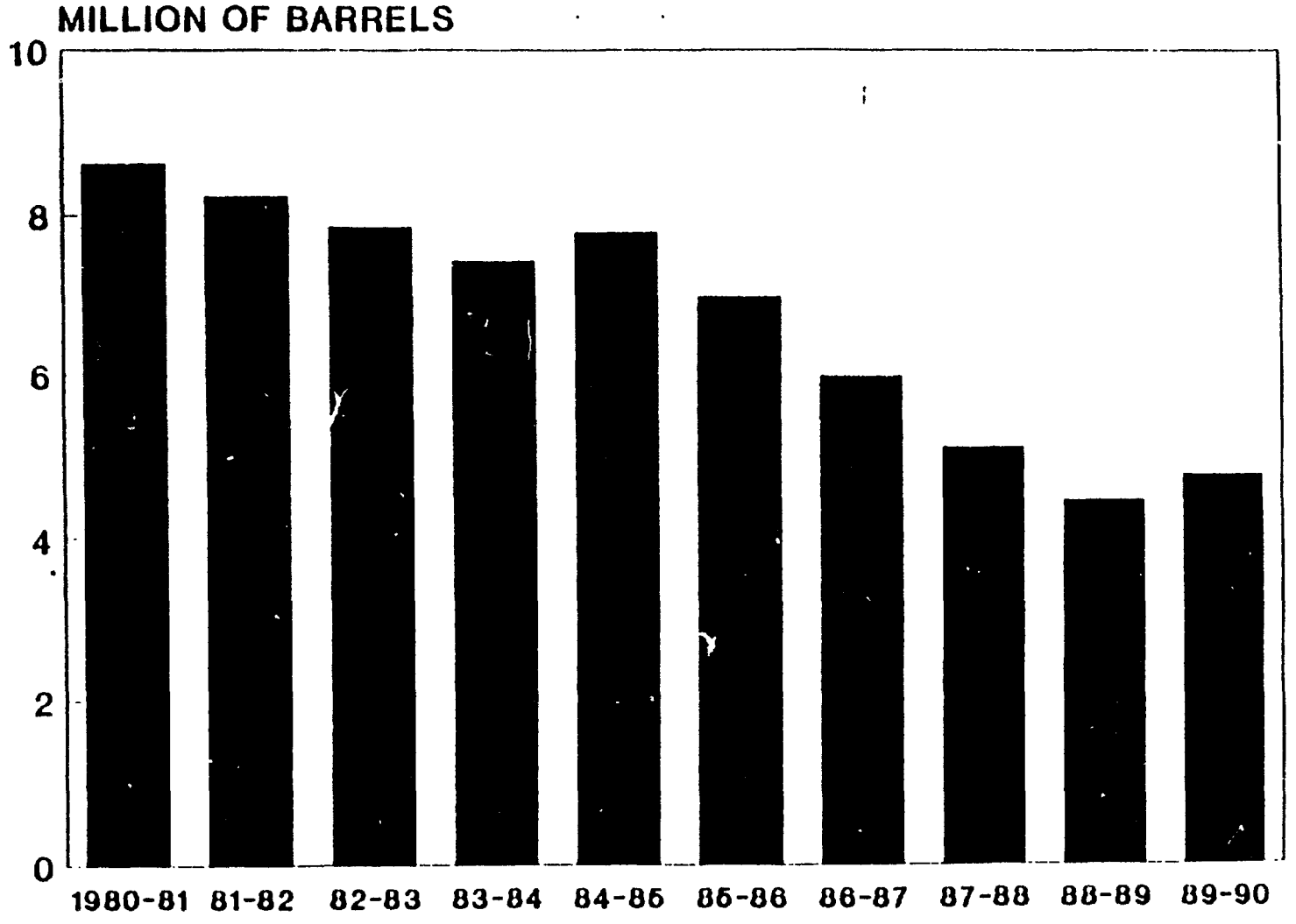


FIG 2. CRUDE OIL REFINING



ANNEX 5.1 (a)

Summary of Industrial Electricity Consumption

Major Industry	Region	Supply kV	1987/88 MWh	1988/89 MWh	1988/89 MWh	No Supply Constraint	% Tot	Supply Constraint due to fuel sharing with associated MEPE Generating Station
Cement Factory Kyangin	Ayeyarwad	66	35129	29357	35846	35000		Gas - Shwedaung/Myanuang GS
Jute Mill Myaungmya	Ayeyarwad	66	5445	4399	4764	5000		
Glass Mill Pathein	Ayeyarwad	66	3711	2303	1859	4000		
Methonol Plant Kyangin	Ayeyarwad	66	2787	3565	3902	4000		Gas - Shwedaung/Myanuang GS
Subtotal			47072	39624	46371	48000	4%	
Paper Mill Yeni	Bago	132	11142	9851	11415	11000		
Spinning Weaving Shwedaung	Bago	11	4899	3350	6675	6500		
Paper Mill Sittaung	Bago	33	1329	1021	6648	6500		
Defence Industry #3 Sinde	Bago	66	6838	5538	5796	6800		
Machine Tool Plant Diak Oo	Bago	66	4742	2845	4889	5000		
Heavy Industries #4 Htonbo	Bago	66	4925	3119	3149	5000		
Subtotal			33875	25724	38572	40800	3%	
Cement Myaing Gale Pa-an	Karen	66	7302	4969	11370	10000	1%	
Sale Fertilizer Plant	Magwe	66	111288	65465	58487	160000		Gas - Chauk GS
Kyawsasa Fertilizer	Magwe	66	120727	103881	96912	150000		Gas - Shwedaung/Myanuang GS
Mann Refinery Minla	Magwe	33	14187	20115	19172	60000		
Kyunchaung Fertilizer	Magwe	66	49823	45603	48529	60000		Gas - Kyunchuang GS
Mann Oil Field Mimbu	Magwe	33	12925	11543	12135	20000		
LPG Factory Mimbu	Magwe	33	11456	11940	5318	15000		Gas - Mann GS
Cement Mill Thayet	Magwe	66	11357	9488	13618	13000		Gas - Swedaung GS
Malun HI No. 2 Defense	Magwe	33	5855	6521	6000	6000		
Hlauk Sha-Pin Oil Field Mimbu	Magwe	33	5182	3857	4412	6000		
Ywalthay- Mimbu	Magwe	33	2384	2424	1808	2500		
Subtotal			345184	280837	266391	492500	42%	
Textile Mill Pallik	Mandalay	33	8519	6075	32137	32000		
Steel Mill Pyn-Oo-Lwin	Mandalay	33	22191	14740	33076	35000		
Textile Mill Meiktila	Mandalay	33	8314	6141	10313	10000		
Subtotal			39024	26956	75526	77000	7%	
Tyre Factory Thaton	Mon	33	9907	7363	9154	12000	1%	Diesel - Thaton GS
Copper Mine Sarlingyi	Saiging	33	54505	31042	31890	60000		
Ywalthitkyi Textile	Saiging	33	7517	4856	7214	7500		
Subtotal			62022	35898	39104	67500	6%	
Daik U Foodstuffs	Yangon	132			5000	28032		
Steel Mill Ywama	Yangon	33	9704	9247	9859	10000		
Yangon Water Supply	Yangon	33	10019	8729	8219	10000		
Glass Factory Thankin	Yangon	6.6	7935	6733	6675	8000		
Jute Mill Yangon	Yangon	33	5520	4332	5520	6000		
Textile Mill Thainaing	Yangon	33	3106	2207	2560	3500		
Subtotal			36284	31248	37833	65532	6%	
Small Industry		11/6.6kV	177899	165072	178330	209000	18%	
Other Medium Industries		11	145742	120290	107215	150000	13%	
Total			904311	737981	809866	1172332	100%	

ANNEX 5.1 (b)

TREND ANALYSIS OF GENERATION, SALES AND LOSSES 1980-2000

	Annual Generation in % of Total Generation						Annual sales in % of Total Sales					Losses in % of Total Generation				
Year	Hydro	Gas	Steam	Diesel	Purchase	Total	Domes	Indust	Bulk	Others	Total	Gen	Trans	Distr	Others	Total
1979/80	67%	24%	3%	4%	1%	100%	28%	53%	14%	4%	100%	3%	4%	21%	2%	29%
1980/81	59%	31%	6%	4%	1%	100%	28%	54%	14%	4%	100%	3%	4%	21%	2%	30%
1981/82	66%	25%	5%	3%	0%	100%	30%	53%	14%	4%	100%	3%	5%	22%	2%	32%
1982/83	62%	29%	5%	3%	1%	100%	30%	53%	14%	4%	100%	3%	6%	22%	2%	32%
1983/84	59%	33%	4%	2%	1%	100%	30%	52%	14%	3%	100%	3%	5%	24%	2%	33%
1984/85	54%	40%	3%	2%	1%	100%	30%	52%	15%	3%	100%	2%	5%	25%	1%	33%
1985/86	47%	47%	3%	2%	1%	100%	28%	60%	9%	3%	100%	2%	4%	24%	1%	31%
1986/87	46%	48%	4%	1%	1%	100%	28%	60%	9%	3%	100%	2%	4%	23%	2%	31%
1987/88	44%	52%	3%	1%	0%	100%	30%	57%	10%	3%	100%	2%	6%	22%	2%	32%
1988/89	42%	55%	2%	1%	0%	100%	35%	52%	10%	3%	100%	2%	5%	27%	1%	36%
1989/90	46%	52%	1%	1%	0%	100%	36%	50%	11%	3%	100%	2%	5%	27%	1%	36%
1990/91	48%	49%	1%	1%	0%	100%	36%	50%	12%	3%	100%	2%	5%	21%	2%	30%

ANNEX 5.2

Existing and Expected Rehabilitated Condition of MEPE Generating Plant

1. Interconnected System

ENEP

Code	Station	Type/ Fuel		Rating Units	MW	Total MW	Firm 1990	Capacity 1992	Year I/S	Status of plant (after rehabilitation in 1992)
LAWP	Lawpita - Existing	hyd	pel	6	28	168	131		1960	Before rehabilitaion under OECF funding
LAWN	Lawpita/Baluchaung#1	hyd	pel	6	28			196	1992	Restore full output(168MW)+28MW in cascade
KIND	Kinda	hyd	fra	2	28	56	28	42	1986	Increased generation allows reservoir filling
SEDA	Sedawgi	hyd	kap	2	12.5	25	8	20	1988	Has competing irrigation requirements
	Tatkyi	hyd		2	0.6	1.2	1		1987	
	Ahlone	stm	fo	3	10				1950	Unlikely to be rehabilitated
	Ahlone	gt	g/fo	2	2.18	4.36	2		1985	Unable to operate in parallel
		gt	g/fo	2	1.1	2.2				
YW1G	Ywama	stm	fo	3	10	30	7	20	1957	Rehabilitation under IDA project
YW2G	Ywama	gt	gas	2	18.45	36.9	37		1980	Gas Operation
YW2O	Ywama	gt	gfr	2	18.45			37	1980	Gas/Fuel oil Operation
KYGT	Kyunchaung	gt	g/fo	3	18.1	54.3	36.2	36	1974	Gas/66 kV limitations
MYJB	Myanaung John Brown	gt	g/fo	1	18.45	18.45	18		1975	66 kV System Constraint
MYGH	Myanaung Hitachi	gt	gas	3	16.4	49.2	36	36	1975	OECF spares rehabilitation
	Kyaiklat	gt	g/fo	5	2.18	10.9	3.05		1983	Unable to Operate in parallel
MANN	Mann	gt	gfr	2	18.45	36.9	34.5	35	1980	
	Chaulk	gt	g/fo	4	2.18	8.72	2.2		1982	Unable to Operate in parallel
SHWE	Shwedaung	gt	gfr	3	18.45	55.35	36	36	1982	
THAK	Thaketa	gt	gfr	3	19	57	19	57	1989	Change to diesel in 1991
THA1	Thaton GT	gt	gfr	1	17	17		17	1985	To be connected to grid in 1992
THA2	Thaton ST	stm	fo	3	6	18		18	1986	To be rehabilitated/connected to grid in 1992
MOUL	Moulmein ST	stm	fo	2	6	12		12	1980	To be rehabilitated/connected to grid in 1992
	Subtotol Interconnectable Capacity MW					661.48	398.95	562		

2. Isolated MEPE Generating Stations

States/Divisions	No	Av. kW	Tot MW	MD MW
Ayewardy	21	540	11	28
Shan	30	427	13	8
Yangon	6	203	1	149
Rachine	18	475	9	1
Mon	13	499	6	10
Mandalay	6	610	4	54
Magwe	18	229	4	90
Bago	5	505	3	75
Tanintharyi	7	713	5	1
Saiging	27	234	6	25
Chin	9	402	4	0
Karin	9	318	3	3
Kayah	4	196	1	1
Kachin	15	417	6	0
	188	402	76	445

Notes

1 Output of Kinda and Sedawgi is restricted by low reservoir levels due to low rainfall and competing irrigation.

2 Output at Shwedaung, Myanaung, Chauk, Kyunchaung Mann and Thaton is restricted by competing fuel needs of nearby industry. See Annex 5.1 (a)

3 The 66kV system constraints associated with Kyunchaung and Myanaung need to be rectified when the stations are to be uprated to combined cycle operation

4 It is feasible to install heat recovery equipment only at Mann, Shwedaung, Myanaung and Thaketa

5 The maximun demands(MD) in each State/Division includes the component supplied by the interconnected system.

ANNEX 5.3 (a)

SUMMARY OF EXISTING COMMITTED AND PROPOSED TRANSMISSION LINES

Existing 230/132kV Transmission Grid System

From	To	km	kV	Cct	ASCR	Year
Lawpita	Toungoo	151.4	230	1	795	1960
Toungoo	Hlawga	248.5	230	1	795	1960
Thaketa	Hlawga	22.5	230	1	795	1985
Prome(Shwdag)	Taungdwingyi	158.4	230	2	2x605	1987
Prome(Shwdag)	Hlawga	234.2	230	2	2x605	1987
Pyinmana	Toungoo	98.2	230	1	2x265	1988
Chauk	Magwe	106.0	132	1	397.5	1987
Magwe	Taungdwingyi	66.6	132	1	397.5	1987
Thazi	Pyinmana	133.8	132	1	795	1988
Lawpita	Kalaw	158.7	132	1	397.5	1963
Kalaw	Thazi	72.7	132	2	397.5	1963
Thazi	Mandalay	130.6	132	1	336.4	1963
Mann	Magwe	61.9	132	1	397.5	1987
Kinda	Thazi	76.6	132	1	300	1985
Thazi	Chauk	144.3	132	1	336.4	1969
Sedawgwi	Mandalay	64.4	132	1	397.5	1987
Toungoo	Daikoo	152.7	132	1	336.4	1988
Toungoo	Yeni	72.4	132	1	397.5	1985
Sedawgwi	Kawlin	212.8	132	1	397.5	
Kyunchaung	Nyaungbingyi	148.2	132	1	397.5	1982
Mandalay	Pyinoolwin	49.2		1	336.4	1983
Total Transmission cctkms		2980.2				

Existing/Committed 66kV O/H U/G Subtransmission

From	To	km		Cct	ASCR	Year
Shwedaung	Pyay	16.1		1	336.4	1981
Kalaw	Taunggyi	47.0		1	336.4	1975
Pyay	Thayet	67.7		1	266.8	1971
Pyay	Kyawzwa	27.4		2	336.4	1984
Chauk	Salc	8.0		1	336.4	1975
Kyunchaung	Wazi	29.0		1	266.8	1975
Kyunchaung	Patokku	33.8		1	266.8	1974
Myanaung	Kyangyi	14.5		1	266.8	1976
Chauk	Nyaung U	45.1		1	266.8	1975
Chauk	Kyunchaung	39.0		2	266.8	1974
Myanaung	Pyay	108.0		2	336.4	1978
Myanaung	Pathein	242.3		2	336.4	1979
Pathein	Myanguya	26.4		2	266.8	1979
Lansdowne	Thaketa	10.9	O/U	2		1991
Thaketa	Syriam	18.5		1		1991
Mayangon	Thaketa	16.4	O/U	2		1991
Ahlone	Lansdowne	6.5	U/G	2		1991
Total Subtransmission cctkms		1233.5				

Proposed New 230/132kVTransmission Lines

Pyinmana	Taungdwiwingyi	90.0	230	1	1998
Henzada	Letpedan	20.0	230	2	1995
Hlawga	Myasungma	150.0	230	1	1998
Kawlin	Kalewa	130.0	132	1	1996
Nyaungbingyi	Kalewa	150.0	132	1	1998
Daikoo	Thaton	140.0	132	1	1992
Nyaungbingyi	Mandalay	140	132	1	1996
Kyunchaung	Chauk	40	132	1	1996
Total Transmission cctkms		860.0			

Proposed New 66kV Subtransmission Lines

Hlawga	Mayangon	15.3
Hlawga	Ywama	11.2
Ywama	RIR	9.1
RIR	Tiger Alley	6.5
Tiger Alley	Thuwunna Stdn	7.6
Tiger Alley	Ahlone	4.9
Lansdowne	Thuwunna Stdn	6
Thaketa	Thingangyun	5.5
Thuwunna Stdn	Mayangon	13.1
Thingangyun	Thuwunna Stdn	5.5
Mayangon	RIR	3.3
Total Subtrans cctkms		88.0

ANNEX 5.3 (b)

SUMMARY OF EXISTING AND COMMITTED TRANSMISSION SYSTEM SUBSTATIONS

230/132kV Transmission Grid Substations

	Substation Name		Region	Capacity No	MVA	Tot	Subtrans kV	kV	Trafo Loading	Recorded MWh loadings 1984-1989 1984/5	1985/6	1986/7	1987/8	1988/9
1	Hlawga 230kV		Yangon	2	60	120		33/11	99%	546240	548260	569100	72?850	728350
2	Taungoo 230/132kV		Bago	1	33	33	66	33	38%	17036	19203	58845	66684	77049
3	Thazi 230/132kV		Mandalay	1	60	60			13%	116070	117706	123337	117045	85621
				1	15	15	66	33/11						
				1	30	30	132	33						
4	Taungdwingyi 230/132kV		Magwe	1	80	80	132	11						
5	Pyinmana 230kV		Mandalay	1	30	30		33						
6	Shwedaung 230kV		Bago	1	100	100	66	11						
7	Thaketa 230kV	G/S	Yangon	2	100	200	66	33/11	18%				187958	215107
8	Lawpita 230/132kV	G/S	Kayah	2	100	200								
9	Chauk 132kV		Magwe	1	40	40	66	11	72%	198860	172842	149537	148048	176772
10	Mann 132kV	G/S	Magwe	1	50	50		33						
11	Myanaung 66kV	G/S	Ayeyarwady			85								
12	Kinda 132kV	G/S	Shan	2	35	70								
13	Sedawgyi 132kV	G/S	Mandalay		est	30								
14	Mandalay 132kV		Mandalay	1	18	18		33/11	67%	162762	172536	180175	186830	195740
				1	30	30		33						
15	Magwe 132kV		Magwe	1	15	15		33/11	85%					234838
16	Kalaw 132kV		Shan	2	15	30		33/11	20%					36391
17	Pyinoolin 132kV		Mandalay	2	15	30		33/11	17%	43388	45423	50159	38174	30454
18	Nyaungbingyi 132kV		Mandalay	1	40	40		33/11	22%	50925	79872	77596	75280	54117
19	Daikoo 132kV		Bago	1	18	18		33/11						
20	Yeni 132kV		Bago	2	15	30		33	19%	0	0		22438	34052
21	Kawlin 132kV		Sagaing	1	15	15		33/6.						
Subtotal 230/132kV grid S/S capacity						694			44%	1135281	1155842	1208749	1567907	1868491
	Ywama G/S to 33kV									168300	168300	190780	127500	152600
Subtotal G/S Substation capacity						675								
Subtotal Transmission System Loading MW @ .7 Capacity factor										213	216	228	276	326

Notes

1 The tables include deatails of all main substation transformers including: Generating Station transformer capacity Transmission System interconnection Transformers, and Sustation Service capcaity supplying the Subtransmission Systems

2 Transformer loading is estimated from total energy sent out annually based on Load Factor = 0.7. Note that output Ywama is supplied directly into the 33kV busbars.

3 See page 2 of 2 for Subtransmission System Transformer capacity.

ANNEX 5.3 (b) (cont'd)

SUMMARY OF EXISTING AND COMMITTED TRANSMISSION SYSTEM SUBSTATIONS

66kV Subtransmission Substations

			Region	Capacity No	MVA	Tot	Subtrans kV	kV	Trafo Loading	Recorded MWh loadings 1984-1989 1984/5	1985/6	1986/7	1987/8	1988/9
1	Pyay(Prome)		Bago	2	10	20		11	41%	46201	49982	49932	52078	49799
2	Taunggyi 33kV		Shan	1	5	5		11						
3	Hinzada		Ayeyarwady	1	5	5		11	46%	10372	11746	13225	14096	14190
4	Yegyi		Ayeyarwady	1	3	3		11	61%	6941	8608	9396	10383	11140
5	Basacin (Pathein)		Ayeyarwady	1	10	10		11	33%	15302	17669	19154	20375	20460
6	Myaungnya		Ayeyarwady	1	8	8		11	23%	9928	12281	12565	12053	11072
7	Pakokku		Magwe	1	2.5	2.5		11						
8	Wazi		Magwe	1	12.6	12.6		6.6						
9	Htombo		Ayeyarwady	1	5	5		6.6	37%	14440	14147	15568	13568	11363
10	Nyaungchadauk		Ayeyarwady	1	10	10		6.6	10%	6680	6745	8572	3790	6128
11	Sinde		Ayeyarwady	1	10	10		6.6						
12	Thayet Cement		Magwe	1	9	9		6.6					11	9
13	Pathein Glass		Ayeyarwady	1	9	9		6.6					4	2
14	Sale Fertilizer		Magwe	1	14	14		3.3					111	65
15	Kyungchaung Fert.		Magwe	1	14	14		3.3					50	46
16	Pa-an		Mon	1	est	5								
17	Mayangon	U/C	Yangon	2	30	60		33						
18	Landsdown	U/C	Yangon	2	30	60		33						
19	Ahlone	U/C	Yangon	2	30	60		33						
20	Ywama	G/S	Yangon											
21	Thaton	G/S	Mon	1	est	20								
22	Shwedaung	G/S	Bago	3	25	75								
23	Kyunchaung	G/S	Mandalay	3	25	75								
	Ywama	G/S	Yangon					33			168300	190780	127500	132600
Subtotal 66kV Subtrans Capacity						152				109864	289478	319192	254019.17	256874.85
Subtotal G/S Substation capacity						170								
Subtotal Subtransmission System Loading MW @ .7 Capacity factor										18	47	52	41	42
Total Transmission System Loading										231	263	280	318	368

ANNEX 5.4 (a) (i)

(i) ELECTRICITY DEMAND FORECAST FOR THE INTERCONNECTED SYSTEM: BASE CASE FORECAST

ASSUMPTIONS FOR FORECAST:

HIGHER ECONOMIC GROWTH RATES; HIGHER POPULATION ELASTICITIES FOR RESIDENTIAL DEMAND, AND MORE RAPID DECLINE IN LOAD FACTOR; TARIFFS KEPT CONSTANT IN REAL TERMS.

	GDP Growth Rates				GDP	Long-Run Price
	1989-91	1992-96	1997-2011		elast	Elast
Agriculture	2.3%	4.3%	6.0%			
Mining	4.6%	8.2%	8.5%			
Industry	7.0%	7.3%	8.5%		1.30	0.6
Services	3.8%	4.9%	6.5%		1.20	0.6
Total GDP	3.3%	5.0%	6.5%			
Residential	Urban Population Growth				POP elast	
	3.0%	3.0%	3.0%	1990-96	2.00	0.5
	Growth in Use per Consumer			1997-2001	2.40	0.5
	3.0%	3.0%	3.0%	2002-2011	2.60	0.5
	Population Growth					
Rural	1.6%	1.6%	1.6%			
Total	1.9%	1.9%	1.9%			

ANNEX 5.4 (a) (i)

(i) ELECTRICITY DEMAND FORECAST FOR THE INTERCONNECTED SYSTEM: BASE CASE FORECAST

FISCAL YEAR	ELECTRICITY DEMAND BY CATEGORY (GWH) INDUSTRY	RESIDENT	OTHER/ SERVICES	UNSERVED DEMAND	NON-TECH LOSSES	TOTAL	DEMAND GROWTH	TOTAL SALES GWH	LOSS FACTORS NON-TECH %	TECH %	GENERATION REQUIREMENTS ENERGY GENERATION DEMAND GWHeo	LOAD FACTOR	MAXIMUM DEMAND MWeo
1989/90	945.0	497.0	194.0	47.3	163.6	1846.9		1636.0	10%	21%	2371.0	72.0%	375.9
1990/91	1031.0	527.0	702.8	61.9	158.5	1981.2	7.3%	1760.9	9%	22%	2552.0	73.0%	399.1
1991/92	1128.8	558.9	214.8	90.3	152.2	2145.0	8.3%	1902.5	8%	22%	2717.8	75.0%	413.7
1992/93	1236.0	592.6	227.4	74.2	143.9	2274.0	6.0%	2056.0	7%	22%	2895.7	73.0%	452.8
1993/94	1353.3	628.4	240.8	67.7	133.3	2423.4	6.6%	2222.4	6%	22%	3086.7	72.0%	489.4
1994/95	1481.7	666.4	254.9	44.5	120.1	2567.6	5.9%	2403.0	5%	21%	3247.3	70.0%	529.6
1995/96	1622.3	706.6	269.9	32.4	104.0	2735.2	6.5%	2598.8	4%	20%	3419.5	69.0%	565.7
1996/97	1801.6	757.8	291.0	36.0	85.5	2971.9	8.7%	2850.3	3%	19%	3654.3	69.0%	604.6
1997/98	2000.6	812.7	313.7	20.0	62.5	3209.6	8.0%	3127.0	2%	18%	3908.8	68.0%	656.2
1998/99	2221.7	871.7	338.1	22.2	68.6	3522.3	9.7%	3431.5	2%	17%	4236.4	68.0%	711.2
1999/00	2467.2	934.8	364.5	24.7	75.3	3866.5	9.8%	3766.5	2%	16%	4593.3	68.0%	771.1
2000/01	2739.8	1002.6	392.9	0.0	82.7	4218.1	9.1%	4135.3	2%	15%	4982.3	67.0%	848.9
2001/02	3042.6	1081.3	423.6	0.0	90.9	4638.4	10.0%	4547.5	2%	14%	5413.7	67.0%	922.4
2002/03	3378.8	1166.2	456.6	0.0	100.0	5101.6	10.0%	5001.6	2%	14%	5954.3	67.0%	1014.5
2003/04	3752.1	1257.8	492.3	0.0	110.0	5612.2	10.0%	5502.2	2%	14%	6550.2	67.0%	1116.0
2004/05	4166.7	1356.5	530.6	0.0	121.1	6175.0	10.0%	6053.9	2%	14%	7207.1	67.0%	1227.9
2005/06	4627.2	1463.1	572.0	0.0	133.2	6795.5	10.0%	6662.3	2%	14%	7931.3	67.0%	1351.3
2006/07	5138.5	1577.9	616.7	0.0	146.7	7479.7	10.1%	7333.1	2%	14%	8729.8	67.0%	1487.4
2007/08	5706.3	1701.8	664.8	0.0	161.5	8234.3	10.1%	8072.9	2%	14%	9610.5	67.0%	1637.5
2008/09	6336.8	1835.5	716.6	0.0	177.8	9066.7	10.1%	8888.9	2%	14%	10582.0	67.0%	1803.0
2009/10	7037.0	1979.6	772.5	0.0	195.8	9984.9	10.1%	9789.1	2%	14%	11653.7	67.0%	1985.6
2010/11	7814.6	2135.0	832.8	0.0	215.6	10998.0	10.1%	10782.4	2%	14%	12836.2	67.0%	2187.0
Avge PAA	10.6%	7.2%	7.2%		0.9%	8.8%		9.4%	-7.7%		8.3%		8.7%

FISCAL YEAR	RESIDENTIAL SALES AND CONNECTIONS RES GWH	Resident Consumers (000)	Inc in Cons per Yr (000)	RES MWH/ Cons	TOTAL ELECTRICITY CONSUMPTION PER CAPITA POP mill	KWH/YR/ PERSON	PROPORTION OF SALES IND	RES	SERV
1989/90	497.0	479.7		1.0	40.12	44.86	57.8%	30.4%	11.9%
1990/91	527.0	493.9	14.2	1.1	40.90	46.93	58.6%	29.9%	11.5%
1991/92	558.9	508.5	14.6	1.1	41.70	49.28	59.3%	29.4%	11.3%
1992/93	592.6	523.5	15.0	1.1	42.51	51.75	60.1%	28.8%	11.1%
1993/94	628.4	538.9	15.5	1.2	43.33	54.36	60.9%	28.3%	10.8%
1994/95	666.4	554.8	15.9	1.2	44.18	57.11	61.7%	27.7%	10.6%
1995/96	706.6	571.2	16.4	1.2	45.04	60.01	62.4%	27.2%	10.4%
1996/97	757.8	594.8	23.6	1.3	45.91	63.94	63.2%	26.6%	10.2%
1997/98	812.7	619.3	24.5	1.3	46.81	68.15	64.0%	26.0%	10.0%
1998/99	871.7	644.8	25.5	1.4	47.72	73.35	64.7%	25.4%	9.9%
1999/00	934.8	671.4	26.6	1.4	48.64	78.98	65.5%	24.8%	9.7%
2000/01	1002.6	699.1	27.7	1.4	49.59	85.06	66.3%	24.2%	9.5%
2001/02	1081.3	732.1	32.9	1.5	50.56	91.75	66.9%	23.8%	9.3%
2002/03	1166.2	766.5	34.5	1.5	51.54	98.99	67.6%	23.3%	9.1%
2003/04	1257.8	802.6	36.1	1.6	52.54	106.82	68.2%	22.9%	8.9%
2004/05	1356.5	840.5	37.8	1.6	53.56	115.28	68.8%	22.4%	8.8%
2005/06	1463.1	880.0	39.6	1.7	54.60	124.45	69.5%	22.0%	8.6%
2006/07	1577.9	921.5	41.5	1.7	55.67	134.36	70.1%	21.5%	8.4%
2007/08	1701.8	964.9	43.4	1.8	56.75	145.10	70.7%	21.1%	8.2%
2008/09	1835.5	1010.4	45.5	1.8	57.85	156.72	71.3%	20.6%	8.1%
2009/10	1979.6	1058.0	47.6	1.9	58.98	169.29	71.9%	20.2%	7.9%
2010/11	2135.0	1107.8	49.8	1.9	60.13	182.91	72.5%	19.8%	7.7%

ANNEX 5.4 (a) (ii)

(ii) ELECTRICITY DEMAND FORECAST FOR ISOLATED RURAL SYSTEMS: BASE CASE FORECAST

ASSUMPTIONS FOR FORECAST:

HIGH ECONOMIC GROWTH, POPULATION ELASTICITY SET AT 3.0; GDP ELASTICITY AT 0.9
LOAD FACTOR ESTIMATED TO INCREASE FROM 26% TO 36.5% OVER PERIOD

	GDP Growth Rates				GDP	Long-Run Price
	1989-91	1992-96	1997-2011		elast	Elast
Agriculture	2.3%	4.3%	6.0%			
Mining	4.6%	8.2%	8.5%			
Industry	7.0%	7.3%	8.5%		0.90	0.6
Services	3.8%	4.9%	6.5%		0.90	0.6
Total GDP	3.3%	5.0%	6.5%			
Residential	Rural Population Growth				POP elast	
	1.6%	1.6%	1.6%	1990-96	3.00	0.5
	Growth in Use per Consumer			1997-2001	3.00	0.5
	2.0%	2.0%	2.0%	2002-2011	3.00	0.5

ANNEX 5.4 (a) (ii)

(ii) ELECTRICITY DEMAND FORECAST FOR ISOLATED RURAL SYSTEMS: BASE CASE FORECAST

FISCAL YEAR	ELECTRICITY DEMAND BY CATEGORY (GWH) INDUSTRY	RESIDENT	OTHER/ SERVICES	UNSERVED DEMAND	NON-TECH LOSSES	TOTAL	DEMAND GROWTH	TOTAL SALES GWH	LOSS FACTORS NON-TECH %	TECH %	GENERATION REQUIREMENTS ENERGY GENERATION DEMAND GWHso	LOAD FACTOR	MAXIMUM DEMAND MWso
1989/90	29.0	52.0	13.0	13.2	9.4	116.6		94.0	10%	22%	138.2	26.0%	60.7
1990/91	30.8	54.5	13.4	13.3	8.9	121.0	3.8%	98.8	9%	26%	152.0	26.5%	65.5
1991/92	32.9	57.1	14.0	13.5	8.3	125.8	4.0%	104.0	8%	26%	157.6	27.0%	66.6
1992/93	35.0	59.9	14.7	13.7	7.7	130.9	4.0%	109.5	7%	26%	163.5	27.5%	67.9
1993/94	37.3	62.7	15.3	13.8	6.9	136.1	4.0%	115.3	6%	26%	169.6	28.0%	69.2
1994/95	39.8	65.7	16.0	14.0	6.1	141.5	4.0%	121.5	5%	25%	173.5	28.5%	69.5
1995/96	42.4	68.9	16.7	14.1	5.1	147.1	4.0%	127.9	4%	24%	177.7	29.0%	70.0
1996/97	45.6	72.2	17.7	14.2	4.1	153.8	4.5%	135.5	3%	23%	183.1	29.5%	70.8
1997/98	49.1	75.7	18.7	14.3	2.9	160.7	4.5%	143.5	2%	22%	188.8	30.0%	71.8
1998/99	52.9	79.3	19.8	14.4	3.0	169.4	5.4%	151.9	2%	20%	194.8	30.5%	72.9
1999/00	56.9	83.1	20.9	14.5	3.2	178.7	5.5%	161.0	2%	18%	201.2	31.0%	74.1
2000/01	61.3	87.1	22.2	14.5	3.4	188.4	5.5%	170.5	2%	16%	208.0	31.5%	75.4
2001/02	65.9	91.3	23.5	14.5	3.6	198.8	5.5%	180.7	2%	16%	220.3	32.0%	78.6
2002/03	71.0	95.7	24.8	14.4	3.8	209.7	5.5%	191.5	2%	16%	233.5	32.5%	82.0
2003/04	76.4	100.2	26.3	14.2	4.1	221.2	5.5%	203.0	2%	16%	247.5	33.0%	85.6
2004/05	82.3	105.1	27.8	14.0	4.3	233.4	5.5%	215.2	2%	16%	262.4	33.5%	89.4
2005/06	88.6	110.1	29.5	13.7	4.6	246.4	5.5%	228.1	2%	16%	278.2	34.0%	93.4
2006/07	95.3	115.4	31.2	13.3	4.8	260.0	5.6%	241.9	2%	16%	295.0	34.5%	97.6
2007/08	102.6	120.9	33.0	12.8	5.1	274.5	5.6%	256.6	2%	16%	312.9	35.0%	102.0
2008/09	110.5	126.7	34.9	12.2	5.4	289.8	5.6%	272.1	2%	16%	331.9	35.5%	106.7
2009/10	118.9	132.8	37.0	11.5	5.8	306.0	5.6%	288.7	2%	16%	352.1	36.0%	111.6
2010/11	128.0	139.2	39.1	10.7	6.1	323.2	5.6%	306.4	2%	16%	373.6	36.5%	116.8
Avge PAA	7.3%	4.8%	5.4%			4.9%		5.8%			4.8%	1.6%	3.1%

FISCAL YEAR	RESIDENTIAL SALES AND CONNECTIONS RES GWH	Resident Consumers (000)	Inc in Cons per Yr (000)	RES MWH/ Cons	RURAL ELECTRICITY CONSUMPTION PER CAPITA POP mill	KWH/YR/ PERSON	PROPORTION OF SALES IND	RES	SERV
1989/90	52.0	105.1		0.5	40.12	2.58	30.9%	55.3%	13.8%
1990/91	54.5	107.9	2.9	0.5	40.90	2.63	31.2%	55.2%	13.6%
1991/92	57.1	110.9	3.0	0.5	41.70	2.69	31.6%	54.9%	13.5%
1992/93	59.9	113.9	3.0	0.5	42.51	2.76	32.0%	54.7%	13.4%
1993/94	62.7	117.1	3.1	0.5	43.33	2.82	32.3%	54.4%	13.3%
1994/95	65.7	120.3	3.2	0.5	44.18	2.89	32.7%	54.1%	13.2%
1995/96	68.9	123.6	3.3	0.6	45.04	2.95	33.1%	53.8%	13.0%
1996/97	72.2	127.0	3.4	0.6	45.91	3.04	33.7%	53.3%	13.0%
1997/98	75.7	130.5	3.5	0.6	46.81	3.13	34.2%	52.7%	13.0%
1998/99	79.3	134.0	3.6	0.6	47.72	3.25	34.8%	52.2%	13.0%
1999/00	83.1	137.7	3.7	0.6	48.64	3.37	35.4%	51.6%	13.0%
2000/01	87.1	141.5	3.8	0.6	49.59	3.51	35.9%	51.1%	13.0%
2001/02	91.3	145.4	3.9	0.6	50.56	3.65	36.5%	50.5%	13.0%
2002/03	95.7	149.4	4.0	0.6	51.54	3.79	37.1%	50.0%	13.0%
2003/04	100.2	153.5	4.1	0.7	52.54	3.94	37.7%	49.4%	13.0%
2004/05	105.1	157.7	4.2	0.7	53.56	4.10	38.2%	48.8%	12.9%
2005/06	110.1	162.0	4.3	0.7	54.60	4.26	38.8%	48.3%	12.9%
2006/07	115.4	166.5	4.4	0.7	55.67	4.43	39.4%	47.7%	12.9%
2007/08	120.9	171.0	4.6	0.7	56.75	4.61	40.0%	47.1%	12.9%
2008/09	126.7	175.7	4.7	0.7	57.85	4.80	40.6%	46.6%	12.8%
2009/10	132.8	180.6	4.8	0.7	58.98	4.99	41.2%	46.0%	12.8%
2010/11	139.2	185.5	5.0	0.8	60.13	5.20	41.8%	45.4%	12.8%

ANNEX 5.4 (a)(iii)

(iii) ELECTRICITY DEMAND FORECAST FOR THE INTERCONNECTED SYSTEM: LOW DEMAND CASE

ASSUMPTIONS FOR FORECAST:

LOW ECONOMIC GROWTH RATES; LOW POPULATION ELASTICITIES FOR RESIDENTIAL DEMAND AND HIGHER LOAD FACTOR; TARIFFS KEPT CONSTANT IN REAL TERMS.

	GDP Growth Rates				GDP elast	Long-Run Price Elast
	1989-91	1992-96	1997-2011			
Agriculture	1.6%	2.5%	2.5%			
Mining	3.3%	4.5%	4.5%			
Industry	4.0%	5.1%	5.1%		1.30	0.6
Services	2.1%	3.0%	3.0%		1.20	0.6
Total GDP	2.0%	3.0%	3.0%			
Residential	Urban Population Growth				POP elast	
	3.0%	3.0%	3.0%	1990-96	1.60	0.5
	Growth in Use per Consumer			1997-2001	1.60	0.5
	3.0%	3.0%	3.0%	2002-2011	1.60	0.5
	Population Growth					
Rural	1.6%	1.6%	1.6%			
Total	1.9%	1.9%	1.9%			

ANNEX 5.4 (a)(iii)

(iii) ELECTRICITY DEMAND FORECAST FOR THE INTERCONNECTED SYSTEM: LOW DEMAND CASE

	ELECTRICITY DEMAND BY CATEGORY (GWH)							TOTAL	LOSS FACTORS		GENERATION REQUIREMENTS ENERGY GENERATION		MAXIMUM
FISCAL YEAR	INDUSTRY	RESIDENT	OTHER/ SERVICES	UNSERVED DEMAND	NON-TECH LOSSES	TOTAL	DEMAND GROWTH	SALES GWH	NON-TECH %	TECH %	DEMAND GWHso	LOAD FACTOR	DEMAND MWso
1989/90	945.0	497.0	194.0	47.3	163.6	1846.9		1636.0	10%	21%	2371.0	72.0%	375.9
1990/91	994.1	521.0	198.9	59.6	154.3	1928.0	4.4%	1714.0	9%	22%	2484.1	73.0%	388.5
1991/92	1060.1	546.2	206.1	84.8	145.0	2042.2	5.9%	1812.4	8%	22%	2589.1	75.0%	394.1
1992/93	1130.3	572.6	213.7	90.4	134.2	2141.2	4.8%	1916.6	7%	22%	2699.4	75.0%	410.9
1993/94	1205.3	600.2	221.5	96.4	121.6	2245.0	4.9%	2027.0	6%	22%	2815.3	75.0%	428.5
1994/95	1285.2	629.3	229.5	90.0	107.2	2341.1	4.3%	2144.0	5%	21%	2897.3	74.0%	446.9
1995/96	1370.4	659.7	237.9	82.2	90.7	2440.9	4.3%	2268.0	4%	20%	2984.2	73.0%	466.7
1996/97	1461.2	691.5	246.6	73.1	72.0	2544.4	4.2%	2399.4	3%	19%	3076.1	72.0%	487.7
1997/98	1558.1	724.9	255.6	62..	50.8	2651.8	4.2%	2538.7	2%	18%	3173.3	71.0%	510.2
1998/99	1661.4	760.0	264.9	49.8	53.7	2789.9	5.2%	2686.3	2%	17%	3316.4	70.0%	540.8
1999/00	1771.6	796.7	274.6	35.4	56.9	2935.1	5.2%	2842.9	2%	16%	3466.9	69.0%	573.6
2000/01	1889.0	835.2	284.6	18.9	60.2	3087.9	5.2%	3008.8	2%	15%	3625.1	68.0%	608.6
2001/02	2014.3	875.6	295.0	0	63.7	3248.5	5.2%	3184.8	2%	14%	3791.4	67.0%	646.0
2002/03	2147.8	917.9	305.7	0.0	67.4	3438.9	5.9%	3371.4	2%	14%	4013.6	67.0%	683.8
2003/04	2290.2	962.2	316.9	0.0	71.4	3640.7	5.9%	3569.3	2%	14%	4249.2	67.0%	724.0
2004/05	2442.1	1008.7	328.4	0.0	75.6	3854.8	5.9%	3779.2	2%	14%	4499.1	67.0%	766.6
2005/06	2604.0	1057.4	340.4	0.0	80.0	4081.9	5.9%	4001.9	2%	14%	4764.1	67.0%	811.7
2006/07	2776.6	1108.5	352.8	0.0	84.8	4322.8	5.9%	4238.0	2%	14%	5045.3	67.0%	859.6
2007/08	2960.7	1162.1	365.7	0.0	89.8	4578.3	5.9%	4488.5	2%	14%	5343.5	67.0%	910.4
2008/09	3157.0	1218.3	379.1	0.0	95.1	4849.4	5.9%	4754.3	2%	14%	5659.9	67.0%	964.3
2009/10	3366.3	1277.1	392.9	0.0	100.7	5137.1	5.9%	5036.3	2%	14%	5995.6	67.0%	1021.5
2010/11	3589.5	1338.8	407.2	0.0	106.7	5442.3	5.9%	5335.6	2%	14%	6351.9	67.0%	1082.2
Avge PAA	6.6%	4.8%	3.6%			5.2%		5.8%			4.7%		5.1%

	RESIDENTIAL SALES AND CONNECTIONS				TOTAL ELECTRICITY CONSUMPTION PER CAPITA		PROPORTION OF SALES		
FISCAL YEAR	RES GWH	Resident Consumers (000)	Inc in Cons per Yr (000)	RES MWH/ Cons	POP mill	KWH/YR/ PERSON	IND	RES	SERV
1989/90	497.0	479.7		1.0	40.12	44.86	57.8%	30.4%	11.9%
1990/91	521.0	488.3	8.5	1.1	40.90	45.68	58.0%	30.4%	11.6%
1991/92	546.2	496.9	8.7	1.1	41.70	46.94	58.5%	30.1%	11.4%
1992/93	572.6	505.8	8.8	1.1	42.51	48.24	59.0%	29.9%	11.1%
1993/94	600.2	514.8	9.0	1.2	43.33	49.58	59.5%	29.6%	10.9%
1994/95	629.3	523.9	9.2	1.2	44.18	50.96	59.9%	29.3%	10.7%
1995/96	659.7	533.3	9.3	1.2	45.04	52.37	60.4%	29.1%	10.5%
1996/97	691.5	542.7	9.5	1.3	45.91	53.83	60.9%	28.8%	10.3%
1997/98	724.9	552.4	9.7	1.3	46.81	55.32	61.4%	28.6%	10.1%
1998/99	760.0	562.2	9.8	1.4	47.72	57.42	61.8%	28.3%	9.9%
1999/00	796.7	572.2	10.0	1.4	48.64	59.61	62.3%	28.0%	9.7%
2000/01	835.2	582.4	10.2	1.4	49.59	61.89	62.8%	27.8%	9.5%
2001/02	875.6	592.8	10.4	1.5	50.56	64.26	63.2%	27.5%	9.3%
2002/03	917.9	603.3	10.5	1.5	51.54	66.72	63.7%	27.2%	9.1%
2003/04	962.2	614.0	10.7	1.6	52.54	69.29	64.2%	27.0%	8.9%
2004/05	1008.7	625.0	10.9	1.6	53.	71.97	64.6%	26.7%	8.7%
2005/06	1057.4	636.1	11.1	1.7	54.60	74.75	65.1%	26.4%	8.5%
2006/07	1108.5	647.4	11.3	1.7	55.67	77.65	65.5%	26.2%	8.3%
2007/08	1162.1	658.9	11.5	1.8	56.75	80.68	66.0%	25.9%	8.1%
2008/09	1218.3	670.6	11.7	1.8	57.85	83.82	66.4%	25.6%	8.0%
2009/10	1277.1	682.5	11.9	1.9	58.98	87.10	66.8%	25.4%	7.8%
2010/11	1338.8	694.7	12.1	1.9	60.13	90.51	67.3%	25.1%	7.6%

ANNEX 5.4 (a) (iv)

(iv) ELECTRICITY DEMAND FORECAST FOR ISOLATED RURAL SYSTEMS: LOW DEMAND CASE

ASSUMPTIONS FOR FORECAST:

SLOW OVERALL ECONOMIC GROWTH OF SOME 3%/YR; POPULATION ELASTICITY FOR RESIDENTIAL DEMAND AT AN ESTIMATED 2.5; IND GDP ELASTICITY AT 0.8; LOAD FACTOR ESTIMATED AT 26% RISING TO 31.3%

	GDP Growth Rates				GDP	Long-Run Price
	1989-91	1992-96	1997-2011		elast	Elast
Agriculture	1.6%	2.5%	2.5%			
Mining	3.3%	4.5%	4.5%			
Industry	4.0%	5.1%	5.1%		0.80	0.6
Services	2.1%	3.0%	3.0%		0.80	0.6
Total GDP	2.0%	3.0%	3.0%			
Residential	Rural Population Growth				POP elast	
	1.6%	1.6%	1.6%	1990-96	2.50	0.5
	Growth in Use per Consumer			1997-2001	2.50	0.5
	2.0%	2.0%	2.0%	2002-2011	2.50	0.5
	Population Growth					
Urban	3.0%	3.0%	3.0%			
Total	1.9%	1.9%	1.9%			

ANNEX 5.4 (a) (iv)

(iv) ELECTRICITY DEMAND FORECAST FOR ISOLATED RURAL SYSTEMS: LOW DEMAND CASE

FISCAL YEAR	ELECTRICITY DEMAND BY CATEGORY (GWH) INDUSTRY	RESIDENT	OTHER/ SERVICES	UNSERVED DEMAND	NON-TECH LOSSES	TOTAL	DEMAND GROWTH	TOTAL SALES GWH	LOSS FACTORS NON-TECH %	TECH %	GENERATION REQUIREMENTS ENERGY GENERATION DEMAND GWHso	LOAD FACTOR	MAXIMUM DEMAND MWso
1989/90	29.0	52.0	13.0	13.2	9.4	116.6		94.0	10%	22%	138.2	26.0%	60.7
1990/91	29.9	54.1	13.2	13.4	8.8	119.3	2.4%	97.2	9%	26%	149.6	26.3%	65.0
1991/92	31.1	56.2	13.5	13.6	8.1	122.6	2.8%	100.9	8%	26%	152.9	26.5%	65.9
1992/93	32.4	58.5	13.9	13.9	7.3	126.0	2.7%	104.8	7%	26%	156.4	26.8%	66.7
1993/94	33.7	60.8	14.2	14.1	6.5	129.5	2.7%	108.8	6%	26%	160.0	27.0%	67.6
1994/95	35.1	63.3	14.6	14.4	5.6	133.0	2.7%	112.9	5%	25%	161.3	27.3%	67.6
1995/96	36.6	65.8	14.9	14.7	4.7	136.6	2.7%	117.3	4%	24%	162.9	27.5%	67.6
1996/97	38.0	68.4	15.3	14.9	3.7	140.3	2.7%	121.7	3%	23%	164.5	27.8%	67.7
1997/98	39.6	71.2	15.6	15.2	2.5	144.1	2.7%	126.4	2%	22%	166.3	28.0%	67.8
1998/99	41.2	74.0	16.0	15.4	2.6	149.3	3.6%	131.2	2%	20%	168.3	28.2%	68.0
1999/00	42.9	77.0	16.4	15.7	2.7	154.7	3.6%	136.3	2%	18%	170.3	28.5%	68.2
2000/01	44.6	80.1	16.8	15.9	2.8	160.3	3.6%	141.5	2%	16%	172.6	28.7%	68.5
2001/02	46.5	83.3	17.2	16.2	2.9	166.0	3.6%	146.9	2%	16%	179.2	29.0%	70.5
2002/03	48.4	86.6	17.6	16.4	3.1	172.0	3.6%	152.6	2%	16%	186.1	29.2%	72.6
2003/04	50.3	90.0	18.1	16.6	3.2	178.3	3.6%	158.4	2%	16%	193.2	29.5%	74.8
2004/05	52.4	93.6	18.5	16.9	3.3	184.7	3.6%	164.5	2%	16%	200.7	29.8%	77.0
2005/06	54.5	97.4	19.0	17.1	3.4	191.4	3.6%	170.9	2%	16%	208.4	30.0%	79.3
2006/07	56.7	101.3	19.4	17.3	3.5	198.3	3.6%	177.5	2%	16%	216.4	30.3%	81.7
2007/08	59.1	105.3	19.9	17.5	3.7	205.5	3.6%	184.3	2%	16%	224.7	30.5%	84.1
2008/09	61.5	109.6	20.4	17.7	3.8	212.9	3.6%	191.4	2%	16%	233.4	30.8%	86.7
2009/10	64.0	113.9	20.9	17.9	4.0	220.7	3.6%	198.8	2%	16%	242.4	31.0%	89.3
2010/11	66.6	118.5	21.4	18.1	4.1	228.7	3.6%	206.5	2%	16%	251.8	31.3%	92.0
Avge PAA	4.0%	4.0%	2.4%	1.5%		3.2%		3.8%			2.8%		2.0%

FISCAL YEAR	RESIDENTIAL SALES AND CONNECTIONS RES GWH	Resident Consumers (000)	Inc in Cons per Yr (000)	RES MWH/ Cons	RURAL ELECTRICITY CONSUMPTION PER CAPITA POP mill	KWH/YR/ PERSON	PROPORTION OF SALES IND	RES	SERV
1989/90	52.0	105.1		0.5	40.12	2.58	30.9%	55.3%	13.8%
1990/91	54.1	107.1	2.1	0.5	40.90	2.59	30.8%	55.6%	13.6%
1991/92	56.2	109.2	2.1	0.5	41.70	2.61	30.9%	55.7%	13.4%
1992/93	58.5	111.4	2.1	0.5	42.51	2.64	30.9%	55.8%	13.2%
1993/94	60.8	113.5	2.2	0.5	43.33	2.66	31.0%	55.9%	13.1%
1994/95	63.3	115.8	2.2	0.5	44.18	2.68	31.1%	56.0%	12.9%
1995/96	65.8	118.0	2.3	0.6	45.04	2.71	31.2%	56.1%	12.7%
1996/97	68.4	120.3	2.3	0.6	45.91	2.73	31.2%	56.2%	12.5%
1997/98	71.2	122.7	2.4	0.6	46.81	2.75	31.3%	56.3%	12.4%
1998/99	74.0	125.1	2.4	0.6	47.72	2.81	31.4%	56.4%	12.2%
1999/00	77.0	127.6	2.5	0.6	48.64	2.86	31.5%	56.5%	12.0%
2000/01	80.1	130.1	2.5	0.6	49.59	2.91	31.5%	56.6%	11.9%
2001/02	83.3	132.6	2.6	0.6	50.56	2.96	31.6%	56.7%	11.7%
2002/03	86.6	135.2	2.6	0.6	51.54	3.02	31.7%	56.7%	11.6%
2003/04	90.0	137.9	2.7	0.7	52.54	3.08	31.8%	56.8%	11.4%
2004/05	93.6	140.6	2.7	0.7	53.56	3.13	31.8%	56.9%	11.2%
2005/06	97.4	143.3	2.8	0.7	54.60	3.19	31.9%	57.0%	11.1%
2006/07	101.3	146.1	2.8	0.7	55.67	3.25	32.0%	57.1%	10.9%
2007/08	105.3	149.0	2.9	0.7	56.75	3.31	32.0%	57.2%	10.8%
2008/09	109.6	151.9	2.9	0.7	57.85	3.37	32.1%	57.2%	10.6%
2009/10	113.9	154.9	3.0	0.7	58.98	3.44	32.2%	57.3%	10.5%
2010/11	118.5	157.9	3.0	0.8	60.13	3.50	32.3%	57.4%	10.4%

ANNEX 5.4 (b)

SUMMARY OF THERMAL GENERATION PLANNING PARAMETERS USED IN WASP/ENPEP STUDIES

Plant Name	ENPEP ID CODE	Operating Capacity Min. MW	Max. MW	Units	Heat Rates Min. Cap. kcal/kWh	Average Incr	Max Effy	Fuel Type	System Parameters Spin Resv %	FOR %	Maintenance Shed. d/yr	Class MW	Operating Cost Fixed O&M $/kW.m	Var. O&M $/MWh	Capital Cost FC $USm	LC $USm
FIXED SYSTEM (Existing / Committed)																
Ywama Steam Turbines	YW1G	3.3	6.5	3	7818	4446	14.0%	FOIL	0%	15%	30	10	4.77	4.80	6.3	3.0
Ywama GT (Gas)	YW2G	9.3	18.5	2	4800	2220	24.5%	GAS	10%	10%	20	20	1.21	2.00	1.3	0.1
Kyunchaung Gas Turbines	KGYT	9.1	18.1	3	4800	2220	24.5%	GAS	10%	10%	20	20	1.21	2.00	2.0	0.2
Myanaung GT (Hitachi)	MYGH	9.3	18.5	1	4800	2220	24.5%	GAS	10%	10%	20	20	1.21	2.00	0.5	0.1
Myanaung GT (John Brown)	MYJB	9.3	18.5	1	4800	2220	24.5%	GAS	10%	10%	20	20	1.21	2.00	0.7	0.1
Mann Gas Turbines	MANN	9.3	18.5	2	4800	2220	24.5%	GAS	10%	10%	20	20	1.21	2.00	1.8	0.2
Shwedaung Gas Turbines	SHWE	9.3	18.5	3	4800	2220	24.5%	GAS	10%	10%	20	20	1.21	2.00	2.5	0.2
Thaketa Gas Turbines	THAK	9.5	19.0	3	4800	3000	22.1%	DIES	10%	10%	20	20	1.21	2.00	0.5	0.1
Thaton Gas Turbine	THA1	8.5	17.0	1	4800	2400	23.9%	FOIL	10%	10%	20	20	1.21	2.00	0.7	0.1
Thaton Steam Turbine	THA2	3.3	6.6	3	4000	3060	24.4%	FOIL	10%	15%	25	6	4.77	4.80	0.5	0.1
Moulmein Steam Turbines	MOUL	3.0	6.0	2	4000	2900	24.9%	FOIL	10%	15%	25	6	4.77	4.80	0.5	0.1
Ywama GT (Diesel)	YW20	9.3	18.5	2	4800	2460	23.7%	DIES	10%	10%	20	20	1.21	2.00		
Total Fixed Thermal Capacity			346.1												17.2	4.1
VARIABLE SYSTEM (Alternative Options)															$/kW	$/kW
C-C#1 Shwedaung	SHWC	18.5	52.0	1	3510	1949	37.4%	GAS	10%	10%	20	20	1.67	4.00	406	101
C-C#3 Myanaung #1	MYCH	16.4	73.0	1	3740	2089	35.0%	GAS	10%	10%	20	20	1.67	4.00	352	151
C-C#4 Myanaung #2	MYCJ	18.5	54.0	1	3510	1745	36.6%	GAS	10%	10%	20	20	1.67	4.00	544	233
C-C#2 Mann	MANC	18.5	82.0	1	3510	1999	36.8%	GAS	10%	10%	20	20	1.67	4.00	482	120
C-C#5 Thaketa	THAC	19.0	85.0	1	3900	2159	33.8%	GAS	10%	10%	20	20	1.67	4.00	359	154
Kalewa Coal Fired ST	KALE	25.0	50.0	6	3045	2557	30.7%	MINE	10%	10%	30	50	2.15	6.20	1583	678
C-C#7 Kyaiklat	KYAC	17.0	50.0	10	3565	1470	39.4%	GAS	10%	10%	20	20	1.67	4.00	652	279
Thaketa Diesel/Gas Engine	THAD	2.0	12.0	10	2389	2332	36.7%	DIES	10%	10%	30	10	1.50	3.00	1018	262
Ahlone Coal Fired ST	AHCO	25.0	100.0	3	3045	2557	32.1%	COAL	10%	10%	30	50	2.15	6.20	840	360
Ahlone Fuel Oil Fired ST	AHLO	25.0	50.0	6	3142	2752	29.2%	FOIL	10%	10%	30	50	2.15	6.20	814	348

Notes:

(i) Rehabilitation Costs allocated to existing plants include new spares provede under the IDA loan together with provision for additional diesel storage and oil handling facilities at Mann, Swedaung and Myanaung. Rate costs shown for the Variable system plants are inclusive of IDC (Interest During Construction).

(ii) For the WASP study it is assumed Thaketa, and Ywama would operate with diesel fuel until 1995 when offshore gas is availlable. Plants using Fuel oil are expected to retire between 2000 and 2005.

(iii)Conversion to Combined Cycle operation at Thaketa, Shwedaung, Mann, and Myanaung would uprate the existing facilities by 28MW (THAK to THAC), 26.5MW (SHWE to SHWC), 26.5MW (MANN to MANC), and 24MW (MYGH to MYCH) + 36.45MW (MYJB to MYCJ).

(iv) A new 600MW combined cycle plant is proposed near Yangon, possibly at Kyaiklat. The first stage is proposed as 6*50MW compatable with the existing system configuration, but the latter stage could be in 100MW increments.

(v) Coal fired plant option include a 6*50MW Minemouth station at Kalewa and a 3*100MW staion using imported coal possibly sited at Ahlone. Alternatively a fuel oil fired steam generating station could be sited in Ahlone.

(vi) Only medium speed dual fuel (gas/diesel) engines have been considered above. If offshore gas delayed beyond 1995 then optional development should consider 4*25MW slow speed multifuel (heavy fuel, gas, diesel) engines.

ANNEX 5.4 (c)

GENERATION EXPANSION ALTERNATIVES - 1990 - 2010

Base Case: High Demand

MW Year	MW Forecast		MW Install	MW Total	% Reserve
1989	398	Existing Capability	399	399	0%
1990	376			399	6%
1990	376	Thaketa changes to oil	60	459	18%
1991	399			459	13%
1991	399			459	13%
1992	414	Rehabilitation Program	562	562	26%
1992	414			562	26%
1993	453			562	19%
1993	453			562	19%
1994	489			562	13%
1994	489	C-C#1/C-C#2 Shwedag/Mann	71	633	23%
1995	530			633	16%
1995	530	C-C#5/C-C#3 Thaketa/Myanaung	52	685	23%
1996	566			685	17%
1996	566	C-C#7 Kyaiklat	50	735	23%
1997	605			735	18%
1997	605	C-C#7 Kyaiklat	50	785	23%
1998	656			785	16%
1998	656	C-C#7 Kyaiklat	50	835	21%
1999	711			835	15%
1999	711	C-C#7 Kyaiklat	100	935	24%
2000	771	Ywama YW1G retires	-36	899	14%
2000	771	C-C#7 Kyaiklat	50	949	19%
2001	849			949	11%
2001	849	C-C#7 Kyaiklat	100	1049	19%
2002	922			1049	12%
2002	922	C-C#7 Kyaiklat	100	1149	20%
2003	1015			1149	12%
2003	1015	Paunglaung	280	1429	29%
2004	1116			1429	22%
2004	1116	Baluchaung #3	48	1477	24%
2005	1228	Retire Thaton/Moulmine	-47	1430	14%
2005	1228	Bilin	240	1670	26%
2006	1351			1670	19%
2006	1351	Yewya	400	2070	35%
2007	1487			2070	28%
2007	1487	Mon Chaung	200	2270	34%
2008	1638			2270	28%
2008	1638	Shwezaye	600	2870	43%
2009	1803			2870	37%
2009	1803	Kun Chaung	84	2954	39%
2010	1986			2954	33%
2010	1986	Retire GT Capacity	-150	2804	29%
		Total	2804	Av	22%

Case 1: Low Demand

MW Year	MW Forecast		MW Install	MW Total	% Reserve
1989	398	Existing Capability	399	399	0%
1990	376			399	6%
1990	376	Thaketa changes to oil	60	459	18%
1991	389			459	15%
1991	389			459	15%
1992	394	Rehabilitation Program	562	562	30%
1992	394			562	30%
1993	411			562	27%
1993	411			562	27%
1994	429			562	24%
1994	429	C-C#1/C-C#2 Shwedag/Man	71	633	32%
1995	447			633	29%
1995	447	C-C#5 Myanaung	24	657	32%
1996	467			657	29%
1996	467			657	29%
1997	488			657	26%
1997	488	C-C#6 Myanaung	36	693	30%
1998	510			693	26%
1998	510			693	26%
1999	541			693	22%
1999	541	Kalewa Coal #1	50	743	27%
2000	574	Ywama YW1G retires	-36	707	19%
2000	574	Kalewa Coal #1	50	757	24%
2001	609			757	20%
2001	609	Kalewa Coal #1	50	807	25%
2002	646			807	20%
2002	646			807	20%
2003	684			807	15%
2003	684	Ahlone Coal #1	100	907	25%
2004	724			907	20%
2004	724			907	20%
2005	767	Retire Thaton/Moulmine	-47	860	11%
2005	767	Ahlone Coal #1	200	1060	28%
2006	812			1060	23%
2006	812			1060	23%
2007	860			1060	19%
2007	860	C-C#5 Thaketa	85	1145	25%
2008	910			1145	21%
2008	910	Baluchaung #3	48	1193	24%
2009	964			1193	19%
2009	964	Kalewa Coal #1	50	1243	22%
2010	1022			1243	18%
2010	1022	Retire GT Capacity	-150	1093	7%
		Total	1093	Av	23%

Case 2: High Demand - Onshore gas only

MW Year	MW Forecast		MW Install	MW Total	% Reserve
1989	398	Existing Capability	399	399	0%
1990	376			399	6%
1990	376	Thaketa changes to oil	60	459	18%
1991	399			459	13%
1991	399			459	13%
1992	414	Rehabilitation Program	562	562	26%
1992	414			562	26%
1993	453			562	19%
1993	453			562	19%
1994	489			562	13%
1994	489	C-C#1/C-C#2 Shwedag/Mann	71	633	23%
1995	530			633	16%
1995	530	C-C#4/C-C#3 Myanaung #1&2	60	693	24%
1996	566			693	18%
1996	566	Ahlone Coal #1	100	793	29%
1997	605			793	24%
1997	605			793	24%
1998	656			793	17%
1998	656	Ahlone Coal #2	100	893	27%
1999	711			893	20%
1999	711	Baluchaung #3	48	941	24%
2000	771	Ywama YW1G retires	-36	905	15%
2000	771	Ahlone Coal #2	100	1005	23%
2001	849			1005	16%
2001	849	Kalewa Coal #1&2	100	1105	23%
2002	922			1105	17%
2002	922	C-C#5 Thaketa	85	1190	23%
2003	1015			1190	15%
2003	1015	Kalewa Coal #1&2	100	1290	21%
2004	1116			1290	14%
2004	1116	Paunglaung	280	1570	29%
2005	1228	Retire Thaton/Moulmine	-47	1523	19%
2005	1228	Yewya	400	1923	36%
2006	1351			1923	30%
2006	1351			1923	30%
2007	1487			1923	23%
2007	1487	Bilin/Ahlone Oil #1	290	2213	33%
2008	1638			2213	26%
2008	1638	Ahlone Oil #2,3,4	150	2363	31%
2009	1803			2363	24%
2009	1803	Kun/Mon Chaung	284	2647	32%
2010	1986			2647	25%
2010	1986	Retire GT Capacity	-150	2497	20%
		Total	2497	Av	22%

ANNEX 5.4 (d)

ELECTRICITY GENERATION: BASE CASE

Summary of Generating Station Production

PLANT	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH
YW2G	0.00	0.00	0.00	0.00	0.00	117.97	118.49	132.64	139.93	137.44	138.71	137.48	137.49	106.23	110.01	18.64	34.49	35.24	62.34	105.29	0.00
THAC	0.00	0.00	0.00	0.00	0.00	499.20	471.39	439.95	423.30	355.87	361.07	346.35	342.49	312.81	319.58	267.98	362.30	249.87	251.11	335.07	499.52
KYAC	0.00	0.00	0.00	0.00	0.00	0.00	307.06	603.62	911.75	1398.28	1738.16	2210.71	2755.74	2681.31	2992.64	2941.85	3000.97	3114.50	2944.65	3264.28	3616.79
PAYAGON/MARTABAN TOTAL	0	0	0	0	0	617.17	896.94	1176.21	1474.98	1891.59	2237.94	2694.54	3235.72	3100.35	3422.23	3228.47	3397.84	3399.61	3258.1	3704.64	4116.31
KYGT	387.91	400.80	404.68	361.57	232.21	159.41	161.97	167.48	192.46	187.67	207.23	203.32	204.74	158.36	162.70	0.00	0.00	0.00	0.00	0.00	0.00
MANN	237.29	228.56	238.45	218.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MANC	0.00	0.00	0.00	0.00	378.28	347.48	337.56	331.51	331.14	314.26	318.84	312.14	311.61	262.45	292.74	163.26	136.51	193.60	240.64	241.88	323.25
MANN/CHAUK TOTAL	625.2	629.36	643.13	580.02	610.49	506.89	499.53	498.99	523.6	501.73	526.07	515.46	516.35	420.81	455.44	163.26	136.51	193.6	240.64	241.88	323.25
MYGH	248.37	240.14	240.54	206.19	176.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MYJB	121.07	121.60	137.12	119.94	76.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SHWE	340.52	321.41	321.11	282.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MYCH	0.00	0.00	0.00	0.00	0.00	281.66	285.34	281.82	282.59	273.31	276.46	273.26	273.02	209.80	220.49	68.89	70.73	122.04	180.78	214.00	287.64
MYCI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	158.90	212.87
SHWC	0.00	0.00	0.00	0.00	456.71	415.51	375.18	353.15	350.71	327.11	331.31	322.19	319.95	281.68	304.12	244.69	161.70	239.64	241.64	306.95	381.30
PROME/PYMO TOTAL	709.96	683.15	698.77	608.54	710.09	697.17	660.52	634.97	633.3	600.42	607.77	595.45	592.97	491.48	524.61	313.58	232.43	361.68	422.42	679.85	881.81
TOTAL GAS PRODUCTN	1335.16	1312.51	1341.9	1188.56	1320.58	1821.23	2056.99	2310.17	2631.88	2993.74	3371.78	3805.45	4345.04	4012.64	4402.28	3705.31	3766.78	3954.89	3921.16	4626.37	5331.37
THAK	0.00	210.49	187.52	151.01	155.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
THA1	0.00	0.00	69.62	50.20	49.65	44.01	44.70	46.12	49.78	49.55	57.71	56.93	57.35	46.45	8.13	0.00	0.00	0.00	0.00	0.00	0.00
THA2	0.00	0.00	71.13	54.32	53.82	2.27	1.79	1.68	2.05	1.11	1.76	1.32	1.42	0.07	0.29	0.00	0.00	0.00	0.00	0.00	0.00
MOUL	0.00	0.00	44.35	34.15	33.55	1.95	1.54	1.41	1.65	0.90	1.37	1.03	1.09	0.05	0.23	0.00	0.00	0.00	0.00	0.00	0.00
YW1G	0.00	2.11	1.17	1.08	0.91	1.37	1.12	1.11	1.44	0.75	1.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
YW2G	116.85	90.99	88.77	60.53	85.76	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Kyaukphyu	138.20	152.00	157.60	153.50	169.60	173.50	177.70	183.10	188.80	194.80	201.20	208.80	220.30	233.50	247.50	262.50	278.20	295.00	312.90	331.90	352.10
TOTAL OIL PRODUCTN	255.05	455.59	620.16	514.79	548.58	223.10	226.85	233.42	243.72	247.11	263.27	268.08	280.16	280.07	256.15	262.50	278.20	295.00	312.90	331.90	352.10
KALE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AHCO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL COAL PRODUCT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LONG	819.40	819.40	819.40	1275.00	1275.00	1275.00	1275.00	1275.00	1275.00	1275.00	1275.00	1275.00	1275.00	2220.00	2220.00	2220.00	2955.00	3650.00	3650.00	3982.00	3982.00
SHRT	271.30	271.30	271.30	271.30	271.30	271.30	271.00	271.00	271.00	271.00	271.00	271.00	271.00	271.00	576.00	2006.00	2006.00	2006.00	3011.30	3011.30	3011.30
TOTAL HYDRO PRODN	1090.70	1090.70	1090.70	1546.30	1546.30	1546.30	1546.00	1546.00	1546.00	1546.00	1546.00	1546.00	1546.00	2491.00	2796.00	4226.00	4961.00	5656.00	6661.30	6993.30	6993.30
TOTAL ENERGY PRODN	2680.91	2858.8	3052.76	3349.63	3415.46	3590.63	3829.84	4089.59	4421.6	4786.85	5181.05	5619.53	6171.2	6783.71	7454.43	8193.81	9005.9C	9905.89	10895.36	11951.57	12678.77

ANNEX 5.4 (e)

SUMMARY OF FUEL REQUIREMENT 1990-2010: BASE CASE FORECAST

PLANT	Heat Rate Kcal/Kwh	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
GAS FIRED GENSETS					ANNUAL PLANT FUEL USAGE FOR BASE FUEL CASE 001 (IN BILLION CUBIC FeET)																	
YW2G	3774	0.00	0.00	0.00	0.00	0.00	1.77	1.77	1.99	2.10	2.06	2.08	2.06	2.06	1.59	1.65	0.28	0.52	0.53	0.93	1.58	0.80
THAC	2767	0.00	0.00	0.00	0.00	0.00	5.48	5.18	4.83	4.65	3.91	3.97	3.80	3.76	3.44	3.51	2.94	3.98	2.74	2.76	3.68	5.49
KYAC	2372	0.00	0.00	0.00	0.00	0.00	0.00	2.89	5.68	8.98	13.16	16.36	20.81	25.94	25.24	28.17	27.69	28.25	29.32	27.72	30.73	34.04
PAYAGON/MARTABAN TOTAL		0.00	0.00	0.00	0.00	0.00	7.25	9.84	12.50	15.33	19.13	22.40	26.67	31.76	30.26	33.33	30.91	32.74	32.59	31.41	35.98	39.53
KYGT	3774	5.81	6.00	6.06	5.41	3.48	2.39	2.43	2.51	2.88	2.81	3.10	3.04	3.07	2.37	2.44	0.00	0.00	0.00	0.00	0.00	0.00
MANN	3774	3.55	3.42	3.57	3.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MANC	2516	0.00	0.00	0.00	0.00	3.78	3.47	3.37	3.31	3.31	3.14	3.18	3.12	3.11	2.62	2.92	1.63	1.36	1.93	2.40	2.41	3.23
MANN/CHAUK TOTAL		9.36	9.42	9.63	8.69	7.25	5.86	5.80	5.82	6.19	5.94	6.29	6.16	6.18	4.99	5.36	1.63	1.36	1.93	2.40	2.41	3.23
MYGH	3774	3.72	3.60	3.60	3.09	2.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MYIB	3774	1.81	1.82	2.05	1.80	1.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SHWE	3774	5.10	4.81	4.81	4.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MYCH	2372	0.00	0.00	0.00	0.00	0.00	2.65	2.69	2.65	2.66	2.57	2.60	2.57	2.57	1.97	2.08	0.65	0.67	1.15	1.70	2.01	2.71
MYCJ	2372	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.50	2.00
SHWC	2372	0.00	0.00	0.00	0.00	4.30	3.91	3.53	3.32	3.30	3.08	3.12	3.03	3.01	2.65	2.86	2.30	1.52	2.26	2.27	2.89	3.68
PROME/PYMO TOTAL		10.63	10.23	10.46	9.11	8.09	6.56	6.22	5.98	5.96	5.65	5.72	5.60	5.58	4.63	4.94	2.95	2.19	3.40	3.98	6.40	8.39
TOTAL GAS		19.99	19.65	20.09	17.80	15.35	19.67	21.85	24.29	27.47	30.72	34.41	38.44	43.52	39.88	43.62	35.49	36.29	37.92	37.79	44.80	51.15
																	(Calorific value of GAS			252000	Kcal/MCF)	
FUEL OIL/DIESEL FIRED GENERATORS					ANNUAL PLANT FUEL USAGE FOR BASE FUEL CASE 001 (IN MILLION BARRELS)																	
THA1	3321	0.00	0.00	0.15	0.11	0.11	0.10	0.10	0.10	0.11	0.11	0.13	0.12	0.12	0.10	0.02	0.00	0.00	0.00	0.00	0.00	0.00
THA2	3321	0.00	0.00	0.15	0.12	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOUL	3321	0.00	0.00	0.10	0.07	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL FUEL OIL		0.00	0.00	0.40	0.30	0.30	0.10	0.10	0.11	0.12	0.11	0.13	0.13	0.13	0.10	0.02	0.00	0.00	0.00	0.00	0.00	0.00
																	(Calorific value of Fuioil			1532000	Kcal/BBl)	Kcal/BBl)
THAK	2516	0.00	0.36	0.32	0.26	0.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
YW1G	4612	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
YW2G	2767	0.22	0.17	0.17	0.11	0.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Diesel	2306	0.22	0.24	0.25	0.26	0.27	0.27	0.28	0.29	0.30	0.31	0.32	0.33	0.35	0.37	0.39	0.41	0.44	0.47	0.49	0.52	0.56
TOTAL DIESEL		0.44	0.78	0.74	0.64	0.70	0.28	0.28	0.29	0.30	0.31	0.32	0.33	0.35	0.37	0.39	0.41	0.44	0.47	0.49	0.52	0.56
																	(Calorific value of Diesel			1463000	Kcal/BBl)	Kcal/BBl)
TOTAL DIESEL/FUEL OIL		0.44	0.78	1.14	0.94	1.00	0.38	0.39	0.40	0.42	0.42	0.45	0.46	0.48	0.47	0.41	0.41	0.44	0.47	0.49	0.52	0.56
PLANT TYPE	**UNITS**				DAILY FUEL REQUIREMENT PER PLANT FOR BASE FUEL CASE 001																	
GAS	mmcfd	54.8	53.8	55.1	48.8	42.0	53.9	59.9	66.6	75.3	84.2	94.3	105.3	119.2	109.3	119.5	97.2	99.4	103.9	103.5	122.7	140.1
FUEL OIL	bpd	1202.4	2137.9	2034.2	1740.5	1916.3	761.1	777.1	800.3	827.8	847.7	879.5	901.7	951.4	1008.4	1068.9	1133.6	1201.4	1274.0	1351.3	1433.3	1520.6

ANNEX 5.5

SUMMARY OF TRANSMISSION AND SUBSTATION INVESTMENT PROPOSALS

		Qty	$000/ Unit	Cost US$000 FC	LC+tax	0% FC
1 Interconnection Thaton System						
132kV O/H lines, km	*	100	90	5400	3600	
230kV Substation bays	*	1	360	216	144	
132kV Substation bays	*	3	280	504	336	
230/132kV Transformer MVA	*	50	15	450	300	
132/66kV Transformer MVA	*	50	16	480	320	
66kV Substation bays	*	1	180	108	72	
Buildings, Land & Civil	*	2	600	240	1200	
Total Thaton project				7398	5972	
2 Yangon 66kV Reinforcement						
230kV O/H lines, km	*	20	120	1440	960	
230kV Substation bays		5	360	1080	720	
230/66kV Transformer MVA		200	15	1800	1200	
66kV O/H lines, km	*	130	40	3120	2080	
66kV U/G cable, km	*	12	150	1080	720	
66kV Substation bays		72	180	7776	5184	
66/11kV Transformer MVA	*	330	18	3564	2376	
Buildings, Land & Civil		8	600	960	4800	
Total Yangon project				20820	18040	
3 Upgrading System Control Facilities						
Communications	*			4000	1600	
Outstations	*	55	80	2640	1760	
System Control Center	*			3000	1200	
Buildings, Land & Civil		1	600	120	600	
Total SCC Project				9640	4560	

		Year I/S	Qty	$000/ Unit	Cost US$000 FC	LC+tax
4 Ayarwardy 66kV Subtransmission						
230kV Substation bays			6	360	1296	864
230kV O/H lines, km			15	120	1080	720
230/66kV Transformer MVA			250	15	2250	1500
66kV Substation bays			2	180	216	144
Buildings, Land & Civil			1	600	120	600
Total Ayarwardy Project					4962	3828
5 Monya/Kyunchaung/Mandalay 132kV System						
132kV O/H lines, km			180	90	9720	6480
132kV Substation bays			6	280	1008	672
66/11kV Transformer MVA			100	18	1080	720
132/33kV Transformer MVA			50	16	480	320
Buildings, Land & Civil			3	600	360	1800
Total Monya Project					12648	9992
6 General Substation Upgrading						
230kV Substation bays			10	360	2160	1440
132kV Substation bays			10	280	1680	1120
66kV Substation bays			6	180	648	432
132/33kV Transformer MVA			200	16	1920	1280
230/132kV Transformer MVA			200	15	1800	1200
230/66kV Transformer MVA			400	15	3600	2400
33/11kV Switchgear Extensions	*		60	50	1800	1200
Buildings, Land & Civil			10	100	200	1000
Total Substations project					13808	10072
Total Transmission Projects					$69,276	$52,464

ANNEX 5.6

SUMMARY OF DISTRIBUTION INVESTMENT PROPOSALS

		Qty	$000/ Unit	Cost US$000 FC	LC+tax @ 0% FC
1	Yangon 11/0.4kV Rehabilitation				
	33kV Switchgear, feeders *	10	20	140	60
	33kV O/H main lines, km *	25	18	270	180
	11kV O/H main lines, km *	175	12	1260	840
	11kV O/H Teeoffs, km *	225	9	1215	810
	11kV O/H switches @ 3km *	133	3	360	40
	11kV U/G Cables, km *	150	45	4725	2025
	11/,4kV Trafos, MVA *	300	18	4860	540
	11kV Switchgear, feeders *	60	12	504	216
	LV O/H Lines, km *	500	8	2400	1600
	LV U/G Cables, km *	390	40	10920	4680
	Consumer Connects ,000 *	180	48	5184	3456
	Industrial Connects *	60	20	840	360
	Tools & Equipment *			1000	0
	Buildings, Land & Civil *	50	20	200	1000
	Total Yangon Project 190MW@$/kW		382	33878	15807
2	Mandalay Division				
	33kV Switchgear, feeders	30	20	420	180
	33kV O/H main lines, km	168	18	1814	1210
	11kV O/H main lines, km	300	12	2160	1440
	11kV O/H Teeoffs, km	100	9	540	360
	11kV O/H switches @ 3km	133	3	360	40
	11/,4kV Trafos, MVA	60	18	972	108
	11kV Switchgear, feeders	40	12	336	144
	LV O/H Lines, km	400	8	1920	1280
	Consumer Connects ,000	50	48	1440	960
	Industrial Connects *	60	8	336	144
	Tools & Equipment			1000	0
	Buildings, Land & Civil	5	20	20	100
	Total Mandalay Project, 35MW@$/kW		494	11318	5966
	Total Distribution Projects			$143,416	$74,223

		Year I/ Qty	$000/ Unit	Cost US$000 FC	LC+tax
3	New Towns Projects				
	33kV Switchgear, feeders	10	20	140	60
	33kV O/H main lines, km	100	18	1080	720
	11kV O/H main lines, km	300	12	2160	1440
	11kV O/H Teeoffs, km	100	9	540	360
	11kV O/H switches @ 3km	133	3	360	40
	11/,4kV Trafos, MVA	40	18	648	72
	11kV Switchgear, feeders	20	12	168	72
	LV O/H Lines, km	400	8	1920	1280
	Consumer Connects ,000	60	48	1728	1152
	Tools & Equipment			1000	30
	Buildings, Land & Civil	5	20	20	100
	Total New Towns Project		431	9764	5326
4	Other Divisions/States	MW	$/kW		
	Ayeyarwady 28-68MW	35	431	9764	5326
	Bago 75-182MW	85	431	23713	12935
	Magwe 90-218MW	100	431	27897	15217
	Siaging 25-60MW	30	431	8369	4565
	Six States/2 Divns 25-60MW	30	431	8369	4565
	Total States/Divisions Project			78112	42608
5	Rural Electrification				
	33kV O/H main lines, km	200	18	2160	1440
	11kV O/H Teeoffs, km	100	9	540	360
	11kV O/H switches @ 3km	33	3	2160	10
	11/,4kV Trafos, MVA	40	18	648	72
	11kV Switchgear, feeders	20	12	168	72
	LV O/H Lines, km	400	8	1920	1280
	Consumer Connects ,000	60	48	1728	1152
	Tools & Equipment			1000	30
	Buildings, Land & Civil	5	20	20	100
	Total First RE Project		425	10344	4516

ANNEX 5.7

CAPITAL INVESTMENTS FOR PLANT GENERATION/REHABILITATION, TRANSMISSION AND DISTRIBUTION

GENERATION/REHABILITATION

			1991-2000		1991-1995		1995-2000	
		Year	TOT	FC	TOT	FC	TOT	FC
Rehabilitation Project		I/S	m$	m$	m$	m$	m$	m$
Lawpita Rehabilitation		1993	55.09	31.24	55.09	31.24		
Baluchaung#1		1994	65.50	41.66	65.50	41.66		
Ywama Steam turbines		1993	9.79	7.29	9.79	7.29		
Spares for Gas Turbines		1994	15.23	12.84	15.23	12.84		
Total Rehabiltation			145.61	93.03	145.61	.3.03		
Generation Projects	mw							
SHW C-C#1 Swedaung	82	1994	41.50	33.30	41.50	33.30		
MAN C-C#2 Mann	82	1994	49.40	39.50	49.40	39.50		
MYC C-C#3 Myanaung#1	65	1995	36.60	25.70	36.60	25.70		
THAC C-C#5 Thaketa	85	1995	43.50	30.40	43.50	30.40		
YAN C_C#1	50	1996	46.60	32.60	46.60	32.60		
YAN C_C#2	50	1997	46.60	32.60	32.90	23.00	13.70	9.60
YAN C_C#3	50	1998	46.60	32.60	5.20	3.60	41.40	29.00
YAN C_C#4	100	1999	93.10	65.20	0.00	0.00	93.10	65.20
YAN C_C#5	50	1999	46.60	32.60	0.00	0.00	46.60	32.60
Total Generation	614		450.5	324.5	255.7	188.1	194.8	136.4
Generation Plants inc Rehabilitation			596.11	417.53	401.31	281.13	194.80	136.40

TRANSMISSION

	Year	1991-2000		1991-1995		1995-2000	
	I/S	TOT	FC	TOT	FC	TOT	FC
Interconnection Thaton System	1994	15.18	8.62	15.18	8.62	0.00	0.00
Yangon 66kV Reinforcement	1996	44.08	24.25	44.08	24.25	0.00	0.00
Upgrading System Control Facilities	1997	16.24	11.23	14.89	9.87	1.35	1.35
Ayarwardy 66kV Subtransmission	1997	9.99	3.78	2.52	0.99	7.46	4.79
Monya/Kyunchaung/Mandalay 132kV Sys	1999	25.71	14.73	0.00	0.00	25.71	14.73
General Substation Upgrading	2000	27.15	16.08	0.00	0.00	27.15	16.08
Total Transmission Projects		138.35	80.69	76.66	43.74	61.68	36.96

DISTRIBUTION

		Year	1991-2000		1991-1995		1995-2000	
		I/S	TOT	FC	TOT	FC	TOT	FC
Yangon 11/0.4kV Rehabilitation		1995	57.04	37.74	57.04	37.74	0.00	0.00
Mandalay Division		1996	19.89	12.61	19.89	12.61	0.00	0.00
New Towns Projects		1998	17.38	10.88	13.10	9.58	4.28	1.30
Other Divisions/States	I	1999	69.52	43.51	42.54	33.59	26.99	9.92
Other Divisions/States	II	2000	69.52	43.51	0.00	0.00	69.52	43.51
Rural Electrification		2000	17.04	11.52	0.00	0.00	17.04	11.52
Total Distribution Projects			250.41	159.78	132.58	93.52	117.83	66.26

ANNEX 5.8

Computation of Short and Long Run Marginal Cost of Supply: Base Case Forecast

Interest (Present Worth/Amortization)				12%		Actual		Amortization Totals				Amortized Operations, Transmission and Distribution Costs in US$millions																					
		FC	LC			FC	LC	Life	Annt	FC	LC	1991		1992		1993		1994		1995		1996		1997		1998		1999		2000			
GENERATION PROJECTS	MW	$/kW	$/kW			m$	m$	Yrs	Factor	m$	m$	FC	LC	FC	LC	FC	LC	FC	LC	FC	LC	FC	LC	FC	LC	FC	LC	FC	LC	FC	LC		
1 Total Rehabilitation					1990	80.0	44.1	25	0.12749996	184	101					10.2	5.6	10.2	5.6	10.2	5.6	10.2	5.6	10.2	5.6	10.2	5.6	10.2	5.6	10.2	5.6		
2 Base Case - No Coal																																	
MWC C-C/6 Bwakwang	52	485.6	301.4	1990		33.3	8.3	20	0.13387878	76	19							6.3	1.1	6.3	1.1	6.3	1.1	6.3	1.1	6.3	1.1	6.3	1.1	6.3	1.1		
MANC C-C/6 Mana	52	481.8	320.4	1990		30.3	9.9	20	0.13387878	90	22							5.3	1.3	5.3	1.3	5.3	1.3	5.3	1.3	5.3	1.3	5.3	1.3	5.3	1.3		
MTCH C-C/6 Mvuvumagiri	75	551.8	350.8	1995		25.7	11.0	20	0.13387878	55	26									3.6	1.3	3.6	1.3	3.6	1.3	3.6	1.3	3.6	1.3	3.6	1.3		
TBAC C-C/9 Thibata	85	398.7	153.7	1995		30.3	13.1	20	0.13387878	63	28									4.1	1.7	4.1	1.7	4.1	1.7	4.1	1.7	4.1	1.7	4.1	1.7		
KYAC C-C/7 Kyahlist	30	652.1	279.5	1996		32.6	14.0	25	0.12749996	62	27											4.2	1.8	4.2	1.8	4.2	1.8	4.2	1.8	4.2	1.8		
KYAC C-C/7 Kyahlist	30	652.1	279.5	1997		32.6	14.0	25	0.12749996	58	25													4.2	1.8	4.2	1.8	4.2	1.8	4.2	1.8		
KYAC C-C/7 Kyahlist	30	652.1	279.5	1998		32.6	14.0	25	0.12749996	54	23															4.2	1.8	4.2	1.8	4.2	1.8		
KYAC C-C/7 Kyahlist	100	652.1	279.5	1999		65.2	28.0	25	0.12749996	100	43																	8.5	3.6	8.5	3.6		
KYAC C-C/7 Kyahlist	30	652.1	279.5	2000		32.6	14.0	25	0.12749996	46	20																			4.2	1.8		
KYAC C-C/7 Kyahlist	100	652.1	279.5	2001		65.2	28.0	25	0.12749996	91	39																						
KYAC C-C/7 Kyahlist	100	652.1	279.5	2002		65.2	28.0	25	0.12749996	75	32																						
LONG Pungbung	280	1839.6	1201.5	2003		515.0	336.6	40	0.12130362	300	336																						
SSRT Bakebung	50	2110.1	1378.2	2004		105.5	68.9	40	0.12130362	90	59																						
SSRT Yawa	400	1214.0	729.9	2005		485.6	292.0	40	0.12130362	353	212																						
LONG Bilin	240	1471.5	961.1	2006		353.2	230.7	40	0.12130362	214	140																						
LONG Mee Chaung	200	2646.6	1597.8	2007		489.3	319.6	40	0.12130362	257	155																						
SSRT Shwenyo	600	4120.2	2691.0	2008		2472.1	1614.6	40	0.12130362	900	588																						
LONG Kun Chaung	100	1600.2	1045.2	2009		160.0	K	40	0.12130362	39	25																						
3 Total Generation Less Repayment Costs										3289	1908	0	0	0	0	10	6	20	8	27	11	32	13	36	15	40	17	48	20	32	22		
										Base in 1990																							
4 Total O&M + Fuel per ENPEP study			873.7		Present Value					69		81.0		94.8		82.8		86.6		67.5		76.0		81.3		91.5		101.2		112.8			
Less Energy not Supplied			16.6		1991 to						9		1.1		0.6		0.6		1.1		2.5		2.0		2.0		2.8		1.5		2.7	
5 Operations & Maintenance			859.0		2010	2000				60	-9 1	81.0	-1.1	94.8	-0.6	82.8	-0.6	86.6	-1.1	67.5	-2.5	76.0	-2.0	81.3	-2.0	91.5	-2.8	101.2	-1.5	112.8	-2.7		
6 PW Increase in Operating Costs(5-Base)					358	145				59.9	-9.1	0.0	0.0	0.0	0.0	0.0	8.5	28.7	8.1	7.7	6.9	16.1	7.2	21.6	7.2	66.6	6.4	71.3	7.6	97.9	6.5		
7 PW Generation plus incremental operating costs					1211	515				3289	1908	0.0	0.0	0.0	0.0	10.2	14.2	48.7	16.1	35.1	18.2	45.7	20.2	57 6	22.0	86.6	23.0	119.5	27.8	150.5	28.4		
8 Total Transmission Projects										32	25					0.0	0.0	0.9	0.8	0.9	0.8	3.6	3.1	3.5	4.1	3.5	4.1	7.1	5.4	8.8	6.7		
9 PW Generation plus Transmission Costs					1266	536						0.0	0.0	0.0	0.0	10.2	14.2	49.6	16.9	36.1	18.9	49.3	23.3	62.8	26.1	92.0	27.1	126.6	33.2	159.1	35.1		
10 Total Distribution Projects										53	27					0.0	0.0	0.0	0.0	0.3	2.0	3.8	2.8	5.8	2.8	7.0	3.5	12.0	6.2	18 3	9.5		
11 PW Generation, Transmission & Subtransmission					1282	532						0.0	0.0	0.0	0.0	10.2	14.2	49.6	16.9	58.2	19.9	52.2	24.7	65.7	27.5	95.5	28.8	132.6	36.3	168.3	39.9		
12 PW Generation, Transmission & Distribution					1298	548						0.0	0.0	0.0	0.0	10.2	14.2	49.6	16.9	60.4	20.9	55.1	26.1	68.6	28.9	99.0	30.6	138.6	39.6	177.4	44.6		
												MW	Gwh	MW	Gwh	MW	Gwh	MW	Gwh	MW	Gwh	MW	Gwh	MW	Gwh	MW	Gwh	MW	Gwh	MW	Gwh		
13 MW/GWh Generated per year												399.1	2552	613.7	2717.8	652.8	2895.7	699.4	3086.7	529.6	3347.5	565.7	3619.5	604.6	3654.3	656.2	3908.8	711.2	4236.4	771.1	4595.5		
PW GWh Generated by investment in new plant					26681	11586									500		1000		1536.7		2695.5		3619.5		3654.3		3908.8		4236.4		4595.5	
PW Increase in MW capacity each year					543	142												36.6		40.2		36.1		38.9		51.6		55		59.9			

Present Loss Situation	Allocation/Unit				LRMC Estimate to 2010			MRMC to 2000		Future Loss Situation	Allocation/Unit				LRMC Estimate to 2010			MRMC to 2000	
	Losses	Sales	Delivery to bus	Cost at bus	Energy GWh	Loss GWh	Peak $kW/mth	Energy GWh	Loss GWh		Losses	Sales	Delivery to bus	Cost	Energy GWh	Loss GWh	Peak $kW/mth	Energy GWh	Loss GWh
Generation	2%		1.00		4.90	0.29	207	2.70	0.16	Generation	2%		1.00		4.90	0.70	207	2.70	0.39
Transmission (230/132/66kV)	3%	20%	0.95	0.13	5 60	0.68	252	3.09	0.37	Transmission (230/132/66kV)	2%	20%	0.96	0.17	5.34	0.76	230	3.02	0.43
Subtransmission (33/66kV)	3%	10%	0.79	0.07	6.99	0.58	285	3.85	0.34	Subtransmission (33/66kV)	2%	10%	0.77	0.09	6.76	0.97	292	3.95	0.56
Medium Voltage (11/6.6kV)	6%	15%	0.66	0.10	7.94	1.40	345	4.79	0.83	Medium Voltage (11/6.6kV)	2%	15%	0.66	0.13	7.94	1.13	345	4.79	0.68
Low Voltage (230/400V)	30%	55%	0.36	0.36	14.49	8.52	629	8 74	5.14	Low Voltage (230/400V)	6%	55%	0.47	0.47	11.12	4.76	482	6.71	2.87
Total	54%	100%		0.66	Av LRM 10 90	11 27	426	6.52	6.76		14%	100%		0.86	Av LRM 9.05	9.05	366	5.41	5.41

ANNEX 5.9

SUMMARY OF MEPE TARIFFS

	Effective September 1,1981					Effective November 1,1988				
CATEGORY	Energy Charges	Pyas/ kWh	Capacity Charges Fixed Charge	Kyats	Kyats /HP	Energy Charges	Pyas/ kWh	Capacity Charges Fixed Charge	Kyats	Kyats /HP
1 General Purpose	First 100kWh	46	Single Phase	1		Flat Rate	50	Single Phase	2	
	Excess	42	Three Phase	3				Three Phase	5	
2 Domestic Power	First 50kWh	23	Single Phase	1		Flat Rate	50	Single Phase	2	
(Yangon)	Excess	19	Three Phase	3				Three Phase	5	
3 Small Power	Flat Rate	25	Single Phase	6	1	Flat Rate	50	Single Phase	8	1
								Three Phase	15	
4 Industrial						Min 2000kWh				
(a) Yangon	First 40kWh/kW MD	17	Three Phase	12		Flat Rate	45	Three Phase	15	
min 50kW	Excess	15	Three Phase	25				Three Phase	25	
(b) Elsewhere	First 200kWh	25	Three Phase	15	1			Three Phase	15	1
min 2000kWh	Excess	20								
5 Large Industry	Flat Rate	12	Three Phase	25		Min 4GWh		Three Phase	25	1
6 Bulk										
(a) Yangon	First 40kWh/kW MD	40	Three Phase	25		Min 2000kWh		Three Phase	25	1
min 50kW	Excess	24				Flat Rate	45			
(b) Elsewhere	First 500kWh	54	Three Phase	15				Three Phase	15	
min 500kWh	Excess	44								
7 Street Lights										
min 40x att	Flat rate	8				Flat rate	8			
	Excess /addn 10W	2				Excess /addn 10W	2			
8 Temporary										
Lighting	As for Gen Purp.	46								
	Excess	42								

ANNEX 6.1

ESTIMATES OF WOODFUEL STANDING STOCK BY DIVISION/STATE
(million ADT)

Division/ State	Closed Forest	Closed Forest Affected by Shift.Cult.	Degrad. Forest	Degraded Forest Affected by Shift.Cult.	Sawmill Residues	Under growth Noncom. Trees	Plantation	Roadside, Villages, Farm Trees	Total
Ayeyarwady	30.83	0.00	4.02	0.00	26.47	0.005	0.10	1.30	62.71
Yangon	5.25	0.22	0.32	0.09	4.56	0.001	0.12	1.30	11.87
Bago	90.63	1.40	3.02	0.85	76.13	0.015	0.88	3.20	177.13
Shan	11.25	60.70	7.64	13.20	68.19	0.015	0.32	3.10	164.40
Rakhine	61.75	6.43	3.12	0.74	56.58	0.011	0.04	1.80	130.48
Mandalay	30.00	4.48	4.06	0.60	29.87	0.006	0.45	1.00	70.47
Sagaing	18.00	24.08	8.35	0.45	39.32	0.008	0.20	1.05	91.46
Mon	2.08	1.76	1.70	0.71	4.11	0.001	0.08	1.25	11.69
Taninthanryi	35.00	6.68	3.02	2.60	35.72	0.007	0.02	0.70	83.75
Chin	12.00	12.60	5.48	12.18	23.53	0.005	0.03	0.10	55.92
Kayah	0.75	6.48	1.60	0.68	7.13	0.002	0.02	0.10	16.76
Kayin	18.75	15.92	1.42	2.03	29.98	0.006	0.08	1.00	69.18
Kachin	17.50	28.96	0.98	1.38	40.06	0.007	0.03	0.75	89.66
Magway	35.00	1.55	13.32	0.72	35.50	0.008	0.24	0.85	87.18
Total	368.78	172.26	58.05	26.24	477.12	0.100	2.61	17.50	1122.65

ANNEX 6.2

CROP RESIDUES AVAILABLE FOR FUEL
(1080 ADT)

State	Paddy			Sorghum			Maize			Sesamum			Cotton			Sugarcane			Pigeon Pea			Total Crop Residue Avail.
	Crop Prod	Res. Prod	Resi. Avail	Crop Prod	Res. Prod	Resi. Avail	Crop Prod	Res. Prod	Resi. Avail	Crop Prod	Res. Prod	Resi Avail	Crop Prod	Res. Prod	Resi Avail	Crop Prod	Res. Prod	Resi Avail	Crop Prod	Res. Prod	Resi. Avail.	
Ayeyarw	3937	4134	1378	0	0	0	13	30	12	5	20	5	0	0	0	31	6	1	0	0	0	1396
Yangon	1445	1517	506	0	0	0	1	2	1	4	16	4	0	0	0	46	9	2	0	0	0	512
Bago	2623	2754	918	0	0	0	20	46	18	37	148	37	2	7	7	785	157	31	0	0	0	1012
Shan	808	848	283	0	0	0	67	154	60	2	8	2	0	0	0	234	47	9	0	0	0	354
Rakhine	831	873	291	0	0	0	1	2	1	0	0	0	0	0	0	41	8	2	0	0	0	293
Mandalay	571	600	200	21	143	31	46	106	41	23	92	23	33	119	119	786	157	31	26	130	130	606
Sagaing	1067	1120	373	14	39	8	58	133	52	20	80	20	12	43	43	92	18	4	7	35	35	544
Mon	651	684	228	0	0	0	2	5	2	1	4	1	0	0	0	150	30	6	0	0	0	237
Taninth	210	221	74	0	0	0	0	0	0	0	0	0	0	0	0	15	3	1	0	0	0	74
Chin	50	53	18	0	0	0	32	74	29	0	0	0	0	0	0	5	1	0	0	0	0	47
Kayah	55	58	19	2	6	1	4	9	4	0	0	0	0	0	0	0	0	0	0	0	0	25
Kayin	280	294	98	0	0	0	1	2	1	1	4	1	0	0	0	55	11	2	0	0	0	102
Kachin	240	225	84	0	0	0	7	16	6	0	0	0	0	0	0	62	12	2	0	0	0	93
Magway	292	307	102	34	95	20	61	140	55	49	196	55	13	47	47	14	3	1	7	35	35	329
Total	13060	13713	4571	101	283	61	313	720	282	142	568	142	60	216	216	2316	463	93	40	200	5625	200

Source: Mission Estimates

ANNEX 6.3

WOODY & NON-WOODY BIOMASS CONSUMPTION ESTIMATES

Division/State	Population 1983		Population 1990		Rural Household Woodfuel Consumpt.	Urban Household Woodfuel Consumpt	Household Woodfuel Consumpt 1990	Non-Hhold Woodfuel Consumpt 1990	Total Woodfuel Consumpt 1990	Household Non-Wdfl Consumpt 1990	Non-Hhold Non-Wd Bio Consumpt 1990	Total Non-Wd Bio Consumpt 1990	Total Biomass Consumpt 1990
	Rural	Urban	Rural	Urban	(mill ADT)	(mill ADT)	(mill ADT)	(mill ADT)	(mill ADT)	(mill ADT)	(mill ADT)	(mill ADT)	(mill ADT)
	(million)		(million)										
Ayeyarwady	4.25	0.74	4.87	0.85	3.34	0.59	3.92	0.07	3.99	0.08	0.05	0.13	4.12
Yangon	1.28	2.69	1.47	3.10	1.01	2.13	2.07	0.63	2.70	0.02	0.42	0.44	3.14
Bago	3.06	0.74	3.50	0.85	2.40	0.59	2.99	0.13	3.12	0.06	0.09	0.15	3.27
Shan	3.06	0.66	3.50	0.76	2.40	0.52	2.93	0.05	2.98	0.06	0.03	0.09	3.07
Rakhine	1.74	0.3	1.99	0.35	1.37	0.24	1.60	0.03	1.63	0.03	0.02	0.05	1.68
Mandalay	3.37	1.21	3.86	1.40	2.65	0.96	3.60	0.19	3.79	0.07	0.13	0.20	3.99
Sagaing	3.33	0.53	3.81	0.61	2.62	0.42	3.03	0.16	3.19	0.06	0.11	0.17	3.36
Magway	2.75	0.49	3.15	0.56	2.16	0.39	2.55	0.09	2.64	0.05	0.06	0.11	2.75
Mon	1.21	0.47	1.39	0.54	0.95	0.37	1.32	0.02	1.35	0.03	0.02	0.04	1.39
Tanintharyi	0.70	0.22	0.80	0.25	0.55	0.17	0.72	0.01	0.74	0.01	0.01	0.02	0.76
Chin	0.31	0.05	0.35	0.06	0.24	0.04	0.28	0.01	0.30	0.01	0.01	0.02	0.31
Kayah	0.13	0.04	0.15	0.05	0.10	0.03	0.13	0.00	0.14	0.00	0.00	0.01	0.14
Kayin	0.95	0.11	1.09	0.13	0.75	0.09	0.83	0.01	0.85	0.02	0.01	0.03	0.87
Kachin	0.72	0.18	0.82	0.21	0.57	0.14	0.71	0.04	0.74	0.01	0.02	0.04	0.78
Totals	26.86	8.43	30.75	9.72	21.09	6.67	26.70	1.45	28.15	0.52	0.97	1.49	29.64

Source: Mission Estimates

ANNEX 6.4

CHARCOAL PRODUCTION AND TRANSPORT COSTS

Item	Cost/Item
Cutting & Transport of Wood	kyats 100-110 ADT
Loading Kiln	kyats 10 per ADT
Firing & Watching	kyats 10 per ADT
Unloading	Kyats 0.2 per viss (1)
Kiln Licence	kyats 0.01 per viss
Cost of Bag/Basket	kyats 0.2 per viss for baskets (kyats 2-2.5 each) kyats 0.55 per viss for bags (kyats 3.5-7 each)
Transport to Packer (Ayeyarwady)	kyats per 0.12 per viss (150 miles)
Packing in Basket/Bag	kyat 0.06 per viss
Transport to Yangon:	
By Ship	kyat 5 per basket (2) (kyats 0.4 per viss; kyats 1.4/ton/mile) plus an average of kyats 1 each for loading and unloading
By Road	kyat 40 per bag (3) (kyats 1.6 per viss; kyats 4.5/ton/mile) plus kyats 3 per bag for loading/unloading
Local Transport	kyat 0.6 per viss

(1) Viss is equivalent to 3.6 lb.

(2) Baskets varied in size from 7.5 to 15 viss (27 to 54 lb), but the average and most common size as seen and measured by the mission was 12.5 viss (45 lb.)

(3) Bags observed were either 16.5 or 25 viss (60 to 90 lbs.), but the most common appeared to be the latter. The trucks are grossly overloaded with 6-ton trucks carrying as much as 9.5 tons (240 90 lb bags). In some instances charcoal was carried in bulk by truck to Yangon.

SOURCE: Mission

ANNEX 6.5

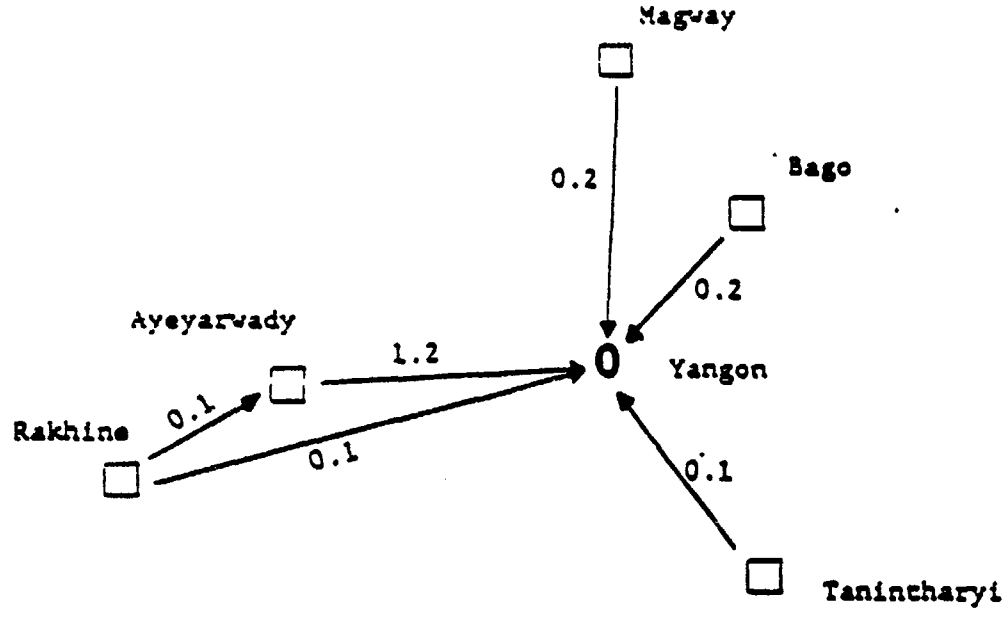
COST OF FUELWOOD COLLECTION AND TRANSPORT

Item	Item (kyats/ADT)
Cutting & Carrying of Wood	105
Loading	20
Transport by Ship	240 (kyats 2.5/ADT/mile)
Transport by Road	140 (kyats 7.0/ADT/mile)
Unloading	30

SOURCE: Mission

Figure 6.1

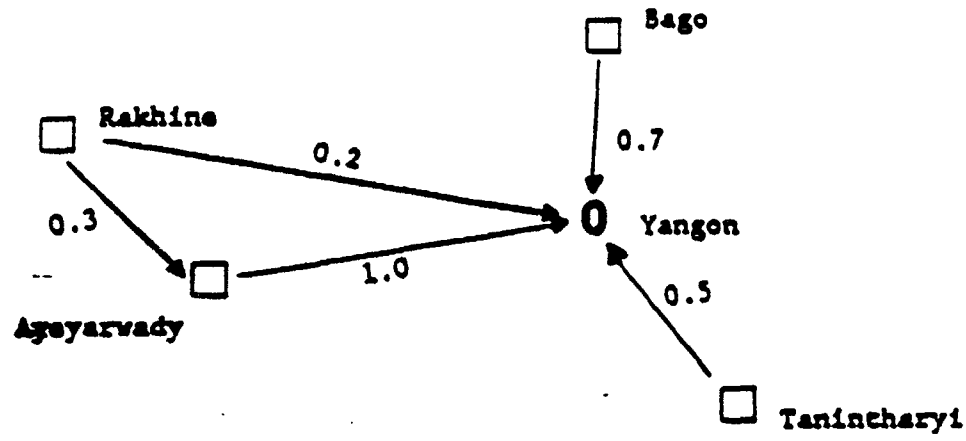
Trade of Woodfuels in Yangon Catchment, 1990
(million ADT)



Yangon consumption in 1990 estimated at 2.7 million ADT of which 1.8 million ADT imported.

Figure 6.2

Trade of Woodfuels in Yangon Catchment, 2005
(million ADT)



In 2005, Yangon woodfuel consumption is projected to be 4.7 million ADT of which 2.4 million ADT is imported.

ANNEX 7.1 (a)

HYDROCARBON FUEL PRICES, IN 1989 IN MYANMAR

FUEL	UNIT	PRICE
Crude Oil & Condensate (MOGE/MPE)	Ky/B	110.00
	Ky/IG	3.14
Gas (MOGE to Consumers)	Ky/MCF	7.50
CNG	Ky/150 CF	10.00
	Ky/MCF	66.67
LPG	Ky/B	297.50
	Ky/IG	8.50
Petrol	Ky/IG	16.00
Kerosene	Ky/IG	13.50
Aviation Fuel	Ky/IG	13.50
Diesel	Ky/IG	10.50
Cooking Gas/Oil	Ky/IG	8.50
Petroleum Coke	Ky/IG	8.50
Methanol	Ky/IG	8.50
Methanol with Petrol	Ky/IG	11.00

SOURCE: MOGE

ANNEX 7.1 (b)

BASE YEAR PRICES OF KEY ENERGY PRODUCTS IN MYANMAR (1991 Dollars)

INTERNATIONAL PRICES			JAN 1991 MYANMAR PRICES		ESTIMATED OPPORTUNITY VALUES IN MYANMAR	
			Kyats	US$ Equiv @ 50 K/US$	Kyats	US$ Equiv @ 50 K/US$
Crude Oil	US$/B	26	3.145 /IG	0.06 /IG	36.60 /IG	0.73 /IG
Diesel	US$/B	32	10.50 /IG	0.21 /IG	45.44 /IG	0.91 /IG
Heavy Fuel Oil	US$/B	25	8.50 /IG	0.17 /IG	35.13 /IG	0.70 /IG
Nat Gas (cost)	US$/MCF	2	7.50 /MCF	0.15 /MCF	100.00 /MCF	2.00 /MCF
LNG	US$/MCF	4				
Coal	US$/ton	39	365.00 /ton	7.30 /ton	1957.00 /ton	39.14 /ton

PARAMETERS AND CONVERSION FACTORS (Parameters with * are "driving" parameters)

B equals	34.9726	IG
l equals	0.219969	IG
l equals	0.00628981	B
crude	1512	mill cal/B
Diesel	1463	mill cal/B
Heavy Fuel Oil	1532	mill cal/B
MCF gas	252	mill cal/MCF
MCF equiv	0.167	B crude oil
Kalewa Coal	5600	mill cal/ton

INTERNATIONAL ENERGY PRICES	1991 FOB Price		Linkage	Ratios *	Deliv Costs *	
Crude Oil *	20.60	US$/B			5	US$/B
Diesel	26.78	US$/B	Diesl/crude	1.3000	5	US$/B
Heavy Fuel Oil	19.57	US$/B	HFO/Crude	0.9500	5	US$/B
Nat Gas Cost *	2.00	US$/MCF				
LNG (delivered)	3.69	US$/MCF	LNG/HFO	0.1500		
Steam Coal	29.14	US$/ton	Coal/HFO	2.0000	10	/ton

OTHER ASSUMPTIONS (PARAMETERS)

Effective Exchange Rate *	50 K/US$
Escalation in Oil Price	3.00% /yr to 2000 then flat

ANNEX 7.1 (b) (cont'd)

BASE YEAR PRICES OF KEY ENERGY PRODUCTS IN MYANMAR

FORECAST OPPORTUNITY VALUE PRICES FOR MYANMAR ENERGY PRODUCTS

End Year	Crude Oil Fob	Crude Oil Cif	Diesel Cif	Fuel Oil Cif	Natural Gas Cif	LNG Cif	Coal Cif
	(1991 Dollars)						
	US$/B	US$/B	US$/B	US$/B	US$/MCF	US$/MCF	US$/TON
1990	20.00	25.00	31.00	24.00	2.00	3.60	38.00
1991	20.60	25.60	31.78	24.57	2.00	3.69	39.14
1992	21.22	26.22	32.58	16	2.00	3.77	40.31
1993	21.85	26.85	33.41	6	2.00	3.86	41.52
1994	22.51	27.51	34.26	[illegible]38	2.00	3.96	42.77
1995	23.19	28.19	35.14	27.03	2.00	4.05	44.05
1996	23.88	28.88	36.05	27.69	2.00	4.15	45.37
1997	24.60	29.60	36.98	28.37	2.00	4.26	46.74
1998	25.34	30.34	37.94	29.07	2.00	4.36	48.14
1999	26.10	31.10	38.92	29.79	2.00	4.47	49.58
2000	26.88	31.88	39.94	30.53	2.00	4.58	51.07
2001	27.00	32.00	40.10	30.65	2.00	4.60	51.30
2002	27.00	32.00	40.10	30.65	2.00	4.60	51.30
2003	27.00	32.00	40.10	30.65	2.00	4.60	51.30
2004	27.00	32.00	40.10	30.65	2.00	4.60	51.30
2005	27.00	32.00	40.10	30.65	2.00	4.60	51.30
2006	27.00	32.00	40.10	30.65	2.00	4.60	51.30
2007	27.00	32.00	40.10	30.65	2.00	4.60	51.30
2008	27.00	32.00	40.10	30.65	2.00	4.60	51.30
2009	27.00	32.00	40.10	30.65	2.00	4.60	51.30
2010	27.00	32.00	40.10	30.65	2.00	4.60	51.30

Source: Parameters, Conversion Rates, and Assumptions in Table 7.1 (b)

ANNEX 7.2 (a)

PETROLEUM PRODUCT PRICES

MAIN ASSUMPTIONS

International Crude Price	17.75	US$/B	at	6.20 k/US$
MOGE handover Price Crude	110	k/B		

Best estimate of costs, prices and tax rates in late 1990

EXISTING SITUATION IN MYANMAR, LATE 1990
PETROLEUM PRODUCT PRICING (k/IG)

		Petrol	Kero	Diesel	Fuel Oil	Av Fuel	TOTALS/ AVGES.
Ex MOGE(crude)		3.14	3.14	3.14	3.14	3.14	3.14
Cost of Refining		2.03	2.15	1.32	2.00	2.15	1.64
Factory cost		5.17	5.29	4.46	5.14	5.29	4.79
Profit Margin	5.0%	0.26	0.26	0.22	0.26	0.26	0.24
ex ref cost without taxes		5.43	5.56	4.69	5.40	5.56	5.03
Commodity Tax Rate		170%	80%	90%	35%	115%	102%
Commodity Tax		8.80	4.24	4.02	1.80	6.09	4.91
Total Cost ex refinery		14.23	9.79	8.70	7.20	11.65	9.94
Excess cost to MPE over handover price		2.43	-0.21	1.10	1.20	1.65	1.45
1990 Fixed Handover Price		11.80	10.00	7.60	6.00	10.00	8.49
Distribution Costs		3.06	2.58	2.14	1.85	2.58	2.34
Profit Margin	2.0%	0.30	0.25	0.19	0.16	0.25	0.22
Sales Tax on o	5.0%	0.80	0.68	0.57	0.42	0.68	0.58
Total Cost ex distrib		15.96	13.51	10.45	8.43	13.51	11.63
Excess cost to MPPE over sales price		-0.04	0.01	-0.05	-0.07	0.01	-0.05
1990 Fixed Consumer Sales Price		16.00	13.50	10.50	8.50	13.50	11.68
All Taxes		9.59	4.91	4.54	2.22	6.76	5.50
Tax as % Cons Price		60.0%	36.9%	39.1%	22.9%	44.4%	41.81%
Consumption 1990 MM IG		38.06	2.21	83.82	24.56	4.64	153.29
Tax Revenues MM kyat		365.1	10.9	380.6	54.6	31.4	842.48
Tax Revenues MM US$							
at k6.2/US$		58.9	1.8	61.4	8.8	5.1	135.97
at assumed FX rate		58.9	1.8	61.4	8.8	5.1	135.97
at k50/US$		7.30	0.22	7.61	1.09	0.63	16.85
COST AND TAXES ON TRUE COST-PLUS BASIS							
Costs (k/IG)		8.79	8.39	7.02	7.41	8.39	7.58
Commodity Tax		8.80	4.24	4.02	1.80	6.09	4.91
Sales Tax on cost-plus price		0.93	0.66	0.58	0.48	0.76	0.66
Total Price on Cost-Plus Basis		18.52	13.29	11.62	9.69	15.24	13.15

The refinery cost allocations are as given by MPE to MOE in late 1990
In refinery operation the Profit margin is 5% of factory cost ,
and commodity tax is calculated on factory cost ex margin
In distribution the 2% margin is on handover price plus dist costs
without taxes. The sales tax is 5% times the official consumer price

ANNEX 7.2 (b)

PETROLEUM PRODUCT PRICES

MAIN ASSUMPTIONS

International Crude Price	25.00	US$/B	at	6.20 k/US$
MOGE handover Price Crude	155	k/B		

Crude oil price increased to US$25/B
Fuel oil commodity tax decreased to 30%, as in early 1991

ILLUSTRATION OF COST-PLUS PRICES, ON BASIS OF US$25/B CRUDE
AS AT EARLY 1991
PETROLEUM PRODUCT PRICING (k/IG)

		Petrol	Kero	Diesel	Fuel Oil	Av Fuel	TOTALS/ AVGES.
Ex MOGE(crude)		4.43	4.43	4.43	4.43	4.43	4.43
Cost of Refining		2.03	2.15	1.32	2.00	2.15	1.64
Factory cost		6.46	6.58	5.75	6.43	6.58	6.07
Profit Margin	5.0%	0.32	0.33	0.29	0.32	0.33	0.30
ex ref cost without taxes		6.78	6.91	6.04	6.75	6.91	6.38
Commodity Tax Rate		170%	80%	90%	30%	115%	101%
Commodity Tax		10.98	5.26	5.17	1.93	7.57	6.17
Total Cost ex refinery		17.76	12.17	11.21	8.68	14.47	12.54
Distribution Costs		3.06	2.58	2.14	1.85	2.58	2.34
Profit Margin	2.0%	0.42	0.30	0.27	0.21	0.34	0.30
Sales Tax on cost-plus price	5.0%	1.12	0.79	0.72	0.57	0.92	0.80
Total Cost ex distrib		22.36	15.84	14.33	11.30	18.32	15.98
All Taxes		12.10	6.06	5.89	2.49	8.48	6.97
Tax as % Cons Price		54.1%	38.2%	41.1%	22.1%	46.3%	41.40%
Consumption 1990 MM IG		38.06	2.21	83.82	24.56	4.64	153.29
Tax Revenues MM kyat		460.5	13.4	493.8	61.3	39.4	1068.23
Tax Revenues MM US$							
at k6.2/US$		74.3	2.2	79.7	9.9	6.35	172.41
at assumed FX rate		74.3	2.2	79.7	9.9	6.35	172.41
at k50/US$		9.21	0.27	9.88	1.23	0.79	21.36
COST AND TAXES ON TRUE COST-PLUS BASIS							
Costs (k/IG)		10.26	9.79	8.44	8.81	9.83	9.01
Commodity Tax		10.98	5.26	5.17	1.93	7.57	6.17
Sales Tax on cost-plus price		1.12	0.79	0.72	0.57	0.92	0.80
Total Price on Cost-Plus Basis		22.36	15.84	14.33	11.30	18.32	15.98

The refinery cost allocations are as given by MPE to MOE in late 1990
In refinery operation the Profit margin is 5% of factory cost ,
and commodity tax is calculated on factory cost ex margin
In distribution the 2% margin is on handover price plus dist costs
witnout taxes. The sales tax is 5% times the cost-plus consumer price

ANNEX 7.2 (c)

PETROLEUM PRODUCT PRICES

MAIN ASSUMPTIONS

International Crude Price	25.00	US$/B	at	50.00 k/US$
MOGE handover Price Crude	1250	k/B		

Crude oil price increased to US$25/B, and fuel oil commodity tax decreased to 30% as at early 1991 and shadow exchange rate of k50/US$

ILLUSTRATION OF COST-PLUS PRICES, ON BASIS OF US$25/B CRUDE AND EXCHANGE RATE OF k50/US$, AS AT EARLY 1991

PETROLEUM PRODUCT PRICING (k/IG)

		Petrol	Kero	Diesel	Fuel Oil	Av Fuel	TOTALS/ AVGES.
Ex MOGE(crude)		35.74	35.74	35.74	35.74	35.74	35.74
Cost of Refining		2.03	2.15	1.32	2.00	2.15	1.64
Factory cost		37.77	37 89	37.06	37.74	37.89	37.38
Profit Marg	5.0%	1.89	1.89	1.85	1.89	1.89	1.87
ex ref cost without taxes		39.66	39.79	38.92	39.63	39.79	39.25
Commodity Tax Rate		170%	80%	90%	30%	115%	101%
Commodity Tax		64.21	30.31	33.36	11.32	43.58	37.75
Total Cost ex refinery		103.87	70.10	72.27	50.95	83.36	77.01
Distribution Costs		3.06	2.58	2.14	1.85	2.58	2.34
Profit Marg	2.0%	2.14	1.45	1.49	1.06	1.72	1.59
Sales Tax o	5.0%	5.74	3.90	3.99	2.83	4.61	4.26
Total Cost ex distrib		114.82	78.04	79.89	56.69	92.28	85.19
All Taxes		69.95	34.22	37.35	14.16	48.19	42.01
Tax as % Cons Price		60.9%	43.8%	46.8%	25.0%	52.2%	46.91%
Consumption 1990 MM IG		38.06	2.21	83.82	24.56	4.64	153.29
Tax Revenues MM kyat		2662.4	75.6	3130.7	347.7	223.6	6440.08
Tax Revenues MM US$							
at k6.2/US$		429.7	12.2	505.3	56.1	36.1	1039.39
at assumed FX rate		53.2	1.5	62.6	7.0	4.5	128.80
at k50/US$		53.25	1.51	62.61	6.95	4.47	128.80
COST AND TAXES ON TRUE COST-PLUS BASIS							
Costs (k/IG)		44.86	43.82	42.54	42.53	44.09	43.18
Commodity Tax		64.21	30.31	33.36	11.32	43.58	37.75
Sales Tax on cost-plus price		5.74	3.90	3.99	2.83	4.61	4.26
Total Price on Cost-Plus Basis		114.82	78.04	79.89	56.69	92.28	85.19

The refinery cost allocations are as given by MPE to MOE in late 1990
In refinery operation the Profit margin is 5% of factory cost ,
and commodity tax is calculated on factory cost ex margin
In distribution the 2% margin is on handover price plus dist costs
without taxes. The sales tax is 5% times the cost-plus consumer price

ANNEX 7.2 (d)

PETROLEUM PRODUCT PRICES

MAIN ASSUMPTIONS

International Crude Price	25.00	US$/B	at	50.00 k/US$
MOGE handover Price Crude	1250	k/B		

Crude oil price increased to US$25/B,
and shadow exchange rate of k50/US$; with decreases in all commodity tax rates

ILLUSTRATION OF COST-PLUS PRICES, ON BASIS OF US$25/B CRUDE
EXCHANGE RATE OF k50/US$, AND COMMODITY TAX REDUCTIONS, AS AT EARLY 1991
PETROLEUM PRODUCT PRICING (k/IG)

		Petrol	Kero	Diesel	Fuel Oil	Av Fuel	TOTALS/ AVGES.
Ex MOGE(crude)		35.74	35.74	35.74	35.74	35.74	35.74
Cost of Refining		2.03	2.15	1.32	2.00	2.15	1.64
Factory cost		37.77	37.89	37.06	37.74	37.89	37.38
Profit Margin	5.0%	1.89	1.89	1.85	1.89	1.89	1.87
ex ref cost without taxes		39.66	39.79	38.92	39.63	39.79	39.25
Commodity Tax Rate		100%	55%	60%	25%	70%	65%
Commodity Tax		37.77	20.84	22.24	9.44	26.52	24.15
Total Cost ex refinery		77.43	60.63	61.15	49.06	66.31	63.41
Distribution Costs		3.06	2.58	2.14	1.85	2.58	2.34
Profit Margin	2.0%	1.61	1.26	1.27	1.02	1.38	1.31
Sales Tax on cost-plus price	5.0%	4.32	3.39	3.40	2.73	3.70	3.53
Total Cost ex distrib		86.43	67.87	67.95	54.66	73.97	70.59
All Taxes		42.09	24.23	25.63	12.17	30.22	27.68
Tax as % Cons Price		48.7%	35.7%	37.7%	22.3%	40.9%	38.04%
Consumption 1990 MM IG		38.06	2.21	83.82	24.56	4.64	153.29
Tax Revenues MM kyat		1602.1	53.6	2148.7	298.9	140.2	4243.47
Tax Revenues MM US$							
at k6.2/US$		258.6	8.6	346.8	48.2	22.6	684.87
at assumed FX rate		32.0	1.1	43.0	6.0	2.8	84.87
at k50/US$		32.04	1.07	42.97	5.98	2.80	84.87
COST AND TAXES ON TRUE COST-PLUS BASIS							
Costs (k/IG)		44.34	43.64	42.32	42.50	43.75	42.91
Commodity Tax		37.77	20.84	22.24	9.44	26.52	24.15
Sales Tax on cost-plus price		4.32	3.39	3.40	2.73	3.70	3.53
Total Price on Cost-Plus Basis		86.43	67.87	67.95	54.66	73.97	70.59

The refinery cost allocations are as given by MPE to MOE in late 1990
In refinery operation the Profit margin is 5% of factory cost ,
and commodity tax is calculated on factory cost ex margin
In distribution the 2% margin is on handover price plus dist costs
without taxes. The sales tax is 5% times the cost-plus consumer price

ANNEX 7.3 (a)

BASE CASE - HIGH DEMAND AT OFFICIAL EXCHANGE RATE

MEPE: Income Sistement BASE CASE (High demand)

FY	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	@ 1990	@ 1991	@ 1992	@ 1993	@ 1994
Gwh Generated net	956.7	1060.0	1205.7	1370.4	1526.9	1646.6	1863.1	2082.3	2207.6	2281.1	2193.3	2371	2552	2717.8	2895.7	3086.7
Gwh Sold	690.1	762.6	853.5	949.6	1050.0	1121.5	1263.6	1458.3	1543.0	1580.0	1428.2	1636.0	1760.9	1902.5	2055.9	2222.4
Sold/generated %	72.1%	71.9%	70.8%	69.3%	68.8%	68.1%	67.8%	70.0%	69.9%	69.3%	65.1%	69.0%	69.0%	70.0%	71.0%	72.0%
Increase in sale %		10.5%	11.9%	11.3%	10.6%	6.8%	12.7%	15.4%	5.8%	2.4%	-9.6%	14.5%	7.6%	8.0%	8.1%	8.1%
Av. Pyas/kwh sold *	24.85	25.01	25.17	27.82	29.83	30.13	30.00	27.25	27.49	28.02	37.25	48.73	48.73	48.73	48.73	48.73
—Kyats million—																
Operating revenue	171.5	190.7	214.8	264.2	313.3	337.9	379.2	397.4	424.3	442.8	532.0	797.2	858.1	927.1	1001.9	1083.0
Operating expenses																
Salaries & wages	30.1	30.5	30.6	44.5	44.7	46.7	47.0	49.5	51.1	56.7	58.2	131.8	133.5	133.5	133.5	133.5
Maintenance	31.2	34.7	36.1	34.2	41.9	43.1	37.5	38.5	49.5	46.7	44.8	62.7	63.1	63.1	63.1	63.1
Fuel #	35.5	34.3	50.3	49.0	54.0	65.9	75.7	76.3	80.8	103.8	163.7	234.5	301.1	362.5	314.0	312.9
Power purchases	1.2	2.3	0.9	1.4	2.7	3.6	4.2	4.5	3.9	1.2	1.3	1.8	1.9	1.9	1.9	1.9
Depreciation	25.7	27.8	31.1	36.8	41.4	48.7	60.3	89.9	116.0	131.4	144.7	144.5	151.7	158.3	186.7	224.1
Commodity/serv Tax	7.0	7.8	8.7	11.1	13.1	14.3	15.9	14.4	15.6	17.2	23.5	31.2	33.5	35.7	38.1	40.6
Total expenses	130.7	137.4	157.7	176.9	197.9	222.2	240.6	273.1	316.9	357.0	436.2	606.5	684.9	755.1	737.3	776.1
Net operatg income	40.7	53.3	57.1	87.3	115.4	115.7	138.6	124.3	107.3	85.8	95.8	190.7	173.1	171.9	264.5	306.9
Other income	3.3	2.6	2.9	6.3	4.9	4.4	4.7	5.8	8.9	38.3	12.1	14.7	16.2	16.2	16.2	16.2
Interest charged	7.2	7.5	14.8	20.6	38.8	52.3	60.6	112.2	112.4	125.2	148.6	43.2	50.8	72.9	153.3	315.4
Net Profit/Loss	36.9	48.4	45.2	73.0	81.5	67.8	82.8	18.0	3.9	(1.1)	(40.7)	162.2	138.5	115	127	8
State Contribution	7.4	14.5	13.6	21.9	24.4	20.3	24.8	5.4	1.2	0.0	0.0	162.2	138.5	115	127	8
Net surplus (Deficit)	29.5	33.9	31.6	51.1	57.0	47.4	57.9	12.6	2.7	(1.1)	(40.7)	0.0	0.0	0	0	0
Rate of Return on Av. net FA in Oper																
Book values ed assets		10.8%	10.1%	13:9%	15.9%	13.1%	14.7%	10.9%	6.9%	4.3%	4.5%	8.5%	5.9%	5.1%	7.7%	8.5%

@ Mission estimates- MEPE accounts for FY 90 not ready in Nov 90.

Fuel costs are high in FY 92, 93 & 94 due to shortfall in gas being made good by diesel oil.

Assumed exchange rate k6.2/US$

ANNEX 7.3 (a) (cont'd)

BASE CASE - HIGH DEMAND AT OFFICIAL EXCHANGE RATE
FUEL USE IN BASE CASE (High demand)

	1990	1991	1992	1993	1994	1995
Gas use bcf	19.99	19.65	20.09	17.80	15.35	19.67
Fuel Oil Use mmb	0.00	0.00	0.40	0.30	0.30	0.10
Diesel Use mmb	0.44	0.78	0.74	0.64	0.70	0.28
Price of gas k/mcf	7.50	7.50	7.50	7.50	7.50	7.50
Price of Fuel Oil US$/b	24.00	24.57	25.16	25.76	26.38	27.03
Price of diesel US$/b	31.00	31.78	32.58	33.41	34.26	35.14
Value of gas mill kyat	149.93	147.38	150.68	133.50	115.13	147.53
Value of Fuel Oil mill kyat	0.00	0.00	62.40	47.91	49.07	16.76
Value of diesel mill kyat	84.57	153.69	149.48	132.57	148.69	61.00
TOTAL FUEL BILL (mill kyat)	234.49	301.06	362.55	313.98	312.88	225.29

Notes: kyat converted at k6.2/US$
Fuel use from WASP analysis

ANNEX 7.3 (b)
LOW DEMAND AT OFFICIAL EXCHANGE RATE

MEPE: Income Statement LOW DEMAND CASE

FY	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	@ 1990	@ 1991	@ 1992	@ 1993	@ 1994
Gwh Generated net	956.7	1060.0	1205.7	1370.4	1526.9	1646.6	1863.1	2082.3	2207.6	2281.1	2193.3	2371	2484.1	2589.1	2699.4	2815.3
Gwh Sold	690.1	762.6	853.5	949.6	1050.0	1121.5	1263.6	1458.3	1543.0	1580.0	1428.2	1636.0	1714.0	1812.4	1916.6	2027.0
Sold/generated %	72.1%	71.9%	70.8%	69.3%	68.8%	68.1%	67.8%	70.0%	69.9%	69.3%	65.1%	69.0%	69.0%	70.0%	71.0%	72.0%
Increase in sale %		10.5%	11.9%	11.3%	10.6%	6.8%	12.7%	15.4%	5.8%	2.4%	-9.6%	14.5%	4.8%	5.7%	5.7%	5.8%
Av. Pyas/kwh sold *	24.85	25.01	25.17	27.82	29.83	30.13	30.00	27.25	27.49	28.02	37.25	48.73	48.73	48.73	48.73	48.73
---Kyats million--																
Operating revenue	171.5	190.7	214.8	264.2	313.3	337.9	379.2	397.4	424.3	442.8	532.0	797.2	835.2	883.2	933.9	987.8
Operating expenses																
Salaries & wages	30.1	30.5	30.6	44.5	44.7	46.7	47.0	49.5	51.1	56.7	58.2	131.8	133.5	133.5	133.5	133.5
Maintenance	31.2	34.7	36.1	34.2	41.9	43.1	37.5	38.5	49.5	46.7	44.8	62.7	63.1	63.1	63.1	63.1
Fuel #	35.5	34.3	50.3	49.0	54.0	65.9	75.7	76.3	80.8	103.8	163.7	234.5	301.1	362.5	314.0	312.9
Power purchases	1.2	2.3	0.9	1.4	2.7	3.6	4.2	4.5	3.9	1.2	1.3	1.8	1.9	1.9	1.9	1.9
Depreciation	25.7	27.8	31.1	36.8	41.4	48.7	60.3	89.9	116.0	131.4	144.7	144.5	151.7	158.3	186.7	224.1
Commodity/serv Tax	7.0	7.8	8.7	11.1	13.1	14.3	15.9	14.4	15.6	17.2	23.5	31.2	32.7	34.0	35.5	37.0
Total expenses	130.7	137.4	157.7	176.9	197.9	222.2	240.6	273.1	316.9	357.0	436.2	606.5	684.0	753.5	734.7	772.5
Net operatg income	40.7	53.3	57.1	87.3	115.4	115.7	138.6	124.3	107.3	85.8	95.8	190.7	151.2	129.7	199.2	215.2
Other income	3.3	2.6	2.9	6.3	4.9	4.4	4.7	5.8	8.9	38.3	12.1	14.7	16.2	16.2	16.2	16.2
Interest charged	7.2	7.5	14.8	20.6	38.8	52.3	60.6	112.2	112.4	125.2	148.6	43.2	50.8	72.9	153.3	315.4
Net Profit/Loss	36.9	48.4	45.2	73.0	81.5	67.8	82.8	18.0	3.9	(1.1)	(40.7)	162.2	116.5	73	62	-84
State Contribution	7.4	14.5	13.6	21.9	24.4	20.3	24.8	5.4	1.2	0.0	0.0	162.2	116.5	73	62	0
Net surplus (Deficit)	29.5	33.9	31.6	51.1	57.0	47.4	57.9	12.6	2.7	(1.1)	(40.7)	0.0	0.0	0	0	-84
Rate of Return on Av. net FA in Oper																
Book values ed assets		10.8%	10.1%	13.9%	15.9%	13.1%	14.7%	10.9%	6.9%	4.3%	4.5%	8.5%	5.2%	3.7%	5.1%	4.5%

@ Mission estimates- MEPE accounts for FY 90 not ready in Nov 90.

Fuel costs are high in FY 92, 93 & 94 due to shortfall in gas being made good by diesel oil.

Assumed exchange rate 6.2 k/US$

ANNEX 7.3 (c)
BASE CASE - HIGH DEMAND AT SHADOW EXCHANGE RATE

MEPE: Income Statement BASE CASE (High demand)

FY	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	@ 1990	@ 1991	@ 1992	@ 1993	@ 1994
Gwh Generated net	956.7	1060.0	1205.7	1370.4	1526.9	1646.6	1863.1	2082.3	2207.6	2281.1	2193.3	2371	2552	2717.8	2895.7	3086.7
Gwh Sold	690.1	762.6	853.5	949.6	1050.0	1121.5	1263.6	1458.3	1543.0	1580.0	1428.2	1636.0	1760.9	1902.5	2055.9	2222.4
Sold/generated %	72.1%	71.9%	70.8%	69.3%	68.8%	68.1%	67.8%	70.0%	69.9%	69.3%	65.1%	69.0%	69.0%	70.0%	71.0%	72.0%
Increase in sale %		10.5%	11.9%	11.3%	10.6%	6.8%	12.7%	15.4%	5.8%	2.4%	-9.6%	14.5%	7.6%	8.0%	8.1%	8.1%
Av. Pyas/kwh sold *	24.85	25.01	25.17	27.82	29.83	30.13	30.00	27.25	27.49	28.02	37.25	75.34	102.53	121.36	104.55	111.25
---Kyats million---																
Operating revenue	171.5	190.7	214.8	264.2	313.3	337.9	379.2	397.4	424.3	442.8	532.0	1232.5	1805.3	2308.8	2149.5	2472.4
Operating expenses																
Salaries & wages	30.1	30.5	30.6	44.5	44.7	46.7	47.0	49.5	51.1	56.7	58.2	131.8	133.5	133.5	133.5	133.5
Maintenance	31.2	34.7	36.1	34.2	41.9	43.1	37.5	38.5	49.5	46.7	44.8	62.7	63.1	63.1	63.1	63.1
Fuel #	35.5	34.3	50.3	49.0	54.0	65.9	75.7	76.3	80.8	103.8	163.7	831.9	1386.8	1859.3	1589.0	1709.9
Power purchases	1.2	2.3	0.9	1.4	2.7	3.6	4.2	4.5	3.9	1.2	1.3	1.8	1.9	1.9	1.9	1.9
Depreciation	25.7	27.8	31.1	36.8	41.4	48.7	60.3	89.9	116.0	131.4	144.7	144.5	151.7	158.3	186.7	224.1
Commodity/serv Tax	7.0	7.8	8.7	11.1	13.1	14.3	15.9	14.4	15.6	17.2	23.5	31.2	33.5	35.7	38.1	40.6
Total expenses	130.7	137.4	157.7	176.9	197.9	222.2	240.6	273.1	316.9	357.0	436.2	1204.0	1770.7	2251.9	2012.4	2173.2
Net operatg income	40.7	53.3	57.1	87.3	115.4	115.7	138.6	124.3	107.3	85.8	95.8	28.5	34.7	56.9	137.1	299.3
Other income	3.3	2.6	2.9	6.3	4.9	4.4	4.7	5.8	8.9	38.3	12.1	14.7	16.2	16.2	16.2	16.2
Interest charged	7.2	7.5	14.8	20.6	38.8	52.3	60.6	112.2	112.4	125.2	148.6	43.2	50.8	72.9	153.3	315.4
Net Profit/Loss	36.9	48.4	45.2	73.0	81.5	67.8	82.8	18.0	3.9	(1.1)	(40.7)	0.0	0.0	0	0	0
State Contribution	7.4	14.5	13.6	21.9	24.4	20.3	24.8	5.4	1.2	0.0	0.0	0.0	0.0	0	0	0
Net surplus (Deficit)	29.5	33.9	31.6	51.1	57.0	47.4	57.9	12.6	2.7	(1.1)	(40.7)	0.0	0.0	0	0	0
Rate of Return on Av. net FA in Oper																
Book values ed assets		10.8%	10.1%	13.9%	15.9%	13.1%	14.7%	10.9%	6.9%	4.3%	4.5%	1.3%	1.2%	1.7%	4.0%	8.3%

@ Mission estimates- MEPE accounts for FY 90 not ready in Nov 90.

Fuel costs are high in FY 92, 93 & 94 due to shortfall in gas being made good by diesel oil.

Assumed exchange rate k50/US$

ANNEX 7.3 (c) (cont'd)

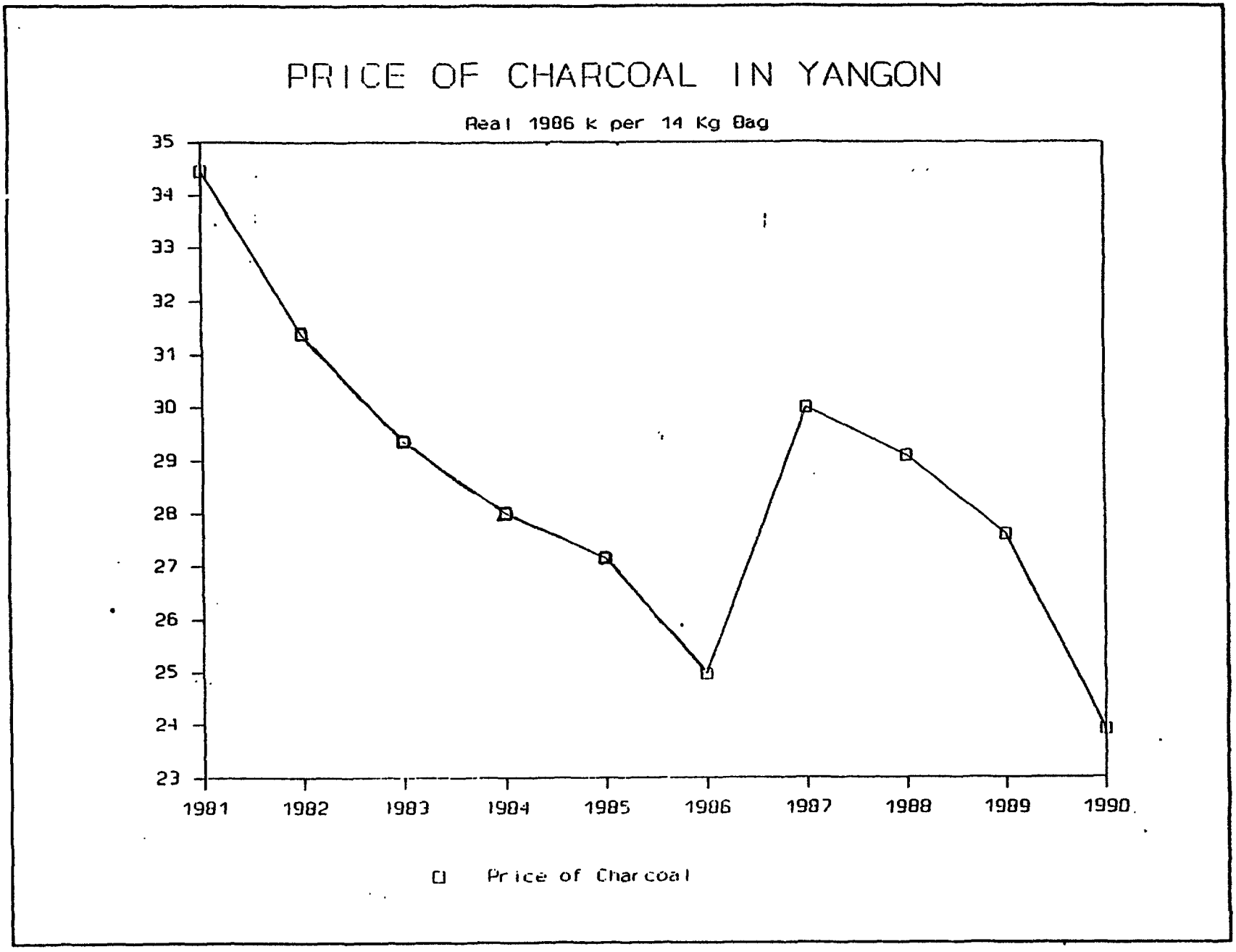
BASE CASE - HIGH DEMAND AT SHADOW EXCHANGE RATE

FUEL USE IN BASE CASE (High demand)

	1990	1991	1992	1993	1994	1995
Gas use bcf	19.99	19.65	20.09	17.80	15.35	19.67
Fuel Oil Use mmb	0.00	0.00	0.40	0.30	0.30	0.10
Diesel Use mmb	0.44	0.78	0.74	0.64	0.70	0.28
Price of gas k/mcf	7.50	7.50	7.50	7.50	7.50	7.50
Price of Fuel Oil US$/b	24.00	24.57	25.16	25.76	26.38	27.03
Price of diesel US$/b	31.00	31.78	32.58	33.41	34.26	35.14
Value of gas mill kyat	149.93	147.38	150.68	133.50	115.13	147.53
Value of Fuel Oil mill kyat	0.00	0.00	503.20	386.40	395.70	135.15
Value of diesel mill kyat	682.00	1239.42	1205.46	1069.12	1199.10	491.96
TOTAL FUEL BILL (mill kyat)	831.93	1386.80	1859.34	1589.02	1709.93	774.64

Notes: kyat converted at 50.00 k/US$

Fuel use from WASP analysis


PRICE OF CHARCOAL IN YANGON
Real 1986 k per 14 Kg Bag
35
34
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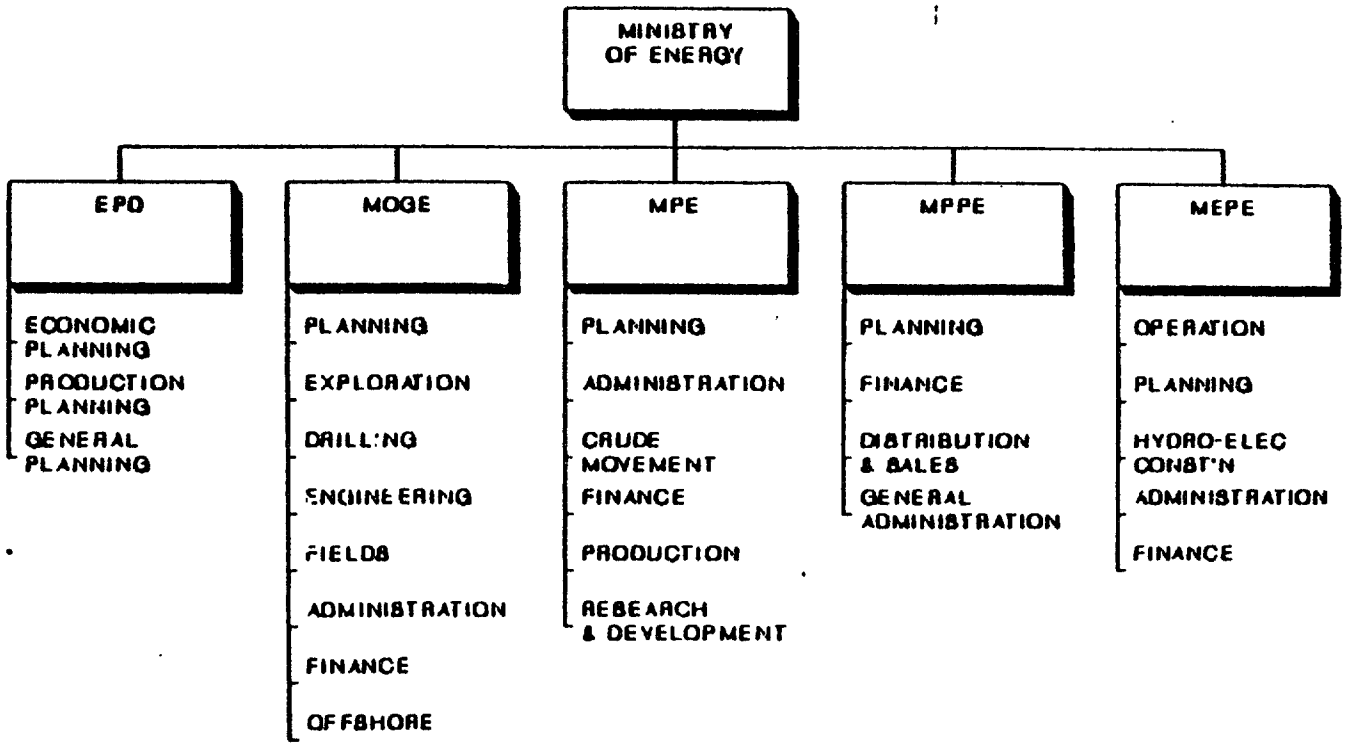
1990
Price of Charcoal



Note: EPD - Energy Planning Department

MOGE - Myanmar Oil and Gas Enterprise

MPE - Myanmar Petrochemical Enterprise

MPPE - Myanmar Petroleum Products Enterprise

EPC - Myanmar Electric Power Enterprise

ANNEX 8.2

Myanmar Oil and Gas Enterprise

Income Statement: 1991 terms

FY	1986	1987	1988	1989	1990	@ 1991	@ 1992	@ 1993	@ 1994	@ 1995
	Actual					Estimate				
Crude oil- Quantity MM	7.01	6.00	5.13	3.87	4.82	4.89	4.24	6.13	7.34	9.96
Nat Gas - Quantity BCF	30.89	35.86	38.11	36.02	36.89	33.30	27.90	23.50	23.70	23.60
					5.71	5.69	4.92	6.70	7.91	10.53
Price/crude/bbl/kyats av. @	42.78	42.73	42.69	74.34	110.00	110.00	136.28	166.47	170.56	174.78
Price/gas/MCF/kyats av. @	1.92	1.94	2.90	5.04	7.50	7.50	11.50	15.50	15.50	15.50
INCOME Kyats million										
Sale of crude oil	299.84	256.26	218.98	287.51	529.74	538.12	578.37	1021.13	1251.91	1740.63
Sale of nat. gas	59.41	69.56	110.61	181.46	276.71	249.75	320.85	364.25	367.35	365.80
Other income @@	14.73	18.98	27.71	23.07	307.76	78.53	69.87	69.87	69.87	69.87
Total Revenue	373.98	344.79	357.30	492.04	1114.21	866.40	969.09	1455.25	1689.13	2176.30
EXPENSES Kyats million										
Salary & wages	84.20	86.22	85.99	83.93	130.17	130.17	130.17	136.98	145.27	163.18
Materials	130.06	91.40	56.45	45.57	71.43	71.43	71.43	75.17	79.72	89.54
Schlumberger charges	72.13	48.55	38.02	38.32	37.24	37.24	37.24	39.19	41.56	46.68
Repairs/ maintain	17.04	15.35	15.86	15.74	20.7	20.70	20.70	21.78	23.10	25.95
POL	17.20	18.06	16.02	23.08	36.79	36.79	36.79	38.72	41.06	46.12
Depreciation	134.11	133.45	124.31	112.00	112.25	129.47	165.63	211.32	269.06	315.55
Royalty & Taxes	6.13	5.24	4.69	3.66	5.01	5.09	4.42	6.38	7.64	10.36
Administration	17.55	17.03	19.33	21.02	30.73	30.73	30.73	31.53	32.51	34.63
Experimental	0.53	2.21	2.47	3.78	3.64	3.64	3.64	3.74	3.85	4.10
others	51.89	52.80	58.72	30.42	79.79	68.80	63.39	63.39	63.39	63.39
Total Optg. expenses	530.84	470.31	421.86	377.52	527.75	534.06	564.13	628.20	707.16	799.50
Successful well costs deferred #	(88.87)	(45.88)	26.36	38.89	(41.98)	(41.96)	(40.24)	(41.98)	(41.98)	(41.98)
Incomplete well cost ++	14.36	a:	5.41	14.83						
Net Optg. expenses	427.61	424.43	442.81	401.58	485.77	492.10	523.89	586.22	665.18	757.52
Financial Cost										
Foreign loan interest	12.15	15.12	15.15	26.39	27.39	41.08	65.75	117.56	183.03	265.76
Local Bank interest	141.05	156.64	167.05	174.75						
Other non-optg cost	3.52	23.56	5.69	44.44	85.50	44.44	85.50	44.44	85.50	44.44
Total Cost	584.33	619.75	630.70	647.16	598.66	577.62	675.14	748.21	933.70	1,067.73
Net Profit	(210.35)	(274.96)	(273.40)	(155.12)	515.55	288.78	293.95	707.03	755.43	1,108.58

(Continued)

ANNEX 8.2

Less Income Tax applicable from FY 91					0.00	86.63	88.19	212.11	226.63	332.57
Contibution to State **	0.00	0.00	0.00	0.00	515.55	202.15	205.77	494.92	528.80	776.00
Net profit after State Take	(210.35)	(274.96)	(273.40)	(155.12)	0.00	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)

@ Prices are assumed at border parity for crude oil from October 1991; for gas at "economic" price.

@@ Other income in FY 90 represents mostly signature bonus from 10 foreign oil companies. This is strictly not an income relevant to operations of the year. Other income from FY91 is mostly for services to foreign oil companies offset by other expenditure.

If a well is successful, the cost of the well is deducted and then written off in 10 years. The net of the year's successful well costs and write offs (10%) of all successful wells is shown here.

++ Cost is deducted pending determination if successful or not.

** The net profit is contributed to the State from FY 90; from Fy 91 a 30% tax is the first charge.

ANNEX 8.2

MEPE: Income Statement

FY	1986	1987	1988	1989	@ 1990	@ 1991	@ 1992	@ 1993	@ 1994	@ 1995
	Actual				Estimate					
Gwh Generated net	2082.3	2207.6	2281.1	2193.3	2371.0	2552.0	2717.8	2895.7	3086.7	3247.0
Gwh Sold	1458.3	1543.0	1580.0	1428.2	1636.0	1760.9	1902.5	2056.0	2222.4	2403.0
Sold/generated %	70.0%	69.9%	69.3%	65.1%	69.0%	69.0%	70.0%	71.0%	72.0%	74.0%
Increase in sale %	15.4%	5.8%	2.4%	-9.6%	14.5%	7.6%	8.0%	8.1%	8.1%	8.1%
Av. Pyas/kwh sold *	27.25	27.49	28.02	37.25	48.73	48.73	53.60	68.22	68.22	68.22
---Kyats million---										
Operating revenue	397.4	424.3	442.8	532.0	786.3	858.1	1019.8	1402.6	1516.1	1639.3
Operating expenses										
Salaries & wages	49.5	51.1	56.7	58.2	131.8	133.5	133.5	133.5	133.5	133.5
Maintenance	38.5	49.5	46.7	44.8	62.7	63.1	63.1	63.1	63.1	63.1
Fuel #	76.3	80.8	103.8	163.7	272.8	434.0	536.5	571.2	555.6	427.1
Power purchases	4.5	3.9	1.2	1.3	1.8	1.9	1.9	1.9	1.9	1.9
Depreciation	89.9	116.0	131.4	144.7	180.9	230.9	290.9	360.9	440.9	540.9
Commodity/serv Tax	14.4	15.6	17.2	23.5	31.2	34.3	40.8	56.1	60.6	65.6
Total expenses	273.1	316.9	357.0	436.2	681.2	897.8	1066.7	1186.7	1255.7	1232.2
Net operating income	124.3	107.3	85.8	95.8	105.0	(39.7)	(47.0)	215.8	260.4	407.1
Other income	5.8	8.9	38.3	12.1	14.7	16.2	16.2	16.2	16.2	16.2
Interest charged	112.2	112.4	125.2	148.6	42.7	77.8	119.8	168.8	224.8	294.8
Net Profit/Loss	18.0	3.9	(1.1)	(40.7)	77.0	(101.3)	(150.6)	63.3	51.9	128.6
State Contribution	5.4	1.2	0.0	0.0	77.0	0.0	0.0	63.3	51.9	128.6
Net surplus (Deficit)	12.6	2.7	(1.1)	(40.7)	0.0	(101.3)	(150.5)	0.0	0.0	0.0

* Tariff increase are required as indicated, namely by 40% from October 1991.
An accounting break even position will then result in the five years FY 91-95.

@ Mission estimates- MEPE accounts for FY 90 not ready in Nov 90.

Fuel costs are high in FY 92-95 due to shortfall in gas being made good by diesel oil.
New prices for gas and fuel products as recommended in the EPIR Report are assumed to come into effect from October 91.
It is important to note that diesel & fuel oil supplied to MEPE to substitute for gas in FY92-95
are presumed to be taxes exempt, so that the prices are not unduly high compared to that of gas.

Price of crude /bbbl		110	136.3	166.5	170.6	174.8
Gas use	bcf	19.7	20.1	17.8	15.4	19.7
Fuel oil	mmb	0.0	0.4	0.3	0.3	0.1
Diesel	mmb	0.8	0.7	0.6	0.7	0.3
Price of gas k/mcf		7.5	11.5	15.5	15.5	15.5
Price of fuel oil k/bbl		297.5	334.8	372.1	376.3	380.8
Price of Diesel k/bbl		367.5	459.6	551.6	555.9	560.3
Fuel bill with taxes		434.0	705.0	740.5	740.0	499.9
Fuel bill w/o tax (applied from FY 92)		319.4	536.5	571.2	555.6	427.1

ANNEX 8.2

MPE: Refineries- Income Statement Kyats MM

FY	1988	1989	1990	1991	1992	1993	1994	1995
	---------Actual---------			----------Estimate----------				
Crude oil refined								
Barrels million	5.11	4.47	4.78	4.89	4.24	6.13	7.34	9.96
Sales	530.58	918.76	1546.75	1583.68	1603.46	2349.17	2774.49	3685.08
Cost of goods	439.01	543.31	906.20	873.88	912.51	1360.00	1593.80	2089.07
Unit cost/price/bbl/kts								
crude+prodn cost	85.85	121.53	189.66	178.64	215.01	221.71	217.14	209.77
crude oil only	42.66	62.39	110.00	110.00	136.28	166.47	170.56	174.78
refining only	43.19	59.14	79.65	68.64	78.73	55.24	46.58	34.99
products sold	103.76	205.52	323.73	323.73	377.82	382.97	378.00	370.02
Gross profit/loss	91.57	375.45	640.56	709.79	690.95	989.17	1180.70	1596.01
Admin. expenses								
Administration	28.50	24.56	29.93	35.03	35.03	42.81	50.36	66.77
Selling & Distr.	3.03	10.75	11.76	13.77	13.77	16.83	19.80	26.24
R & D	0.37	0.19	0.35	0.41	0.41	0.50	0.59	0.78
Comm.& Serv. taxes	210.57	357.92	668.34	684.29	593.65	858.03	1026.72	1393.07
Profit/ Loss								
(5% of costs from FY 92)	(150.91)	(17.97)	(69.83)	(23.71)	48.09	71.01	83.23	109.14
Other Income	9.80	10.57	2.70	10.57	10.57	10.57	10.57	10.57
Interest	121.28	137.82	70.00	70.00	70.00	70.00	70.00	70.00
Net profit/ loss	(262.38)	(145.22)	(137.13)	(83.14)	(11.34)	11.58	23.80	49.71
Optg. ratio	128%	102%	105%	101%	97%	97%	97%	97%
Refinery margin/bbl								
(before interest)	(29.51)	(4.02)	(14.61)	(4.85)	11.33	11.58	11.34	10.96

Foreign loans received by MPE

Lender	Loan Date	Loan Amoun	currency MM	Int rate	Grace No of Yrs	Repayment instalm	-Amount defaulted- Princip	Interest	- Beneficiary		Conversion 1 Fe= Kts
KFW FRG	31.3.79	64	DM	0.020	6	12 semi		4	Fertilizer	DM	3.63
KFW FRG	31.3.79	128	DM	0.008	6	12 semi		1	Fertilizer	AS	0.55
KFW FRG	31.3.79	33	DM	0.075	6	12 semi	8	3	Fertilizer	Yen	0.0486
IBA	1980	510	A.Sch	0.070	2	20 semi	59	42	Fertilizer		
KFW FRG	1982	25	DM	0.070	3	20 semi	3	1	Methanol		
MHI/Japan		6800	Yen	0.078	end 1984	16 semi	1700	179	LPG		
OECF		7960	Yen	0.025	end 1994			319	Refinery		
OECF		7100	Yen	0.025	end 1994			494	LPG		
OECF	1977	29950	Yen	0.030	7	37 semi	3237	619	Refinery		
Total in MM Kts		3708.26					310.50	135.47			
Total in $ MM		598.11					50.08	21.85			

ANNEX 8.2

MPPE: Income Statement

	FY	1988	1989	1990	1991	1992	1993	1994	1995
		Actual			Estimate				
Sales Qty	Index	105.2	80.4	100.0	125.2	134.0	151.2	153.6	208.3
Sales Income	Kyats MM	570.99	983.34	1897.21	2374.90	2473.91	2806.22	2805.75	3692.13
Cost of Goods		489.15	717.52	1345.66	1684.48	2104.09	2406.42	2412.75	3204.61
Freight & Handling		34.51	44.03	65.73	82.28	70.35	74.16	66.77	89.19
Service Tax		26.22	44.93	87.00	95.11	115.60	131.13	131.11	172.53
Gross Profit/ Loss		21.12	176.86	398.82	513.03	183.86	194.51	195.11	225.80
Administration		11.13	14.18	20.15	21.16	21.52	22.21	22.31	24.52
Distribution		54.76	66.80	108.72	114.19	116.11	119.84	120.36	132.28
Financial Expenses		0.00	1.65	0.00	0.00	0.00	0.00	0.00	0.00
Profit/ Loss (2% of costs from FY 92)		(44.77)	94.23	269.95	377.67	46.24	52.45	52.44	69.01
Contribution to State		0.00	29.26	269.95	377.67	46.24	52.45	52.44	69.01
Net Surplus/ (Deficit)		(44.77)	64.97	0.00	0.00	0.00	0.00	0.00	0.00

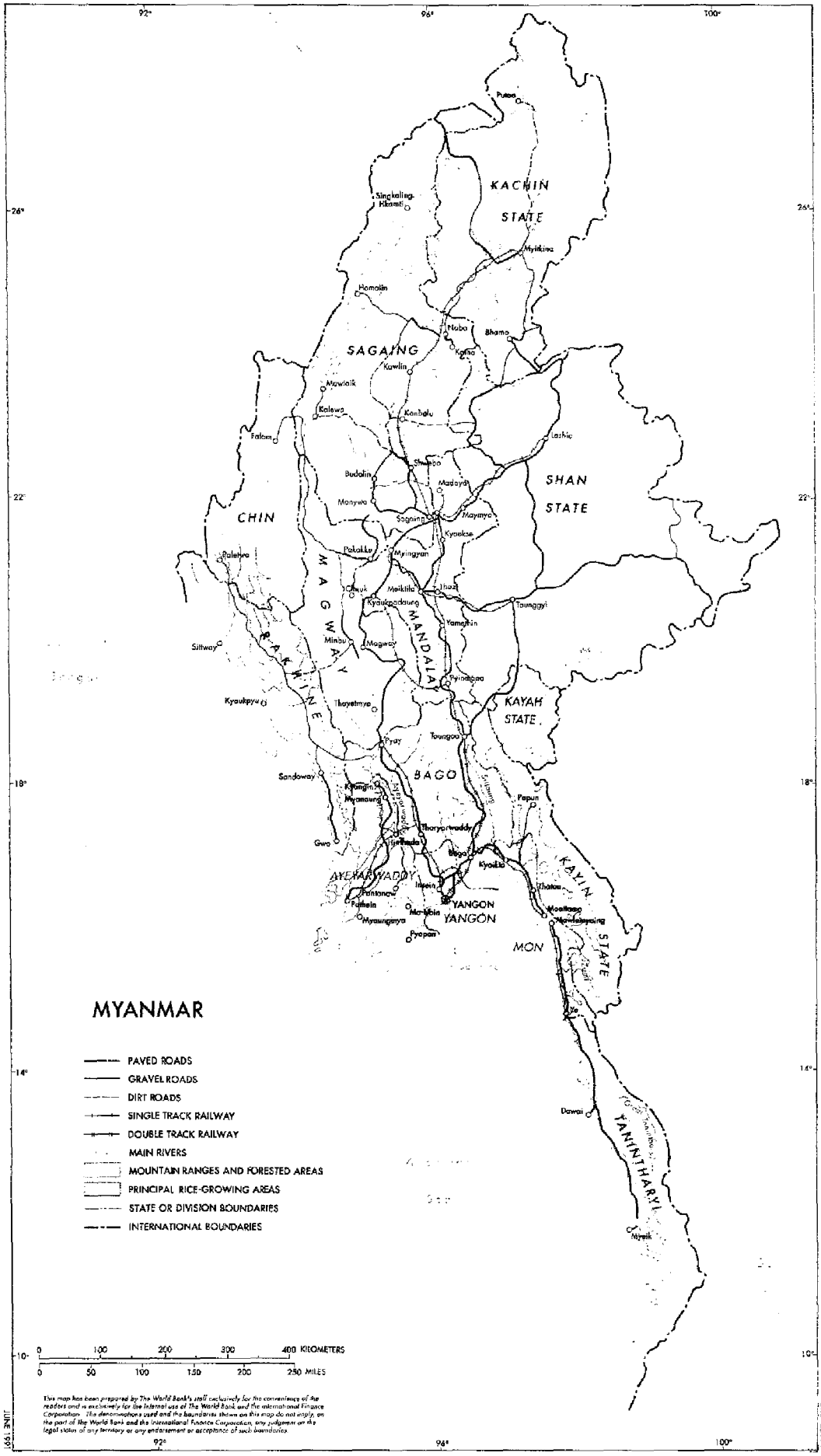
			Gasoline	Kerosene	Diesel	Fuel Oil	Total	
Product Mix	IG	FY 1988	49.26	5.94	72.01	34.08	161.29	
		FY 1989	34.28	4.76	66.23	17.92	123.19	
		FY 1990	38.06	6.85	83.82	24.56	153.29	
							191.88	
							205.37	35 imports)
							231.71	35 imports)
							235.38	35 imports)
							319.37	

MPE Unit Costs	FY	1988	1989	1990	1991	1992	1993	1994	1995
Unit cost/price/IG/kts									
crude+prodn cost		2.45	3.47	5.42	5.10	6.14	6.33	6.20	5.99
crude oil only		1.22	1.78	3.14	3.14	3.89	4.76	4.87	4.99
refining only		1.23	1.69	2.28	1.96	2.25	1.58	1.33	1.00
products sold		2.96	5.87	9.25	9.25	10.79	10.94	10.80	10.57
admin expenses		0.18	0.23	0.25	0.29	0.33	0.28	0.28	0.27
commodity tax average		1.18	2.29	4.00	4.00	4.00	4.00	4.00	4.00
commodity tax/costs %		44.7%	61.8%	70.5%	74.1%	61.7%	60.4%	61.7%	63.8%
commodity tax/sales %		39.7%	39.0%	43.2%	43.2%	37.0%	36.5%	37.0%	37.8%

ANNEX 8.3

Total Investments in the Energy Sector
($ million-1991 prices)

	1991-2000		1991-1995		1995-2000	
	Total	F.E	Total	F.E	Total	F.E
Coal Sector						
Exploration	5.00	4.00	5.00	4.00		
Feasibility study	1.00	1.00	1.00	1.00		
Total coal sector	6.00	5.00	6.00	5.00		
Oil and Gas Sector						
Rehabilitation/oil fields	119.00	71.40	119.00	71.40	0.00	0.00
Pndeveloped/proven/probable	579.00	329.40	399.00	239.40	150.00	90.00
Total oil fields	698.00	400.80	518.00	310.80	150.00	90.00
Possible res'vs (excluded) not included	575.00	273.00	288.00	172.80	167.00	100.20
Rehabilitation/Gas	71.00	42.60	71.00	42.60	0.00	0.00
Unproven Probable	86.50	51.90	66.50	39.90	20.00	12.00
Possible reserves(excluded)	86.50	51.90	66.50	39.90	20.00	12.00
Gas pipeline-Yangon-Moattama	173.00	125.00	173.00	125.00		
Total oil sector	1028.50	620.30	828.50	518.30	170.00	102.00
Possible reserves						
Refinery Investments						
Spare parts	6.00	6.00	6.00	6.00		
P/Chaulk/Thanlyn	4.00	3.00	4.00	3.00		
Rehab'n/ tug fleet	50.00	25.00	10.00	7.00	40.00	18.00
Modernization/distribution/comp	5.00	4.00	5.00	4.00		
Loss control/efficiency	25.00	18.00	5.00	4.00	20.00	14.00
Yangon depot	20.00	10.00	20.00	10.00		
Mann refinery	15.00	11.00			15.00	11.00
Rehabilitation/fertilizer plants	11.00	10.00	11.00	10.00		
Total Refinery sector	136.00	87.00	61.00	44.00	75.00	43.00
Power Sector Investments						
Rehabilitation	145.61	93.03	145.61	93.03		
Generation	450.50	324.30	255.70	188.10	194.80	136.40
Transmission projects	138.35	80.69	76.66	43.74	61.68	36.96
Distribution Projects	250.41	159.78	132.58	93.52	117.83	66.26
Total power sector	984.87	658.00	610.55	418.39	374.31	239.62
Traditional Energy Sector	51.47	12.87	25.74	6.43	25.74	6.43
TOTAL ENERGY SECTOR	2206.84	1383.17	1531.79	992.12	645.05	391.05



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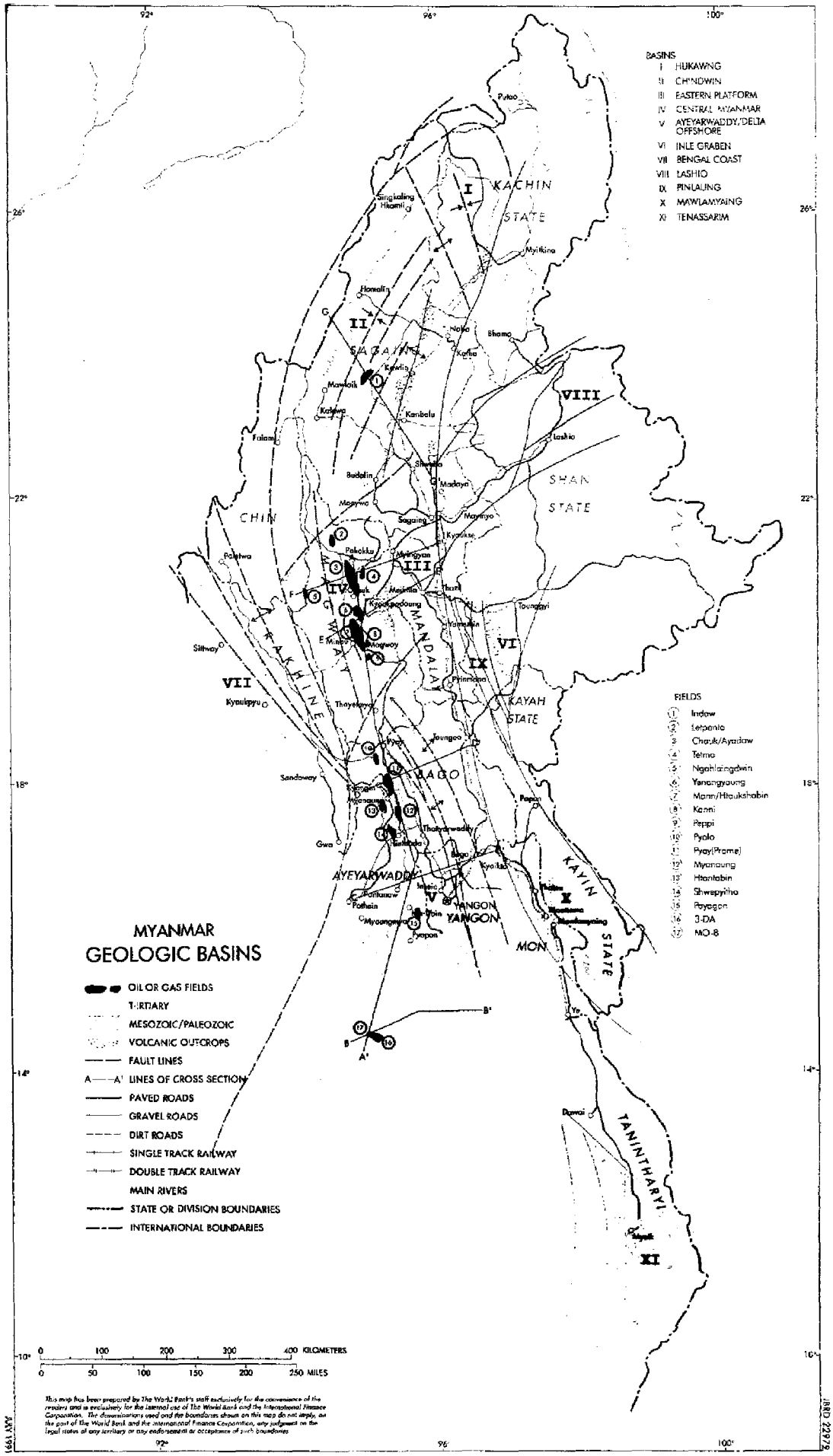

MYANMAR
GEOLOGIC BASINS
OIL OR GAS FIELDS
TERTIARY
MESOZOIC/PALEOZOIC
VOLCANIC OUTCROPS
FAULT LINES
A——A' LINES OF CROSS SECTION
PAVED ROADS
GRAVEL ROADS
DIRT ROADS
SINGLE TRACK RAILWAY
DOUBLE TRACK RAILWAY
MAIN RIVERS
STATE OR DIVISION BOUNDARIES
INTERNATIONAL BOUNDARIES
BASINS
I HUKAWNG
II CHINDWIN
III EASTERN PLATFORM
IV CENTRAL MYANMAR
V AYEYARWADDY/DELTA OFFSHORE
VI INLE GRABEN
VII BENGAL COAST
VIII LASHIO
IX PINLAUNG
X MAWLAMYAING
XI TENASSARIM
FIELDS
1 Indaw
2 Letpanto
3 Chauk/Ayadaw
4 Tetma
5 Ngahlaingdwin
6 Yenangyaung
7 Mann/Htaukshabin
8 Kanni
9 Peppi
10 Pyalo
11 Pyay(Prome)
12 Myanaung
13 Htantabin
14 Shwepyitha
15 Payagon
16 3-DA
17 MO-8
KACHIN STATE
SAGAING
SHAN STATE
CHIN
MANDALAY
KAYAH STATE
BAGO
AYEYARWADDY
YANGON
MON
KAYIN STATE
TANINTHARYI
Putao
Myitkina
Homalin
Bhamo
Kawlin
Mawlaik
Kalewa
Kanbalu
Falam
Lashio
Budalin
Madaya
Monywa
Sagaing
Maymyo
Kyaukse
Pakokku
Myingyan
Paletwa
Meiktila
Thazi
Toungoo
Yamethin
Minbu
Magwoy
Sittway
Kyaukpyu
Thayetmyo
Pyay
Sandoway
Papun
Thayarwaddy
Gwa
Bago
Kyaikto
Pantanaw
Pathein
Myaungmya
Pyapon
Ye
Dawei
Myeik
0 100 200 300 400 KILOMETERS
0 50 100 150 200 250 MILES
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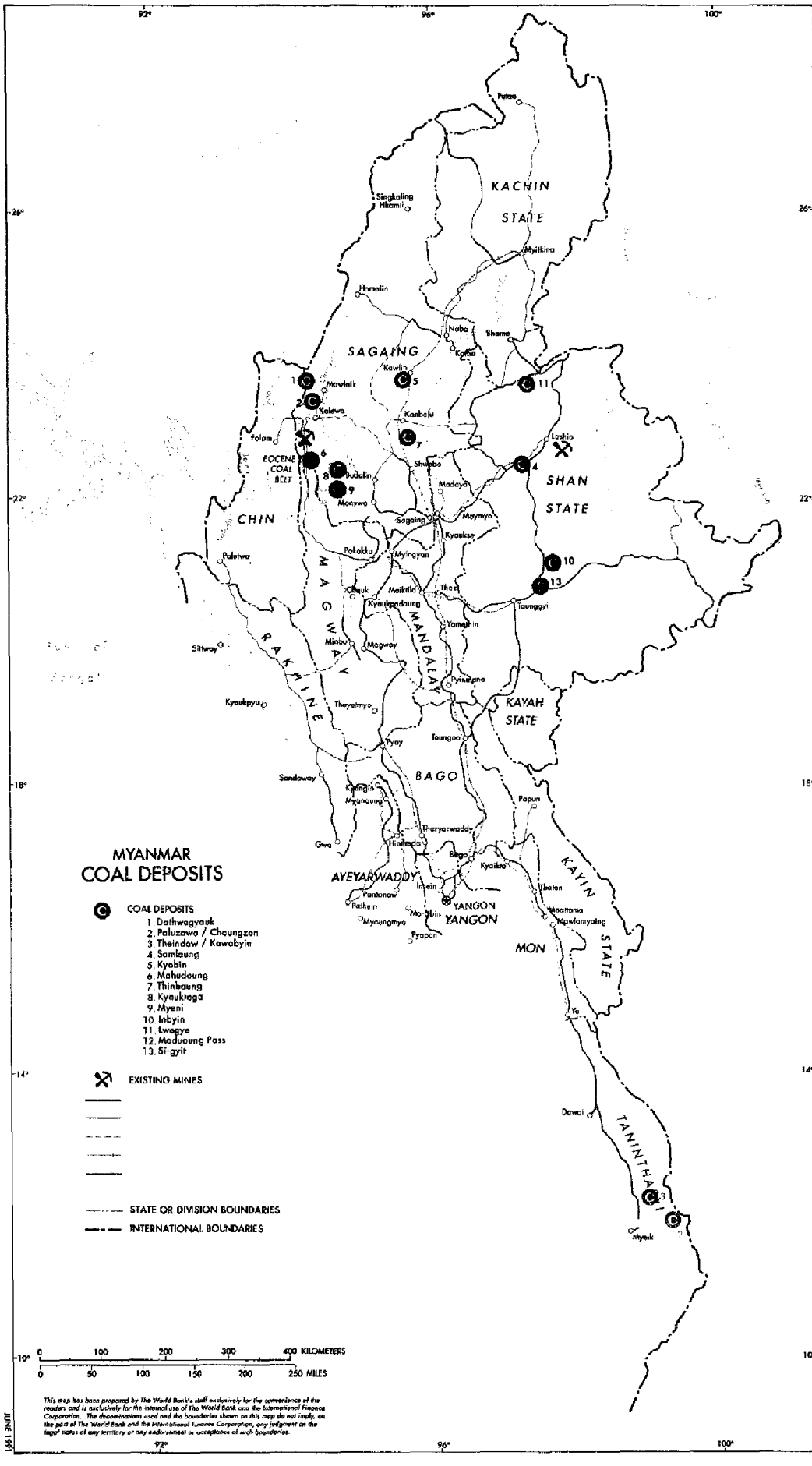
MYANMAR
COAL DEPOSITS
COAL DEPOSITS
1. Dathwegyauk
2. Paluzawa / Chaungzon
3. Theindaw / Kawabyin
4. Samlaung
5. Kyabin
6. Mahudoung
7. Thinbaung
8. Kyauktaga
9. Myeni
10. Inbyin
11. Lwegye
12. Maduaung Pass
13. Si-gyit
EXISTING MINES
STATE OR DIVISION BOUNDARIES
INTERNATIONAL BOUNDARIES
KACHIN STATE
SAGAING
SHAN STATE
CHIN
MAGWAY
MANDALAY
RAKHINE
KAYAH STATE
BAGO
AYEYARWADDY
YANGON
MON
KAYIN STATE
TANINTHARI
EOCENE COAL BELT
Putao
Singkaling Hkamti
Myitkina
Homalin
Naba
Bhamo
Kawlin
Mawlaik
Kalewa
Kanbalu
Folam
Lashio
Budalin
Shwebo
Madaya
Monywa
Sagaing
Maymyo
Kyaukse
Pakokku
Myingyan
Paletwa
Chauk
Meiktila
Thazi
Kyaukpadaung
Taunggyi
Yamethin
Minbu
Magway
Sittway
Pyinmana
Kyaukpyu
Thayetmyo
Toungoo
Pyay
Sandoway
Kyangin
Myanaung
Papun
Tharyarwaddy
Gwa
Hinthada
Bago
Kyaikto
Insein
Thaton
Pantanaw
Pathein
Mo-Ubin
Moattama
Mawlamyaing
Myaungmya
Pyapon
Ye
Dawei
Myeik
92°
96°
100°
26°
22°
18°
14°
10°
0 100 200 300 400 KILOMETERS
0 50 100 150 200 250 MILES
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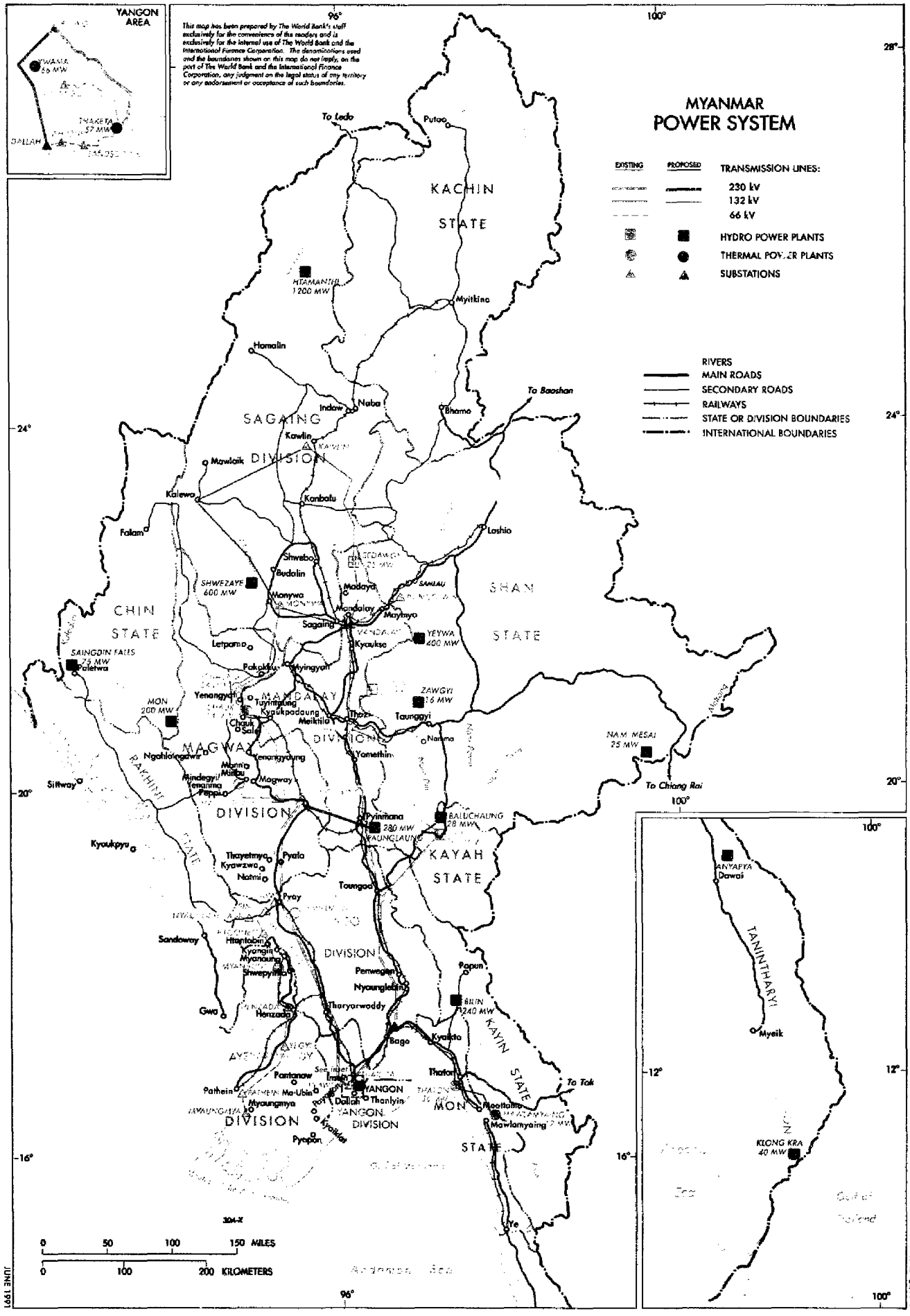
IBRD 23051



MYANMAR
POWER SYSTEM
EXISTING
PROPOSED
TRANSMISSION LINES:
230 kV
132 kV
66 kV
HYDRO POWER PLANTS
THERMAL POWER PLANTS
SUBSTATIONS
RIVERS
MAIN ROADS
SECONDARY ROADS
RAILWAYS
STATE OR DIVISION BOUNDARIES
INTERNATIONAL BOUNDARIES
YANGON AREA
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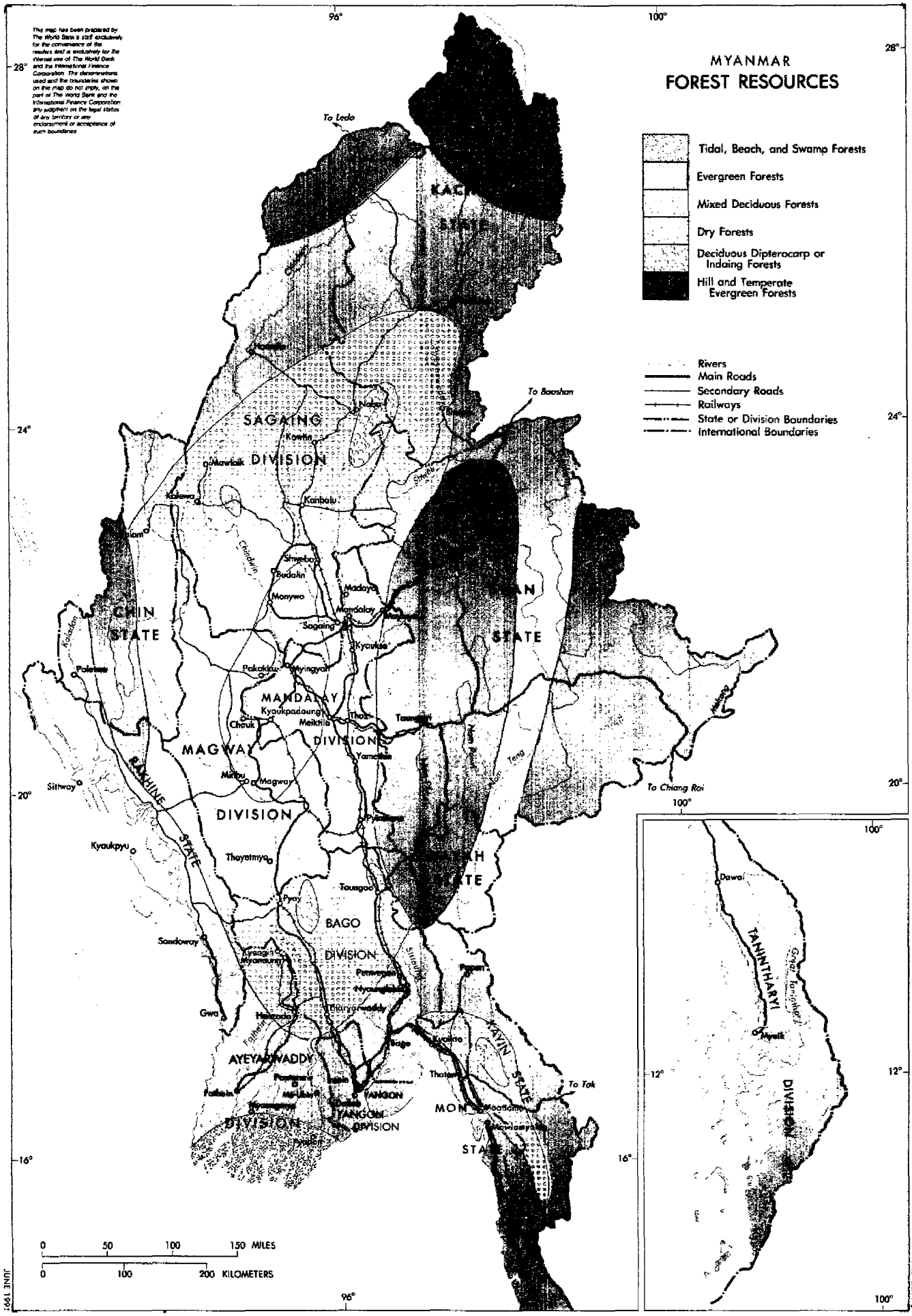
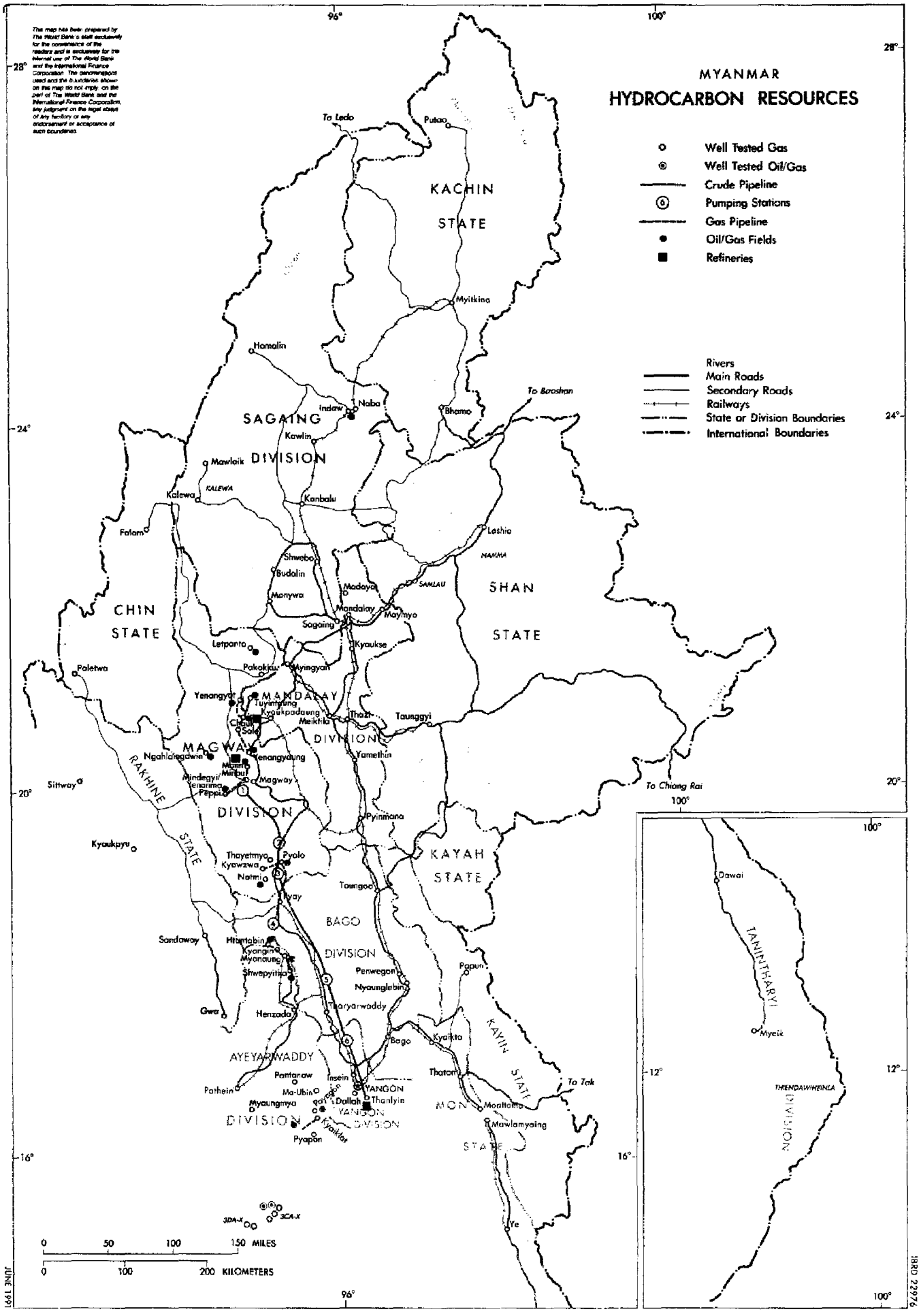
KACHIN STATE
SAGAING DIVISION
CHIN STATE
SHAN STATE
MANDALAY DIVISION
MAGWAY DIVISION
KAYAH STATE
KAYIN STATE
MON STATE
YANGON DIVISION
To Ledo
To Baoshan
To Chiang Rai
To Tak
HTAMANTHI 1200 MW
SHWEZAYE 600 MW
SAINGDIN FALLS 75 MW
MON 200 MW
YEYWA 400 MW
ZAWGYI 16 MW
NAM MESAI 25 MW
BALUCHAUNG 28 MW
280 MW
BILIN 240 MW
ANYAPYA
Dawai
TANINTHARYI
Myeik
KLONG KRA 40 MW
0 50 100 150 MILES
0 100 200 KILOMETERS
JUNE 1991
IBRD 22974



MYANMAR
FOREST RESOURCES
Tidal, Beach, and Swamp Forests
Evergreen Forests
Mixed Deciduous Forests
Dry Forests
Deciduous Dipterocarp or Indaing Forests
Hill and Temperate Evergreen Forests
Rivers
Main Roads
Secondary Roads
Railways
State or Division Boundaries
International Boundaries
SAGAING DIVISION
CHIN STATE
MANDALAY DIVISION
MAGWAY DIVISION
BAGO DIVISION
AYEYARWADDY DIVISION
YANGON DIVISION
MON STATE
KAYIN STATE
RAKHINE STATE
To Ledo
To Baoshan
To Chiang Rai
To Tak
Kawlin
Mawlaik
Kalewa
Kanbalu
Shwebo
Budalin
Monywa
Madaya
Mandalay
Sagaing
Kyaukse
Pakokku
Myingyan
Kyaukpadaung
Meiktila
Chauk
Thazi
Yamethin
Minbu
Magway
Sittway
Kyaukpyu
Thayetmyo
Toungoo
Pyay
Sandoway
Gwa
Henzada
Pathein
Bago
Kyaikto
Thaton
Moulmein
Mawlamyaing
Papun
Dawei
Myeik
TANINTHARYI DIVISION
Great Tanintharyi
0 50 100 150 MILES
0 100 200 KILOMETERS
96°
100°
28°
24°
20°
16°
12°
JUNE 1991
IBRD 22978



MYANMAR
HYDROCARBON RESOURCES
Well Tested Gas
Well Tested Oil/Gas
Crude Pipeline
Pumping Stations
Gas Pipeline
Oil/Gas Fields
Refineries
Rivers
Main Roads
Secondary Roads
Railways
State or Division Boundaries
International Boundaries
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KACHIN STATE
SAGAING DIVISION
CHIN STATE
SHAN STATE
MANDALAY DIVISION
MAGWAY DIVISION
RAKHINE STATE
KAYAH STATE
BAGO DIVISION
AYEYARWADDY DIVISION
YANGON DIVISION
KAYIN STATE
MON STATE
To Ledo
To Baoshan
To Chiang Rai
To Tak
Putao
Myitkina
Homalin
Naba
Indaw
Bhamo
Kawlin
Mawlaik
KALEWA
Kalewa
Kanbalu
Falam
Lashio
NAMMA
SAMLAU
Shwebo
Budalin
Monywa
Madaya
Mandalay
Maymyo
Sagaing
Kyaukse
Letpanto
Pakokku
Myingyan
Paletwa
Yenangyat
Tuyintaung
Kyaukpadaung
Meiktila
Thazi
Taunggyi
Chauk
Sale
Yamethin
Ngahlaingdwin
Yenangyaung
Minbu
Mindegyi/Yenanma
Magway
Peppi
Sittway
Pyinmana
Kyaukpyu
Thayetmyo
Pyalo
Kyawzwa
Natmi
Taungoo
Ryay
Sandaway
Htantabin
Kyangin
Myanaung
Shwepyitha
Penwegon
Nyaunglebin
Papun
Gwa
Henzada
Tharyarwaddy
Bago
Kyaikto
Thatom
Pantanaw
Insein
Pathein
Ma-Ubin
YANGON
Thanlyin
Dallah
Myaungmya
Payagon
Kyaiklat
Pyapon
Moattama
Mawlamyaing
Ye
3DA-X
3CA-X
0 50 100 150 MILES
0 100 200 KILOMETERS
Dawai
TANINTHARYI
Myeik
THENDAWHEINLA
DIVISION
96°
100°
28°
24°
20°
16°
12°
JUNE 1991
IBRD 22976